Market Assessment Report for 1st Quarter of 2026

26 December 2025 to 25 March 2026

JUNE 2026

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Philippine Electricity Market Corporation –
Market Assessment Department and approved
by the Market Surveillance Committee

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EXECUTIVE SUMMARY

As of the end of Q1-2026, the total registered capacity in the Wholesale Electricity Spot Market (WESM) reached 31,414.6 MW, reflecting an increase of 1,320.8 MW or 4.39% from the 30,093.8 MW in the previous quarter. On a year-on-year basis, this represents a growth of 1,553.6 MW or 5.20% compared to the 29,861 MW registered in the same period last year.

Despite this growth, the average capacity offered or nominated in the market declined to 19,415.20 MW, equivalent to 61.80% of total registered capacity. This reflects a 1.90% decline from the Q4-2025 average of 19,790.62 MW and 2.91% or 582.80 MW decrease compared with Q1-2025. The reduction in offered capacity during the period was mainly attributed to a higher incidence of plant outages which constrained the volume of capacity available to the market.

The capacity not offered/nominated saw a decrease of 5.94%, averaging 5,128.14 MW in Q1-2026, accounting for 16.32% of the total registered capacity during the period.

Meanwhile, capacity of plants under Commissioning Test increased significantly to 875.63 MW, up 68.48% from the preceding quarter, representing 2.79% share of total registered capacity. This indicates continued entry of new generating units into the market pipeline.

The average capacity on outage rose to 4,777.99 MW, accounting for 15.21% of the total registered capacity during Q1-2026. This reflects a 13.64% increase from the preceding quarter and a 16.03% increase year-on-year. The rise in average capacity on outage was primarily driven by increased outage of coal plants, which increased to 2,278.21 MW or 16.24% higher than in the preceding quarter, following the outage of the two (2) units of GNPower Dinginin (GNPD) plant, currently among the largest registered units in the market. Further during this period, there have been an increase in outages in natural gas plants by 212.54 MW or 22.85% due to unavailability of three (3) units of Batangas Combined Cycle Power Plant (EERI).

System demand averaged 13,049.33 MW during the Q1-2026, declining by 4.88% from Q4 2025 and by a marginal 0.68% compared with Q1-2025. The lower demand during the quarter was generally observed in the early part of the review period, consistent with the higher number of holidays and the cooler weather conditions during the rainy and cool-dry seasons.

The average load weighted average price (LWAP) was recorded at PHP 3,772.92/MWh, reflecting a 12.16% decrease from the preceding quarter. However, on a year-on-year basis, this represents a 4.26% increase relative to Q1-2025.

Spot market participation among load participants slightly increased during Q1-2026, with spot transactions averaging 13.75% of total energy requirements compared with 13.60% in Q4-2025. This indicates that majority of energy requirements continued to be supplied through bilateral contracts.

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QUARTERLY MARKET ASSESSMENT REPORT

This quarterly report presents an assessment of the results of the Wholesale Electricity Spot Market (WESM) operations for the First Billing Quarter of 2026 (Q1-2026), covering the period 26 December 2025 to 25 March 2026, and how the market performed compared with the preceding quarter.

I. SUPPLY

A. Registered Capacity

As of the end of Q1-2026, the total registered capacity in the WESM reached 31,414.6 MW, reflecting an increase of 1,320.8 MW (4.39%) from the 30,093.8 MW recorded as of 25 December 2025. On a year-on-year basis, the capacity grew by 1,553.6 MW or 5.20% compared with the 29,861 MW registered in the same period last year.

The increase in capacity was primarily driven by the registration of new generating plants, which contributed an aggregated 1,511.4 MW (see Table 1). This was partially offset by a net reduction of 190.6 MW resulting from changes in registered capacities among 37 existing plants. Further details are provided in Annex A – Plants with Change in Capacity.

Table 1. New Generation Facilities for Q1-2026

Plant Type	Registered Capacity (MW)	Facility Name
Luzon		
Solar	491.1	Bugallon Solar Power Plant
Solar	61.2	Pasuquin-Burgos Solar Power Plant Phase 1
Solar	850	Terra Solar Project Phase 1A and 1B
Visayas		
Battery	20	Tabango Battery Energy System
Solar	30	Silay 2A Solar Power Project
Solar	20.1	Silay 2B Solar Power Project
Mindanao		
Solar	18.7	Misamis Solar Power Project
Hydro	18.2	Pulanai River Hydroelectric Power Project
Hydro	2.1	Apo Agua Infrastructura, Inc. Hydroelectric Power Plant

Overall, the trend indicates continued but moderate growth in market participation. While capacity additions remained steady during the period, operational adjustments among existing facilities continue to exert an offsetting impact.

Figure 1 illustrates that coal and natural gas plants continued to dominate the WESM capacity mix, collectively accounting for 52.89% of total registered capacity as of the end of Q1 2026. However, this represents a decline of 2.89% compared to the previous quarter. On a year-on-year basis, the combined share decreased modestly by 4.29%, suggesting a gradual diversification of the capacity mix as renewable and alternative energy sources incrementally expand their capacity.

Natural gas capacity remained stable at 4,555 MW, indicating no material quarter-on-quarter variation. In contrast, coal capacity declined to 12,062 MW, reflecting a 2.06% reduction from the preceding quarter. The decrease was primarily attributable to adjustments in the declared maximum capacities of the Kauswagan Coal-Fired Power Plant Units 1 to 4 in Mindanao, as well as the Quezon Power Plant in Luzon, which collectively impacted the reported coal capacity within the system.

Meanwhile, solar capacity posted significant growth during Q1-2026. Total registered capacity of solar plants increased to 4,969 MW, up by 1,472.7 MW or 42.13% from the previous quarter, and by 2,114.7 MW, or 74.10%, on a year-on-year basis. This growth was driven in part by the registration and commencement of testing and commissioning of five (5) solar facilities, all of which became active during the March billing period, as detailed in Table 1. This upward trend in solar capacity underscores the sector's continued alignment with the Department of Energy's (DOE) policy objectives on renewable energy integration and reflects a sustained commitment among market participants to diversify the generation portfolio toward cleaner energy sources.

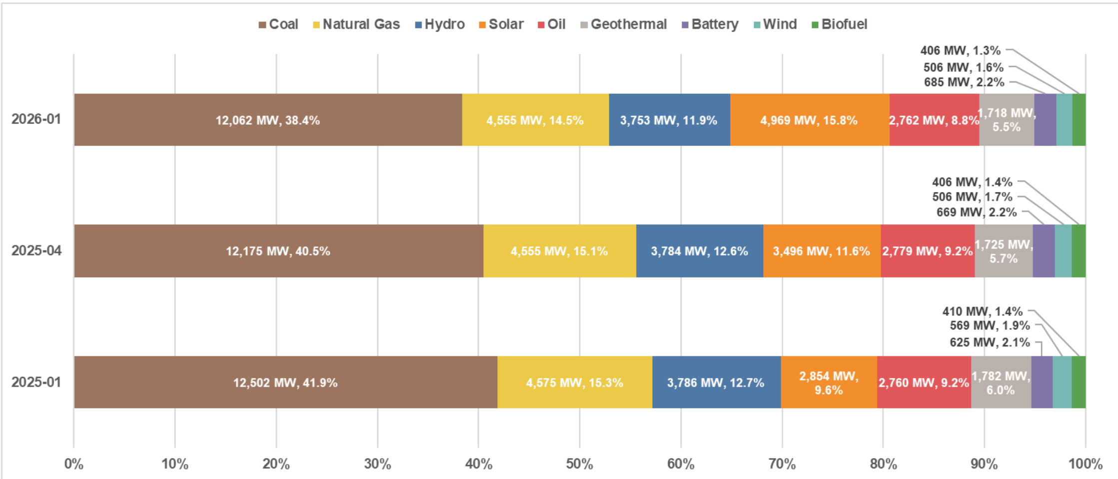


Figure 1. Registered Capacity by Plant type, as of the end of each billing quarter, Q1-2025, Q4-2025, and Q1-2026

Table 2 presents the distribution of registered capacity by classification. As illustrated, the share of must-dispatch capacity increased during the quarter, which rose to 90.18% during the current quarter compared to the previous reporting period. As discussed in the preceding sections, this increase was primarily driven by the entry of additional renewable energy (RE) facilities into the system. Given that such facilities are classified as must-dispatch due to their priority grid integration status, the continued expansion of renewable capacity has materially shifted the overall composition of registered capacity toward this classification.

Table 2. Summary per Plant Classification, Q4-2025 vs Q1-2026

Classification	Quarter		Month on Month % Change
	Q4 2025	Q1 2026	
BESS	668.70	684.50	2.36%
Must dispatch	4,461.70	5,953.60	33.44%
Non-scheduled	81.00	81.00	0.00%
Priority Dispatch	1,272.80	1,272.80	0.00%
Scheduled	23,609.60	23,422.70	-0.79%
Total	**30,093.80**	**31,414.60**	**4.39%**

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, during the covered period, the recorded Market Intervention (MI) events were all initiated by the Market Operator (MO) *(See Table 13)*. The affected trading intervals from these MI events (involving all regions) were excluded in the analysis. A detailed discussion of these MI events is provided in Administered Price (AP) section.

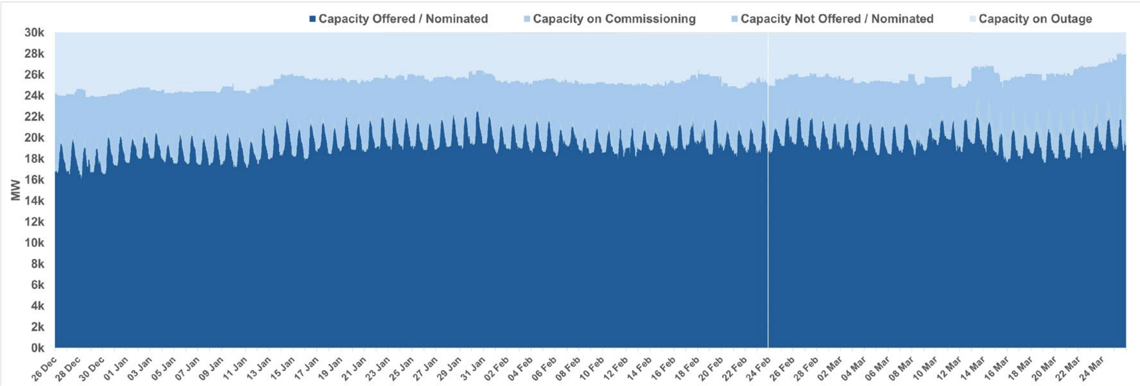


Figure 2. System: Capacity Profile, Q1-2026

Note: Missing portions represent the occurrence of Market Intervention

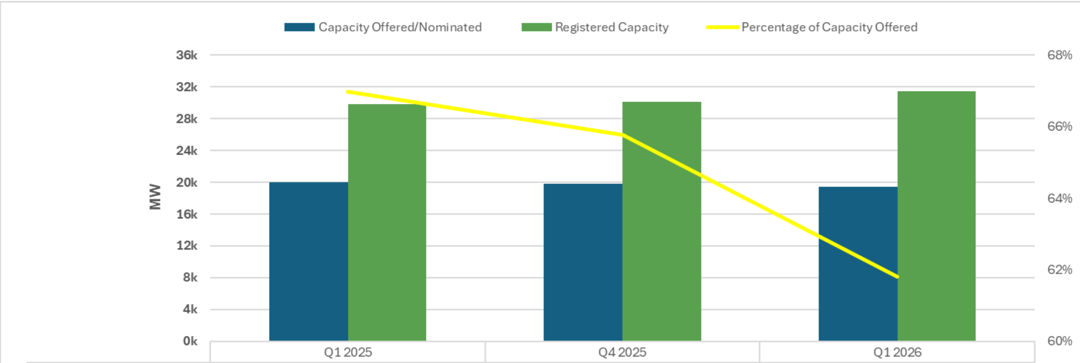
i. Capacity Offered/Nominated

Total registered capacity in WESM remained relatively stable during the quarter. However, the portion of capacity offered/nominated declined by 375.42 MW, representing a 1.90% decrease from the preceding quarter. This downward trend is likewise evident on a year-on-year basis, with reduction of 582.80 MW or 2.91% relative to Q1-2025 *(see Figure 3)*.

The decline in offered capacity was primarily attributable to the increase in capacity on outage, which reduced the level of capacity available to the market. Further discussion of capacities not offered appears in the following sections of this report

In addition, this sustained decline may indicate evolving operational conditions among generation facilities, particularly hydroelectric plants, due to the onset of hot-dry season. Such conditions typically constrain available water resources, thereby limiting operational output.

On a regional basis, all regions recorded lower capacity offered/nominated relative to the preceding quarter. Among these, the Visayas grid exhibited the most pronounced decline, registering a 4.35% reduction on a quarter-on-quarter basis.



	Q1 2025	Q4 2025	Q1 2026
Capacity Offered/Nominated	19,998.00	19,790.62	19,415.20
Registered Capacity	29,861.00	30,093.80	31,414.60
Percentage of Capacity Offered	66.97%	65.76%	61.80%

Figure 3. System: Offered/Nominated Capacity, Q1-2025, Q4-2025, and Q1-2026

On a plant-type basis, coal-fired power plants, which hold the largest share of registered capacity, likewise accounted for the largest share of capacity offered/nominated at 47.67% during the quarter. Notably, the average capacity offered for coal increased by 45.95 MW relative to the preceding quarter.

Natural gas-fired power plants ranked second, contributing an average share of 17.15% of total offered capacity, a level broadly consistent with their share in registered capacity. However, average offered capacity from natural gas plants declined by 99.26 MW quarter-on-quarter, reflecting reduction in dispatch or operational availability.

In contrast, RE facilities, including geothermal, hydro, solar, wind, and biomass, collectively accounted for 21.01% of average offered/nominated capacity during the quarter, reflecting a 1.37% decrease from the preceding period. The overall decline in RE nominations was primarily driven by lower hydro output, which posted a substantial drop of 503.97 MW, equivalent to a 20.43% decrease quarter-on-quarter.

Average hydro capacity offered declined by 503.97 MW or 20.43% quarter-on-quarter. On a year-on-year basis, hydro capacity offered likewise declined by 636.08 MW, or approximately 24%, relative to Q1 2025. The sustained reduction was mainly attributable to prevailing hot-dry conditions, which constrained water availability, alongside increased outage levels among hydro units during the period, as discussed further in the succeeding section of this report.

Conversely, and consistent with trends observed in registered capacity, solar generation continued to expand its market participation. Average capacity nominated from solar plants increased by 99.62 MW or 19.53% compared to the previous quarter, reflecting improved availability and continued expansion of installed solar capacity.

The increasing participation of solar and wind facilities is further reinforced by their classification as must-dispatch resources within the WESM framework, thereby affording them priority in dispatch and shielding them from direct competition under conventional market clearing mechanisms. Meanwhile, other RE technologies, such as geothermal, hydro, and biomass, may be classified as scheduled, non-scheduled, must-dispatch, or priority dispatch units depending on their respective registration and operational characteristics within the market.

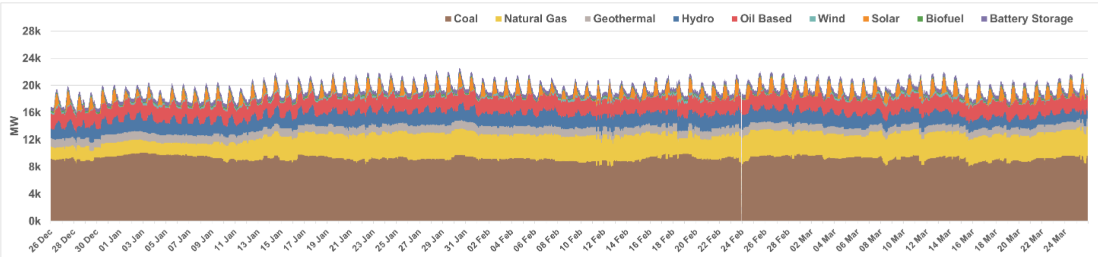


Figure 4. System: Offered/Nominated Capacity by Plant Type, Q1-2026

For the covered period, average effective supply[1] stood at 17,175.79 MW, reflecting a 3.33% decline from the preceding quarter. The reduction was primarily driven by higher plant outage levels, alongside lower output from both hydro and natural gas facilities. Hydro generation decreased by 286.76 MW, or 12.83%, while natural gas declined by 196.21 MW, or 7.47%. These reductions are largely attributable to operational constraints affecting hydro plants during the prevailing hot-dry season, as well as an increased incidence of outages among natural gas-fired generation units.

Notwithstanding the quarter-on-quarter decline, effective supply remained higher on a year-on-year basis, increasing by 446.79 MW, or 2.67%, relative to Q1 2025. This indicates that, despite the impact of outages during the period, overall system capacity and resource availability have continued to improve over time.

It is further noted that effective supply is influenced not only by outages but also by operational and technical limitations, including ramp-rate constraints. Dispatch schedules within the WESM are determined through market optimization, based on generators' submitted offers and declared technical parameters. Accordingly, while

[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

certain generating units may have available installed capacity, their ability to respond to fluctuations in system demand may be limited by their ramping capabilities.

Slower-ramping units, such as coal-fired power plants, may not be able to adjust output instantaneously in response to abrupt changes in demand levels. Consequently, during periods characterized by rapid load variations, such as weekends or holidays, the effective supply available within a dispatch interval may be limited to units capable of faster ramping.

These conditions underscore that effective supply depends not only on total available capacity, but also on operational flexibility of the generation fleet in responding to dynamic system demand requirements.

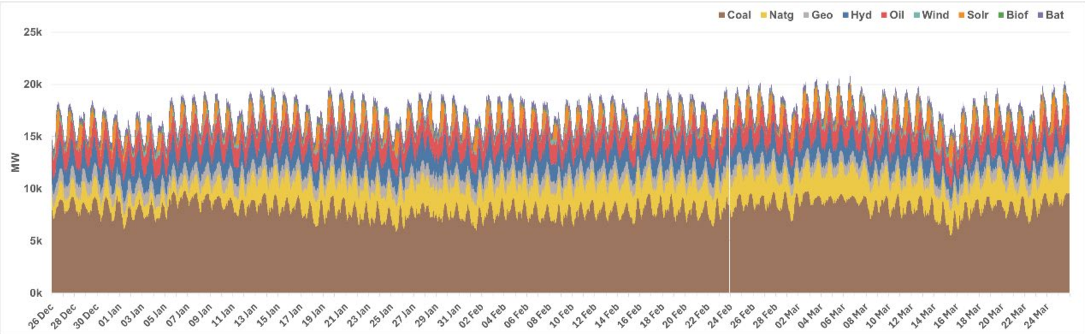


Figure 5. System: Effective Supply by Plant Type, Q1-2026

In terms of plant types scheduled for dispatch within the WESM, coal-fired power plants accounted for the largest share of the Real-Time Dispatch (RTD) schedule during Q1-2026, averaging 7,529.23 MW or 57.75% of total RTD. This is consistent with their dominant contribution to registered capacity. However, on a quarter-on-quarter basis, this share declined slightly by 0.41%, reflecting variations in system demand and outage levels during the period.

Natural gas-fired power plants followed, accounted for 15.18% of the RTD schedule, representing an 8.80% decline from the preceding quarter. The reduction was primarily attributable to increased outage levels, which constrained the availability of natural gas units for dispatch.

RE plants collectively accounted for 26.75% of the total RTD schedule, reflecting dispatch commitments based on forecasted availability. This represents a marginal increase of 0.57% relative to the previous quarter. Despite the continued expansion in registered solar capacity, the increase in solar RTD share was limited to 192.47 MW, or 36.36%, primarily because several large solar facilities remained under testing and commissioning during the March billing period.

In contrast, hydro generation experienced a significant decline in RTD participation, decreasing by 256.04 MW or 17.40% quarter-on-quarter. This reduction was mainly attributable to prevailing weather conditions during the hot-dry season, which reduced reservoir levels and water inflows, alongside increased outage levels among hydro units during the period.

As illustrated in Figure 6, observed dips in RTD schedules during Q1 2026 corresponded with periods of lower system demand, particularly during weekends and holidays that fell on weekdays. These reductions are consistent with historical load patterns, wherein declines in commercial and industrial consumption are only partially offset by residential consumption. The occurrence of holidays within regular working days further contributed to more pronounced reductions in RTD levels relative to typical weekday demand.

During the transition from the cool dry and hot dry seasons, RTD schedules exhibited increased variability driven by both changes in generation availability and temperature-related demand patterns. Increased solar irradiance supported higher solar generation output. However, the resulting gains were partially offset by lower hydro generation output due to lower reservoir levels and reduced inflows typical of the dry season.

Average temperature during the period was recorded at 33.28°C, which is lower compared to the previous billing period average of 35.18°C. While elevated temperatures generally sustain higher electricity demand due to increased cooling requirements, the reduction in hydro output contributed to fluctuations and occasional dips in RTD schedules throughout the quarter[2].

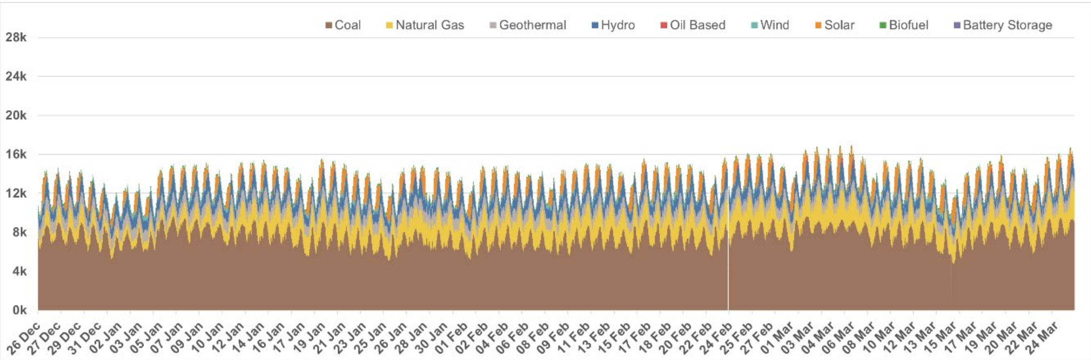


Figure 6 System: RTD Schedule by Plant Type, Q1-2026

ii. Capacity not Offered/Nominated

The capacity not offered/nominated saw a decrease of 5.94%, averaging 5,128.14 MW in Q1-2026 compared with 5,451.75 MW in Q4-2025. This represents 16.32% 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

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

[3] WESM Compliance Bulletin Issue No. 11.1

rigorous compliance monitoring procedures of PEMC's Enforcement and Compliance Office (ECO).

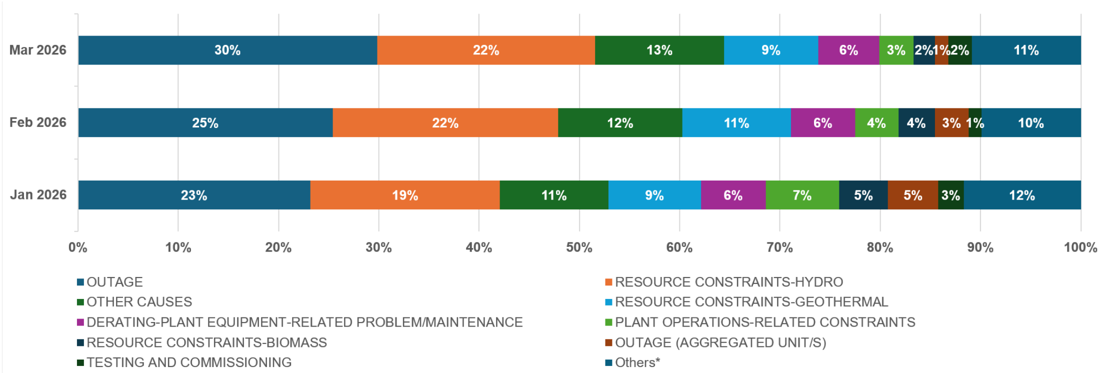


Figure 7. Reasons for Capacities not Offered/Nominated for Q1 2026[4]

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

The capacity of plants under Commissioning Test increased significantly during the period, reaching 875.63 MW, representing a 68.48% increase compared to the preceding quarter. This corresponds to approximately 2.79% of the total registered capacity for the quarter. The increase in commissioning capacity reflects the ongoing entry of new generation assets into the WESM, which is expected to contribute to future growth in available capacity upon completion of their respective testing phases.

During the period, several generation facilities commenced testing and commissioning activities *(see Table 6)*.

Table 3 Plants that Started Testing and Commissioning Q1-2026

Plant Type	Facility Name	Registered Capacity (MW)	Remarks	Commissioning Level (MW)
Battery	Tabango Battery Energy System	20	Started testing and commissioning effective 23 March 2026	-
Solar	Pasuquin-Burgos Solar Power Plant Phase 1	61.2	Started testing and commissioning effective 19 March 2026	31.05
Solar	550.016 MWp Bugallon Solar	491.1	Started testing and commissioning	50

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

Plant Type	Facility Name	Registered Capacity (MW)	Remarks	Commissioning Level (MW)
	Power Plant (SPP)		effective 13 March 2026	
Solar	850 MW Terra Solar Project Phase 1A and 1B	850	Started testing and commissioning effective 13 March 2026 with Commissioning Level of 203.77 MW	203.77
Solar	43.986 MW Silay 2A Solar Power Project	30	Started testing and commissioning effective 19 March 2026	4.61
Solar	25.025 MW Silay 2B Solar Power Project	20.1		4.61
Hydro	18.200 MW Pulanai River Hydroelectric Power Project	18.2	Started testing and commissioning effective 21 February 2026	17

During the quarter, there were plants that also started submitting nominations or started their commercial operations *(see Table 4).*

Table 4 Plants that Started Submission of Nominations/Commercial Operations Q1-2026

Plant Type	Facility Name	Registered Capacity (MW)	Remarks
Solar	20.774 MWP Misamis Solar Power Project (SPP)	18.7	Started submitting of nominations on 23 March 2026
Battery	22.928 Sangali Battery Energy Storage System (BESS)	20	
Solar	20.155 MWP / 17.500 MWAC Taft Solar Power Plant (SPP)	17.5	Started Commercial Operations on 20 March 2026
Solar	3.7 MW Agrosolis Solar Power Plant	3.7	Started submitting of nominations on 04 March 2026
Solar	23.776 MWP Bongabon Solar Power Project	19.8	Started Commercial Operations on 12 February 2026
Hydro	2.424 MW Apo Agua Infrastructura, Inc. Hydroelectric Power Plant (HEPP)	2.1	Started Commercial Operations on 11 March 2026

iv. Capacity on Outage

The average capacity on outage reached 4,777.99 MW, representing 15.21% of the total registered capacity. This reflects an increase of 573.50 MW, or 13.64%, compared with the preceding quarter.

On a year-on-year basis, outage capacity likewise increased by 659.99 MW, equivalent to 16.03% relative to Q1 2025. This sustained increase indicates a higher incidence of generation unavailability during the period, which has materially impacted overall system capacity and market participation.

1. Capacities on Outage by Plant Type

A breakdown of capacity on outage by plant type indicates that coal-fired power plants accounted for the largest share during the quarter, comprising 46.62% of total outage capacity. Notably, the average outage capacity for coal increased to 2,278.21 MW, representing a 16.24% increase compared to the preceding quarter *(see Figure 8)*.

Major contributors to coal outages included GNPower Dinginin (GNPD) Units 1 and 2 and SUAL Units 1 and 2, with capacities of approximately 668 MW and 600 MW, respectively. These units experienced both planned and forced outages during the quarter. In particular, the outages affecting the GNPD units were associated with boiler, pump, and turbine-related operational issues.

Natural gas-fired power plants accounted for the second-largest share of outage capacity at 23.38% of the total. Average outage capacity for natural gas plants increased by 212.54 MW or 22.85% quarter-on-quarter, primarily driven by outages involving Batangas Combined Cycle Power Plant (EERI) Units 1, 2, and 3.

Outage levels among natural gas plants were particularly elevated during the January billing period, when average outage capacity reached 1,801.91 MW before declining to 760.46 MW in March. The highest recorded natural gas outage occurred from 02 January at 2355h to 06 January at 1636h, during which outage capacity peaked at 2,774.30 MW.

Month-on-month analysis further shows that the January 2026 billing month recorded the highest average outage level at 5,142 MW. During this period, natural gas registered the highest outage levels among plant types. In addition, geothermal, oil-based, and battery storage plants also recorded their highest average monthly outage levels in January relative to other months within the quarter.

The peak outage event for the quarter occurred on 15 March 2026 during 1450h and 1550h trading intervals, with an average outage capacity of

6,543.09 MW. During this interval, coal outages reached their highest level for the quarter at 3,587.20 MW. This was primarily driven by concurrent outages of units GNPD Unit 1 and SUAL Unit 1, together with the extended outage of PAGBILAO Unit 2 from the previous trading day. These outages were associated mainly with turbine and boiler tube-related issues, which collectively contributing to the elevated system-wide outage levels during the period.

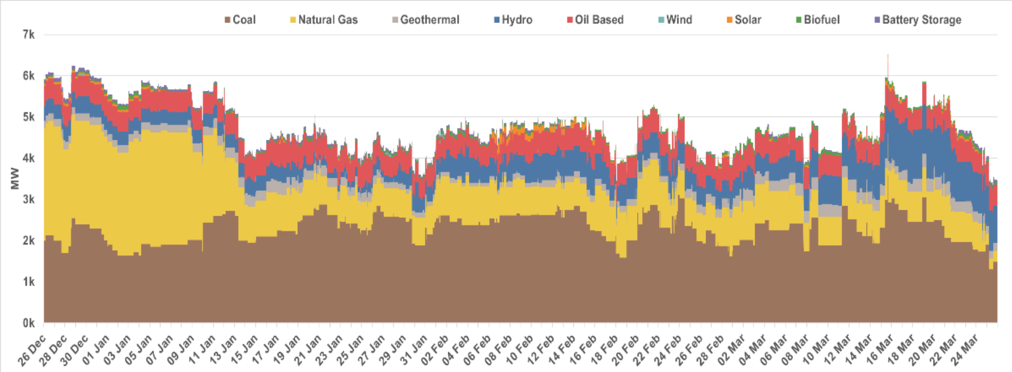


Figure 8. System: Capacity on Outage by Plant Type, Q1-2026

2. Capacities on Outage by Category

This section further examines outages by category, specifically planned, forced, maintenance, and deactivated shutdowns during the billing quarter. The observed increase in total outage capacity was primarily driven by both planned and forced outages. Planned outages averaged at 1,916.20 MW, reflecting a 10.37% increase from the preceding quarter, while forced outages averaged 2,628.92 MW, representing a 10.57% increase *(see Figure 9)*.

As discussed in the previous section, several large coal-fired units significantly contributed to the increase in planned outages during the quarter. In particular, GNPD Unit 2 underwent an extended planned outage beginning on 20 February 2026 at 0003h. Similarly, SUAL Unit 2 experienced a prolonged planned outage beyond its initial completion target of 22 January 2026. PAGBILAO Unit 3 likewise underwent a scheduled outage commencing on 16 January 2026 and concluding on 18 February 2026. Collectively, these outages contributed significantly to the elevated level of planned outage capacity for coal-fired generation during the period.

Natural gas-fired power plants also contributed to the increase in planned outages. Affected facilities included EERI Unit 3, Sta. Rita Units 1, 2, 5, and 6, and Ilijan Units 1 and 2, all of which were placed under planned outage schedules during the quarter.

On a month-on-month basis, January 2026 recorded the highest average planned outage capacity at 2,285.59 MW. This level declined in February before increasing again in March to an average of 2,080.36 MW. In contrast, forced outages remained consistently elevated throughout the quarter, with average capacity exceeding 2,400 MW across all billing months. January likewise recorded the highest average forced outage capacity at 2,706.81 MW.

These outage patterns are consistent with the previously discussed impacts of generation unavailability on market outcomes. In particular, increases in outage capacity, whether planned or forced, reduce the available supply in the system and may consequently exert upward pressure on market prices as supply conditions tightens.

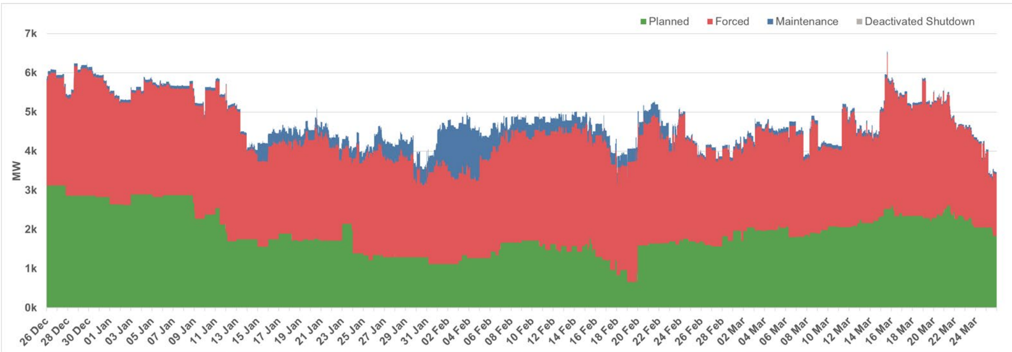


Figure 9. Capacity on Outage by Category, Q1-2026

C. Generation Mix

Coal-fired power plants, which hold the largest share of registered capacity, consistently generated the highest portion of electricity across the October 2025 to March 2026 billing periods. Coal's share of total generation increased from 55.44% in Q4 2025 to 56.85% in Q1 2026, thereby maintaining its position as the dominant source of generation, reinforcing its position as the primary energy supplier of electricity generation *(see Figure 10)*.

Notwithstanding the increase in average outage capacity for coal-fired plants discussed in the preceding section, overall coal generation continued to rise during the period. This indicates that available coal-fired units remained heavily utilized to meet prevailing system demand requirements.

In contrast, natural gas-fired generation declined from 17.04% in Q4 2025 to 15.47% in Q1 2026. The reduction was largely attributable to higher outage levels among natural gas plants, which constrained their availability for dispatch.

Meanwhile, RE resources collectively accounted for 27.09% of the total generation mix in Q1 2026, representing a slight decrease from 27.68% in the preceding quarter. The decline was primarily driven by reduced hydro generation resulting from increased outage capacity and prevailing dry season conditions, which adversely affected water availability for hydro facilities.

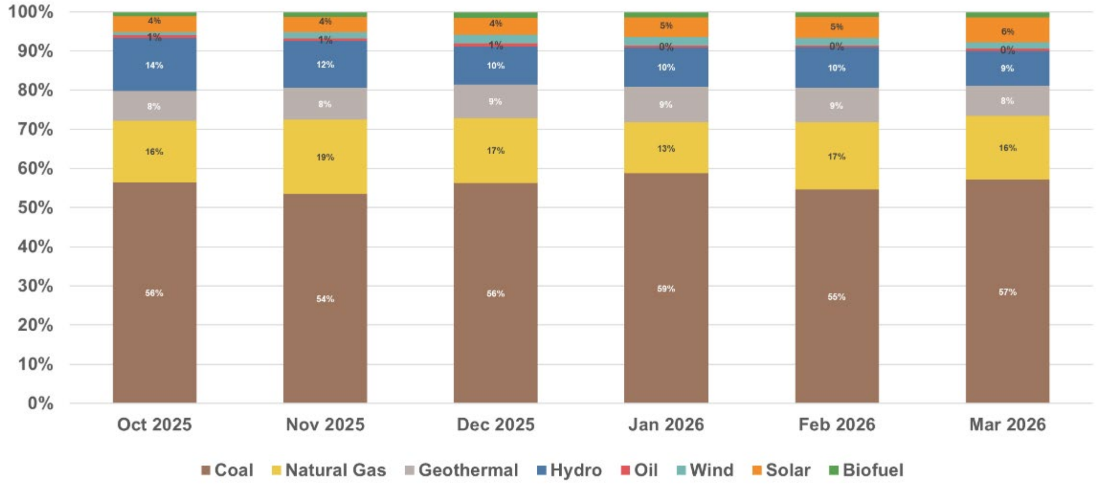


Figure 10. Generation Mix (Based on Metered Quantity) – Oct 2025 to Mar 2026

Hourly generation by plant type reflected a consistent daily demand cycle throughout the covered period, with peak generation typically occurring during daytime hours and lower output levels observed during nighttime periods. Coal-fired power plants remained the dominant source of generation, serving as the primary baseload resource and accounting for the largest share of total generation. Natural gas plants provided mid-merit support by adjusting output in response to demand fluctuations, while RE sources introduced variability and seasonal flexibility into the generation mix *(see Figure 11).*

Consistent with the earlier discussion on RTD schedules, observed declines in hourly generation corresponded with periods of lower system demand, particularly during weekends and non-working holidays that fell on weekdays. During these intervals, lower electricity consumption resulted in lower metered quantities or energy output across all plant types.

In addition, relatively cooler weather conditions during the early part of the review period, contributed to lower overall system demand and, consequently, reduced levels of dispatch and generation levels.

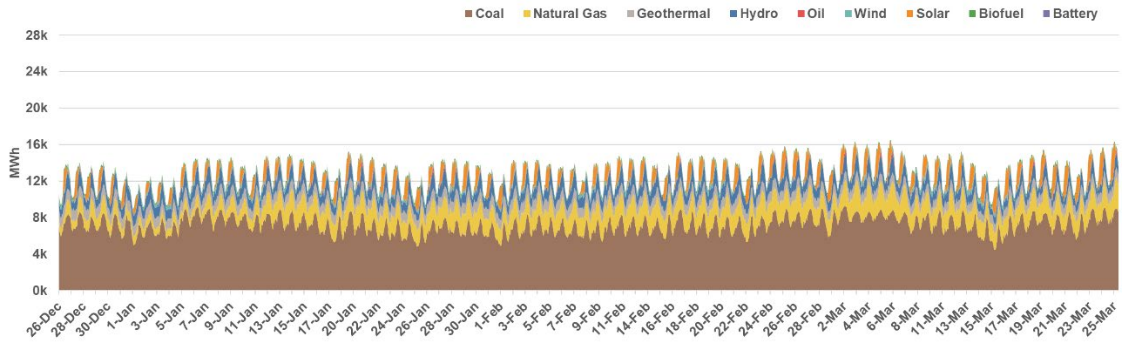


Figure 11. Hourly Generation Metered Quantity – Q1-2026

II. DEMAND

Overall system demand decreased by an average of 4.88% during Q1 2026, reaching 13,049.33 MW compared with 13,719.47 MW in Q4 2025. On a year-on-year basis, however, demand exhibited only a marginal decrease of 0.68% relative to Q1 2025, when average demand was recorded at 13,139 MW.

The decline in demand was primarily observed during the early part of the review period, consistent with seasonal expectations. This trend may be attributed to the higher incidence of holidays during the quarter, together with relatively cooler weather conditions associated with the cool-dry season. As detailed in *Annex E*, system demand exhibited a gradual upward trajectory over the course of the quarter, with January recording the lowest levels and March posting the highest levels.

The lowest average daily demand was recorded at 10,747.18 MW on 01 January 2026, a recognized holiday and typically characterized by reduced consumption. Similar declines in demand were observed during other holiday periods within the review timeframe, including 30–31 December 2025 (Rizal Day and New Year's Eve), 01 January 2026 (New Year's Day), 17 February 2026 (Chinese New Year), and 20 March 2026 (Observance of Eid'l Fitr). These periods registered an average demand of 12,215.24 MW *(see Table 5),* reflecting the typical reduction in industrial and commercial activity during non-working days, which is not fully offset by residential consumption.

Table 5. Average Demand based on Day Type – Q1 2026

Day Type	Average Demand (in MW)
Weekday	13,421.75
Weekend	12,365.69
Holiday	12,215.24

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 the increase in capacity on outage, which accounted for 13.79% of total registered capacity, the system's effective supply remained sufficient to meet both energy and reserve requirements throughout the period.

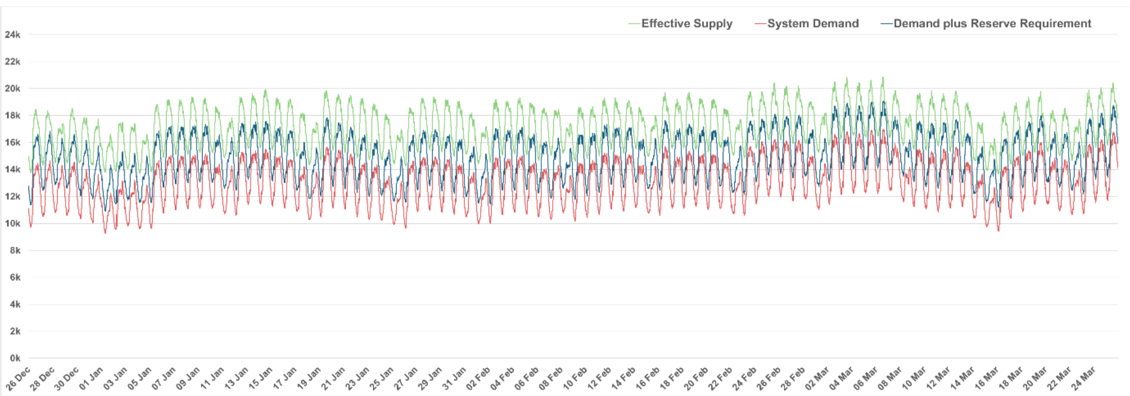


Figure 12. Demand, Supply and Demand plus Reserve Schedule, Q1-2026

To support system reliability across the three major grid regions, Luzon, Visayas, and Mindanao, regional capacity sharing was facilitated through the High Voltage Direct Current (HVDC) interconnection. This enabled bi-directional power transfers between Luzon and Visayas, as well as between Visayas and Mindanao.

During the period under review, power flows were predominantly directed from Luzon to Visayas, accounting for 60.50% of total transfers. Notwithstanding this, there were instances of HVDC outages during the quarter, which affected transfer capabilities; these events are detailed in Figure 13 and Tables 6 and 7.

Table 6. HVDC Flow, Q1 2026

HVDC Flow	Actual Capacity	Min (in MW)	Max (in MW)	Percent of Time
Luz-Vis	250	0.07	250	60.50%
Vis-Luz	420	0.05	420	35.31%
Vis-Min	450	0.05	366.66	9.95%
Min-Vis	450	0.01	450	86.01%

Table 7. List of Prolonged Outages HVDC (Luzon-Visayas), Q1 2026

Transmission Line	Outage	Date Time Out	Date Time In	Remarks
Naga CS - Ormoc CS 350 kV HVDC Line	Forced	12/28/2025 18:03	12/28/2025 18:08	NCS: DC filter line 1 overload protection, protective Y-Block ON OCS: Protective Y-block from other station
		12/28/2025 18:39	12/28/2025 22:08	
		2/7/2026 5:01	2/7/2026 17:25	Isolated due to shutdown of VisLuz HVDC as per PANR NSO-2026-01-0003 to PANR NSO-2026-01-0005
		2/8/2026 5:03	2/8/2026 17:03	
		3/17/2026 20:07	3/18/2026 13:10	Ormoc-Naga 350kV HVDC (Visayas-Luzon) auto-blocked at 2007H from reverse power direction, with protective Y-block order and line fault level detection action indications.

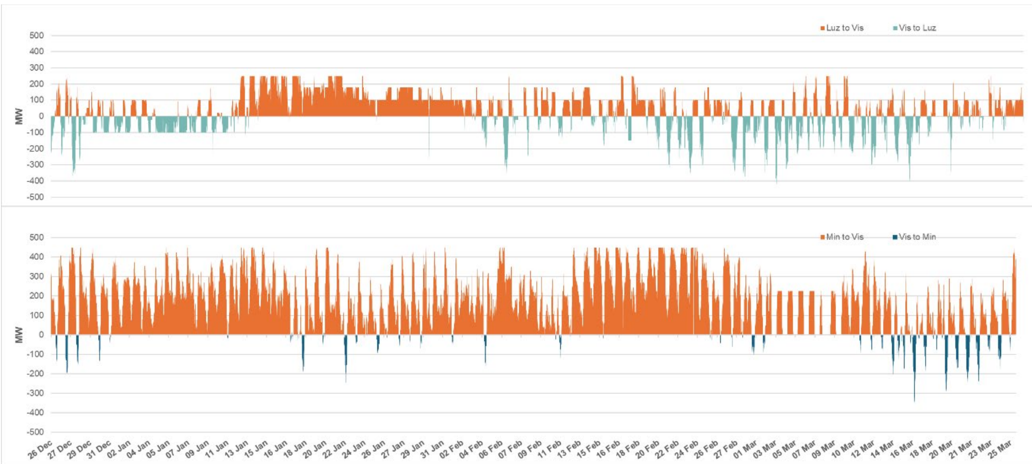


Figure 13. High Voltage Direct Current (HVDC) Flow, Q1 2026

Notwithstanding the availability of regional capacity sharing, a localized grid alert was issued by the System Operator (SO) for the Visayas Grid during the quarter, indicating potential constraints in resource availability within the region. This occurred despite ongoing support from Luzon and Mindanao through HVDC power transfers.

The issuance of such alerts underscores the presence of localized supply-demand imbalances and operational limitations that cannot be fully mitigated by interconnection alone. These events are further illustrated in Figures 14 and 15 and detailed in Table 8.

Table 8. List of Grid Alerts as issued by the SO

Date	Region	Alert	Interval	Remarks
20 January 2026	Visayas	Yellow	1800H-1945H	Total Forced Outage of 431.5 MW and Total Deration of 249.6 MW

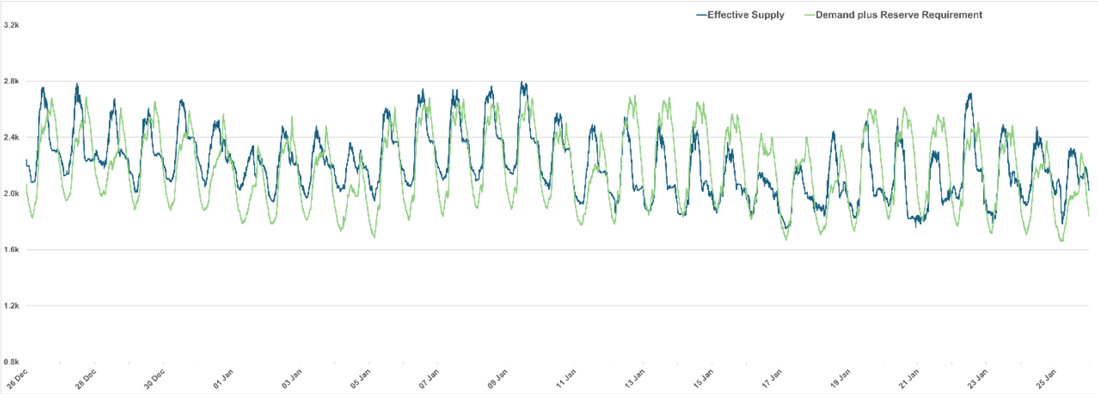


Figure 14. Supply and Demand plus Reserve Schedule – Visayas, January 2026

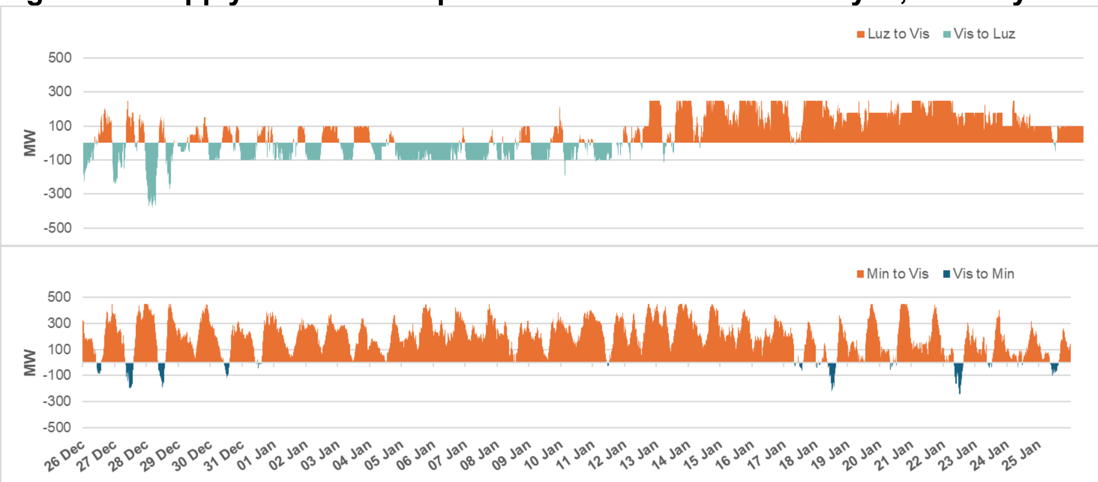


Figure 15. Capacity Sharing of Luzon and Mindanao to Visayas, January 2026

Electricity demand is partly attributable to variations in the heat index, with demand generally exhibiting a direct relationship with temperature levels. Higher temperatures tend to drive increased electricity consumption, primarily due to elevated cooling requirements. However, variations in demand are not solely temperature-driven. The type of day, such as weekends or non-working holidays, also exerts a significant influence on overall consumption patterns. During these periods, reduced commercial and industrial activity typically leads to lower electricity demand, even when temperature levels remain relatively elevated *(see Figure 16)*.

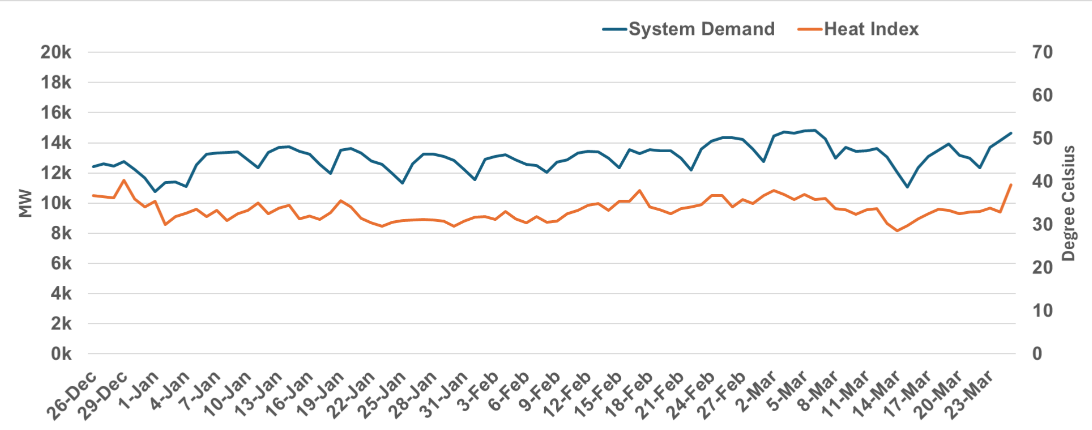


Figure 16. Daily Max Demand and Max Heat Index[5], Q1-2026

III. MARKET PRICE OUTCOME

A. Market Prices

The average Load Weighted Average Price (LWAP) for Q1 2026 was recorded at PHP 3,772.92/MWh, reflecting a 12.16% decrease compared to the preceding quarter. On a year-on-year basis, however, this represents a 4.26% increase relative to Q1 2025. Notwithstanding the quarter-on-quarter decline, average LWAP during the March 2026 billing period increased significantly to PHP 4,585/MWh, representing a 26.40% increase compared to February and a 21.84% increase relative to January. These trends indicate that, while average quarterly prices declined, interval-level market prices remained highly volatile due tightening supply conditions, regional outages, and fluctuations in demand *(see Figure 17)*.

Significant price spikes were recorded during both off-peak and peak periods throughout the quarter. The highest LWAP was observed on 28 December 2025, reaching PHP 31,521.87/MWh during a Sunday trading interval. A total of ten (10) price spikes were observed at 2130h affecting the Luzon and Visayas grids. Additional spikes occurred between 1745h and 1800h in Mindanao, while further price movements between 1900h–1920h and 2205h–2220h primarily affected the Luzon grid.

The price spikes in Luzon and Mindanao during this period were primarily driven by a combination of supply constraints, including forced outages of coal-fired plants due to mechanical issues associated with detached liner plates and coal crusher malfunctions, as well as unplanned outages requiring corrective maintenance. A concurrent reduction in hydro capacity, amounting to approximately 435 MW from San Roque Units 1 to 3, further aggravated supply limitations. In addition, the unavailability of the HVDC interconnection on 28 December 2025 constrained inter-regional power transfers, contributing to localized supply tightness and elevated prices.

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

Another significant pricing event occurred on 05 March 2026, when the highest LWAP reached PHP 31,034.24/MWh. A total of eighteen (18) price spikes were recorded throughout the day, with fourteen (14) occurring between 1800h and 2205h and affecting the Luzon–Visayas grids, and four (4) additional spikes observed at 1805h and 1810h impacting the Luzon and Visayas grids separately.

These price movements were driven by persistent outages that began in preceding days and continued throughout the period, including significant capacity losses such as the 668 MW GNPD coal unit and additional coal and geothermal units (e.g., 83.1 MW CEDC Unit 3, 97 MW Magat Unit 3, and 40.3 MW Tongonan Unit 1). At the same time, average system demand increased by 352 MW relative to the previous week, further tightening supply margins.

The majority of price spikes occurred during the evening peak period, when demand increased incrementally across dispatch intervals, averaging 37 MW in Luzon and 13 MW in the Visayas between 18:00h and 18:35h. Although demand moderated slightly in subsequent intervals, market prices remained elevated above threshold levels due to continuing supply constraints. Additional reductions in hydro output in Luzon, declining by 170 MW at 21:05h and 181 MW at 22:05h, further constrained available supply.

During these intervals, export transfer limits were likewise reached, resulting in price separation across regions. Specifically, Mindanao exports reached constrained levels, while Luzon exports simultaneously reached maximum capacity during certain intervals, leading to market price divergence among the grids.

Also, during the period of 17–18 March, instances of significant price increases were observed due to higher demand during the period, which were further aggravated by the unavailability of the HVDC interconnection.

Overall, the elevated market prices observed during March billing period are consistent with previously discussed supply-demand dynamics, particularly the tightening of supply margins arising from concurrent planned and forced outages, combined with increasing demand during the billing period. These conditions reduced effective supply during critical trading intervals and exerted upward pressure on market prices.

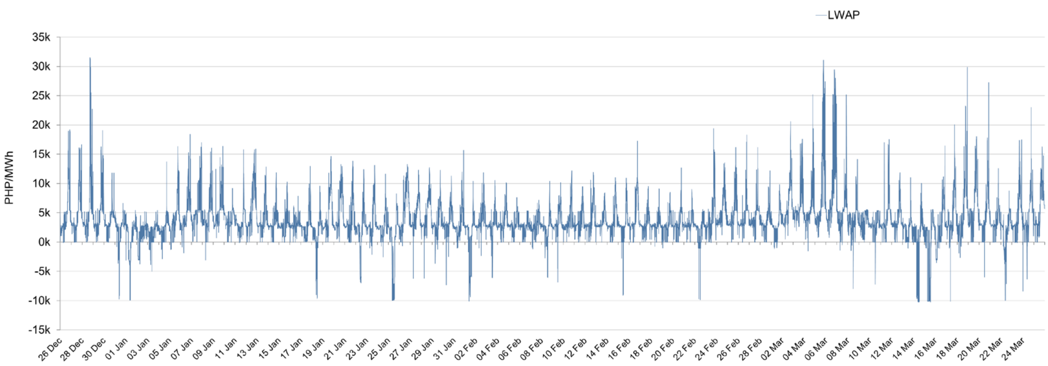

Figure 17. System: Market Price Trend, Q1-2026

On a regional basis, the average LWAP in Luzon, at PHP 3,323.24/MWh, remained lower than the corresponding averages in the Visayas and Mindanao, which recorded PHP 4,894.41/MWh and PHP 4,656.77/MWh, respectively.

However, during the March billing period, LWAP levels in Luzon increased significantly relative to the preceding months. In certain intervals, prices in selected Luzon zones exceeded those observed in portions of the Visayas and Mindanao grids. This shift is attributable to the heightened incidence of outages during the March billing period, including outages involving major generating units, which reduced available supply within the Luzon grid.

In addition, there was a notable increase in the frequency of capacity transfers from the Visayas to Luzon, occurring approximately 45% of the time, representing a 76.18% increase compared to the previous billing month. This increased reliance on inter-regional support further reflects the tightening supply conditions in Luzon during the period *(see Figures 18 to 20, and Annex F).*

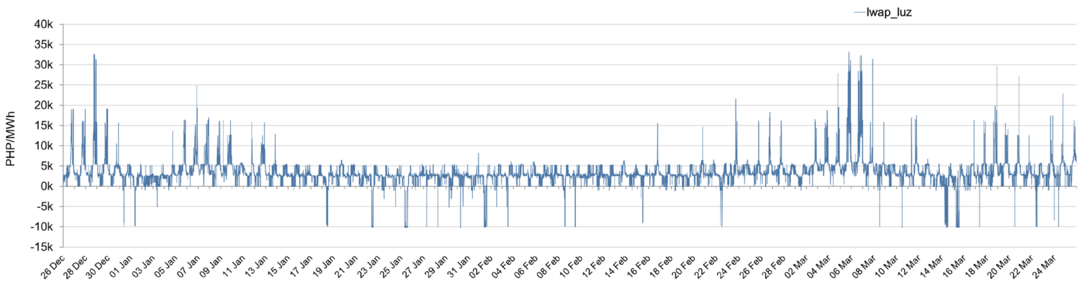

Figure 18. Luzon: Market Price Trend, Q1-2026

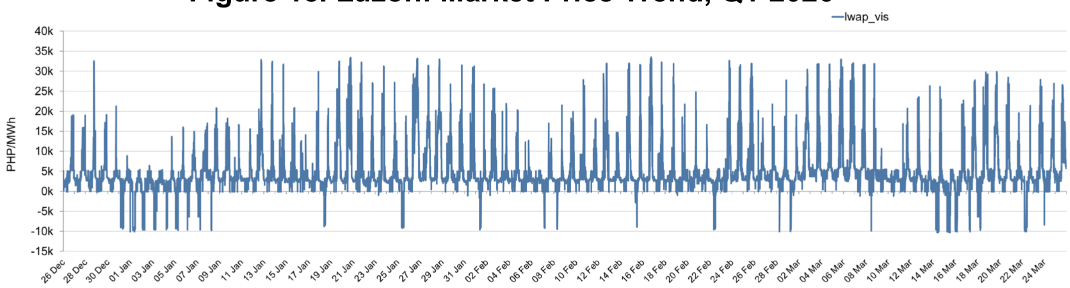

Figure 19. Visayas: Market Price Trend, Q1-2026

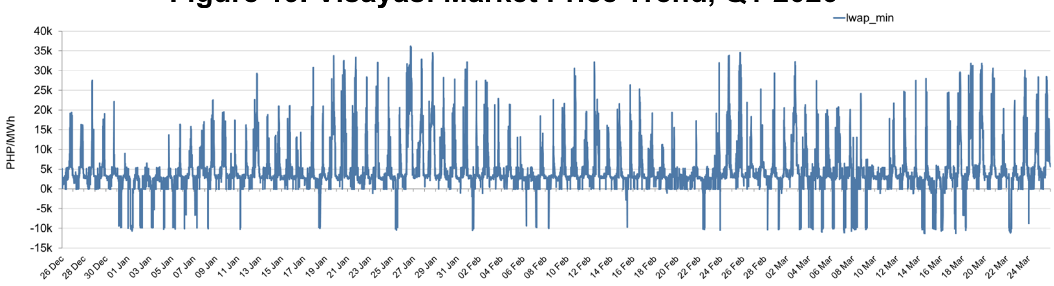

Figure 20. Mindanao: Market Price Trend, Q1-2026

Consistent with the earlier discussion on reduced load during weekends and holidays, Table 9 presents the corresponding average LWAP by day type. The data indicate that LWAP levels during weekends and holidays were generally lower compared to those observed on regular weekdays.

This pattern reflects the impact of reduced system demand during non-working days, wherein lower commercial and industrial activity results in decreased pricing pressure within the market. Accordingly, variations in LWAP across different day types further underscore the relationship between demand conditions and market price outcomes within the WESM framework.

Table 9. LWAP per Day Type, Q1-2026

Type of Day	LWAP Php/MWh
Weekday	4,159.48
Weekend	2,821.37
Holiday	2,962.60

B. Price Distribution

During Q1 2026, LWAP levels remained predominantly concentrated within the lower price bands, with 69.71% of trading intervals registering prices in the range of PHP 0/MWh to PHP 5,000/MWh. These low-priced intervals persisted notwithstanding periods of tightened supply conditions and elevated outage levels observed throughout the billing quarter.

On a year-on-year basis, the proportion of low-priced intervals declined from 81.99% to 69.71%, reflecting a modest shift toward higher price ranges during Q1 2026. However, relative to Q4 2025, the share of low-priced intervals increased from 67.75%, indicating an overall moderation in price levels compared with the preceding quarter.

Meanwhile, the share of trading intervals within the higher price ranges of PHP 5,000/MWh to PHP 32,000/MWh remained limited. While the PHP 5,000/MWh to PHP 10,000/MWh range recorded a slight increase relative to Q4 2025, most upper price bands above PHP 10,000/MWh exhibited lower shares compared with Q1 2025, indicating a reduced frequency of extreme price excursions across the quarter..

Despite the occurrence of high-price intervals, particularly during the March billing period, their overall impact was moderated by the predominance of low-price intervals in January and February. As a result, the quarterly average LWAP remained relatively subdued *(see Figure 21 and Table 10).*

Overall, lower-priced intervals continued to dominate the price distribution during the quarter. Nevertheless, the modest shift toward mid-range price levels suggests the presence of tightening supply conditions and system constraints during specific periods within the quarter.

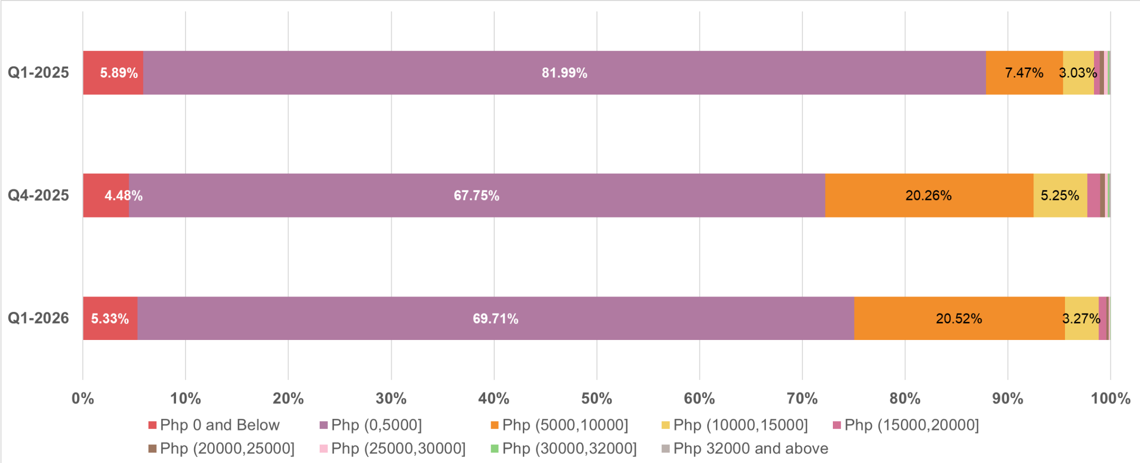

Figure 21. System: Market Price Band, Q1-2025, Q4-2025, and Q1-2026

Table 10 presents the tabular distribution of market prices across the billing months covered in Q1 2026, providing a detailed breakdown of price intervals and their corresponding frequency. This representation complements the visual trends illustrated in Figure 21 by quantifying the proportion of trading intervals within each price bracket.

Such disaggregation enables a clearer assessment of price behavior across the quarter, highlighting the concentration of trading intervals within specific price ranges and facilitating a more granular understanding of market price dynamics over the billing period.

Table 10. Details System: Market Price Band, Q1-2026

Price Range (Php/MWh)	%Distribution		
	January 2026	February 2026	March 2026
Php 0 and Below	5.69%	3.35%	7.53%
Php (0,5000]	71.18%	77.42%	59.60%
Php (5000,10000]	18.75%	17.52%	25.95%
Php (10000,15000]	4.01%	1.49%	4.21%
Php (15000,20000]	0.37%	0.22%	1.46%
Php (20000,25000]	0.00%	0.00%	0.68%
Php (25000,30000]	0.00%	0.00%	0.47%
Php (30000,32000]	0.00%	0.00%	0.10%

C. Market Pricing Conditions

During Q1-2026, the WESM was mostly under normal pricing conditions for an average of 23,772 trading intervals or at 92% of the time. However, other intervals were placed under various market pricing adjustments / corrections as follows:

i. Pricing Error Notice (PEN) [6]

[6] 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.

A total of 987 total trading intervals with system-wide PEN issuances were recorded during Q1-2026. These were associated with inappropriate input data that subsequently affected the market outcomes and required price corrections.

ii. Price Substitution Methodology (PSM) [7]

Due to recorded congestion events within the electricity transmission network, the PSM was applied on a system-wide basis across 1,048 trading intervals during the quarter, reflecting a 12.09% increase compared to Q4 2025. This increase indicates a higher frequency of instances wherein market clearing prices required adjustment to address significant price divergences arising from transmission constraints. The average LWAP during intervals in which PSM was imposed was PHP 3,029.18/MWh *(see Table 11)*.

At the regional level, PSM application varied across the different grid areas. In the Luzon grid, PSM was applied for 12 trading intervals, during which no power flows were recorded across the Luzon-Visayas interconnection. Meanwhile, PSM was simultaneously applied in both the Luzon and Visayas grids for a total of 121 trading intervals, indicating the presence of inter-regional network constraints affecting power transfers between the two grids.
In contrast, the Mindanao grid recorded only two (2) intervals with PSM application, suggesting relatively limited congestion or transmission constraint events within that region during the period under review.

These occurrences highlight the role of transmission constraints in influencing market price outcomes and underscore the importance of network reliability in maintaining efficient price convergence across interconnected grid regions.

Table 11. Top 10 List of Equipment under Congestion

Line ID	Equipment Name	Frequency of Congestion
5DAAN_4TAB2	DAANBNTAY-TABANGO 230 kV LINE 2	2362
1BALSIK_TR1	BALSIK SUBSTATION TRANSFORMER 1	760
LEYTE_TO_CEBU	LEYTE-CEBU TRANSMISSION LINE	534
5DAAN_4TAB1	DAANBNTAY-TABANGO 230 kV LINE 1	427
DASMA_CORR	DASMARINAS CORRIDOR	333
1BAUA_1LAT1	BAUANG-LATRINI 230 kV LINE 1	160
1BAUA_1LAT2	BAUANG-LATRINI 230 kV LINE 2	154
1BOTOL_TR2	BOTOLAN SUBSTATION TRANSFORMER 2	62
3STRO_3CLA1	STROSA-CLACA 230 kV LINE 1	38

iii. Administered Price (AP)

Market Intervention remained recurring factors influencing pricing dynamics during the billing quarter, affecting a total of 22 trading intervals. The specific triggers were as follows:

[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.

Table 12. MI Events

Date	Interval	Initiated / Declared by	Region Affected	Reason/s
12 January 2026	1440h 1 interval	MO	LVM[8]	Failure to generate RTD results
13 February 2026	0215h 1 interval	MO	LVM	
15 February 2026	0805h 1 interval	MO	LVM	
23 February 2026	2105h – 2230h 18 intervals	MO	LVM	
15 March 2026	0705h 1 interval	MO	LVM	

The APs during the MI events vary significantly, as they are determined under market conditions that differ from the prevailing market conditions. These APs may affect both generators and consumers, given that APs shall be determined and shall replace market prices for energy and will apply only to transactions above the declared bilateral contract quantities.

Table 13. Load Weighted Administered Prices on MI Event

Date	Intervals	Declared by	Region Affected	Price Before MI (PHP/MWh)	Administered Price During MI (PHP/MWh)	Price After MI (PHP/MWh)
12 January 2026	1440h 1 interval	MO	LVM	8,474.52	5,372.02	10,844.55
13 February 2026	0215h 1 interval	MO	LVM	2,853.95	2,589.20	2,586.97
15 February 2026	0805h 1 interval	MO	LVM	501.52	-2,771.77	504.43
23 February 2026	2105h – 2230h 18 intervals	MO	LVM	14,396.28	13,327.20	12,803.78
15 March 2026	0705h 1 interval	MO	LVM	-200.76	-717.02	-1,021.75

iv. Secondary Price Cap (SPC)[9]

For Q1-2025, no issuance of the Secondary Price Cap (SPC) was recorded.

Table 14. Monthly Pricing Condition for Q1-2026

		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	January 2026	8,092	90.64%	573	6.42%	262	2.93%	0	0.00%	1	0.01%
	February 2026	8,432	94.44%	315	3.53%	161	1.80%	0	0.00%	20	0.22%
	March 2026	7,206	89.36%	99	1.23%	758	9.40%	0	0.00%	1	0.01%
Visayas	January 2026	8,092	90.64%	574	6.43%	261	2.92%	0	0.00%	1	0.01%
	February 2026	8,432	94.44%	315	3.53%	161	1.80%	0	0.00%	20	0.22%
	March 2026	7,216	89.48%	100	1.24%	747	9.26%	0	0.00%	1	0.01%
Mindanao	January 2026	8,092	90.64%	574	6.43%	261	2.92%	0	0.00%	1	0.01%
	February 2026	8,432	94.44%	315	3.53%	161	1.80%	0	0.00%	20	0.22%
	March 2026	7,323	90.81%	112	1.39%	628	7.79%	0	0.00%	1	0.01%

[8] Luzon, Visayas, Mindanao

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

IV. GENERATOR OFFER PATTERN

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

Coal-fired power plants maintained offer price patterns broadly consistent with those observed in the preceding quarter, with a substantial portion of offered capacity submitted at or below PHP 0/MWh. Across trading hours, this price band accounted for approximately 80% to 90% of total coal offer quantities, while most of the remaining capacity was concentrated within the PHP 0 to PHP 5,000/MWh range. Offers above PHP 5,000/MWh remained minimal.

On a quarter-on-quarter basis, only marginal variations were observed between the two lowest price bands. Offer quantities within the PHP 0 to PHP 5,000/MWh range increased slightly by 1.53%, while offers at or below PHP 0/MWh declined by 0.89%. Overall, effective quantity of coal-based offers decreased by 2.94%, primarily due to outages affecting coal plants, as discussed in the preceding sections of this report.

Despite the decline in overall offered capacity, the shift in distribution, marked by a slight reduction in zero or negative-priced offers and a corresponding increase in offers within the PHP 0 to PHP 5,000/MWh range, indicates sustained strong reliance on low-price submissions to secure dispatch.

This behavior remains consistent with the typical operating profile of coal-fired plants, which generally function as baseload generators with a preference for continuous dispatch to meet contractual obligations. The prevalence of offers at or below PHP 0/MWh may also reflect the influence of bilateral contract positions and cost recovery considerations that are not solely dependent on spot market revenues *(see Figure 22)*.

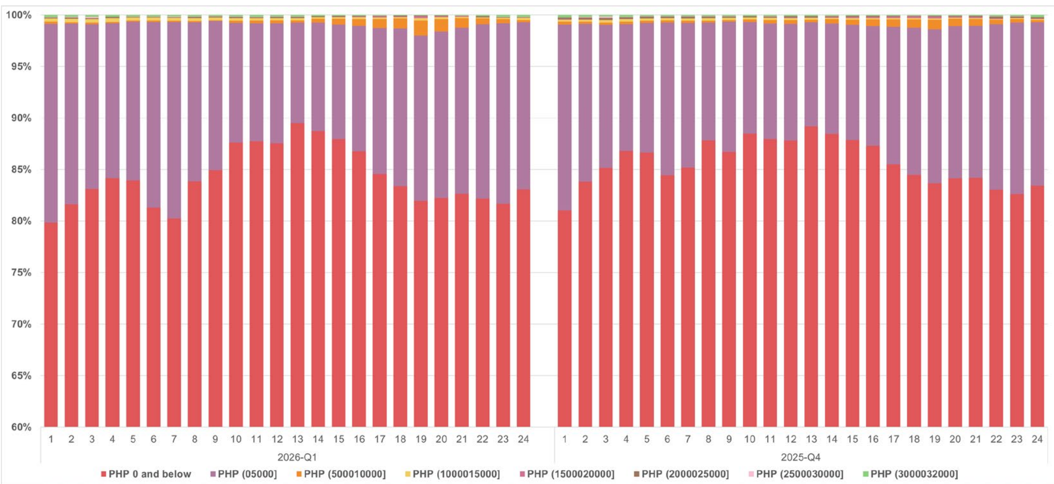

Figure 22. Coal Power Plants Offer Pattern – Q1-2026 and Q4-2025

Natural gas-fired power plants exhibited offer behavior broadly similar to those of coal-fired facilities, with a significant concentration of offers submitted at or below PHP

0/MWh. This behavior remains consistent with their operational role across baseload and mid-merit dispatch. Across trading hours, the lowest price band generally accounted for approximately 80% to 90% of total offered capacities, while most of the remaining offers were largely concentrated within the PHP 0 to PHP 5,000/MWh range.

Relative to the previous quarter, the total effective quantity of natural gas offers declined by 11.70%, primarily attributable to the increased incidence of outages affecting natural gas plants, as discussed in earlier sections of this report. This reduction in available capacity was reflected mainly in lower offer volumes within the PHP 0/MWh and below price band.

The observed decrease in offered quantities therefore appears to have been driven primarily by availability constraints rather than by any material shift in bidding behavior. In particular, the temporary unavailability of generating units that typically submit low-priced offers reduced the volume within the lowest price bands during specific intervals. Notwithstanding these constraints, the underlying offer strategies of available units remained broadly consistent with the operational characteristics of natural gas facilities, particularly combined-cycle plants, which are generally structured to support sustained and continuous generation.

Overall, offer patterns for natural gas plants remained relatively stable across trading hours and comparable with those observed with the preceding quarter, with only minor intra-day variations observed in the distribution between the lowest price bands. No significant changes in overall bidding behavior were evident during the period *(see Figure 23)*.

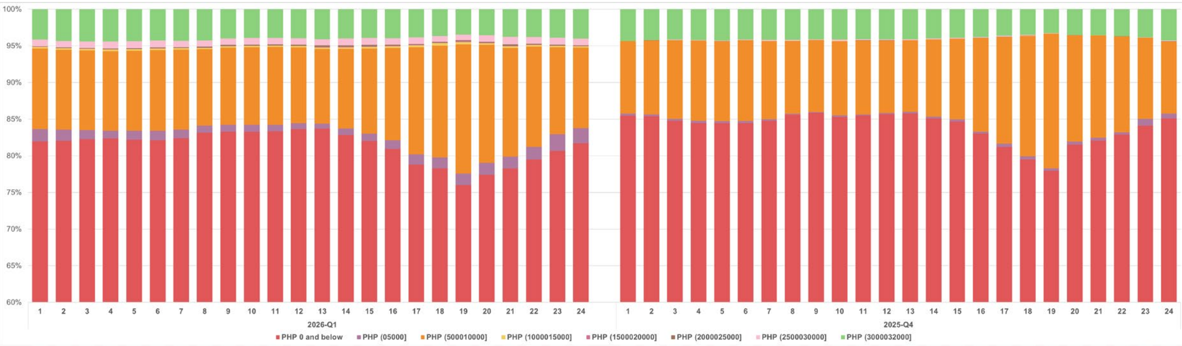

Figure 23. Natural Gas Power Plants Offer Pattern – Q1-2026 and Q4-2025

Hydropower plants exhibited a more diversified offer distribution compared to thermal generators, with offer quantities allocated across multiple price bands. While the largest share of offers remained at or below PHP 0/MWh, this represented a comparatively smaller proportion of total offers relative to coal and natural gas plants, generally accounting for approximately 50% across trading hours. A notable portion of offers was likewise concentrated within the PHP 10,000/MWh to PHP 15,000/MWh range, with intermittent submissions observed in higher price bands *(see Figure 24).*

Relative to the preceding period, the share of offers submitted at or below PHP 0/MWh showed moderate variation, accompanied by corresponding shifts in mid-level price bands. Overall, the effective quantity of hydro offers declined during the quarter, primarily reflecting the impact of reduced availability due to outages, as discussed in the earlier section of this report.

Despite these reductions, hydro offer behavior remained responsive to prevailing system conditions. Bidding patterns continued to be distributed across both low- and mid-price ranges, rather than being concentrated solely within the lowest price bands, indicating the operational flexibility of hydro resources in responding to market dynamics.

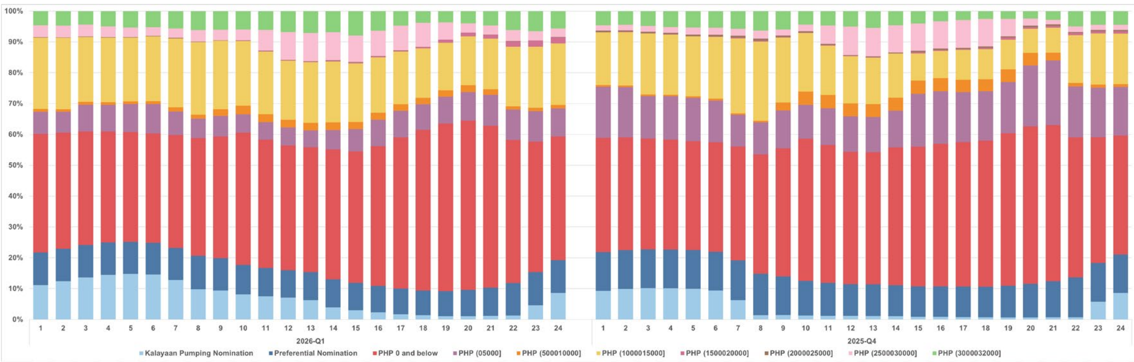

Figure 24. Hydro Power Plants Offer Pattern – Q1-2026 and Q4-2025

Oil-based power plants continued to exhibit offer patterns concentrated within the higher price bands, reflecting their inherently higher operational and fuel costs. These units typically function as peaking plants and are dispatched primarily during periods of elevated demand or supply shortfalls, when fast-response capabilities are required to maintain system balance.

Consistent with this role, oil-based plants maintained a substantial concentration of offers within the PHP 25,000/MWh to PHP 32,000/MWh range across both Q1 2026 and the preceding quarter. Notably, the share of offers above PHP 25,000/MWh increased during the quarter, while submissions within lower price bands remained relatively limited.

Compared with the preceding quarter, the proportion of offers submitted within the higher price bands increased modestly during Q1 2026, indicating greater positioning of oil-based units for dispatch during supply-constrained intervals.

This shift indicates that, in response to reduced availability of lower-cost generation—particularly due to outages among baseload and mid-merit plants—oil-based units were increasingly positioned to support system adequacy during constrained intervals. Overall, the persistence of high-priced offer submissions reflects the economic and operational characteristics of oil-fired generation, which is typically dispatched only under tight supply conditions rather than for continuous operation. The observed offer distribution therefore remains consistent with the higher relatively costs of oil-based generation compared with coal, natural gas, and hydro resources *(see Figure 25)*.

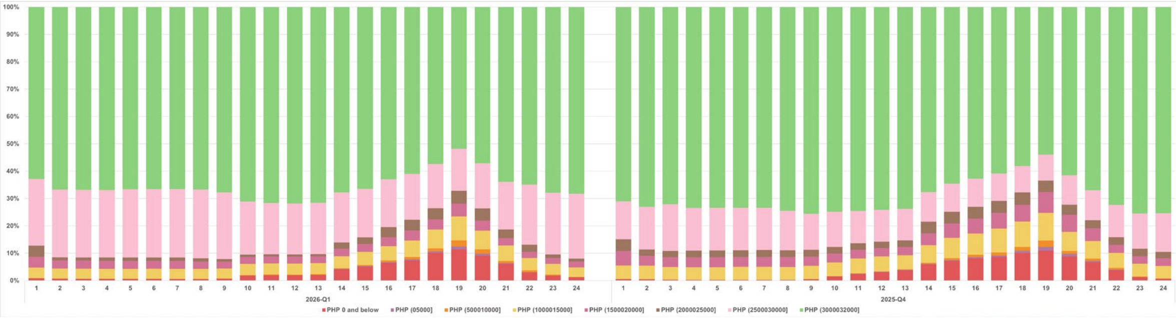

Figure 25. Oil-based Power Plants Offer Pattern – Q1-2026 and Q4-2025

V. STRUCTURAL COMPETITION INDICES

A. Residual Supply

The Market Residual Supply Index (RSI)[10], plotted against the number of pivotal suppliers, averaged 101.06% in Q1 2026 *(see Figure 26)*, representing a slight decline from 101.29% in Q4 2025, but an increase from 100.38% in Q1 2025.
The RSI measures the extent to which system demand can be met without reliance on a single supplier. An RSI above 100% indicates that sufficient residual supply exists to satisfy demand even in the absence of the largest market participant.

Although the quarterly average RSI remained above the 100% threshold, indicating overall adequacy of residual supply, underlying market conditions during the quarter suggested comparatively tighter supply margins relative to the preceding period. This was primarily driven by reduced offered capacity and elevated outage levels, which constrained available supply and heightened system vulnerability.

Consequently, despite the average RSI remaining above 100%, increased outage and reduced offer volumes contributed to a higher incidence of pivotal supplier conditions during peak demand intervals. This, in turn, elevated market power risks and the potential for price volatility.

This relationship is reflected in the observed market prices across RSI conditions. Intervals in which the RSI fell below 100% recorded an average market price of PHP 5,715.99/MWh, while intervals with RSI above 100% recorded a significantly lower average price of PHP 2,702.06/MWh. These results illustrate the inverse relationship between RSI levels and market prices, wherein tighter residual supply conditions corresponded with elevated market outcomes.

At the upper end of the range, the RSI peaked at 111.93%, during which the corresponding market price declined to -PHP 5.17/MWh. Conversely, when the RSI reached its minimum observed level of 93.81%, the market price increased sharply to

[10] Dynamic continuous index measured as ratio of the available generation without a generator to the total generation required to supply the demand.

PHP 31,521.87/MWh. These observations further underscore the close interrelationship among supply availability, demand conditions, and pricing outcomes within the market.

Table 15 provides a summary of the intervals corresponding to the minimum and maximum RSI values and their associated market prices.

Table 15. RSI vs LWAP, Q1-2026

	RSI	Price	Date and Time Interval
RSI (Max)	111.93	- 5.17	1/1/2026 11:05
RSI (Min)	93.81	31,521.87	12/28/2025 17:50
	Price	**RSI**	**Date and Time Interval**
Price (Max)	31,521.87	93.81	12/28/2025 17:50
Price (Min)	- 10,208.45	105.16	3/14/2026 12:45

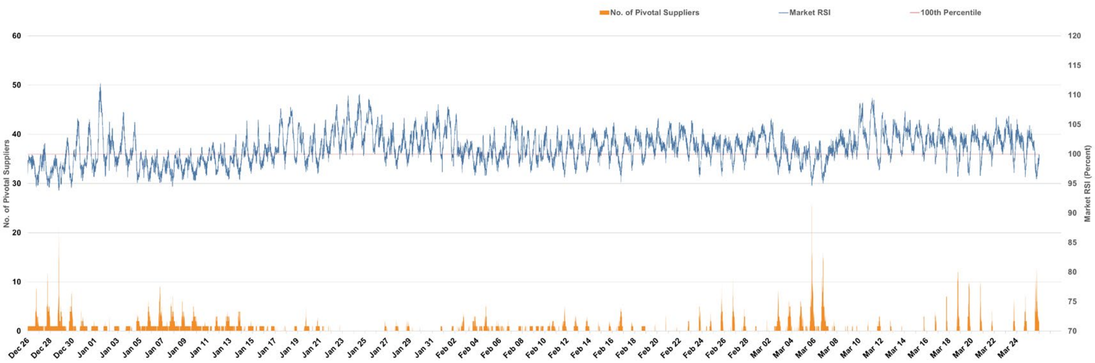

Figure 26. Market RSI vs. Pivotal Suppliers, Q1-2026

B. Pivotal Suppliers[11]

Figure 27 illustrates the top ten (10) system-wide pivotal suppliers in the market during Q1 2026. Consistent with its ranking in Q4 2025, the GNPower Dinginin Coal-Fired Thermal Power Plant (CFTPP) remained the most frequently pivotal facility. The plant was identified as pivotal in 7,328 trading intervals, or 28.27% of the total intervals during the quarter. The Sta. Rita Natural Gas Power Plant (NGPP) ranked second, with 2,335 pivotal intervals, accounting for approximately 9.01% of the total.

Despite the average RSI remaining slightly above the 100% threshold at 101.06%, market conditions during Q1 2026 reflected tighter operating margins due to reduced effective supply and elevated outage levels, as discussed in earlier sections of this report. These conditions increased the frequency of intervals in which major generating facilities became pivotal to meeting system demand.

Further analysis indicates that seven (7) of the ten (10) most frequently pivotal suppliers were coal-fired power plants, while two (2) were natural gas-fired facilities and one (1) was a hydroelectric plant. This distribution highlights the continued prominence of

[11] 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.

baseload and mid-merit generators in influencing system adequacy and underscores their critical role in maintaining supply under constrained conditions.

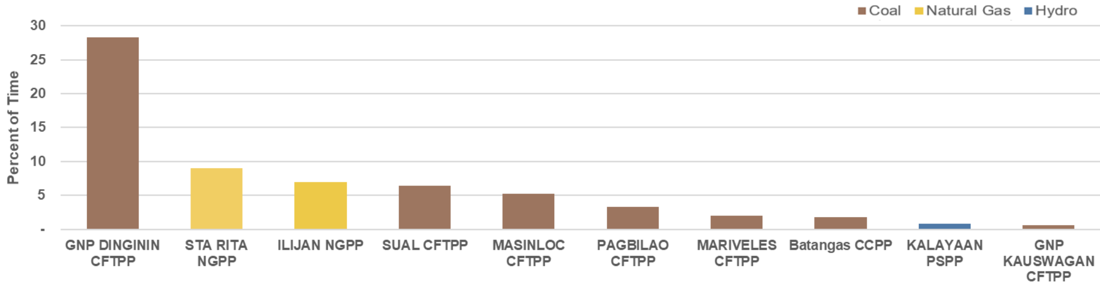

Figure 27. Top 10 System: Pivotal Suppliers, Q1-2026

VI. CAPACITY FACTOR

The Capacity Factor, which measures the utilization of generating units based on actual metered output relative to their maximum available generation, averaged 42.03% during the quarter under review. This reflects a decrease from the 44% recorded in the preceding quarter.

Generation utilization during the quarter was influenced by several factors, including available generating capacity, outage levels, operational schedules of generation facilities, and prevailing system demand conditions. Despite the overall decline in capacity factor, price signals within the market continued to incentivize the dispatch of available units, resulting in sustained levels of electricity generation. This indicates that dispatch remained primarily governed by the price-based merit order, wherein lower-priced offers are prioritized in the dispatch stack.

Observed declines in capacity factor were likewise consistent with earlier discussions regarding the influence of day type on generation levels, particularly during weekends and holidays when system demand is typically lower. In addition, transmission constraints and network disturbances, including line limitations and transmission outages, may have further constrained system utilization during certain intervals, thereby contributing to the observed reduction in overall capacity factor *(see Figure 28)*.

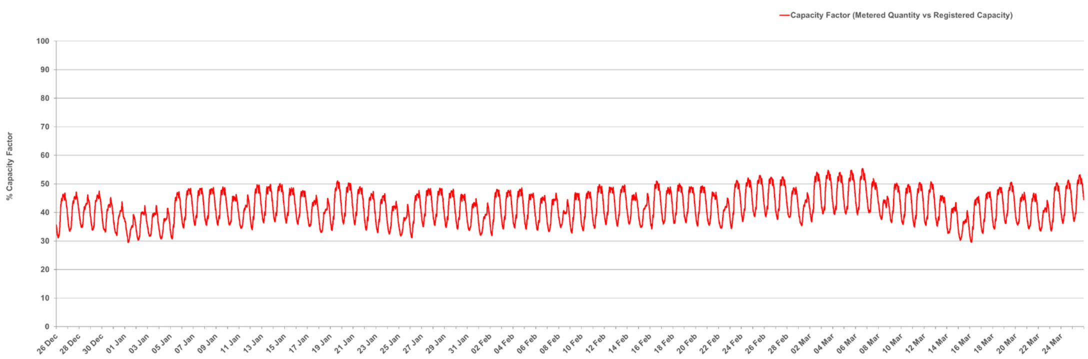

Figure 28. System: Capacity Factor (Metered Quantity vs Registered Capacity), Q1-2026

On a resource-type basis, baseload power plants accounted for the largest share of dispatch in the WESM, reflecting their dominant role in overall system utilization. Among all resource types, geothermal power plants recorded the highest average capacity factor at 63.09%, followed closely by coal-fired power plants at 61.46% *(see Figure 29)*.

The high utilization of geothermal resources remains consistent with their priority dispatch classification and the relative stability of their energy supply. Coal-fired plants likewise maintained high utilization levels due to their role as primary baseload generation resources, although their capacity factor remained slightly lower than that of geothermal facilities partly due to elevated outage levels during the quarter.

Natural gas-fired plants ranked third, with average capacity factors increasing to 50.20% compared to the preceding quarter. Hydropower plants likewise recorded an higher utilization levels, reaching 41.97%, or a 9.55% improvement relative to the previous period, reflecting improved availability during certain intervals.

Despite the increase in hydro capacity factor, hydro generation during the quarter continued to be affected by prevailing dry season conditions and outage-related constraints, as discussed in the earlier sections of this report. The observed increase in utilization therefore likely reflects changes in dispatch patterns and operational scheduling during specific intervals rather than a broad improvement in hydro resource conditions.

Oil-based and battery storage facilities continued to exhibit the lowest capacity factors, consistent with their operational role as peaking and reserve resources. Their dispatch remained largely limited to periods of constrained supply or elevated demand conditions, resulting in comparatively lower overall utilization.

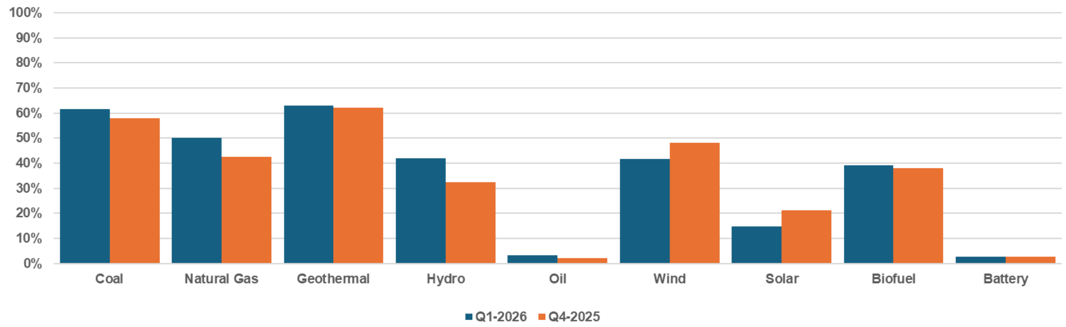

Figure 29. System Capacity Factor Per Resource Type (Registered Capacity vs Actual Generation) – Q4-2025 and Q1-2026

VII. SPOT EXPOSURE

Spot market transactions among load participants increased slightly during Q1 2026, averaging 13.75% compared with 13.60% in Q4 2025. This indicates that the majority of energy requirements continued to be supplied through bilateral contracting arrangements rather than spot market purchases.

A daily comparative analysis between Q1 2025 and Q1 2026 reveals variability in spot exposure levels. In most instances, spot market exposure in Q1 2025 was higher than that observed in the corresponding period in 2026, with the largest observed recorded difference of 15.99% on 25 January 2026. The relatively higher spot exposure in 2025 may have been influenced by reduced bilateral contract coverages arising from the expiration or termination of certain Power Supply Agreements (PSAs), which necessitated greater reliance on the spot market to meet demand requirements.

In response to these conditions, the Energy Regulatory Commission (ERC) issued an advisory allowing the immediate implementation of Emergency Power Supply Agreements (EPSAs), pursuant to Section 2.3.5 of the Department of Energy (DOE) 2023 Competitive Selection Process (CSP) Policy[12] and relevant ERC guidelines, without the need for provisional authority.

The subsequent implementation of EPSAs likely contributed to the gradual reduction in spot market exposure, as distribution utilities were able to secure committed energy through bilateral arrangements rather than relying on spot market transactions *(see Figure 30)*.

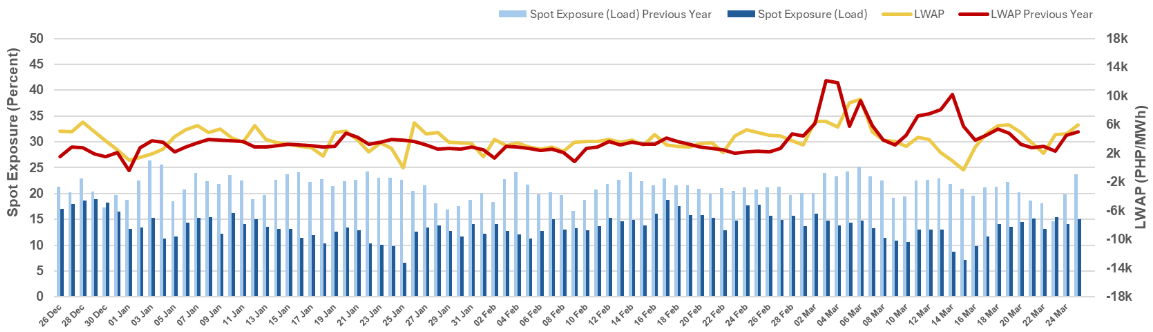

Figure 30. Daily Profile of Spot Market Exposure, Q1 2025 vs Q1-2026

An hourly analysis of spot market exposure and corresponding average prices reveals distinct intraday patterns during the quarter. Spot exposure generally increased during the early morning hours, peaking at approximately 0700h, likely reflecting the ramp-up in demand prior to the material contribution of solar generation.

A secondary peak in spot exposure was likewise observed during the evening period, particularly between 1800h and 2000h, coinciding with the evening demand ramp and the decline in solar output. During these intervals, additional dispatchable capacity was required to meet system demand.

Despite these periods of relatively higher spot exposure, market prices remained relatively stable during midday intervals, supported by sufficient available capacity within the system. However, modest price increases were observed during transitional periods at approximately 1700h and 1900h, corresponding with rising evening demand levels and declining output from variable renewable energy sources.

12 Department Circular No. DC2023-06-0021

These dynamics indicate a gradual tightening of supply-demand balance during the early evening hours, which exerted upward pressure on market prices, even in instances where spot exposure remained within moderate levels.

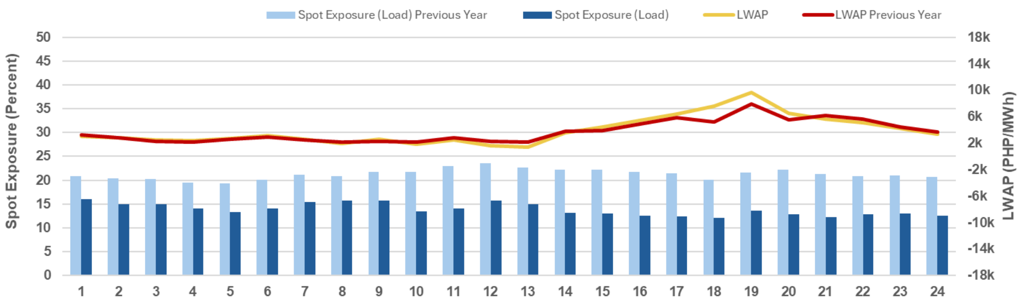

Figure 31. Hourly Profile of Spot Market Exposure, Q1 2025 vs Q1-2026

Annex A. Plants with Change in Capacity

Plant Type	Resource ID	Facility Name	Registered Capacity		Quarter-on-Quarter Change (MW)
			2026-Q1	2025-Q4	
Luzon					
HYDRO	01AMBUK_U01	Ambuklao Hydroelectric Power Plant Unit 1	37.4	37.5	-0.10
HYDRO	01AMBUK_U02	Ambuklao Hydroelectric Power Plant Unit 2	37.3	37.5	-0.20
HYDRO	01AMBUK_U03	Ambuklao Hydroelectric Power Plant Unit 3	37.3	37.5	-0.20
HYDRO	01AMPHAW_G01	Ampohaw Hydroelectric Power Plant	8	8.3	-0.30
HYDRO	01ANGAT_M	Angat Hydroelectric Power Plant Unit M	99.8	149.5	-49.70
HYDRO	03LMHP_G01	Laguio (Laginbayan) Malaki 1 River	1	2	-1.00
SOLAR	01MARSOL_G01	Bataan Solar Power Project	17.6	16	1.60
OIL	02TMOBIL_G01	Mobile 3 Bunker C-Fired Diesel Power Plant	56.9	63.8	-6.90
OIL	02TMOBIL_G03	Mobile 5 Bunker C-Fired Diesel Power Plant	50.1	55.2	-5.10
COAL	03QPPL_G01	Quezon Power Plant	400	460	-60.00
GEO	03TIWI_C	Tiwi Geothermal Power Plant - Plant C (Units 5 and 6)	106.9	113.8	-6.90
Visayas					
BATTERY	04TONGO_BAT	Tongonan Battery Energy Storage System	10	14.2	-4.20
HYDRO	08TIMBA_G01	Timbaban Hydroelectric Power Plant	18	17.8	0.20
Mindanao					
COAL	10GNPK_U01	Kauswagan Coal Fired Power Plant Unit 1	138	151.9	-13.90
COAL	10GNPK_U02	Kauswagan Coal Fired Power Plant Unit 2	138	151	-13.00
COAL	10GNPK_U03	Kauswagan Coal Fired Power Plant Unit 3	138	151.3	-13.30
COAL	10GNPK_U04	Kauswagan Coal Fired Power Plant Unit 4	138	151	-13.00
OIL	09JIMDSL_U01	Misamis Occidental Bunker C-Fired Diesel Power Plant 3 Unit 1	7.6	7.5	0.10
OIL	09JIMDSL_U02	Misamis Occidental Bunker C-Fired Diesel Power Plant 3 Unit 2	8.2	8	0.20
OIL	10IDP1_U01	Iligan Diesel Power Plant Unit 1	4.9	5	-0.10
OIL	10IDP1_U02	Iligan Diesel Power Plant Unit 2	4.9	5	-0.10
OIL	10IDP1_U03	Iligan Diesel Power Plant Unit 3	4.9	5	-0.10
OIL	10IDP1_U04	Iligan Diesel Power Plant Unit 4	4.9	5	-0.10
OIL	10IDP1_U05	Iligan Diesel Power Plant Unit 5	4.8	4.9	-0.10
OIL	10IDP1_U06	Iligan Diesel Power Plant Unit 6	4.8	4.9	-0.10
OIL	10IDP1_U07	Iligan Diesel Power Plant Unit 7	5	5.1	-0.10
OIL	10IDP1_U08	Iligan Diesel Power Plant Unit 8	4.9	5	-0.10
OIL	10IDP1_U09	Iligan Diesel Power Plant Unit 9	4.8	4.9	-0.10
OIL	10IDP1_U10	Iligan Diesel Power Plant Unit 10	5	5.1	-0.10
OIL	10IDP1_U11	Iligan Diesel Power Plant Unit 11	4.9	5	-0.10
OIL	10IDP1_U12	Iligan Diesel Power Plant Unit 12	4.9	5.1	-0.20
OIL	10IDP2_U02	Iligan Diesel Power Plant - Plant 2 Unit 2	5.6	5.7	-0.10
OIL	10IDP2_U05	Iligan Diesel Power Plant - Plant 2 Unit 5	5.6	5.7	-0.10
OIL	12TM2_U01	Therma Marine, Inc. (TMI) Mobile 2 - Unit 1	49	50	-1.00
OIL	12TM2_U02	Therma Marine, Inc. (TMI) Mobile 2 - Unit 2	49	50	-1.00
OIL	13MPCDIG_G01	Digos Modular Diesel Power Plant	16.8	16.9	-0.10
OIL	13TM1_U02	Mobile 1 Bunker C-Fired Diesel Power Plant Unit 2	48.7	50	-1.30

Annex B-1. Capacity Profile by Category

Capacity Profile	1st Quarter of 2025 (26 Dec to 25 Mar)		4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)	
	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap
Capacity Offered/Nominated	19,998.00	66.97%	19,790.62	65.76%	19,415.20	61.80%
Capacity on Commissioning	1,048.00	3.51%	519.72	1.73%	875.63	2.79%
Capacity not Offered/Nominated	4,749.00	15.90%	5,451.75	18.12%	5,128.14	16.32%
Capacity on Outage	4,118.00	13.79%	4,204.49	13.97%	4,777.99	15.21%

Capacity Profile	%Change 1st Qtr 2026 to 1st Qtr 2025	%Change 1st Qtr 2026 to 4th Qtr 2025
Capacity Offered/Nominated	2.91%▼	1.90%▼
Capacity on Commissioning	16.45%▼	68.48%▲
Capacity not Offered/Nominated	7.98%▲	5.94%▼
Capacity on Outage	16.03%▲	13.64%▲

Capacity Profile	January 2026 (26 Dec to 25 Jan)		Febraury 2026 (26 Jan to 25 Feb)		March 2026 (26 Feb to 25 Mar)	
	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap
Capacity Offered/Nominated	18,920.80	150.03%	19,689.95	151.21%	19,659.04	144.93%
Capacity on Commissioning	657.66	5.21%	680.52	5.23%	1,332.52	9.82%
Capacity not Offered/Nominated	5,354.28	42.46%	5,055.83	38.83%	4,957.66	36.55%
Capacity on Outage	5,141.76	40.77%	4,534.11	34.82%	4,644.67	34.24%

Annex B-2. Capacity Profile by Plant Type

Offered/Nominated Capacity by Plant Type

Plant Type	4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)		Quarter-on-Quarter % Change
	Average (in MW)	% of Offered Cap	Average (in MW)	% of Offered Cap	
Coal	9,209.53	46.53%	9,255.49	47.67%	0.50% ▲
Natural Gas	3,429.33	17.33%	3,330.06	17.15%	2.89% ▼
Geothermal	1,137.03	5.75%	1,148.97	5.92%	1.05% ▲
Hydro	2,466.49	12.46%	1,962.51	10.11%	20.43% ▼
Oil Based	2,149.76	10.86%	2,190.17	11.28%	1.88% ▲
Wind	171.13	0.86%	196.84	1.01%	15.03% ▲
Solar	510.09	2.58%	609.71	3.14%	19.53% ▲
Biofuel	164.78	0.83%	161.84	0.83%	1.79% ▼
Battery Storage	552.48	2.79%	560.02	2.88%	1.36% ▲

Effective Supply by Plant Type

Plant Type	4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)		Quarter-on-Quarter % Change
	Average (in MW)	% of Eff Supply	Average (in MW)	% of Eff Supply	
Coal	8,026.66	47.32%	8,094.81	47.17%	0.85% ▲
Natural Gas	2,626.59	17.60%	2,430.39	14.16%	7.47% ▼
Geothermal	1,095.34	6.42%	1,151.42	6.71%	5.12% ▲
Hydro	2,235.92	14.03%	1,949.16	11.36%	12.83% ▼
Oil Based	1,727.00	7.39%	1,837.63	10.71%	6.41% ▲
Wind	202.79	0.51%	252.75	1.47%	24.63% ▲
Solar	535.58	3.00%	722.76	4.21%	34.95% ▲
Biofuel	158.99	0.59%	161.70	0.94%	1.71% ▲
Battery Storage	534.14	3.14%	560.60	3.27%	4.95% ▲

RTD Capacity by Plant Type

Plant Type	4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)		Quarter-on-Quarter % Change
	Average(in MW)	Percentage	Average(in MW)	Percentage	
Coal	7,434.31	56.79%	7,529.23	57.75%	1.28% ▲
Natural Gas	2,170.09	16.58%	1,979.17	15.18%	8.80% ▼
Geothermal	1,068.95	8.17%	1,135.50	8.71%	6.23% ▲
Hydro	1,471.94	11.24%	1,215.90	9.33%	17.40% ▼
Oil Based	56.37	0.43%	40.52	0.31%	28.12% ▼
Wind	200.54	1.53%	252.74	1.94%	26.03% ▲
Solar	529.34	4.04%	721.81	5.54%	36.36% ▲
Biofuel	157.03	1.20%	161.65	1.24%	2.94% ▲
Battery Storage	3.11	0.02%	1.66	0.01%	46.66% ▼

Annex C. Details and Breakdown for the Others*

JANUARY 2026

Event Category	Total Count per Hour Inteval
OUTAGE (AGGREGATED UNIT/S) AND DERATING-PLANT PROBLEM	1,484
DISTRIBUTION-LINE RELATED CONSTRAINTS	1,383
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-GEOTHERMAL	1,322
WITH PENDING/ONGOING REGISTRATION UPDATE	1,190
CO-GENERATION POWER PLANTS	1,177
RESOURCE CONSTRAINTS-SOLAR	890
MARKET SYSTEM CONSTRAINTS	762
DERATING-PLANT DEGRADATION/CONDITION	741
START-UP PROCEDURES	502
OUTAGE (AGGREGATED UNIT/S) AND CO-GENERATION	430
TRANSMISSION-RELATED CONSTRAINTS	315
DERATING-PLANT EQUIPMENT-RELATED MAINTENANCE (PLANT TEST)	120
SHUTDOWN PROCEDURES	69
RESOURCE CONSTRAINTS-HYDRO & TRANSMISSION-RELATED CONSTRAINTS	54
RESOURCE CONSTRAINTS-WIND	14
DERATING-AMBIENT CONDITION AND PLANT PROBLEM/MAINTENANCE	10
RESOURCE CONSTRAINTS-GEOTHERMAL & DERATING-PLANT PROBLEM/MAINTENANCE	3
STATION USE HOUSE LOAD OR INDUSTRIAL LOAD	1

FEBRUARY 2026

Event Category	Total Count per Hour Inteval
CO-GENERATION POWER PLANTS	1,173
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-GEOTHERMAL	1,130
DISTRIBUTION-LINE RELATED CONSTRAINTS	935
MARKET SYSTEM CONSTRAINTS	841
RESOURCE CONSTRAINTS-SOLAR	738
DERATING-PLANT DEGRADATION/CONDITION	726
TRANSMISSION-RELATED CONSTRAINTS	716
OUTAGE (AGGREGATED UNIT/S) AND DERATING-PLANT PROBLEM	480
START-UP PROCEDURES	468
OUTAGE (AGGREGATED UNIT/S) AND CO-GENERATION	457
RESOURCE CONSTRAINTS-GEOTHERMAL & DERATING-PLANT PROBLEM/MAINTENANCE	321
WITH PENDING/ONGOING REGISTRATION UPDATE	101
DERATING-PLANT EQUIPMENT-RELATED MAINTENANCE (PLANT TEST)	97
SHUTDOWN PROCEDURES	55
RESOURCE CONSTRAINTS-HYDRO & TRANSMISSION-RELATED CONSTRAINTS	54
FORCE MAJEURE	29
STATION USE HOUSE LOAD OR INDUSTRIAL LOAD	27
RESOURCE CONSTRAINTS-NATURAL GAS	24
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-HYDRO	6
SECURITY LIMIT CANCELLATION (PLANT TEST)	4
PUMP STORAGE POWER PLANTS	4
LEGAL OR REGULATORY COMPLIANCES	1

MARCH 2026

Event Category	Total Count per Hour Inteval
CO-GENERATION POWER PLANTS	1,471
MARKET SYSTEM CONSTRAINTS	1,468
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-GEOTHERMAL	1,364
TRANSMISSION-RELATED CONSTRAINTS	991
DISTRIBUTION-LINE RELATED CONSTRAINTS	941
DERATING-PLANT DEGRADATION/CONDITION	664
START-UP PROCEDURES	483
RESOURCE CONSTRAINTS-SOLAR	289
OUTAGE (AGGREGATED UNIT/S) AND DERATING-PLANT PROBLEM	232
RESOURCE CONSTRAINTS-GEOTHERMAL & DERATING-PLANT PROBLEM/MAINTENANCE	162
LABOR AND MANAGEMENT CONFLICTS	131
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-HYDRO	128
PUMP STORAGE POWER PLANTS	121
RESOURCE CONSTRAINTS-HYDRO & TRANSMISSION-RELATED CONSTRAINTS	116
WITH PENDING/ONGOING REGISTRATION UPDATE	63
SHUTDOWN PROCEDURES	33
DERATING-PLANT EQUIPMENT-RELATED MAINTENANCE (PLANT TEST)	22
OUTAGE (AGGREGATED UNIT/S) AND CO-GENERATION	8
RESOURCE CONSTRAINTS-WIND	4
FORCE MAJEURE	3
SECURITY LIMIT CANCELLATION (PLANT TEST)	1

Annex D-1.1. Capacity on Outage by Plant Type

Plant Type	4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)		Quarter-on-Quarter % Change
	Average(in MW)	Percentage	Average(in MW)	Percentage	
Coal	1,959.88	45.50%	2,278.21	46.62%	16.24%▲
Natural Gas	930.20	21.60%	1,142.74	23.38%	22.85%▲
Geothermal	174.82	4.06%	202.28	4.14%	15.71%▲
Hydro	482.56	11.20%	521.45	10.67%	8.06%▲
Oil Based	570.16	13.24%	519.84	10.64%	8.83%▼
Wind	49.91	1.16%	52.96	1.08%	6.13%▲
Solar	31.66	0.74%	73.57	1.51%	132.35%▲
Biofuel	55.51	1.29%	52.63	1.08%	5.18%▼
Battery Storage	52.67	1.22%	43.53	0.89%	17.34%▼

Plant Type	January 2026	February 2026	March 2026
	Average(in MW)	Average(in MW)	Average(in MW)
Coal	2,184.81	2,443.25	2,198.89
Natural Gas	1,801.91	828.86	760.46
Geothermal	210.98	138.00	263.81
Hydro	309.09	489.15	792.33
Oil Based	520.86	518.32	520.39
Wind	44.98	55.79	52.90
Solar	49.63	124.43	55.02
Biofuel	40.33	51.42	67.60
Battery Storage	52.99	38.47	32.81

Plant Type	January 2026 (26 Dec to 25 Jan)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Coal	729.00	10/3/2025 2:40	2,781.00	9/30/2025 23:35	2,184.81
Natural Gas	263.00	9/30/2025 7:00	1,548.60	10/19/2025 23:50	1,801.91
Geothermal	138.20	9/29/2025 6:25	512.55	10/1/2025 0:40	210.98
Hydro	157.80	9/29/2025 17:55	1,228.50	10/7/2025 6:15	309.09
Oil Based	473.50	10/15/2025 9:05	796.00	10/1/2025 1:10	520.86
Wind	13.20	10/25/2025 17:30	81.00	10/10/2025 5:50	44.98
Solar	3.40	10/20/2025 16:15	172.60	10/2/2025 19:30	49.63
Biofuel	32.60	10/12/2025 0:05	120.60	10/7/2025 4:45	40.33
Battery Storage	20.00	10/6/2025 8:05	100.00	10/1/2025 1:10	52.99

Plant Type	Febraury 2026 (26 Jan to 25 Feb)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Coal	1,507.00	10/27/2025 6:20	3,347.80	11/3/2025 0:05	2,443.25
Natural Gas	420.60	10/31/2025 8:50	2,047.40	11/10/2025 3:55	828.86
Geothermal	55.40	11/12/2025 21:45	531.67	11/10/2025 8:50	138.00
Hydro	200.80	11/3/2025 16:35	791.70	11/22/2025 9:15	489.15
Oil Based	485.50	11/24/2025 22:00	853.50	11/1/2025 13:40	518.32
Wind	13.20	10/26/2025 9:30	102.80	11/4/2025 10:20	55.79
Solar	3.40	10/26/2025 0:05	257.20	11/4/2025 11:05	124.43
Biofuel	34.60	11/19/2025 8:05	156.60	11/10/2025 11:35	51.42
Battery Storage	20.00	11/4/2025 23:15	50.00	11/18/2025 8:20	38.47

Plant Type	March 2026 (26 Feb to 25 Mar)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Coal	1,056.90	12/23/2025 15:05	2,774.50	11/27/2025 12:30	2,198.89
Natural Gas	683.60	11/26/2025 0:05	2,725.10	12/24/2025 0:05	760.46
Geothermal	65.33	12/17/2025 10:30	256.79	11/30/2025 13:25	263.81
Hydro	358.50	12/24/2025 18:20	789.60	12/1/2025 15:30	792.33
Oil Based	474.00	11/26/2025 0:05	824.80	12/2/2025 18:55	520.39
Wind	36.70	11/27/2025 8:30	126.10	12/15/2025 17:30	52.90
Solar	5.00	11/29/2025 14:10	103.40	12/15/2025 19:05	55.02
Biofuel	17.60	12/9/2025 11:40	89.00	12/4/2025 12:55	67.60
Battery Storage	20.00	11/26/2025 10:05	168.20	12/19/2025 17:10	32.81

Annex D-2.1. Capacity on Outage by Category

Plant Category	4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)		Quarter-on-Quarter % Change
	Average(in MW)	% of Outage	Average(in MW)	% of Outage	
Planned	1,736.10	41.11%	1,916.20	40.10%	10.37% ▲
Forced	2,377.65	56.30%	2,628.92	55.02%	10.57% ▲
Maintenance	97.96	2.32%	232.96	4.88%	137.81% ▲
Deactivated Shutdown	11.50	0.27%	-	0.00%	100.00% ▼

Plant Category	January 2026	February 2026	March 2026
	Average(in MW)	Average(in MW)	Average(in MW)
Planned	2,285.59	1,398.55	2,080.36
Forced	2,706.81	2,684.50	2,481.16
Maintenance	149.21	452.12	83.04
Deactivated Shutdown	-	-	-

Plant Category	January 2026 (26 Dec to 25 Jan)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Planned	747.20	10/1/2025 0:05	1,773.00	10/6/2025 9:05	2,285.59
Forced	1,203.35	10/3/2025 10:00	3,882.65	10/1/2025 1:15	2,706.81
Maintenance	30.00	10/14/2025 11:55	485.00	10/22/2025 8:15	149.21
Deactivated Shutdown	-	-	11.50	9/26/2025 0:05	-

Plant Category	Febraury 2026 (26 Jan to 25 Feb)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Planned	1,283.50	10/30/2025 0:05	2,760.00	11/23/2025 10:05	1,398.55
Forced	1,560.85	10/27/2025 8:45	3,535.87	11/10/2025 8:50	2,684.50
Maintenance	30.00	10/31/2025 6:40	243.40	10/31/2025 14:40	452.12
Deactivated Shutdown	-	-	11.50	10/26/2025 0:05	-

Plant Category	March 2026 (26 Feb to 25 Mar)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Planned	1,086.10	12/20/2025 0:50	2,823.80	12/25/2025 3:55	1,851.20
Forced	1,566.26	11/29/2025 22:40	3,574.63	12/16/2025 18:30	103.02
Maintenance	35.00	11/26/2025 0:05	266.00	12/1/2025 9:20	1,576.49
Deactivated Shutdown	-	-	-	-	

Annex E. Supply and Demand

Capacity Profile	1st Quarter of 2025 (26 Dec to 25 Mar)		4th Quarter of 2025 (26 Oct to 25 Dec)		1st Quarter of 2026 (26 Dec to 25 Mar)	
	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap
Effective Supply	16,729.00	56.02%	17,767.46	59.04%	17,175.79	54.67%
System Demand	13,139.00	44.00%	13,719.47	45.59%	13,049.33	41.54%
Demand plus Reserve Requirement	15,855.00	53.10%	15,691.03	52.14%	14,933.17	47.54%

Capacity Profile	%Change 1st Qtr 2026 to 1st Qtr 2025	%Change 1st Qtr 2026 to 4th Qtr 2025
Effective Supply	2.67% ▲	3.33% ▼
System Demand	0.68% ▼	4.88% ▼
Demand plus Reserve Requirement	5.81% ▼	4.83% ▼

Capacity Profile	Jan 2026	Feb 2026	Mar 2026
	Average(in MW)	Average(in MW)	Average(in MW)
Effective Supply	16,782.85	17,252.09	17,526.54
System Demand	12,611.41	13,021.80	13,564.60
Demand plus Reserve Requirement	14,550.19	14,856.40	15,441.16

Annex F. Load Weighted Average Prices

Load Weighted Average Prices (Quarterly)

	4th Quarter of 2025 (26 Oct to 25 Dec)			1st Quarter of 2026 (26 Dec to 25 Mar)			Quarter-on-Quarter % Change
	Min	Max	Average	Min	Max	Average	
System	-10,208.45	31,521.87	3,772.92	-10,180.63	44,636.78	4,295.27	13.84%▼

Load Weighted Average Prices (Monthly)

	January 2026 (26 Dec to 25 Jan)			Febraury 2026 (26 Jan to 25 Feb)			March 2026 (26 Feb to 25 Mar)		
	Min	Max	Average	Min	Max	Average	Min	Max	Average
System	-9,989.91	31,521.87	3,763.46	-10,096.95	19,393.98	3,627.38	-10,208.45	31,034.24	4,584.85
Luzon	-10,272.46	32,700.51	3,368.26	-10,344.25	21,542.99	2,743.02	-10,200.71	33,320.77	4,331.56
Visayas	-10,091.95	33,360.25	4,648.48	-9,570.04	33,561.11	5,806.87	-10,200.71	32,911.61	5,576.59
Mindanao	-10,694.84	33,754.30	4,635.88	-10,540.22	36,155.58	5,675.89	-11,277.37	32,263.33	4,856.39

Zonal Prices (Monthly)

Zones	January 2026 (26 Dec to 25 Jan)	Febraury 2026 (26 Jan to 25 Feb)	March 2026 (26 Feb to 25 Mar)
Luzon			
Northern Luzon	3,388.49	2,278.25	4,459.71
Metro Manila	3,394.15	2,746.24	4,358.12
Southern Luzon	3,341.28	2,710.65	4,232.22
Visayas			
Bohol	4,671.54	5,915.10	5,721.77
Cebu	4,602.41	5,770.86	5,515.58
Leyte	4,500.73	5,665.17	5,514.53
Negros	4,668.08	5,850.29	5,646.87
Panay	4,806.23	5,899.61	5,650.62
Mindanao			
Lanao	4,098.46	5,021.34	4,367.08
North Central Mir	4,268.20	5,151.91	4,410.50
North-East Minda	4,829.27	5,841.51	5,124.54
North-West Mind	4,913.53	5,982.07	5,086.07
South-East Minda	4,629.22	5,673.96	4,895.96
South-West Mind	4,818.45	6,018.49	5,035.93