Methods and Assumptions

Wholesale electricity market performance report 2020

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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 2020* (the performance report) and aims to communicate how we have use 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 also published:

- *Wholesale electricity market performance report 2020 – 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.
- *Wholesale electricity market performance report 2020 – Generators earnings modelling approaches and limitations* which sets our approach in estimating incumbent generator costs, revenues and earnings over the last six years.

We also published the Statement of Approach and 2020 Focus, which provide information on the general approach we have taken in the performance report.[3] [4]

[1] National Electricity Law, Part 3 Division 1A

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

[3] AER, Wholesale electricity market performance monitoring, Statement of approach

[4] AER, Wholesale electricity market performance monitoring, 2020 Focus

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 spot price multiplied by native demand in each region for every 30 minute trading interval in a financial quarter, then divided by the sum of all native demand in each region for every 30 minute trading interval in a financial quarter. Likewise annual VWA price is calculated on annual basis.

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

In performing a count of prices, we take all trading interval 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 spot price for each matching trading interval 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?

Spot price for each 30 minute trading interval 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 spot price data used is in 30 minute trading intervals (average of the prices of the six 5 minute dispatch intervals that make up the trading interval). Demand data is in 30 minute trading 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 $200; greater than $200 and less than or equal to $300; greater than $300 and less than or equal to $1,000; greater than $1,000 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 2.4, Figure 2.5, Figure 2.6, Figure 2.12, Figure 4.9

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, rooftop solar PV and batteries.

Electricity generation by fuel source is the total generation output in the NEM as a whole as well as 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 trading 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.

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 2.2, Figure 2.3, Figure 2.11

3 Price setter by fuel type

What is price setter?

The price in the NEM for each region is set every five minutes. For each region, the highest priced offer needed to meet demand sets the price every 5 minutes (dispatch price). Every 30 minutes, the six dispatch prices are averaged to determine the spot price and generators that were dispatched are paid this price for the electricity they produce regardless of how they bid. 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 every five minutes in each NEM region.

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 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 dispatch intervals 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.
- 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. This is why the total can be more than 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 6:30pm in 2019, we sum the counts for each fuel type at the 6:30pm 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 4.2, Figure 4.4, Figure 4.12

4 Average native demand by time of day

What is native demand?

Native demand represents the sum of initial supply and total intermittent generation in a region.

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 trading interval to find total demand for each 30 minute trading interval.

To find time of day, we summed the total demand for each individual trading 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 trading interval and divided by the number of days in the year.

Reference to figure in the performance report

Figure 2.10

5 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 half hour trading interval and divide by the number of trading 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 trading 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 trading 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

Figure 4.1, Figure 4.3, Figure 4.5, Figure 4.6, Figure 4.7, Figure 4.8, Figure 4.10, Figure 4.11

6 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 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 all generating units* – includes all market scheduled, and market semi-scheduled generating units in the NEM.
  - *For flexible generating units* – includes all market scheduled generating units that are able to start within 30 minutes of receiving a dispatch instruction from AEMO. This primarily includes fast start gas (OCGT), hydro and batteries.
- 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. For instance, Callide Power Trading is a 50/50 joint venture between InterGen and CS Energy and allocated 50/50 while Millmerran Energy Trader is primarily owned by InterGen.

Reference to figure in the performance report

Figure 3.1, Figure 3.4

7 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, it does not account well for 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 the entire 2019-20 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 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.
  - *For flexible generating units* – includes all market scheduled generating units that are able to start within 30 minutes of receiving a dispatch instruction from AEMO. This primarily includes fast start gas (OCGT), hydro and batteries.
- Interconnectors—Interconnector 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, Callide Power Trading is a 50/50 joint venture between InterGen and CS Energy and allocated 50/50 while Millmerran Energy Trader is primarily owned by InterGen.

Reference to figure in the performance report

Figure 3.2, Figure 3.5

8 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 period when the market was suspended during the South Australia black out and system restoration is 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, Callide Power Trading is a 50/50 joint venture between InterGen and CS Energy and allocated 50/50 while Millmerran Energy Trader is primarily owned by InterGen.

Reference to figure in the performance report

Figure 3.3

9 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 measure 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.

- *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 2017-18 and 2019-20 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 3.5

10 Regional interconnector exports

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. Regional interconnector exports looks at flows out of one region into another and sums the total energy export for each quarter.

Where is the data from?

Interconnector flows are sourced from AEMO's MMS database.

How did we determine the regional interconnector exports?

- Resolution—Interconnector flow and limit data. Expressed as a total quarterly export for each regional boundary (for example, total exports by Queensland to NSW and from NSW to Queensland across QNI and Directlink are expressed in one figure).
- Interconnectors—Data from all interconnectors in the NEM was used to calculate price alignment, including Queensland to NSW Interconnector (QNI), Terranora Interconnector, Victoria to NSW, Basslink, Heywood Interconnector and Murraylink.

Reference to figure in the performance report

Figure 3.7

11 Regional price alignment

What is price alignment?

Price alignment between regions occurs when dispatch price in all regions are set by one or more generators at the same price. However prices may vary slightly from region to region to account for transmission losses, depending on the distance between the price setting units to the region. When price alignment occurs, the generation capacity in the exporting regions (usually priced cheaper) offers competitive constraint in importing regions (usually with higher priced generation) to achieve most economic dispatch of electricity.

Where is the data from?

Interconnector flow and limit data is sourced from AEMO's MMS database.

The occurrences of price alignment between regions can be calculated from interconnector flows and limits dataset. When the flow into a region on an interconnector is below its limit, an interconnector is said to be unconstrained. When this occurs, the dispatch prices in the two regions connected by the interconnector can be set by the next cheapest offer in the bid stack in those two regions (meaning prices will be aligned in the two regions). When a region has two or more interconnectors from the same neighbouring region, price alignment can occur as long as one interconnector is unconstrained, even if others may be flowing at their limits. Price alignment between regions can therefore be deduced by working out when interconnectors are unconstrained from flow and limit datasets

How did we determine the regional interconnector exports?

- Resolution—Interconnector flow and limit data.
- Interconnectors—Data from all interconnectors in the NEM was used to calculate price alignment, including Queensland to NSW Interconnector (QNI), Terranora Interconnector, Victoria to NSW, Basslink, Heywood Interconnector and Murraylink.

Reference to figure in the performance report

Figure 3.8

12 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:

$$PST_2 = \frac{regional\ bid\ avail + \sum \text{IM limit} - \sum \text{forced IM} - (bid\ avail_1 + bid\ avail_2)}{regional\ demand - \sum forced\ IM + \sum forced\ EX}$$

  - **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, Callide Power Trading is a 50/50 joint venture between InterGen and CS Energy and allocated 50/50 while Millmerran Energy Trader is primarily owned by InterGen.

Reference to figure in the performance report

Figure 3.9, Figure 3.10, Figure 3.11

13 Time of day analysis using the 2 pivotal supplier test

What is this metric?

Time of day analysis using the pivotal supplier test (PST) measures the extent to which one or more participants is 'pivotal' to clearing the market at certain times of day. Two periods were considered: 'daytime' and 'evening'.

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 Market Management System (MMS) database.

How did we determine the time of day analysis using the 2 pivotal supplier test?

Calculations performed using method detailed in section 12.

- Time of day—Two time periods were used in this analysis:
  - 'Daytime' from 11 am to 2 pm (including PST-2 calculations for the dispatch intervals from 11 am to 1.55 pm inclusive).
  - 'Evening' from 5 pm to 8 pm (including PST-2 calculations for the dispatch intervals from 5 pm to 7.55 pm inclusive).
- Resolution—PST-2 calculations were aggregated to average hourly outcomes. Each data point represents one hour in each financial year for either 'daytime' or 'evening'. That is, every day in the 2017-18 and 2019-20 financial years is represented by 3 data points for 'daytime' and 3 for the 'evening'.
- Demand—Demand that appears on the chart corresponds to the 'total demand' level for a given region that was part of the calculation.

Reference to figure in the performance report

Figure 3.10, Figure 3.11

14 Contract markets analysis

This section details the approach used in our contract markets analysis

14.1 ASX base futures liquidity ratio

What is this metric?

It is a ratio that provides an indication of how much volume is traded via 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?

Base futures trade volumes are sourced from ASX Energy.

Native demand is sourced from AEMO's Market Management System (MMS) database.

How did we determine the liquidity ratio?

- Resolution—Quarterly for each region that has contracts on the ASX (Queensland, NSW, Victoria and South Australia).
- Liquidity ratio calculation—Included total traded volumes for base futures and native demand:

$$Liquidity\ ratio_{region\ i} = \frac{base\ futures\ traded\ volume}{native\ demand}$$

  – **Base futures traded volume**: traded volume for base futures for the quarter of interest (for example, the traded volume for Q1 2020 Queensland base futures).
  – **Native demand**: total native demand for the quarter of interest (for example, Q1 2020 native demand includes the total native demand for all periods in Q1 2020).

Reference to figure in the performance report

Figure 3.13

14.2 ASX open interest

What is this metric?

Open Interest refers to the total number of outstanding electricity derivative contracts on the ASX. It measures the size of the market at a point in time.

Where is the data from?

ASX Energy

How did we determine open interest?

The total volume for each region is calculated by summing the open interest for each base future contract in that region on the last trading day of the month.

Reference to figure in the performance report

Figure 3.14

14.3 Futures contract trades in the lead up to the contract period

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. 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?

Trade volumes for ASX base, peak and cap contracts are sourced from ASX Energy.

How did we determine futures contract trades in the lead up to the contract period?

- Resolution—Across all markets combined (Queensland, NSW, Victoria and South Australia).
- Calculation—The total volume of trades for a particular contract that were undertaken in a month that was a certain number of months away from the close of that contract (for example, trades undertaken for a Q1 2020 base futures contract in July 2019 would appear as trades in 6-9 months away from the close of that contract).

Reference to figure in the performance report

Figure 7.1

15 FCAS analysis

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

15.1 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 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 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 8.1, Figure 8.2, Figure 8.4, Figure 8.5, Figure 8.6, Figure 8.7, Figure 8.9

15.2 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.

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 8.3, Figure 8.4, Figure 8.6

15.3 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:

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 2.13, Figure 8.8, Figure 8.9

16 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 2020—LCOE & LCOS modelling approach, limitations and results*.

Reference to figure in the performance report

Figure 2.8, Figure 2.9, Figure 4.2