Methods and Assumptions

Wholesale electricity market performance report 2022

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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 two 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 preformed.[2]

This methodology document contains a discussion of the analysis undertaken in our *Wholesale electricity market performance report 2022* (the performance report) 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 the performance report, the method we have applied, the data sources for our analysis, and references to the relevant figures in the performance report.

In addition, we have published:

- *Wholesale electricity market performance report 2022— Economic withholding approach, limitations and results* which sets out our approach to screening for potential economic withholding behaviour by participants. Our economic withholding analysis aims to assess whether participants may be exercising market power by withholding capacity to influence the price.
- *Wholesale electricity market performance report 2022 – LCOE & LCOS modelling approaches, limitations and results* which sets out our approach in estimating the underlying costs for a range of new entrant generators in the long run.

We also published the Statement of Approach and 2022 Focus, which provide information on the general approach we have taken in the performance report.[3]

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1 National Electricity Law, Part 3 Division 1A

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

3 AER, Wholesale electricity market performance monitoring, Statement of approach, March 2018; AER, Wholesale electricity market performance monitoring, 2022 Focus, November 2021.

1 Volume weighted average price

What is this?

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

Quarterly VWA price is the sum of 30 minute prices multiplied by native demand in each region for every 30 minutes in a financial quarter, then divided by the sum of all native demand in each region for every 30 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 divided by the sum of all native demands 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 30 minute 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?

30 minute prices in each region and native demand in each region are sourced from AEMO's Market Management System (MMS) database.

What factors are considered?

- Resolution— The price data is in 30 minute resolution and is an average of the prices of the six 5 minute dispatch intervals. Demand data is in 30 minute intervals.
- 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 the performance report

Figure 2.1, Figure 2.5, Figure 2.6

2 Generation output by fuel source

What is this?

Renewable generation share of total generation is the total renewable generation output in the NEM as a share of total NEM generation output, particularly output from large-scale solar farms, wind, hydro, rooftop solar PV and batteries.

Electricity generation by fuel source is the total generation output in the NEM as a whole and in each NEM region. It describes the proportion of output from each fuel type each financial year.

For electricity generation by time of day, 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 6:30pm, we sum the generation for each fuel type at 6:30pm and divide by the number of days in the year.

Energy is calculated by summing metered generation on a 30 minute basis divided by 2000 to express a figure in terawatt hours.

Where is the data from?

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

Reference to figure in the performance report

Figure 2.3, Figure 2.4, Figure 2.14

3 Baseload outages

What is this?

Baseload generators are units that generate for almost all dispatch intervals and provide a steady supply to the market. We only considered black and brown coal units for this analysis.

A unit is on 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 the performance report

Figure 2.10

4 Available capacity factor

What is this?

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 the performance report

Figure 2.11

5 Price setter by fuel type

What is price setter?

The price for each region in the NEM is set every five 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.

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 five 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 five minutes. Then looked at what fuel source that unit used and gave it a count of one for that five minutes.

We then added up the counts of each fuel type and divided it by the number of five 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 five 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 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 two units setting a price both with the same fuel type, they were counted as one occasion for that fuel type each five minutes. If they were different fuel types setting a price then each fuel type would get a count for that five 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 the performance report

Figure 2.7, Figure 2.15, Figure 5.8, Figure 5.13

6 Average native demand by time of day

What is native demand?

Native demand represents the sum of total demand and total non-scheduled generation.

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 five 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 the performance report

Figure 2.13

7 Market share by generation capacity

What is market share by capacity?

Market share by capacity represents the potential share that an organisation has to provide to the market. 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 a 30 June each year using the ownership of each generating unit on that date as well.

Ownership of each generating unit was determined by using information published by AEMO on their 'generation information' and 'registrations and exemptions'. Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

How did we determine market share by capacity?

- Resolution—Market share by capacity is based on registered capacity as a 30 June of each year.
  - *For solar generators*, maximum capacity was used rather registered capacity, because inverter constraints prevent solar units from dispatching their full registered capacity.
  - *For all generating units* – includes all market scheduled, and market semi-scheduled generating units in the NEM.
- Interconnectors—Interconnectors are not included in market share calculations, and are reported separately.
- Market Loads—Were excluded from the analysis because they move electricity rather than generate it.
- Regions—Market share is calculated for each NEM region.
- Fuel type— Our share of fuel type analysis included only coal, gas, battery, hydro, wind and solar. Other fuel types such as liquid and biomass were excluded.
- Participant controlling the relevant asset—Ownership for each generating unit was attributed to the organisation that has control over the generating asset. This was the 'owner' in the first instance or the 'intermediary' where an intermediary operated the generating asset on behalf of the owner. Where a unit is owned by multiple parties, ownership was attributed to the largest participant or divided evenly between the participants. For instance, Cathedral Rocks wind farm is a 50/50 joint venture between Energy Australia and Acciona Energy and allocated 50/50 while Kiamal Solar Farm is majority-owned by Total Eren, which was allocated 100% of the farm's capacity.

Reference to figure in the performance report

Figure 3.1, Figures 3.7, Figure 3.8, Figure 3.9, Figure 3.10

8 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, however may under-represent market participants with flexible generation plant with an ability to respond to peak prices, but operated infrequently.

Where is the data from?

Generation market share uses 30 minute metered data, aggregated for 2020-21 and 2021-22 financial years 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 each generating unit was determined by using information published by AEMO on their 'generation information' and 'registrations and exemptions'. Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

How did we determine market share by generation output?

- Resolution—Market share by capacity is based on registered capacity as a 30 June of each year.
  - For all generating units – includes all market scheduled, and market 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—Ownership for each generating unit was attributed to the organisation that has control over the generating asset. This was the 'owner' in the first instance or the 'intermediary' where an intermediary operated the generating asset on behalf of the owner. Where a unit is owned by multiple parties, ownership was attributed to either the largest participant or divided evenly between the participants in each 30 minute period. For instance, Cathedral Rocks wind farm is a 50/50 joint venture between Energy Australia and Acciona Energy and allocated 50/50 while Kiamal Solar Farm is majority-owned by Total Eren, which was allocated 100% of the farm's capacity.

Reference to figure in the performance report

Figure 3.2, Figure 3.12

9 HHI by bid availability

What is HHI by bid availability?

HHI (Herfindahl-Hirschman Index) is a useful metric to summarise market concentration, by tallying the sum of squared market share percentages, based on 5 minute bid availability, of all participants in a 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. It measures the degree of market concentration that accommodates the intermittency of all forms of generation, due to, for example, plant outages, fuel supply or other reasons.

Where is the data from?

The bid availability data is sourced from AEMO's MMS database. Ownership of each generating unit was determined by using information published by AEMO on their 'generation information' and 'registrations and exemptions'. Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

How did we determine HHI by bid availability?

- Resolution—Bid availability for an organisation in each NEM region is obtained for each 5-minute dispatch interval over a specific time period. The administered pricing period from 12 to 23 June was excluded from this analysis.
- Regions—We calculated HHI for each NEM region.
- Ownership—Ownership for each generating unit was attributed to the organisation that has control over the generating asset. This was the 'owner' in the first instance or the 'intermediary' where an intermediary operated the generating asset on behalf of the owner. Where a unit is owned by multiple parties, ownership was attributed to either the largest participant or divided evenly between the participants in each 30 minute period. For instance, Cathedral Rocks wind farm is a 50/50 joint venture between Energy Australia and Acciona Energy and allocated 50/50 while Kiamal Solar Farm is majority-owned by Total Eren, which was allocated 100% of the farm's capacity.
- 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. For example, to determine the average HHI for 6am in 2021-22, HHI scores for all 5 minute intervals between 6am and 7am in 2021-22 were summed and divided by the total number of intervals between 6am and 7am for that financial year.
- Wind Curves — To determine the effect of wind availability on concentration we separated HHI scores into two groups, those where wind was above it's annual mean generation for the analysed region and those were wind generation was below the mean. The time of day average calculation method was then repeated using these each of the two score groupings.

Reference to figure in the performance report

Figure 3.3, Figure 3.4, Figure 3.5, Figure 3.6

10 Market share for 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 two 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 account for large C&I 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 financial year.

How did we determine market share?

- Resolution—Calculated for each region for the 2019-20 and 2021-22 financial year using total generation output and total retail load.
- Participant categories
  - Named participants – included the largest vertically integrated participants when both retail and generation market shares were considered. Their share of regional generation output and retail load is included in the chart and data.
  - Other vertically integrated participants – included all other vertically integrated participants in each region.
  - Other non-vertically integrated participants – includes all merchant generators and standalone retailers.

Reference to figure in the performance report

Figure 3.12

11 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?

Bid availability for each generating unit, total demand, and interconnector limits data is sourced from AEMO's MMS database. How did we determine the proportion of time that the 2 largest participants were pivotal?

- Resolution—Bid availability for an organisation in each NEM region is obtained for each 5 minute dispatch interval over a specific time period. Proportion of time outcomes in 2017-18 and 2019-20 were determined by identifying all 5 minute periods throughout the year when some combination of two 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 market semi scheduled generating units in the region of interest.
  - **Bid avail$_1$**: the bid availability for the first tested participant
  - **Bid avail$_2$**: the bid availability for the second tested participant

  - **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.

- Ownership—Ownership for each generating unit was attributed to the organisation that has control over the generating asset. This was the ‘owner’ in the first instance or the ‘intermediary’ where an intermediary operated the generating asset on behalf of the owner.

  Where a unit is owned by multiple parties, ownership was attributed to either the largest participant or divided evenly between the participants in each 30 minute period. For instance, Cathedral Rocks wind farm is a 50/50 joint venture between Energy Australia and Acciona Energy and allocated 50/50 while Kiamal Solar Farm is majority-owned by Total Eren, which was allocated 100% of the farm’s capacity.

Reference to figure in report

Figure 3.11

12 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 occur when electricity flows in the opposite direction to price in order to manage congestion.

Where is the data from?

Data sourced from AEMO *NEM Constraint Report 2021 summary data*, March 2022

Reference to figure in the performance report

Figure 3.15

13 Interconnector binding capacity and constrained period

What is this metric?

Interconnectors allow transfer of generation between NEM regions. Most of the time, energy flows from lower priced regions to higher priced regions, which allows competition to occur across regions. Interconnector binding capacity looks at the average quarterly flows out of one region into another, when the interconnector is constrained. It also provides the proportion of time for which the interconnector was constrained over the quarter.

Where is the data from?

Interconnector 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 indicates the amount of generation that can flow into or out of a region. The average binding capacity is the average flows of the interconnector, when the flow is at its 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 the performance report

Figure 3.14

14 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 Interconnector Capabilities report.

Reference to figure in the performance report

Figure 3.13

15 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 28 October 2022.

Where is the data from?

Data sourced from ASX energy.

Reference to figure in the performance report

Figure 2.2

16 Traded volumes in ASX electricity contracts

What is this metric?

It is the total traded volumes for ASX electricity contracts, aggregated by quarter and contract type and expressed in Terawatt hours.

Where is the data from?

Data is sourced from ASX Energy.

Reference to figure in the performance report

Figure 4.1

17 Average daily price change, base futures contracts

What is this metric?

It is the average daily price change, calculated daily, for all quarterly base future contracts with a published daily settled price.

Where is the data from?

Data sourced from ASX Energy.

How did we determine the average daily price change?

• Resolution — Daily for all quarterly base future contracts in all regions that have a published daily settled price

• Calculation— the daily price change (T) for each base future contract is calculated for all quarterly base future contracts by subtracting the daily settled price (T-1) from the daily settled price (T). The average daily price change is then calculated by taking the average of all daily price changes (T).

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

Note: A positive average price indicates that average prices increased and a negative average price change indicates that average fell compared to the previous day.

Reference to figure in the performance report

Figure 4.2

18 ASX traded volume percentage, by trade type

What is this metric?

It is the percentage of traded volume, by quarter, for each of the 4 trade types; block trade, exchange for physical, normal and strip.

Where is the data from?

Data sourced from ASX Energy.

How did we determine the average daily price change?

- Resolution — Quarterly for all traded ASX contracts
- Calculation— The volume (MWh) of all contracts traded are summed by trade type and then divided by the total traded volume (MWh) to calculate the percentage for each quarter.

Reference to figure in the performance report

Figure 4.3

19 Open Interest

What is this?

Monthly open interest refers to the total number of outstanding futures and options contracts on the ASX Energy exchange which are yet to be settled.

Where is the data from?

Data sourced from ASX energy.

Reference to figure in the report

Figure 4.4

20 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 ($15,000 per MWh).

Where is the data from?

Data is sourced from AEMO's MMS database.

How did we calculate average quarterly offers?

We create illustrative price bands in order to effectively display aggregate offer data. For each price band, we sum the total capacity offered at that level across every 30 minutes and divide by the number of intervals for that period. This provides an average offer figure.

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 monthly 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 month.

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 has to be dispatched.

Reference to figure in the performance report

Figures 5.1, Figure 5.4, Figure 5.6, Figure 5.9, Figure 5.10, Figure 5.15

21 Participant offers

What are participant offers?

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 ($15,000 per MWh).

How did we calculate participants offers?

We calculate aggregated average offers for all generation and load units allocated to a participant.

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 monthly 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 month.

What assumptions do we use?

Generation and load units are allocated to a participant based on who operates the unit. Participants are attributed using public generator information published by AEMO and supplemented by market intelligence. [4]

Reference to figure in the performance report

Figure 5.2, Figure 5.3, Figure 5.5, Figure 5.7, Figure 5.11, Figure 5.12, Figure 5.14

[4] AEMO, Generator Information, 30 November 2022; AEMO, NEM Registration and Exemption List, 6 December 2022.

22 Physical withholding

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 asses 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. We have conducted this comparison by time of day for each of the past 5 financial years.

Where does the data come from?

Data is taken form AEMO's MMS database.

How did we calculate this?

At a NEM level, we subtract participants' bid maximum availability from their bid PASA for every 5-minute dispatch interval. This gives us 525,888 data points. We then calculate the average of this by every hour of the day during each financial year, which gives us 120 data points.

Reference to figure in the performance report

Figure 6.7

23 Operating costs and potential earnings for generators

We modelled the relationship between the operating costs and potential earnings of generation technologies in the National Electricity Market (NEM). In particular we have focused on mainland regions where technology options for generators are most diverse. In addition to earnings from the spot market alone, we have included simplified contracting models to replicate common generator contracting behaviour (Chapter 3). The use of contracts to provide revenue certainty and support generation is a common practice by all generators.

Our assessment covers the 5 year period from 2017-18 to 2021- 22 and relies on publicly available information. This includes:

- Spot market generation and regional spot price data from AEMO's Market Management System database (MMS).
- Generator specific information, such as operating and maintenance costs and performance characteristics from AEMO's national transmission planning studies, the Integrated System Plan (ISP) and National Transmission Network Development Plan (NTNDP).
- Fuel prices for each region from gas spot market data and international coal price sources such as globalCOAL
- ASX Energy contract prices and other contracting information, which we used to inform the contracting strategies and contract revenue adjustments.

Using public data to determine the financing strategies and arrangements for all participants is challenging as individual participants will have different operating costs and potential earnings. The results presented by our analysis cannot therefore be seen as representing the profitability or viability of any individual participant or participant group.

What did we model?

We modelled spot revenue, generator operating earnings and generator operating costs.

In this analysis we refer to revenue and operating earnings as 2 separate concepts. For the purposes of this analysis, revenue is total income earned from generation before costs, while operating earnings is revenue less operating costs. We model 2 variants of both revenue and cost. Spot revenue is income earned only from the spot market. Contract adjusted revenue accounts for generators engaging in risk management through contracting, and adjusts spot revenue with simple contracting assumptions. Spot fuel cost are based on cost from the spot market and to assess generator's operating costs we have used the data available in the ISP and NTNDP.

Which generators did we include?

While our analysis considered most generators in the NEM, we excluded some generators to avoid potentially distorting our results (Table 23.1).

In our analysis we included generators registered in the market scheduled, market semi-scheduled and market non-scheduled categories. We excluded generators classified as non-market, non-scheduled as there are only a few of them and their behaviour may be governed by factors external to market operations. For the report, we aggregated our analysis by generation technology.

AEMO's MMS reports output from some generators before they are fully operational. For example, generators undergoing commissioning may operate at low levels for extended periods to verify or test their systems. So, to avoid potentially distorting our results, we excluded generators that were in the process of commissioning, or that were mothballed in a particular financial year from the 'by fuel type' analysis.

Table 23.1 Generators excluded from our analysis

Generation Technology	
Brown coal	Excluded any plant that was mothballed in a year for example, Anglesea, Morwell
Black coal	Excluded any plant that was mothballed in a year, for example Wallerwang
Natural gas (CCGT)	Does not include Queensland Nickel, Sithe and Yarwun as their operational decisions may be governed by other factors outside of electricity market operations.
Natural gas (OCGT)	Does not include dual-fuelled OCGTs, this excluded Oakey, Hallet.
Wind	Commissioning plant was excluded in the year it was being commissioned
Solar	Commissioning plant was excluded in the year it was being commissioned

Methodology

As we are required to use publicly available information in the first instance, we have largely relied on information published by AEMO. A full list of our input assumptions and sources is in Appendix A.

Spot revenue and contract revenue calculation

We modelled spot revenue, as well as contract-adjusted revenue for all technologies. For contract-adjusted revenue we modelled generator revenue using base and cap contracts as well as power purchase agreements (PPA).

For each, we performed the following calculations:

- Spot revenue = Generation as dispatched * Spot price * Marginal Loss Factor
- Base contract revenue = Spot revenue + (VWA base price – average spot price) * contracted capacity
- Cap contract revenue = Spot revenue + (VWA cap price – final cap price) * contracted capacity
- PPA contracts = PPA price * dispatch volume of relevant year
- Where:
- VWA base price = sum of (trade volume * trade price) / total traded volume, this was calculated separately for each region from quarterly base futures for that region.

- VWA cap price = sum of (trade volume * trade price) / total traded volume, this was calculated separately for each region from quarterly caps for that region
- The VWA is for every trade over the period that the product is traded.
- To determine the revenue per megawatt hour (MWh) for a generation technology, we divided the revenue by that technology's total output for a financial year.

Contract market data and setting contract levels

Contracting behaviours affect a generators ultimate revenue.

We modelled contract adjusted revenues for each generation technology using ASX Energy data, applying assumptions around the level and type of contracts sold. These assumptions include:

- Generators contract for about 80% of the total energy traded in the NEM
- 75% of all contracts are base swaps, and the remainder are cap contracts.
- Different technologies prefer different contracts. For example, black coal generators sell base contracts, OCGT generators sell cap contracts.
- Different technologies prefer to contract for different proportions of their total generation. For example, black coal generators sell contracts to cover a larger percentage of their output than hydro.
- Vertically integrated participants contract to a lesser degree, reflecting internal hedging arrangements.

Cost data

To assess the operating costs for each mainland generator in the NEM we have modelled 2 variants of costs, one used the public data available in the ISP and NTNDP, the second used spot market fuel prices for the relevant gas and coal generators. However, as the purpose of this data is to forecast to plan future transmission developments we have supplemented ISP data where possible.

We sourced the following components from AEMO's 2022 Integrated System Plan:

- Fixed operating and maintenance costs (FOM)—AEMO defines FOM as the recurring annual cost that occurs regardless of the variation of quantity (output) of a generator. Does not include depreciating and finance cost.
- Variable operating and maintenance costs (VOM) —AEMO defines VOM as the cost occurs relating to the variation of quantity (output) of generator (for example, labour costs, operation and maintenance costs).
- Heat Rate—the measure of how much electricity is produced for each unit of fuel.
- Marginal Loss Factors (MLF) —represents the average losses incurred by a generator to get its power to the regional reference node.
- Auxiliary load—the amount of energy used in the power station to support the generation of electricity.

For generators not listed in the ISP, such as those that retired earlier than 2022, we drew assumptions from other publications such as the NTNDP. In some instances we saw that methodology changes cause unexplained differences in values between the ISP and NTNDP. In these cases, we adjusted costs to be more consistent with the values in the ISP.

In the model where we used spot market fuel prices for each region:

- The price for NSW coal was based on monthly prices from the Newcastle coal price index sourced from globalCOAL, and coal prices for AGL Energy's Bayswater and Liddell power stations were further adjusted in line with the ratio of ISP fuel prices for these stations and other NSW coal generators.
- Victorian coal price information is sourced from the 2022 ISP.
- Daily gas spot prices from the Brisbane, Sydney and Adelaide Short Term Trading Markets and the Victorian Declared Wholesale Gas Market is used to represent the opportunity cost to fuel power stations that use natural gas in each region.
- We determined the total cost of operation for each generator for each interval using the following formula:
- Total cost = FOM + VOM + Fuel cost (heat rate * fuel price * MLF)

To determine the cost per megawatt hour (MWh) for a generation technology, we divided the total cost by that technology's output for a financial year.

Generator operating earnings calculation

To calculate generator operating earnings, we subtracted modelled generator operating costs from potential revenue.

Limitations

This analysis uses simplified models and public data to estimate generator potential revenues, operating costs and earnings. However, to avoid misinterpretation, it is important to understand the various limitations:

- The ISP cost data does not account for capital expenditure, financing costs, asset values and depreciation for existing generators.
- While public information on fixed operations and maintenance provides a guide over time, in practice it is more likely to be lumpy and plant specific. When this occurs to an aged generator it may complicate decisions regarding investment to extend its life.
- The price for black coal in NSW and natural gas in each region are based on fuel spot market prices. While individual generator fuel costs are likely to also be affected by factors such as storage levels and longer term contracts, fuel spot market prices provide a reasonable proxy for a generator's maximum marginal fuel cost.
- Only revenue from the energy market has been included in our model, and we excluded revenues from frequency control ancillary service markets, directions, and network support agreements.
- Each generator only sells a single contract type and the contracted percentage of a generator's total output was fixed for every year. In practice generators sell various

contract types and target contracted levels may change based on prevailing conditions. Similarly, contract quantity is based on broad and simple estimates, and may not accurately represent the complex contracting behaviour of a generator with variations in its generation portfolio.

- The majority of wind and large-scale solar generators have PPAs, but details of these contracts are confidential. Some public information is available on ACT Government PPA prices, which we used as a general proxy. A single PPA price for wind and large-scale solar is not necessarily realistic as the price of these contracts change from year to year.

Reference to figure in the performance report

Figure 2.12, Figure 9.10

24 Entry and exit

What is this metric?

Past and committed 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 the performance report

Figure 7.1

25 Cost and proportion of time directions applied in South Australia

What is 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 2021, Q3 2022*

Reference to figure in the performance report

Figure 8.1

26 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 megawatt (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 2021 summary data*, March 2022

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

Reference to figure in the performance report

Figure 8.2

27 FCAS analysis

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

27.1 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 Market Management System database.

Where applicable, ownership was determined using the following:

- Registered capacity of each generating unit 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 using the ownership of each generating unit on that date as well.
- Ownership of each generating unit was determined by using information published by AEMO on their 'generation information' and 'registrations and exemptions'. Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

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.[5] 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:

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

$$Local\ Cost^{6} = Local\ Revnue = \sum_{Local\ DUID} Enablement\ Target \times FCAS\ Price/12$$

Reference to figure in the report

Figure 2.16, Figure 9.1, Figure 9.2

27.2 Maximum and effective FCAS availability

Each unit that offers into FCAS markets has a maximum availability and an effective availability. Maximum availability refers to the full amount of capacity offered into each market. Effective availability reflects the actual amount of capacity able to be dispatched into FCAS accounting for factors that may limit the provision of FCAS in real time, such as co-optimisation with energy.

How did we determine maximum FCAS availability?

For each unit in each FCAS market, we determined its maximum FCAS availability for a dispatch interval using participants' FCAS offers. We also created some rules to better reflect the features of different types of FCAS service providers:

- For battery storage, maximum availability for each FCAS market is capped by the maximum availability in its FCAS offer.[7]
- For other participants who are physically capable of providing FCAS services without providing energy on the spot market at the same time, if they have zero energy availability[8] but a positive actual availability[9] for an FCAS market, their maximum availability is capped by the maximum available volume[10] in their FCAS offers.

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

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

7 In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER.

8 In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER where the BIDTYPE is "ENERGY".

9 In AEMO's MMS, the ACTUALAVAILABILILTY for the FCAS service in the dataset DISPATCHLOAD.

10 In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER.

- If a participant does not offer availability in the energy market[11] at all, its maximum availability is capped by the maximum availability[12] in its FCAS offer. This adjustment rule is used for FCAS providers that do not participate in the energy market, such as demand response aggregators (DRA).
- For all other participants, for each FCAS service, if a participant has a positive fixed load,[13] its maximum FCAS availability is capped by the lesser of its energy availability,[14] the maximum availability[15] in its FCAS offer or the fixed load for the FCAS market. Otherwise, its maximum FCAS availability is capped by the lesser of its energy availability and the maximum availability in its FCAS offer.

How did we determine effective FCAS availability?

Effective FCAS availability is capped by the actual availability of the FCAS service.[16]

Specifically for wind farms providing regulation services, if a participant's actual availability for FCAS is zero, then its effective FCAS availability is capped by the lesser of its FCAS availability[17] and its maximum enablement point.[18] This rule was used to cater for cases in which a unit has a positive enablement target in the regulation FCAS market but has zero actual FCAS availability.

Reference to figure in the report

Figure 9.3, Figure 9.4, Figure 9.5, Figure 9.6, Figure 9.7

27.3 Market intervention and revenue

When AEMO intervenes in the market, 'what-if' pricing is invoked. What-if pricing is used to set the price at the level it would have been had intervention not occurred, in order to preserve market price signals. What-if pricing is determined through the pricing run and what actually happens is determined through the physical run.

How did we analyse FCAS availability and price?

When applicable, the what-if dispatch price and enablement target in the pricing run (where the INTERVENTION flag equals 0) was used.

How did we estimate participants' FCAS revenue?

When applicable, the what-if price from the pricing run (where the INTERVENTION flag equals 0) and the FCAS enablement target in the physical run (where the INTERVENTION flag equals 1) was used. This is because the revenue is based on the FCAS enablement target in the physical run. For each unit, its estimated revenue for a FCAS service in a dispatch interval is calculated as:

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[11] In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER where the BIDTYPE equals "ENERGY" is missing.

[12] In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER.

[13] In AEMO's MMS, the column "FIXEDLOAD" in the dataset BIDPEROFFER.

[14] In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER where the BIDTYPE is "ENERGY".

[15] In AEMO's MMS, the column "MAXAVAIL" in the dataset BIDPEROFFER.

[16] In AEMO's MMS, the ACTUALAVAILABILILTY for the FCAS service in the dataset DISPATCHLOAD.

[17] In AEMO's MMS, the column "RAISEREGAVAILABILITY" or "LOWERREGAVAILABILITY" in the DISPATCHLOAD dataset.

[18] In AEMO's MMS, the column "ENABLEMENTMAX" in the BIDPEROFFER dataset.

$$Revenue = Enablement\ Target \times FCAS\ Price/12$$

Reference to figure in the performance report

Figure 9.8, Figure 9.9, Figure 9.10

How did we calculate energy cost?

To calculate energy cost we used the following formula:

$$Energy\ cost = Energy\ withdrew\ from\ grid \times Spot\ price \times Marginal\ loss\ factor$$

Reference to figure in the report

Figure 9.10

28 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.

For more information on heat rates and fuel costs, see our Wholesale electricity market performance report 2022—LCOE & LCOS modelling approach, limitations and results.

Reference to figure in the performance report

Figure 2.8, Figure 2.9

Appendix A- Generator earnings input assumptions

Table 1 Parameters, assumptions and sources

Parameter	Assumption	Data source and description
Generator and load dispatch data	None	30 minute metered generator/load dispatch data for each registered unit from AEMO MMS.
Regional electricity spot prices	None	30 minute spot price data for each region from AEMO MMS
FOM, VOM, heat rate, MLF, auxiliary load	Fixed values for all years (2017 to 2022)	AEMO 2022 ISP inputs and assumptions data.[19] AEMO 2016 NTNDP planning studies—additional modelling data and assumptions summary.[20] For generators that retired before 2021-22, we sourced costs information from NTDNP reports.
Fuel prices	NSW black coal price based on Newcastle export black coal price	globalCOAL—NSW coal price information sourced from globalCOAL, information on their data is available www.globalcoal.com We then discounted the coal prices applied to Bayswater and Liddell power stations in proportion to ISP values (that is by the same proportion they were different to other NSW black coal stations using ISP values).
	AEMO fuel cost data for Queensland black coal and Victoria brown coal	AEMO 2022 ISP inputs and assumptions data.[21] AEMO 2016 NTNDP Planning Studies—additional modelling data and assumptions summary.[22]
	Spot gas price	Brisbane, Sydney and Adelaide Short Term Trading Market prices. Victorian Declared Wholesale Gas Market prices.

19 AEMO, 2022 ISP inputs and assumptions https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

20 AEMO, 2016 NTNDP database

21 AEMO, 2022 ISP inputs and assumptions https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

22 AEMO, 2016 NTNDP database

Parameter	Assumption	Data source and description
Black coal, brown coal, CGGT contract volume and price	Black coal: 18,400MW (60% contracted) Brown coal: 4,700MW (75% contracted) CCGT: 2,500MW (45% contracted)	Regional quarterly ASX Energy flat strip contract price. Prices for futures contracts from ASX Energy, available at www.asxenergy.com.au