



# Quarterly Energy Dynamics

## Q4 2018

Author: Market Insights | Markets

# Important notice

## PURPOSE

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q4 2018 (1 October to 31 December 2018). This quarterly report compares results for the quarter against other recent quarters, focussing on Q3 2018 and Q4 2017. Geographically, the report covers:

- The National Electricity Market – which includes Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.
- The Wholesale Electricity Market operating in Western Australia.
- The gas markets operating in Queensland, New South Wales, Victoria and South Australia.

## DISCLAIMER

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, the Wholesale Electricity Market Rules, the National Gas Law, the National Gas Rules, the Gas Services Information Regulations or any other applicable laws, procedures or policies. AEMO has made every effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

## VERSION CONTROL

Version	Release date	Changes
1	13/02/2019	Initial release

## Executive summary

Highlights for Q4 2018 include:

### Record wholesale electricity and gas prices despite low demand

- Quarterly average spot gas prices were the highest on record in Victoria's Declared Wholesale Gas Market (DWGM) and the Short Term Trading Market (STTM) in Adelaide and the second highest on record in the Brisbane and Sydney STTMs, and the Gas Supply Hub (GSH).
  - The increase in gas prices in AEMO-operated markets has been influenced by: record high daily pipeline deliveries to Curtis Island for LNG export (3,583 TJ/day); comparatively high NEM electricity prices; and reduced supply from Longford compared to Q4 2017 (-29%), which was offset by lower gas-powered generation (GPG) demand. These domestic gas price results occurred despite a 33% drop in international Brent prices (oil) and a related fall in LNG netback pricing.
- Quarterly average NEM spot electricity prices were \$82-96/MWh, which is the highest Q4 on record in all regions except Tasmania. These high electricity prices were notable because they occurred despite: average mainland operational demand for the quarter falling to its lowest level since 2002; and a lack of high spot prices above \$300/MWh.
- A combination of shorter and longer-term factors has contributed to these electricity price outcomes:
  - In the shorter-term, the downward trend in output from baseload and mid-merit gas powered generation (GPG) in 2018 has contributed to higher prices. Between Q4 2017 and Q4 2018, there was an approximately 50% reduction in GPG capacity offered below \$100/MWh, influenced by comparatively higher gas prices as well as several extended outages (see Section 1.4.1).
    - Q4 recorded an increased incidence of gas playing a price setting role. GPG set the price 25% of the time in the NEM compared to the long-term average of 15%. GPG also set the price at higher levels: for example, when GPG set Victoria's price it averaged \$115/MWh compared to \$91/MWh in Q4 2017.
  - Other contributors include the structural shift of offers from black coal-fired generators to higher prices between 2014 and 2018<sup>1</sup>, as well the progressive closure of approximately 4,000 MW of coal-fired capacity between 2013 and 2017.
- Average mainland NEM operational demand during the quarter reduced to its lowest level since 2002. NEM average operational demand has been declining since 2009, influenced by: the decline of energy-intensive industries; increased uptake of rooftop PV; and higher uptake of energy efficiency improvements.
  - South Australia set a new all-time minimum demand record of 599 MW at 1300hrs on 21 October 2018. This represents a continuation of the decreasing average daytime demand, primarily driven by increasing rooftop PV uptake.

### Gas-powered generation falls and new renewables capacity enters the NEM

- Q4 2018 recorded the lowest quarterly average GPG on record for the current GPG fleet. GPG has declined steadily from Q4 2017, influenced by: increased penetration of variable renewable energy (VRE); rising domestic and international gas prices in 2018; and comparatively high hydro output in 2018.
- Over 3 GW of large-scale VRE commenced generation in the NEM during 2018, representing a 66% increase in VRE capacity from the start of the year. This contributed to a 34% decrease in spot Large-scale Generation Certificate prices over the quarter.

### Other east coast highlights included:

- During the quarter, AEMO directed generators in Victoria for system security purposes (voltage control and system strength). This was required due to outages of brown coal-fired units and low operational demand.
- NEM interconnectors were constrained at their limits for the least amount of time on record for a quarter, which contributed to price convergence across some NEM regions (see Section 1.6). For example, Victoria and South Australia's prices were set by a common marginal unit for 95% of the quarter, with the two regions recording the same average wholesale electricity price of \$96/MWh.
- A record high of 5,875 TJ of gas was delivered through the GSH over Q4 2018, up 47% when compared to the previous highest quarter (Q4 2017).

<sup>1</sup> See for example Australian Energy Regulator. 2018. *Wholesale electricity market performance report*. ONLINE. Available at: [www.aer.gov.au/system/files/Wholesale%20electricity%20market%20performance%20report%20-%20December%202018.pdf](http://www.aer.gov.au/system/files/Wholesale%20electricity%20market%20performance%20report%20-%20December%202018.pdf)

**Western Australia highlights included:**

- The Wholesale Electricity Market (WEM) in Western Australia experienced one of its lowest Q4 operational demand intervals for 11 years in Q4 2018. Demand decreased to 1,199 MW at 1030hrs (AWST) on 28 October 2018.
- Wholesale electricity prices in both the Balancing Market and STEM decreased in Q4 2018 compared to Q3 2018 and Q4 2017. This was driven by lower average demand, higher mid-merit generator availability and participant bidding behaviour.
- AEMO called upon Backup Load Following Ancillary Service for the first time ever on 18 October 2018, then a second time on 26 December 2018, due to high variability in solar PV output and wind generation.
- The 2018-19 Capacity Year commenced on 1 October 2018. Some key highlights include:
  - The Reserve Capacity Requirement increased slightly (1.5%) from 4,552 MW to 4,620 MW.
  - The Reserve Capacity Price paid to generators increased 24% to \$138,760.39.
  - The Reserve Capacity Mechanism was valued at approximately \$662 million for the 2018–2019 Capacity Year.

## Contents

<b>Executive summary</b>	<b>3</b>
<b>1. NEM market dynamics</b>	<b>6</b>
1.1 Weather	6
1.2 Electricity demand	6
1.3 Wholesale electricity prices	8
1.4 Electricity generation	10
1.5 Other NEM-related markets	15
1.6 Inter-regional transfers	18
1.7 Power system management	19
<b>2. Gas market dynamics</b>	<b>21</b>
2.1 Gas demand	21
2.2 Wholesale gas prices	22
2.3 Gas supply	24
2.4 Pipeline flows	25
2.5 Gas Supply Hub	26
2.6 Gas – Western Australia	27
<b>3. WEM market dynamics</b>	<b>28</b>
3.1 Electricity demand	28
3.2 Wholesale electricity pricing	29
3.3 Power system security	31
3.4 Reserve Capacity Mechanism	32
Abbreviations	33

## 1. NEM market dynamics

### 1.1 Weather

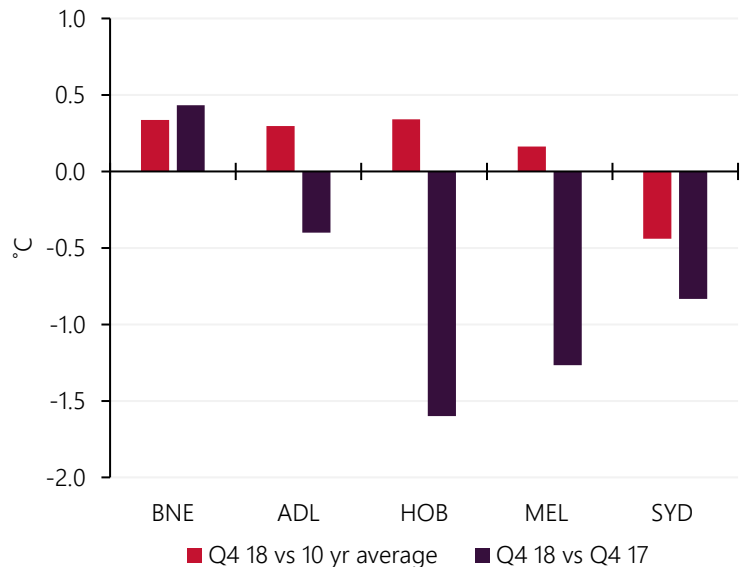
Q4 2018 was a quarter of warm conditions across most of the nation, particularly December which was the warmest on record for Australia, with prolonged periods of extreme heat.<sup>2</sup>

However, the national trend of warm weather was not reflected across all major capitals (Figure 1):

- Brisbane, Adelaide, Hobart and Melbourne all had higher than average maximum temperatures when compared to the long term Q4 average. This was mostly due to much higher than average December temperatures.
- Sydney average maximum temperatures were cooler than average, mostly due to colder than average October temperatures.

For rainfall, some areas of the east coast had above average rainfall, largely due to tropical cyclone activity. This, in combination with favourable weather patterns, meant that rain fell along parts of coastal Queensland and south-east Australia. Tasmania received below average rainfall during Q4, particularly in western Tasmania.

**Figure 1** Average maximum temperature variance by capital city – Q4 2018 vs Q4 2017 and 10-year Q4 average



Source: Bureau of Meteorology

### 1.2 Electricity demand

NEM average operational demand has been reducing since 2009, influenced by: the decline of energy-intensive industries; increased uptake of rooftop PV; and energy efficiency improvements.

This overall trend of declining demand continued in Q4 2018 with average NEM operational demand decreasing by 213 MW on average compared to Q4 2017, the lowest mainland NEM result since 2002 (Figure 2). Almost the entirety of Q4 2018 NEM demand reductions occurred in Victoria where average operational demand decreased by 215 MW (-4%) compared to Q4 2017. A small decrease in demand of less than 1% also occurred in New South Wales, with small demand increases of less than 1% occurring in South Australia, Queensland and Tasmania.

The decrease in Victorian demand was due to a combination of factors including:

- Mild weather over November, with average maximum temperatures of 22.5°C, 4°C lower than November 2017.<sup>2</sup> Temperatures between 18 and 22°C typically do not require significant amounts of heating or cooling load and thus can result in reduced electricity demand.
- A 26% increase in rooftop PV generation compared to Q4 2017 (Section 1.4.4).
- Incremental energy efficiency improvements that reduce long-term energy consumption.

<sup>2</sup> BOM. 2019. *Climate Data Online*. ONLINE. Available at: <http://www.bom.gov.au/climate/data/>. Accessed 22 January 2019.

**Figure 2 Average operational demand for Q4 (2013 to 2018)**



Note: Demand by region has been normalised with Q4 2018 as the base. Values greater than 1 indicate that demand was higher than in Q4 2018 while values less than one represent the opposite. Units within the columns are in MW.

### Maximum and minimum demand

Table 1 outlines the maximum and minimum demands which occurred in Q4 2018 and the respective regional records. Of note, two demand records were broken in Q4 2018.

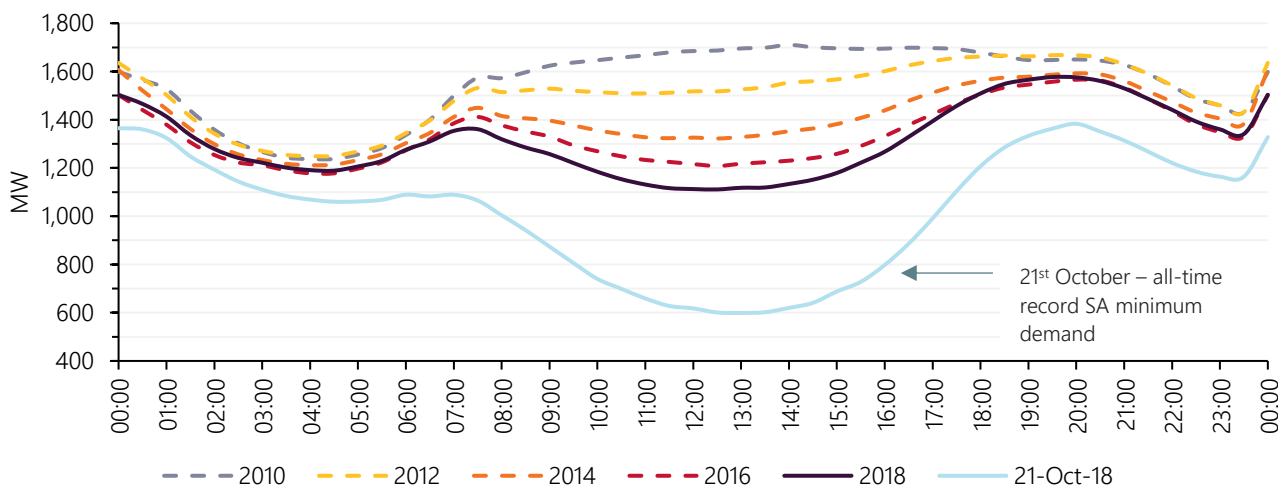
- South Australia set a new all-time minimum demand record of 599 MW on 21 October 2018 at 1300hrs, 62 MW lower than the previous record. This represents a continuation of the decreasing average demand trend in the region, primarily driven by increasing rooftop PV uptake (Figure 3).
- Queensland recorded its highest Q4 demand on 21 December 2018 at 1700hrs when operational demand peaked at 9,502 MW during hot conditions (35°C), with demand 685 MW (+8%) higher than the previous record.

**Table 1 Maximum and minimum operational demand (MW) by region – Q4 2018 vs records<sup>3</sup>**

	QLD		NSW		VIC		SA*		TAS	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q4 2018	<b>9,502</b>	4,798	11,443	5,617	8,756	3,484	2,578	<b>599</b>	1,395	868
All Q4	<b>8,817</b>	2,894	13,620	4,636	9,462	3,217	3,135	<b>661</b>	1,585	552
All-time	9,798	2,894	14,744	4,636	10,576	3,217	3,399	<b>661</b>	1,790	552

\* Excluding system black event in South Australia and subsequent market suspension in the region (28 September – 11 October 2016)

**Figure 3 Average Q4 daily operational demand in South Australia**



<sup>3</sup> Table records refer to those prior to the commencement of Q4 2018. Instances where the previous record has been broken are shown with red text. The records go back to when the NEM began operation as a wholesale spot market in December 1998. Tasmania joined in May 2005.

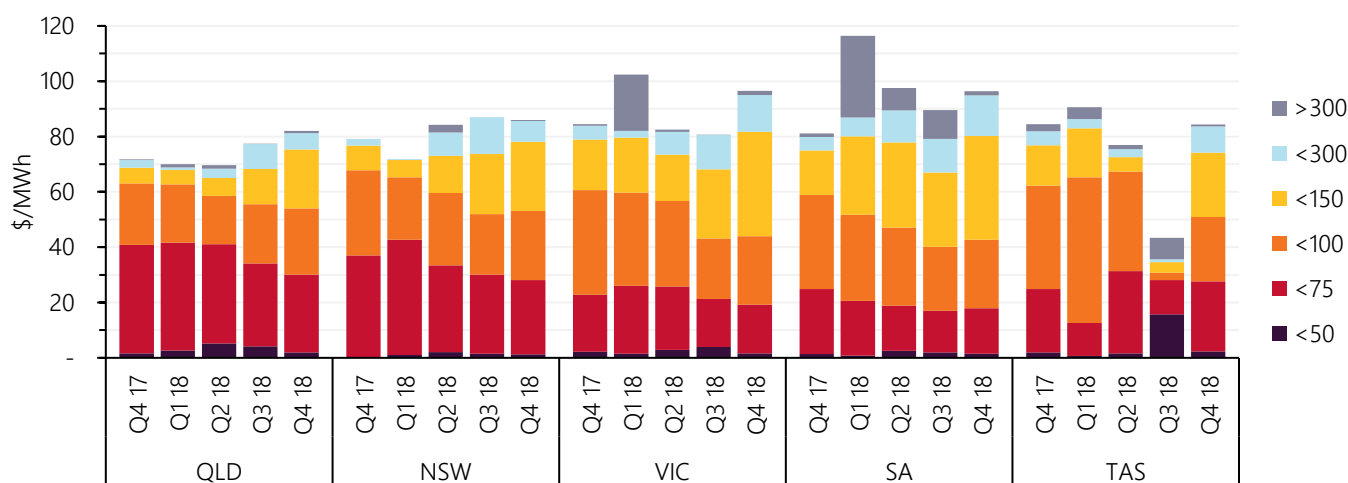
## 1.3 Wholesale electricity prices

Quarterly average wholesale electricity prices were the highest Q4 on record in all NEM regions except for Tasmania (Figure 4). Queensland’s average price of \$82/MWh was its highest in more than a year, while South Australia’s quarterly average price has been sustained at, or above, \$90/MWh throughout 2018. These results are particularly noteworthy as they occurred despite:

- Quarterly average mainland NEM demand reaching its lowest level since Q4 2002.
- Increased VRE penetration compared to Q4 2017 which, all else being equal, will typically reduce spot prices because VRE’s market offers are typically \$0/MWh or lower.
- A comparative lack of prices above \$300/MWh. Average cap returns were \$0.83/MWh for the quarter, compared to \$2.89/MWh in Q3 2018.

Short-term contributors to the elevated prices are listed below. Longer-term contributors include the structural shift of offers from black coal-fired generators to higher prices<sup>4</sup>, as well the progressive closure of approximately 4,000 MW of coal-fired capacity between 2013 and 2017.

**Figure 4 Average wholesale electricity price by region**



Note: The average quarterly price is broken up into six parts to show the contribution of prices in different ranges to the average price. For example, the yellow band shows the contribution of prices between \$100-150/MWh to average prices.

### Wholesale electricity price drivers in Q4 2018

<b>Reduced GPG availability and output</b>	Average GPG output during the quarter was 44% lower than in Q4 2017, representing a continuation of the downward trend since the end of 2017. In particular, there was reduced availability of baseload and mid-merit CCGTs – which typically offer a material portion of their capacity at, or below, \$0/MWh (see Section 1.4.1) – with reduced output from these power stations contributing to comparatively higher prices.
<b>High gas prices</b>	An increase in offer price from some GPG which typically play a significant price-setting role, potentially reflecting higher gas input costs. This contributed to GPG setting the price at higher levels than in recent quarters – for example, when GPG set Victoria’s price during the quarter it averaged \$115/MWh compared to \$91/MWh in Q4 2017.
<b>Coal-fired generation outages</b>	Planned and unplanned outages of coal-fired generators in Victoria reduced availability of electricity priced below \$100/MWh by 470 MW on average compared to Q3 2018.
<b>Higher priced hydro offers</b>	<ul style="list-style-type: none"> <li>• Mainland: the amount of hydro capacity priced below \$100/MWh reduced to 430 MW on average, representing a 565 and 109 MW reduction on Q3 2018 and Q4 2017 levels, respectively. The shift in offers coincided with dry conditions and replenishment of dam levels in the lead up to summer (Section 1.4.3).</li> <li>• Tasmania: the amount of hydro capacity priced below \$100/MWh reduced by 746 MW on average compared to Q3 2018, but was consistent with Q4 2017 levels.</li> </ul>

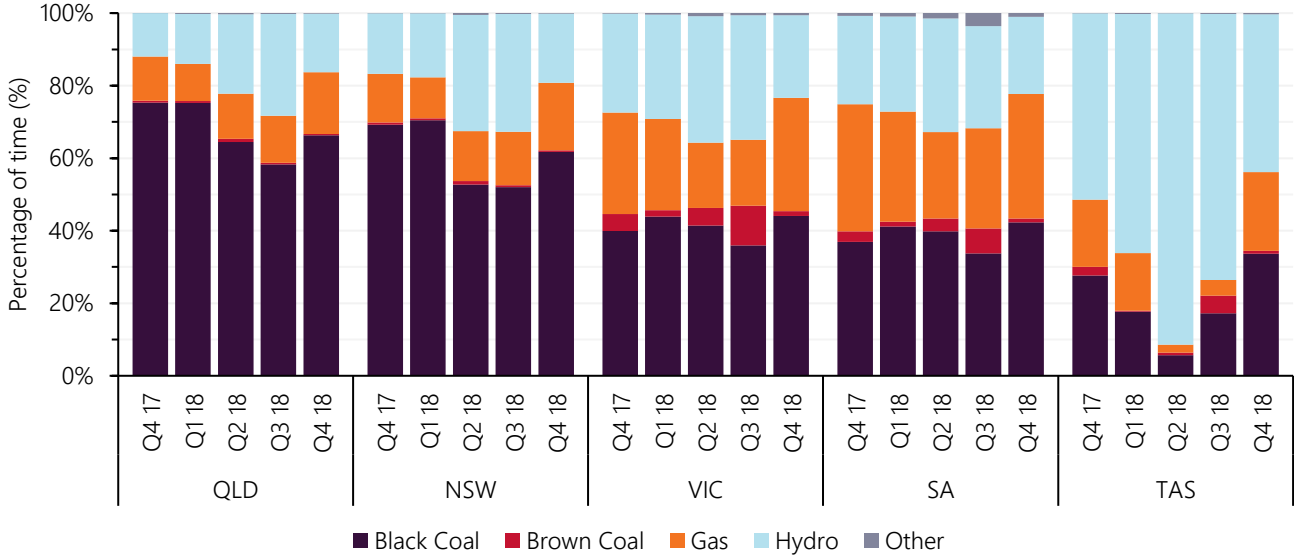
<sup>4</sup> See for example Australian Energy Regulator. 2018. *Wholesale electricity market performance report*. ONLINE. Available at: [www.aer.gov.au/system/files/Wholesale%20electricity%20market%20performance%20report%20-%20December%202018.pdf](http://www.aer.gov.au/system/files/Wholesale%20electricity%20market%20performance%20report%20-%20December%202018.pdf)



1.3.1 Price-setting trends

Compared to Q3 2018 black coal-fired generation and GPG set the spot electricity price more frequently, and hydro generation set the price less frequently (Figure 5).

**Figure 5 Price-setting by fuel type – Q4 2018 vs prior quarters**



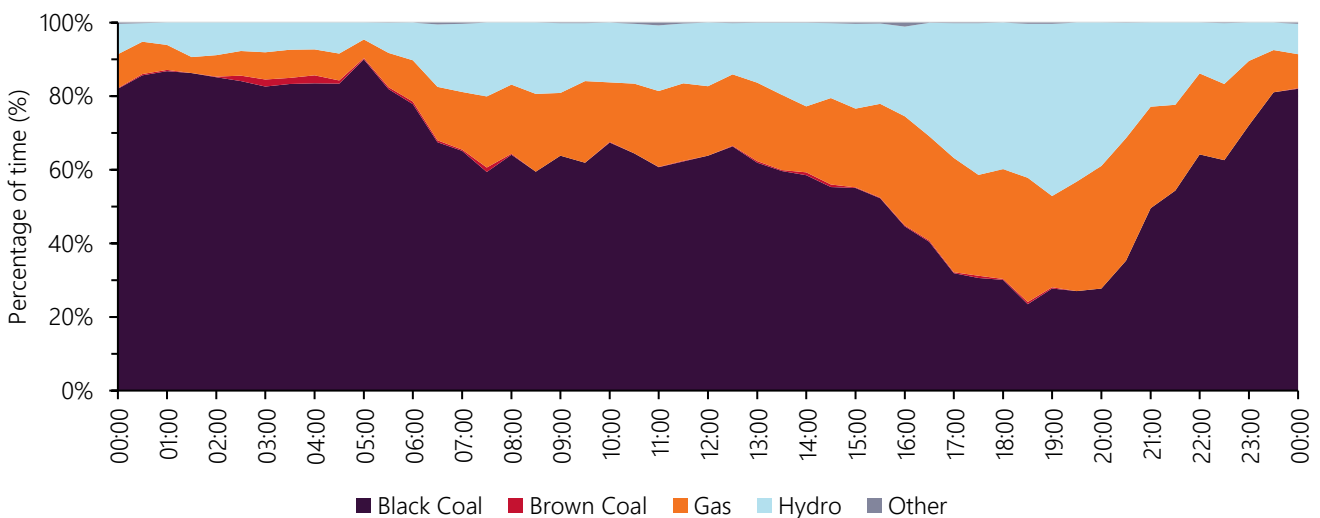
Note: Price setting can occur inter-regionally: for example, Victoria’s price can be set by generators in other NEM regions.

Black coal remained the dominant price-setter in the mainland NEM, particularly in Queensland and New South Wales, where it was the marginal generator more than 60% of the time. In Victoria and South Australia, black coal set the price around 40% of the time. The most frequent price setting power stations were Gladstone (11%), Bayswater (10%) and Stanwell (9%) power stations.

Despite the lowest GPG output since 2006 (Section 1.4.1), GPG set the price more often in every region compared to Q4 2017 and Q3 2018. GPG set the price most often in Victoria and South Australia around 30% of the time, partially displacing the role of hydro as the marginal generator. Hydro’s reduced price-setting role coincided with reduced output and availability at prices below \$100/MWh (Section 1.3). When GPG set the price, the units involved typically came from South Australia (Torrens Island (9%) and Pelican Point (5%)). GPG also set the price at higher levels: for example, when GPG set Victoria’s price it averaged \$115/MWh compared to \$91/MWh in Q4 2017.

As mentioned in Section 1.4.6, the price-setting dynamics vary depending on the time of day (Figure 6). During the off-peak<sup>5</sup>, when demand is typically lower, black coal is typically the price setting fuel. During peak periods, when demand is highest, gas and hydro are the marginal generators the majority of the time.

**Figure 6 Price-setting by time of day – New South Wales Q4 2018**



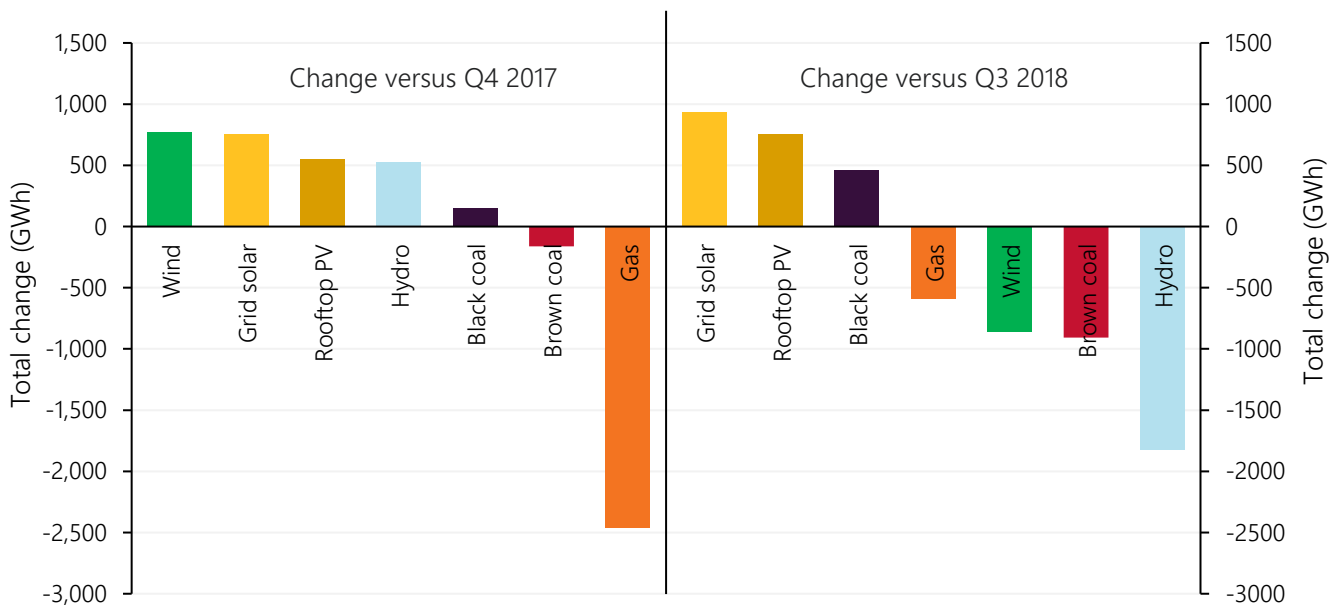
<sup>5</sup> For context, the off-peak period is defined as the period from 22:00 to 07:00hrs EST

## 1.4 Electricity generation

During Q4 2018 there was a continuation in the large shifts in the electricity supply mix which have occurred throughout 2018. Figure 7 shows the changes for the quarter when compared to last year (Q4 2017) and last quarter (Q3 2018). Notable outcomes included:

- Lowest quarterly GPG since 2006 (and effectively lowest on record for the current fleet)<sup>6</sup> – increased VRE and high gas prices contributed to quarterly GPG of 3,184 GWh, the lowest total since 2006 and 44% lower than in Q4 2017.
- Lowest quarterly brown coal-fired generation since NEM start – planned and unplanned outages led to quarterly output of 8,227 GWh, which was 161 GWh lower than the next lowest quarter (Q4 2017).
- Increased penetration of VRE – compared to Q4 2017, combined wind and large-scale solar increased by approximately 1,500 GWh, driven by new wind and solar capacity commissioned.

**Figure 7 Change in supply – Q4 2018 versus Q4 2017 and Q3 2018**



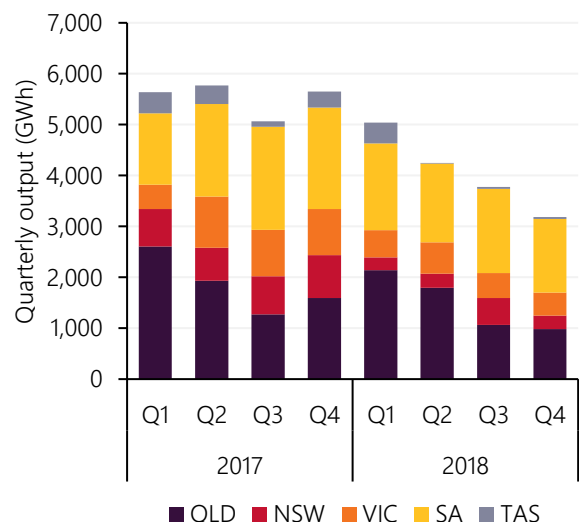
### 1.4.1 Gas-powered generation

Q4 2018 marked a continuation of the decline in electricity supplied by GPG, with average output of 3,184 GWh the lowest level since 2006 (Figure 8). Notably, the majority of GPG's reduction has come from baseload and mid-merit GPGs, including Tallawarra, Darling Downs and Osborne power stations (down 73%, 71% and 75% respectively compared to Q4 2017).

Contributors to reduced GPG included:

- Increased VRE penetration – the steady increase of NEM VRE capacity in 2018 has resulted in higher VRE output which has contributed to displacement of GPG.
- High domestic and international gas prices – other things being equal, high gas prices can affect GPGs in two ways: 1) GPGs without contracted gas will factor in the higher gas costs into their electricity price offers; 2) GPGs with contracted gas may look to sell their gas to domestic or international markets, resulting in reduced output. In 2018 domestic and international gas prices have been at elevated levels (see Section 2.2).

**Figure 8 Quarterly gas-powered generation**

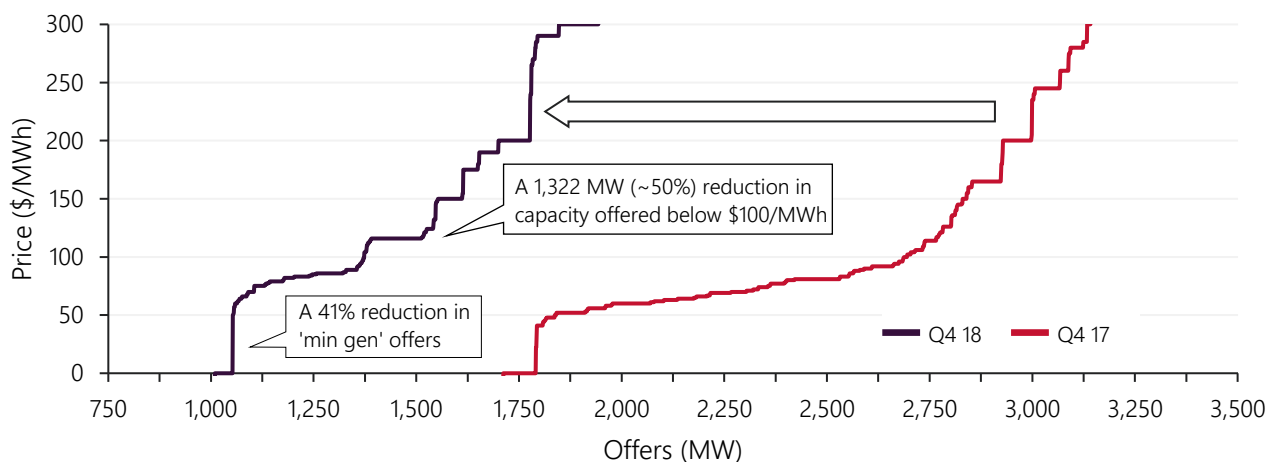


<sup>6</sup> Several large GPGs have entered the NEM since 2006, include Darling Downs, Mortlake and Tallawarra power stations.

- High hydro output – GPG and hydro generation typically play a peaking-generation role in the NEM, providing flexible capacity and generating at comparatively higher levels during peak periods. Comparatively high hydro output in 2018 (Section 1.4.3) has contributed to the GPG reduction.

Figure 9 illustrates the shift in GPG offers which has occurred between Q4 2017 and Q4 2018, with a 1,322 MW reduction (approximately 50%) in capacity offered below \$100/MWh. In addition, there was a 738 MW (41%) reduction in GPG capacity priced at or below \$0/MWh which is reflective of the removal of 'minimum generation' offers from intermediate GPG. The shift also reflects comparatively high gas prices during 2018 as well as several extended outages during the quarter (for example, Tallawarra and Osborne power stations).

**Figure 9 Bid supply curve – NEM GPG**



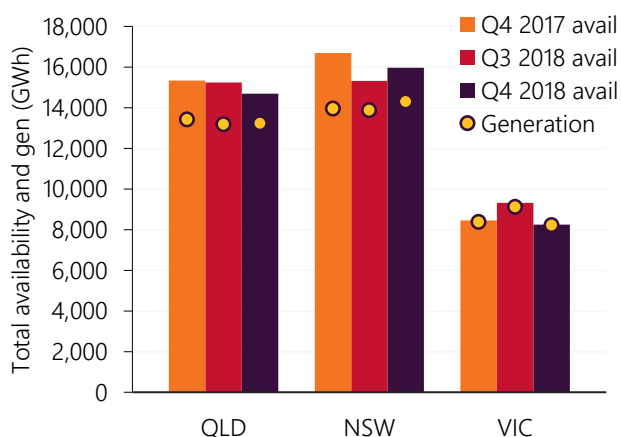
## 1.4.2 Coal-fired generation

Total brown coal-fired generation during Q4 2018 was 8,227 GWh, representing the lowest quarterly average since market inception (Figure 10). This was a function of extended outages at Yallourn and Loy Yang A power stations, with output at these power stations reducing by 666 GWh and 322 GWh respectively when compared to Q3 2018. Record low brown coal output contributed to Q4 2018 recording the lowest quarterly emissions level since NEM-start (see Section 1.4.6).

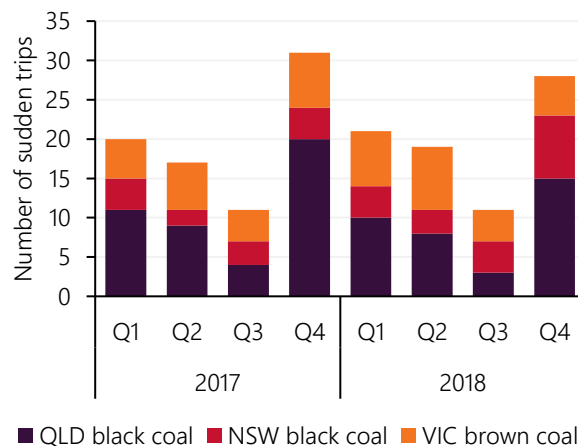
Black coal-fired generation in New South Wales was 420 GWh (3%) higher than in Q3 2018 despite lower electricity demand, driven by higher wholesale electricity prices (see Section 1.3) and increased availability. The largest increases were at Vales Point and Bayswater power stations (+399 GWh and 284 GWh respectively) which were partially offset by a 486 GWh reduction in output from Eraring Power Station. Output from Queensland's black coal-fired generation was consistent with Q3 2018 results, with higher wholesale prices balancing the impact of lower availability.

There was also a relatively high number of sudden generator trips when completed to recent quarters, particularly in Queensland and New South Wales (Figure 11). At this stage, however, Q4 2018 results are not indicative of a longer-term trend, with the number of sudden unit trips in 2018 consistent with results in recent years.

**Figure 10 Coal availability and generation**



**Figure 11 Coal fleet – sudden unit trips<sup>7</sup>**



<sup>7</sup> Definition of sudden unit trip for this report: when a unit is generating above its minimum generation level and falls to zero within two DIs.

## 1.4.3 Hydro generation

There were mixed results for hydro generation in Q4 2018 depending on the comparison period. Compared to Q4 2017, hydro output this quarter was 527 GWh higher, with most of the increased occurring in Tasmania (Figure 12).

However, when compared to Q3 2018 – which was the third highest quarter since NEM start – there was a significant reduction in hydro output, down 1,825 GWh (-35%).

From a regional perspective:

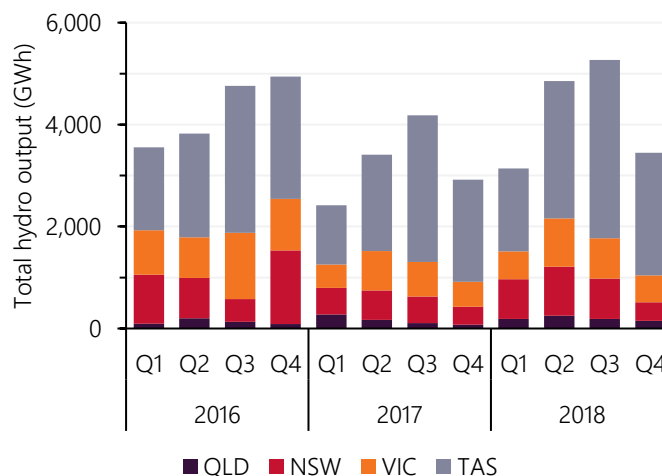
- The largest reduction was in Tasmania, where hydro generation was almost 1,097 GWh lower than in Q3 2018. The reduced output coincided with below average rainfall in Tasmania and a consequent reduction in supply offered by Hydro Tasmania. Around 690 MW that was previously offered at or below \$0/MWh was shifted to higher priced bands during the quarter.
- Reduced output in New South Wales and Victoria – combined there was a reduction of 693 GWh, the majority due to a shift in offers to higher priced bands. This coincided with above average rainfall in the Snowy mountains and rebuilding of dam storage levels: Lake Eucumbene closed the year at 27%, up from 21% at the start of the quarter albeit below the 10-year long-term average end-of-year closing balance (45%).

## 1.4.4 Wind and solar generation

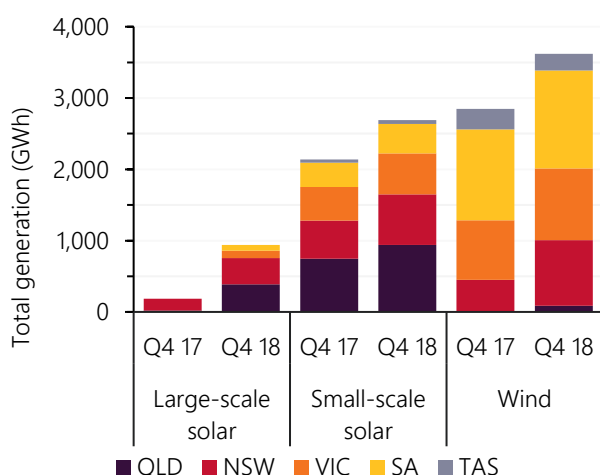
Compared to Q4 2017, large-scale<sup>8</sup> wind and solar generation in Q4 2018 increased from 3,035 GWh to 4,563 GWh (+50%), almost doubling its contribution to the supply from 6% in Q4 2017 to 10% in Q4 2018 (Figure 13). Total wind generation was up 773 GWh and large-scale solar generation increased by 755 GWh compared to Q4 2017, as additional capacity was brought online.

The rapid deployment of large-scale solar generation has continued with seven new solar farms totalling 700 MW capacity commencing generation in Q4 2018 – an increase of over 40% since the end of Q3 2018 (Table 2). Of this new large-scale solar capacity, 341 MW (49%) commenced generation in Queensland, 202 MW (29%) in Victoria and 135 MW (19%) in South Australia. In contrast, only one wind farm commenced generation in Q4 2018 – the 80 MW Crowlands Wind Farm in Victoria.

**Figure 12 Quarterly hydro output**



**Figure 13 NEM wind and solar generation by region**



**Table 2 New entrants<sup>9</sup> in the NEM in Q4 2018**

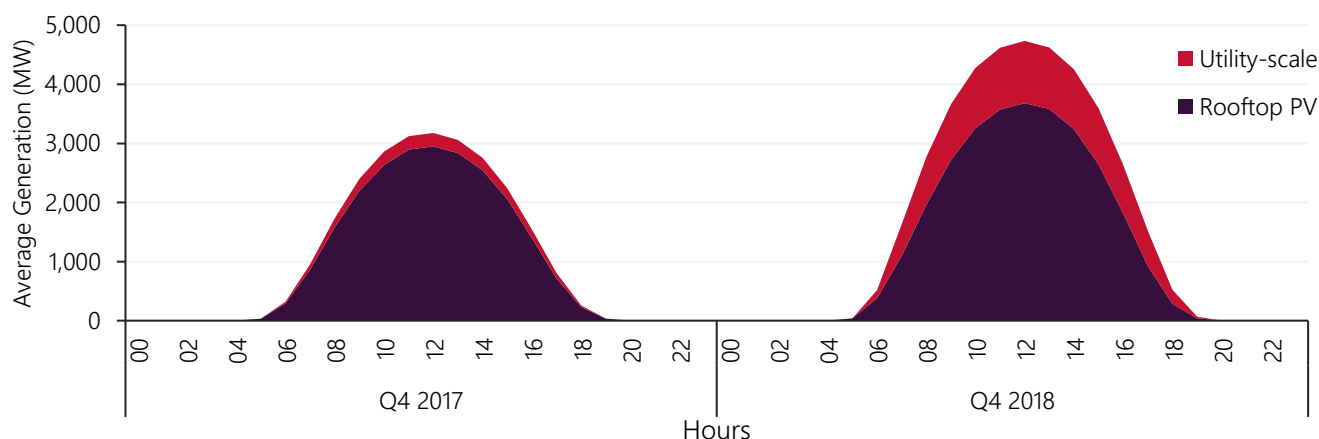
Technology	New entrant	Capacity (MW)	Region
Solar PV	Bungala Two Solar Farm	135	SA
	Daydream Solar Farm	168	QLD
	Emerald Solar Park	88	QLD
	Susan River Solar Farm	85	QLD
	Karadoc Solar Farm	104	VIC
	Wemen Solar Farm	98	VIC
	White Rock Solar Farm	22	NSW
Wind	Crowlands Wind Farm	80	VIC
Battery Storage	Ballarat Battery Energy Storage System	30 MW / 30 MWh	VIC
	Gannawarra Energy Storage System	25 MW / 50 MWh	VIC

<sup>8</sup> Large-scale generation includes market generators (a generator which sells all of its sent-out electricity through the NEM) and non-market generators with registered capacity equal to or greater than 30 MW.

<sup>9</sup> Table includes new entrants that began generating during the quarter. Several of these projects are still undergoing testing and have yet to commence generating at full capacity.

In Q4 2018 rooftop PV generation increased from 2,140 GWh to 2,690 GWh (+26%) when compared to Q4 2017. The largest increase was in New South Wales (32%), with large increases also occurring in Queensland (26%), Victoria (23%) and South Australia (21%). The average daily peak generation of rooftop PV<sup>10</sup> increased from 3,110 MW to 3,878 MW (+25%) between Q4 2017 and Q4 2018. Increases in generation correspond with a record amount of installed rooftop PV capacity over 2018, with the Clean Energy Regulator estimating that 1,600 MW was installed across Australia over the year, with over 1 GW of this capacity expected in the NEM.<sup>11</sup> Large-scale and rooftop PV generated an average of 3,631 GWh in Q4 2018 compared to 2,327 GWh in Q4 2017 (+56%). As illustrated in Figure 14 below, despite rapid growth in large-scale solar installations, rooftop PV continues to provide a large majority share of solar generation – making up 74% of total solar generation in Q4 2018.

**Figure 14 Average NEM hourly large-scale solar and rooftop PV generation profile across Q4 2017 and Q4 2018**



## 1.4.5 Storage

Storage charging or pumping load in the NEM was 231 GWh for the quarter, comprising 217 GWh from pumped hydro storage and 14 GWh from battery storage (Figure 15). Pumping load was approximately 51% higher than the prior quarter and 79% above Q4 2017, and the highest level since 2008.

Key factors impacting upon increased pumping / charging include:

- Higher spreads between peak and off-peak prices. The difference between peak and off-peak prices in New South Wales and Queensland<sup>12</sup> has averaged \$47/MWh for Q4 2018, up from \$25/MWh in Q4 2017.
- Contributions from battery storage facilities including the Hornsdale Power Reserve and the new Gannawarra and Ballarat Battery Energy Storage Systems (Table 2).

The spot arbitrage value of existing storage in the NEM can be measured through the 'park spread'<sup>13</sup>. The park spread calculates the wholesale energy and Frequency Control Ancillary Service (FCAS) margin for storage above its energy costs.<sup>14</sup> For Q4 2018, park spreads for battery storage were \$20/MWh, which was around \$17/MWh (or 45%) lower than that in Q3 2018 (Figure 16). The decline was due to lower participation in FCAS markets to date for new battery energy storage system (BESS) entrants in the NEM. For pumped hydro, park spreads are estimated at \$0/MWh, which was \$3/MWh below the prior quarter.

The difference in park spreads for battery storage relative to pumped hydro, was primarily due to greater battery participation in multiple FCAS markets. On average over Q4 2018, over 2.22 MW of FCAS was enabled per MW of battery charging capacity, relative to 0.01 MW per MW of pumped hydro capacity.

<sup>10</sup> The maximum rooftop PV generated across a 30-minute trading interval each day averaged across the quarter.

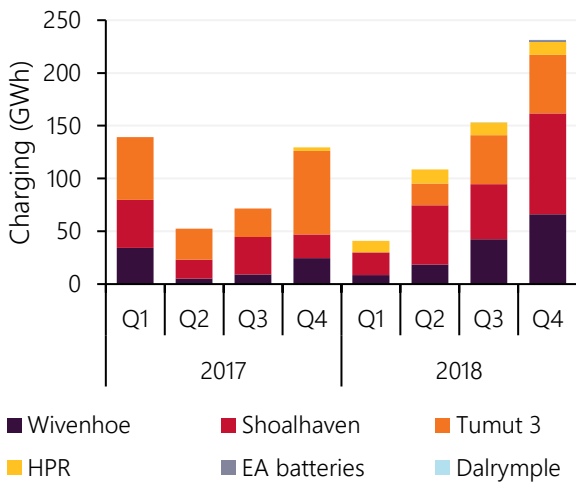
<sup>11</sup> CER. 2018. *Small-scale technology certificate market update – December 2018*. ONLINE. Available at: <http://www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Small-scale%20technology%20certificate%20market%20updates%20by%20month/Small-scale-technology-certificate-market-update-%E2%80%93-December-2018.aspx>. Accessed 14 January 2019.

<sup>12</sup> Peak periods have been defined as periods between 5pm to 9pm, while off-peak periods have been defined as periods between 1am and 5am. The analysis excludes price volatility (i.e. prices above \$300/MWh) in the calculation of the price spread.

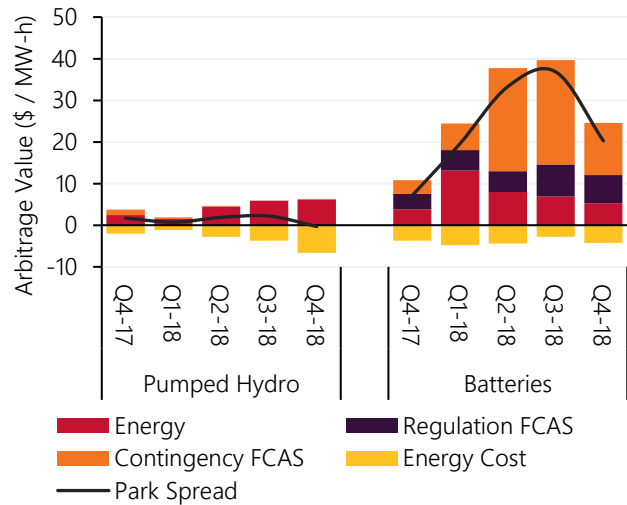
<sup>13</sup> Storage arbitrage value is calculated as the estimated average spot value of energy and ancillary services (spot price x energy charged/discharged) over the period relative to the amount of charging capacity in the NEM. The 'park spread' is calculated as the difference between (i) estimated spot revenues of energy discharge and ancillary services enabled (i.e. the price of energy or FCAS x the MWh dispatched or enabled for the period) and (ii) the estimated energy costs of charging (i.e. the price of energy multiplied by the MWh purchased for the period). The 'park spread' is measured as a proportion of the charging capacity (in MW) of storage facilities in service in the NEM.

<sup>14</sup> It is important to note that this metric does not incorporate investment costs.

**Figure 15 Quarterly charging/pumping in the NEM<sup>15</sup>**



**Figure 16 Sources of revenue by storage technology<sup>16</sup>**



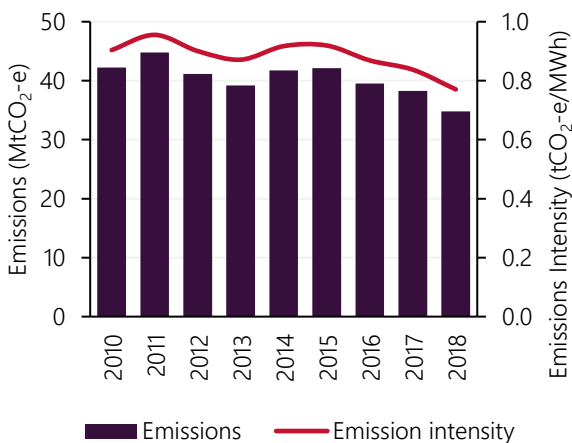
1.4.6 NEM emissions

Quarterly NEM emissions for the Q4 2018 were the lowest on record<sup>17</sup>, both in terms of absolute emissions and emissions intensity (Figure 17). Absolute NEM emissions in Q4 2018 were 3.5 MtCO<sub>2</sub>-e (-9%) lower than Q4 2017. Drivers of the downward trend include: record low brown coal-fired generation; increased renewable generation; and lower NEM demand.

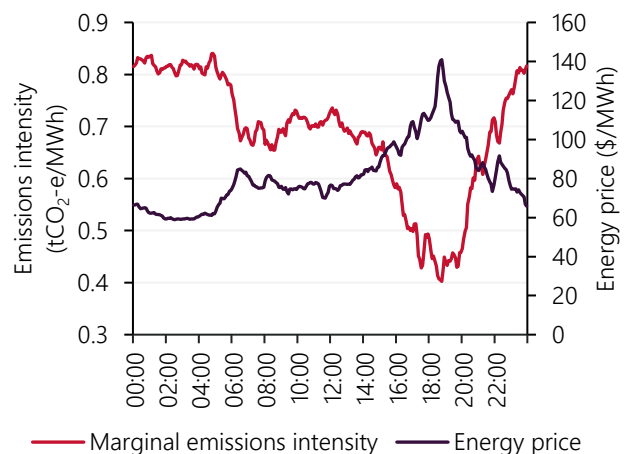
Figure 18 shows the marginal emissions intensity<sup>18</sup> and wholesale electricity price by time day in Queensland during the quarter, with the two factors inversely correlated. This inverse correlation is currently typical in the NEM and is a function of the different generation types:

- Coal fired-generators typically offer electricity at comparatively lower prices than other fuel types and have a higher emissions intensity. This means that when coal-fired generators are marginal, this typically results in comparatively low spot electricity prices but a high marginal emissions intensity.
- Gas-powered and hydro generators typically offer electricity at comparatively higher prices than other fuel types and have a lower emissions intensity. This means that when these generators are marginal, this typically results in comparatively high spot electricity prices but a low marginal emissions intensity.

**Figure 17 Quarterly NEM emissions and emissions intensity (Q4s)**



**Figure 18 Marginal emissions intensity and price by time of day – Q4 2018, QLD**



<sup>15</sup> The EA batteries refer to the Gannawarra and Ballarat Battery Energy Storage Systems that are contracted to Energy Australia, who holds the rights to charge and dispatch energy from the battery storage systems into the National Electricity Market until 2030 and 2033 respectively. Further information available [\[here\]](#)

<sup>16</sup> The calculation of storage arbitrage value for pumped hydro excludes Tumut 3 facility as its sources of water include both pumped water from Jounama Pondage and inflows from Tumut 1 and Tumut 2 underground power stations and into Talbingo Reservoir. Further information available [\[here\]](#).

<sup>17</sup> NEM emissions are only estimated from 2001 onwards, whereas the NEM commenced in 1998.

<sup>18</sup> A marginal emissions intensity is indicative of shifts in supply or load at the margins rather than on average. For example, it demonstrates the impact of changes to emissions that result from storage charging and/or discharging.

## 1.5 Other NEM-related markets

### 1.5.1 Electricity futures markets

The price of electricity swap contracts traded on the ASX rose steeply in all regions at the beginning of the quarter, but these increases were mostly eroded by the end of November (Figure 19). A recovery in price in December resulted in an increase of between 2-8% for calendar year (Cal) 2019 swap products and 5-12% for Cal 2020 swap products over the quarter (Table 3).

Overall price increases across all regions in both Cal 19 and 20 swaps coincided with:

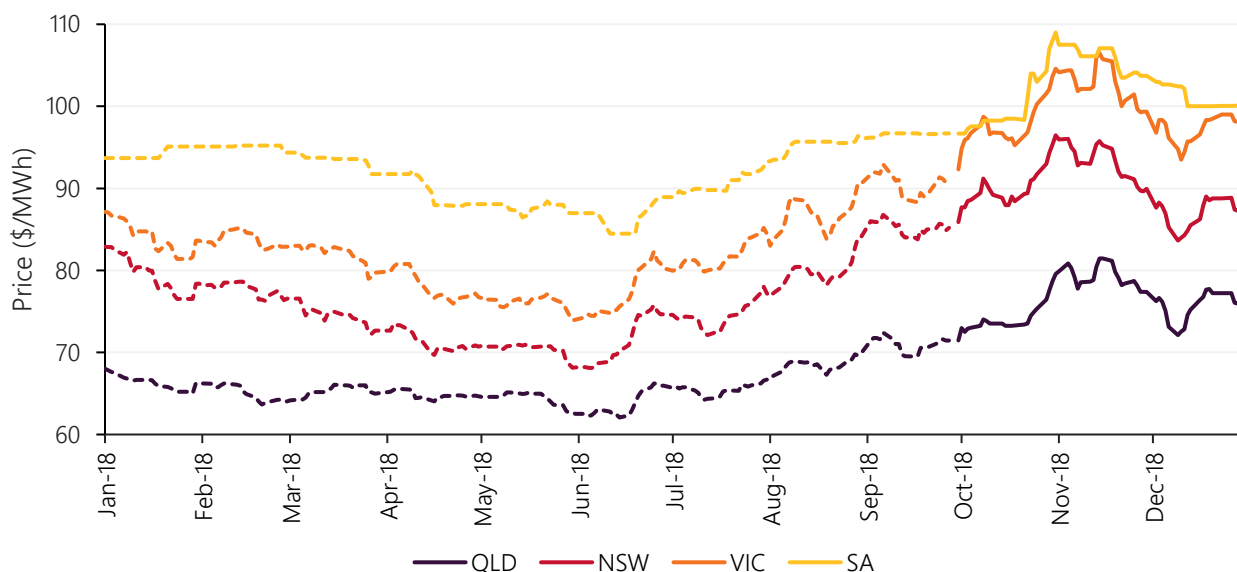
- Relatively low hydro storage levels on the mainland – Lake Eucumbene<sup>1</sup> closed the year at 27%, below the typical end-of-year closing balance (Section 1.4.3).
- Sustained high wholesale gas prices during 2018 (Section 2.2), which has the potential to influence market sentiment ahead of 2019.

Q1 2019 cap prices were down in New South Wales (-13%) and Victoria (-11%) and up in South Australia (+13%), with a small increase in Queensland (+1%). The price reductions in New South Wales and Victoria reversed large increases over Q3 2018.

**Table 3 Change over Q4 2018 for Cal 2019 and Cal 2020 swap prices**

Region	Cal 19	Cal 20
QLD	▲ \$4.28 (6%)	▲ \$6.33 (11%)
NSW	▲ \$1.82 (2%)	▲ \$3.38 (5%)
VIC	▲ \$7.46 (8%)	▲ \$8 (12%)
SA	▲ \$3.53 (4%)	▲ \$6.68 (9%)

**Figure 19 ASX energy – Calendar year 2019 swap prices by region**



### 1.5.2 International coal prices

The average Q4 2018 spot price for high quality Australian Newcastle thermal coal (6000 kcal) fell 10% compared to the previous quarter, averaging approximately \$144/tonne (AUD). The decreasing price of premium coal was matched by the price of lower quality coal (5500 kcal) which reduced by 8% over the quarter. The key driver behind falling spot prices appears to be a reduction in Chinese demand and falling commodity prices due to stronger Chinese production and lower power demand over a milder winter.<sup>19</sup> While weakening somewhat, ongoing underlying demand is reflected in the forward market, where coal futures prices remain above \$130/tonne in 2019.<sup>20</sup>

As illustrated in Figure 20, a wide gap in the spot price of high- and lower-quality thermal coal has formed over 2018. The quarterly average price premium for 6000 kcal when compared to 5500 kcal was 65% at the end of Q4 2018, compared to a longer-term average of around 25%. There are several possible reasons for this growing gap:

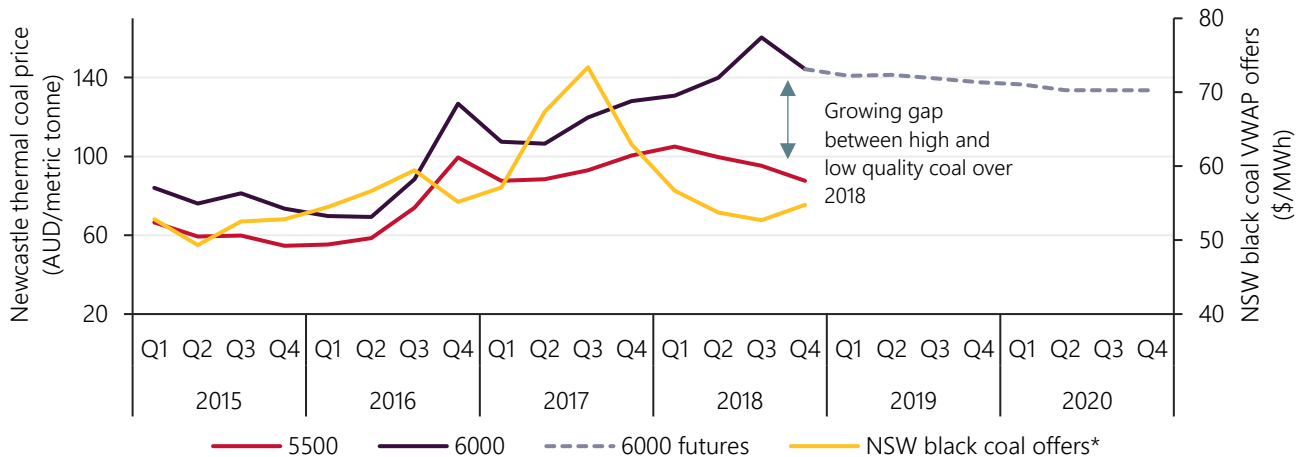
<sup>19</sup> Department of Industry. 2019. *Resources and Energy Quarterly*. ONLINE. Available at: <https://publications.industry.gov.au/publications/resourcesandenergyquarterlydecember2018/documents/Resources-and-Energy-Quarterly-December-2018.pdf> Accessed 24 January 2019.

<sup>20</sup> Assuming the exchange rate at the end of Q4 2018 remains constant – AUD/USD: 0.71

- Higher quality coal typically creating less emissions, resulting in increased Asian demand for premium coal supply as global environmental regulations tighten.<sup>21</sup>
- Less certain high-quality coal supply, due to reduced output from South African mines and declining supplies of premium coal as exploration for the fuel slows and government mining approvals become harder to get.<sup>19</sup>
- Some market commentary suggests an increase in market concentration following Rio Tinto's sale of its coal assets.<sup>22</sup>

5500 kcal is typically the quality of coal used by Australian black coal generators in the NEM and there appears to be partial convergence between New South Wales black coal offers and the 5500 spot price following a period of separation over 2017, when high demand for incremental coal resulted in rail congestion, supply shortages and higher bidding strategies (Figure 20).<sup>23</sup>

**Figure 20 Quarterly average international black coal spot, futures and contract prices**



Source for Newcastle thermal spot and futures prices: Bloomberg

\*Black coal offers are the volume weighted average price of NSW black coal generators priced between \$40-\$120/MWh.

### 1.5.3 Environmental Markets

The Large-scale Generation Certificate (LGC) spot price fell 34% to just below \$50/certificate over Q4 2018 – its lowest price since May 2015. Most of this drop occurred in mid-December when the spot price fell 21% over a four-day period (Figure 21, Table 4). Prior to this, the LGC price had been on a steady downward trajectory since early 2018. The fall in the spot price likely reflects:

- A growing supply of LGCs as new renewable generation commences (Section 1.4.4).
- The possibility that liable entities subject to the Large-scale Renewable Energy Target (LRET) will choose to utilise short-fall provisions provided for under the LRET. The provisions allow liable entities to go into an LGC deficit (by paying a charge) and then make good the deficit and receive a refund of the charge at a future date when LGC prices are expected to be lower.<sup>24</sup>
  - Some of these entities may have chosen to sell their LGCs in December while prices were still relatively high (the forward curve in Figure 21 shows prices falling below \$20/certificate), enter deficit and then purchase LGCs at a lower price in the future to make good the deficit.
- Small-scale Technology Certificate (STC) prices were up \$2.25/certificate, finishing the quarter at \$36.6/certificate despite record rooftop PV installations.<sup>25</sup> The price rise may relate to the Clean Energy Regulator (CER) announcement that they 'expect the 2019 small-scale technology percentage (STP) is likely to be higher than the non-binding STP of 12.13 percent published earlier in the year'.<sup>25</sup>

<sup>21</sup> Forbes. 2018. *The Inconvenient Truth Of Rising Coal Prices*. ONLINE. Available at: <https://www.forbes.com/sites/timreadgold/2018/09/20/the-inconvenient-truth-of-rising-coal-prices/#13ba7f936b55> Accessed 14 January 2019

<sup>22</sup> AFR. 2018. *Yancoal: Record premiums for quality thermal coal lifts 'bulletproof' YAL*. ONLINE. Available at: <https://www.afr.com/business/mining/record-premiums-for-quality-thermal-coal-lifts-yal-20180907-h152cn> Accessed 22 January 2019

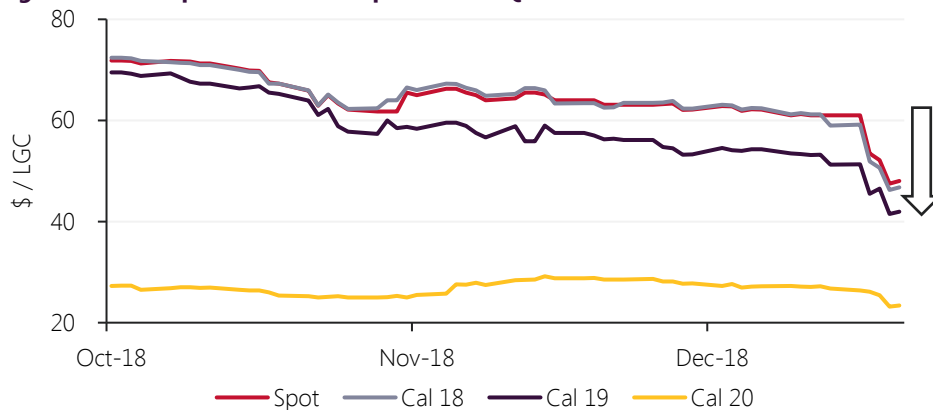
<sup>23</sup> See international coal prices section of QED Q3 2018 for more information. Available at: [https://www.aemo.com.au/-/media/Files/Media\\_Centre/2018/QED-Q3-2018.pdf](https://www.aemo.com.au/-/media/Files/Media_Centre/2018/QED-Q3-2018.pdf)

<sup>24</sup> CER. 2018. *Surrender of large-scale renewable energy certificates and payment of shortfall charges*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Renewable-Energy-Target-liable-entities/Refunds-of-large-scale-generation-shortfall-charges#Surrender-of-largescale-renewable-energy-certificates-and-payment-of-shortfall-charges>. Accessed 14 January 2019.

<sup>25</sup> CER. 2018. *Small-scale technology certificate market update – December 2018*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Small-scale%20technology%20certificate%20market%20updates%20by%20month/Small-scale-technology-certificate-market-update-%E2%80%93-December-2018.aspx>. Accessed 14 January 2019.



**Figure 21 LGC spot and forward prices over Q4 2018**



Source: Mercari

**Table 4 LGC prices**

Product	Change over Q4 18
Spot	▼ \$24.25 (34%)
Cal 18	▼ \$25.38 (35%)
Cal 19	▼ \$28.53 (40%)
Cal 20	▼ \$2.63 (10%)

## 1.5.4 Frequency control ancillary services

Total FCAS costs for the quarter decreased by \$14.5m compared to Q3 2018 (Figure 22) but remained at comparatively high levels compared to longer-term results. By market:

- Contingency Raise – most of the cost reductions occurred in these markets, down \$14.8 million compared to Q3 2018. Drivers of reduced costs included: 1) increased supply from hydro generation, with increased FCAS availability at lower prices during the quarter; 2) fewer significant contingencies requiring the local provision of Contingency Raise FCAS; 3) new supply from demand response (additional EnerNOC capacity in South Australia) and batteries (Dalrymple North battery).
- Regulation Raise and Lower – in contrast to other FCAS markets, costs in these markets increased by \$5.7 million compared to Q3 2018. During the quarter AEMO ran a two-month trial of procuring an additional 30 MW of Raise and Lower Regulation FCAS services in mainland NEM regions.<sup>26</sup> This contributed to demand increases of 22% for Regulation Raise and 9% for Regulation Lower. Higher demand for these services, coupled with reduced availability from mainland hydro generators, were the main drivers of the cost increases for the quarter.
- Contingency Lower – costs in these markets reduced by \$5.5 million, largely due to fewer significant contingencies requiring the local provision of Contingency Lower FCAS.

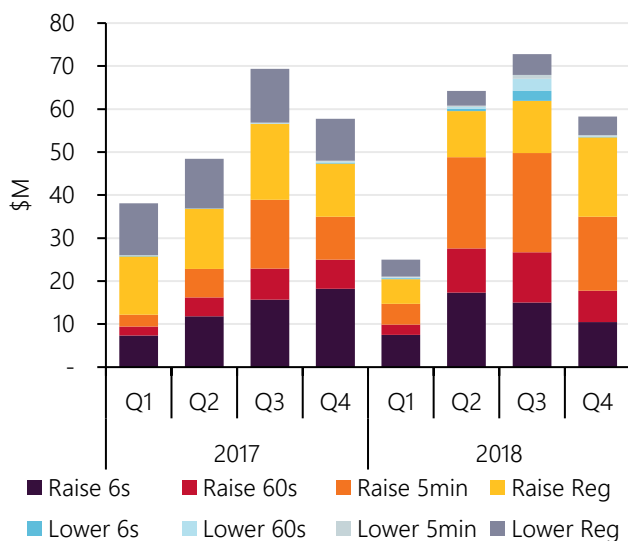
Figure 23 shows FCAS costs and payments by participant type for Q4 2018.<sup>27</sup> Key outcomes by participant category included:

- Hydro – during the quarter hydro generators received comparatively high net payments (approximately \$6 million), due to their proportionally high market share of FCAS supply: hydro generators made up around 6% of the energy mix but provided around 20% of raise FCAS.
- Storage and demand response – these technologies are continuing to capture progressively larger shares of FCAS markets, particularly in the higher-priced Raise FCAS markets. During Q4 2018 storage and demand response captured 10 and 17% of these markets respectively, resulting in FCAS payments of around \$4 million.
- Coal-fired generators – while costs and payments vary by generator, overall costs and payments for these generators mostly balanced with \$3.5 million in costs for brown coal-fired generators and \$1.2 in net payments for black coal-fired generators. As the largest provider of Regulation FCAS, black coal-fired generators were allocated approximately 57% of quarterly payments under the causer pays framework.
- VRE and retail – these participant types were allocated the highest net FCAS costs over the quarter. Of note, these participant categories incurred the highest share of Regulation FCAS costs which are allocated under the causer pays framework: retail \$7.9 million; wind farms \$2.9 million and solar farms \$0.8 million.

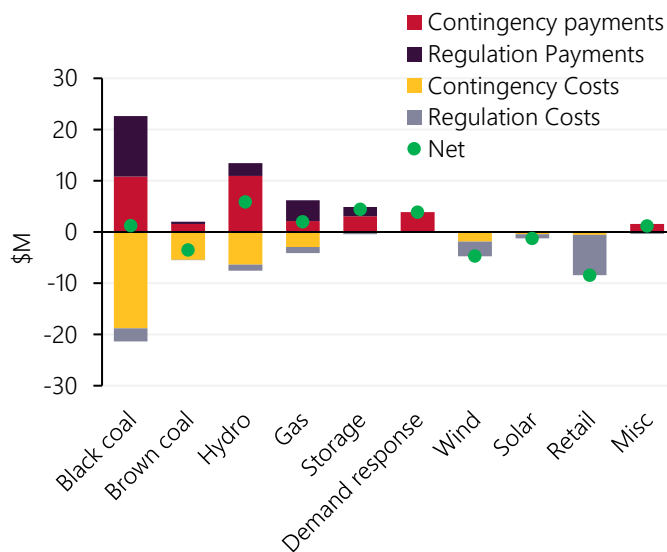
<sup>26</sup> The trial was intended to: 1. Determine the impact of revised regulation FCAS market volumes for managing frequency performance and arresting the current degrading trend; 2. Inform recommendations for optimal management of regulation FCAS and time error. See: <http://aemo.com.au/Market-Notices?searchString=64715>

<sup>27</sup> These are estimate of costs associated with different participants and fuel types and subject to changes in settlement process.

**Figure 22 Quarterly FCAS costs by service**



**Figure 23 FCAS payments and costs by participant type (Q4 2018)**



## 1.6 Inter-regional transfers

Total inter-regional transfers during the quarter decreased to approximately 2,700 GWh (-29%) compared to Q3 2018, representing the lowest level since Q1 2016 (when Basslink was out of service for the entire quarter, Figure 24). The decline in transfers was primarily a function of: generator outage patterns; fewer periods of high wind output in Victoria and South Australia; shifts in regional demand and reduced generation in Tasmania.

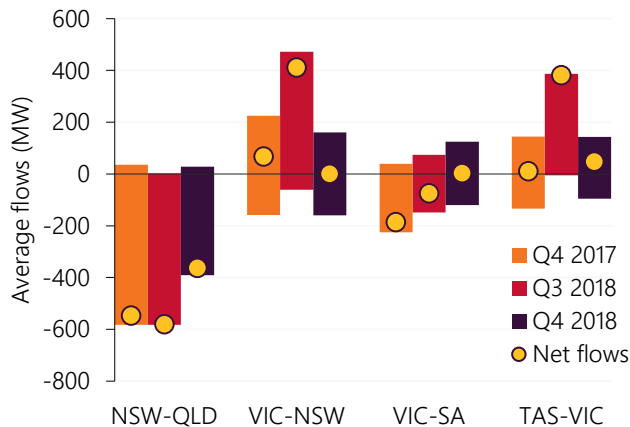
The reduction in inter-regional transfers compared to Q3 2018 also contributed to a 52% reduction in time at which interconnectors were binding at their limits, reaching the lowest quarterly level of constrained interconnectors in the history of the NEM (Figure 25). This has implications for pricing across NEM regions: when an interconnector is open, the two regions on either side of the interconnector can have their price set by the same marginal generator. Conversely, when interconnector constraints are binding, the two regions on either side of the interconnector cannot have their price set by the same marginal generator.

By regional interconnector<sup>28</sup>:

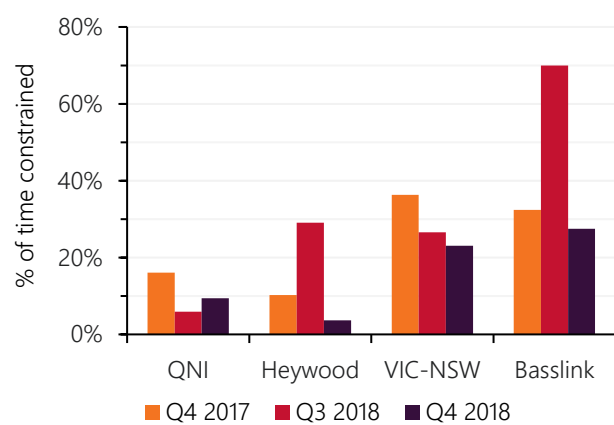
- New South Wales to Queensland** – Inter-regional transfer was almost exclusively south at net 362 MW on average, although reduced by 218 MW against Q3 2018 levels, due to higher availability and output from black coal-fired generators in New South Wales (see Section 1.4.2). Despite the reduction in flows, the percentage of time QNI was binding at its limits increased to 9% (from 6%). The relatively infrequent level of QNI being binding at its limits resulted in an inter-regional price spread of \$3.89/MWh.
- Victoria to New South Wales** – compared to Q3 2018 there was a 410 MW average decrease in net transfers north on the interconnector. This change was a function of reduced wind output in South Australia and Victoria, as well as reduced brown-coal fired generation in Victoria. The VIC-NSW interconnector was binding at its limits for 23% of the quarter contributing to some price separation between the two regions: the inter-regional price spread was \$10.5/MWh, representing an increase of around \$4/MWh when compared to Q3 2018 and Q4 2017.
- Victoria to South Australia** – total quarterly inter-regional transfers were comparable to previous quarters, but more evenly balanced on a directional basis, with net average flows of 4 MW into South Australia (compared to 74 MW into Victoria in Q3 2018). This, coupled with a reduction in transmission network constraints, resulted in Heywood only binding at its limit for 4% of the quarter, contributing to price convergence between the two regions.
- Tasmania to Victoria (Basslink)** – the prevailing flow on Basslink remained north (net average 48 MW), however reduced from the heavy flows north into Victoria that occurred in Q3 2018 (-87%). The driver of this reduction was a decline in output from Hydro Tasmania, coinciding with dry conditions in the region. This also resulted in reduced local price setting in Tasmania, with local units setting the price 35% of the time, down from 68% in Q3 2018.

<sup>28</sup> For simplicity, where there are multiple interconnectors between two regions results for these interconnectors are taken in aggregate.

**Figure 24 Quarterly inter-regional transfers<sup>29</sup>**



**Figure 25 Time interconnector flows binding at limits**



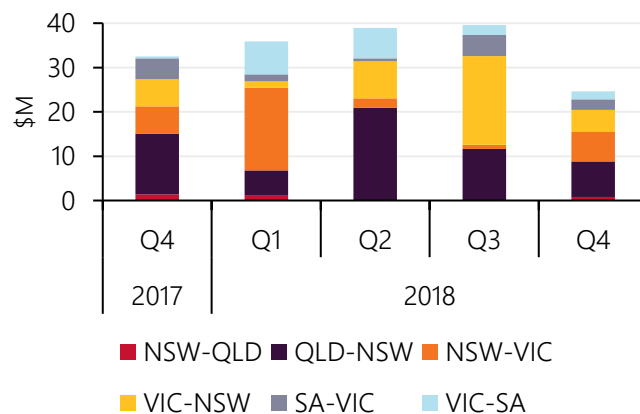
## 1.6.1 Inter-regional settlement residue

With a reduction in inter-regional price separation and inter-regional transfers, there was a resulting 38% reduction in inter-regional settlement residue<sup>30</sup> (IRSR) for the quarter compared to Q3 2018 (Figure 26). The quarterly value of \$24.6 million represents the lowest IRSR in three years.

The largest reduction in IRSR value by directional interconnector was for flows from Victoria into New South Wales, which decreased by 75% to \$5 million. This was a function of reduced flows north on the VIC-NSW interconnector, as well as fewer periods in which Victoria had a lower spot wholesale electricity price than New South Wales.

IRSR value for the Victoria to South Australia interconnectors also reduced – nearly to an all-time low – due to the Heywood interconnector rarely binding with a consequent reduction in price spread between the two regions.

**Figure 26 Quarterly positive IRSR value**



## 1.7 Power system management

### System security

During Q4 2018, AEMO issued directions to generators to maintain system security in the NEM. The level of directions for system security in South Australia declined relative to prior quarters, with directions in place for 13% of the time in South Australia during Q4, compared to 29% during Q3 2018 (Figure 27). Curtailments of non-synchronous (wind) generation in South Australia amounted to 4% of available generation for the quarter, down from 10% in Q3 2018.

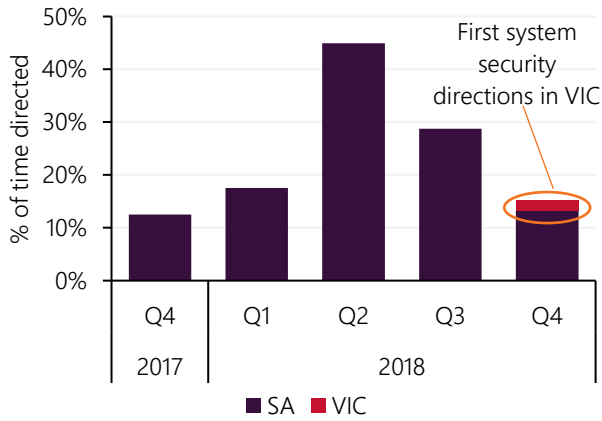
The quarter also marked the first major set of directions in Victoria to maintain system security. AEMO issued four directions in total to units to ensure system strength and control voltage levels in Victoria during November, with units in the region directed for 1.9% of the time over the quarter. The security issues tended to occur during times of low demand and low levels of brown coal-fired generation in the region (Figure 28).

<sup>29</sup> Positive transfers are denoted for: New South Wales transfers into Queensland; Victorian transfers into New South Wales and South Australia; Tasmanian transfers into Victoria.

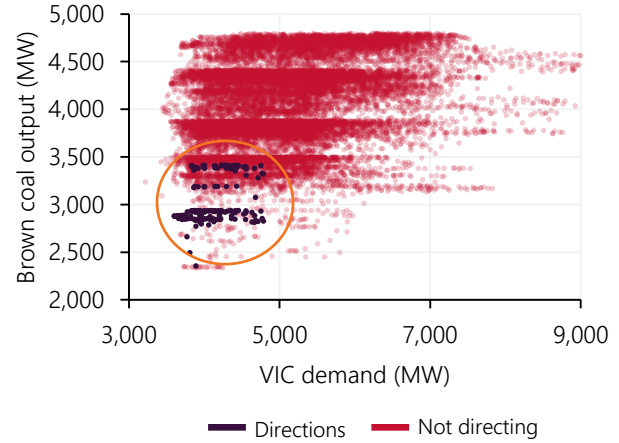
<sup>30</sup> For further details on IRSR see: AEMO. 2018, *Guide to the Settlements Residue Auction*. ONLINE. Available at: [www.aemo.com.au/-/media/Files/Electricity/NEM/Settlements\\_and\\_Payments/Settlements/2018/Guide-to-the-Settlements-Residue-Auction.pdf](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Settlements_and_Payments/Settlements/2018/Guide-to-the-Settlements-Residue-Auction.pdf). Accessed 15 January 2019.

AEMO also revised its operating guidance with respect to system strength in South Australia. Previous AEMO guidance set a single fixed limit on non-synchronous generation of 1,295 MW given minimum synchronous unit combinations.<sup>31</sup> The revised procedure introduces different levels of non-synchronous generation allowed (ranging from 1,000 MW to 1,460 MW) based on the synchronous unit combinations available.

**Figure 27 Directions for system security in South Australia and Victoria**



**Figure 28 Conditions for system security directions in Victoria**



<sup>31</sup> AEMO. 2018. *Transfer Limit Advice – South Australia System Strength, December 2018*. ONLINE. Available at: [https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security\\_and\\_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf](https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf). Accessed 17 January 2019.

## 2. Gas market dynamics

### 2.1 Gas demand

Total gas demand<sup>32</sup> decreased by 17 PJ during the quarter compared to Q4 2017, primarily due to a 42% reduction in GPG demand (Table 5). Factors contributing to the 20 PJ decrease in GPG demand were increased VRE output and high gas prices.

There was a slight decrease in residential, commercial and industrial demand, of 4 PJ.

The above reductions were partially offset by an increase in demand from LNG exporters, reflected in a 7 PJ increase in Curtis Island demand for export LNG.

**Table 5 Gas demand – quarterly comparison**

Demand	Q4 2018 (PJ)	Q3 2018 (PJ)	Q4 2017 (PJ)	Percentage change from Q4 2017
<b>AEMO Markets *</b>	62	114	66	▼ -5%
<b>GPG **</b>	28	34	48	▼ -42%
<b>QLD LNG</b>	330	309	323	▲ +2%
<b>TOTAL</b>	420	457	438	▼ -4%

\* AEMO Markets demand is the sum of customer demand in each of the Short-Term Trading Markets (STTMs) and the Declared Wholesale Gas Market (DWGM).

\*\* Includes demand for GPG usually captured as part of total DWGM demand. Excludes Yabulu Power Station.

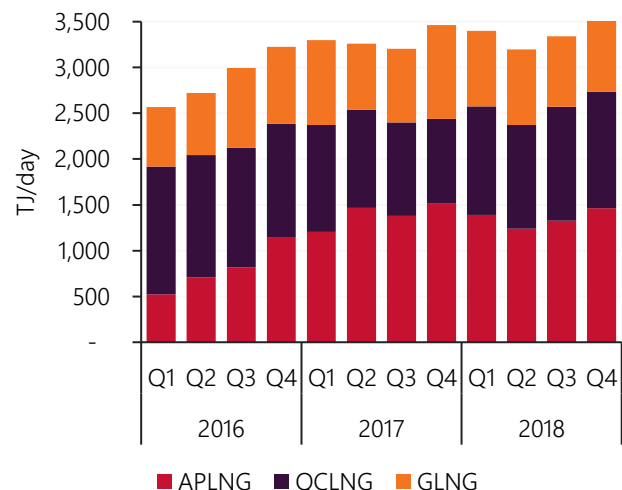
#### 2.1.1 LNG demand

Record high average daily pipeline deliveries of 3,583 TJ/d were directed to Curtis Island during Q4 2018, an increase of 119 TJ/d compared to Q4 2017 and an increase of 242 TJ/d compared to the prior quarter (Figure 29). Increased flows of gas to Curtis Island in Q4 2018 compared to Q3 2018 – due to increased APLNG (+10%) and GLNG (+10%) demand – contributed to these record deliveries.

An additional 5 LNG cargoes (82 in total) were exported during Q4 2018 compared to the previous quarter, although this was consistent with Q4 2017 exports. The vast majority of cargo volume appears to have been contracted, with only four identified spot cargoes loaded over Q4 2018<sup>33</sup>:

- This equates to 5% of Curtis Island cargoes over Q4 2018 and a total estimated volume of 13 PJ; and
- Estimated free on board (fob) prices of between low US\$9 and \$11.25/GJ.

**Figure 29 Average daily pipeline flows to Curtis Island**



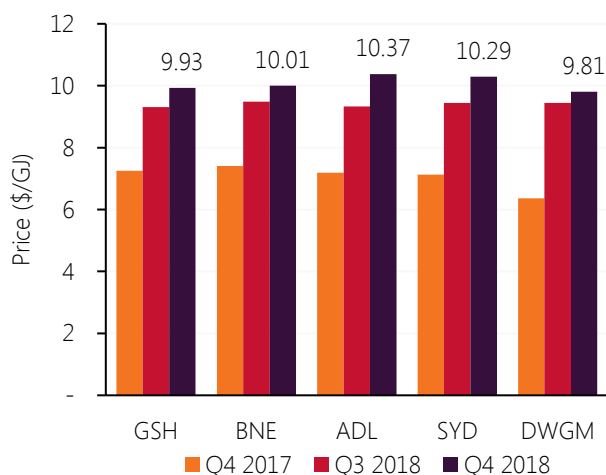
<sup>32</sup> AEMO's wholesale gas markets, gas demand for gas-powered generation and pipeline deliveries to the Curtis Island LNG projects. Total demand does not include regional demand i.e. demand that is not captured by one of the markets.

<sup>33</sup> Information provided by Argus Direct.

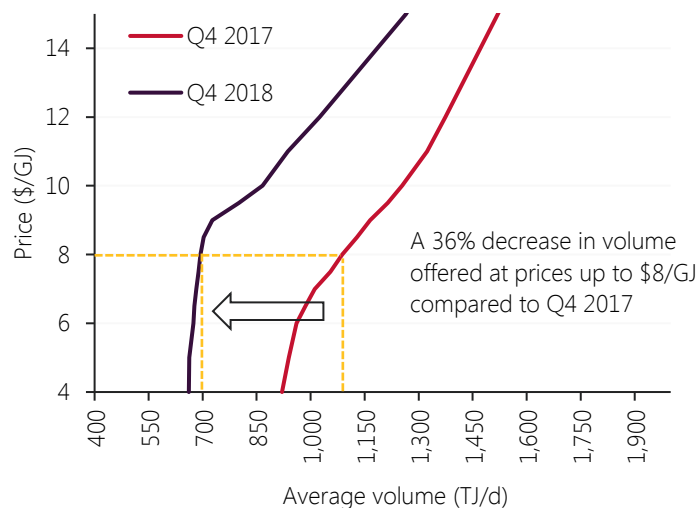
## 2.2 Wholesale gas prices

Record high average prices were recorded in the Adelaide STTM (\$10.37/GJ) and Victorian DWGM (\$9.81/GJ) and the second highest on record for the GSH (\$9.93/GJ), and the Brisbane (\$10.01/GJ) and Sydney (\$10.29/GJ) STTMs (Figure 30). Table 6 lists contributors to these pricing outcomes.

**Figure 30 GSH, DWGM and STTM average quarterly prices**



**Figure 31 DWGM and STTM injection bid supply curve**



**Table 6 Changes in gas prices**

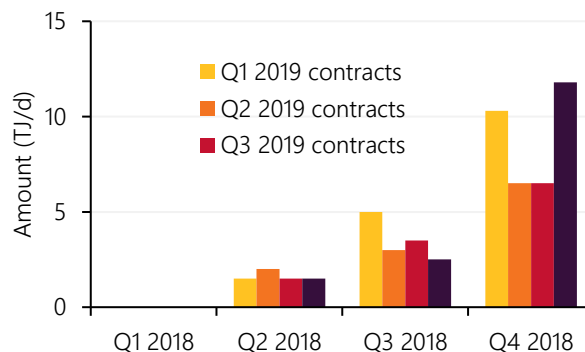
<p><b>Prices increase against Q4 2017</b></p>	<p>The quarterly price across all markets increased by an average of 43% compared to Q4 2017. The largest price increases took place in the DWGM (+54%), and Adelaide and Sydney STTMs (both up 44%). The driver of the price increases was higher priced gas injection bids – in Q4 2018 the quantity of gas priced below \$8/GJ reduced by 36% (Figure 31). Key underlying drivers of this change in bidding behaviour were supply driven:</p> <ul style="list-style-type: none"> <li>• An overall drop in gas production of 22.7 PJ, mostly due to a 29% fall in Longford production (Section 2.3.1).</li> <li>• High injections into Iona (5.8 PJ) relative to Q4 2017 (2.6 PJ), further tightening supply during the quarter (Section 2.3.2).</li> <li>• Record high pipeline deliveries to Curtis Island for export.</li> </ul>
<p><b>Prices increase against Q3 2018</b></p>	<p>Price increases between Q3 and Q4 2018 (up an average of 7% across all markets) ran contrary to historical trends where prices typically fall as gas markets move out of the high demand winter period. This was reflected in an 8% fall in overall demand between Q3 and Q4 (Section 2.1).</p> <p>The price increase was influenced by large reductions in supply, with production decreasing by 36 PJ (-8%) between quarters (Section 2.3).</p>

## 2.2.1 Gas futures markets

In addition to electricity futures contracts, the ASX offers forward hedging contracts for domestic gas at the GSH (Wallumbilla) and DWGM. Historically, market participants have not used the ASX trading platform to hedge their future gas positions. However, over 2018 there was a progressive increase in volumes traded for 2019 positions in the DWGM (Figure 32).

Over Q4 2018, the largest volumes were for forward contracts for Q4 2019 (11.8 TJ/d) and Q1 2019 (10.3 TJ/d). There was a 2-5% increase in the price of contracts over the quarter, with contracts prices closing at between \$10.45-\$10.95/GJ across the various 2019 products.

**Figure 32 ASX quarterly gas volumes (DWGM)**



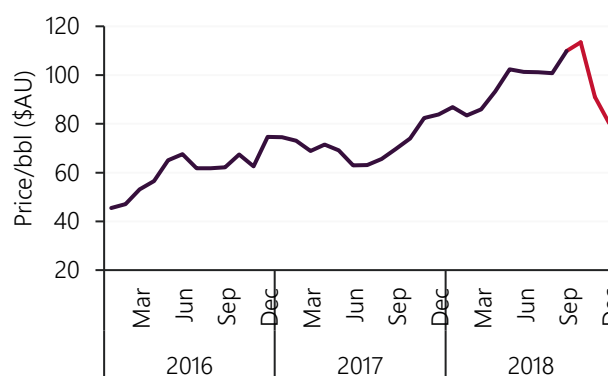
Source: ASX

## 2.2.2 International gas and oil prices

International Brent prices reversed consistent price rises over most of 2018 to drop 33% in Q4 2018 to finish the year at \$76/bbl. Oil prices over Q4 2018 were influenced by concerns surrounding global oversupply and softening oil demand, amid high uncertainty about global economic growth.<sup>34</sup>

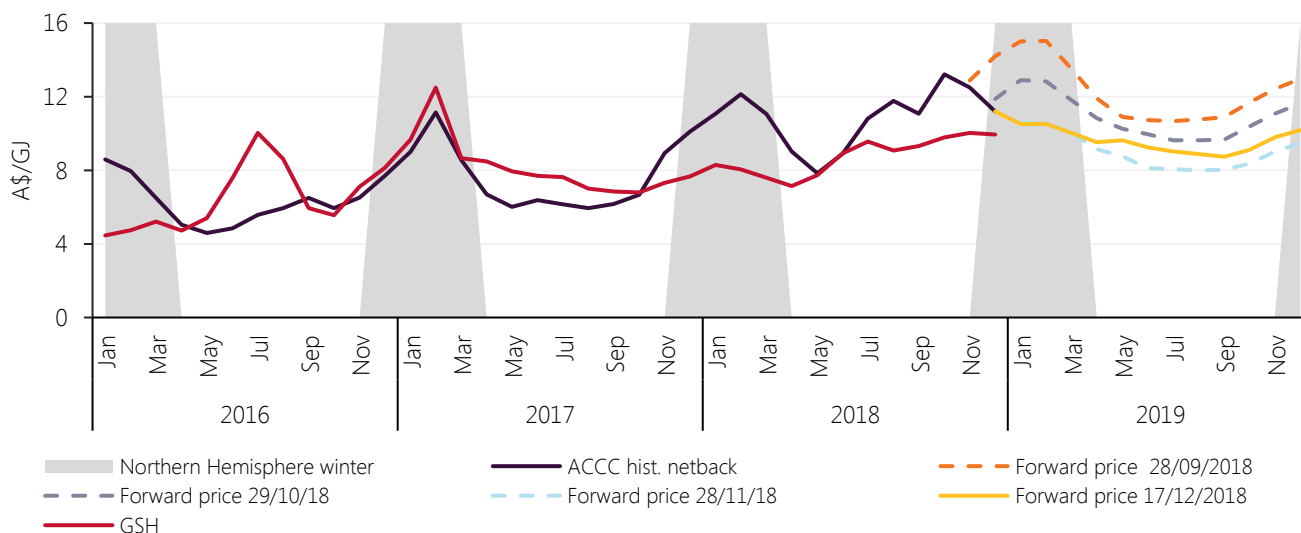
The ACCC continued the publication of a historic and forward LNG netback price – a theoretical export parity price that a gas supplier can expect to receive for exporting its gas.<sup>35</sup> Figure 34 shows the ACCC LNG netback price falling over Q4 2018, finishing the year at \$11.20/GJ. Reduced prices occurred despite record high Chinese demand (Figure 34) and was likely influenced by the declining oil price and an increase in global supply from projects such as the Icythys, Royal Dutch Shell's Prelude floating plant, Dominion's Cove Point and Cheniere's Corpus Christi projects in the United States.<sup>36</sup>

**Figure 33 ICE Brent futures price – monthly average**



Source: Bloomberg

**Figure 34 Historical and forward monthly average ACCC LNG netback and Gas Supply Hub prices**



\*GSH price: daily delivered volume weighted average price

Source: ACCC and AEMO

<sup>34</sup> OPEC. 2018. *OPEC Monthly Oil Market Report*. ONLINE. Available at: [https://www.opec.org/opec\\_web/en/](https://www.opec.org/opec_web/en/). Accessed 17 January 2019.

<sup>35</sup> ACCC 2018, *LNG netback price series*. ONLINE. Available at: [www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series](http://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series). Accessed 17 January 2019.

<sup>36</sup> Reuters. 2019, *Worries for LNG as prices slip amid record North Asia imports*. ONLINE. Available at: <https://www.reuters.com/article/column-russell-lng-asia/column-worries-for-lng-as-prices-slip-amid-record-north-asia-imports-russell-idUSL3N1ZH206>. Accessed 21 January 2019.

## 2.3 Gas supply

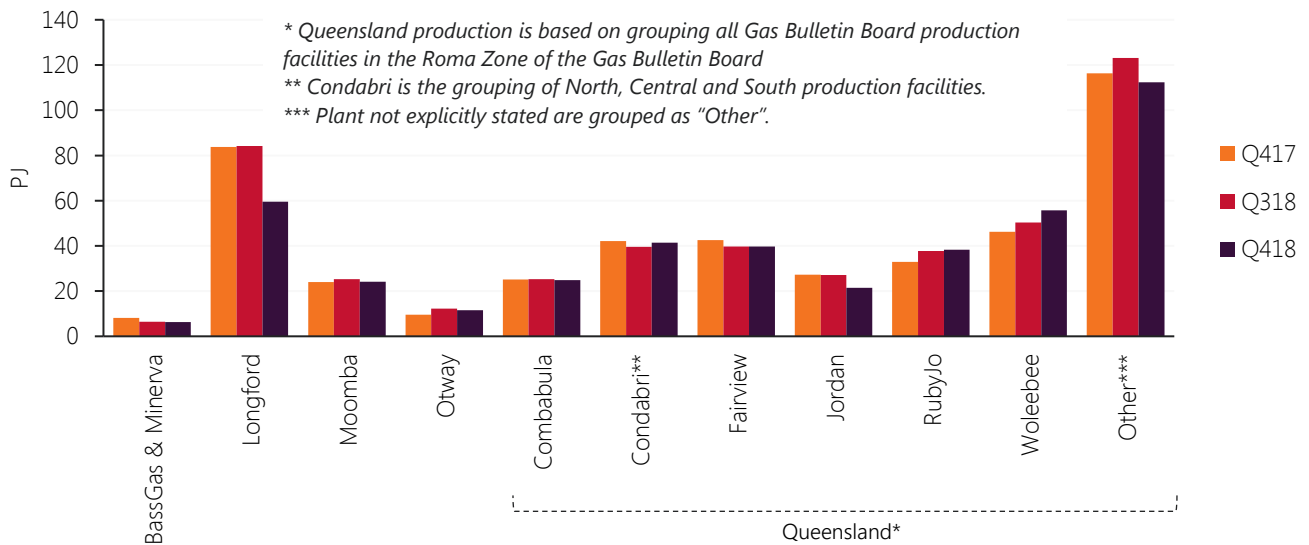
### 2.3.1 Gas production

East coast gas production of 435 PJ was recorded during Q4 2018, a 23 PJ (-5%) reduction compared to Q4 2017 and a 36 PJ (-8%) reduction when compared to the prior quarter (Figure 35). This reduction was mostly due to falling Longford production (see Table 7 for more detail), contributing to a large reduction in gas flowing out of Victoria (Section 2.4).

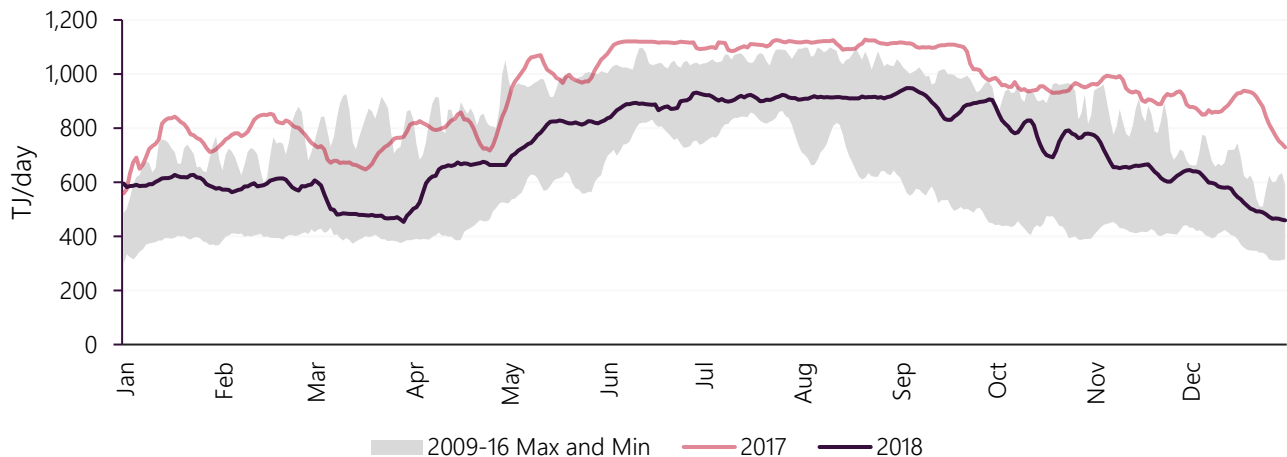
**Table 7 Changes in gas production**

<b>Production decrease against Q4 2017</b>	<ul style="list-style-type: none"> <li>• Large fall in Longford production, down 24 PJ (-29%) compared to record high 2017 production (Figure 36).</li> <li>• Increases in Otway production, up 2 PJ (+21%) offset by reduced BassGas &amp; Minerva production, down 1.9 PJ (-23%).</li> <li>• No material changes in Queensland production, up 1 PJ (+0.34%).</li> </ul>
<b>Production decrease against Q3 2018</b>	<ul style="list-style-type: none"> <li>• Reduced Longford production, down 25 PJ (-29%). The fall is consistent with historical reductions between Q3 and Q4, due to shifts in seasonal demand.</li> <li>• Falls in Queensland production, down 9 PJ (-3%). Production falls occurred at the same time as record high flows to Curtis Island (Section 2.1.1).</li> </ul>

**Figure 35 Quarterly gas production by plant**



**Figure 36 Historical Longford production\***



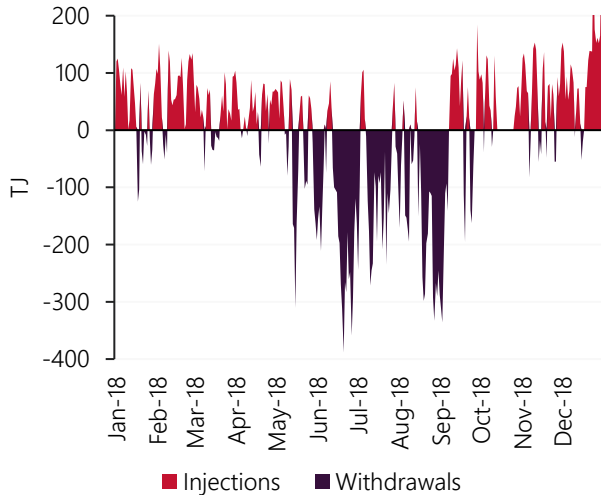
\* Seven day rolling average of production



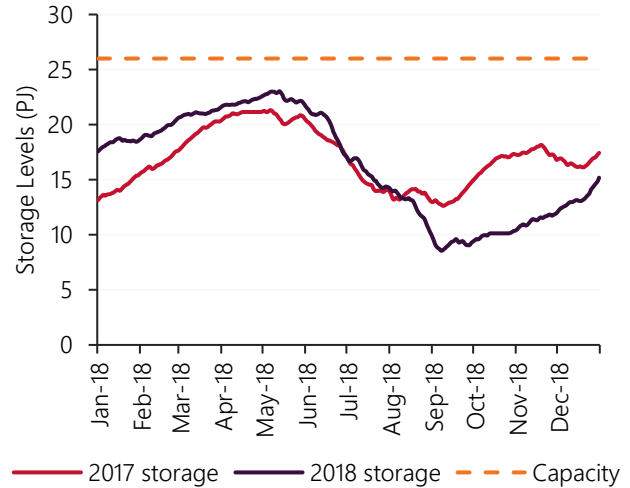
**2.3.2 Gas storage**

A gas balance of 15.2 PJ was recorded at the Iona Underground Storage Facility (Victoria) as at 31 December 2018. Gas filling exceeded gas emptying (net filling) by 5.8 PJ during the quarter, compared to net filling of 2.6 PJ during Q4 2017 (Figure 37 and Figure 38). Increased rates of filling corresponded with reduced GPG and residential, commercial and industrial demand (Section 2.1).

**Figure 37 Iona Daily filling & emptying**



**Figure 38 Iona Underground Storage Facility – storage levels**



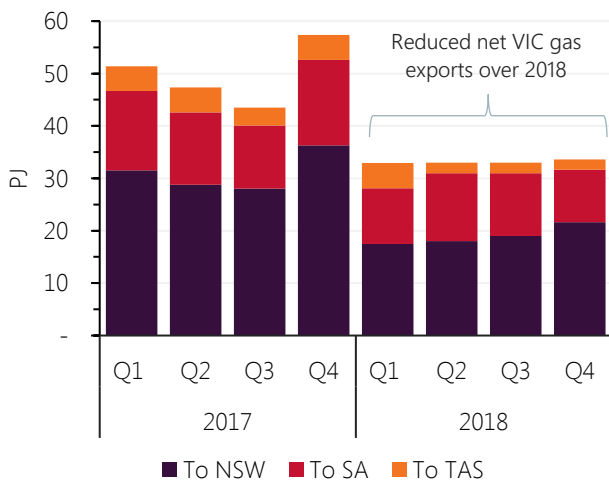
**2.4 Pipeline flows**

During 2018, there was a large reduction in Victorian deliveries to other states compared to 2017 (Figure 39). Q4 2018 deliveries were down 24 PJ (-41%) compared to Q4 2017 and total 2018 flows were down 67 PJ (-34%). Contributors to reduced flows include:

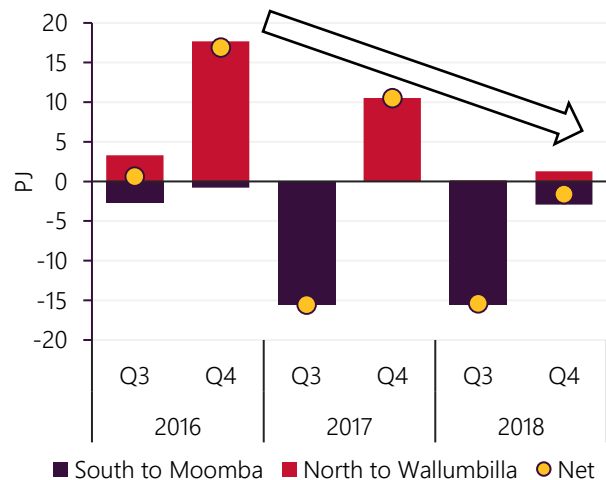
- Lower GPG demand (Section 1.4.1);
- Lower Longford production (Section 2.3.1); and
- Increased amount of Iona injections (Section 2.3.2).

The amount of gas flowing north to Wallumbilla on the South West Queensland Pipeline (SWQP) during Q4s has reduced year-on-year since 2016 (Figure 40). In Q4 2018, there was a net flow south of 1.6 PJ, representing a 12.1 PJ net reduction in flows north compared to Q4 2017.

**Figure 39 Victorian net gas exports to other states**



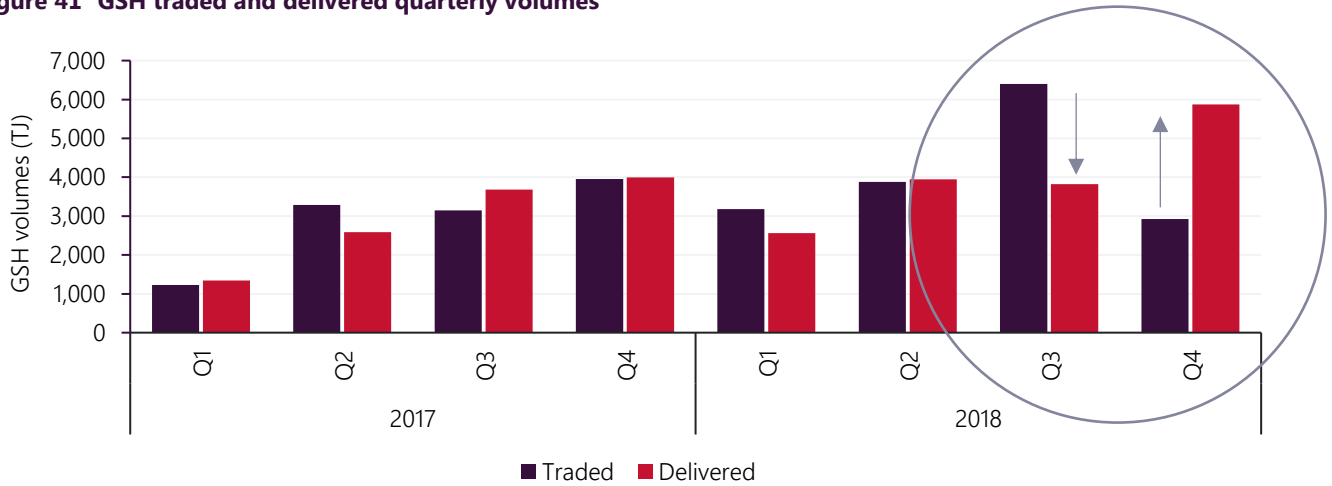
**Figure 40 South West Queensland Pipeline at Wallumbilla**



## 2.5 Gas Supply Hub

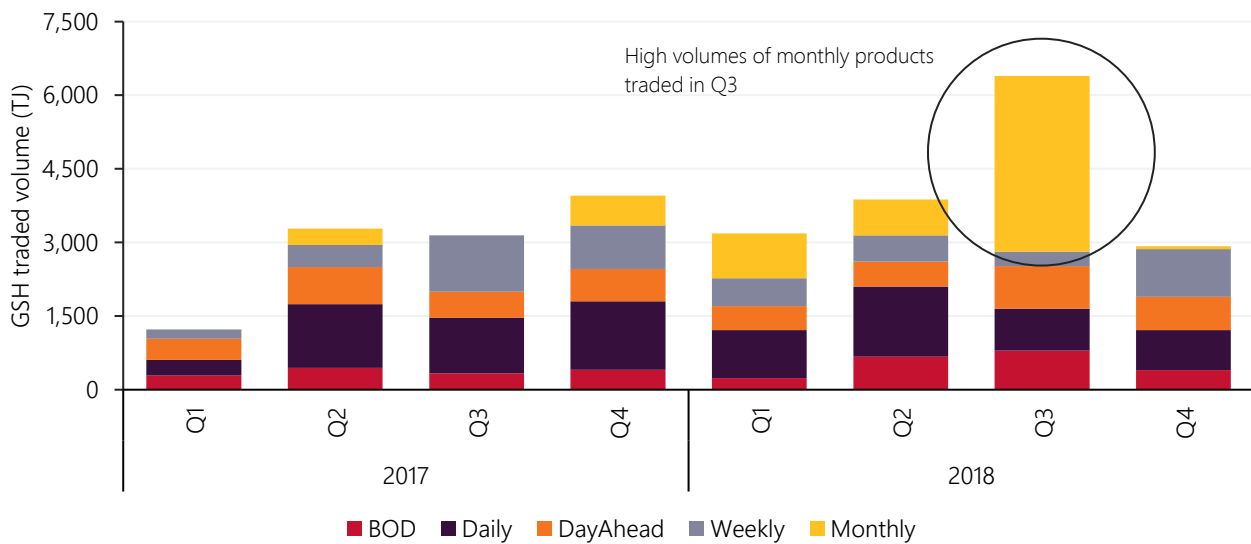
A record high of 5,875 TJ of gas was delivered through the Gas Supply Hub (GSH) over Q4 2018, up 47% when compared to the previous highest quarter (Q4 2017). Historically the volume of gas delivered in a given quarter closely corresponds with the amount of gas traded.<sup>37</sup> This is because previously most of the products traded on the GSH were for delivery on or within the next day or week. This resulted in relatively uniform quantities of traded and delivered gas. As shown in Figure 41, this mostly uniform relationship between traded and delivered gas diverged in Q3 2018, when record high trades took place, but deliveries were relatively low.

**Figure 41 GSH traded and delivered quarterly volumes**



The driver of this change was a large increase in the trade of monthly products (which allow for delivery in future months), which resulted in volumes traded in Q3 being delivered in Q4 2018 (Figure 42).

**Figure 42 GSH traded volumes by trade type**



<sup>37</sup> Volume delivered refers to when a trade is delivered – as opposed to volume traded which refers to the timing of the initial trade.

## 2.6 Gas – Western Australia

In Q4 2018 Western Australia’s total gas consumption remained relatively stable, decreasing by 1.4 PJ (2%) compared to Q3 2018 (Figure 43). This reduction was largely driven by:

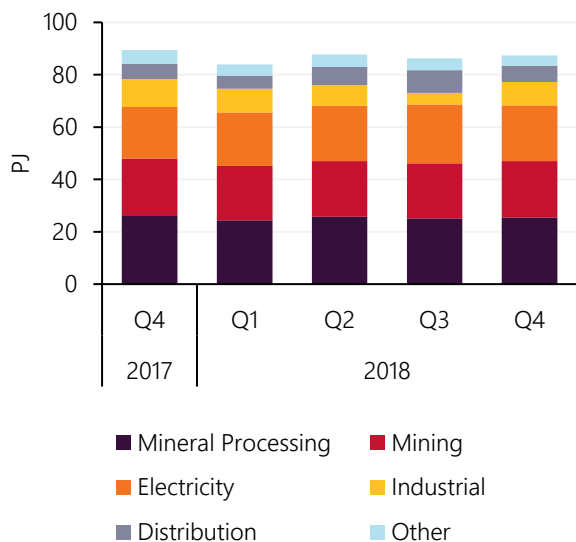
- A decrease in consumption from the distribution system (-2.4 PJ), due to changes in seasonal demand.
- Reduced GPG consumption (-1.2 PJ), due to lower average electricity demand in the WEM (Figure 43).

These reductions were offset by a significant increase in the industrial sector of 4.5 PJ (51%), due to a large industrial consumer completing its turnaround program and returning to operation.

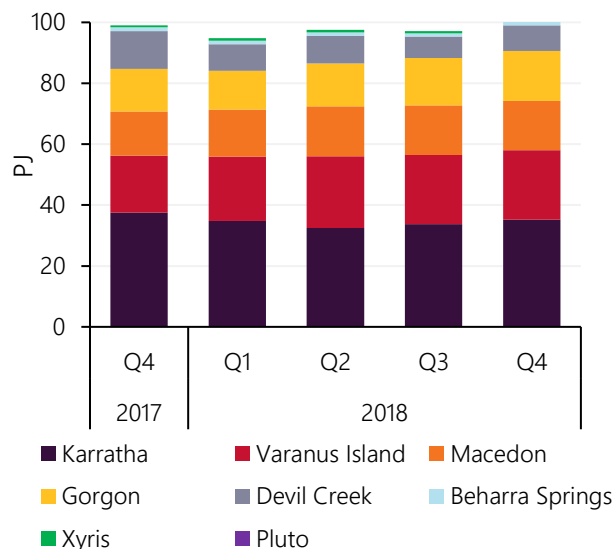
In Q4 2018 gas supply increased 3.9 PJ (4%) compared to Q3 2018 (Figure 44), with the most significant increase occurring at Devil Creek (+1.4 PJ). The Pluto production facility came online in November 2018, injecting up to 25 TJ/day into the Dampier to Bunbury Natural Gas Pipeline.

Lower quarterly consumption but higher production suggests that there was an increase in linepack, as well as increased gas storages: during the quarter there were 3.1 PJ of net injections into storage facilities.<sup>38</sup>

**Figure 43 WA gas demand**



**Figure 44 WA gas supply**



<sup>38</sup> Mondarra and Tubrudgi Storage Facilities.

## 3. WEM market dynamics

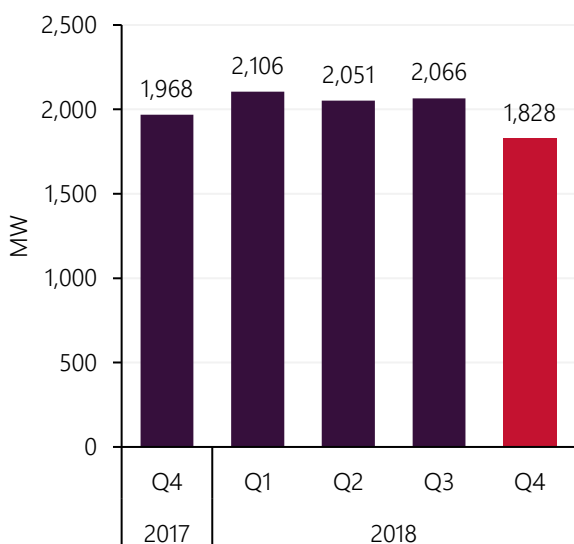
### 3.1 Electricity demand

The average temperature in Perth was milder during Q4 2018 compared to the Q4 ten-year average (-0.8°C). In addition, the average maximum temperature in Perth during was -1.3°C lower than Q4 2017.

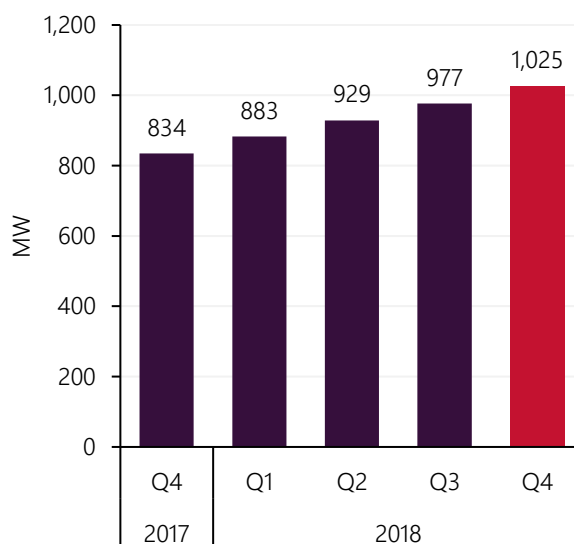
Average operational demand decreased compared to both Q3 2018 (-238 MW or -11.5%) and Q4 2017 (-139 MW or -7.1%) (Figure 45). Contributors to reduced demand included: reduced cooling requirements due to milder weather; and increased uptake of rooftop PV.

In Q4 2018, rooftop PV capacity by increased 48 MW (+5%) from Q3 2018, with total capacity exceeding 1 GW (Figure 46). Since Q4 2017, rooftop PV capacity has increased by 191 MW (+23%) affecting demand, electricity price (see Section 3.2.1) and ancillary service (Section 3.2.2) outcomes in the Wholesale Electricity Market (WEM) during the quarter.

**Figure 45 WEM average operational demand**



**Figure 46 WEM rooftop capacity installed**



In Q4 2018 the WEM recorded its lowest operational demand<sup>39</sup> for 2018 (1,199 MW) at 1030hrs (AWST) on 28 October 2018. This is the lowest Q4 demand since 2007 and only 26 MW higher than the all-time minimum demand<sup>40</sup> since WEM commencement<sup>41</sup> (Table 8). This low demand event was influenced by increased rooftop PV capacity in the WEM, as well as mild temperatures.

**Table 8 WEM maximum and minimum demand (MW) - Q4 2018 vs records**

Maximum demand (MW)			Minimum demand (MW)		
Q4 2018	All-time	All Q4	Q4 2018	All-time	All Q4
3,143	4,006	3,587	1,199	1,173	1,173

<sup>39</sup> All demand measurements use 'operational demand' which is the average measured total of all wholesale generation in the SWIS and is based on non-loss adjusted sent out SCADA data.

<sup>40</sup> All time minimum Operational Demand occurred at 03:30 on Sunday, 15 October 2006.

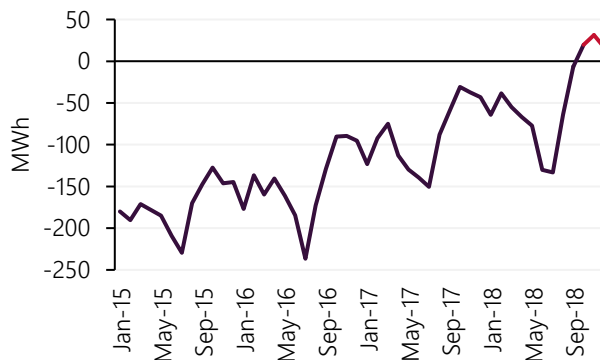
<sup>41</sup> The Wholesale Electricity Market of Western Australia commenced on 21 September 2006.

## 3.1.1 Notional Wholesale Meter

The Notional Wholesale Meter is a term used to define the aggregate quantity of all customers without interval meters<sup>42</sup> and unmetered loads. This is largely comprised of residential and non-contestable customers<sup>43</sup> in the South West Interconnected System (SWIS).

For the first time since WEM commencement, the Notional Wholesale Meter recorded net interval level generation (rather than consumption). This occurred on 100 on-peak periods in Q4 2018, on days that were mild and sunny (25-27°C) (Figure 47). During these periods, total generation from distributed energy resources for customers without interval meters exceeded their total consumption.

**Figure 47 Maximum output from notional wholesale meter**

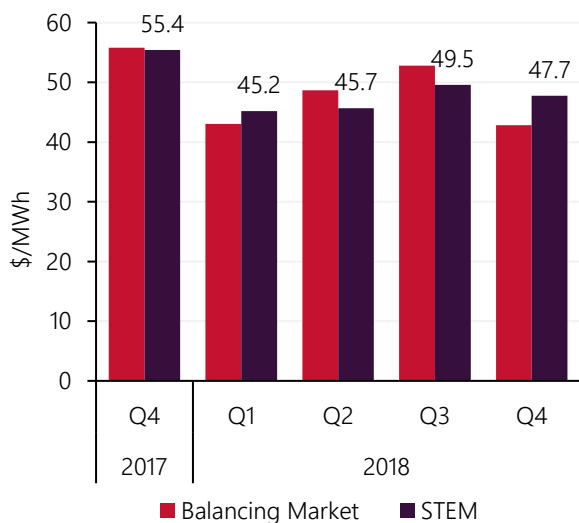


## 3.2 Wholesale electricity pricing

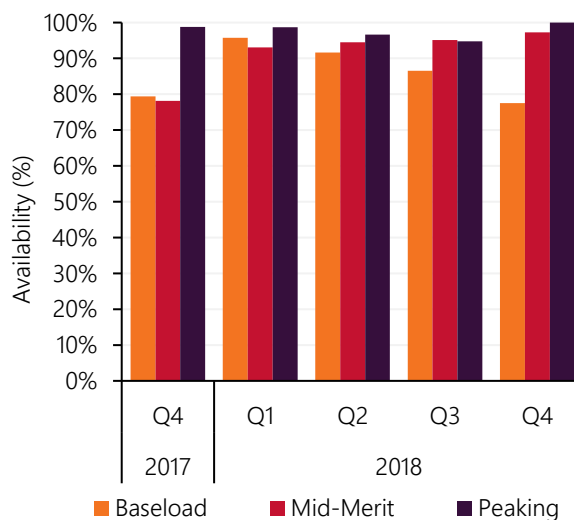
### 3.2.1 Balancing and STEM prices

During the quarter, average wholesale electricity prices in both the Balancing Market and Short Term Electricity Market (STEM) decreased compared to Q3 2018 and Q4 2017. Prices were 19% and 4% lower respectively compared to Q3 2018, and 23% and 14% lower respectively compared to Q4 2017 (Figure 48). This was primarily due to lower average demand, higher mid-merit generator availability<sup>44</sup> (Figure 49) and participant bidding behaviour.

**Figure 48 WEM wholesale electricity prices**



**Figure 49 WEM generation availability**



In Q4 2018 the lowest balancing price was -\$65.47/MWh, which occurred during an on-peak period (0800 to 2200hrs), at 1200hrs on 20 November 2018. This was the lowest balancing price since Q2 2013. Factors which contributed to this outcome included:

- Low operational demand of 1,423 MW, influenced by rooftop PV generation and mild temperatures.
- Relatively high proportion of non-scheduled generation, with wind, solar and landfill gas providing 14% of generation for the interval.
- Participant bidding behaviour.

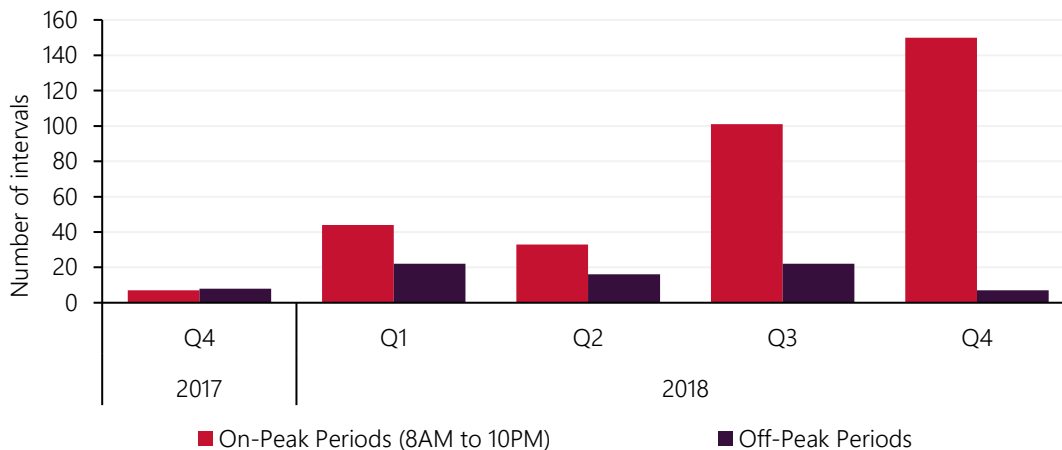
<sup>42</sup> An interval meter reads import and export of electricity from the Network in 30-minute intervals.

<sup>43</sup> The threshold for contestable customer status is annual consumption of over 50 MWh.

<sup>44</sup> Mid-merit generation facilities are contrast to Baseload and Peaking facilities. Mid-Merit facilities are regularly the marginal generator, therefore higher availability both reduces average Short Run Margin Cost of generation and increases competition in the market, reducing Balancing Price. Availability in the WEM means a generator is not on outage.

The trend of increasing occurrence of negative Balancing Prices during the daytime continued in Q4 2018, with 150 intervals clearing at a negative price during on-peak periods (0800 to 2200hrs) (Figure 50). The increased occurrence of daytime negative prices is linked to falling daytime minimum demand, driven by increased rooftop PV generation.

**Figure 50 WEM negative Balancing Price intervals**

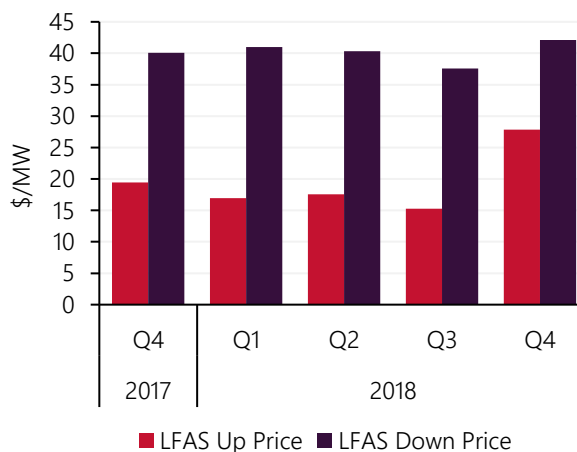


### 3.2.2 Load Following Ancillary Service prices

In Q4 2018 the average Load Following Ancillary Service (LFAS) Up and LFAS Down<sup>45</sup> prices increased by 83% and 12% respectively compared to Q3 2018 (Figure 51). There were 910 intervals (20%) where LFAS Up was higher-priced than LFAS Down; in contrast, this only occurred in two intervals between Q1 2017 to Q3 2018. LFAS Down is traditionally higher-priced than LFAS Up, due to forgone energy which is not compensated in the Balancing Price.

During the quarter there was no change to the approved LFAS requirement of 72 MW.<sup>46</sup> LFAS changes were likely influenced by the changing dynamics in the Balancing Market – in particular, increased occurrences of negative price intervals affecting participant bidding behaviour<sup>47</sup>. There are a limited number of market participants in the LFAS market and therefore any changes in bids can have a significant price impact.

**Figure 51 WEM average LFAS prices**



<sup>45</sup> LFAS is used to continuously balance supply and demand. LFAS accounts for the difference between scheduled energy (what has been dispatched), actual load, and intermittent generation. LFAS Up requires the provision of additional generation to increase frequency in real-time and LFAS Down requires the reduction in generation to decrease frequency.

<sup>46</sup> Refer to the 2018 Ancillary Services Report - <https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf>

<sup>47</sup> Negative Balancing Prices result in generators being charged for any electricity generated relative to their Net Contract Position.

## 3.3 Power system security

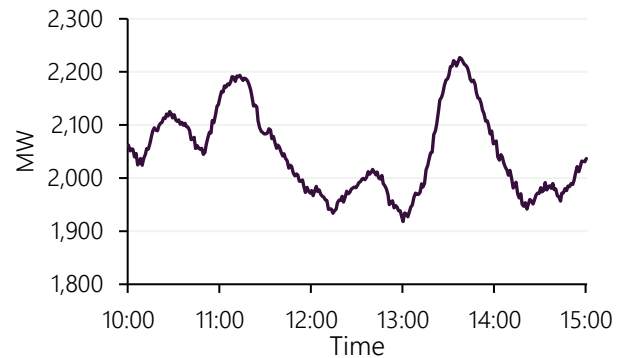
### Backup Load Following Ancillary Services on 18 October 2018

On 18 October 2018, due to rapid changes in wind and solar generation, AEMO called on Backup LFAS<sup>48</sup> for the first time since WEM commencement.<sup>49</sup>

Between 1000 and 1100hrs, load fluctuations of up to 150 MW occurred due to large swings in solar PV and compounded by changes wind output (Figure 52).<sup>50</sup> This increased the magnitude of frequency fluctuations on the system, increasing the response required from LFAS providers. At 1130hrs, 50 MW of Backup LFAS Down and 50 MW of Backup LFAS Up was enabled for 3.5 hours to meet the volatile load profile and maintain system frequency within tolerance.

Total Backup LFAS during these intervals cost Market Customers and Non-Scheduled Generators<sup>51</sup> approximately \$36,000.

**Figure 52 Load on 18 October 2018**



### Backup Load Following Ancillary Services on 26 December 2018

On 26 December 2018 at 0100hrs, AEMO called on Backup LFAS for the second time due to rapid changes in output from wind generation. Due to this volatility, AEMO determined that LFAS alone was not sufficient to manage system frequency within tolerance. As such, 35.5 MW of Backup LFAS Up and 35.5 MW of Backup LFAS Down was enabled for 8.5 hours, costing Market Customers and Non-Scheduled Generators approximately \$81,000.

### Out of merit dispatch on 31 October 2018

At 1513hrs on 31 October 2018, AEMO issued a dispatch advisory informing market participants that out-of-merit dispatch would be required to maintain power system security.

In balancing the competing demands of changing load dynamics (forecasts reduced by up to 200 MW), ancillary service requirements, generator characteristics and safety considerations, AEMO identified that generation from the Balancing Portfolio<sup>52</sup> online at the time could not be further reduced. Therefore, the decision was made to constrain off Independent Power Producers:

- 30 MWh between 1513 and 1600hrs; and
- 60 MWh between 1600 and 1640hrs.

Generators were compensated for the out-of-merit dispatch, costing Market Customers<sup>53</sup> approximately \$2,500.

<sup>48</sup> Backup LFAS is contingency capacity bid into the LFAS market in addition to the current 72 MW requirement.

<sup>49</sup> The Wholesale Electricity Market of Western Australia commenced on 21 September 2006.

<sup>50</sup> Refer to presentation 'WEM - Back up LFAS: Enablement of Backup LFAS on 18/10/2018 – Brent Glover'. Presented at the WAECF on 11 December 2018. [https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/~/\\_link.aspx?id=3D7342EE45384B16B25B68A256260C55&z=z](https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/~/_link.aspx?id=3D7342EE45384B16B25B68A256260C55&z=z)

<sup>51</sup> LFAS costs are allocated based on Metered MWh during the month for all Market Customers and Non-Scheduled Generators (but not Scheduled Generators).

<sup>52</sup> The Balancing Portfolio refers to Synergy's Registered Facilities other than: (a) Stand Alone Facilities; (b) Demand Side Programmes; (c) Dispatchable Loads; and (d) Interruptible Loads.

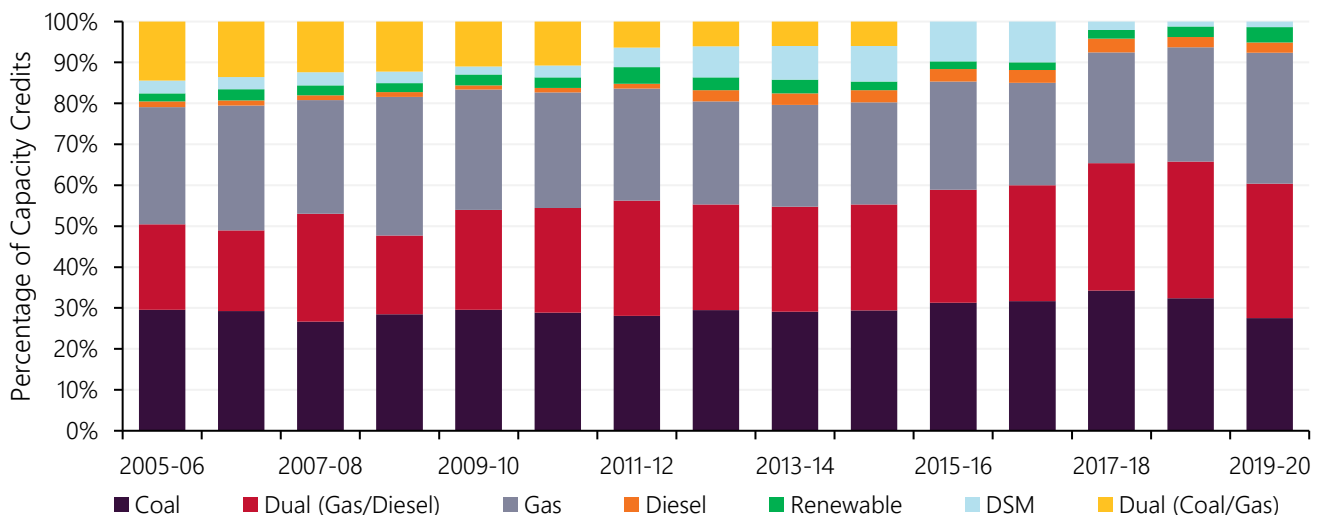
<sup>53</sup> Constrained compensation costs are allocated based on Metered MWh during the month for all Market Customers.

## 3.4 Reserve Capacity Mechanism

Q4 2018 marks the start of the 2018–19 Capacity Year in the Reserve Capacity Mechanism (RCM) with notable changes as follows:

- **Reserve Capacity Requirement:** Compared to the previous Capacity Year, there has been a slight increase (1.5%) in the Reserve Capacity Requirement from 4,552 MW to 4,620 MW.
- **Capacity Credits:** The total number of Capacity Credits assigned by AEMO decreased from 5,193 MW in Capacity Year 2017–18 to 4,819 MW in Capacity Year 2018–19. This was due to:
  - A new 9.9 MW solar facility located at Northam was certified to provide Reserve Capacity.
  - Several facilities did not apply for Certified Reserve Capacity in 2018–19 including 120 MW of baseload generation facilities and 180 MW of peaking generation facilities.<sup>54</sup>
  - Accordingly, there was a large decrease (-183.5 MW) of capacity procured in excess of the Reserve Capacity Requirement and an increase in the Capacity Credits assigned to renewable generation facilities (wind, solar and landfill gas) to 154 MW (Figure 53).
- **Reserve Capacity Price:** The Reserve Capacity Price paid to generators in Capacity Year 2018–19 increased to \$138,760.39, 24% higher than in the 2017–2018 Capacity Year. This was driven by the increase in the Reserve Capacity Requirement which was set in 2016<sup>55</sup> and is a product of a number of factors, including the 2016 Benchmark Reserve Capacity Price, responses to the 2016 RCM Expression of Interest and higher forecast peak demand in 2018–19.
- **Value of the RCM:** The RCM was valued at approximately \$662 million for the 2018–2019 Capacity Year. This value represents the total number of Capacity Credits assigned, multiplied by the relevant<sup>56</sup> Reserve Capacity Price.

**Figure 53 Capacity Credits by fuel type**



<sup>54</sup> This included the Muja A and B coal fired generators and Mungarra and West Kalgoorlie gas turbine generators.

<sup>55</sup> The Reserve Capacity Target and Reserve Capacity Price are set two years ahead of the Capacity Year.

<sup>56</sup> A different price is used for Demand Side Programmes compared to generators.



# Abbreviations

Abbreviation	Expanded name
<b>AEMO</b>	Australian Energy Market Operator
<b>ASX</b>	Australian Stock Exchange
<b>BBL</b>	Barrel
<b>BESS</b>	Battery energy storage system
<b>Cal</b>	Calendar year
<b>CER</b>	Clean Energy Regulator
<b>CCGT</b>	Combined cycle gas turbine
<b>DRF</b>	Dynamic Refund Factor
<b>DWGM</b>	Declared Wholesale Gas Market
<b>FCAS</b>	Frequency control ancillary services
<b>GJ</b>	GigaJoule
<b>GPG</b>	Gas-powered generation
<b>GSH</b>	Gas Supply Hub
<b>GWh</b>	GigaWatt hour
<b>IRSR</b>	Inter-regional settlement residue
<b>LFAS</b>	Load Following Ancillary Services
<b>LGC</b>	Large-scale Generation Certificates
<b>LNG</b>	Liquefied natural gas
<b>LRET</b>	Large-scale Renewable Energy Target
<b>MW</b>	MegaWatt
<b>MWh</b>	MegaWatt hour
<b>NEM</b>	National Electricity Market
<b>PJ</b>	PetaJoule
<b>PV</b>	Photovoltaic
<b>QNI</b>	New South Wales to Queensland interconnector
<b>RCM</b>	Reserve Capacity Mechanism
<b>STC</b>	Small-scale technology certificate
<b>STEM</b>	Short Term Energy Market
<b>STP</b>	Small-scale technology percentage
<b>STTM</b>	Short Term Trading Market
<b>SWIS</b>	South West Interconnected System
<b>SWQP</b>	South West Queensland Pipeline
<b>TJ</b>	TeraJoule
<b>USD</b>	United States dollars
<b>VRE</b>	Variable renewable energy
<b>WEM</b>	Wholesale Electricity Market