Australian Government

AUSTRALIAN ENERGY REGULATOR

Methods and assumptions

Wholesale electricity market performance report 2026

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1 Introduction

This document outlines the approach we have taken to market monitoring and the methodologies used to construct each figure in the 2026 Wholesale electricity market performance report. In doing so, this document provides discussion and analysis of the monitoring methodology applied as required under 18C(3)(d) of the National Electricity Law. It is intended to provide transparency to stakeholders on how we have applied data sources, assumptions and calculations to develop the indicators presented in the report.

As set out in our Enhanced wholesale market monitoring guideline, we have used the structure-conduct-performance framework as the primary basis for analysing the wholesale electricity market (Table 1). In undertaking our analysis, we have had regard to the interactions between these concepts, rather than considering each in isolation, and our assessment draws on a broad range of measures. Certain measures are intended to be indicative in nature, highlighting conditions that may warrant further investigation rather than establishing the underlying cause of observed outcomes. Our approach is designed to support an integrated assessment of prices, competition and system conditions.

Table 1 Structure-conduct-performance components

Component	High-level explanation of component	Assessment
Structure	Refers to the market structure and includes the number and size of buyers and sellers, the nature of the products and the height of barriers to entry.	Features of market structure can be intrinsic to the market or result from participant behaviour. We will assess structural features such as: • market concentration • barriers to entry, participation and exit • the extent of vertical integration.
Conduct	Refers to firms' behaviour in the market, including production, buying and selling decisions.	We will examine the relationship between participant behaviour and market outcomes and seek to understand the incentives driving that behaviour.
Performance	Refers to market outcomes, usually by reference to concepts of efficiency.	We will examine the efficiency of the market separately to the competitiveness of the market. A competitive market may still have inefficient outcomes.

We have relied on data from AEMO's Market Management System (MMS) and publicly available information. Since our 2024 report, we have added analysis using data from our first Electricity Market Monitoring Information Order (MMIO-ELEC-2025-02). The collection and monitoring of this contract-related information has enabled us to build a more holistic view of wholesale markets by including participants' contracting behaviour, which has significantly improved our capability to evaluate performance, competition and efficiency. We have supplemented this analysis with ASX data and assessed traded volumes, liquidity and hedging behaviour to provide additional context on how participants manage price risk and the extent of trading activity ahead of contract periods.

We have included an update on the progress of the energy transition by examining changes in the generation mix, including both generation output and installed capacity. We have assessed how these changes have affected market outcomes, including price dynamics, variability across the day, system reliability and security, and emissions.

In assessing market structure and participant behaviour, we have adopted a trading rights framework to allocate generation capacity and output. This approach attributes ownership based on the entity that controls the output of a generating unit, including through power purchase agreements and tolling arrangements. This is intended to better reflect the incentives faced by market participants when making bidding and investment decisions. Where information on ownership of output is not publicly available, we have attributed ownership based on asset ownership. Where multiple owners were invested in a generating unit, the output of that unit was split proportionally between owners according to their percentage of total ownership.

We have also incorporated a range of metrics that are designed to support the analysis of participant conduct and outcomes under different system conditions.

A number of metrics make use of proxies or simplifying assumptions to enable consistent and comparable analysis across regions and over time. For example, surplus capacity is calculated as the difference between available capacity and load, which provides an indication of system tightness. Similarly, in our FCAS analysis we used observed regional prices to distinguish between local and global market outcomes. These approaches are intended to provide a practical representation of complex system dynamics using available data.

In most cases, metrics have been calculated at the 5-minute dispatch interval level, consistent with how the market operates, then aggregated to 30-minute, quarterly or annual levels to identify broader trends over time. We have also used volume weighted averages, meaning periods of higher demand have a proportionally greater influence on results. The aggregation of 5-minute data into longer time periods and averages may reduce the visibility of short-term variability or extreme events.

Unless otherwise stated, contract volumes are expressed in terawatt-hours (TWh), participant-level results are aggregated at the corporate group level where appropriate, and small categories may be combined to improve readability and manage confidentiality risks.

The dollar values used in this report are nominal. Where this is relevant, the word nominal has been added to the figure axis.

References to OTC contracts in this report mean OTC standard contracts with terms that reflect the essential characteristics of ASX-traded base futures, caps, morning peak futures, evening peak futures, average rate options and base strip options, although the terms may not be identical. Differences may include the cap strike price, contract period, and margining and settlement terms. Load-following swaps are an example of contracts excluded from this definition.

2 Market conditions

Metric	Figure	Methodology and assumptions
Annual volume weighted average prices in the NEM	2.1 2.2 2.3	Sum of price multiplied by native demand for every 5-minute dispatch interval divided by the sum of all native demand in the year. We define native demand as the sum of initial supply and total intermittent generation in a region. For the contribution by price band, we only used intervals where the 30-minute price was within the defined bands. For prices by time of day, we only used intervals that fell within the time band.
Revenue by time of day	2.4	Sum the revenue earned in each time band based on 30-minute settlement data.
Daily settlement prices of calendar year base futures and caps	2.5 2.6	Daily settlement prices ($/MWh) for calendar-year base futures and caps. Prices are shown separately by NEM region, with each curve representing a different delivery calendar year.
Registered capacity by fuel type	2.7	Registered capacity refers to the highest amount of electricity a generator has been registered to produce per hour. A typical generator will produce electricity at a rate lower than its registered capacity most of the time, with different generation technologies able to produce electricity at different rates relative to their capacity. Loads and non-scheduled generation have been excluded. For solar and battery units, we used the maximum capacity metric rather than registered capacity because inverter constraints may prevent these units from dispatching their full registered capacity. Rooftop solar is behind-the-meter rather than being NEM registered generation capacity.
Generation as a share of total generation by fuel type	2.8 2.9	Sum of generation as a share of total generation over the relevant period for each fuel type including rooftop solar output in metered output.
Generation by fuel type and emissions	2.10 2.13	Sum of generation over the relevant period for each fuel type. We did not include rooftop solar output in generation output. Average generation by time of day is the sum of generation for each 30-minute interval divided by the number of trading days in the period.
Average native demand	2.11 2.12	Native demand represents the sum of total demand and total non-scheduled generation. For average native demand by time of day, we summed the total demand for each individual interval and divided it by the number of days in the period to find an average. Variation from average daily demand compared the time-of-day averages to the daily average, using 30 minute data.
Average available capacity factor for	2.14	Available capacity factor represents a generator's capacity available for dispatch compared to its registered capacity. For

black and brown coal		black coal, this has been done including and excluding Liddell and Callide C, as Liddell closed in 2023 and Callide C had an extended period offline due to a major failure in 2021.
Planned and unplanned coal outages	2.15	Time weighted MW maximum capacity average over the entire quarter, calculated at the 5-minute interval.
Monthly input cost of coal per MWh	2.16	We source coal prices (in USD per tonne) from GlobalCOAL and use the Newcastle coal price index as a reference price for spot thermal coal at Newcastle Port in NSW. To convert coal prices from USD per tonne to AUD per MWh, we use the following formula: $ per MWh = coal cost (USD per tonne) x exchange rate (monthly average) x heat rate (GJ per MWh) / low heating value (GJ per tonne) We used a constant heat rate of 9 GJ per MWh, and a low heating value of 23 GJ per tonne.
Monthly input cost of gas per MWh	2.17	We used Brisbane, Sydney and Adelaide Short Term Trading Market and Victorian Declared Wholesale Gas Market gas spot prices ($ per GJ). To convert the gas prices from $ per GJ to $ per MWh we used the following formula: $ per MWh = gas cost ($ per GJ) x heat rate (GJ per MWh) We used a constant heat rate of 8 GJ per MWh.
Price setter by fuel type	2.18 2.19 2.20 2.21 2.22	For each region, the highest priced offer needed to meet demand generally sets the price (dispatch price) for each 5-minute dispatch interval. There can be more than one unit that contributes to setting the price and AEMO's dispatch algorithm co-optimises energy and frequency control ancillary service (FCAS) offers to find the cheapest option for supply to meet demand. We counted each 5-minute interval each fuel type contributed to setting the price. Where 2 units of the same fuel type set a price, they were counted as one occasion. Where 2 units of different fuel types set a price, each fuel type was counted for that 5 minutes. We scale the proportions of time setting price so that they scale to 100%. We did not include instances where constraints, interconnectors or FCAS contributed to price setting. We also excluded intervals where the administered price cap was breached and when the market was suspended.
Global and local FCAS costs	2.23	We estimated local and global FCAS costs as equal to the estimated revenue for each local and global FCAS market. We calculate the revenues as the sum of the estimated revenues for each generating unit that provides a global or local service.
Quarterly global FCAS prices	2.24	We used the NSW FCAS price as a proxy for the global price as no official global FCAS price exists. For Queensland and South

		Australia, if the price differed from the NSW price, we considered that price to be a local price for that region. For Tasmania: • If the price equalled the NSW price, we deemed it to be global. • If the price differed from the NSW price by less than or equal to $0.01 AND the Basslink target flow is all priced at less than or equal to $0.01 or lower, we deemed it to be global. Otherwise, we considered the price to be local.
FCAS revenue as a percentage of wholesale market revenue by region	2.25	Total FCAS revenue is equal to the sum of FCAS enablement revenue for each region divided by the annual energy revenue for each region.

3 Contract markets

Metric	Figure	Methodology and assumptions
Traded volumes in ASX electricity contracts	3.1	Total traded volumes of ASX electricity contracts during each calendar quarter, aggregated by contract type and expressed in TWh. Volumes are grouped by the quarter in which trades occurred, rather than the delivery period of the traded contracts. Calculated using ASX Energy trade log data.
ASX liquidity ratio	3.2	Liquidity ratio is calculated as ASX contract traded volume divided by NEM native demand, with both measured in TWh. Contract volumes are allocated to the delivery period specified in the contract, rather than the period in which the contract was traded. For contracts covering more than one quarter, volumes are prorated across the relevant delivery periods.
ASX daily open interest	3.3	Daily open interest refers to ASX Energy futures and options contracts that remain outstanding as at close of business on the previous trading day. Open interest is summed by ASX electricity contract type across all NEM regions.
ASX base futures daily price movements	3.4	Distribution of absolute daily price movements for quarterly base futures, expressed as a percentage of observations within each quarter. Only contracts with delivery starting in the next four quarters are included, as these contracts are more liquid. Prices are included for Queensland, New South Wales and Victoria only. South Australia is excluded due to lower liquidity, which may make settlement prices less representative of the underlying contract value.
Volume-weighted average premium and strike price of ASX options	3.5	Volume-weighted average premiums and strike prices ($/MWh) are calculated using traded volume (MWh) as weights. The analysis includes ASX-traded electricity options, including swaptions and average rate options. Results are shown separately for calls and puts, with each curve representing a different NEM region. South Australia is excluded due to lower liquidity.
Proportion of ASX-traded volume by participant type	3.6	Proportions of ASX-traded volume are calculated over the 2021–2025 period as reported traded volume from energy market participants, collected through MMIO, divided by total ASX-traded volume. The top 5 energy market participants are selected separately by purchase/sale direction and contract type, and may therefore differ across categories. Energy market participants outside the top 5 are grouped as other energy market participants. The difference between reported energy market participant traded volume and total ASX-traded volume is assumed to reflect non-energy market participant activity. Results are shown separately by contract type and purchase/sale direction.

Total reported traded volume by participant type and trade type	3.7	Total reported quarterly traded volumes collected through MMIO are presented separately for ASX purchases, ASX sales, OTC purchases and OTC sales. Purchases are shown as positive values and sales as negative values. The top 5 energy market participants are identified based on total traded volume across all trade types, with remaining energy market participants grouped as other energy market participants.
Energy market participant and total market open interest	3.8 3.10	Daily open interest is shown in TWh for all ASX Energy contracts. Total market open interest refers to ASX-reported open interest. Each MWh of ASX open interest reflects one market participant holding a 1 MWh long position and another market participant holding a 1 MWh short position. Reported energy market participant open interest is estimated separately for long and short positions using MMIO-reported exchange trade data. A reported position is assumed to contribute to open interest where it has not been closed out or expired. Only 2024 and 2025 are shown because the reported trade data covers trades from 2021 to 2025, and ASX Energy contracts can be traded more than three years ahead of delivery.
Energy market participants' share of total ASX traded volume	3.9 3.11	Energy market participants' shares of ASX-traded volume are calculated as reported purchase or sale volume divided by total ASX-traded volume, shown on the secondary vertical axis. For Figure 3.9, the top 5 energy market participants are identified separately by purchase/sale direction. For Figure 3.11, they are identified separately by purchase/sale direction, trading year and contract type. All remaining energy market participants are grouped as other energy market participants. The top 5 may differ across categories. Non-energy market participants also trade ASX electricity derivatives but are excluded from the chart, so the percentages do not sum to 100%. The secondary line shows total annual ASX-traded volume in TWh, by state for Figure 3.9 and by contract type for Figure 3.11.
Energy market participants' share of total ASX open interest by contract type	3.12	Energy market participants' share of total ASX open interest is calculated as average daily estimated energy market participant long/short open interest divided by average daily total ASX open interest over 2024–2025, by contract type. Results are shown separately for long and short positions. Each stacked column represents one contract type and position direction, with the share split between the top 5 energy market participants and other energy market participants. The top 5 are identified separately for each contract type and direction, so their composition may differ across categories. Non-energy market participants also hold ASX electricity derivatives but are excluded from the chart, so the percentages do not sum to 100%.

ASX hedging horizon: energy market participants vs non-energy market participants by contract type for contracts expiring in 2025	3.13	This metric shows ASX-traded volume (in MWh) shares by participant group, purchase/sale direction and hedging horizon for contracts expiring in 2025. Hedging horizon is calculated as the number of days between the trade date and contract expiry date, with trades grouped into hedging horizon buckets. For each contract type, direction and hedging horizon bucket, participant shares are calculated as traded volume for each group divided by total ASX traded volume, so each stacked column sums to 100%.
		Participant groups comprise the top 5 energy market participants, other energy market participants and non-energy market participants. The top 5 energy market participants are identified using MMIO-reported ASX-traded volume for contracts expiring in 2025, separately for each purchase/sale direction and contract type. The composition of the top 5 may therefore differ across direction and contract type combinations. Remaining MMIO-reported energy market participants are grouped as other energy market participants. Any ASX-traded volume not reported through MMIO is assumed to reflect non-energy market participant activity. The secondary line shows total ASX traded volume for each hedging horizon bucket.
ASX hedging horizon composition : top 5 energy market participants vs other energy market participants by contract type for contracts expiring in 2025	3.14	This metric shows the hedging horizon composition of MMIO-reported ASX-traded volumes in MWh for energy market participants for contracts expiring in 2025. Hedging horizon is calculated as the number of days between the trade date and contract expiry date, with trades grouped into hedging horizon buckets. For each contract type, purchase/sale direction and participant group, traded volumes are allocated across hedging horizon buckets and expressed as shares of total traded volume for that contract type, direction and participant group. Each stacked column therefore sums to 100%. Results are shown separately for the top 5 energy market participants and other energy market participants and exclude ASX-traded volume not reported through MMIO.
Total ASX and OTC traded volume reported by energy market participants	3.15	Total ASX and OTC purchase and sale volumes reported to the AER through MMIO. Purchases are shown as positive values and sales as negative values. The figure reflects reported energy market participant activity and does not include trades by non-energy market participants, such as banks or trading businesses, where these trades are not reported through MMIO.
ASX and OTC shares of total reported volume by state	3.16	ASX and OTC shares are calculated as each market’s share of total reported standard contract traded volume for each state and year. The figure provides an indicative comparison by state based on trades reported to the AER through MMIO by energy market participants and excludes trades by non-energy market participants where they are not reported through MMIO.

Volume comparison of reported ASX and OTC trades by contract type	3.17	Reported ASX and OTC traded volumes from 2021–2025 are compared by contract type. The first chart shows total reported volume by contract type and market type, while the second chart shows each contract type's share of reported ASX and OTC volume.
Reported volumes of OTC caps by different strike price	3.18	Reported OTC cap purchase and sale volumes from 2021 to 2025 are broken down by strike price. Differences between reported purchase and sale volumes reflect the MMIO reporting scope. Non-energy market participants are not required to report trades to the AER under MMIO, so where one counterparty is a non-energy market participant, the trade may only be reported by one party.
Reported traded volumes of OTC peak contracts by state	3.19	Reported OTC peak swap traded volumes from 2021 to 2025 are broken down by NEM region and presented separately for morning peak and evening peak swaps.
Share of reported PPA volumes by fuel type	3.20	Reported PPA volumes from 2021 to 2025 are broken down by fuel type and presented separately for purchases and sales. Differences between purchase and sale shares by fuel type reflect the MMIO reporting scope. Non-energy market participants are not required to report trades to the AER under MMIO, so where one counterparty to a PPA transaction is a non-energy market participant, the trade may only be reported by one party.

4 Market structure

Metric	Figure	Methodology and assumptions
Herfindahl-Hirschman Index (HHI) for bids	4.1 4.2 4.3	HHI provides an indication of market concentration and can range from close to zero (in a market with many small firms) to 10,000 (for a monopoly). We calculate HHI based on 5-minute bid availability, which means the measure accommodates the intermittency of generation due to plant outages, cloudy or calm weather or other reasons. HHI is calculated for each region by summing squared market shares, based on 5-minute bid availability, of all participants in the market. We excluded market suspension periods from the analysis, as well as administered price cap periods where the price was at the cap. We included bid availability from all market scheduled and semi-scheduled generating units in the analysis, as well as from wholesale demand response and bidirectional units.
Market share by generation output	4.4 4.5	This metric represents a participant's share of energy delivery and reflects the nature of a market participant's generation fleet and contribution to market outcomes. Market share by output is calculated using metered data for each region and includes all market scheduled and semi-scheduled generating units. Output from rooftop solar systems and non-scheduled units is not included. Interconnectors are not included in market share calculations and are reported separately. Energy consumption, including from scheduled loads and bidirectional units, is also not included in the analysis.
Market share by registered capacity	4.6 4.7 4.8 4.9	Market share by registered capacity measures a participant's share of total registered generation capacity at a point in time. We present this measure in several ways. The primary category used in this report is dispatchable generation. This includes all scheduled generating units and excludes semi-scheduled or non-scheduled units. We also present market shares by service type. The NEM wholesale market settings review categorised the replacement capacity for outgoing coal generation according to 3 types – bulk energy, shaping and firming – depending on the service it provides to the market. In this report, bulk energy includes grid-scale wind and solar generating units. Shaping includes battery and pumped hydro units. Firming includes gas, hydro (excluding pumped hydro), diesel and other liquid fuel generating units. Throughout this analysis, maximum capacity was used instead of registered capacity for solar and battery units, because inverter constraints prevent these units from dispatching their full registered capacity.

Pivotal supplier test (PST)	4.10 4.11 4.12	PST measures the extent to which one or more participants are 'pivotal' to clearing the market and indicates the risk of exercise of market power. A participant is pivotal if market demand exceeds the capacity of all other participants including possible imports via interconnectors (import and export limits). In these circumstances, the participant must be dispatched (at least partly) to meet demand. Proportion of time outcomes were determined by identifying all 5-minute periods throughout the year when either one participant or some combination of two participants was pivotal to meeting demand.
Registered capacity for each FCAS service	4.13 4.14	Shows the total maximum capacity (MW) registered to provide each service by provider in Queensland and South Australia as at 7 April 2026.
Daily average capacity offered and daily maximum local requirement for 1 second lower service	4.15	The stacked area shows the daily average actual capacity (MW) offered in the local 1 second service by registered participant in South Australia each day in 2025. The line shows the highest local 1 second FCAS requirement in South Australia each day.
Interconnection in the NEM	4.16	The interconnector map illustrates the 'import limit' and 'export limit' of interconnectors, which indicate the amount of generation that can flow in or out of a region.
Inter-regional trade	4.17	Gross amount of energy (TWh) imported and exported annually by each region.
Price alignment	4.18	Regional price alignment shows the proportion of the time that prices in one NEM region were the same as those in at least one neighbouring region. Entire mainland price alignment shows the proportion of the time prices in all mainland NEM regions were the same. Transmission losses were accounted for.
Proportion of time an interconnector is export-constrained or import-constrained	4.19	An interconnector is export-constrained if the technical limit prevents further exports, and import-constrained when the limit prevents further imports. The technical limit can change depending on the direction of flow, network outages, other physical constraints and limits imposed by AEMO to manage system security. This metric measures the proportion of time each month that the interconnector was export-constrained or import-constrained. At times, an interconnector's export and import limits may be equal. For these intervals, we used regional prices to classify the constraint direction. We classified the interconnector as export-constrained when the price was lower in the exporting region, and as import-constrained when the price was lower in the importing region. By convention, an interconnector's exporting region is the region to the south or east and its importing region is the region to the north or west.

Average monthly export and import limit when binding	4.20	The daily MW export or import capacity when the interconnector was constrained averaged monthly.
Proportion of SRA units purchased by energy market vs financial participants for 2025 products	4.21	Share of settlement residue auction units purchased by energy market participants and financial participants for each interconnector direction, using all 12 tranches for the 2025 products. Volumes include units which were later sold as secondary units.
Average unit price for each tranche by interconnector for 2025 products	4.22	Average SRA unit price for each tranche by interconnector, across all quarterly products for 2025.

5 Participant conduct

Metric	Figure	Methodology and assumptions
Energy bids and rebids FCAS bids	5.1 5.2 5.3	Uses AEMO's BIDDAYOFFER table and includes a count of all bids made into the market. The data is presented in several different ways: • by 'initial offers' (bids made prior to gate closure, at 12.30 pm the previous day) and 'rebids' (bids made after gate closure, once price bands are set) • FCAS market bids and energy market bids • bids made by different fuel types 'Other fuel types' include brown coal, liquid fuels, scheduled loads, virtual stations and demand response aggregators.
Offers	5.4 5.5 5.6 5.7 5.8 5.11 5.14 5.15 5.16 5.17 5.21 5.22 5.23 5.24 5.25 5.26 5.27 5.30 5.31 5.33 5.34 5.36	We create illustrative price bands to effectively display aggregate offer data. For each price band, we sum the total capacity offered within that range in each dispatch interval and divide by the number of intervals in the relevant period to calculate average offered capacity. This provides an average offer figure. We calculate these averages over annual, quarterly and monthly periods, and by time of day. For time-of-day analysis, we sum the total capacity offered by price band at each 30-minute interval and divide by the number of trading days in the period. Some charts show the proportion of capacity offered within specified price bands. We calculate this by dividing the capacity offered within each price band by the total capacity offered within the relevant period. Other charts show the change in capacity offered within specified price bands between two periods. Some charts in the chapter use cumulative price thresholds. For example, one series on a chart might show the change in capacity offered below $0 per MWh, while another shows the change in capacity offered below $50 per MWh, which includes the first series plus the change between $0 and $50 per MWh. Average offers have variously been grouped according to region, price band, fuel type, market participant, power station or generating unit. Fixed load is the part of an offer that effectively gives AEMO a target that a unit must run at. We treat this as an offer priced less than $0 per MWh as the unit must be dispatched.
Prices set	5.13	For each region, the highest priced offer needed to meet demand generally sets the dispatch price for each 5-minute dispatch

	5.19 5.20 5.29	interval. More than one unit may contribute to setting the price. AEMO's dispatch algorithm co-optimises energy and frequency control ancillary service (FCAS) offers to find the cheapest option for supply to meet demand.
	5.32 5.35	We present price setter data by the proportion of time setting price and by average price set, with results grouped by fuel type, participant or station. To calculate the average price set by a fuel type, participant or station within a given period and region, we sum the prices it set and divide by the number of times it set price. We scale the proportions of time setting price so that they scale to 100%. For charts showing price setters by fuel type, participant or station, multiple units in the same category that set the price in the same dispatch interval were counted as one occasion. Where units from different categories set the price, each category was counted once for that interval. For example, two solar units setting price in the one dispatch interval was counted as one instance of solar setting price. We excluded instances where constraints, interconnectors or FCAS contributed to price setting. We also excluded intervals where the Administered price cap was breached and when the market was suspended.
Surplus capacity and residual demand levels	Box figure 5.1 Box figure 5.2 5.9 5.10 5.12 5.18	Box figures 5.1 and 5.2 - Percentage of dispatch intervals in NSW in 2021 and 2025, by surplus capacity and residual demand levels. Figure 5.9 and 5.10 - Average % of NSW battery effective capacity (standalone and in-portfolio) willing to be dispatched (offered below ROP) in 2025, by surplus capacity and residual demand levels. Figure 5.12 - Average % of NSW gas generators' effective capacity offered below the threshold price in 2025 by surplus capacity and residual demand levels. The price threshold is the total of ISP-indicated SRMC and a buffer (the higher of $50/MWh and 25% of their individual SRMC). Figure 5.18 - Average % of NSW black coal generators' effective capacity offered below the threshold price in 2025 by surplus capacity and residual demand levels. The price threshold is the total of ISP-indicated SRMC and a buffer ($50/MWh).
Annual output from Snowy Hydro's hydro assets in NSW	5.28	Annual metered output from Snowy Hydro's Tumut 3, Upper Tumut, Guthega and Blowering power stations (Station IDs SNOWY1, SNOWY2, SNOWY3 and SNOWY6).

6 Entry and exit

Metric	Figure	Methodology and assumptions
Net cumulative new capacity in the NEM	6.1	Net capacity is the sum of new capacity less the sum of closed capacity for each fuel type. We used registered capacity, except for solar and batteries where we use maximum capacity. The new entry date is taken as the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar.
Volume weighted average revenue and costs	6.2 6.5 6.6 6.7	This metric compares the revenues earned by different technologies from the spot market over the last 5 years to the 2025 cost of new generation for that technology. This indicates the likely prospects for new entry for each type of technology, for example, if revenue exceeds cost, then there is likely an incentive for new entry. The revenue each technology earned is calculated as the sum of price multiplied by the generation of the specific fuel type for every 5-minute interval in the year divided by the sum of total generation by the fuel type in the year. We summed the MW amount generated by the units belonging to each fuel type at the start of the period (INITIALMW) as total generation. We shifted the INITIALMW value by 5 minutes for solar, wind, gas and coal generation in our calculations. For battery, we took the original INITIALMW value as generation. The 2025 cost is the levelised cost of electricity (LCOE) for new generation and the levelised cost of storage (LCOS) for new storage from the CSIRO analysis as part of the 2025–26 GenCost report. This analysis is only intended to provide an indication. Real-world investment decisions are based on a range of factors including future expected revenue, contract arrangements, other sources of revenue, market conditions and confidence.
Wholesale market revenue by fuel type	6.3	We compared the specific fuel type's annual volume weighted average price in each region as calculated in Figure 6.2 to that region's annual volume weighted average price.
Large-scale generation certificate spot and forward prices	6.4	Figure 2.2 of the Clean Energy Regulator's quarterly carbon market report December 2025.
Government tender schemes	6.8 6.9	Information on successful tenders was taken from the ASL tender announcements and the status of the projects was taken from AEMO's July 2026 generator information. Capacity for each project was based on the tender information announcements.
Cumulative exit from the NEM	6.10	Sum of registered capacity for units expected to close based on AEMO's July 2026 Generating unit expected closure year.

Average output from Yallourn, Eraring and Gladstone	6.11	Sum of the hourly average of each generating unit's metered generation for each 5-minute interval in the year.
System security costs	6.12	Figure 70 of AEMO's Quarterly Energy Dynamics Q4 2025.
Hours and impact from network congestion	6.13	The binding hours and impact of system normal constraints was used to provide an indication of network congestion. This metric excludes impacts from FCAS, outages, network support and commissioning constraints. The data is from AEMO's NEM Constraint Report 2024 summary data.