Methods and Assumptions

Wholesale electricity market performance report 2024

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AUSTRALIAN ENERGY REGULATOR

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Contents

Background

The National Electricity Law (NEL) requires the AER to monitor the wholesale market and report on its performance at least every 2 years.[1] Particularly, the NEL stipulates that the report must contain a discussion and analysis of the monitoring methodology applied and the results of indicators, tests and calculations performed.[2]

This methodology document contains a discussion of the analysis undertaken in our *Wholesale electricity market performance report 2024* (WEMPR) and aims to communicate how we have used data sources to form metrics as supporting evidence. It includes information on metrics we have had regard to in WEMPR, the method we have applied, the data sources for our analysis, and references to the relevant figures in WEMPR.

Our Enhanced wholesale market monitoring guideline provides more information on the general approach we have taken in WEMPR.[3]

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1 National Electricity Law, Part 3 Division 1A

2 NEL, Section 18C(3)(d)

3 See also our Wholesale performance reporting webpage.

1 Volume weighted average price

What is this?

Volume weighted average (VWA) price is a measure of average wholesale electricity price for each National Electricity Market (NEM) region. This metric is useful in showing trends in average prices in the market.

Quarterly VWA price is the sum of 5-minute prices multiplied by native demand in each region for every 5 minutes in a financial quarter, then divided by the sum of all native demand in each region for every 5 minutes in a financial quarter. Likewise annual VWA price is calculated on an annual basis.

The contribution to VWA price by each price band is calculated by summing the product of 30-minute prices and native demand only when 30-minute prices are within the defined bands, then dividing by the sum of native demand for every 30 minutes in a financial quarter.

In performing a count of prices, we take all 30-minute prices for a period and compare them to a set threshold. If a price exceeds the threshold it receives a count of one. We then add up all counts for each region.

For prices by time of day, we sum the product of the 5 minute interval price and native demand, then divide it by the sum of native demand in those intervals. For example, to find the annual VWA price at 6.30 pm, we sum the product of price and demand for every 6.30 pm interval in the year, and divide by the annual total demand at 6.30 pm.

Where is the data from?

5-minute prices in each region and native demand in each region are sourced from the Australian Energy Market Operator's (AEMO's) Market Management System (MMS) database.

What factors are considered?

- Demand—The AER defines native demand as the sum of initial supply and total intermittent generation in a region.
- Price bands—The price bands used are prices less than or equal to $0; greater than $0 and less than or equal to $50; greater than $50 and less than or equal to $100; greater than $100 less than or equal to $500; greater than $500 and less than or equal to $5,000; greater than $5,000.
- Regions—VWA price is calculated for each NEM region.

Reference to figure in WEMPR

Figure 2.1, Figure 2.4, Figure 2.16, Figure 2.17, Figure 7.4, Figure 7.5, Figure 7.6, Figure 7.7

2 Generation output by fuel source

What is this metric?

Electricity generation by fuel source is the total generation output in the NEM as a whole or in each NEM region. It may describe either the total amount or the proportion of output from each fuel type in the relevant period. When calculating the proportion of output from each fuel source, we included rooftop solar output in total generation output.

In some charts, we displayed electricity generation by fuel source by time of day. To do this, we sum the generation for each matching 30-minute interval and divide it by the number of trading days in the period. For example, to find annual average generation at 6:30 pm, we sum the generation for each fuel type at 6:30 pm and divide by the number of days in the year.

For some charts, we displayed average generation levels which we represented using megawatts (MW) or gigawatts (GW) as the unit of output. For other charts, we summed metered generation on a 30-minute basis and divided by 2 to express a figure in megawatt hours (MWh).

Where is the data from?

Other than rooftop solar, data is sourced from AEMO’s MMS database. Rooftop solar data is sourced from other published datasets from AEMO. The data is organised by financial year, except for rooftop solar prior to 2016–17. Due to limitations in the source data, calendar year data is used for rooftop solar up to 2016–17 (2015–16 uses 2016 data etc.). From 2017–18, figures represent actual financial year data.

Reference to figure in WEMPR

Figure 2.9, Figure 2.10, Figure 2.12, Figure 2.18, Figure 7.2.

Figure 5.15 uses this method as well as the method from section 3 Energy consumption by battery storage.

3 Energy consumption by battery storage

What is this metric?

This metric shows the consumption of energy by battery storage units in the NEM.

Where is the data from?

Data is sourced from AEMO’s MMS database.

How is it calculated?

For battery storage energy consumption by time of day, we sum the consumption for each matching 30-minute interval and divide it by the number of trading days in the period. For example, to find annual average consumption at 6:30 pm, we sum the consumption for each scheduled battery storage unit at 6:30 pm throughout the year and divide by the number of days in the year.

Reference to figure in WEMPR

Figure 5.15 uses this method as well as the method from section 2 Generation output by fuel source

4 Baseload outages

What is this metric?

Baseload generators are units that generate for almost all dispatch intervals and provide a steady supply to the market.

For this metric, a unit is measured as experiencing an outage when the capacity dispatched for the day is equal to zero, with the outage attributed to a unit equal to its registered capacity (MW). A unit's actual maximum capacity can differ from its registered capacity due to changing performance of units through time and seasonal factors.

There is no distinction made between planned and unplanned outages for this analysis. We combined the registered capacity of all units that had zero dispatch in a day and averaged this figure for each month and financial year.

Where is the data from?

Data is sourced from AEMO's MMS database.

Reference to figure in WEMPR

Figure 2.7

5 Available capacity factor

What is this metric?

Available capacity factor represents a generator's capacity available for dispatch compared to its registered capacity. This analysis compared black and brown coal generator's availability for 30-minute intervals to registered capacity. This was then averaged for each quarter.

Where is the data from?

Data is sourced from AEMO's MMS database.

Reference to figure in WEMPR

Figure 2.8

6 Price setter by fuel type

What is price setter?

The price for each region in the NEM is set every 5 minutes. For each region, the highest priced offer needed to meet demand generally sets the price (dispatch price). There can be more than one unit contributing to setting the price. The market operators dispatch algorithm co-optimises energy and frequency control ancillary service (FCAS) offers to come up with the cheapest option for supply to meet demand.

Price setter by fuel type shows which fuel type contributed to setting the price.

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we determine who set price?

AEMO publishes data which identifies what contributed to setting the price every 5 minutes. This can contain units, constraints and interconnectors. It can also contain other markets, such as FCAS, that contributed to setting the price for energy.

We determined which units contributed to setting the price every 5 minutes. We then looked at what fuel source that unit used and gave it a count of one for that 5 minutes.

We then added up the counts of each fuel type and divided it by the number of 5-minute intervals that a unit set the price in that period for each region to make it a percentage.

We also calculated the average price when each fuel type was setting price. This was done by adding the offer prices together of each fuel type then dividing it by the number of 5-minute intervals that a unit set the price in that period.

- Exclusions—We didn't include constraints or interconnectors as contributing to price setter as they don't have a fuel type. We also excluded occurrences of loads setting price. We were only concerned with energy offers so we did not include when FCAS offers contributed to setting the price in the energy market. We also excluded intervals where the Administered price cap is breached and when the market has been suspended.
- Assumptions—If there were 2 units setting a price both with the same fuel type, they were counted as one occasion for that fuel type each 5 minutes. If they were different fuel types setting a price then each fuel type would get a count for that 5 minutes. The occasions were then converted to 100 per cent.

For price setter by time of day, we sum the price setter count for a particular dispatch interval and divide it by the number of trading days in the period. For example, to the proportion of fuel types setting price at 6.30 pm in 2019, we sum the counts for each fuel type at the 6.30 pm dispatch interval for a year and divide by the number of days in the year to get a percentage.

Reference to figure in WEMPR

Figure 2.13, Figure 2.14, Figure 2.15, Figure 7.8

7 Price setter by scheduled loads

What is this metric?

The price for each region in the NEM is set every 5 minutes. For each region, the highest priced offer needed to meet demand generally sets the price (dispatch price). There can be more than one unit contributing to setting the price. The market operators dispatch algorithm co-optimises energy and FCAS offers to come up with the cheapest option for supply to meet demand.

Loads are usually excluded from our price setter analysis, but they can set price – for example, if it is cheaper to reduce scheduled load consumption by 1 MW than to dispatch an extra MW of generation. Our analysis of price setter by scheduled loads looks at the proportion of time that loads set price in the market.

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we calculate it?

We counted the instances of scheduled loads setting price in each region for each hour of the day in a financial year. We then divided each of these hourly totals by the number of days in the year. This gave us a proportion of the time that loads set price for each hour of the day in each region. For example, to calculate the proportion of time that loads set price in Queensland at 7 am in 2023–24, we counted all instances throughout the financial year where loads set price in Queensland between 7:00 am and 7:55 am and divided this by 366.

Reference to the figure in the report

Figure 5.16, Figure 5.17, Figure 7.9

8 Average native demand by time of day

What is native demand?

Native demand represents the sum of total demand and total non-scheduled generation[4]

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we determine average native demand by time of day?

AEMO publishes data on demand for every 5-minute dispatch interval. We summed native demand for each of the 6 dispatch intervals that make up a 30-minute interval to find total demand for each 30-minute interval.

To find 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. For example, to find annual average demand at 6:30pm, we summed the demand for each 6:30pm interval and divided by the the number of days in the year.

Reference to figure in WEMPR

Figure 2.11, Figure 7.1

4 More information on the inputs to calculate native demand can be found in AEMO's Demand terms in MMS data Model, June 2024.

9 Trading Rights

What are trading rights?

Trading rights is a metric unique to the AER that seeks to capture the owner of the output of a generating unit. We track ownership of output because it is likely to influence how the buyer operates its broader portfolio. It may also give the owner control or influence over the trading of that particular unit. Ownership of output can come about due to:

- Ownership of the asset itself (and direct control/influence over trading).
- Power purchase agreements (PPAs), where a purchaser signs a contract with a generator (often an intermittent renewable generating unit) for the sale and supply of energy.
- Tolling arrangements, which give the purchaser the ability to direct how the unit is operated and dispatched.

In cases where we did not find publicly available information about the owner of a unit's output, we allocated the unit's trading rights to the owner of the asset itself.

Where do we get the data from?

Publicly available online sources such as company websites and news reports

What are the changes from the WEMPR 2022?

For our 2022 report, we allocated trading rights to the owner of a unit's output only in cases where the owner was a participant with its own generation assets. If the purchaser of the output did not have its own assets (or where we could not find information about output ownership), trading rights were instead allocated based on asset ownership information published by AEMO on their 'generation information' and 'registrations and exemptions' pages. Where an intermediary operated on behalf of the owner, the market share for that capacity was attributed to the intermediary. This method has been updated for our 2024 report.

In our 2024 report, we have allocated trading rights to the owner of the output regardless of whether the owner is a participant with its own generation assets. For example, in the case of Gladstone power station in Queensland, likely about half of the output is traded by CS Energy with the other half purchased by Boyne Island Aluminium Smelter. Previously we had allocated 100% of trading rights to CS Energy because the smelter does not have its own generation portfolio. However, this approach may have overstated CS Energy's market share and Queensland market concentration. In 2024 we have allocated 50% ownership of output to CS Energy and 50% to the smelter. This has led to updated results for our market share, Herfindahl-Hirschman Index (HHI) and pivotal supplier test (PST) metrics. In 2024, where we have not been able to find information on ownership of output, we have attributed trading rights to the owner of the asset (using publicly available information).

We will continue to review our method for allocating trading rights seeking to most accurately assess the structure of the market.

10 Market share by generation capacity

What is market share by capacity?

Market share by capacity represents the potential share that a participant is able to provide to the market.[5] It is a good overall measure of total market capacity. However, this measure does not account for outages or how different types of plant are offered into the market. This measure does not capture factors that may affect a participants' ability to generate such as network constraints, fuel availability and plant conditions.

Where is the data from?

Registered capacity of each generating unit in the NEM is reported to AEMO and is shown in the unit standing data information in AEMO's MMS database. We used registered capacity as at 30 June each year allocating this based on trading rights over the unit at that date.

Our method for allocating trading rights for each generating unit has changed since our 2022 report. Please refer to section 9 Trading Rights for an explanation of these changes.

How did we determine market share by capacity?

- Resolution—Market share by capacity is based on registered capacity as at 30 June of each year. We included all market scheduled and semi-scheduled generating units in the NEM.
  - *For solar generators*, maximum capacity was used rather registered capacity, because inverter constraints prevent solar units from dispatching their full registered capacity.
- Interconnectors—Interconnectors are not included in market share calculations and are reported separately.
- Market Loads—Were excluded from the analysis.
- Regions—Market share is calculated for each NEM region.
- Fuel type— Our share of fuel type analysis included only coal, gas, battery storage, hydro, wind and solar. Other fuel types such as liquid and biomass were excluded.
- Participant controlling the relevant asset—Control is determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset.

Reference to figure in WEMPR

Figure 4.1, Figure 4.6, Figure 4.7, Figure 4.8, Figure 4.9, Figure 7.24, Figure 7.26

5 There are entities that own trading rights that are not participants in the wholesale market. In the charts in the report all of these entities are grouped within the "other" category, except for 7.24 which includes the ACT government.

11 Market share by generation output

What is market share by generation output?

Market share by generation output represents a participant's share of annual energy delivery. It better reflects the nature of a market participant's generation fleet and contribution to market outcomes but may under-represent market participants with flexible generation plant that are able to respond to peak prices but are operated infrequently.

Where is the data from?

Generation market share uses 30-minute metered data, aggregated for 2023–24 financial year and expressed in terawatt hours sourced from AEMO's MMS database. Where changes in ownership have occurred throughout the year, output is attributed to the owner of the generation unit at the point in time of the generation output. Ownership of output was determined as per our trading rights methodology. The method of allocating trading rights for each generating unit has changed since our 2022 report. Please refer to section 9 Trading Rights for an explanation of these changes.

How did we determine market share by generation output?

- Resolution—Market share by output uses 30-minute metered data, aggregated for the 2023–24 financial year and expressed in terawatt hours. It includes all market scheduled and semi-scheduled generating units in the NEM.
- Interconnectors—Interconnectors are not included in market share calculations and are reported separately.
- Regions—Market share is calculated for each NEM region.
- Participant controlling the relevant asset—Market shares are determined based on ownership of each unit's output. Where we were unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Output is split on a pro rata basis if ownership changed in 2023–24. Where multiple owners are invested in a generating unit, the output of that unit has been split proportionally between owners according to their percentage of total ownership.
- Output from rooftop solar systems and loads are not included in the data.

Reference to figure in WEMPR

Figure 4.2

12 HHI by bid availability

What is HHI by bid availability?

HHI (Herfindahl-Hirschman Index) provides an indication of market concentration and allows for comparisons across regions and over time. The index is calculated by summing squared market shares, based on 5-minute bid availability, of all firms in the market. The index can range from close to zero (in a market with many small firms) to 10,000 (for a monopoly). In a financial year, each region in the NEM will have 105,120 HHI values representing each 5-minute dispatch interval in that year. This measure of market concentration accommodates the intermittency of all forms of generation, due to, for example, plant outages, cloudy or calm weather, or other reasons.

Where is the data from?

The bid availability data for each unit is sourced from AEMO's MMS database and was allocated to participants according to unit trading rights. Our method for allocating unit trading rights has changed since our 2022 report. Please refer to section 9 Trading Rights for an explanation of these changes.

How did we determine HHI by bid availability?

- Resolution—Bid availability for a trading rights holder in each NEM region is obtained for each 5-minute dispatch interval over the chosen period. We excluded market suspension periods from the analysis, as well as administered price cap periods where the price was at the cap. We included all market scheduled and semi-scheduled generating units in the analysis, as well as wholesale demand response where the direction of offer was to generate.
- Regions—We calculated HHI for each NEM region.
- Participant controlling the relevant asset—Control is determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset.
- Time of day averages—Where time of day analysis was used, the HHI score for each 5-minute dispatch interval throughout a given financial year was recorded, these were then summed together and divided by the number of intervals for a given time of day within the year.
- Quarterly rolling averages—Quarterly rolling averages were calculated by averaging HHI values across 4 quarters. For example, the rolling average for Q2 2024 is calculated by summing the average HHI values for Q3 2023, Q4 2023, Q1 2024 and Q2 2024, and dividing by 4.
- Variability in HHI—To display the variability of HHI, we found the highest, lowest and median HHI values for a given region and period.

Reference to figure in WEMPR

Figure 4.3, Figure 4.4, Figure 4.5, Figure 7.25

13 Vertical integration

What is this metric?

Market share for generation and retail load allows us to assess the extent to which certain participants are vertically integrated. We used 2 measures of market share:

- Market share by generation output represents a participant's share of annual energy delivery. It better reflects the nature of a market participant's generation fleet and contribution to market outcomes.
- Market share by retail load represents a participant's share of annual energy consumption. It better reflects the size of a market participants retail load as it can account for the differences in size of customers and for large commercial and industrial customers. Where is the data from? AEMO's MMS database.

Where is the data from?

- AEMO's MMS database.
- For generation output – 'metered' dispatch data for each dispatchable unit identifier (DUID), aggregated for each financial year.
- For retail load – 'load' data for each financially responsible market participant (FRMP), aggregated for each quarter.

How did we determine market share?

- Resolution—Calculated for South Australia for the period between Q3 2021and Q1 2024 using total generation output and total retail load.
- Participant categories: Unnamed participants—included several vertically integrated participants in South Australia; Unidentified participant—included one vertically integrated participant in South Australia.

Reference to figure in WEMPR

Figure 7.27, Figure 7.28

14 Pivotal Supplier Test

What is this metric?

The pivotal supplier test (PST) measures the extent to which one or more participants is 'pivotal' to clearing the market. A participant is pivotal if market demand exceeds the capacity of all other participants, accounting for possible imports. In these circumstances, the participant must be dispatched (at least partly) to meet demand. The PST gives an indication of the risk of the exercise of market power.

Where is the data from?

We sourced data from AEMO's MMS database:

- Bid availability data for each unit. This was allocated to participants according to unit trading rights. Our method for allocating unit trading rights has changed since our 2022 report. Please refer to section 9 Trading Rights for an explanation of these changes.
- Total demand data.
- Interconnector limits data.

How did we determine the proportion of time that the largest participants were pivotal?

- Resolution—Bid availability for a trading rights holder in each NEM region is obtained for each 5-minute dispatch interval over a chosen period. Proportion of time outcomes in 2021–22 and 2023–24 were determined by identifying all 5-minute periods throughout the year when either one participant or some combination of 2 participants was pivotal to meeting demand.
- Regions—We calculated PST-1 and PST-2 for each mainland NEM region.
- How we treated interconnectors:
  - Interconnectors have a nominal limit which indicates the amount of generation that the interconnector is built to transport. However, due to all the constraints that operate in the NEM, interconnectors have technical limits, which may change every 5 minutes and differ to the nominal limits. Each interconnector has an 'import limit' and an 'export limit' which indicates the amount of generation that can flow into or out of a region. There can be instances where constraints force imports or exports into or out of a region. The PST formulation needs to consider when such flows are forced.
  - The numerator of the PST formulation is the pool of available generation that can be strategically offered by participants to maximise profitability. The availability is increased by the import limits of the interconnectors in that region, less any forced imports into that region as these are a technical requirement of the power system not an economic pricing signal. Similarly, the denominator is the demand that must be serviced by that region. Demand is reduced by forced imports and increased by

forced exports to accurately reflect the pool of demand that must be serviced by that region.

- PST calculation—Included 5-minute demand, bid availability and interconnector limits:

$$PST2 = regional\ bid\ avail + \sum \text{IM limit} - \sum \text{forced IM} - (bid\ avail1 + bid\ avail2)$$
$$regional\ demand - \sum forced\ IM + \sum forced\ EX -$$

  – **Regional bid avail**: bid availability of all market scheduled and semi scheduled generating units in the region of interest, as well as wholesale demand response where the direction of offer was to generate.
  – **Bid avail1**: the bid availability for the first tested participant
  – **Bid avail2**: the bid availability for the second tested participant (note: this term is not included for PST-1)
  – **Regional demand**: total demand, as defined by AEMO, for a given dispatch interval, for the region of interest.
  – **∑ forced IM**: the sum of all forced imports into the region of interest, as determined by constraints on the relevant interconnectors.

∑ forced EX: the sum of all forced exports out of the region of interest, as determined by constraints on the relevant interconnectors

- Participant controlling the relevant asset—Control is determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset.

Reference to figure in report

Figure 4.10

15 Negative Settlement residues

What is this metric?

Interregional settlement residues occur when there are energy flows between neighbouring regions and the prices between those regions differ. Negative settlement residues reflect the cost of counter-price flows that occur when network congestion causes electricity to flow in the opposite direction to price.

Our analysis focussed on constraints to manage negative settlement residues. These are invoked by AEMO to limit or 'clamp' exports from the higher priced exporting region into the adjoining region. We reported on the binding hours and impact of negative settlement residue constraints. See section Hours and impact from network congestion for more explanations.

Where is the data from?

AEMO report congestion information annually, generally publishing in March for the previous year. For more detail see AEMO, Statistical Reporting Streams.

Reference to figure in WEMPR

Figure 4.13

16 Interconnector binding capacity and constrained period

What is this metric?

Interconnectors enable energy transfers between the NEM's 5 regions. Interconnectors generally deliver energy from lower priced regions to higher priced regions. They also increase the reliability and security of the power system by enabling demand in one region to be met by generation from an adjacent region.

The ability of generators to supply energy to other regions is limited by the capacity of the transmission network. This capacity can change depending on the direction of flow, outages on the network or other physical constraints and limits AEMO imposes to manage system security.

An interconnector is constrained when the flow across it reaches its technical limit. When an interconnector is constrained, cheaper sources of generation in one region cannot replace more expensive generation in another, effectively separating those regions into distinct markets.

Where is the data from?

Interconnector limits and flows are sourced from AEMO's MMS database.

How did we determine the average binding capacity?

Each interconnector has an 'import limit' and an 'export limit' which indicate the amount of generation that can flow into or out of a region. This limit may change every 5 minutes. The average binding capacity in each direction is the average flow of the interconnector in that direction when the flow is at the import or export limit.

How did we determine the constrained period?

The constrained period is the proportion of time that the flows of the interconnector was at its import (or export) limit, over the quarter.

Reference to figure in WEMPR

Figure 4.12

17 Interconnector Map

What is this metric?

Interconnectors allow transfer of generation between NEM regions. The interconnector map illustrates the ‘import limit’ and an ‘export limit’ of interconnectors which indicates the amount of generation that can flow into or out of a region.

Where is the data from?

Sourced from AEMO Network status and Capability

Reference to figure in WEMPR

Figure 4.11

18 Final and current quarterly base future contract prices

What is this metric?

Final contract prices are equal to the cash settlement price, calculated by taking the arithmetic average of the wholesale spot prices over the contract term. Non-final prices are the daily settled price for the Quarterly base future contract on 13 November 2024.

Where is the data from?

Data sourced from ASX energy.

Reference to figure in WEMPR

Figure 2.3

19 Traded volumes in ASX electricity contracts

What is this metric?

It is the total traded volumes for Australian Securities Exchange (ASX) electricity contracts, aggregated by quarter or year and contract type and expressed in Gigawatt hours.

We also calculated the proportion of traded volume by trade size.

Where is the data from?

Data is sourced from ASX Energy.

How did we determine the proportion of trade volume by contract size?

- Resolution — Annual for all traded ASX contracts, segmented by different trade size, 1 MW, 2 MW, 3 to 5 MW, 6 to 10 MW, 11 to 30 MW and >30 MW.
- Calculation— The volume (MWh) of all contracts traded summed by trade size and then divided by the total traded volume (MWh) to calculate the percentage for each year.

Reference to figure in WEMPR

Figure 3.1, Figure, 3.2, Figure 7.10, Figure 7.11, Figure 7.12, Figure 7.13, Figure 7.14, Figure 7.15, Figure 7.20.

Figure 7.18 and Figure 7.19 use this method as well as the method described in section 21 Daily settled prices, base future contracts.

20 Daily price change, base futures contracts

What is this metric?

It is the price change, calculated daily, for all quarterly base future contracts with a published daily settled price within 12 months of expiry, expressed as a percentage based on a stated range.

Where is the data from?

Data sourced from ASX Energy.

How did we determine the daily price change?

- Resolution—Daily for all quarterly base future contracts in all regions that have a published daily settled price and are within 12 months of expiry.
- Calculation—the daily price change (at T) for each base future contract is calculated for all quarterly base future contracts within 12 months of the expiry date, by subtracting the daily settled price (at T-1) from the daily settled price (at T). The absolute value of this daily price change is then calculated for each price change. The percentages are then calculated by counting the number of values which fall within each specified range and dividing by the total number of values.

  where: T is the settlement day and T-1 is the settlement day preceding T

Reference to figure in WEMPR

Figure 3.6

21 Daily settled prices, base future contracts

What is this metric?

It is the daily price at which a base future contract is settled.

Where is the data from?

Data sourced from ASX Energy.

Reference to figure in WEMPR

Figure 5.11 uses this method as well as the method from section 30 Drivers of significant price events.

Figure 7.18 and Figure 7.19 use this method as well as the method from section 19 Traded volumes in ASX electricity contracts.

22 Hedging horizon

What is this metric?

This metric identifies when the proportion of trading is undertaken in the lead up to the close of a contract period, with reference to the expiry date of the contract. This is a useful measure for identifying how far out contracts are traded and provides an indication of how liquid the market is ahead of a contract period.

Where is the data from?

Data sourced from ASX energy.

How did we determine the average daily price change?

- Resolution—For base futures, all trades for contracts with a contract period between 2018–19 to 2023–24 inclusive. For calendar year swaptions, all trades for contracts with a contract period between 2020 and 2024 inclusive. For financial year swaptions, all trades for contracts with a contract period between 2020–21 and 2024–25 inclusive.
- Calculation—The number of days prior to expiry was calculated by subtracting the date of trade from the contract expiry date. The total number of contracts traded within each stated range (using the number of days calculated in the previous step to identify which range each trade is assigned to) was then calculated and converted into a percentage by dividing the counted trades in each range by the total number of trades.

Reference to figure in WEMPR

Figure 3.4 and Figure 3.5

23 Volume weighted average swaption premium price

What is this metric?

Indicates the VWA premium price paid for swaption contracts during each quarter, categorised into call and put.

Where is the data from?

Data sourced from ASX energy.

How did we determine the average daily price change?

- Resolution—Quarterly, from Q1 2019 to Q3 2024 inclusive.
- Calculation—Quarterly VWA premium price is the sum of swaption premium prices multiplied by the volume of the trade for each trade recorded in a quarter, then divided by the sum of all traded volume in each quarter. This calculation is performed for call swaption and put swaptions separately.

Reference to figure in WEMPR

Figure 3.7

24 Liquidity ratio for all contract types

What is this metric?

It is a ratio that provides an indication of how much volume is traded via ASX contracts relative to demand in a region. This is one of the measures we use to assess the liquidity of contract markets.

Where is the data from?

Data is sourced from ASX energy and AEMO's MMS database.

How did we determine the liquidity ratio?

- Resolution— Quarterly for each region that has contracts traded on the ASX.
- Calculation—The liquidity ratio is calculated for each region by dividing the total volume of all ASX contracts traded for each quarter by the total native demand during each quarter.

Reference to figure in WEMPR

Figure 3.8, Figure 7.16

25 Open Interest

What is this?

Daily open interest refers to the total number of ASX Energy outstanding futures and options contracts that are not closed or delivered as at close of business on the previous day.

Where is the data from?

Data sourced from ASX energy.

How did we determine open interest?

- Resolution—Daily
- Calculation—The total open interest volume is determined by summing the open interest for each ASX electricity contract type across all regions.

Reference to figure in the report

Figure 3.3, Figure 7.17

26 Average offers

What is an offer?

Participants can offer their capacity into the NEM across 10 different price bands. The price bands must be between the price floor (-$1,000 per MWh) and the price cap ($16,600 per MWh in the 2023–24 financial year).

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we calculate average offers?

We create illustrative price bands in order to effectively display aggregate offer data. For each price band, we sum the total capacity offered within that range across every 30 minutes and divide by the number of intervals for that period. This provides an average offer figure. Periods we have averaged over include annual, quarterly and monthly groupings. We have also calculated average offers by time of day.

For offers by time of day, 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. For example, to find annual average offers at 6.30 pm, we sum the total capacity offered by price band for every 6.30 pm interval and divide by the number of days in the year.

For some charts, we calculated the percentage of offers that were offered within certain price bands. In these cases, we used the same method but converted the capacity offered within a price band into a percentage of all capacity offered within that time grouping.

Average offers have variously been grouped according to NEM region, fuel type, market participant, power station or generating unit.

Are there any assumptions?

Fixed load is 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.

Reference to figure in WEMPR

Figure 5.1, Figure 5.2, Figure 5.3, Figure 5.4, Figure 5.5, Figure 5.7, Figure 5.8, Figure 5.9, Figure 5.10, Figure 5.12, Figure 5.13, Figure 5.14, Figure 5.18, Figure 5.19, Figure 5.20, Figure 7.29, Figure 7.30

27 Surplus capacity (economic withholding screen)

What is surplus capacity?

Surplus capacity (also known as ‘the supply cushion’) measures market tightness by subtracting the current load in a period from the available capacity in that period. That is, surplus capacity is the quantity of generation that can be called upon. When the level of surplus capacity is low, this should typically mean that prices are high. This is because more expensive generators must be dispatched to satisfy the load, therefore leading to a higher dispatch price. The opposite is true for a high level of surplus capacity.

The surplus capacity metric aims to be a market-wide screen for periods in which the dispatch price is significantly higher than would be expected given the tightness of the market. This means it can identify ‘outlier’ (high price) periods to then focus further analysis on whether the period may be caused by a participant or plant that is withholding.

Where is the data from?

Data is sourced from AEMO’s MMS database.

How did we calculate it?

Mathematically, the domestic surplus capacity, for state s in period t, SC_{st}, is:

$$SC_{st} = C_{st} - L_{st}$$

Where for a period t and state s, C_{st} is the total *effective* generation capacity and L_{st} is the load. For a more detailed explanation, see *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*.

Reference to figure in WEMPR

Figure 7.31

28 Returns to withholding capacity (economic withholding incentive measure)

What is the returns to withholding capacity metric?

The returns from withholding capacity (RWC) methodology estimates a participant's profit gain from withholding capacity for a specific settlement period. It attempts to capture the additional revenues a participant could earn by withholding capacity. These additional revenues are a function of the sensitivity of prices to withholding and the amount of remaining operating capacity owned by the participant which would earn higher revenues. This metric measures the potential gains rather than actual behaviour.

Where is the data from?

For gas prices, we use the local gas spot market prices. For Queensland, NSW and South Australia, these are the Brisbane, Sydney and Adelaide Short Term Trading Market prices. For Victoria, these are the Victorian Declared Wholesale Gas Market prices. These prices are in $ per GJ.

Electricity dispatch price, native demand, effective capacity, and level of output from wind and solar generators are sourced from AEMO's MMS database.

How did we calculate it?

Mathematically, the RWC of participant *i* in period *t* is the product of a price and portfolio effect:[6]

$$RWC_{it} = \underbrace{\Delta p_t}_{Price\ effect} \cdot \underbrace{(Q_{it} - 10)}_{Portfolio\ effect}$$

Where:

- $\underbrace{\boldsymbol{\Delta p_t}}$ = price effect is the extent that withholding 10 MW increases the dispatch price in period t.[7]
- $\underbrace{(\boldsymbol{Q_{it} - 10})}$ = portfolio effect is the generation portfolio that benefits from the estimated price increase from withholding 10MW. We consider both a 'raw' portfolio, which is the

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6 Note: the calculation assumes that the marginal cost of the withheld capacity is equal to the dispatch price. The implication is that the lost profit of the withheld capacity is zero. If the marginal cost of the withheld capacity is less than the dispatch price, then the RWC will be lower. While this does affect the interpretation of the *level* of the RWC, it should have less effect on *changes* of the RWC (that is, whether the incentive to withhold has increased or decreased).

7 Note: we divide the $ per MWh price increase by 12 to calculate the profit increase for 5 minutes (rather than for one hour). Note also there is no *i* subscript for the price effect as all participants benefit equally from a price increase.

total in-merit capacity of participant i in period t, and additionally a contract-adjusted portfolio.

Price effect

The price effect method was updated from the process used for WEMPR 2022. For this report, we first estimated the relationship between the regional dispatch price (RRP) and a range of impacting factors at the dispatch interval level using the equation below:

$$
\begin{aligned}
RRP = \alpha &+ \beta_1 SupplyCushion + \beta_2 IntermitLevel + \beta_3 SupplyCushion\colon IntermitLevel \\
&+ \beta_4 SupplyCushion * SupplyCushion + \sum_i \beta_i \, SupplyCushion_{neighbour_i} \\
&+ \sum_i \beta_i \, SupplyCushion * SupplyCushion_{neighbour_i} + \beta_{gas} GasPrice \\
&+ \sum_{month} \beta_{month} \, Month + \sum_{hour} \beta_{hour} \, Hour + \beta_k RRP_{prev} + \beta_p RRP_{TI\_temp} + \varepsilon
\end{aligned}
$$

Where:

β_i denotes the effect of a change in surplus capacity in the neighboring region, which we use as a proxy for the impact of interconnector flows;

β_j denotes the change in the coefficient β_1 given the surplus capacity level in a neighboring region;

β_{gas} , β_{month} and β_{hour} denote the effect of spot gas prices and seasonality on the dispatch price;

β_k denotes the effect of the RRP in the previous dispatch interval on the RRP in the current interval;

β_p denotes the effect of average RRP in the previous dispatch intervals in the current trading interval, and this is only applicable before the introduction of 5-minute settlement.

Then, based on the regression result from the equation above, we calculated the total price effect of a change in the regional supply cushion at the dispatch interval level using the following formula:

$$
\Delta p_t = \left(\beta_1 + \beta_3\colon IntermitLevel_t + \beta_4 * SupplyCushion_t + \sum_i \beta_i * SupplyCushion_{neighbour_i,t} \right) * 10
$$

Where:

t denotes the dispatch interval;

β_1, β_3, β_4 and β_i are the estimated coefficients.

Portfolio effect

Our analysis calculated the portfolio effect in 2 ways:

Raw: Total capacity dispatched during the period. This assumes that all a participant's in-merit capacity would benefit from a price increase. However, we know that in practice participants contract a significant amount of generation.

Contract adjusted: Adjusts the capacity dispatched to account for the capacity that is contracted. This approach assumes that only capacity above the contracted capacity benefits from a price increase.[8] For this analysis, we have used actual swap and cap information for a selected participant.

Reference to figure in WEMPR

Figure 7.32

[8] A participant's incentive to withhold likely depends on the extent that it has pre-sold in the forward market ("contracted"). To see this, consider 3 different levels of contracting:

- **Uncontracted:** the plant fully benefits from any increase in the spot price – that is, effectively the "raw" RWC
- **Half contracted:** first 50% of capacity sold at a fixed price. Therefore, a price increase only benefits the plant for any generation above this 50%
- **Fully contracted:** the plant receives zero benefit from a higher spot price.

Contracting affects incentives in 2 ways. First, a plant has a greater incentive to withhold its uncontracted capacity (as only this capacity benefits from the price increase). Second, a plant has an incentive to bid competitively for its contracted capacity because it has an obligation to fulfil (as otherwise it needs to purchase this generation from the spot market). Note that in the long run, even a contracted participant may have an incentive to withhold if sustained increases in the spot price allow it to negotiate higher priced forward contracts.

29 Physical withholding (withdrawn capacity)

What is physical withholding?

Physical withholding involves a participant removing capacity from the market entirely with the intention to influence price. It is difficult to differentiate between capacity withdrawn with intention to influence price and capacity withdrawn to manage supply conditions, such as a need to conserve fuel or manage start-up costs.

How do we assess physical withholding behaviour?

Our proxy measure for physical withholding involves comparing participants' Projected Assessment of System Adequacy (PASA) availability with their maximum availability. A participant's PASA availability is the capacity it can supply to the market. By contrast, its 'maximum availability' is the capacity that it actually offers to the market. As such, the difference between PASA availability and maximum availability should reflect the capacity that participants could supply but choose not to.

Where does the data come from?

Data is taken form AEMO's MMS database.

How did we calculate this?

We subtract participants' bid maximum availability from their bid PASA for every 5-minute dispatch interval. We then calculate the average of this according to the time grouping chosen for our analysis. For example, Figure 5.5 shows the average monthly capacity withdrawn for selected power stations. To calculate this we summed the capacity withdrawn for these power stations in every 5-minute interval of each month and divided this by the number of 5-minute intervals in the month.

Figure 5.6 shows the average capacity withdrawn by time of day in 2023–24 for selected power stations. To calculate this for 1 am (for example) we added the capacity withdrawn for all 5-minute intervals between 1 and 2 am during 2021–22, and divided by the total number of intervals between 1 am and 2 am for that financial year.

Reference to figure in WEMPR

Figure 5.5, Figure 5.6

30 Drivers of significant price events

An energy market significant price outcome occurs when in a given region the 30-minute price exceeds $5,000 per MWh in the spot market.[9] The AER must report on the drivers of these price events. At a minimum, the AER's must examine whether available capacity, network availability, or offer, bidding and rebidding behaviour contributed to price event.

Where does the data come from?

For the analysis in this report, we surveyed past AER reports into significant price events and the drivers described in those reports.

Reference to figure in WEMPR

Figure 5.11 uses this method as well as the method from section 21 Daily settled prices, base future contracts.

[9] AER, "Significant price reporting guideline", 29 September 2022, p.3.

31 Entry and Exit

What is this metric?

Past investment and withdrawn capacity in the NEM.

Where is the data from?

AEMO's MMS database.

How did we determine capacity?

Capacity includes scheduled and semi-scheduled generation but does not include rooftop solar capacity. Registered capacity is used for every fuel type except for solar, which is based on maximum capacity, to reflect its different technical constraints. Generators are marked as having entered from their first dispatch date and does not reflect stages of commissioning.

Reference to figure in WEMPR

Figure 6.1

32 Price signals for new entry

Volume weighted average by fuel type

Volume weighted average price (VWAP) by fuel type is a measure of average wholesale electricity price for different fuel type. This metric is useful in showing trends based on different fuel in average prices in the market.

VWAP by fuel type is the sum of 5-minute prices multiplied by generation by different fuel type for every 5 minutes in a fiscal year, then divided by the sum of total generation by fuel type in a fiscal year.

Where is the data from?

5-minute prices and generation sourced from AEMO's MMS database. LCOE data obtained from GenCost 2023–24. LCOS data sourced from Renewable Energy Storage Roadmap March 2023.

What factors are considered?

We shifted the INITIALMW value by 5 minutes for solar, wind, gas and coal generation in our calculations. For battery storage units, we took the original INITIALMW value as generation.

Reference to figure in WEMPR

Figure 6.3, Figure 6.4, Figure 6.5, Figure 6.6, Figure 6.7, Figure 6.8

33 Cost and proportion of time directions applied in South Australia

What are directions?

AEMO issue directions to registered market participants to take action to maintain or re-establish the power system to a secure, satisfactory or reliable operating state.

Where does the data come from?

Sourced from AEMO *Quarterly Energy Dynamics Q4 2023, Q3 2024*

Reference to figure in WEMPR

Figure 7.21, Figure 7.22

34 Hours and impact from network congestion

What is this metric?

The binding hours and impact of system normal constraints provides an indication of network congestion. The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval from the marginal constraint cost re-run over the period considered. The marginal value is a mathematical term for the market impact arising from relaxing the right-hand side of a binding constraint by one MW. Binding impact represents the financial cost associated with that binding constraint equation and can be a good way of picking up congestion issues, however it is only a proxy (and always an upper bound) of the value per MW of congestion over the period calculated.

Where is the data from?

Data sourced from AEMO *NEM Constraint Report 2023 summary data*, April 2024

Data excludes impacts from FCAS, outages, network support and commissioning constraints.

Reference to figure in WEMPR

Figure 6.9

35 FCAS analysis

This section details the approach used in our frequency control ancillary services (FCAS) analysis.

35.1 Local and global FCAS methodology

What is the difference between local and global FCAS?

When a region has to supply its own FCAS we deem it to be a local market. This usually occurs at the ends of the network where the regions are only connected to a single region, such as in Queensland, South Australia, and Tasmania. If a region does not have to supply its own FCAS, we consider it to be part of the global (NEM-wide) market.

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we determine local and global FCAS price?

We use the NSW price as a proxy for the global price. No official global price exists.

For Queensland and South Australia, if the price differs from the NSW price we consider that price to be a local price for that region.

For Tasmania:

- If the price equals the NSW price, then we deemed it to be global.
- If the price differs 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, then we deemed it to be global.
- Otherwise, we consider the price to be local.

How did we determine local and global FCAS datasets?

For each FCAS market, if we have determined the price of a region to be local in a dispatch interval, then we consider a local market to have formed in the region. If a local market exists for a service, then that region does not provide any FCAS to the global market for that service. As a result, for each FCAS market in each dispatch interval, we assume the global FCAS price is determined by the supply and demand in all regions that are providing global FCAS. Similarly, we assume the local FCAS price is determined by the supply and demand in the local region. These assumptions help us to understand and analyse the price formation process in FCAS markets.

How did we estimate local and global FCAS costs?

The calculation of local and global FCAS costs is based on the estimated revenue for each local and global FCAS market. In this report, we assume that in a dispatch interval, for each FCAS market, the global cost equals the global revenue, which we calculate to be the sum of estimated revenue for each generating unit that provides a global service.[10] Also, we assume the local cost equals the local revenue, which is the sum of estimated revenue from generating units that provide a local service.

For each FCAS market, the local and global FCAS cost in each dispatch interval is calculated as:

$$Global\ Cost = Global\ Revenue = \sum_{Global\ DUID} Enablement\ Target \times FCAS\ Price/12$$

$$Local\ Cost^{11} = Local\ Revnue = \sum_{Local\ DUID} Enablement\ Target \times FCAS\ Price/12$$

Reference to figure in WEMPR

Figure 2.19, Figure 2.21, Figure 7.23

35.2 FCAS enablement

There are 2 types of FCAS enablement – enablement for regular services which is the volume of FCAS actually provided and enablement for contingency services, which is the volume produced in the case of a contingency event.

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we calculate FCAS enablement?

FCAS enablement is the monthly average of all units raise 6-second target grouped by fuel type. Total enablement represents the target (MW) of all units providing the service, averaged for each month.

Reference to figure in WEMPR

Figure 2.22

10 AEMO's Market Management System database lists providers by their dispatchable unit identifier (DUID).

11 Local FCAS cost is calculated for each region separately if more than one region is flagged as local.

36 Fuel cost conversion

What are fuel prices?

Fuel prices can be stated in different ways. For example, gas prices are typically in a $ per gigajoule (GJ) format. To compare fuel costs to generation, we convert fuel costs into a $ per MWh figure.

Where is the data from?

For gas prices, we use the local gas spot market prices. For Queensland, NSW and South Australia, these are the Brisbane, Sydney and Adelaide Short Term Trading Market prices. For Victoria, these are the Victorian Declared Wholesale Gas Market prices. These prices are in $ per GJ.

We source coal prices from GlobalCOAL, using the Newcastle coal price index as a reference price for spot thermal coal at Newcastle Port in NSW. These prices are in USD per tonne.

How did we calculate fuel costs?

Gas

To convert gas prices from $ per GJ to $ per MWh we use the following formula:

> $ per MWh = gas cost ($ per GJ) x heat rate (GJ per MWh)

For gas we use a constant heat rate of 8 GJ per MWh

Coal

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)

For coal we use a constant heat rate of 9 GJ per MWh, and a low heating value of 23 GJ per tonne.

Reference to figure in WEMPR

Figure 2.5, Figure 2.6

37 Energy and FCAS revenue

We measure the NEM turnover and the FCAS revenue by region.

Where is the data from?

Data is sourced from AEMO’s MMS database.

How did we calculate fuel costs?

We sum the annual energy generator revenue for each state in the NEM over the past 5 financial years (2019–20 to 2023–24) to calculate the NEM turnover by region. Similarly, the FCAS enablement revenue for each state over the past 5 financial years is summed to get the total FCAS revenue.

FCAS costs were also calculated as a percentage of wholesale market revenue.

Reference to figure in WEMPR

Figure 2.2, Figure 2.20