



# Quarterly Energy Dynamics Q1 2020

Market Insights and WA Market Operations

# 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 Q1 2020 (1 January to 31 March 2020). This quarterly report compares results for the quarter against other recent quarters, focusing on Q4 2019 and Q1 2019. 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.

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## VERSION CONTROL

Version	Release date	Changes
1	23 April 2020	

# Executive summary

## East coast electricity and gas Q1 2020 highlights

### Lowest wholesale electricity and gas prices since 2016

- East coast wholesale gas market prices averaged \$5.63 per gigajoule (GJ), down from \$9.75/GJ in Q1 2019, marking the lowest gas market prices in four years.
  - Reduced gas prices were due to a continuation of the trend of more gas being offered into the markets at lower prices, which coincided with falling international gas prices, lower NEM spot and contract prices, and increased Queensland gas production.
- Despite extreme price volatility in January, National Electricity Market (NEM) average spot electricity prices fell to their lowest level since Q4 2016, at \$66 per megawatt hour (MWh). The Queensland average price dropped to its lowest level since Q3 2016, at \$54/MWh, and South Australia average prices dropped to their lowest level since Q1 2016, at \$65/MWh.
  - Lower wholesale electricity prices were a function of reduced operational demand, lower wholesale gas prices, and the downward shift in bids from dispatchable generation.
- NEM average operational demand<sup>1</sup> declined by 951 megawatts (MW), or 4%, compared to Q1 2019, with underlying demand<sup>2</sup> decreasing by 688 MW and rooftop photovoltaic (PV) increasing by 263 MW. The marked reduction in underlying demand was largely driven by reduced daytime cooling requirements due to milder conditions in February and March across all NEM regions.
  - The nationwide restrictions which commenced mid-March due to COVID-19 resulted in reduced operational demand in the NEM, although did not materially affect quarterly average results.

### Major power system separation events drive record system costs and price volatility

- Total NEM system costs<sup>3</sup> increased to \$310 million, which is 8% of the energy costs for the quarter – much higher than its typical quarterly value of 1-2%. Of these quarterly system costs, \$144 million was recovered from retailers and \$166 million from generators (noting that generators are also recipients of revenue for providing these system services).
- The main driver of record NEM system costs was three major power system events, most notably the 18-day separation of the Victorian and South Australian power systems after a storm event knocked out key transmission lines on 31 January<sup>4</sup>. These events contributed \$229 million, or 74%, of system costs for the quarter.

<sup>1</sup> Operational demand refers to the electricity used by residential, commercial, and large industrial consumers, as supplied by scheduled, semi-scheduled, and significant non-scheduled generating units

<sup>2</sup> Underlying demand is consumers' total demand for electricity from all sources, including the grid and distributed resources such as rooftop photovoltaic (PV) systems.

<sup>3</sup> In this report, NEM system costs refer to the costs associated with: Frequency Control Ancillary Services, directions compensation, the Reliability and Emergency Reserve Trader function, and variable renewable energy curtailment.

<sup>4</sup> Other major separations included the separation of the New South Wales and Victorian power systems on 4 January 2020 and the separation of the South Australian and Victorian power systems on 2 March 2020.

- Frequency Control Ancillary Service (FCAS) costs were the main contributor to system costs, rising to a quarterly record high of \$227 million.
- The cost of directing units to maintain system strength increased to \$33 million, the highest quarter on record.
- New South Wales and Victoria experienced high levels of price volatility during these events with quarterly cap returns<sup>5</sup> of \$31/MWh and \$29/MWh respectively. South Australia experienced very high FCAS costs but only \$14/MWh of cap returns.

## COVID-19 impacts operational demand and energy markets

- While the public safety measures which commenced mid-March in response to the COVID-19 pandemic had a modest impact on Q1 NEM electricity demand, energy prices recorded sharp declines.
- Electricity futures contracts traded on the Australian Stock Exchange (ASX) for Q2 and Q3 2020 fell 11% in the last two weeks of March as the potential impact on future electricity demand became evident.
- In March 2020, international oil prices crashed to their lowest levels since 2003, due to the combined impacts of the Saudi Arabia-Russia oil price war and COVID-19-related demand reductions.
- Asian Liquefied Natural Gas (LNG) prices<sup>6</sup> decreased from \$7.12/GJ at the end of 2019 to reach \$4.44/GJ by 31 March 2020, due to a combination of an already oversupplied market and the escalating impact of COVID-19 on global demand.

## Western Australia Wholesale Electricity Market (WEM) Q1 highlights

- A new WEM-record minimum interval average demand was set for the second consecutive quarter, with operational demand reaching 1,135 MW on Saturday, 4 January, 24 MW lower than the previous record set on 13 October 2019. Rooftop photovoltaics (PV) accounted for 44% of total underlying demand at the time.
- The WEM also recorded its third highest daily peak demand on record, with operational demand reaching 3,916 MW on 4 February, driven by high temperatures in Perth (42.7°C).
- Despite lower than average maximum temperatures for the quarter, high overnight temperatures and increasing underlying demand offset the growth in rooftop PV, resulting in average operational demand increasing by 3.9% compared to Q1 2019.
- The average Balancing Price increased by 2.7% compared to Q1 2019 due to increased operational demand and decreased availability of black coal-fired generation.
- In 2019 AEMO proposed a new Load Following Ancillary Service (LFAS) requirement which was implemented from August 2019. Whereas previous requirements were constant for all trading intervals, the new requirements are higher for peak daytime hours when more demand volatility is expected, and lower for off-peak hours which are generally more stable. Two new participants were also certified to provide LFAS in 2019. As a result of increased competition and the new LFAS requirements, total LFAS costs in Q1 2020 were 24% lower than in Q1 2019.

## Western Australia gas highlights

- Total Western Australia gas consumption and production decreased slightly (by 3% and 4% respectively). Consumption by industrial consumers, mainly in the Dampier region, decreased by 37%, while consumption for gas-powered generation (GPG) increased by 6% to meet increased WEM demand.

- Tropical Cyclone Damien impacted gas production at the Karratha and Devil Creek Gas Plants, which both shut down briefly to deal with the cyclone.
- Q1 2020 saw an increase in the number of Linepack Capacity Alerts (LCAs), with 37 Amber and Red LCAs compared to a total of 20 in the previous five years combined. The two Red LCAs were associated with a compressor trip, while Tropical Cyclone Damien caused five Amber LCAs. Some of the LCAs were caused by planned maintenance.

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<sup>5</sup> A measure of volatility in electricity prices is the presence of high price events – prices above \$300/MWh. Often represented as 'quarterly cap returns' which is the sum of the NEM pool price minus the \$300 Cap Price for every half hour in the contract quarter where the pool price exceeds \$300/MWh, divided by the number of half hours in the quarter.

<sup>6</sup> Based on the Japan/Korea Marker (JKM) and converted from US\$/MMBtu to A\$/GJ

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# 1. NEM market dynamics

## 1.1 Weather

Q1 2020 weather was mild across all east coast cities, with average maximum temperatures well below the 10-year average and the record high levels of Q1 2019 (Figure 1). Below average temperatures were most evident in Melbourne and Adelaide, which reduced cooling requirements by 71% and 57%, respectively (Figure 2).

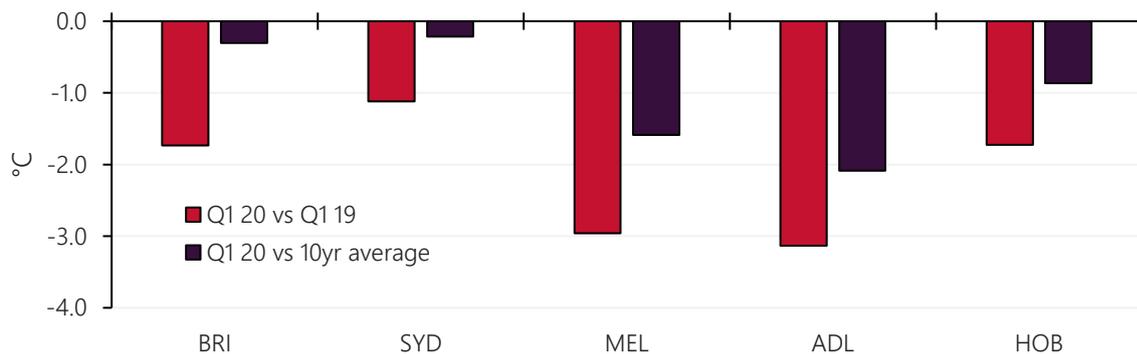
While temperatures were relatively mild throughout the quarter, Sydney, Adelaide, and Melbourne still recorded several days of extreme heat in January.

- Sydney had record high temperatures on 4 January with temperatures at Penrith reaching 48.9°C.
- There was a heatwave across the east coast at the end of January, with Adelaide reaching a maximum temperature of 43.9°C on 30 January while Melbourne reached 43.6°C on 31 January.

Q1 2020 was a comparatively wet quarter compared to the record dry conditions of 2019, with above average rainfall in January and February<sup>7</sup>.

**Figure 1 Mild Q1 across all capital cities**

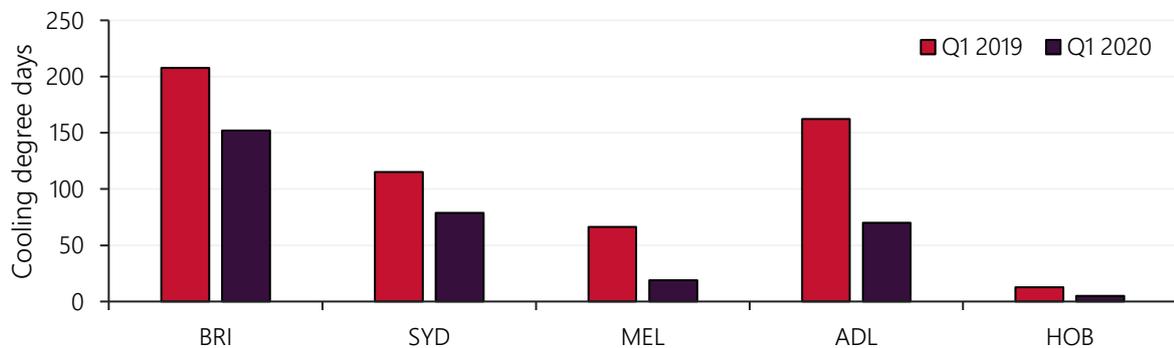
Average maximum temperature variance by capital city – Q1 2020 vs 10-year Q1 average



Source: Bureau of Meteorology

**Figure 2 Reduced cooling needs in all states**

Change in cooling degree days<sup>8</sup> - Q1 2020 versus Q1 2019



<sup>7</sup> Bureau of Meteorology 2020, Australia in summer 2019-20: <http://www.bom.gov.au/climate/current/season/aus/archive/202002.summary.shtml>.

<sup>8</sup> A "cooling degree day" (CDD) is a measurement used as an indicator of outside temperature levels above what is considered a comfortable temperature. CDD value is calculated as max (0, temperature - 24).

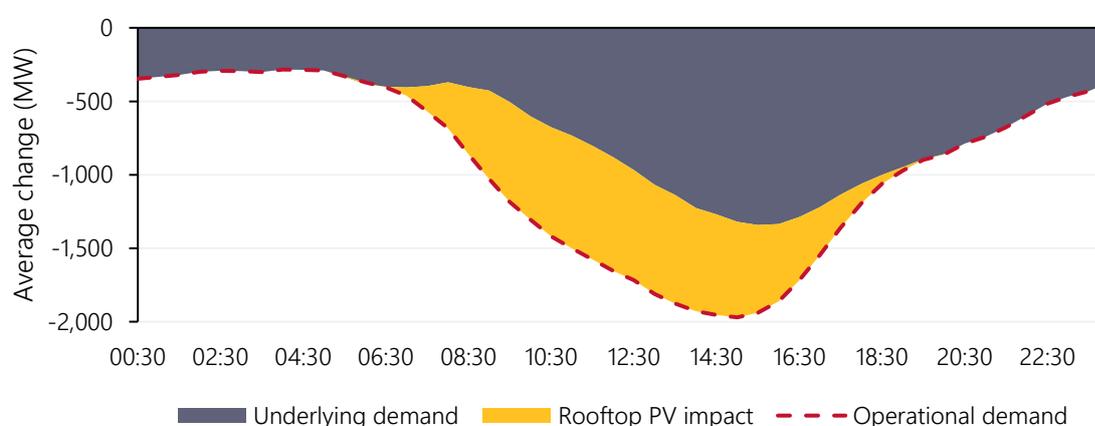
## 1.2 Electricity demand

NEM average operational demand declined by 951 MW in Q1 2020 compared to Q1 2019, as rooftop PV increased by 263 MW<sup>9</sup> and underlying demand decreased by 688 MW (Figure 3). The marked reduction in underlying demand was driven by reduced daytime cooling requirements (Section 1.1), particularly during February and March. Quarterly average operational demand reduced across all NEM regions, with the largest reduction occurring in New South Wales (492 MW) and the second largest in Victoria (217 MW).

The nationwide restrictions which commenced mid-March due to COVID-19 resulted in reduced operational demand, but did not materially affect quarterly average results. AEMO estimates a small reduction (up to approximately 3-4%) in New South Wales and southern Queensland operational demand in late March, and will continue to monitor these demand-side impacts.

**Figure 3 Mild average Q1 conditions and increased rooftop PV reduces operational demand**

Change in NEM-average operational demand by region and time of day (Q1 2020 versus Q1 2019)



Compared to Q1 2019, average daytime rooftop PV output (from 0700 to 1900 hrs) increased by 524 MW to reach 3,023 MW. This contributed to the largest operational demand reduction by time of day of 1,970 MW, which occurred at Trading Interval ending 1500 hrs with rooftop PV contributing 33% of this reduction.

### Maximum and minimum demand

Table 1 outlines the maximum and minimum demands which occurred in Q1 2020, and the regional records. On 1 January 2020, new Q1 minimum demand records were set for Victoria and South Australia due to the combination of mild weather (26.3°C in Melbourne and 27°C in Adelaide), sunny conditions, and low demand typically associated with the New Year's Day public holiday.

**Table 1 Maximum and minimum operational demand (MW) by region – Q1 2020 vs previous records**

	Queensland		New South Wales		Victoria		South Australia		Tasmania	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q1 2020	9,853	5,052	13,835	5,652	9,667	3,300	3,100	520	1,335	822
All Q1	10,044	3,260	14,744	4,642	10,576	3,311	3,399	695	1,499	552
All-time	10,044	3,102	14,744	4,642	10,576	3,217	3,399	458	1,790	552

Note: table records refer to those before the start of Q1 2020 and exclude black system events. Red text highlights instances where the previous record has been broken. The records go back to when the NEM began operation as a wholesale spot market in December 1998.

<sup>9</sup> Increased rooftop PV generation results in reduced operational demand because rooftop PV is behind the meter.

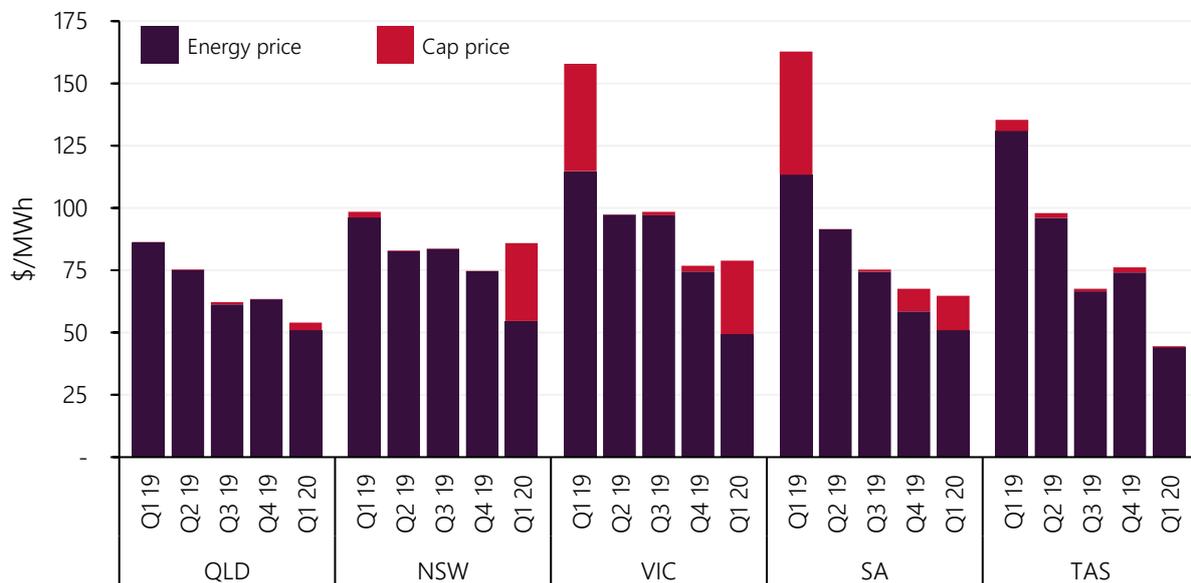
### 1.3 Wholesale electricity prices

Q1 average wholesale electricity prices continued to trend downward, with NEM-average prices reaching \$66/MWh, down 49% from \$130/MWh in Q1 2019 (Figure 4). This represents the lowest NEM quarterly average price since Q4 2016. Queensland’s average price declined to \$54/MWh – its lowest level since Q3 2016 – while South Australia reduced to \$65/MWh, which is its lowest level since Q1 2016<sup>10</sup>. This is despite Q1 typically being the highest-price quarter in these regions. Tasmanian spot prices fell to average \$45/MWh, due to lower priced offers from hydro generation in the region (Section 1.4.3).

Lower average energy prices in New South Wales and Victoria were partially offset by short periods of extreme price volatility (Section 1.3.1), but overall they remained lower than in Q1 2019. Victoria’s spot price only exceeded \$100/MWh 3% of the time, compared to 58% of the time in Q1 2019.

**Figure 4 Spot wholesale electricity prices decline to lowest level since Q4 2016**

Average wholesale electricity price by region



#### Reduced wholesale electricity prices: Q1 2020 drivers

<b>Low gas prices</b>	Reduced wholesale gas prices (Section 2.2) were reflected in lower-priced offers from GPG in Queensland. Compared to Q1 2019, around 200 MW of higher priced marginal Queensland GPG capacity (\$70-\$300/MWh) was moved to prices below \$70/MWh (see Section 1.4.1).  Lower gas prices also influence market bids from other fuel types (hydro and black coal-fired generation).
<b>Reduced demand</b>	Compared to Q1 2019, increased rooftop PV output and mild weather in the second half of the quarter substantially reduced average daytime operational demand (see Section 1.2).
<b>Shift in offers from black coal-fired and hydro generation</b>	In Q1 2020, there was a material shift in offers from black coal-fired generation and hydro generation. Compared to Q1 2019, 740 MW of higher priced marginal black coal-fired generation (\$60-\$150/MWh) was moved to prices below \$60/MWh (see Section 1.4.1). For hydro generation, 1,000 MW of capacity priced above \$100/MWh was moved to prices below \$100/MWh. These shifts coincided with lower gas prices, reduced demand, and increased renewable output.
<b>Increased wind and solar output</b>	Compared to Q1 2019, combined grid-scale wind and solar output increased by 551 MW due to the ramping up of new capacity entering the system (see Section 1.4.3).

<sup>10</sup> The results exclude the period of Market Suspension in South Australia in Q4 2016, following the South Australia Black System Event.

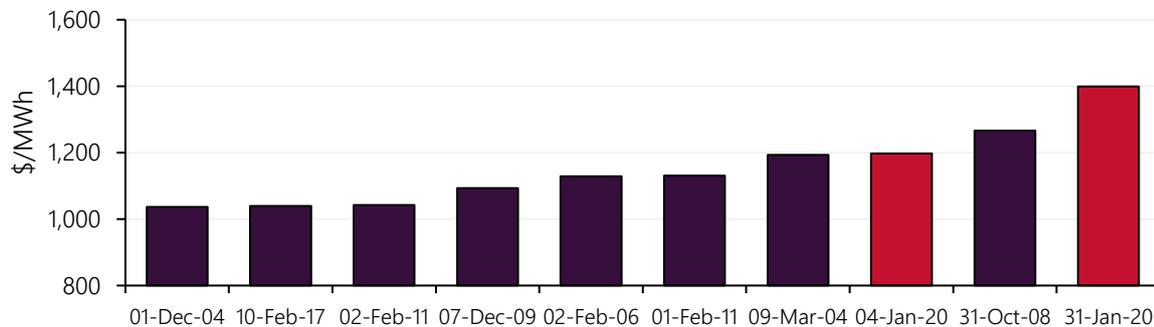
### 1.3.1 Wholesale electricity price volatility

In Q1 2020, price volatility results were mixed across NEM regions. New South Wales and Victoria experienced high levels of price volatility with cap returns<sup>11</sup> of \$31/MWh and \$29/MWh respectively, while Queensland and Tasmania recorded low price volatility. Despite being separated from the rest of the NEM for an extended period (Section 1.6), South Australia caps returns declined to \$14/MWh, the lowest Q1 level since 2016.

<p><b>Extreme price volatility in New South Wales and Victoria</b></p>	<p><b>4 Jan 2020</b> – record Sydney temperatures, coupled with separation of the New South Wales and Victorian systems due to bushfires, led to extreme New South Wales prices, actual Lack of Reserve 2 (LOR2) conditions, and Reliability and Emergency Reserve Trader (RERT) utilisation.</p> <ul style="list-style-type: none"> <li>• Spot prices spiked to \$14,700/MWh for one hour, and remained very high for another one and a half hours.</li> <li>• Use of RERT in response to LOR2 conditions resulted in costs of around \$8 million.</li> </ul> <p><b>31 Jan 2020</b> – a heatwave across the east coast led to very high operational demand. The NEM daily maximum operational demand peaked at 35,440 MW, the third highest day on record. On the supply side, some thermal units had reduced capacity due to the extreme heat and five coal-fired units were offline mostly due to unplanned outages. Wind capacity factors were comparatively low (around 10-20%) in New South Wales and Victoria due to low wind speed, temperature de-ratings and transmission line outages. At 1325 hrs, a severe storm brought down power lines, leading to separation of the South Australian and Victorian power systems. Prior to separation, Victoria was importing 550 MW from South Australia on the Heywood Interconnector, the loss of which led to very low reserve conditions in New South Wales and Victoria.</p> <ul style="list-style-type: none"> <li>• New South Wales spot prices spiked above \$12,000/MWh for 90 minutes – and were above \$1,500/MWh for another 210 minutes – resulting in the highest daily cap returns in New South Wales since NEM start.</li> <li>• Victoria spot prices spiked above \$7,000/MWh for 270 minutes resulting in the third highest daily cap returns in Victoria since NEM start.</li> <li>• Pre-activation and activation of RERT contracts in response to actual LOR2 conditions in Victoria and New South Wales regions resulted in costs of \$18.5 million<sup>12</sup>. RERT was also utilised in New South Wales on 23 January 2020, bringing quarterly RERT costs to \$34 million.</li> <li>• On both 4 Jan and 31 Jan 2020, there was also market-based activation of demand response, with Tomago aluminium smelter switching off potlines in response to the high prices.</li> </ul>
<p><b>Declining Q1 price volatility in South Australia</b></p>	<ul style="list-style-type: none"> <li>• Fewer high demand periods due to milder temperatures – compared to Q1 2019, there was a 62% reduction in trading intervals in which operational demand exceeded 2,600 MW. No high demand periods (operational demand exceeding 2,600 MW) were recorded during February or March.</li> <li>• Increased variable renewable energy (VRE) during high demand periods – South Australian VRE output during high demand periods averaged 722 MW, representing an 88% increase on Q1 2019 levels.</li> </ul>

**Figure 5 New South Wales record cap return day set on 31 January 2020**

New South Wales 10 highest cap return days on record (daily average cap returns)



Note: the relative order of daily price volatility days changes if the level of the Market Price Cap is taken into account – it increased steadily from \$10,000/MWh in 2009-10 to \$14,700/MWh in 2019-20.

<sup>11</sup> A measure of volatility in electricity prices is the presence of high price events – prices above \$300/MWh. This is often represented as ‘quarterly cap returns’, which is the sum of the NEM pool price minus the \$300 Cap Price for every half hour in the contract quarter where the pool price exceeds \$300/MWh, divided by the number of half-hours in the quarter.

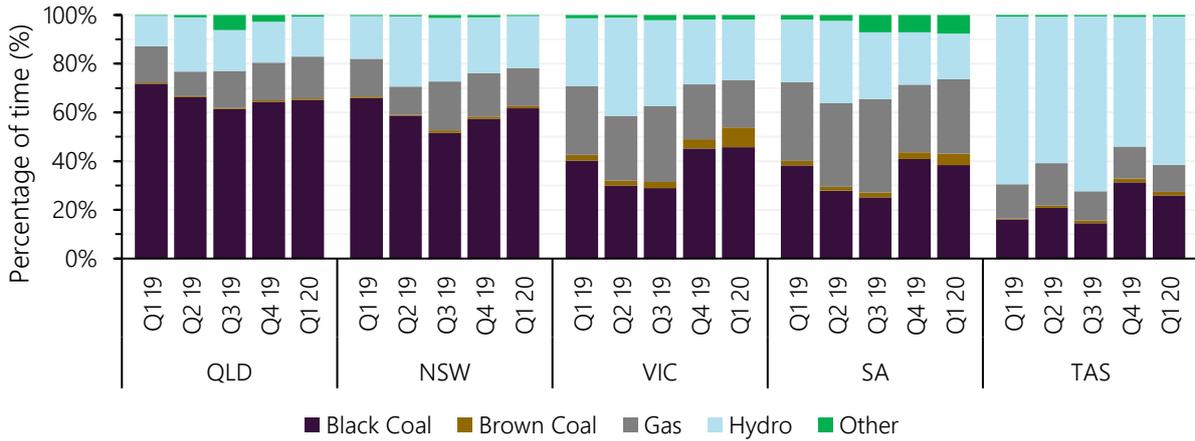
<sup>12</sup> Further details on these RERT activations can be found at <https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting>.

### 1.3.2 Price-setting dynamics

Spot electricity price-setting dynamics in Q1 2020 were similar to outcomes in recent quarters. On a NEM-average basis, black coal-fired generation set the price 47% of the time, hydro 28% of the time, and GPG 19% of the time (Figure 6). While GPG was not the most frequent price setting fuel type in the NEM, gas prices can influence the price of bids from black coal-fired generation and hydro generation.

**Figure 6 Black coal-fired generation remains the dominant price setting fuel type in the NEM**

Price-setting by fuel type – Q1 2020 versus prior quarters

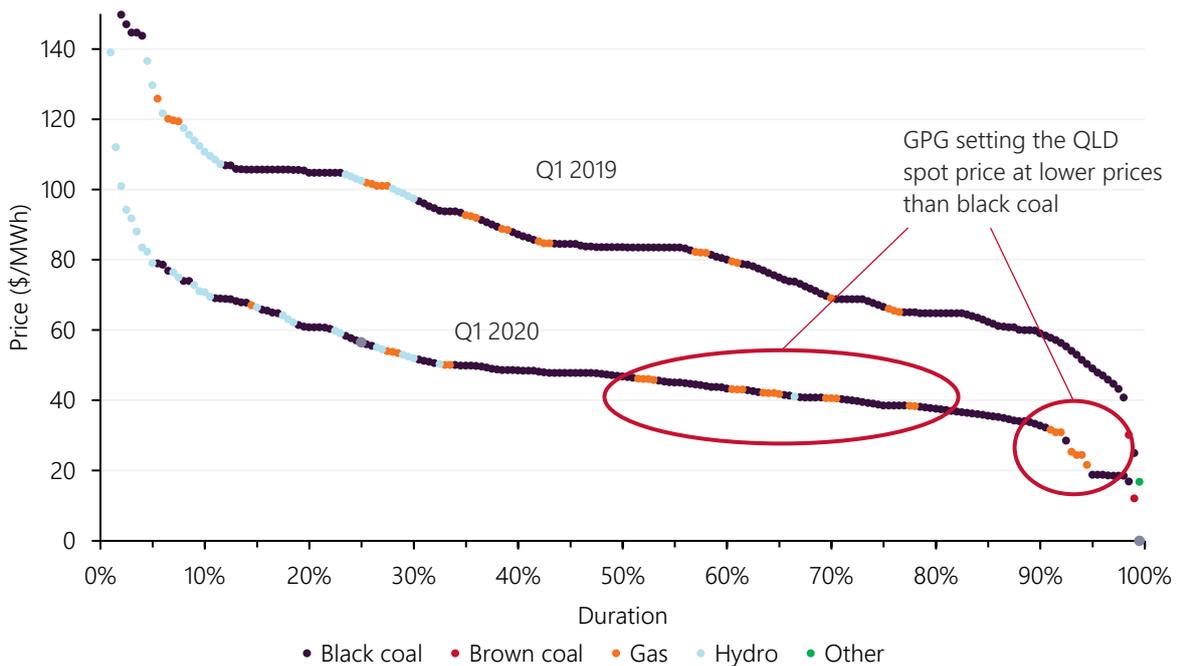


Note: price setting can occur inter-regionally: for example, Victoria's price can be set by generators in other NEM regions.

In Queensland, GPG set the spot price 17% of the time, its highest value since Q2 2017. With the structural shift in prices of bids from dispatchable generation, and reduced operational demand, all major price setting fuel types set the price at lower levels than in Q1 2019 (Figure 7). When Queensland GPGs set the spot price in the region, it averaged \$51/MWh compared to \$97/MWh in Q1 2019. Due to the shift in bids, Queensland GPGs regularly set the spot price at lower levels than black coal-fired generation (Figure 7).

**Figure 7 Gas often setting the spot electricity price at lower prices than coal (Queensland)**

Queensland price-setting duration curve by fuel type

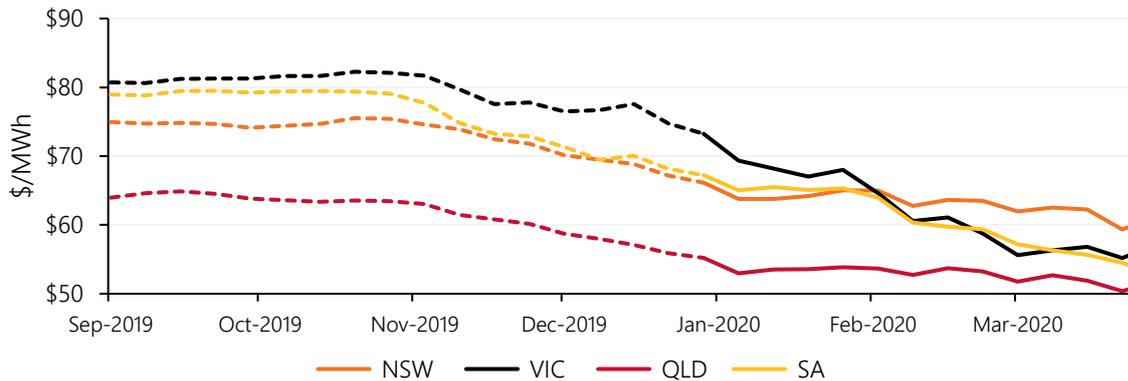


### 1.3.3 Electricity future markets

The price of NEM electricity futures contracts continued to decline during Q1 2020, with Calendar 2021 (Cal21) prices finishing the quarter at multi year lows across all regions (Figure 8). These futures price reductions were influenced by lower spot electricity and gas prices, expectations of further increases in renewables and rooftop PV, and concerns about the impact of COVID-19 on demand.

**Figure 8 ASX Futures continue to decline in Q1 2020**

ASX Energy – Cal21 swap prices by region – seven day averages



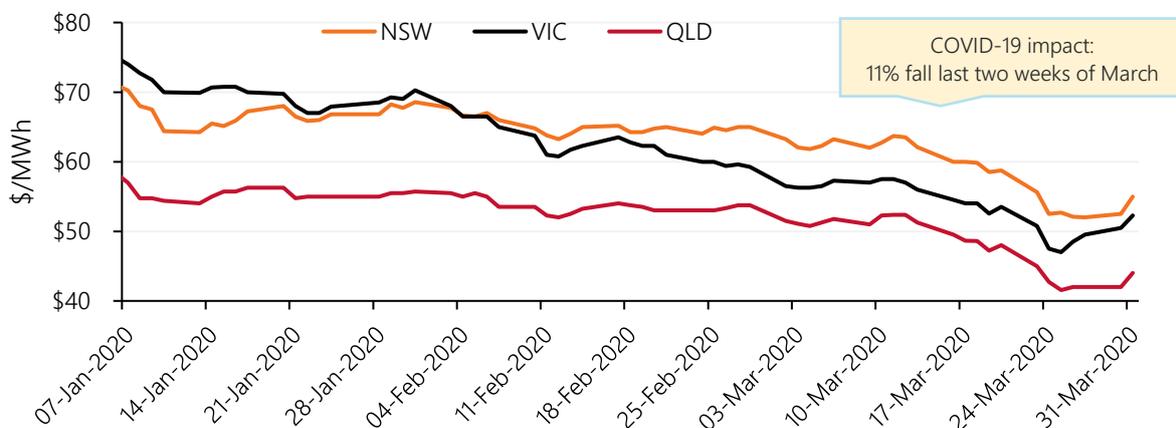
By region:

- The largest futures price reductions occurred in Victoria, which also recorded one of the largest spot price reductions this quarter. Victorian Cal21 swaps declined by \$17/MWh to reach \$56/MWh, while Cal22 swaps decreased to \$51.50/MWh (-\$15/MWh). Similar futures price reductions occurred for South Australian swaps.
- From a futures pricing perspective, New South Wales became the highest priced state, due to only relatively small price reductions compared to Victoria and South Australia. New South Wales Cal21 swaps declined to \$60/MWh (-\$6/MWh).
- Queensland remained the lowest priced state on the ASX, as Cal21 declined \$5/MWh to \$51/MWh.

From mid-March, electricity futures markets began to price in the impact of COVID-19 for upcoming quarters. Similar to global energy markets, the largest price reductions occurred in Q2 and Q3 2020 futures, which fell 11% between 13 March to 31 March (Figure 9).

**Figure 9 ASX Q2 2020 Futures decline from middle of March**

ASX Energy – Q2 2020 swap prices by region



## 1.4 Electricity generation

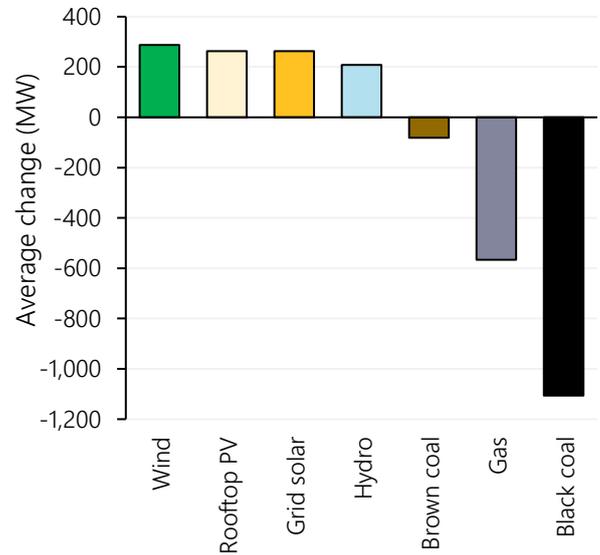
During the quarter, a combination of low operational demand, thermal unit outages and pricing of dispatchable generation shaped the NEM generation mix. Figure 10 shows the average change in generation by fuel type compared to Q1 2019, and Figure 11 illustrates the change by time of day.

Quarter highlights include:

- Average black coal-fired generation was 12,024 MW, decreasing by 1,106 MW compared to Q1 2019, reaching its lowest Q1 level since Q1 2015. The decline was driven by a comparatively high number of unit outages in February and March, reduced operational demand, and displacement by both solar and Queensland GPG.
- Reduced NEM-wide GPG (-566 MW) was a function of lower average pool prices and reduced operational demand. South Australian GPG accounted for the largest decrease.
- Grid-scale variable renewable energy (VRE) output increased by 551 MW compared to Q1 2019, as recently installed capacity continued to ramp up.
- Average hydro output rebounded from very low levels in Q1 2019, increasing by 208 MW, with Tasmania and New South Wales leading the increase.

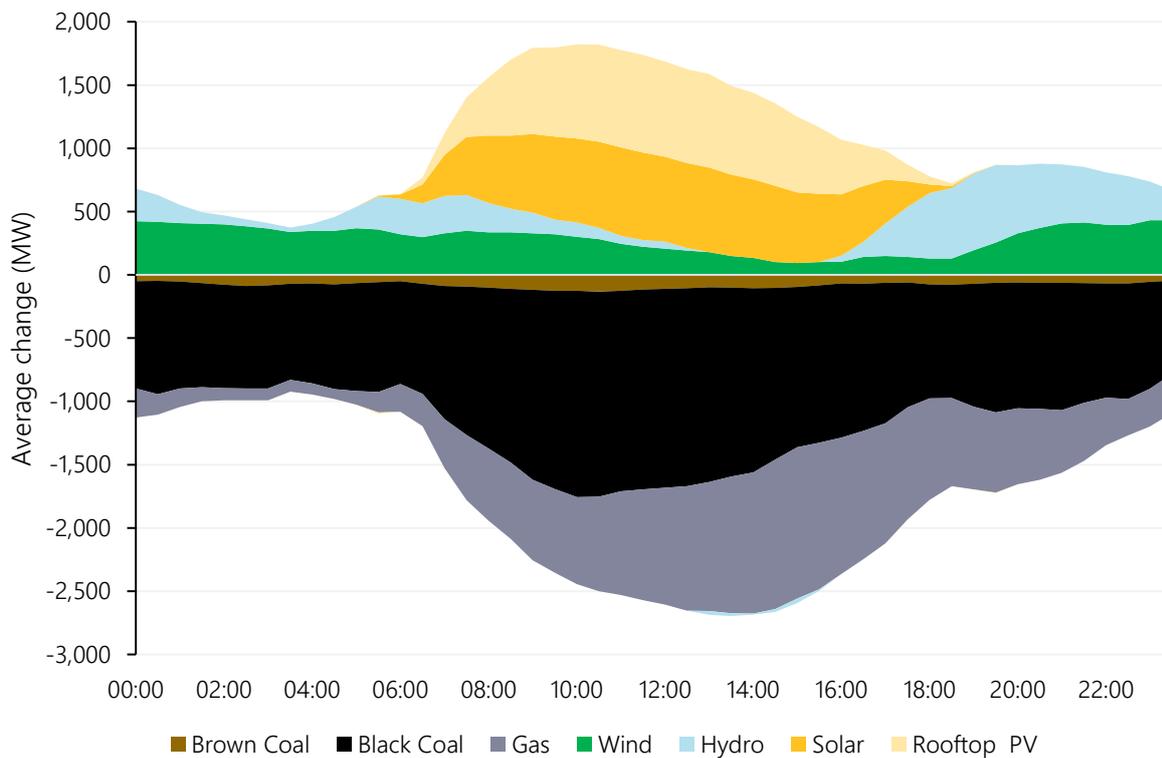
**Figure 10 Large reductions from thermal generation**

Change in supply – Q1 2020 versus Q1 2019



**Figure 11 Reduced coal and GPG across the day; increased overnight hydro and daytime solar**

Change in supply – Q1 2020 versus Q1 2019 by time of day



### 1.4.1 Coal-fired generation

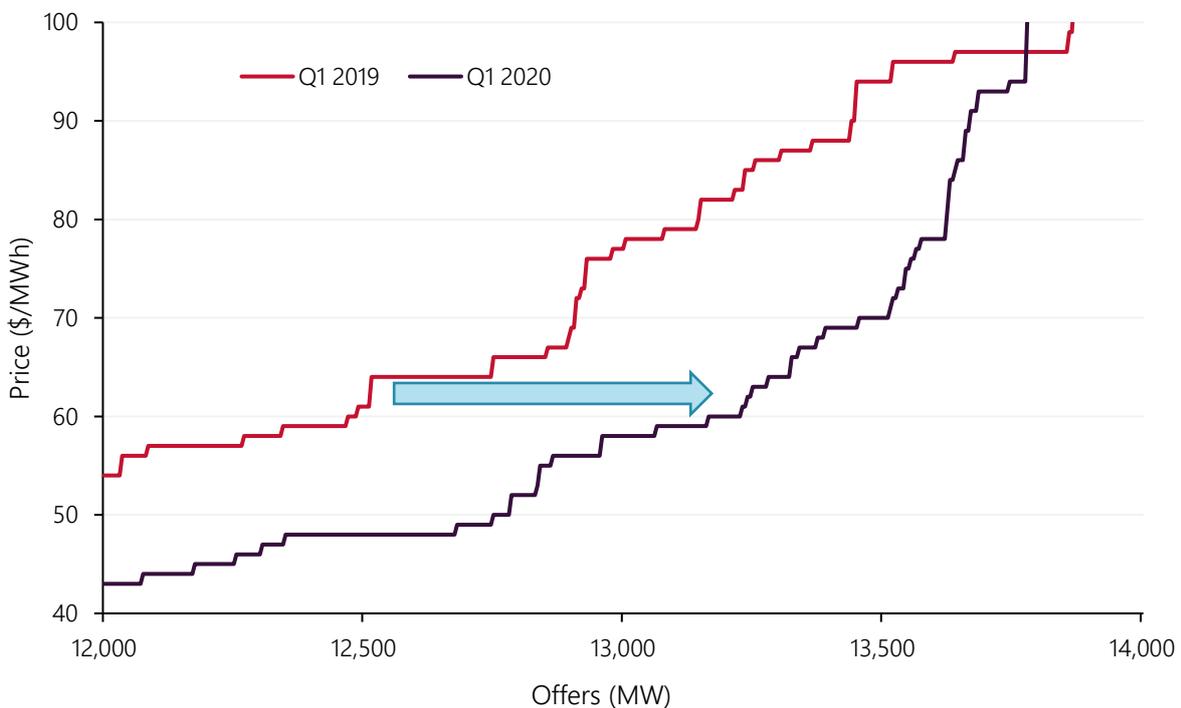
#### Black coal fleet

During Q1 2020, black-coal generation reduced by 1,106 MW on average compared to Q1 2019, with the New South Wales fleet leading the reduction (-885 MW).

Of note, this large reduction occurred despite a structural shift in black coal-fired generation bids into lower priced bands. Compared to Q1 2019, on average 740 MW of capacity shifted from higher priced bands to prices below \$60/MWh (Figure 12). This change was influenced by lower gas market prices, reduced operational demand, and the continued growth in VRE output.

**Figure 12 Black coal-fired generation bidding capacity at lower prices**

NEM black coal-fired generation bid supply curve – Q1 2020 versus Q1 2019



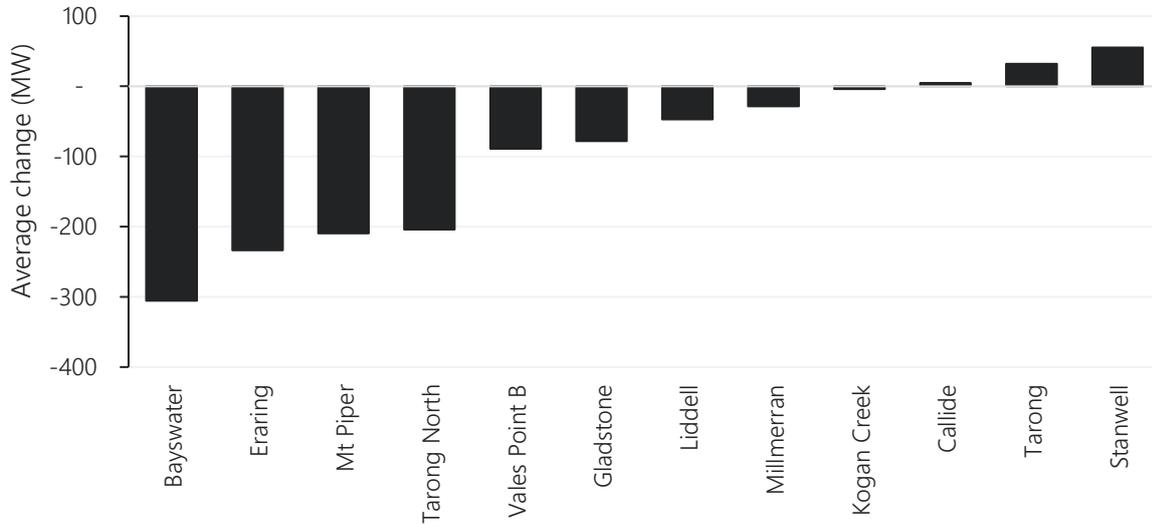
Key drivers of reduced New South Wales output this quarter included low operational demand, displacement by solar and GPG, and a comparatively high number of outages in February and March. By station, compared to Q1 2019 (Figure 13):

- Outages reduced Bayswater Power Station average output by 305 MW. Bayswater units were out of service for 21 days on average compared to seven days in Q1 2019 (Figure 14). This 200% increase in outages was predominantly driven by outages at Unit 4 (out for 60% of the quarter), which returned to service from a major unit upgrade in December 2019.
- Average output at Eraring Power Station reduced by 234 MW this quarter, as it continued to be displaced by daytime solar, with average daytime<sup>13</sup> output down by 327 MW. In addition, Eraring was also affected by lower operational demand in New South Wales as well as some displacement by lower-priced Queensland GPG (Section 1.4.2).
- While coal supply constraints at Mount Piper Power Station have eased since mid-November 2019, output was 210 MW lower than in Q1 2019, as it was impacted by an increased number of outages. On average, Mount Piper units were on outage for 21.5 days more than in Q1 2019 (mostly planned).

<sup>13</sup> Daytime refers to the period from 0800 to 1600 hrs.

**Figure 13 Bayswater leads black coal output reduction**

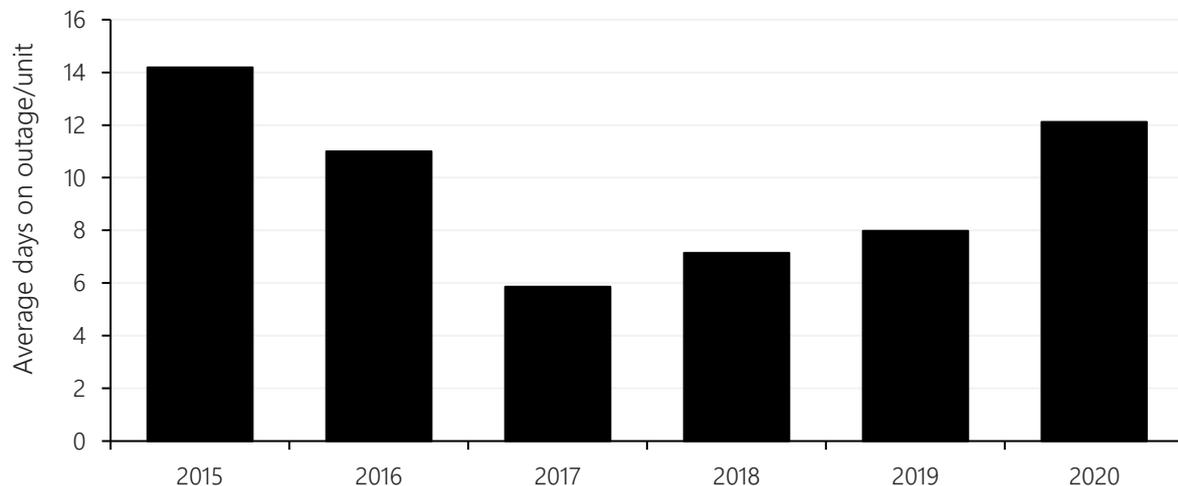
Change in black coal-fired generation – Q1 2020 versus Q1 2019



In Queensland, an extended outage at Tarong North due to transformer issues from 12 February 2020 cut its average quarterly output by 53%. At Gladstone Power Station, the decline in output (-78 MW on average) was mainly driven by daytime solar displacement as well as a small increase in outages (it had a comparatively high number of outages in both Q1 2020 and Q1 2019). In addition, an increase in low-priced market offers (below \$40/MWh) from Queensland GPG units such as Darling Downs and Swanbank E in March also led to some output being displaced (Section 1.4.2).

**Figure 14 Highest level of Q1 unit outages since 2015 (mostly in February and March)**

Black coal-fired generation average day on outage/unit – Q1s



### Brown coal fleet

Compared to Q1 2019, average brown coal-fired generation this quarter was relatively flat, decreasing slightly by 81 MW. The 226 MW decrease at Loy Yang A was largely offset by increased output from Yallourn and Loy Yang B. While average brown coal unit outages (10 days) were lower compared to Q1 2019 (11 days), Loy Yang A Unit 2 – which was out of service for 68% of 2019 and returned 24 December 2019 – accounted for 39% of the Q1 2020 total, resulting in a 173 MW reduction in output at that unit compared to Q1 2019.

### 1.4.2 Gas-powered generation

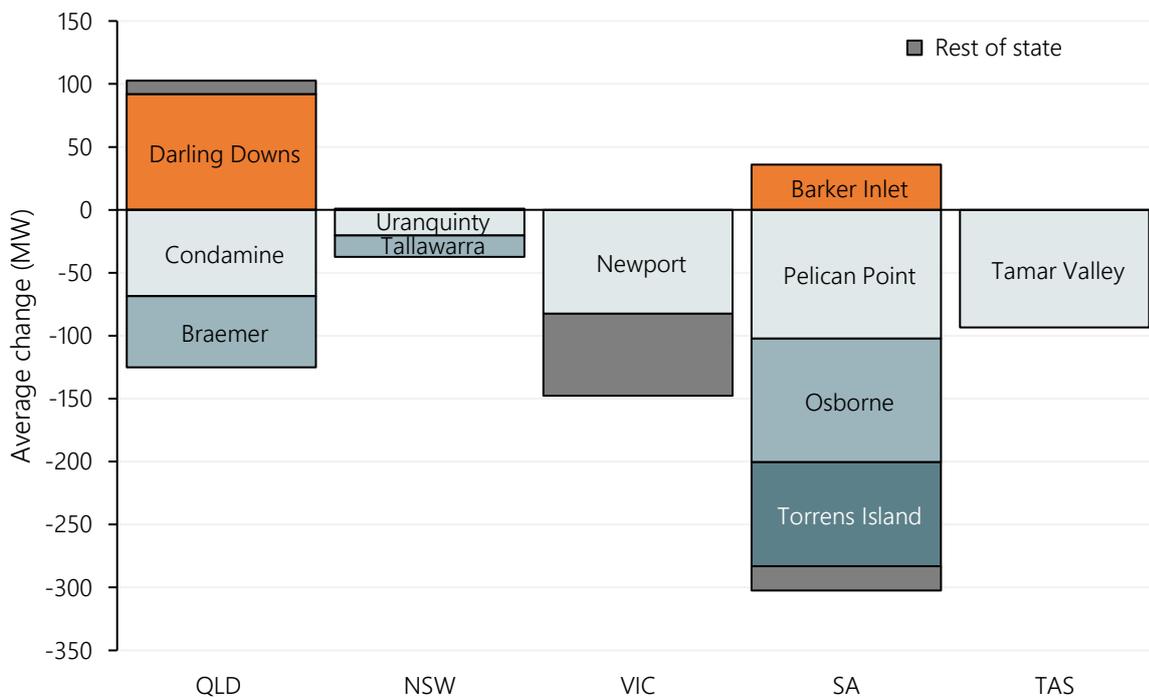
NEM GPG decreased by 566 MW on average compared to Q1 2019 (Figure 15), largely due to lower operational demand and increased VRE output in the southern regions. On a regional basis there were mixed results, with large reductions in South Australia (-266 MW) and Victoria (-148 MW), but only slight reductions in Queensland (-22 MW).

By region:

- South Australia declined to its lowest Q1 average GPG since 2016, largely driven by reduced operational demand in the region (-167 MW on average compared to Q1 2019).
  - There were sizeable reductions in average output from all three major GPGs, with Pelican Point down 102 MW, Osborne down 98 MW, and Torrens Island down 83 MW. Osborne Power Station was only online 24% of the time and was frequently withdrawn from the market for commercial reasons. The reduction in output at these power station would have been greater if not for 66 MW of directed South Australian GPG on average this quarter (Section 1.6.2).
  - Average output at AGL’s newly commissioned Barker Inlet Power Station was 36 MW. This was its first full quarter of operation.
- Victorian GPG declined to its lowest Q1 average since 2017, due to reduced operational demand in the region (-217 MW on average) and increased local VRE output (162 MW on average). Compared to Q1 2019, a 95 MW average increase at EnergyAustralia’s Yallourn Power Station reduced the requirement for Newport. The regional reduction in GPG would have been greater if not for 82 MW of Mortlake output directed online on average this quarter due to the 18-day separation event (Section 1.6).
- Tasmanian GPG decreased by 94 MW. This was due to increased hydro generation in the region, which meant Hydro Tasmania did not require Tamar Valley to return to service this summer.

**Figure 15 Queensland’s Darling Downs ramps up as the south declines**

Change in GPG – Q1 2020 versus Q1 2019



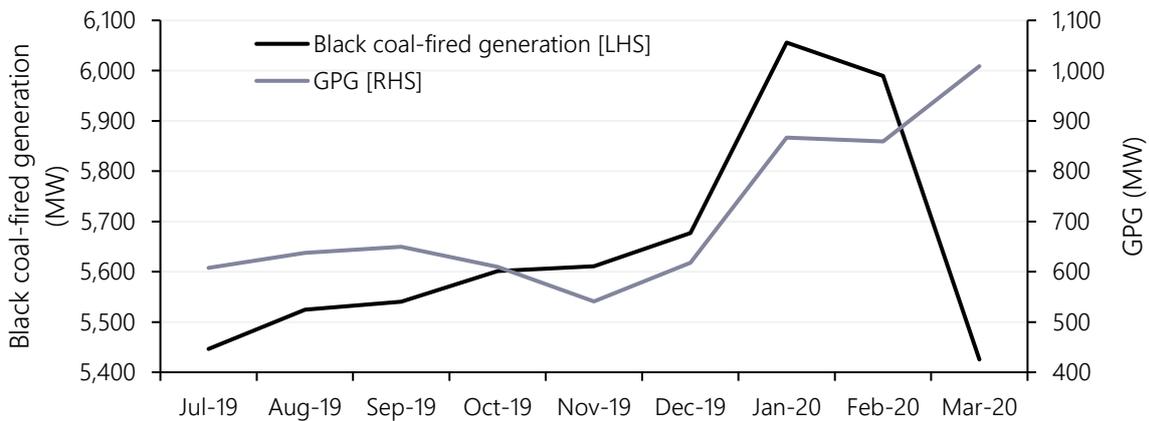
## Queensland GPG

In contrast to South Australia and Victoria, Queensland GPG only reduced slightly, with increased average output from Darling Downs (92 MW) and Swanbank E (15 MW) offsetting reductions at Condamine (-69 MW) and Braemar (-55 MW).

During the quarter, Queensland GPG progressively ramped up in output despite falling spot electricity prices, leading to some displacement of black coal-fired generation. In March, Queensland GPG averaged 1,009 MW – its highest monthly average since January 2018 – while black coal-fired generation averaged 5,425 MW – its lowest level since May 2016.

**Figure 16 Queensland GPG ramps up while black coal-fired generation in the region falls**

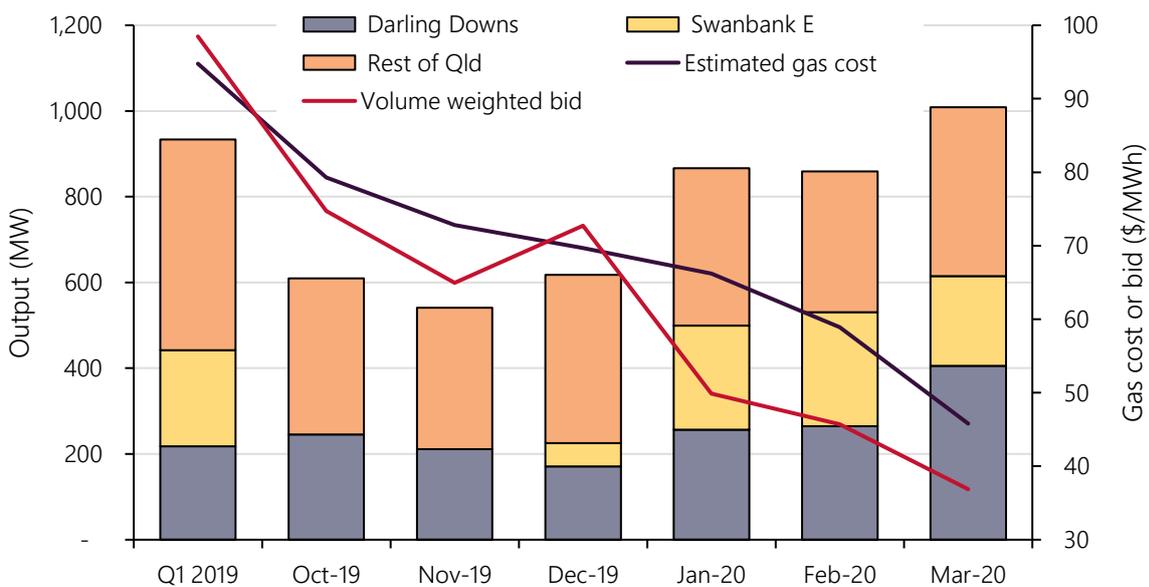
Queensland monthly average GPG and black-coal-fired generation



The driver of increased GPG was lower-priced offers from Darling Downs and Swanbank E, which coincided with lower gas market prices. The volume-weighted price of marginal GPG bids (\$0-\$150/MWh) declined from \$98/MWh in Q1 2019 to \$37/MWh in March 2020, coinciding with the Wallumbilla gas price falling to \$4.60/GJ (Figure 17).

**Figure 17 Lower gas prices drive increased Queensland GPG output**

Queensland GPG output, GPG VWAP bid, and estimated GPG input cost



Note: The input cost is the estimated gas cost based on the quarterly average gas price in the Gas Supply Hub (GSH) and a heat rate of 10 GJ/MWh. Volume-weighted price of bids is based on capacity bid at prices between \$0-150/MWh.

### 1.4.3 Hydro

Average hydro generation across the NEM was 208 MW higher than Q1 2019, despite lower spot electricity prices and demand. The driver of increased output was a material reduction in the price of hydro offers, which coincided with lower gas market prices, increased rainfall, and lower spot prices<sup>14</sup>. On average, from Q1 2019, 1,000 MW of capacity was shifted to prices below \$100/MWh (Figure 18).

**Figure 18 Significant reduction in the price of hydro generation offers in Q1 2020**

NEM hydro bid supply curve – Q1 2020 versus Q1 2019

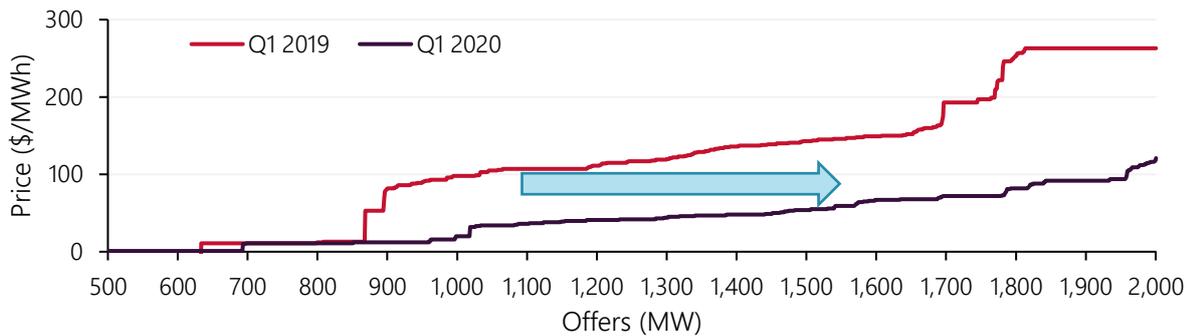


Figure 19 shows the change in average output by state. On a regional basis:

- Tasmania’s quarterly average hydro generation was 892 MW, a 28% increase compared to Q1 2019, which more than offset reduced local GPG (Section 1.4.2) and enabled increased transfers into Victoria (Section 1.5). Although Tasmania’s water storage levels dropped from 47% to 38%, it finished higher than in Q1 2019.
- New South Wales average hydro generation was up, due to increased output from Upper Tumut (from historically low levels in Q1 2019). Despite above average rainfall in New South Wales in February (103mm<sup>15</sup>) and increased dam levels across Greater Sydney region (83% by the end of the quarter<sup>16</sup>), dam levels at Lake Eucumbene (Snowy Hydro’s largest water storage) remained low at 26% (Figure 20).
- Queensland hydro decreased by 98 MW, reaching its lowest Q1 level since 2016. The decreased output was driven by comparatively low generation from Kareeya and Barron Gorge.

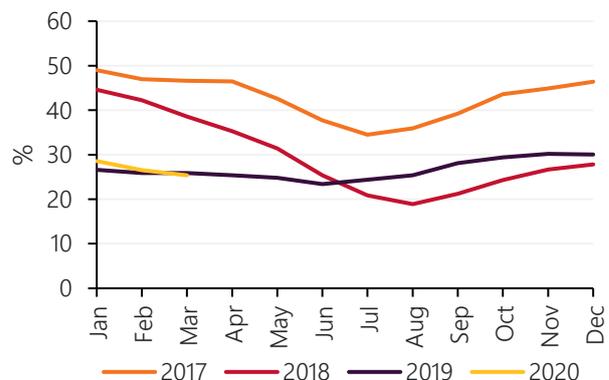
**Figure 19 Tasmania and NSW lead hydro increase**

Change in hydro generation by region – Q1 2020 versus Q1 2019



**Figure 20 Snowy hydro remains at low levels**

Weekly gross storage levels in percentage



<sup>14</sup> With lower spot prices, hydro generators need to lower the price of offers to be dispatched into the electricity market.

<sup>15</sup> Bureau of Meteorology 2020, Australia in February 2020: <http://www.bom.gov.au/climate/current/month/aus/archive/202002.summary.shtml>.

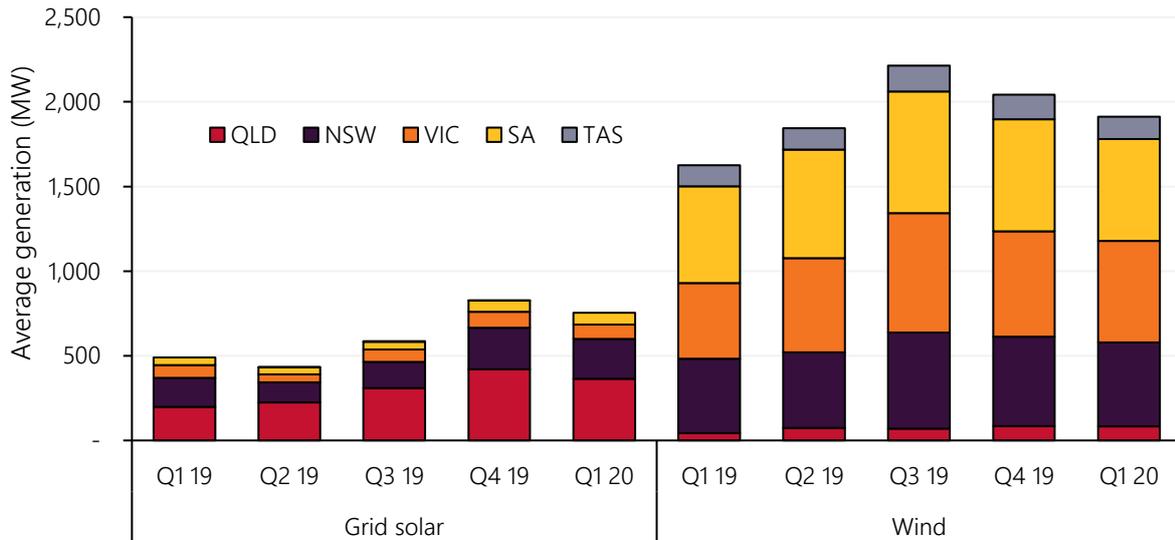
<sup>16</sup> WaterNSW 2020, Greater Sydney water storage and supply report: [https://www.watnsw.com.au/\\_data/assets/pdf\\_file/0007/155662/Thursday-2-April-2020.pdf](https://www.watnsw.com.au/_data/assets/pdf_file/0007/155662/Thursday-2-April-2020.pdf).

### 1.4.4 Wind and solar

Compared to Q1 2019, average grid-scale VRE generation in Q1 2020 increased by 551 MW to 2,667 MW (Figure 21), but was lower than in Q4 2019 due to reduced capacity factors (Q1 is not typically the windiest nor sunniest quarter). The increase compared to Q1 2019 was a product of continued ramping up of recently installed capacity as well as a slight addition in generation from new projects commencing generation this quarter.

**Figure 21 Higher levels of grid-scale VRE driven by ramping up of recently installed capacity**

VRE average generation by region – Q1 2020 versus Q1 2019



While grid-scale solar output was higher compared to Q1 2019 (+263 MW), driven by newly installed capacity, the increase was partially offset by an approximate 6% reduction in solar irradiation across all states.

In Victoria, despite additional generation from Numurkah Solar Farm, average solar output only increased marginally by 10 MW compared to Q1 2019, due to system security constraints limiting output at four other solar projects (Section 1.6.3). Since the second half of 2019, growth of grid-scale solar projects slowed; this quarter, only two Queensland projects commenced generation (Yarranlea Solar Farm, 103 MW and Maryborough Solar Farm, 34.5 MW) and one began in New South Wales (Bomen Solar Farm, 100 MW).

Average wind generation increased by 288 MW compared to Q1 2019, largely driven by ramping up of recently installed capacity and partially by newly commissioned projects in Victoria (Dundonnell Wind Farm, 336 MW) and Tasmania (Cattle Hill Wind Farm, 149 MW and Granville Harbour Wind Farm, 111.6 MW).

- Victoria had the largest increase on average (152 MW), driven by higher wind capacity factors and ramping up of recently installed capacity. This was partially offset by reduced average output at Macarthur and Portland wind farms (-19 MW combined) resulting from the 18-day separation of the South Australian and Victorian power systems (Section 1.6.3).
- While overall wind generation increased in South Australia (31 MW) and Queensland (40 MW), the increase was partially offset by lower wind speeds in these two states compared to Q1 2019. In Queensland, increased output was due to additional generation from Coopers Gap Wind Farm; however, this was offset by lower output from Mount Emerald Wind Farm, affected by lower wind speed and system strength constraints (Section 1.6.3).

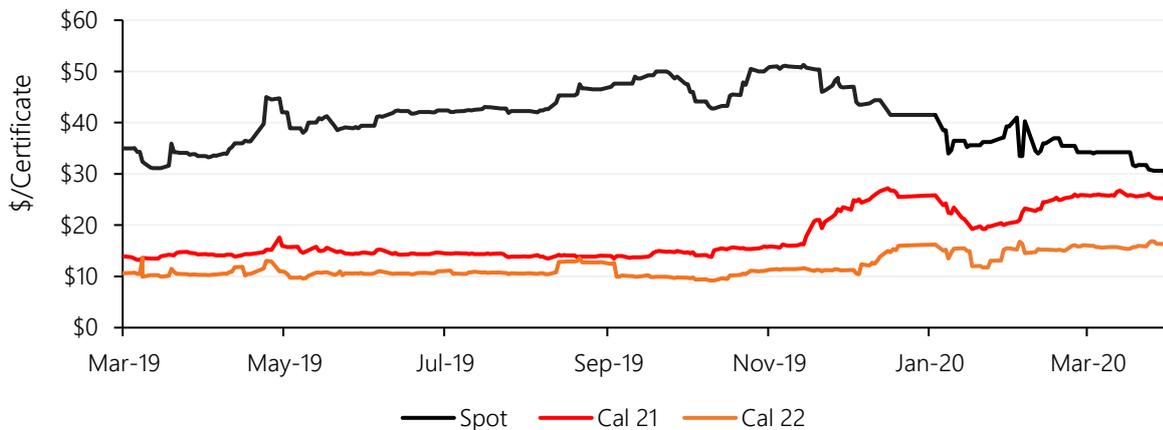
### 1.4.5 Environmental markets

Spot Large-scale Generation Certificates (LGCs) decreased on average by \$11.60/certificate compared to Q4 2019 (Figure 22), while Cal21 increased by an average of \$4.25/certificate. The spread between spot and Cal21 narrowed quickly towards the end of the quarter to \$2.63/certificate.

These price movements were due, in part, to the strategies of retailers. In the February 2020 certificate surrender (for 2019 liabilities) there was a record certificate shortfall of 7.7 million certificates<sup>17</sup>, which participants are likely to 'make good' in future years. During Q1 2020, this had the practical effect of easing demand for spot certificates but increasing demand (and price) for certificates in future years.

**Figure 22 LGC spot and Cal 21 gap narrows**

LGC spot and forward price over time



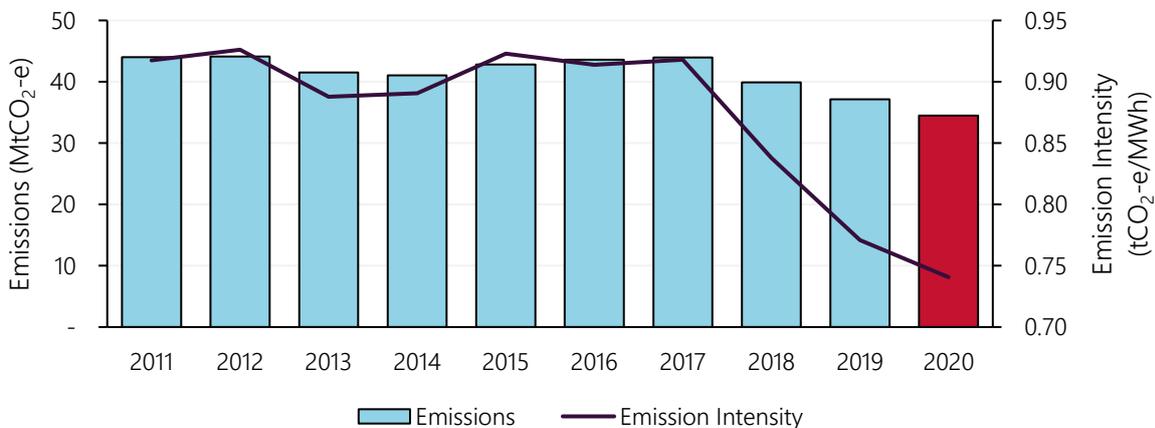
Source: Mercari

### 1.4.6 NEM emissions

NEM emissions reduced to the lowest level on record for a first quarter (Figure 23), and the third-lowest quarter on record overall, falling to 34.5 million tonnes of carbon dioxide equivalent (MtCO<sub>2</sub>-e), while the average emissions intensity fell to 0.74 tCO<sub>2</sub>-e/MWh. Continued increases in both grid-scale renewable projects and rooftop PV, combined with lower demand and coal-fired generation, continued to drive the downward trend.

**Figure 23 Record low first quarter NEM emissions**

Quarterly NEM emissions and emissions intensity (Q1s)



<sup>17</sup> Clean Energy Regulator data. Further details available in the CER's upcoming Quarterly Carbon Market Report.

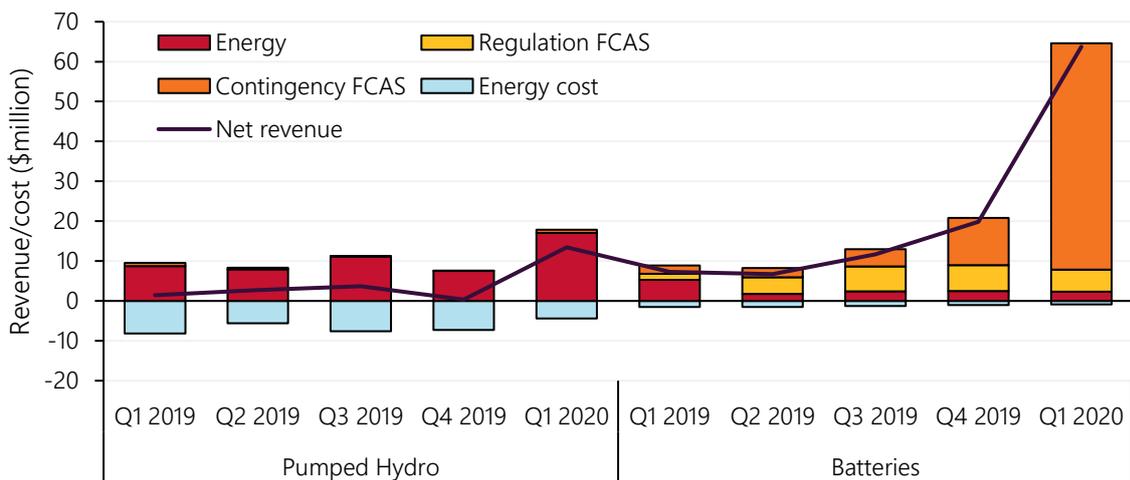
### 1.4.7 Storage

During Q1, NEM batteries and pumped hydro projects increased spot market revenues substantially compared to recent quarters (Figure 24). Compared to Q4 2019, battery net revenue increased by 221% to reach \$64 million, its highest level on record by a significant margin. Pumped hydro net revenue rose from \$0.3 million to \$13 million, driven by increased energy arbitrage value. These results were primarily due to event-related price volatility:

- Grid-scale batteries – during the South Australian separation events, South Australian batteries provided high levels of FCAS and received an estimated \$50 million in spot FCAS revenue<sup>18</sup>.
  - Grid-scale battery energy arbitrage revenue remained steady at \$2.4 million, with 67% of this occurring on two days with high spot price volatility (30 and 31 January).
- Pumped hydro – on 31 January, New South Wales recorded its highest daily cap returns since NEM start (see Section 1.3.1). Shoalhaven Pumped Hydro generated at high levels for the entire price spike, earning \$8.1 million in pool revenue for the day (Figure 25). This comprised 47% of total pumped hydro spot revenue for the quarter.

**Figure 24 Storage revenue increases substantially in Q1 2020**

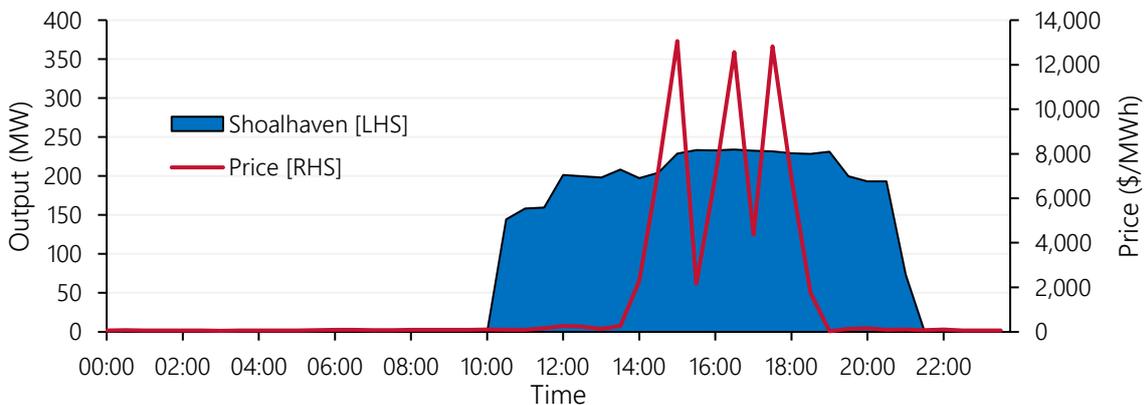
Revenue sources by storage technology



Note: 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.

**Figure 25 Shoalhaven generated at high levels during an extended price spike (New South Wales)**

Shoalhaven pumped hydro output on 31 January 2020



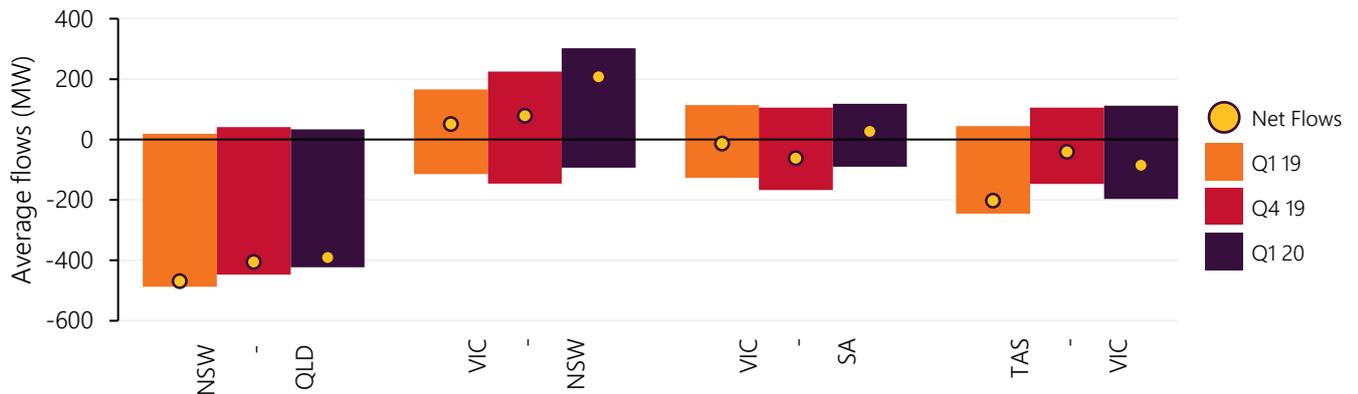
<sup>18</sup> Based on enabled levels and dispatch interval pricing.

## 1.5 Inter-regional transfers

In Q1 2020, there was a slight increase in NEM inter-regional transfers (+51 MW on average) compared to Q1 2019, with increases on the Victoria – New South Wales and Tasmania – Victoria interconnectors partially offset by decreases on the New South Wales – Queensland and Victoria – South Australia interconnectors (Figure 26). Power line outages affecting the Heywood Interconnector, low operational demand, and generator outages were the main drivers for changes in inter-regional transfers over the quarter. This quarter, Victoria was a net exporter to all three neighbouring regions for the first time since Hazelwood Power Station closed (in Q1 2017).

**Figure 26 Victoria was the net exporter for all three neighbouring regions this quarter**

Quarterly inter-regional transfers



By regional interconnector:

- Victoria to South Australia** – unplanned transmission outages affecting transfers on the Heywood Interconnector were the key drivers of the 33 MW reduction in average transfers between Victoria and South Australia compared to Q1 2019. These outages, coupled with lower operational demand in Victoria, contributed to a 40 MW swing in average transfers, resulting in Victoria being a net exporter to South Australia.
  - On 31 January, an unplanned transmission outage caused by a severe storm resulted in the disconnection of the South Australian region, Alcoa Portland aluminium smelter, and Mortlake Power Station from the rest of the NEM power system for 18 days (see Section 1.6 for further details). The outage limited export from South Australia during periods of excess generation (which typically occur during windy daytime conditions).
- Victoria to New South Wales** – compared to Q1 2019, total transfers between Victoria and New South Wales increased by 41%, driven by increased local generation and reduced operational demand in Victoria, as well as high number of coal-fired unit outages in New South Wales in February and March.
- Tasmania to Victoria** – total transfers between Tasmania and Victoria increased compared to recent quarters. Despite increased output from hydro generators, Tasmania remained a net importer this quarter (84 MW), predominantly importing overnight and during the day when Victorian pool prices were lower while exporting during the evening peak when Victoria prices were high.
- New South Wales to Queensland** – transfers continued to occur mostly in a southerly direction on the New South Wales and Queensland interconnectors. The magnitude of transfers was partially offset by lower operational demand in New South Wales and increased imports from Victoria, and transfers reduced by 10% compared to Q1 2019. In addition, the price spread between the two states increased from \$12/MWh in Q1 2019 to \$32/MWh, coinciding with a slight increase in occurrence of the Queensland – New South Wales Interconnector (QNI) binding at its limits (+57%), and increased price volatility in New South Wales.

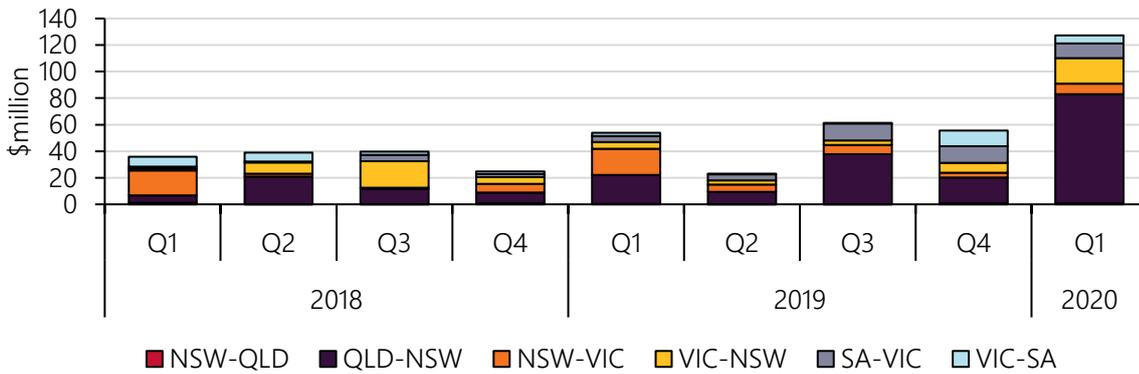
### 1.5.1 Inter-regional settlement residue

Total inter-regional settlement residue<sup>19</sup> (IRSR) increased to \$127 million, the third highest quarter on record, and highest since Q1 2017 (Figure 27). The main driver of this result was an increased value for transfers into New South Wales, which accounted for 80% of total Q1 2020 IRSR value. Compared to Q1 2019, the \$73.2 million increase was a function of:

- Extreme price volatility in New South Wales on 4 January and 31 January, which contributed around \$72 million in IRSR value for Queensland to New South Wales flows. During high price periods<sup>20</sup> in New South Wales on these days, Queensland to New South Wales transfers averaged 1,069 MW.
  - Price volatility on 4 January also contributed \$11.5 million in IRSR value for Victoria to New South Wales flows.
- Negative spot prices in South Australia, with negatively priced intervals contributing to 28% of the IRSR value for South Australia to Victoria flows, up from zero in Q1 2019.
- Increased transfers on the Victoria to New South Wales interconnector (see Section 1.5).

**Figure 27 Third highest IRSR value on record**

Quarterly positive IRSR value



Large positive returns occurred for Settlement Residue Auction (SRA) units for flows from Queensland into New South Wales (Figure 28), where the residue per unit was \$68,598, around \$56,000 higher than the average tranche unit clearing price. These positive returns were driven by increased price separation due to extreme volatility in New South Wales on 4 January and 31 January resulting from power system separation events (including due to bushfires), unplanned unit outages, and very high demand.

**Figure 28 Large positive returns for units purchase for exports from Queensland to New South Wales**

SRA tranche analysis – price paid for units versus actual value (Q1 2020)



<sup>19</sup> For further details on IRSR see: AEMO 2018, *Guide to the Settlements Residue Auction*.

<sup>20</sup> Dispatch intervals when New South Wales' spot price exceeds \$1,000/MWh.

## 1.6 Power system management

Total NEM system costs<sup>21</sup> increased to record levels of \$310 million, which is 8% of the energy costs for the quarter – much higher than its typical value of 1-2% (Figure 29). Of these quarterly system costs, approximately \$166 million was recovered from generators, with the remainder (\$144 million) recovered from retailers. The main driver of record system-related costs were three major separation events (mostly the 31 January event, Table 2), which contributed to increased system costs across all four categories and were responsible for approximately 74% of the total system costs for the quarter (Table 3).

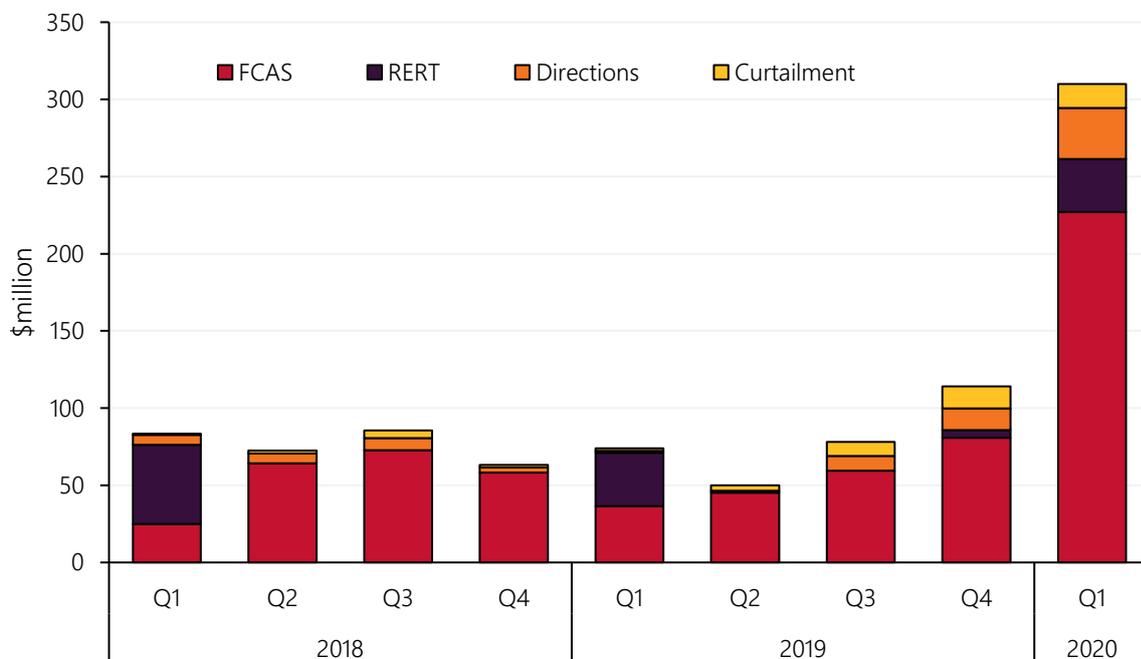
**Table 2 NEM major separation events during Q1 2020**

Date	Regions	Details
4 January 2020	New South Wales and Victoria	Multiple transmission lines in southern New South Wales tripped due to bushfires, resulting in the separation of the NEM into two islands, north and south of this area, for just under seven hours.
31 January 2020	Victoria and South Australia	On 31 January 2020, at approximately 1324 hrs, towers supporting two 500 kilovolt (kV) transmission lines in western Victoria were damaged, resulting in the disconnection of the South Australian region, Alcoa Portland aluminium smelter and Mortlake Power Station from the rest of the NEM power system. These systems were re-connected on 17 February 2020*.
2 March 2020	Victoria and South Australia	A circuit breaker at Heywood Terminal Station tripped, resulting in disconnection of the South Australian region and Mortlake Power Station from the rest of the NEM power system for approximately eight hours.

\* Noting that there was still a credible contingency for separation until the second line was restored in early March, which had some operational impact.

**Figure 29 NEM system costs increase to record levels**

Quarterly system costs by category



<sup>21</sup> In this report, NEM system costs refer to the costs associated with FCAS, directions compensation, RERT, and VRE curtailment.

By component:

- **FCAS** made the highest contribution to system costs, increasing to a record quarterly level of \$227 million. Section 1.6.1 provides details on FCAS costs for the quarter.
- The cost of **directing units** to maintain system security increased to \$33 million, the highest quarter on record. Section 1.6.2 provides details on system security directions for the quarter.
- **Reliability and Emergency Reserve Trader (RERT)** costs were lower than recent first quarters, with quarterly costs of \$34 million. AEMO publishes separate quarterly reports with details on RERT costs<sup>22</sup>.
- Estimated **VRE curtailment** costs<sup>23</sup> increased to record quarterly levels of \$15 million. Section 1.6.3 provides details on VRE curtailment for the quarter.

**Table 3 NEM separation events contribution to system costs**

Category	Q1 2020 cost (\$m)	Separation events' cost contribution (\$m)	Separation events' cost contribution (%)
FCAS	227	175	77%
RERT*	34	27	78%
Directions	33	22	65%
Curtailment	15	6	37%
<b>Total</b>	<b>310</b>	<b>229</b>	<b>74%</b>

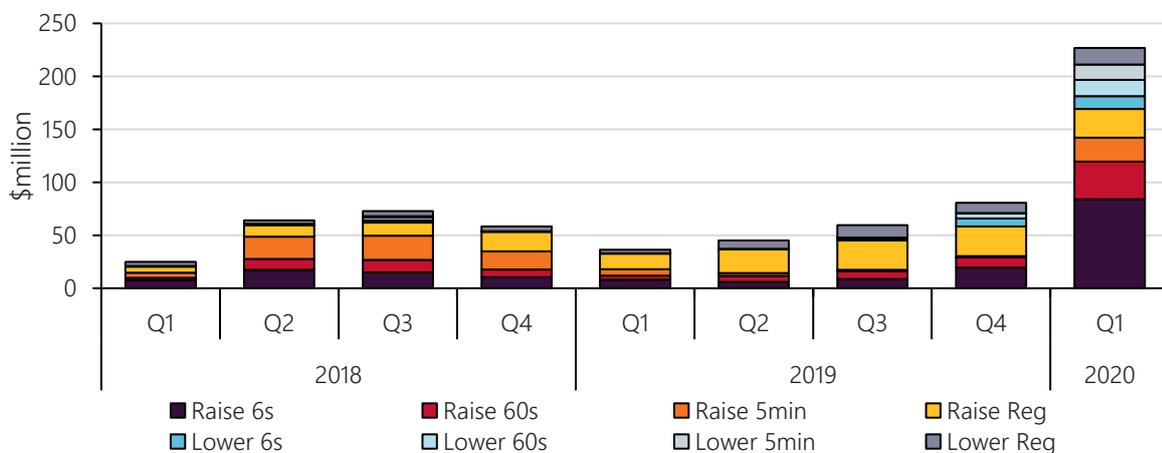
\* The separation events were not the only drivers, but were contributors, to the actual LOR2 conditions which necessitated RERT utilisation.

### 1.6.1 Frequency control ancillary services

In Q1 2020, NEM quarterly FCAS<sup>24</sup> costs increased to record levels of \$227 million (Figure 30), largely due to the extended separation of the South Australian and Victorian power systems. Of these costs, \$166 million was recovered from generators, with the remainder (\$61 million) recovered from retailers. The largest increase in costs by category occurred in the Contingency Raise FCAS markets, which increased from \$30 million in Q4 2019 to \$142 million in Q1 2020.

**Figure 30 FCAS costs reach record levels**

Quarterly FCAS costs by market



<sup>22</sup> Quarterly RERT reports can be found at <https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting>.

<sup>23</sup> Excludes economic curtailment. The cost of curtailed VRE output estimated to be \$40/MWh of output curtailed.

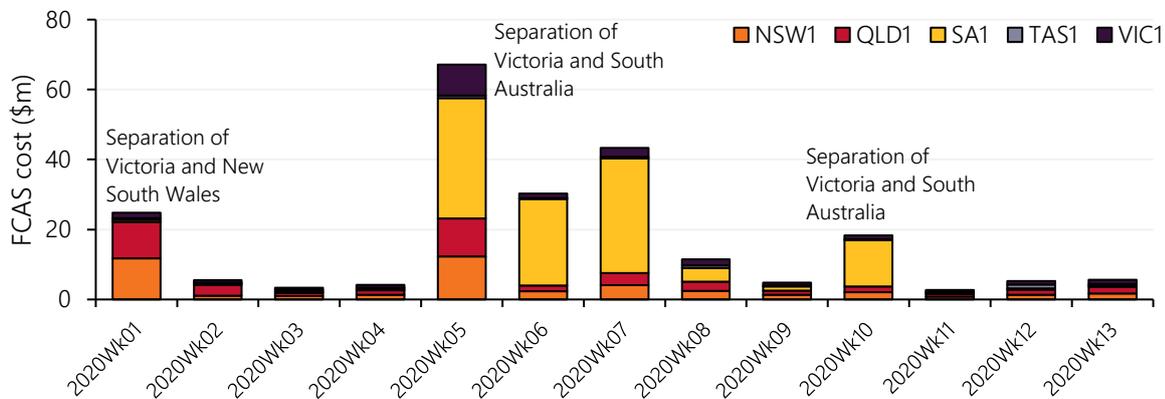
<sup>24</sup> Background on FCAS markets available at <https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf>.

The three major separation events (Section 1.6) were the key drivers of high Q1 2020 FCAS prices and costs, contributing to \$175 million, or 77%, of total FCAS costs for the quarter (Figure 31). Power system separation events often result in FCAS prices spiking to extremely high levels, due to:

- Increased FCAS demand – due to FCAS requirements needing to be set on a local regional basis, rather than the typical NEM-wide basis.
  - For example, during the 18-day separation of the South Australian power system from the rest of the NEM, the average amount of Lower 5 Minute FCAS enabled in the region increased by 98%, and the average amount of Raise 6 Second FCAS enabled increased by 10%. This increased local demand was mostly met by increased supply from GPGs.
- FCAS demand can only be provided by local supply, which can lead to a tight supply/demand balance and/or increased market concentration.

**Figure 31 Separation events drive high FCAS costs**

Weekly FCAS costs by NEM region – Q1 2020

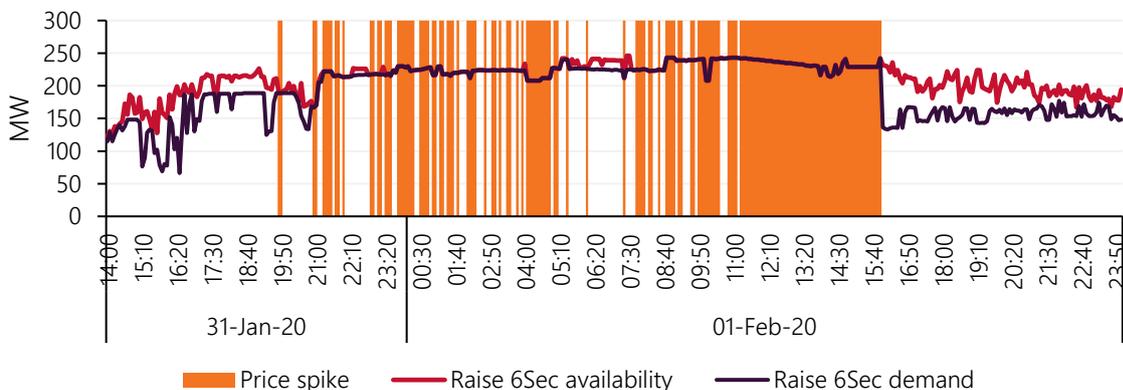


Of note was the extended price spike of the Raise 6 Second FCAS market in South Australia from 31 January to 1 February 2020, hitting the \$14,700/MWh price cap for 365 minutes. This resulted in the Cumulative Price Threshold being exceeded, leading to an Administered Price Period for FCAS markets in the region.

During this high-priced period South Australia, along with Mortlake Power Station and Portland Aluminium Smelter, was separated from the rest of NEM. To manage frequency control in South Australia, FCAS was procured locally from a limited local supply. In addition, South Australia's Contingency Raise requirements at the time were being set by Mortlake Power Station<sup>25</sup>, with these combined factors leading to periods of insufficient Raise 6 Second supply in the region to meet AEMO requirements.

**Figure 32 Raise 6 Second Cumulative Price Threshold exceeded in South Australia**

Raise 6 Second availability and requirement in South Australia – 31 January to 1 February 2020



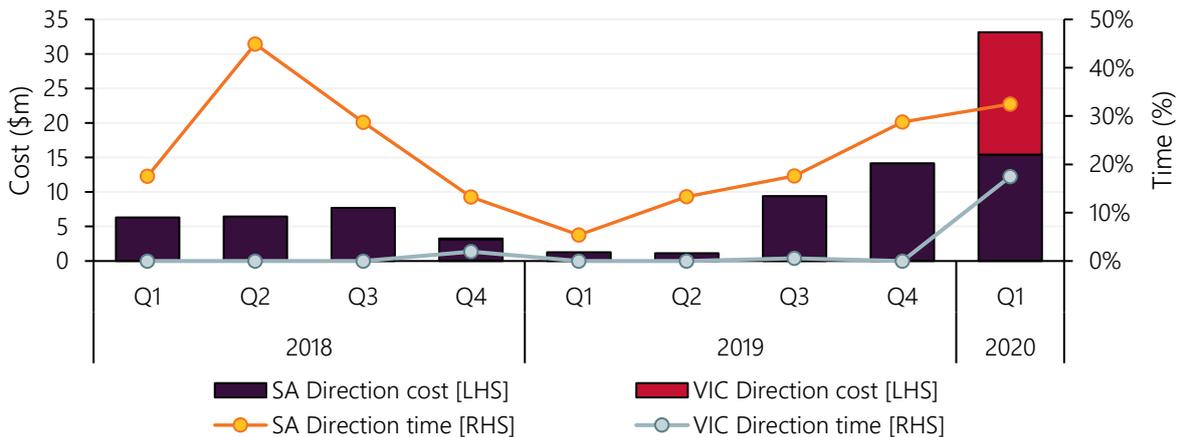
<sup>25</sup> Although Mortlake Power Station is located in Victoria, the separation effectively resulted in it being part of the South Australian power system.

## 1.6.2 Directions

During the quarter, AEMO issued directions to GPGs in South Australia and Victoria to maintain system security, including during the 31 January power system separation event. Total NEM direction costs for energy reached \$33 million, more than doubling the record set in Q4 2019 (Figure 33). Victoria accounted for 53% of total direction costs, while South Australia accounted for the remaining 47%. On average this quarter, 82 MW of GPG was directed in Victoria, and 66 MW in South Australia.

**Figure 33 Victoria drives NEM direction costs to record quarterly levels**

Frequency and cost of system security directions (energy only) in South Australia and Victoria

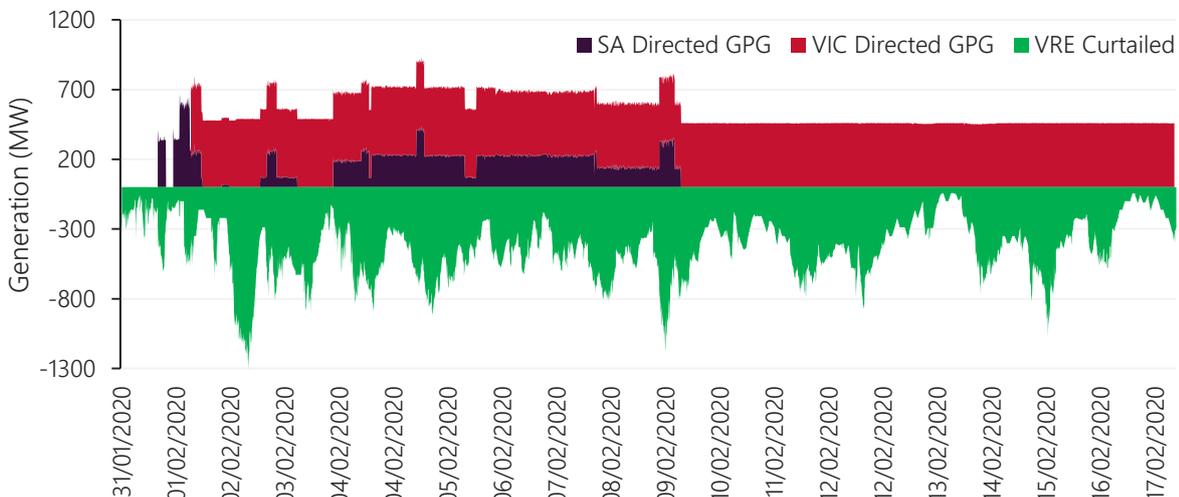


Note: direction costs reported are preliminary estimates which are subject to revision.

The significant increase in direction costs and frequency was largely driven by the separation events that occurred between South Australia and Victoria. Almost all Victoria's time on direction this quarter (18%) was a result of the separation event, while 27% of South Australia's time on direction was during the separation event.

The first separation event that occurred from 31 January to 17 February 2020 resulted in approximately \$21.5 million of direction costs, with costs in Victoria amounting to \$17.7 million. During this event, multiple GPG units in South Australia and Mortlake Power Station in Victoria were directed to remain in the market to ensure system security was maintained, and output was curtailed at several South Australian and Victorian wind farms (Figure 34). During the separation event, an average 435 MW of GPG was directed in Victoria and 87 MW in South Australia, while 432 MW of VRE output was curtailed.

**Figure 34 High levels of GPG directions and VRE curtailment during South Australia – Victoria separation event (31 January – 17 February 2020)**



In addition to the separation events, the combination of reduced daytime operational demand and spot prices in South Australia compared to Q1 2019 continued to drive South Australian GPG to de-commit from the market based on economic reasons. In order to maintain system strength in the state, these units were then subsequently directed to remain online.

### 1.6.3 VRE curtailment

During Q1 2020, NEM-wide VRE curtailment<sup>26</sup> increased to 7% of total VRE output, the highest amount on record (Figure 35).

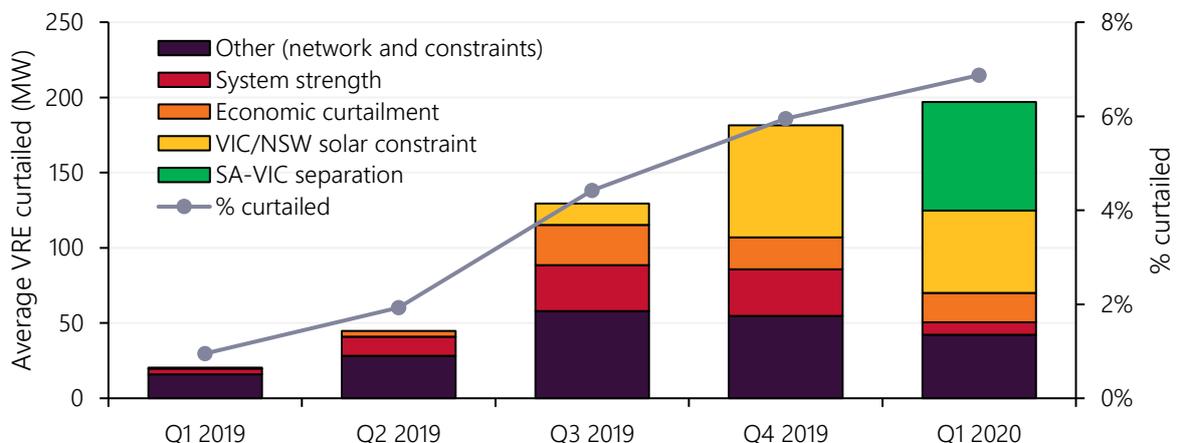
The key driver of the increased curtailment was separation of South Australia from the rest of the NEM (Section 1.6). During the 18-day separation, output at six wind farms was curtailed to zero for system security purposes. The event contributed an estimated average curtailment of 72 MW (on a quarterly basis) and was the main driver of increased curtailment in Q1 2020 compared to the previous quarter<sup>27</sup>.

Most other factors contributed similar levels of curtailment to Q4 2019, which is still higher than historical outcomes. The one exception was the South Australian system strength constraint, which curtailed 8 MW of wind output on average compared to 31 MW in Q4 2019. This was due to a 40% reduction in high wind output periods<sup>28</sup> compared to Q4 2019.

The system security constraint on five solar farms (four in Victoria, one in New South Wales) remained in place for the entire quarter, but its impact reduced by 27% compared to Q4 2019 due to a 6% reduction in solar irradiation.

**Figure 35 South Australian separation leads to record NEM VRE curtailment**

Average NEM VRE curtailed by curtailment type



Note: curtailment amount based on combination of market data and AEMO estimates.

There were also two other new drivers of curtailment:

- **Queensland system strength arrangements (system security constraints)** – in March 2020, Powerlink, with assistance from AEMO, developed and announced new system strength limits in North Queensland. These limits involve constraining the output of three generators in North Queensland (Mount Emerald Wind Farm, Houghton Solar Farm, and Sun Metals Solar Farm) to maintain power system security, depending on the synchronous units online in Queensland at the time<sup>29</sup>. From 19–31 March, these

<sup>26</sup> For detailed curtailment definitions, see AEMO’s Renewable Integration Study Stage 1 Report (upcoming publication) at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/future-grid/renewable-integration-study>.

<sup>27</sup> Curtailed wind farms included Canunda, Lake Bonney 1-3, Macarthur, and Portland.

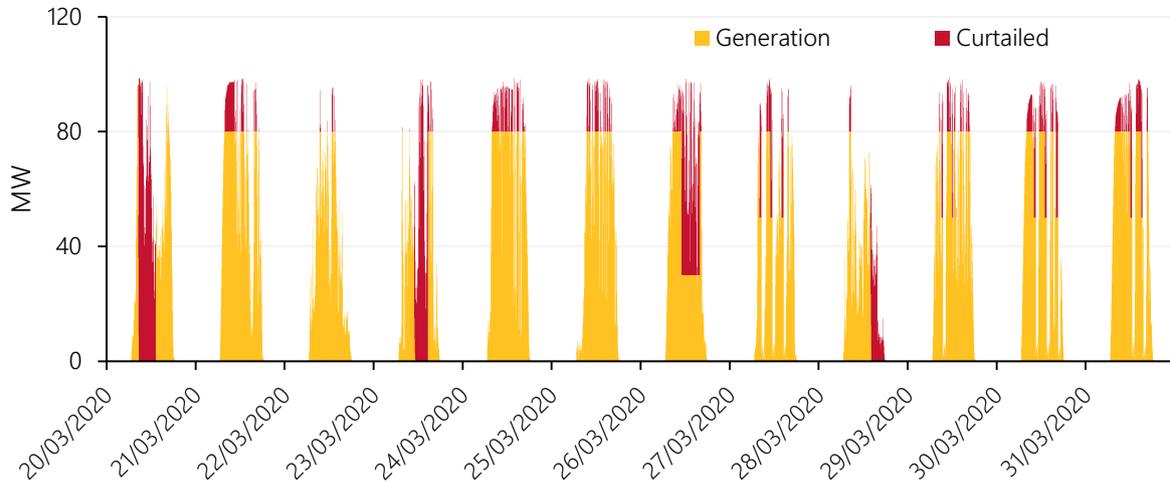
<sup>28</sup> “High wind periods” refers to dispatch intervals when South Australian wind output exceeds 1,150 MW.

<sup>29</sup> For further details, see Market Notice 74987.

constraints limited output 25% of the time, with curtailment reducing output at Houghton Solar Farm by an estimated 18% (Figure 36), and at Mount Emerald Wind Farm by 7%<sup>30</sup>.

**Figure 36 System strength curtailment begins in Queensland**

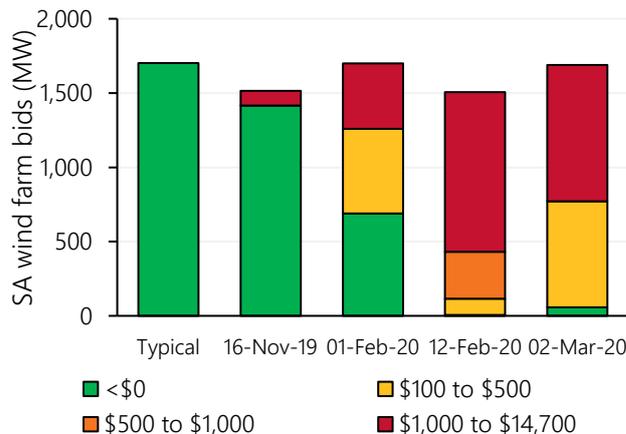
Houghton Solar Farm estimated curtailment – 20-31 March 2020



- VRE response to high FCAS prices (economic curtailment)** – during the South Australia separation events, FCAS prices frequently spiked to very high levels (Section 1.6.1). This led to South Australian wind farms progressively adjusting behaviour to mitigate FCAS liabilities<sup>31</sup> as their experience with these events increased. Semi-scheduled wind farms removed themselves from the market by raising the price of their energy bids and subsequently not being dispatched (Figure 37).
  - An example of this behaviour was on 12 February 2020, when the South Australian Raise 60 Second FCAS price spiked to \$14,500/MWh for two hours. This led to 11 of 14 online South Australian wind farms self-curtailing output due to high FCAS liabilities, which resulted in a sudden and unforecast reduction in wind output (Figure 38).

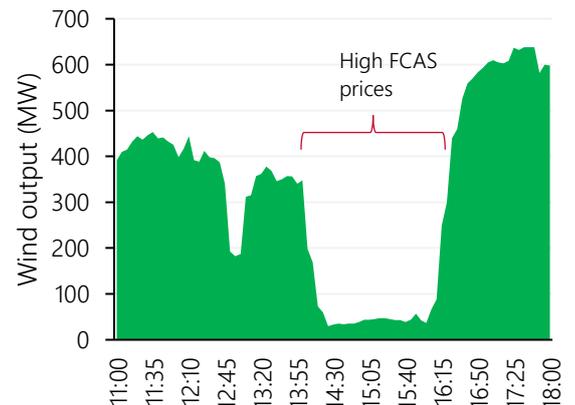
**Figure 37 South Australian wind farms respond to high FCAS prices**

South Australian wind farm bids on days with high FCAS prices



**Figure 38 SA wind farms reduce output due to avoid high FCAS exposure**

12 February 2020 example



<sup>30</sup> Includes all curtailment of these generators during the period, not limited to system strength curtailment.

<sup>31</sup> Under the FCAS market framework, Contingency Raise FCAS costs are pro-rated over market generators based on their energy generation in the trading interval, so in the rare circumstances where Contingency Raise prices are very high and FCAS liabilities exceed energy returns, generators can have an incentive to switch off to avoid losses.

# 2. Gas market dynamics

## 2.1 Gas demand

Total east coast gas demand for Q1 2020 increased slightly compared to Q1 2019 primarily due to higher LNG exports from Curtis Island. Residential, commercial, and industrial demand increased marginally, while GPG demand recorded a notable decrease (Table 4).

**Table 4 Gas demand – quarterly comparison**

Demand (PJ)	Q1 2020	Q4 2019	Q1 2019	Change from Q1 2019
AEMO Markets *	55	67	55	-
GPG **	36	36	44	-7 (17%)
QLD LNG	338	349	329	9 (3%)
<b>TOTAL</b>	<b>429</b>	<b>452</b>	<b>428</b>	<b>2 (0.6%)</b>

Note: some entries in this table may have minor variations to numbers published in QED reports, due to changed accounting of GPGs.

\* 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) and excludes GPG.

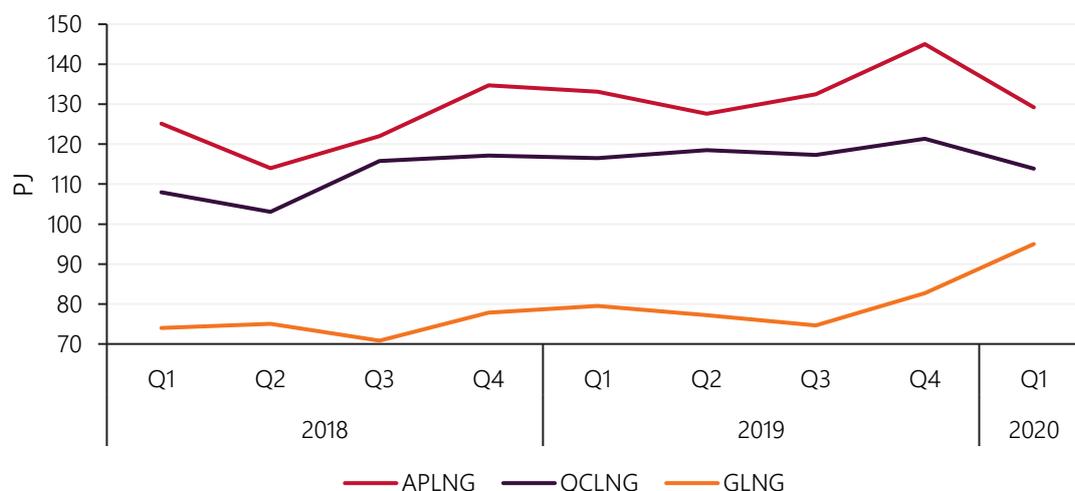
\*\* Includes demand for GPG usually captured as part of total DWGM demand. Excludes Yabulu Power Station.

Total pipeline deliveries of 338 petajoules (PJ) flowed to Curtis Island during Q1 2020, an increase of 8.9 PJ compared to Q1 2019, but a decrease of 10.1 PJ compared to the previous quarter (Figure 39). This is the second highest quarter on record and occurred despite a sharp decline in international oil and gas prices (contracted LNG can be benchmarked against a lagged oil price, Section 2.2.1).

There were 85 LNG cargoes exported during Q1 2020, slightly lower than 87 in Q4 2019. Australia Pacific LNG (APLNG) and Queensland Curtis LNG (QCLNG) both reduced their cargoes, however Gladstone LNG (GLNG) increased from 22 to 27. This is reflected in an increase in GLNG flows to Curtis Island (+12.3 PJ), and a decrease in APLNG flows (-15.8 PJ) and QCLNG flows (-7.5 PJ).

**Figure 39 GLNG ramps up LNG exports**

Total quarterly pipeline flows to Curtis Island



GPG demand decreased by 17% compared to Q1 2019, with reductions across all states and the largest declines occurring in South Australia and Victoria (Section 1.4.2). The main driver for this was lower NEM demand due to milder weather leading to lower cooling requirements.

## 2.2 Wholesale gas prices

Wholesale gas prices continued the downward trend from Q4 2019, falling by an average of 42% compared to Q1 2019 and reaching their lowest levels since Q1 2016 (Figure 40). The largest decreases occurred in at the Brisbane Short-Term Trading Markets (STTM, -45%). This was followed by Sydney STTM (-44%), the Gas Supply Hub (GSH, -42%), the Declared Wholesale Gas Market (DWGM, -41%), and Adelaide STTM (-39%).

**Figure 40 Gas market prices drop to lowest level in four years**

GSH and DWGM quarterly average prices

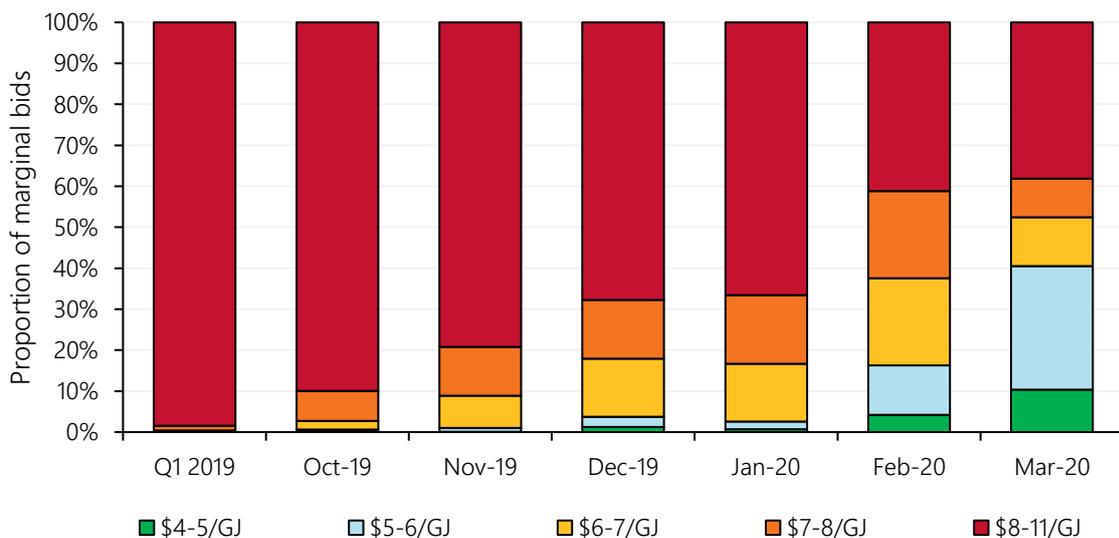


Like Q4 2019, price decreases have continued despite a moderate increase in demand, with the continuation of more gas being offered at lower prices into the markets. In Q1 2020, 50% of bids in the DWGM were priced under \$8/GJ, compared to 1.5% in Q1 2019 (Figure 41). These lower-priced offers continue to coincide with declining international gas prices (Section 2.2.1), lower NEM spot and contract prices (Section 1.3.1) and increased Queensland gas production (Section 2.3.1).

There was also a continuation in competition in bids from Longford producers – during Q1 2020, BHP offered marginally priced gas below \$6/GJ, while Esso offers remained unchanged at \$9.50-\$10/GJ.

**Figure 41 Structural shift in gas market bids continues**

DWGM – proportion of marginal bids by price band

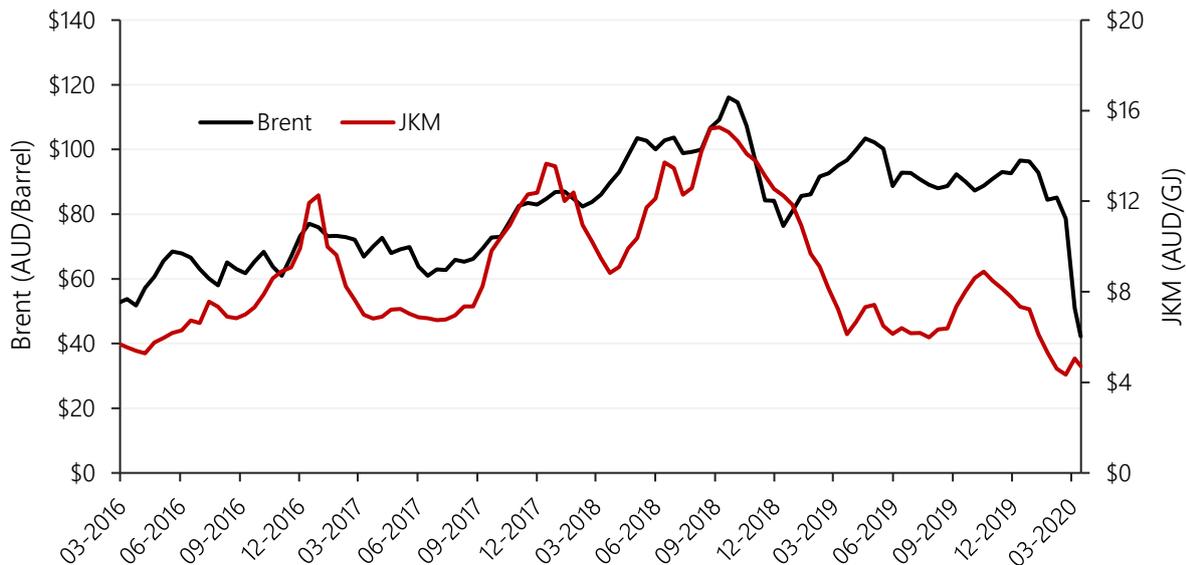


## 2.2.1 International gas and oil prices

Brent Crude oil prices decreased sharply from A\$94/barrel at the end of 2019 to A\$37/barrel towards the end of Q1 2020 (Figure 42), levels not seen since 2003. The first major decline occurred in early March, as OPEC and Russia failed to reach an agreement to extend production cuts, and instead engaged in a price war. This was followed by the global COVID-19 lockdown, which significantly reduced oil demand.

**Figure 42 Brent Crude and JKM LNG prices decrease sharply**

Brent Crude oil and JKM LNG prices in Australian dollars

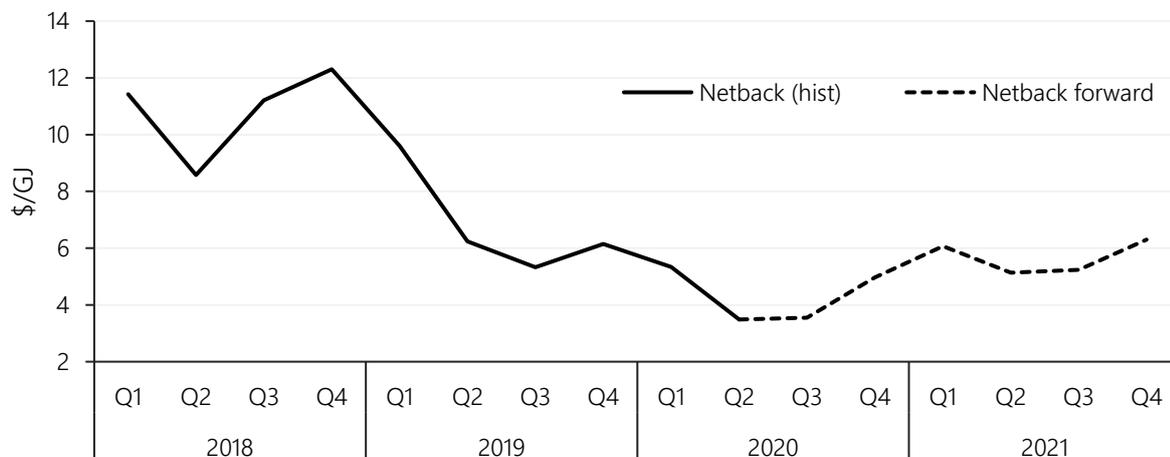


Source: Bloomberg data in 14 day averages.

JKM LNG prices decreased from A\$7.12/GJ at the end of 2019 to reach A\$4.44/GJ by the end of March 2020, due to a combination of an already oversupplied market and the escalating impact of COVID-19 on global demand. These price declines were somewhat softened by the coinciding fall in the Australian dollar. Lower Asian gas prices were also reflected in the ACCC's latest netback price, which remains below \$6/GJ until the end of 2021 (Figure 43).

**Figure 43 The ACCC netback price continues at low levels**

ACCC netback price historical and forward



Source: ACCC 2020, LNG netback series: <https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series>.

## 2.3 Gas supply

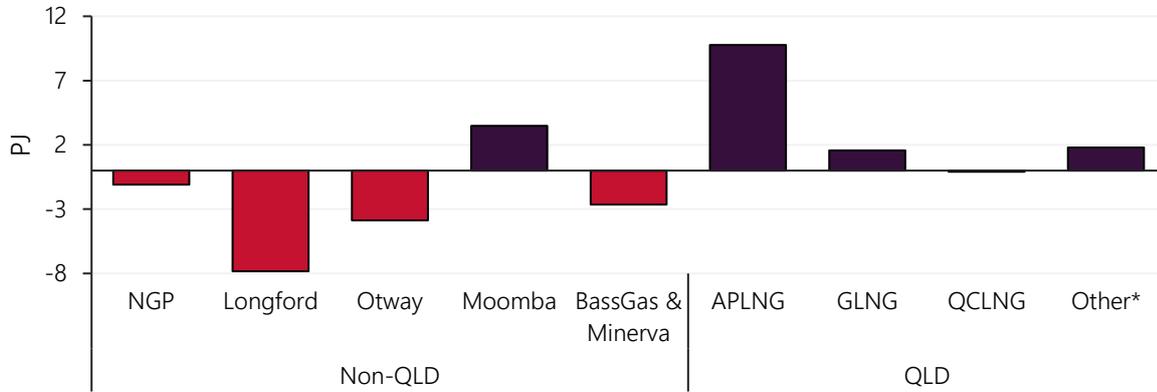
### 2.3.1 Gas production

Q1 2020 east coast gas production marginally increased by 0.4% compared to Q1 2019, but decreased compared to Q4 2019 due to lower domestic demand (Figure 44). Production changes compared to Q1 2019 included:

- Higher Queensland production (+13.1 PJ), which mostly came from existing APLNG-owned gas facilities.
- Higher Moomba production (+3.5 PJ).
- Reduced Victorian production from Longford (-7.8 PJ), Bass Gas and Minerva (-2.6 PJ). Of note, Longford quarterly production of 45.2 PJ was its lowest since Q1 2015.

**Figure 44 Queensland gas supply increases**

Change in east coast gas supply – Q1 2020 versus Q1 2019

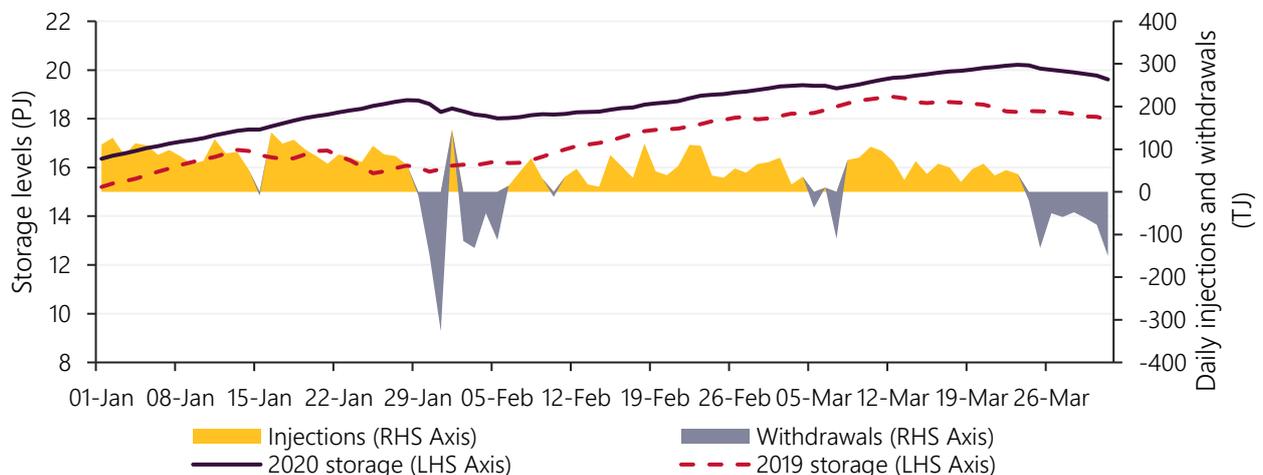


### 2.3.2 Gas storage

A gas balance of 19.5 PJ was recorded at the Iona Underground Storage Facility in Victoria at 31 March 2020, 1.6 PJ higher than at the end of Q1 2019 (Figure 45). Iona refilled on most days; however, withdrawals occurred in late January and early February to meet GPG demand resulting from the major separation of the South Australian and Victorian power systems (Section 1.6.2). Storage levels also depleted daily in the last week of March, but remained higher than the corresponding period in 2019.

**Figure 45 Iona Q1 2020 storage levels above 2019 levels**

Iona storage levels



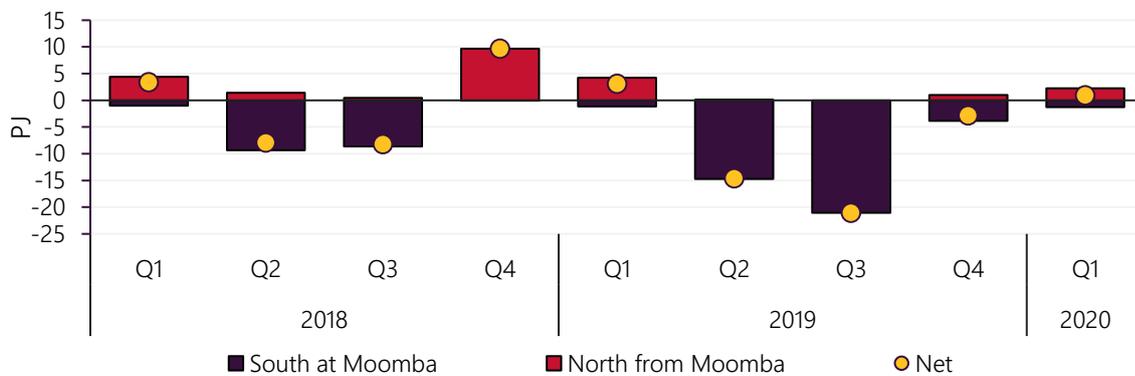
## 2.4 Pipeline flows

Compared to Q1 2019, there was a 2.1 PJ reduction on net transfers north on the South West Queensland Pipeline (SWQP) (Figure 46). This is the lowest Q1 volume since Q1 2015, when net flows were southwards to Moomba, at a time when the Queensland LNG projects were in the commissioning phase and resulted in excess gas flowing into the domestic market. Since their completion, every Q1 has seen a net flow north on SWQP. Reasons for the reduction in Q1 2020 flows include:

- Little requirement for flows south over the low demand Q1 period, particularly with GPG reductions.
- Increased Queensland production.
- Increased Moomba production (3.5 PJ). This coincided with an increase on flows on the Carpentaria Gas Pipeline (CGP) to the Mount Isa region (2.5 PJ). As a result, Northern Gas Pipeline (NGP) flows from the Northern Territory decreased.

**Figure 46 South West Queensland Pipeline transfers reduce to lowest level since Q1 2015**

Flows on the South West Queensland Pipeline at Moomba

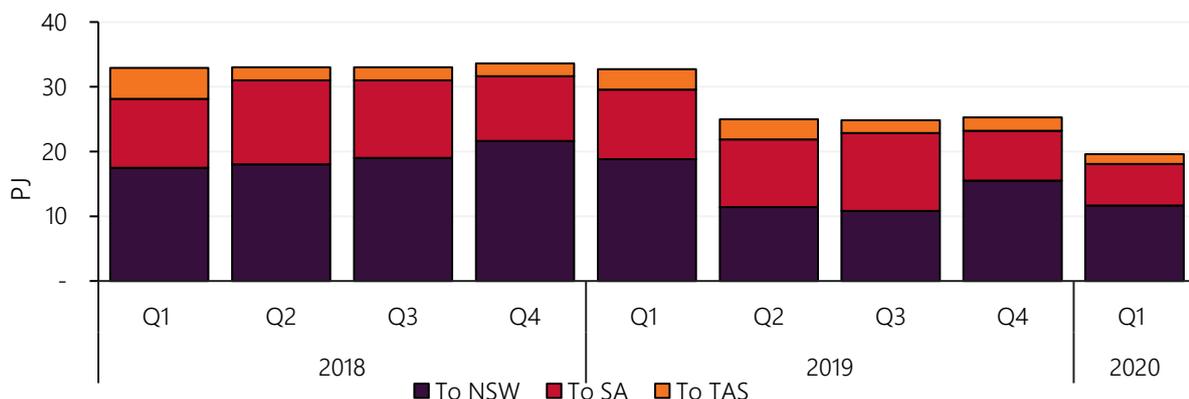


Victorian net gas exports in Q1 2020 reduced by 13.1 PJ compared to Q1 2019 (Figure 47), due to lower southern GPG demand, and a sharp decrease in Victorian production. Compared to Q1 2019 there was decreased flow from:

- Victoria to New South Wales – Victoria exported a net 1 PJ via Culcain, compared to a net export to New South Wales via Culcain of 3.6 PJ in Q1 2019. Exports to New South Wales via the Eastern Gas Pipeline (EGP) decreased by 4.5 PJ.
- Victoria to South Australia, by 4.4 PJ.
- Victoria to Tasmania, by 1.6 PJ.

**Figure 47 Reduced Victorian gas exports in Q1 2020**

Victorian net gas exports to other states

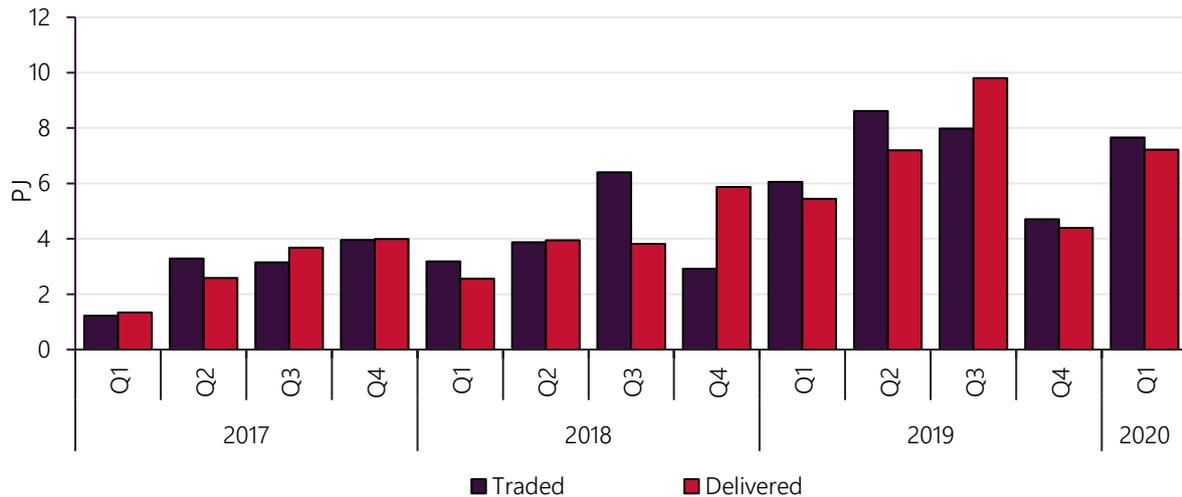


## 2.5 Gas Supply Hub

In Q1 2020, the GSH experienced an increase in trading volumes for both traded and delivered volume compared to Q4 2019 and Q1 2019 (Figure 48). Compared to Q1 2019, traded volume increased by 1.6 PJ (+26%), and delivered volume increased by 1.8 PJ (+33%). These traded and delivered volumes represent record levels for a first quarter.

**Figure 48 GSH trades remain at comparatively high levels**

Gas Supply Hub – quarterly trades and deliveries



## 2.6 Pipeline Capacity Trading and Day Ahead Auction

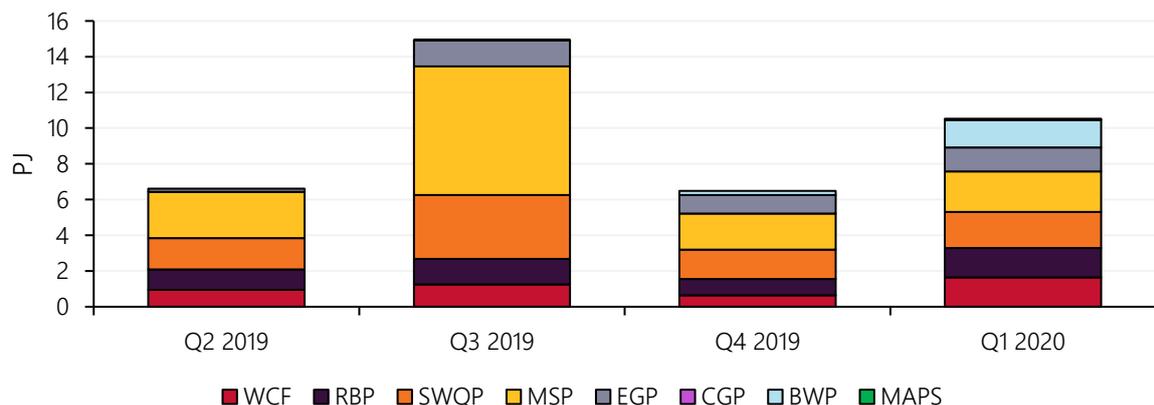
Compared to Q4 2019, there was a large increase in day ahead auction (DAA) utilisation (Figure 49). All pipelines saw an increase, with the emergence of significant volumes on the Berwyndale to Wallumbilla Pipeline (BWP) (+1.3 PJ), and the first use of the Moomba to Adelaide Pipeline System (MAPS) in March.

Average auction clearing prices ranged from \$0/GJ on the BWP, EGP, MAPS, Moomba to Sydney Pipeline (MSP), SWQP, and Wallumbilla Compressor Facility (WCF), and \$0.08/GJ on the Roma to Brisbane Pipeline (RBP). The higher RBP price can be attributed to higher competition for capacity on that pipeline, compared to the amount of spare capacity.

There was one recorded capacity trade on the capacity trading platform (CTP), for 1 terajoule (TJ) on 3 February. This is the first capacity trade executed.

**Figure 49 Day ahead auction trading increases compared to Q4 2019**

Day Ahead Auction Results by quarter

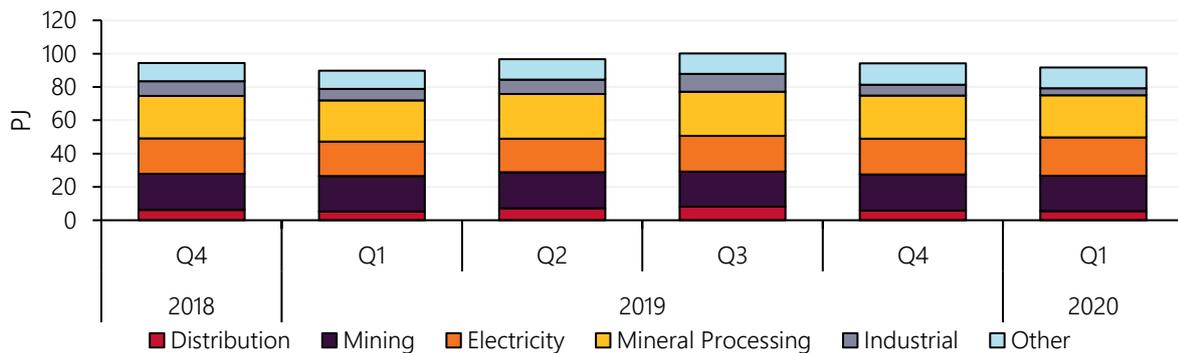


## 2.7 Gas – Western Australia

In Q1 2020, total Western Australian gas consumption was 91.7 PJ, representing a 3% reduction on Q4 2019 levels (Figure 50). This reflects lower consumption by both Large Users (-1.8 PJ) and other users (-0.4 PJ), and reduced flow into the distribution network (-0.3 PJ). Among Large Users, there was reduced consumption by Mining (-1%) and Mineral Processing (-2%) and Industrial consumers (-37%), but an increase in consumption by GPG for electricity generation (+6%). The decrease in consumption by Industrial users was primarily associated with Yara Fertilisers Pilbara plant, which was shut down in November for unplanned maintenance<sup>32</sup>, remained shut down until early January, and slowly increased consumption through Q1 2020.

**Figure 50 Western Australia gas consumption down 3% compared to Q4 2019**

Western Australia quarterly gas consumption by industry

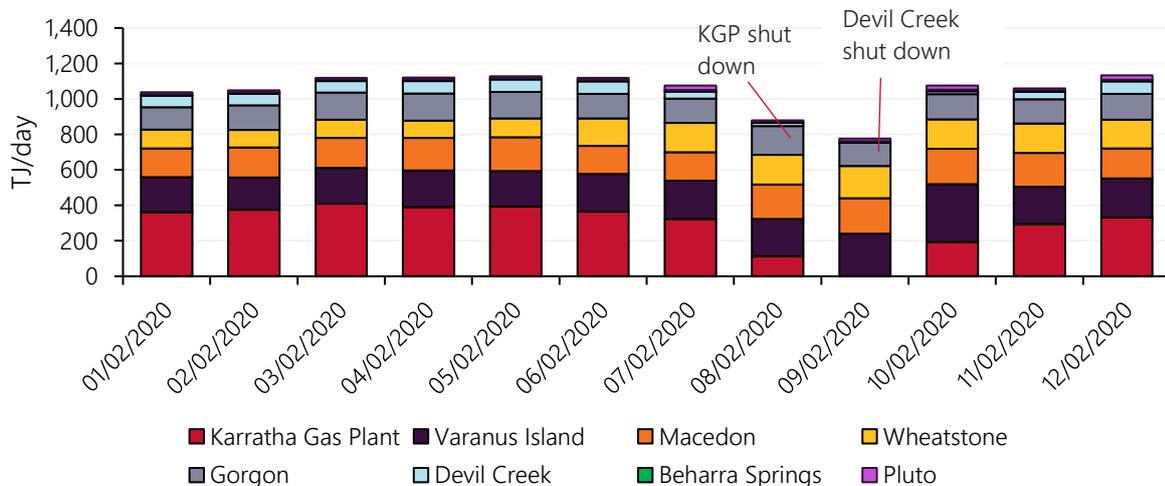


With reduced demand, there was a corresponding reduction in gas production. A total of 100 PJ was produced in Q1 2020, down 4% compared to Q4 2019 (Figure 52).

Gas production was impacted by Tropical Cyclone Damien. The cyclone made landfall directly over Karratha as a Category 3 Cyclone on 8 February, subjecting the Karratha and Dampier region to extreme wind and rain<sup>33</sup>. This resulted in the Karratha Gas Plant (KGP) and Devil Creek briefly shutting down production, leading to three amber LCAs in the following days (Figure 51). An Amber LCA is advised by the pipeline operators and indicates the likely curtailment of interruptible gas flows.

**Figure 51 Cyclone Damien causes shutdown of Gas Production Facilities**

Western Australian daily gas production



<sup>32</sup> Pilbara News 2019, Rupture shuts down Yara plant: <https://www.pilbaranews.com.au/news/pilbara-news/rupture-shuts-down-yara-plant-ng-b881394640z>.

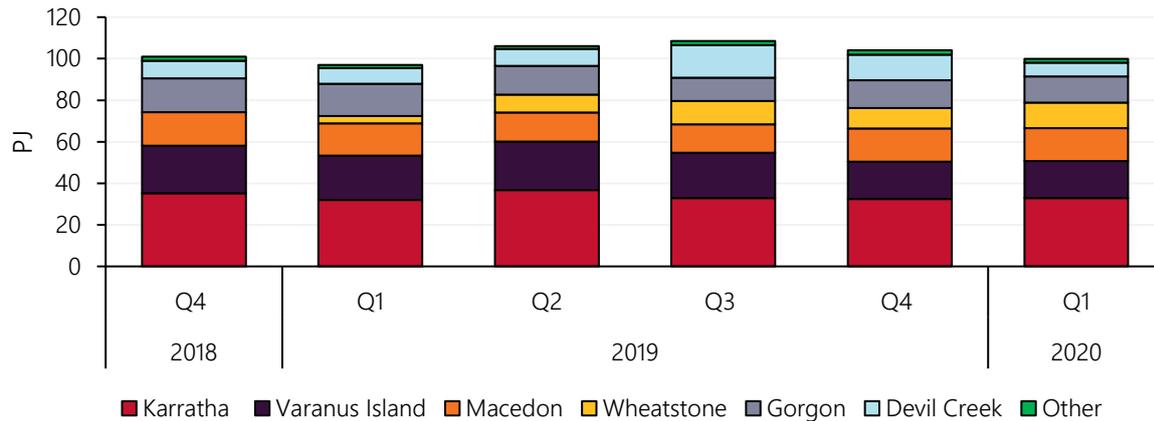
<sup>33</sup> Bureau of Meteorology 2020, Severe Tropical Cyclone Damien: <http://www.bom.gov.au/cyclone/history/damien-2020.shtml>.

The Xyris Production Facility was closed in December 2019 for maintenance and expansion<sup>34</sup> and did not produce gas during Q1 2020, accounting for a 0.2 PJ decrease. The facility is expected to come back online in Q3 2020 with increased capacity and a new connection to the Dampier to Bunbury Natural Gas Pipeline<sup>35</sup>. Devil Creek was the main contributor to the drop, with a reduction of 5.6 PJ, which was partly offset by Wheatstone which increased production (+2.6 PJ).

The amount of gas transferred to storage facilities (Tubridgi and Mondarra) was 7.0 PJ, down 1.9 PJ compared to Q4 2019 levels.

**Figure 52 Western Australia gas production down 4% compared to Q4 2019**

Western Australia quarterly gas production by production facility



Note: "Other" includes Beharra Springs, Pluto, and Xyris Production Facility.

Q1 2020 saw a significant increase in the number of Amber and Red LCAs advised by pipeline operators. An Amber LCA indicates likely curtailment of interruptible flows, while a Red LCA indicates likely curtailment of firm flows. Over the five years prior to Q1 2020 there have been a total of 19 Amber LCAs and 1 Red LCAs. In Q1 2020 alone there were 35 Amber LCAs and 2 Red LCAs. Causes of these LCAs included planned maintenance, unplanned maintenance, and the impact of Severe Tropical Cyclone Damien.

<sup>34</sup> Mitsui E&P Australia 2019, Waitsia Stage 1 Expansion site works set to commence end of December 2019: <https://mitsuiepmidwest.com.au/waitsia-stage-1-expansion-site-works-set-to-commence-end-of-december-2019/>.

<sup>35</sup> Mitsui E&P Australia, Stage 1 Expansion: <https://mitsuiepmidwest.com.au/what-we-do/production/stage-1-expansion/>.

# 3. WEM market dynamics

## 3.1 Electricity demand and weather

Perth temperatures in Q1 2020 were slightly cooler than average, with a quarterly average maximum of 30.8°C (0.4°C cooler than the 10-year Q1 average). This was 0.2°C warmer than Q1 2019. Other weather-related highlights included:

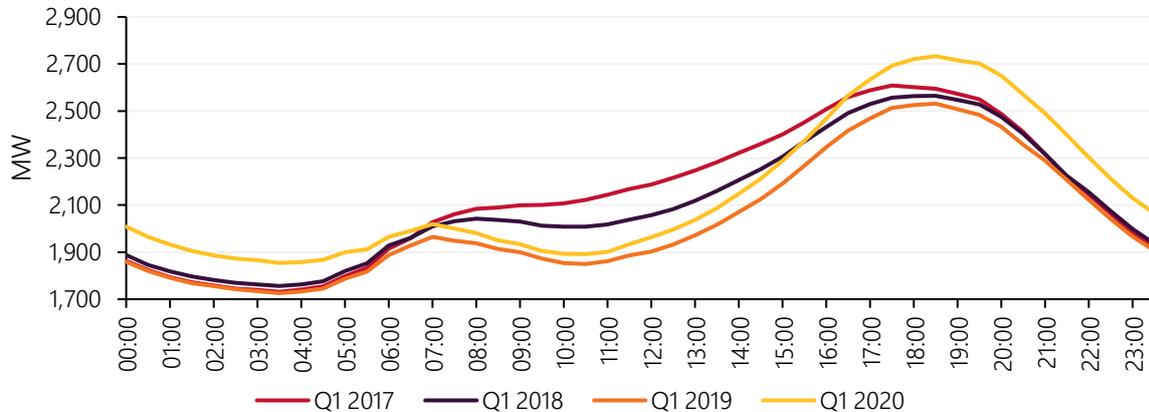
- The February mean maximum was 1.2°C warmer than the 10-year average.
- The February month high of 42.7°C was Perth’s hottest February day since 1997<sup>36</sup>.
- February and March experienced warm nights, with the monthly mean minimum for February and March being 1.3°C and 0.3°C warmer than the 10-year average, respectively. For February, this was the second highest level on record<sup>36</sup>.

Generally high evening and overnight temperatures resulted in comparatively high off-peak demand. In contrast, peak demand during the day was generally lower than recent first quarters (Figure 53 and Figure 54). This was influenced by lower temperatures and increasing rooftop PV uptake offsetting any increase in underlying demand.

As a result – and despite lower than average mean maximum temperatures – average WEM operational demand in Q1 2020 was 80 MW (3.9%) higher than Q1 2019.

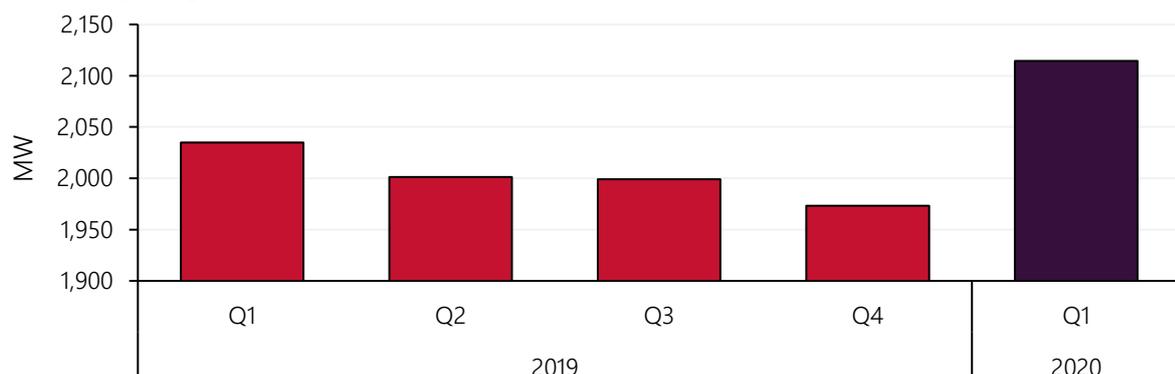
**Figure 53 High overnight temperatures drive high average WEM demand**

WEM Q1 hourly average operational demand by year



**Figure 54 High overnight temperatures drive high average WEM demand**

WEM quarterly average operational demand



<sup>36</sup> Bureau of Meteorology 2020, Greater Perth in February 2020: <http://www.bom.gov.au/climate/current/month/wa/archive/202002.perth.shtml>.

### Maximum and minimum demand

For the second consecutive quarter, a new record minimum demand was set in the WEM<sup>37</sup> (Table 5). Operational demand fell to 1,135 MW for the interval commencing 1100 hrs AWST on Saturday, 4 January 2020, 24 MW lower than the previous record set on 13 October 2019. Rooftop PV output at the time is estimated to be 908 MW, or about 44% of the total underlying demand, so high distributed PV output was the main driver for this event.

The WEM recorded its third highest daily peak demand on record, with operational demand reaching 3,916 MW for the interval commencing 1730 hrs on Tuesday, 4 February. This was primarily driven by very hot conditions in Perth on the day (42.7°C), after a two-day period of hot conditions (over 34°C). The estimate of distributed PV output during the peak was 111 MW, whereas the output in the preceding interval was estimated at 247 MW. This highlights that the system was required to accommodate an additional 136 MW in load due to changes in distributed PV output alone.

**Table 5 WEM maximum and minimum operational demand – Q1 2020 vs previous records**

Maximum demand (MW)			Minimum demand (MW)		
Q1 2020	All-time	All Q1	Q1 2020	All-time	All Q1
3,916	4,006	4,006	1,135	1,135	1,135

### Impact of COVID-19

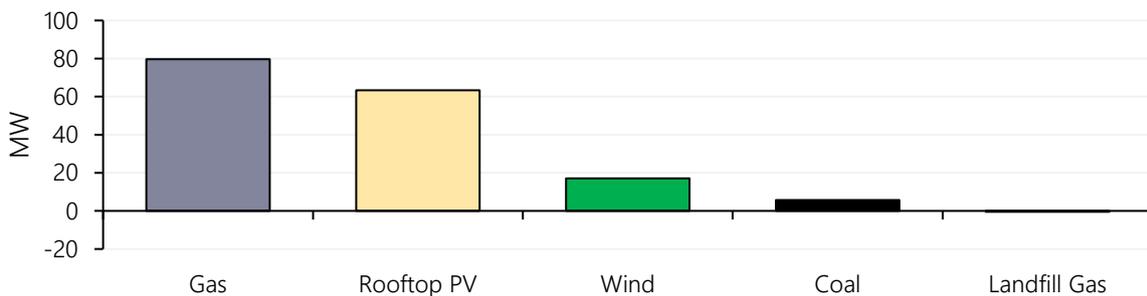
Nationwide restrictions to manage COVID-19 commenced in mid-March, however AEMO has observed no discernible change to operational demand, which remains largely temperature-driven. AEMO will continue to monitor the potential impacts of COVID-19 on the WEM.

## 3.2 Electricity generation

Figure 55 shows the average quarterly change in generation by fuel type compared to Q1 2019; Figure 56 shows the average changes by time of day. These changes highlight the supply mix transformation occurring in the WEM.

**Figure 55 Gas, solar account for majority of supply increase in the WEM**

Average change in WEM supply – Q1 2020 versus Q1 2019



An overall increase in generation compared to Q1 2019 was driven by increased demand as outlined above, with key shifts as follows:

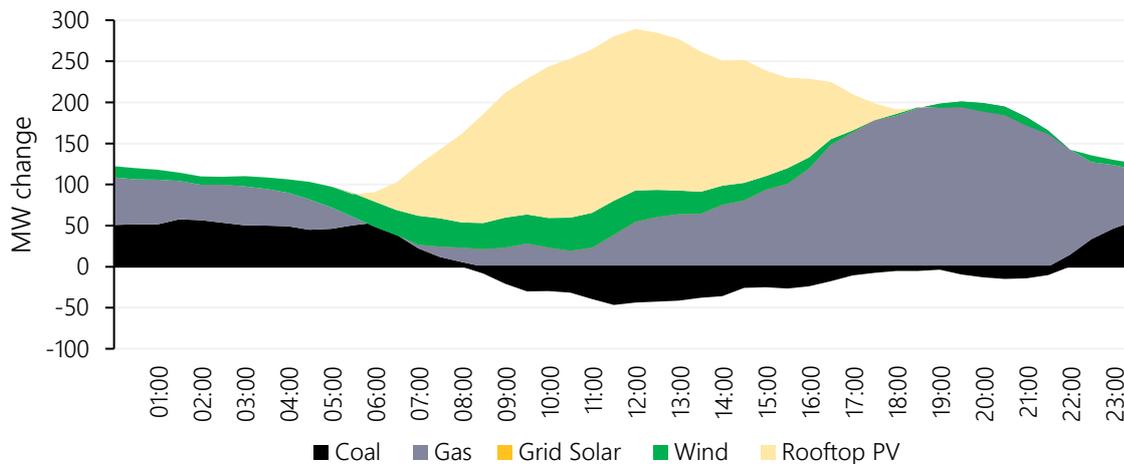
- Average GPG increased by 80 MW, driven by higher average operational demand (200 MW) during the evening peak period (Section 3.1) which was almost entirely met by GPG.

<sup>37</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. 'Operational Demand' is expressed as the average demand over an interval.

- The installed capacity of rooftop PV in the South-west Interconnected System (SWIS) continues to increase. Rooftop PV increased by an estimated 63 MW on average over the quarter, with an estimated maximum interval average output of 974 MW in Q1 2020.
- Total coal-fired generation was steady (<1% change). Some coal-fired generation during the day was displaced by rooftop PV, but there was increased generation through the late evening to early morning to meet increased off peak demand.
- Wind generation increased by 17 MW (7%) on average, predominantly due to increased generation at existing wind farms. The connection of Badgingarra Wind Farm (130 MW) in early Q1 2019 and Beros Road Wind Farm (9.9 MW) during Q3 2019 also contributed to the increase.

**Figure 56 Solar displaces coal during the day; GPG left to meet demand during evening peak**

Change in WEM supply by time of day and fuel type – Q1 2020 versus Q1 2019



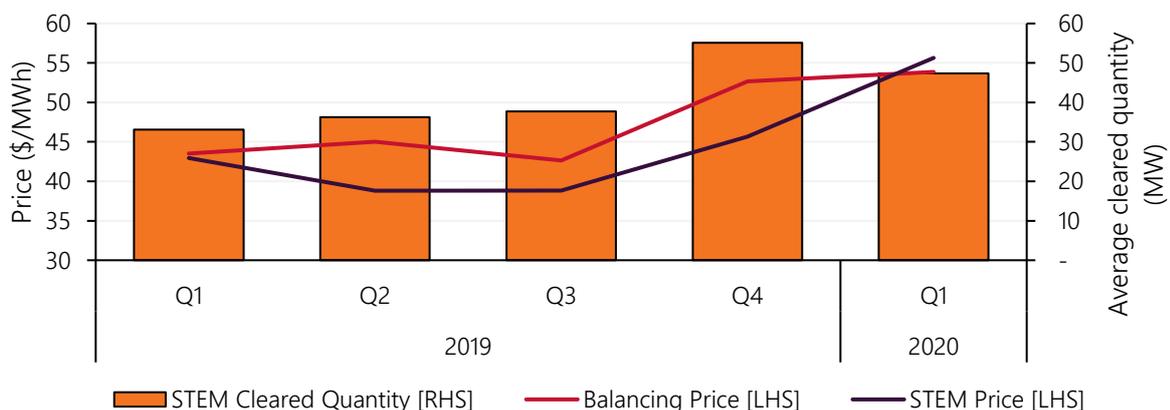
### 3.3 Wholesale electricity pricing

The average Balancing Price in Q1 2020 increased by 23.7% compared to Q1 2019 (Figure 57), primarily due to a 3.9% increase in average operational demand and a decrease in availability of comparatively low cost black coal-fired generation from 90% to 88%. In total, 53% of this unavailability was caused by forced outages. As higher-priced generators supplied a greater proportion of energy, the Balancing Price rose.

Average prices in the Short-Term Energy Market (STEM) increased by 29.5% from Q1 2019. This was predominately due to changes in Market Participant bidding and hedging behaviour; as Market Participants anticipate higher prices in the Balancing Market, they are more likely to hedge greater quantities in STEM.

**Figure 57 Higher demand and greater outages led to higher Balancing Price**

WEM Balancing Price, STEM Price, and STEM cleared quantity by quarter



### 3.4 Spinning Reserve rule change analysis

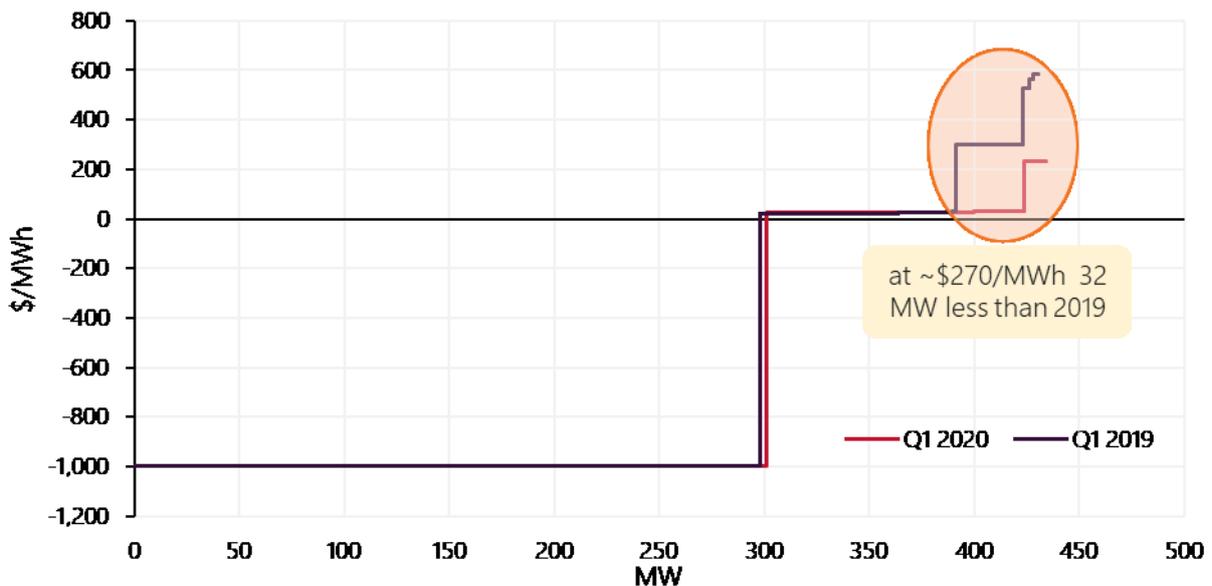
The cost of procuring Spinning Reserve Services is recovered from all generators synchronised to the system that have an applicable capacity of over 10 MW in a given Trading Interval. The cost recovery mechanism was amended from 1 September 2019 as RC\_2018\_06 (Full Runway Allocation of Spinning Reserve Costs) came into effect.

This rule change replaced the modified runway methodology, where Spinning Reserve costs were calculated for generators based on allocating their output to strict cost allocation blocks, with a full runway methodology<sup>38</sup>. The aim of the new approach was to incentivise large generators to make more capacity available at lower prices by replacing the allocation blocks with each generator’s output.

Figure 58 illustrates the resulting change in behaviour from Q1 2019 to Q1 2020. In Q1 2019, generators were withholding capacity (operating at 390 MW on average) to avoid additional Spinning Reserve costs incurred when increasing generation and moving into the next cost allocation block. On average, in Q1 2020, an additional 32 MW of generation capacity from coal facilities was offered at around \$30/MWh instead of at the Maximum STEM Price (\$302/MWh at the time). This demonstrates additional generation capacity is becoming available at lower prices, as the rule change intended.

**Figure 58 Spinning Reserve rule change results in more available capacity at lower costs**

WEM Bid supply curve for coal-fired generation – Q1 2020 versus Q1 2019



### 3.5 Load Following Ancillary Services market dynamics

The total cost of Load Following Ancillary Services (LFAS) in Q1 2020 reduced by \$4.95 million (24%) when compared to Q1 2019 (Figure 59). AEMO has identified two contributing factors to this significant reduction:

1. AEMO introduced a ‘sculpted’ LFAS requirement<sup>39</sup> in the 2019-20 Financial Year in its approved Ancillary Services Report<sup>40</sup>. Prior to this, AEMO would procure 72 MW of LFAS Up and Down for each interval. The updated LFAS requirements commenced on 28 August 2019 and set the requirements at 85 MW LFAS Up

<sup>38</sup> Full details of RC\_2018\_06 and the change in methodology can be found on the Economic Regulation Authority (ERA) website: [https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc\\_2018\\_06](https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc_2018_06).

<sup>39</sup> The equivalent of this service in the NEM is the Regulation FCAS markets. The Regulation FCAS markets procure a minimum quantity, but requirements are also adjusted in real time based on measured time error.

<sup>40</sup> Ancillary Services Report published by AEMO in June 2019: <https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf>.

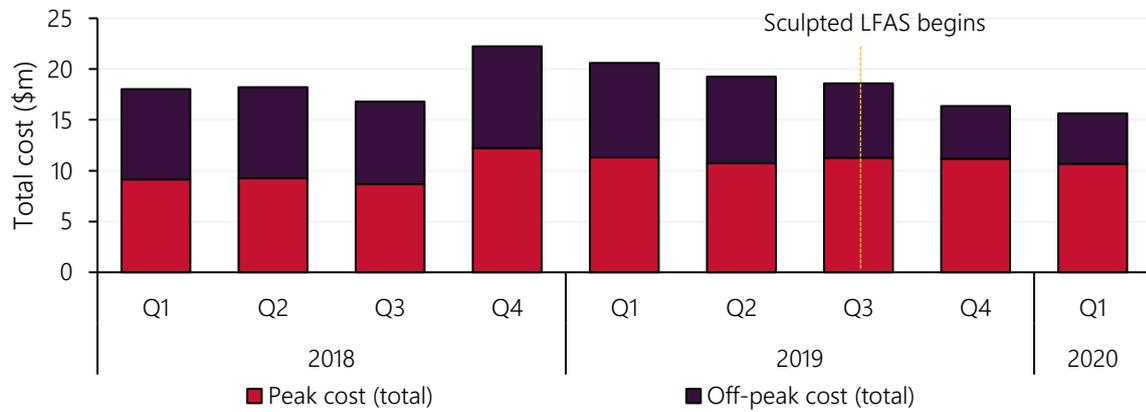
and Down between 0530 hrs and 1930 hrs (Peak) and 50 MW between 1930 hrs and 0530 hrs (Off-peak). LFAS is procured through the LFAS market.

- In setting these requirements, AEMO identified that increasing volatility due to higher PV penetration and increase in Non-Scheduled Generation (NSG) contributed to the need for a sculpted requirement to reflect that overnight there is no variability from PV systems.
  - Since the commencement of Sculpted LFAS, the average price of LFAS Up and LFAS Down has decreased by 19% and 17%, respectively, when compared to 2019 LFAS prices.
2. Three additional Facilities were certified to provide LFAS in 2019: ALINTA\_PNJ\_U1, ALINTA\_PNJ\_U2 (Q1 2019), and NEWGEN\_NEERABUP\_GT1 (Q3 2019). The addition of these Facilities has introduced more competition in the LFAS market.

An increase in competition in the LFAS market, and a more dynamic procurement of LFAS, has led a more cost-effective procurement of LFAS, while ensuring sufficient LFAS is available for system security.

**Figure 59 LFAS prices and cost has declined since competitive market start and Sculpted LFAS mechanism**

Total and per-interval cost of LFAS in the WEM



# Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
ASX	Australian Stock Exchange
APLNG	Australia Pacific LNG
AUD	Australian dollars
AWST	Australian Western Standard Time
BBL	Barrel
BWP	Berwyndale Wallumbilla Pipeline
CER	Clean Energy Regulator
CGP	Carpentaria Gas Pipeline
CTP	Capacity trading platform
CDD	Cooling degree day
COVID-19	Coronavirus disease 2019
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FY	Financial year
GJ	Gigajoule
GLNG	Gladstone LNG
GPG	Gas-powered generation
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
JKM	Japan Korea Marker
KGP	Karratha Gas Plant
LCA	Linepack Capacity Alert
LFAS	Load Following Ancillary Services
LGC	Large-scale Generation Certificates
LNG	Liquefied natural gas

Abbreviation	Expanded term
LOR	Lack of Reserve
MAPS	Moomba to Adelaide Pipeline System
MMBtu	Metric Million British thermal unit
MSP	Moomba to Sydney Pipeline
MtCO <sub>2</sub> -e	Million tonnes of carbon dioxide equivalents
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NSG	Non-scheduled generation
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
QNI	Queensland to New South Wales Interconnector
RBP	Roma to Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SRA	Settlement Residue Auction
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
VRE	Variable renewable energy
WEM	Wholesale Electricity Market
WCF	Wallumbilla Compressor Facility