AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Quarterly Energy Dynamics Q2 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 Q2 2020 (1 April to 30 June 2020). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2020 and Q2 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.

DISCLAIMER

VERSION CONTROL

Version	Release date	Changes
1	22 July 2020	

Executive summary

COVID-19 has only a modest impact on demand

- Despite the widespread economic impact of the COVID-19 pandemic, its impact on Australia's total electricity demand in Q2 was relatively modest.
- Compared to Q2 2019, National Electricity Market (NEM) operational demand was down 2%. COVID-19 contributed an estimated 2.1% reduction, and increased distributed photovoltaics (PV) a further 1.2% reduction, but this was offset by increased heating requirements due to cooler weather which increased demand by 1.4%.
  - By sector, large industrial load was broadly flat, commercial load was significantly down (around 10-20%), and residential load increased, almost offsetting the commercial load reductions.
  - Regional impacts of COVID-19 varied, with modelling showing the largest demand reductions in Queensland and New South Wales.
- In Western Australia's Wholesale Electricity Market (WEM), allowing for distributed PV output, COVID-19 had a negligible impact on overall demand (0.1% decrease). However, there was a slight shift in consumption from the morning to the midday to evening peak period.
  - COVID-19 resulted in a 7.3% decrease in consumption by large users[1] and an 8.2% increase in consumption by smaller users.
- During Q2, COVID-19 drove significant price volatility in oil, LNG, and thermal coal markets.
  - Brent Crude oil prices continued their decline from Q1 2020, reaching a low of A$30.76/barrel towards the end of April (the lowest levels since 1999), before recovering to around A$60/barrel by the end of the quarter.
  - Japan Korea Marker (JKM) liquified natural gas (LNG) prices fell to reach a record low of A$2.77/gigajoule (GJ) towards the end of Q2 2020.
  - Newcastle thermal coal prices declined from A$113/tonne at the end of March to finish the quarter at A$73/tonne (-35%).

East coast electricity and gas highlights

Lowest wholesale electricity and gas prices since 2015

- NEM average[2] regional spot wholesale electricity prices reduced by between 48-68% compared to Q2 2019, reaching their lowest levels since 2015.
  - The key driver of reduced spot prices was an increase in lower-priced offers, with contributing factors including lower gas and coal prices, easing of coal constraints at Mount Piper, increased rainfall (and hydro output), and new renewable supply.

[1] WEM large users classified as consumers which consumed at least 160 MWh the 12 months prior to implementation of COVID-19 restrictions.

[2] Uses the time-weighted average which is the average of spot prices in the quarter and is directly comparable to the swap contract price in the wholesale market. The Australian Energy Regulator (AER) reports the volume-weighted average price which is weighted against demand in each 30 minute trading interval and is an indicator of total market costs in the quarter.

- NEM electricity futures contract prices were mostly flat at comparatively low levels compared to recent quarters, with Calendar Year 2021 (Cal21) priced at $40/ megawatt hour (MWh) in Queensland and around $56/MWh in the other mainland states.
- Wholesale gas prices continued to fall, with the Gas Supply Hub (GSH) price averaging $4.10/GJ, its lowest level since Q4 2015. Factors influencing low gas prices included declining international gas prices (and subsequently a reduction in LNG exports and high levels of gas flows south from Queensland), lower electricity prices, and increased supply from Moomba and Orbost.

Other highlights

- NEM system costs returned to typical quarterly levels of around $63 million compared to $310 million last quarter, primarily due to the lack of occurrence of major power system separation events. Frequency Control Ancillary Service (FCAS) quarterly costs reduced to $45 million[3], despite increased requirements compared to 2019.
- Black coal-fired generation reduced by 1,148 megawatts (MW) on average compared to Q2 2019, reaching its lowest Q2 level since 2014. The decrease was due to comparatively low operational demand and displacement by lower-priced generation.
- Total inter-regional transfers increased to 3.4 terawatt hours (TWh), the highest quarterly level in almost two years, driven by increased transfers across three of the four regional interconnectors. A large increase occurred on Basslink, with comparatively high levels of net transfers into Victoria (223 MW on average), driven by increased Tasmanian output (mostly hydro output).

Western Australia electricity and gas highlights

- A new WEM record minimum demand for Q2 was set, with operational demand reaching 1,155 MW on Sunday, 26 April. Distributed PV accounted for 37% of underlying demand at the time.
- A combination of higher average temperatures during Q2 (resulting in reduced heating requirements) and continued uptake of distributed PV resulted in average operational demand decreasing by 8.2% in Q2 2020 compared to Q2 2019.
- Significant outages resulted in an average decrease in coal-fired generation of 130 MW compared to Q2 2019 and to an increase in gas-powered generation (GPG) of 100 MW.
  - Despite the decrease in operational demand, average Balancing Prices increased by 16.1% as a result of the change in fuel mix towards higher-priced fuels. As a result, participants were more willing to hedge against Balancing Prices in the Short-Term Energy Market (STEM), which saw a 31.5% increase in average cleared price and a 0.8% increase in average cleared quantity.
- Gas consumption and production increased by 8% and 10% respectively, compared to Q1 2020.

[3] Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions

Contents

1. NEM market dynamics

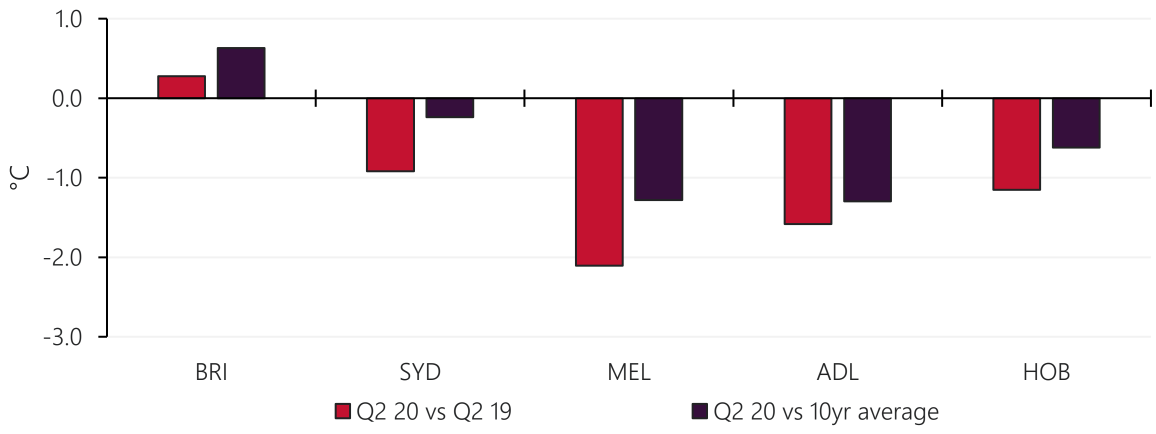
1.1 Weather

The weather over the quarter was cooler than average across all east coast capitals apart from Brisbane (Figure 1). Average maximum temperatures in Melbourne and Adelaide were below the 10-year average (1.3°C below) particularly during April and May, which increased heating requirements by 24% and 16% in these cities respectively, compared to Q2 2019 (Figure 2).

During the quarter, states in the southeast (New South Wales, Victoria, and Tasmania) recorded above average rainfall, largely driven by heavy rainfall in April[4]. In contrast, Queensland and South Australia experienced a much drier quarter with below average rainfall.

Figure 1 Cooler than average Q2 in the south

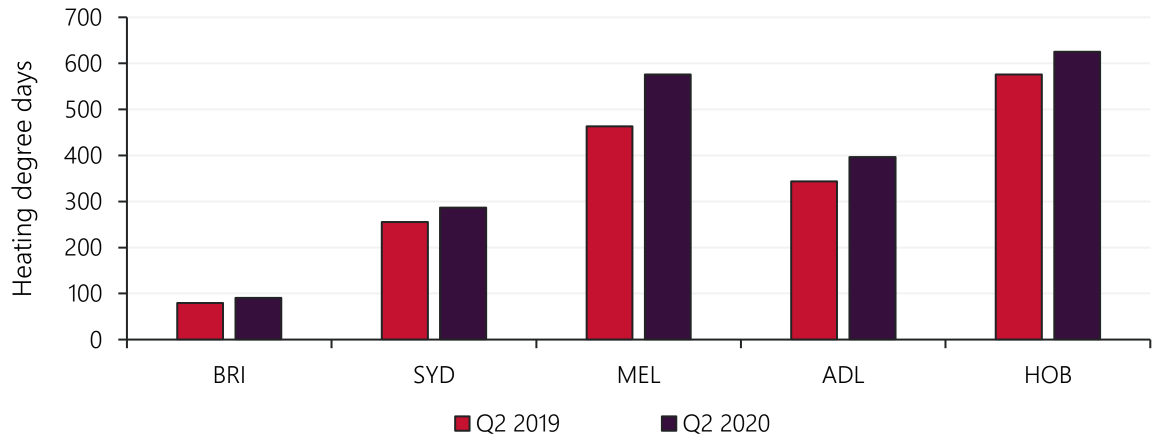
Average maximum temperature variance by capital city – Q2 2020 vs 10-year Q2 average



Source: Bureau of Meteorology

Figure 2 Higher heating requirements across all capital cities

Heating degree days[5]



[4] Bureau of Meteorology 2020, Australia in April 2020: http://www.bom.gov.au/climate/current/month/aus/archive/202004.summary.shtml.

[5] A "heating degree day" (HDD) is a measurement used as an indicator of outside temperature levels below what is considered a comfortable temperature. Here, the HDD value is the sum of daily HDD values over the quarter which are calculated as max (0, 18 – temperature).

1.2 Electricity demand

NEM average operational demand declined by 429 MW (-2%) in Q2 2020 compared to Q2 2019, due to increased distributed PV[6] (+256 MW on average) and reduced underlying demand (-173 MW, Figure 3). On average, reductions attributed to COVID-19 resulted in a 483 MW (-2.1%) decrease in operational demand, which was offset by a 310 MW increase (+1.4%) due to increased heating requirements (due to cooler weather) and other factors. The detailed impact of COVID-19 on demand is discussed in Section 1.2.1.

Compared to Q2 2019, operational demand reduced in all NEM regions except South Australia (Table 1). The largest reductions occurred in Queensland (-205 MW) and New South Wales (-192 MW), due to these regions having the biggest increase in distributed PV, as well as COVID-19 related demand reductions. In Victoria and South Australia, operational demand was relatively flat, with reduced demand due to increased PV and COVID-19 restrictions mostly offset by increased heating requirements.

Figure 3 Lower demand during morning peak and middle of the day; slight increase during evening peak

Change in NEM-average operational demand by time of day (Q2 2020 versus Q2 2019)

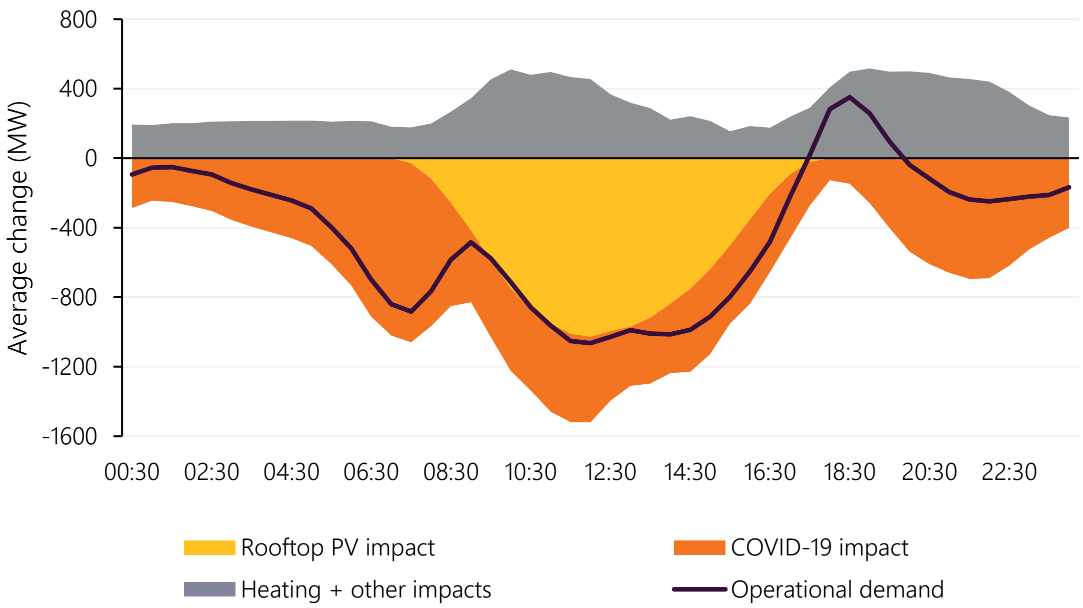


Table 1 Average change in underlying demand, distributed PV, operational demand – Q2 20 vs Q2 19

Average MW	Queensland	New South Wales	Victoria	South Australia	Tasmania
Operational demand	-205	-192	-26	+18	-24
Underlying demand impact	-112	-109	+27	+44	-23
Distributed PV impact	-93	-83	-53	-26	-1

Maximum and minimum demand

The COVID-19 impact on maximum and minimum demands was relatively muted – only one Q2 minimum demand record was set. South Australia set a new Q2 minimum demand record at 1330 hrs on Easter Sunday 12 April, when operational demand fell to 533 MW (216 MW lower the previous Q2 record). Sunny conditions coupled with the public holiday were the primary drivers of the record minimum demand. At the time of minimum demand, South Australia's distributed PV output was 780 MW.

[6] Increased distributed PV generation results in reduced operational demand because distributed PV is behind the meter.

1.2.1 COVID-19 electricity demand impact

This section provides an in-depth examination of these impacts and differs from the usual approach in the QED; rather than comparing historical data to previous relevant comparison periods (for example, Q2 2019) AEMO has used analytical tools to project what the demand would have been if the pandemic had not occurred. AEMO's Operational Forecasting and Integrated Energy System teams have developed state of the art models which unbundle the impact of COVID-19 from other factors such as temperature, humidity, day of the week, time of the year, and the amount of distributed PV.

In the NEM, the COVID-19 impact on electricity demand has varied greatly by region and by sector. Sector-based impacts in Q2 included:

- **Large industrial** – minimal changes in demand from large industrial users, with most factories, mines, and smelters continuing their typical operation during this period.
- **Commercial** – reduced demand across the commercial sector due to lockdown restrictions limiting business activity.
- **Residential** – increased demand across the sector due to lockdowns and working from home arrangements.

Figure 4 illustrates the modelled change in demand for Victoria's residential and commercial sector in April and May by time of day. Commercial load during this period decreased by an estimated 276 MW on average due to restricted business activity, but this was largely offset by increased residential load (+248 MW).

On a regional basis, the COVID-19 impact on demand varied based on:

- **The mix of residential and commercial loads** – regions with a lower proportion of residential load such as Queensland typically demonstrated a larger reduction in demand.
- **Climate impacts** – residential load is typically more weather sensitive than other sectors, so cooler weather has led to an overall increase in residential demand. Figure 5 shows the increased sensitivity of South Australia's demand to cool temperatures, driven by the COVID-19 increase in proportion of residential demand.
- **Household appliance installation** – regions such as Victoria that have a high proportion of gas heating systems compared to electric heating systems recorded a lower impact on residential electricity demand than other regions.

Figure 4 COVID-19: Decreased commercial load offset by increased residential load

Change in VIC-average weekday demand by sector and time of day (1/4 to 17/5 2020 versus 1/4 to 17/5 2019)[7]

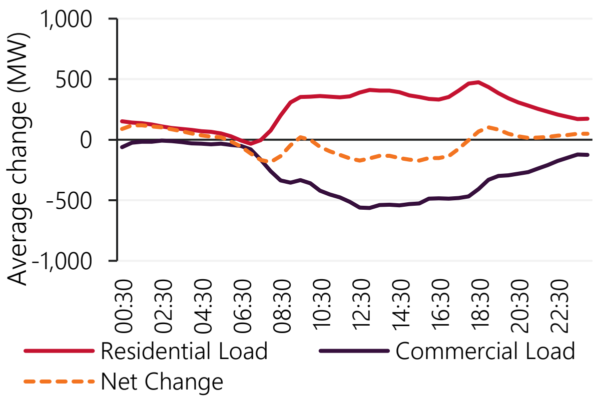
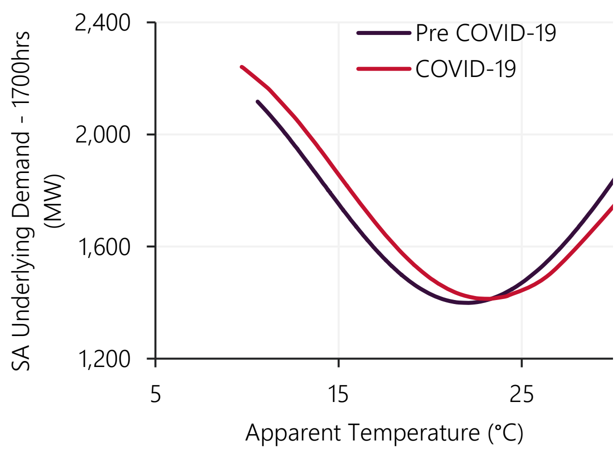


Figure 5 COVID-19: South Australian load more sensitive to cooler weather



[7] AEMO estimates residential load using sampling techniques derived from residential household metered data. Commercial load (distribution only) was estimated using the difference between total delivered distribution load and estimated residential load.

By state in Q2:

- **New South Wales and Queensland** demand was most affected by COVID-19 restrictions. This was mainly due to the combination of mild weather (which limited the COVID-19 related increase in residential demand) and COVID-19 related in commercial demand in these regions.
  - As shown in Figure 6, the New South Wales COVID-19 related demand decrease was largest during April (-5% on average) when strict restrictions were imposed for the whole month. However, demand reductions progressively eased during May and June (-1%), due to cooler weather and the gradual relaxation of restrictions.
  - Queensland's COVID-19 demand impact was similar to New South Wales', except with slightly greater demand reductions, as well as less easing of the COVID-19 impact into June.
- **Victoria's** COVID-19 demand reduction was moderate. Compared to the pre-COVID-19 control model, weekday operational demand in April reduced by 1%, with the largest decrease during the morning (Figure 7). The comparatively cooler climate meant that decreased commercial demand was offset by increased residential demand, driven by higher heating requirements. By June, demand reductions in Victoria shifted to increases, predominantly due to cooler winter temperatures.
- In contrast to other regions, **South Australia's** operational demand increased due to COVID-19. This was a function of South Australia's low proportion of commercial load, comparatively high proportion of electricity heating systems, and colder than average conditions during Q2.

Figure 6 COVID-19 impact on New South Wales electricity demand

% change in NSW-average weekday operational demand by time of day (actual versus pre-COVID-19 control model)

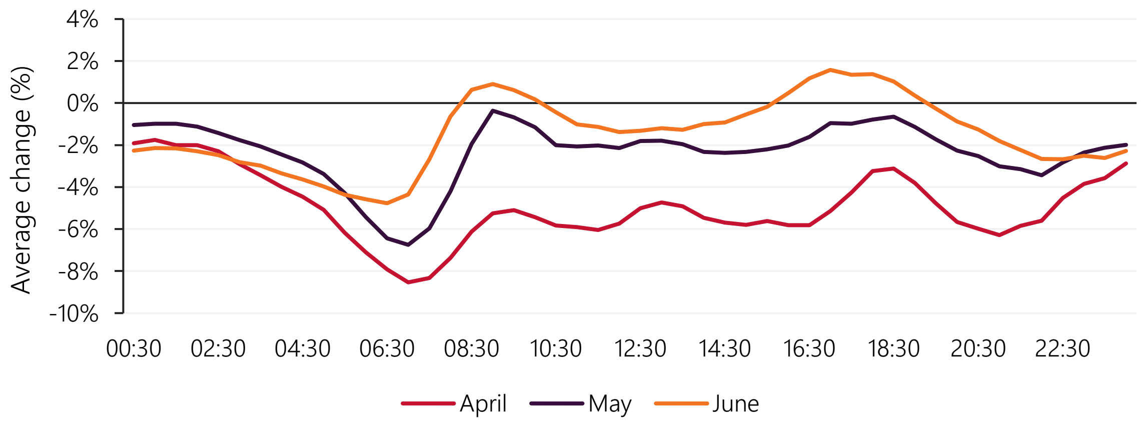
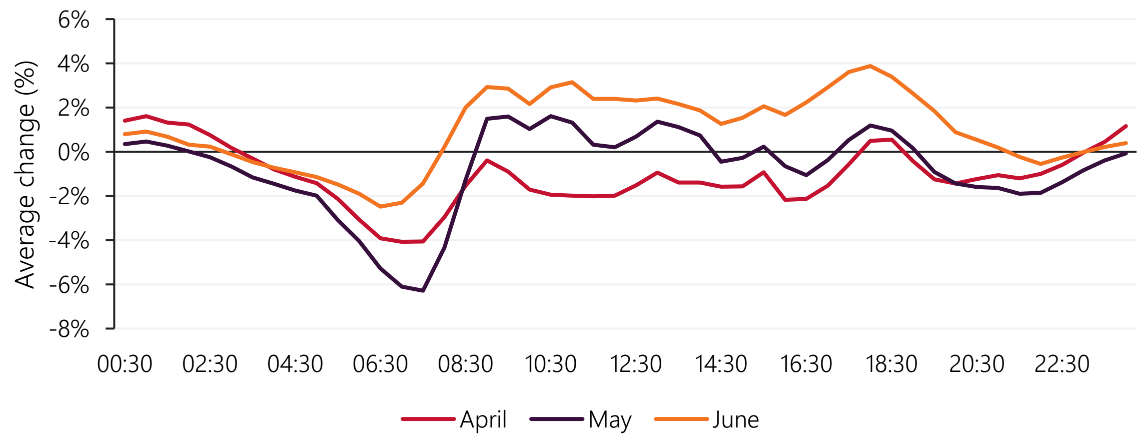


Figure 7 COVID-19 impact on Victorian electricity demand

% change in VIC-average weekday operational demand by region and time of day (actual versus pre-COVID-19 control model)



Source: AEMO Operational Forecasting team

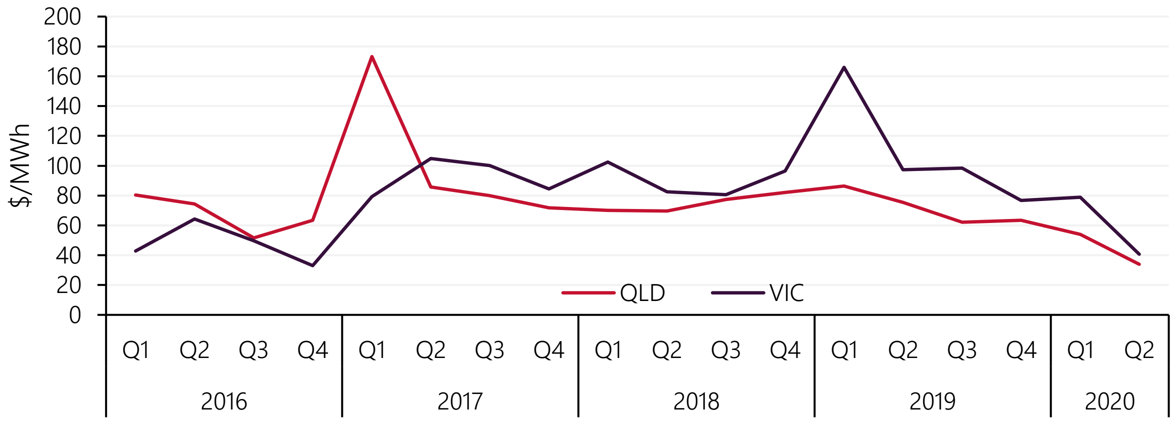
1.3 Wholesale electricity prices

NEM average[8] spot wholesale electricity prices declined significantly in Q2 2020, ranging between $32-43/MWh, representing a 48-68% reduction on Q2 2019 levels. Highlights included:

- Queensland's quarterly average price of $34/MWh represents the lowest mainland NEM price since Q4 2016, and the lowest Queensland price since Q2 2015.
- South Australia recorded its lowest quarterly average since Q1 2015, Victoria its lowest average price since Q4 2016, New South Wales its lowest average price since Q1 2016, and Tasmania its lowest average price since Q4 2011.

Figure 8 Spot wholesale electricity prices at lowest levels since 2015

Average wholesale electricity price – Queensland and Victoria

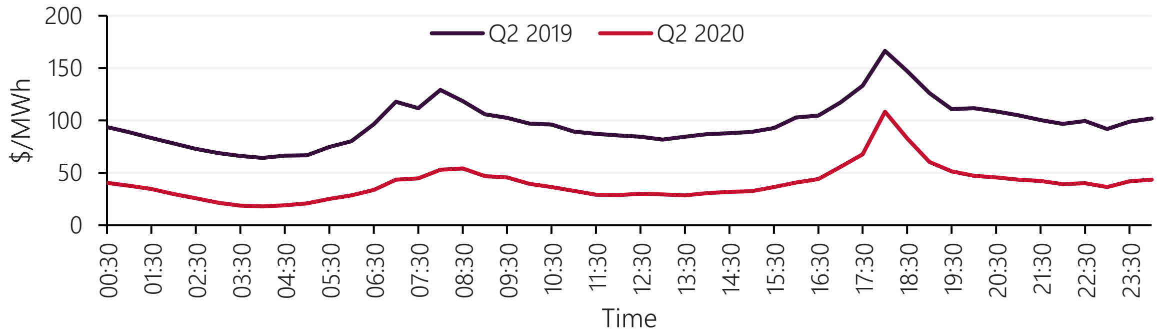


Other notable aspects of lower NEM-wide spot prices included:

- Inter-regional price convergence – the average inter-regional price spread reduced to $5.42/MWh (down from $7.11/MWh in Q2 2019), representing the second lowest price spread in six years. Reduced price separation was a function of the NEM-wide reduction in the price of offers from marginal units (Section 1.3.3), coupled with interconnectors binding at their limits relatively infrequently (Section 1.5).
- Intra-day pricing profile – as shown in Figure 9 (for Victoria), the intra-day pricing profile has remained largely unchanged compared to Q2 2019, with the lowest prices occurring in the early hours of the morning and the middle of the day (early morning spot prices remained lower than midday prices).
- Price volatility – there were few instances of spot price volatility this quarter, with quarterly cap returns under $1/MWh in all mainland NEM regions.

Figure 9 Intra-day spot pricing profile remains unchanged

Victoria – average wholesale electricity price by time of day



[8] Uses the time-weighted average which is the average of spot prices in the quarter and is directly comparable to the swap contract price in the wholesale market. The AER reports the volume-weighted average price which is weighted against demand in each 30 minute trading interval and is an indicator of total market costs in the quarter.

1.3.1 Reduced wholesale electricity prices: Q2 2020 drivers

A significant increase in comparatively low-priced offers, coupled with a 2% reduction in operational demand, were the key drivers for the fall in spot electricity prices this quarter. As shown in Figure 10, between Q2 2019 and Q2 2020 there was a progressive reduction in the price of marginal offers: in Q2 2020, 69% of marginal offers were priced below $45/MWh compared to just 33% of offers below $45/MWh in Q2 2019[9].

Overall, there was a 2,257 MW increase in low-priced offers (below $35/MWh) on average compared to Q2 2019, with increases occurring across every major fuel type (Figure 11). Key changes by fuel type included:

- **Hydro** provided 732 MW (32%) of the increase in low-priced offers, reflecting increased rainfall (and ability to generate).
- **Black coal-fired generation** provided 654 MW (29%) of the increase in low-priced offers. The main contributor to this was the easing of coal constraints at Mount Piper Power Station, which resulted in a 478 MW increase in offers priced below $35/MWh compared to Q2 2019.
- Increased **brown coal-fired generator** availability drove a 322 MW increase in low-priced offers.
- Higher **wind and solar** output provided a 454 MW increase in low-priced supply.
- **Reduced operational demand** (429 MW) due to increased distributed PV and COVID-19 restrictions also contributed to lower spot prices, however, was a much smaller contributor than the supply-side impacts.

Figure 10 Progressive increase in low-priced electricity offers

NEM – proportion of marginal bids by price band

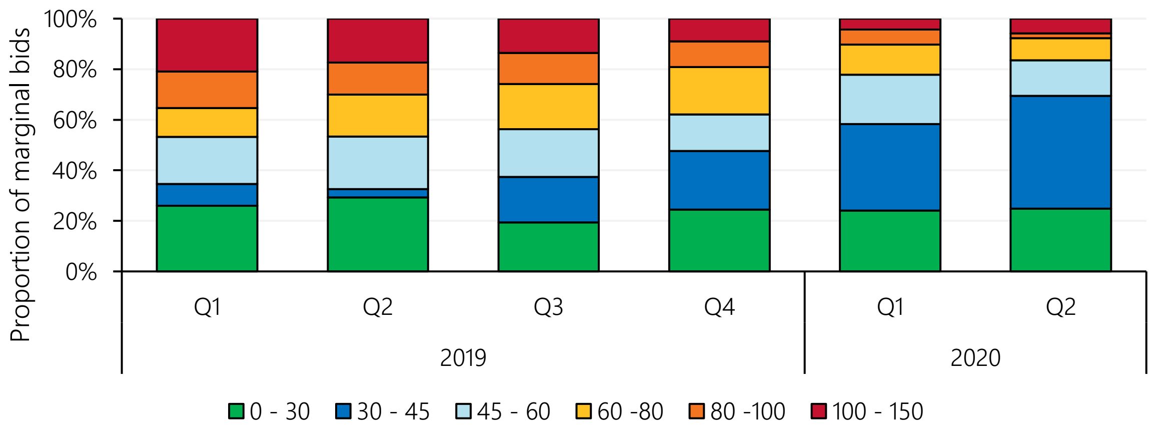
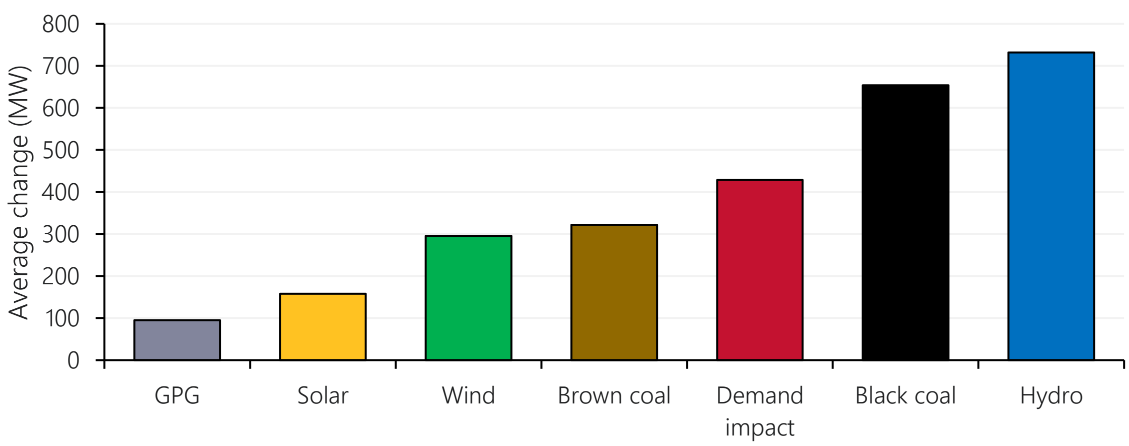


Figure 11 All fuel supply types contribute to increase in low-priced offers

Change in average supply priced below $35/MWh by fuel type – Q2 2020 versus Q2 2019



[9] The AER will undertake a detailed analysis of participant offer behaviour in its upcoming Wholesale Markets Quarterly

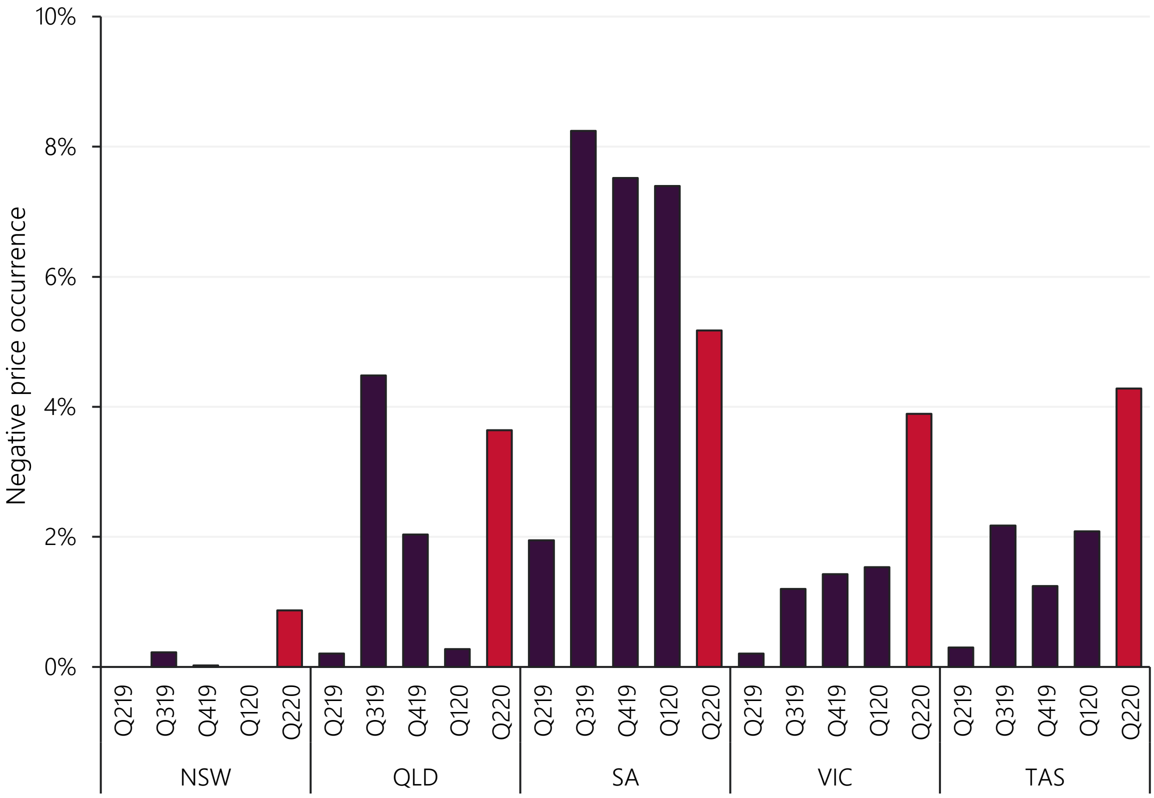
1.3.2 Negative wholesale electricity prices

During Q2 2020, the occurrence of negative and zero spot prices[10] was no longer confined to only South Australia and Queensland, with a higher prevalence in other NEM regions (Figure 12). NEM-wide negative spot prices occurred in 3.6% of the trading intervals this quarter, surpassing Q3 2019 levels (3.3%) to reach the highest quarterly level on record. Increased levels of negative spot prices this quarter were due to reduced operational demand and a 1,215 MW increase in supply priced below $0/MWh. The AER will undertake a detailed analysis of negative prices in its upcoming Wholesale Markets Quarterly.

While negative spot price occurrences were relatively high this quarter across all states, negative price impact was limited. Negative prices only reduced South Australia and Queensland's average quarterly price by $1.52/MWh and $1.32/MWh, respectively. The impact on Victoria's spot prices was just $0.40/MWh.

Figure 12 High negative price occurrences across the NEM

Frequency of negative spot prices and price impact in the NEM – Q2 2019 to Q2 2020



South Australia and Queensland continued to have high levels of negative spot prices this quarter. Spot prices were negative or zero 5.2% of the time in South Australia, compared to 1.9% in Q2 2019. In Queensland, spot prices were negative 3.6% of the time, its second highest quarter on record. Queensland's result was partly driven by export constraints on the Queensland to New South Wales interconnector following an unplanned outage on the Tamworth–Armidale line between 30 April 2020 and 4 May 2020.

In Victoria, negative spot prices occurred 3.9% of the time, which was a new quarterly record. The high degree of price alignment between Victoria and South Australia (Section 1.5) meant that 92% of negative prices in Victoria occurred at the same time as negative prices in South Australia.

[10] Hereafter referred to as negative spot prices

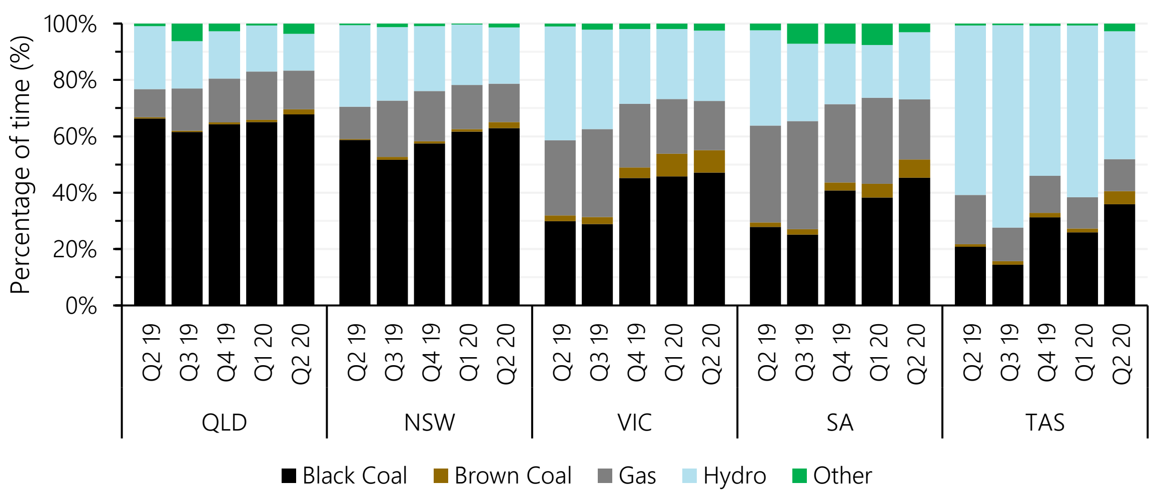
1.3.3 Price-setting dynamics

Figure 13 shows price setting results for Q2 2020 compared to recent quarters. Key outcomes included:

- Increased price setting role for combined black and brown coal-fired generation in all NEM regions – across the NEM, coal was the marginal fuel type 57% of the time, up from 42% of the time in Q2 2019. This represents the highest quarterly price setting role for coal-fired generation since Q4 2016.
  - This was due to the significant reduction in spot electricity prices, which was driven by a large increase in comparatively low-priced offers (Section 1.3.1), coupled with reduced operational demand (Section 1.2).
- Reduced occurrence of gas and hydro as the price-setting marginal unit. GPG units set the price 15% of the time, the lowest level in two years, and hydro units set the price 25% of the time.
- Across the NEM, the three main marginal fuel types (black coal, gas, and hydro) set the price at significantly lower levels than in recent second quarters (Figure 14 shows this for New South Wales). This was a function of:
  - Increased variable renewable output, higher brown coal-fired unit availability, and lower demand.
  - Marginal price setting units shifting electricity offers to lower prices, coinciding with lower domestic gas market prices, lower international gas and coal prices, and increased hydro output.

Figure 13 Increased price-setting role for coal-fired generation across all NEM region

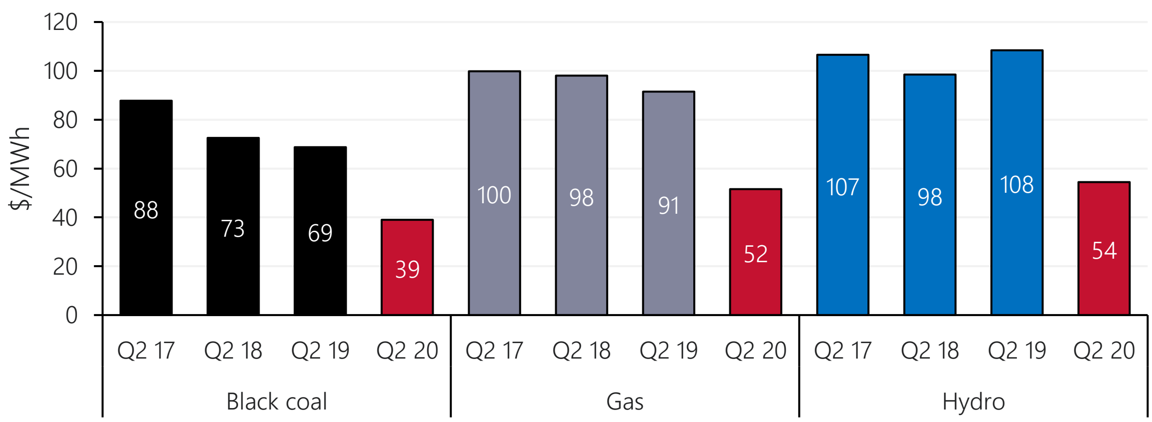
Price-setting by fuel type – Q2 2020 versus prior quarters



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

Figure 14 All marginal fuel types setting the price at lower levels

Average price set by fuel type – New South Wales (Q2s)



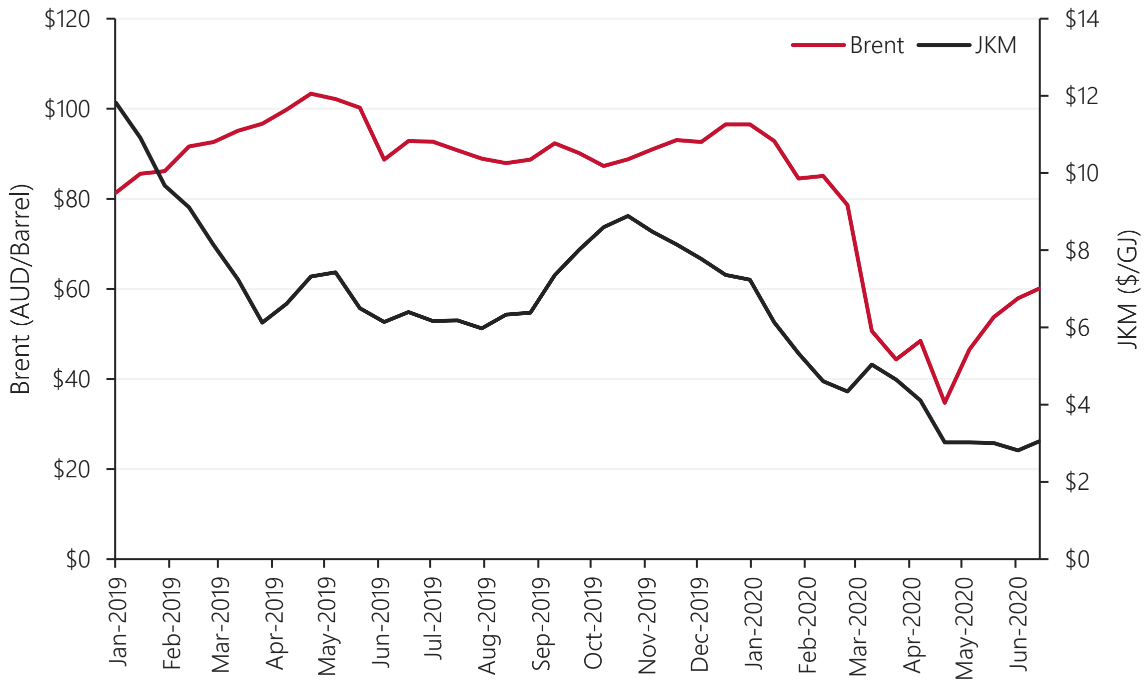
1.3.4 International commodity prices

During Q2, the global economy and demand for energy commodities continued to be severely impacted by COVID-19 and various levels of country lockdowns. This resulted in significant demand reduction and price volatility in oil, LNG, and thermal coal markets.

Brent Crude oil prices continued their decline from Q1 2020, reaching a quarterly-low of A$30.76/barrel on 21 April, due to the global lockdown and its severe impact on oil demand (Figure 15). This represents the lowest Brent Crude oil price since 1999. Oil prices rebounded to around A$60/barrel by the end of the quarter, as the Organisation of the Petroleum Exporting Countries (OPEC) and Russia agreed to cut production by 9.7 million barrels per day from May to end of July[11].

Figure 15 Brent Crude and JKM LNG prices hit by COVID-19

Brent Crude oil and JKM LNG prices in Australian dollars



Source: Bloomberg data in 14-day averages.

JKM LNG prices fell to a record low of A$2.77/GJ on 8 June as the various levels of COVID-19 related lockdowns reduced global demand. The continuation of lower Asian gas prices was also reflected in the Australian Competition and Consumer Commission's (ACCC's) latest netback price, with Cal21 averaging A$5.25/GJ, around A$2.5/GJ lower than price expectations prior to the COVID-19 pandemic (Figure 16).

Newcastle thermal coal prices declined from A$113/tonne at the end of March to finish the quarter at A$73/tonne (-35%). In Q2 China eased domestic production restrictions, while India also increased domestic production, resulting in reduced international coal prices (Figure 17)[12].

[11] OPEC 2020, The 10th (Extraordinary) OPEC and non-OPEC Ministerial Meeting concludes: https://www.opec.org/opec_web/en/press_room/5891.htm.

[12] Department of Industry, Science, Energy and Resources 2020, Resources and Energy Quarterly - June 2020: https://www.industry.gov.au/data-and-publications/resources-and-energy-quarterly-june-2020.

Figure 16 ACCC gas netback prices remain at low levels

ACCC netback price historical and forward[13]

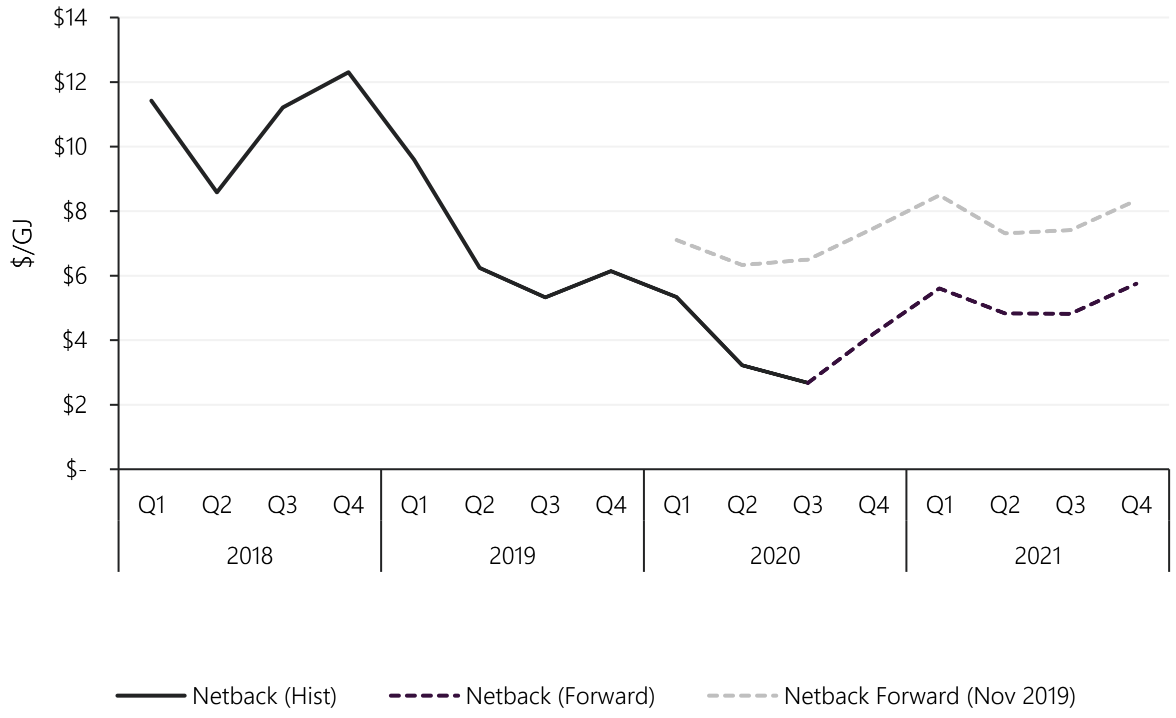
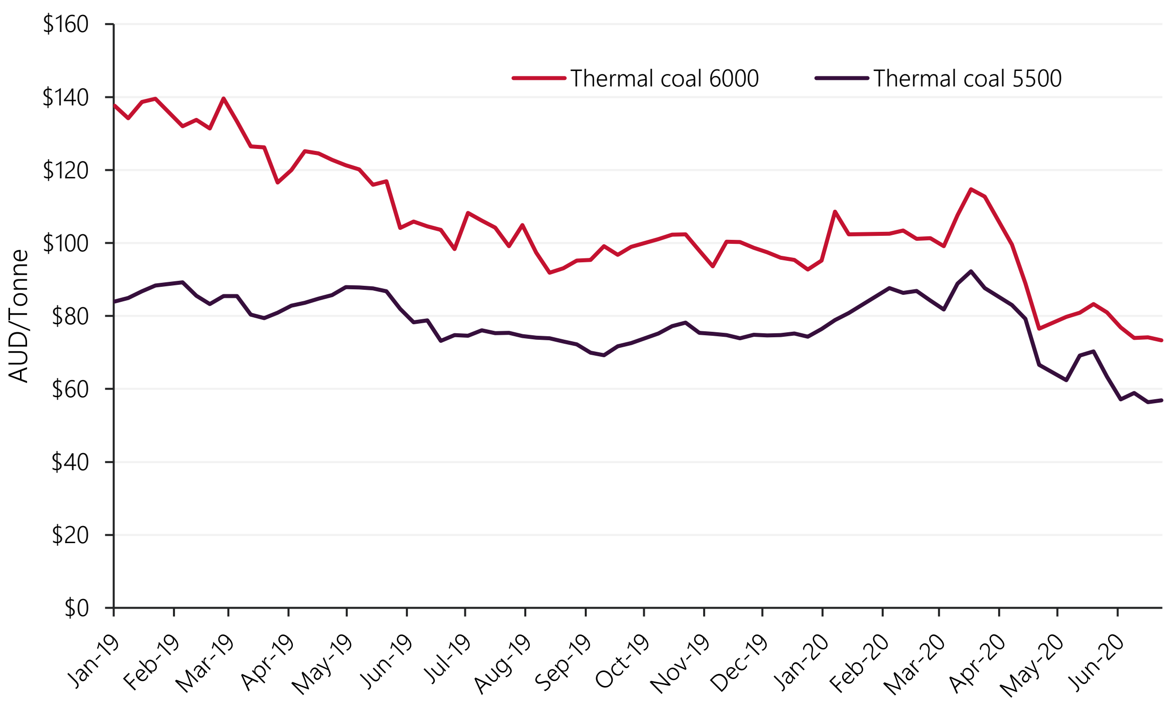


Figure 17 Thermal coal decline

Newcastle thermal coal



Source: Bloomberg

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

1.3.5 Electricity future markets

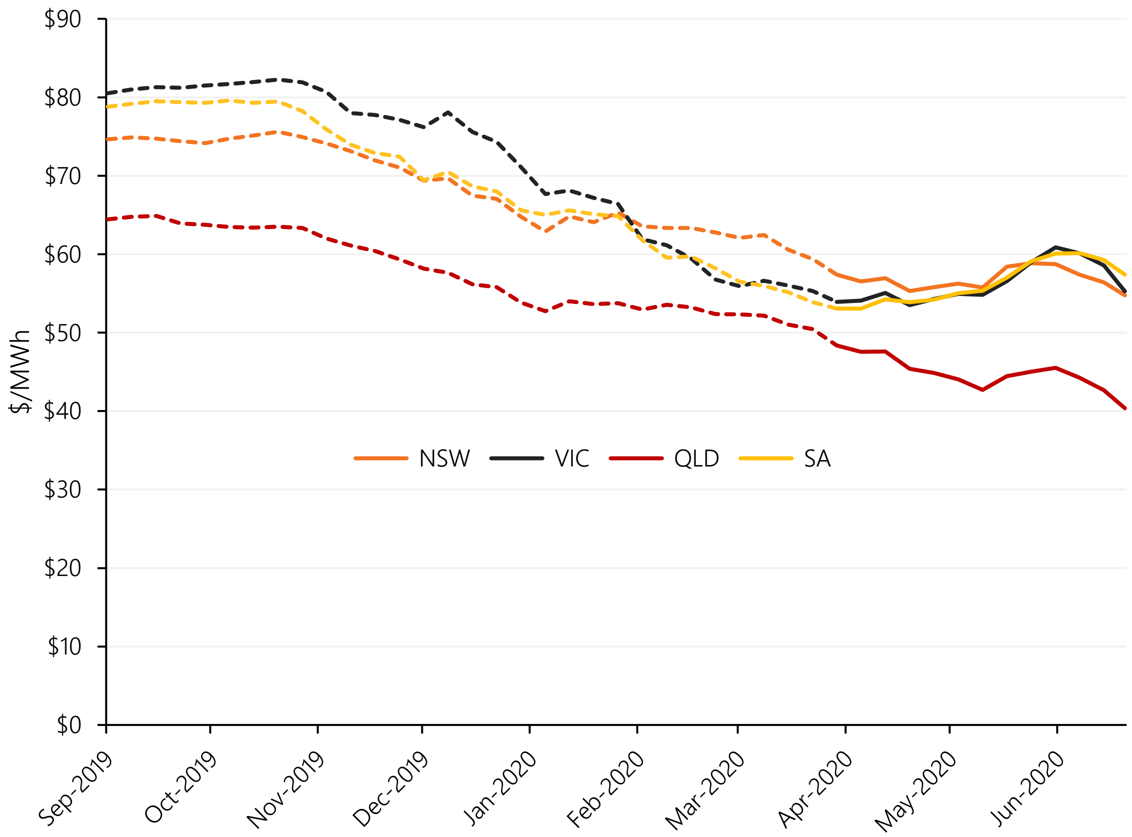
During the quarter, NEM electricity futures contract prices were mostly flat at comparatively low levels compared to recent quarters (Figure 18). Cal21 swap contract prices reduced during April but increased in the second half of the quarter to finish at $40/MWh in Queensland and around $56/MWh in other states.

By region:

- Queensland's continued lower spot wholesale electricity prices compared to other states (Section 1.31.3) were reflected in futures prices. The state recorded the largest futures price reduction, with Cal21 swaps declining $10/MWh during the quarter to finish at $40/MWh, an average $16/MWh discount to the other states, while Cal22 swaps also decreased to $40/MWh (-$9/MWh).
- Previous Cal21 swap prices differences for the remaining states narrowed towards an average of $56/MWh by the end of the quarter, with average spot wholesale electricity trending down and converging. New South Wales was the highest priced state on the ASX for Cal22 at $53/MWh, averaging $5/MWh above Victoria and South Australia and $13/MWh higher than Queensland.

Figure 18 ASX futures stabilise at comparatively low prices

ASX Energy – Cal21 swap prices by region – 7-day averages

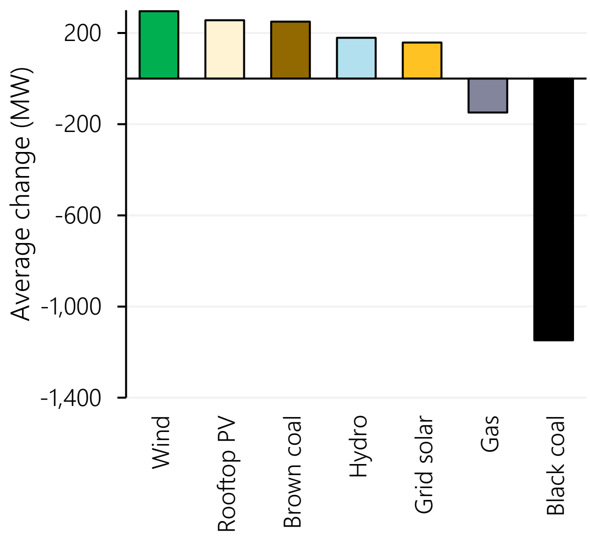


1.4 Electricity generation

During Q2 2020, changes to the NEM generation mix were driven by reduced operational demand, new supply (increased variable renewable energy [VRE]), and changed price offers from of dispatchable generation. Figure 19 shows the average change in generation by fuel type compared to Q2 2019, and Figure 20 illustrates the change by time of day.

Figure 19 Significant reductions from black coal-fired generation

Change in supply – Q2 2020 versus Q2 2019



Compared to Q2 2019:

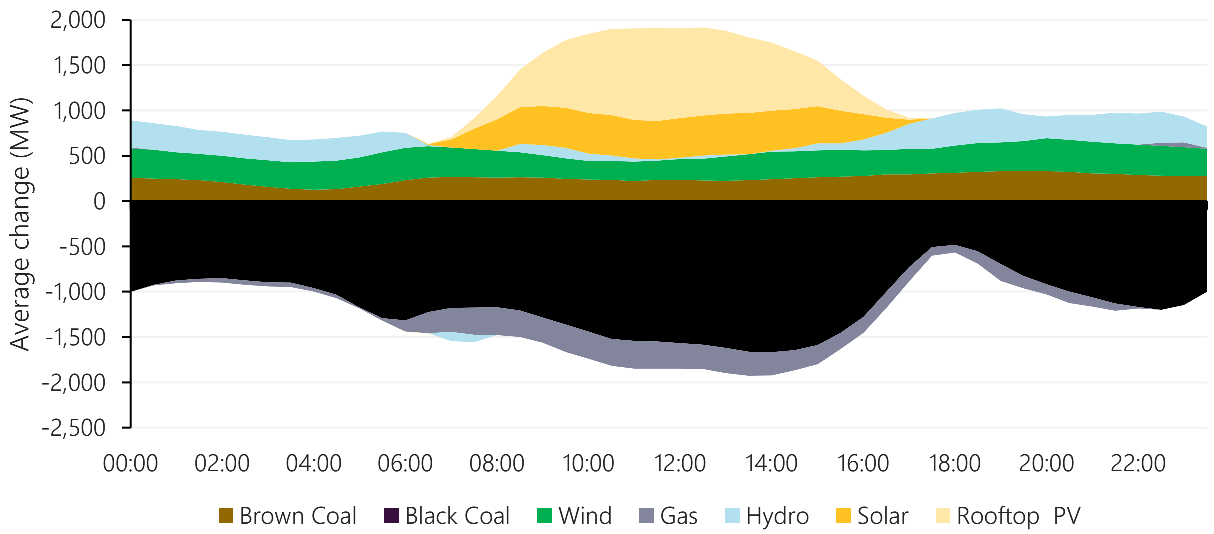
- Average black coal-fired generation was 11,189 MW, down by 1,148 MW, reaching its lowest Q2 level since 2014. The decrease was due to comparatively low operational demand and displacement by lower-priced generation (brown coal, solar, and wind). Black coal's proportion of the NEM supply mix declined from 56% to 52% this quarter (Table 2).
- Grid-scale VRE output increased by 454 MW. VRE accounted for 13% of the supply mix, up from 10% in Q2 2019.
- Above average rainfall in Tasmania and Victoria increased average hydro output by 179 MW.

Table 2 NEM supply mix by fuel type – Q2 2020 versus Q2 2019

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar
Q2 2019	56%	17%	9%	8%	8%	2%
Q2 2020	52%	19%	8%	9%	10%	3%
Change	-4.2%	+1.5%	-0.5%	+1.0%	+1.5%	+0.8%

Figure 20 Reduced black coal and GPG across the day, increased overnight hydro and daytime solar

Change in supply – Q2 2020 versus Q2 2019 by time of day



1.4.1 Coal-fired generation

Black coal fleet

During Q2 2020, average black coal generation reduced by 1,148 MW compared to Q2 2019, with New South Wales and Queensland fleets decreasing by 539 MW and 609 MW, respectively. While there were some minor delays in planned outages due to COVID-19 restrictions, there was no material impact on the market, with NEM black coal availability similar to Q2 2019, and average unit outages around 15 days for both quarters.

Results varied for New South Wales as significant decreases in output from Eraring, Vales Point, and Liddell were partially offset by increases at Mount Piper and Bayswater (Figure 21). By station:

- Average output at Eraring Power Station declined to 1,440 MW (-823 MW), its lowest Q2 generation since 2013. Reduced generation from Eraring this quarter was driven by a combination of low operational demand, increased unit outages (plus nine days), and displacement from low-priced supply, including solar, wind, and brown coal-fired generation (Section 1.3.1).
  - Low spot prices this quarter (especially in April and May) drove Eraring units to operate close to minimum generation levels[14] more frequently. Units 1, 2 and 3 were operating close to minimum generation 12% of the time this quarter, up from less than 1% in Q2 2019 (Figure 22).
- Increased outages (both unplanned and planned) at Vales Point Power Station, coupled with displacement from low-priced supply, reduced output by 247 MW on average, its lowest Q2 output since 2012. On average, Vales Point units were out of service for 23 days compared to nine days in Q2 2019.
- As coal supply constraints eased at Mount Piper Power Station, average generation reached 977 MW this quarter, up by 431 MW on Q2 2019 (when Mount Piper started to experience output disruptions).

Figure 21 Eraring leads black coal generation reduction

Change in black-coal fired generation – Q2 2020 versus Q2 2019

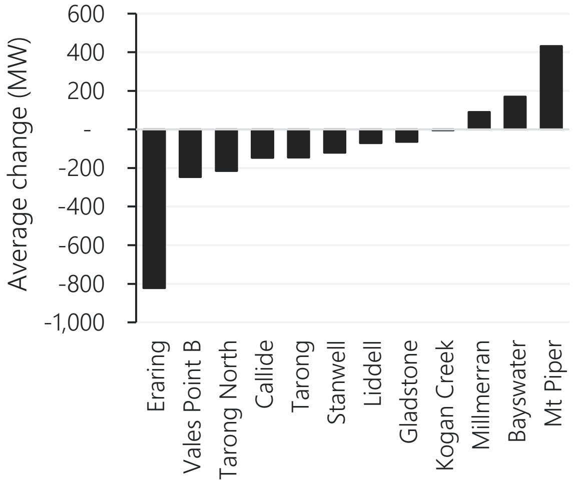
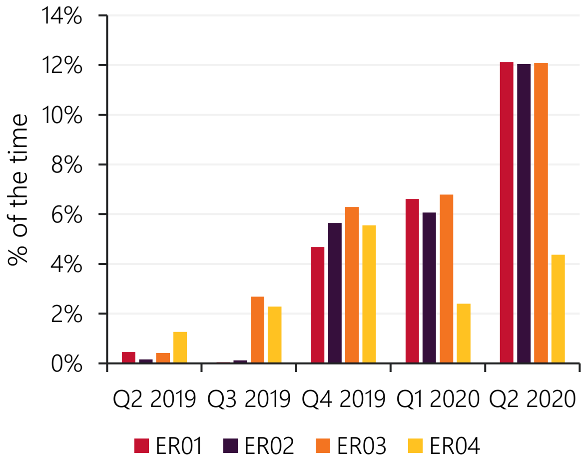


Figure 22 Eraring operating close to minimum generation levels more frequently

% of the time close to minimum generation – Eraring



In Queensland, key drivers of reduced output this quarter included reduced operational demand, displacement by solar and GPG, and increased outages at Tarong North and Callide power stations:

- Output at Tarong North was 215 MW lower than Q2 2019 as it was on an extended outage for majority of the quarter (it returned to service on 10 June 2020). Tarong North was out of service for 70 days this quarter compared to 21 days in Q2 2019.
- At Callide Power Station, the decline in output (148 MW) was driven by increased outages (mostly planned) and some solar displacement.

[14] Determined based on a unit's economic and technical minimum generation level. A range between 180 MW and 221 MW was used for Eraring units for this analysis.

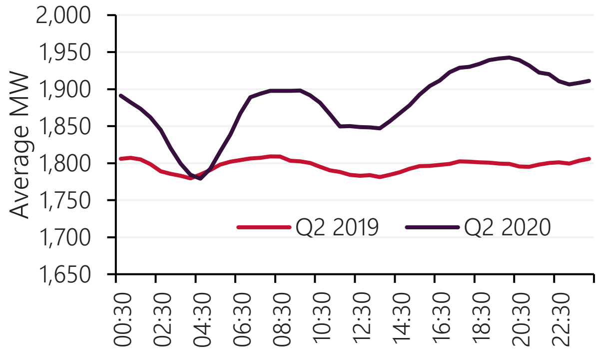
Brown coal fleet

Average brown coal-fired generation for the quarter was 4,029 MW, up 250 MW on Q2 2019 levels (a quarter with a very high number of outages). The combined 405 MW output increase from Loy Yang (LY) A and LYB power stations was partially offset by a 155 MW decrease from Yallourn. Average brown coal unit outages this quarter (12 days) were lower than Q2 2019 (18 days).

There was a notable shift in LYA's generation pattern compared to Q2 2019 (Figure 23), driven by increased occurrence of low and negative prices in Victoria (Section 1.3.2). LYA was operating more flexibly, ramping down overnight and up during the day.

Figure 23 Operational flexibility at Loy Yang A

LYA average generation by time of day – Q2 2020 versus Q2 2019



1.4.2 Hydro

Q2 NEM hydro generation was 179 MW higher on average than in Q2 2019. The main driver of the increased output was higher rainfall in Tasmania and Victoria, enabling increased output and a shift in offers; there was 732 MW more hydro supply priced below $35/MWh than in Q2 2019.

Figure 24 shows the change in average output by state compared to Q2 2019:

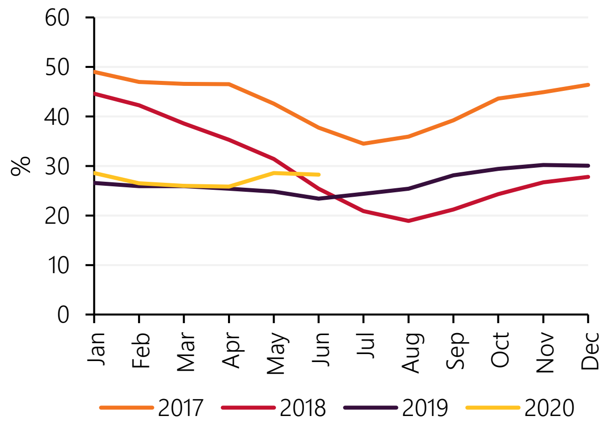
- Tasmania's quarterly average hydro generation increased to 1,323 MW (+270 MW), due to above average rainfall, especially during April, which increased dam levels to 39.6% on average for the quarter compared to 32.3% the same time last year. This more than offset reduced GPG in the region and resulted in increased interconnector transfers to Victoria (Section 1.5).
- New South Wales average hydro generation decreased by 99 MW, mainly due to lower output from Upper Tumut (84 MW). Above average rainfall in April increased Snowy's Lake Eucumbene dam levels from historical lows last year but they remained comparatively low at the end of June (28%, Figure 25).
- Victoria increased by 97 MW on average compared to Q2 2019, mainly due to increased output from Murray (92 MW).
- Dry Queensland conditions resulted in decreased generation (89 MW), mostly from Kareeya (-49 MW).

Figure 24 Tasmania leads hydro increase

Change in average hydro generation – Q2 2019 versus Q2 2020

Figure 25 Snowy hydro levels increase slightly

Weekly gross storage levels in percentage



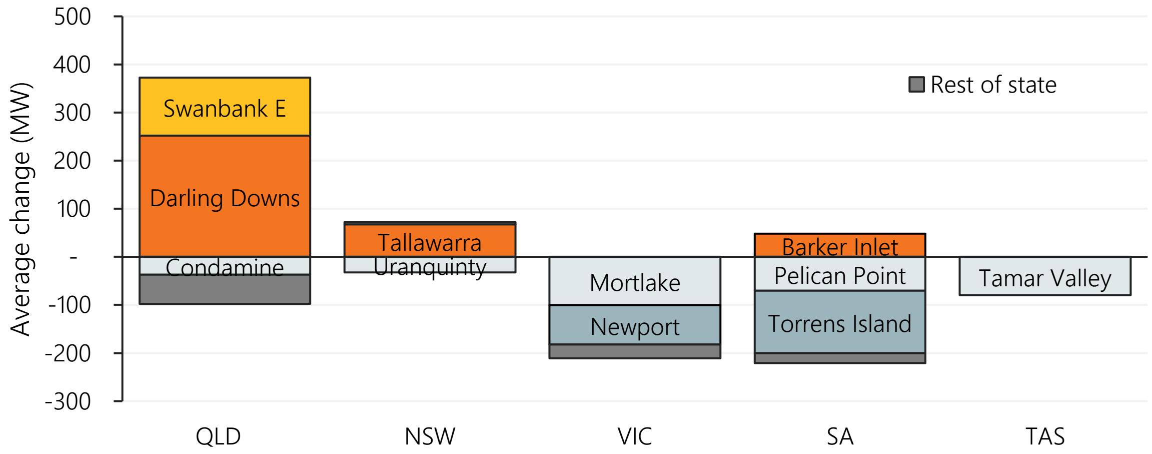
1.4.3 Gas-powered generation

NEM GPG decreased by 149 MW on average compared to Q2 2019 (Figure 26), mainly due to reduced operational demand and increased low-priced supply from other fuel types. On a regional basis:

- South Australia declined by 172 MW to its lowest Q2 average (683 MW) since 2016. The decline was led by AGL's Torrens Island (-129 MW), partly offset by an increase from their newer Barker Inlet station (48 MW). The regional reduction was influenced by increased imports of lower-priced generation from Victoria.
- Victorian GPG declined by 211 MW to its lowest Q2 average (135 MW) since 2015, with the largest reductions occurring at Newport and Mortlake power stations (-82 MW and -100 MW respectively). Decreased local GPG was due to increased generation from brown coal (250 MW) and local VRE (114 MW), and increased imports from Tasmania (Section 1.5).
- Tasmanian GPG decreased by 80 MW on average, due to increased hydro generation in the region (270 MW on average), which meant Hydro Tasmania did not require Tamar Valley to run as frequently.

Figure 26 Queensland ramps up as the south declines

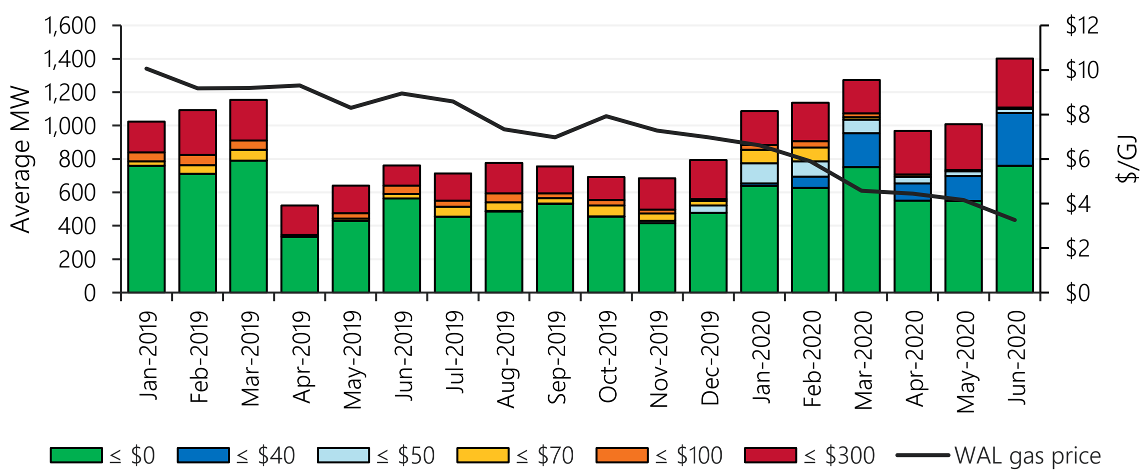
Change in GPG – Q2 2020 versus Q2 2019



In contrast to the rest of the NEM, Queensland average GPG increased by 275 MW to reach its highest Q2 since 2017. In particular, there was increased average output at Darling Downs (+252 MW) and Swanbank E (+120 MW) as the Wallumbilla gas price reached new lows (Section 2.1). During Q2, Queensland GPGs bid a comparatively high amount of capacity at prices below $40/MWh (Figure 27), reflecting lower gas prices, and resulting in some displacement of higher-priced black coal-fired generation.

Figure 27 Queensland GPG bids reflecting low gas prices

Queensland GPG bids and GSH price – monthly average



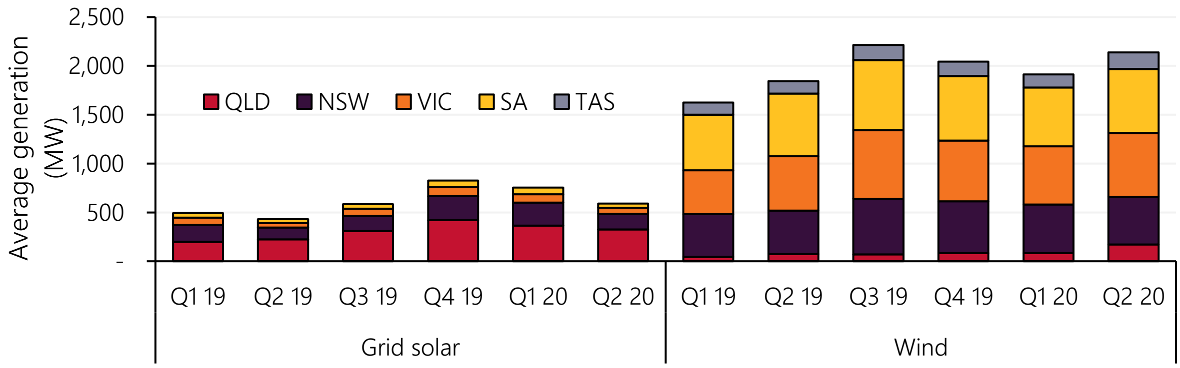
1.4.4 Wind and solar

Compared to Q2 2019, average grid-scale VRE generation this quarter was 2,730 MW, up by 454 MW (Figure 28). During the quarter, several grid-scale VRE records were set. Trading interval records included:

- **Highest grid-scale VRE share of NEM operational demand** – NEM VRE output met 34% of NEM operational demand at 1130 hrs on 11 April 2020.
- **Highest wind output on record** – NEM wind output reached 4,996 MW at 2230 hrs on 1 May 2020.

Figure 28 Higher levels of grid-scale VRE driven by ramping up of recently installed capacity

VRE average generation by region



Grid-scale solar generation increased by 158 MW on average compared to Q2 2019, with the largest increases occurring in Queensland (+100 MW) and New South Wales (+42 MW). In Queensland, this was driven by a combination of ramping up of newly installed capacity, as well as higher solar irradiation (+3.5%). In New South Wales, increased output was mainly due to ramping up of newly installed capacity and partially by new capacity additions (Goonumbla Solar Farm, 70 MW). This was, however, offset by lower solar irradiation (-4%).

Average wind generation this quarter reached 2,140 MW, 296 MW higher than Q2 2019. This was largely driven by ramping up of recently installed capacity, and partially by newly commissioned projects in Victoria (Bulgana Green Project 194 MW, Cherry Tree Wind Farm 58 MW, and Elaine Wind Farm 84 MW).

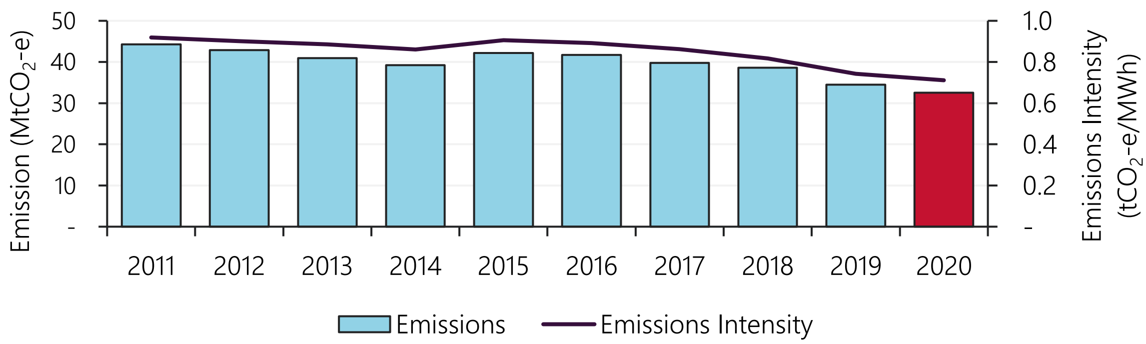
In Victoria, despite large capacity additions, average wind output in Victoria only increased by 98 MW compared to Q2 2019, mainly due to lower wind speeds across the state. Queensland's increased output (97 MW) was mainly driven by the continued ramp up of Coopers Gap.

1.4.5 NEM emissions

NEM emissions for Q2 2020 declined to their lowest on record at 32.5 million tonnes of carbon dioxide equivalent (MtCO_2-e), while the average emissions intensity fell to 0.71 tCO_2-e/MWh. Total emissions were 2 MtCO_2-e lower than Q2 2019 and 0.4 MtCO_2-e lower than the previous record low in Q4 2019. Key drivers included lower black coal-fired generation, reduced operational demand, and increased renewable output.

Figure 29 Emissions intensity sets new record low

Quarterly NEM emissions and emissions intensity (Q2s)



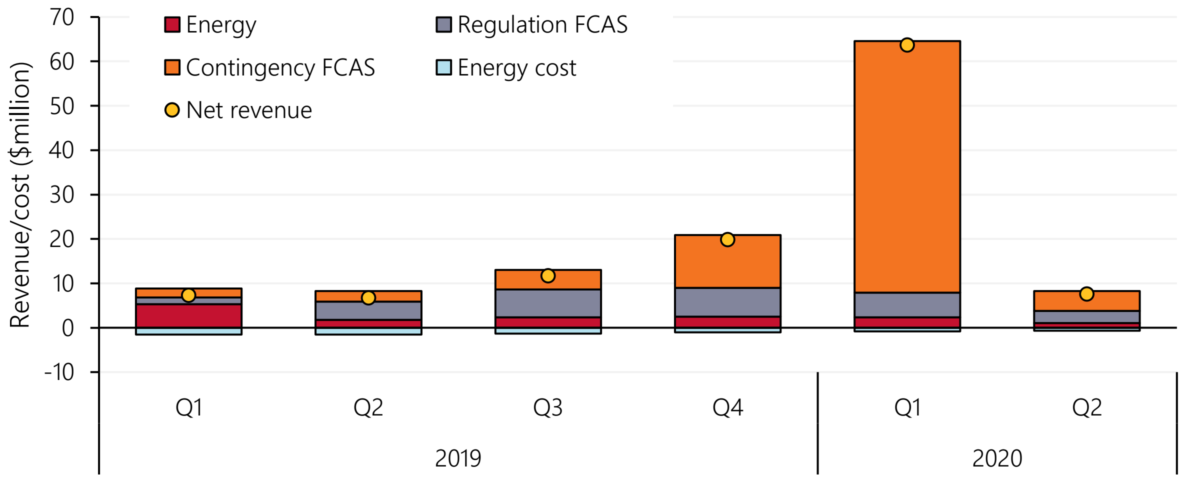
1.4.6 Storage

Batteries

During Q2, battery spot market net revenue was $7.6 million, substantially lower than recent quarters, primarily due to lower returns from FCAS markets (Figure 30). The decline in FCAS returns was driven by a lack of event-driven FCAS price volatility in South Australia (which occurred in Q4 2019 and Q1 2020). However, FCAS markets remained the primary source of battery spot market revenue, contributing 88% of total battery revenue.

Figure 30 Reduced FCAS prices result in lower battery revenue

Battery revenue sources

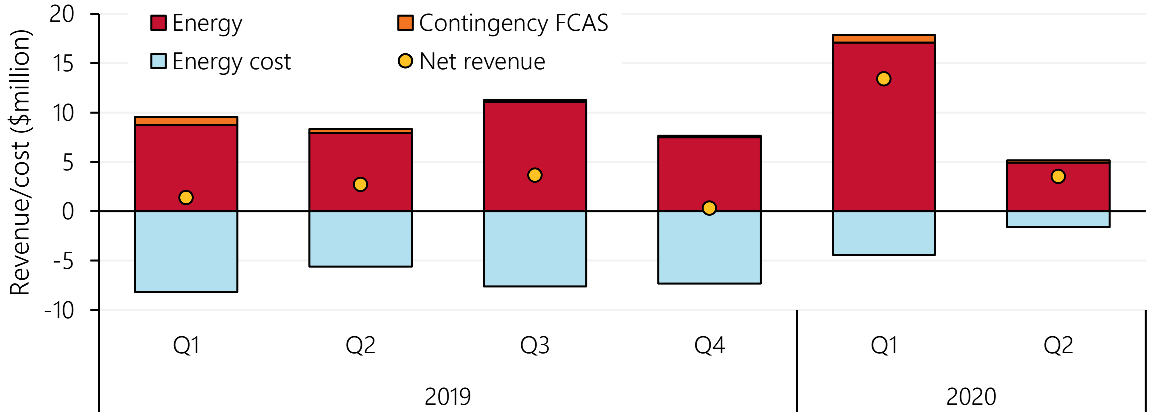


Pumped hydro

During Q2, pumped hydro spot market net revenue was $3.6 million, lower than in Q1 2020, but relatively consistent with 2019 results (Figure 31). The reduction compared Q1 2020 was due to an absence of spot price volatility in New South Wales and Queensland this quarter. Compared to 2019, lower pumped hydro energy revenues were offset by reduced pumping costs.

Figure 31 Pumped hydro quarterly revenue similar to 2019 levels

Pumped hydro revenue sources

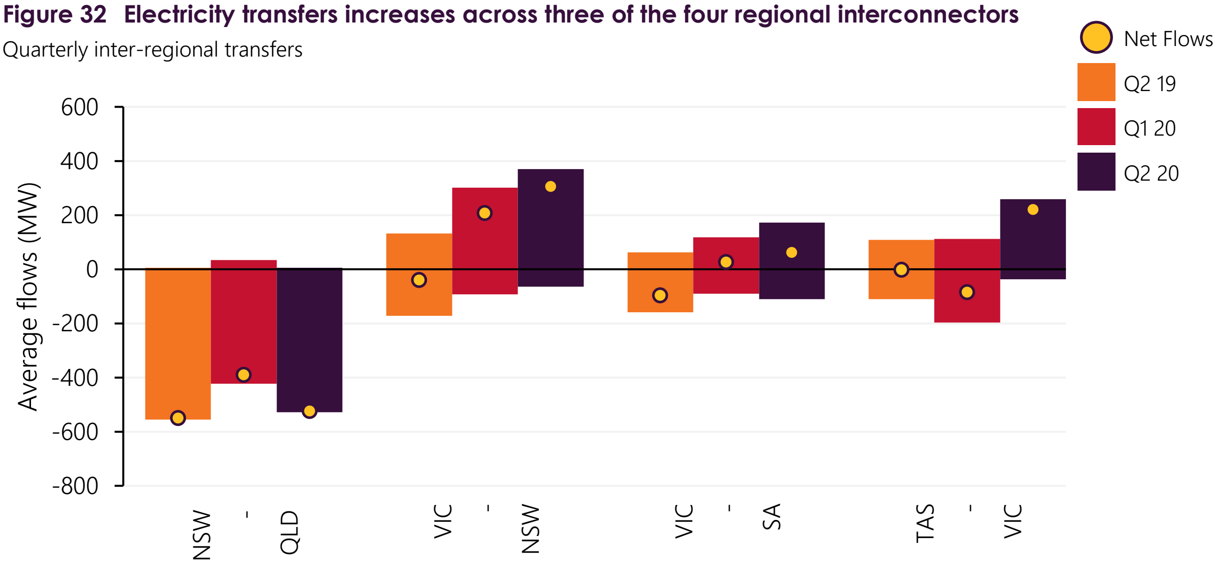


1.5 Inter-regional transfers

Total inter-regional transfers increased to 3.4 TWh, 19% higher than in Q2 2019, driven by increased transfers across three of the four regional interconnectors (Figure 32). This represents the highest level of quarterly inter-regional transfers in almost two years.

Figure 32 Electricity transfers increases across three of the four regional interconnectors

Quarterly inter-regional transfers

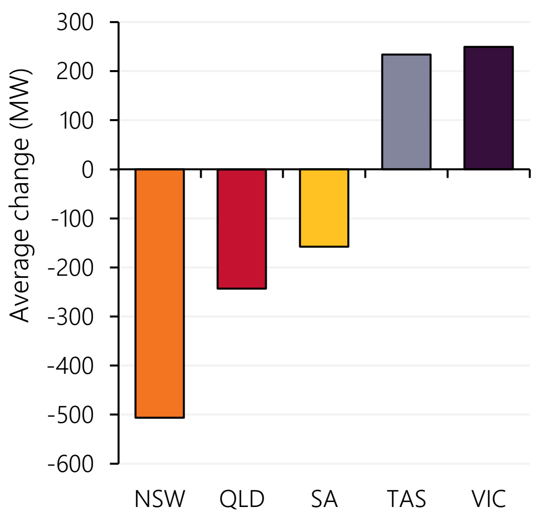


Key changes compared to Q2 2019 included:

- **Exports from Victoria** – increased low-priced local supply (Figure 33) – largely wind and brown-coal fired generation – and increased imports from Tasmania resulted in higher net average transfers from Victoria into New South Wales (345 MW) and South Australia (158 MW).
  - The Heywood Interconnector was only binding at its limits 11% of the time, contributing to a high degree of price alignment between Victoria and South Australia.
- **Exports from Tasmania** – increased local generation (hydro 270 MW, and wind 43 MW, on average) led to increased net exports into Victoria (223 MW).
- **Imports into New South Wales** – net transfers into New South Wales increased by 319 MW on average, driven by imports from Victoria, with transfers from Queensland recording a small decrease. The increase in lower-priced supply in the southern regions, coupled with reduced New South Wales demand, resulted in displacement of 506 MW of New South Wales generation on average.
  - The Queensland – New South Wales Interconnector (QNI) was binding at its limits 22% of the time, contributing to a price spread of $10/MWh between the two regions.

Figure 33 Increased supply in the southern regions; decreases in the north

Change in regional supply – Q2 2020 versus Q2 2019

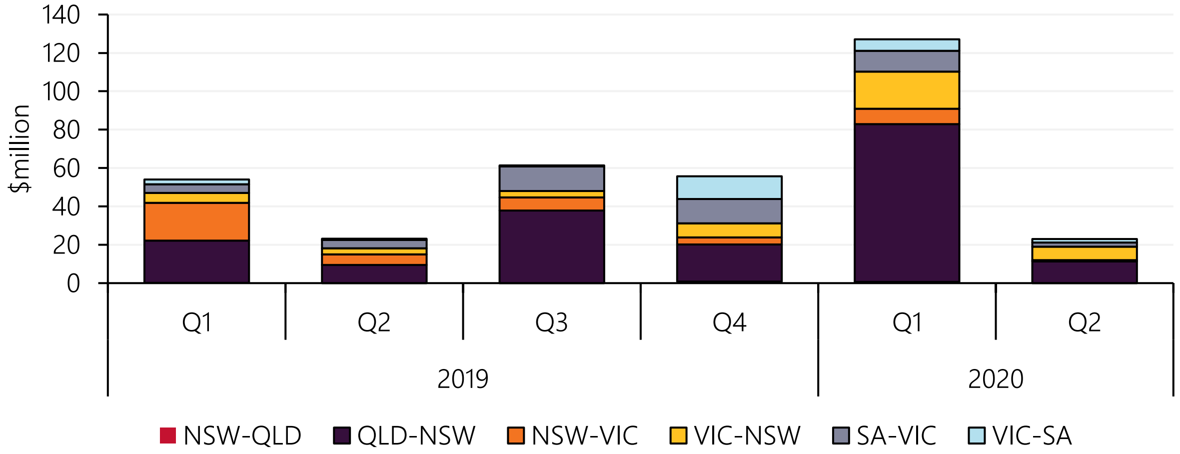


1.5.1 Inter-regional settlement residue

Quarterly inter-regional settlement residue (IRSR) fell to $23 million, the lowest level since Q4 2015 (Figure 34). This was despite increased inter-regional transfers and was due to the high degree of price alignment across regions (Section 1.3). Victoria to New South Wales was the only interconnector direction to materially increase in IRSR value compared to 2019 results, due to comparatively high transfers (Section 1.5).

Figure 34 Inter-regional settlement residue declines to lowest level since Q4 2015

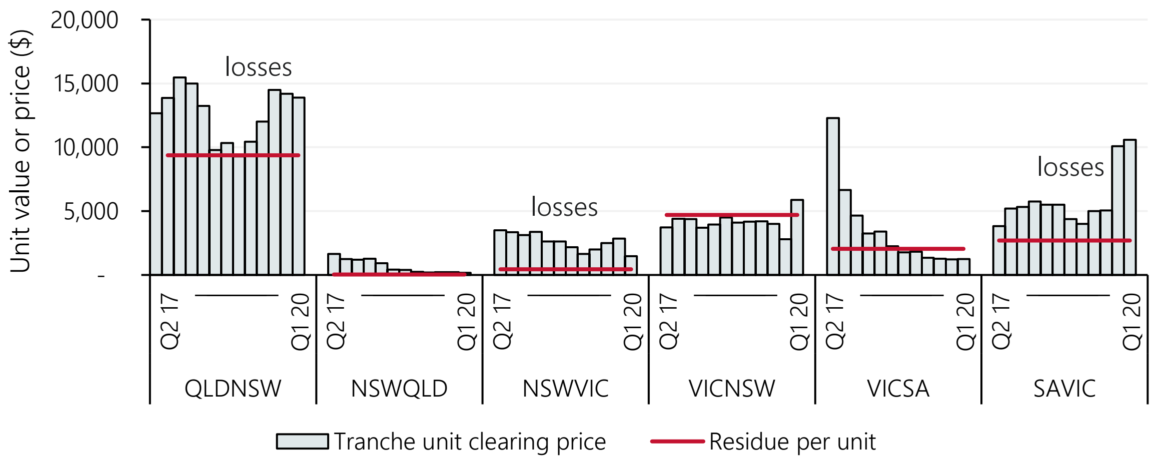
Quarterly positive IRSR value



In general, large negative returns occurred for Settlement Residue Auction (SRA) units for flows across all interconnectors, indicating lower than expected inter-regional price separation this quarter (Figure 35). The exception was for units for transfers from Victoria to New South Wales, which roughly broke even due to increased exports from Victoria. The 15 June SRA marked the third auction with secondary trading of units previously purchased at auction[15], with 2% of total units sold at the auction through the secondary trading process.

Figure 35 Large negative returns for most Settlement Residue Auction units this quarter

SRA tranche analysis – price paid for units versus actual value (Q2 2020)



[15] For further details on secondary trading, see: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/guide-to-settlements-residue-auction.

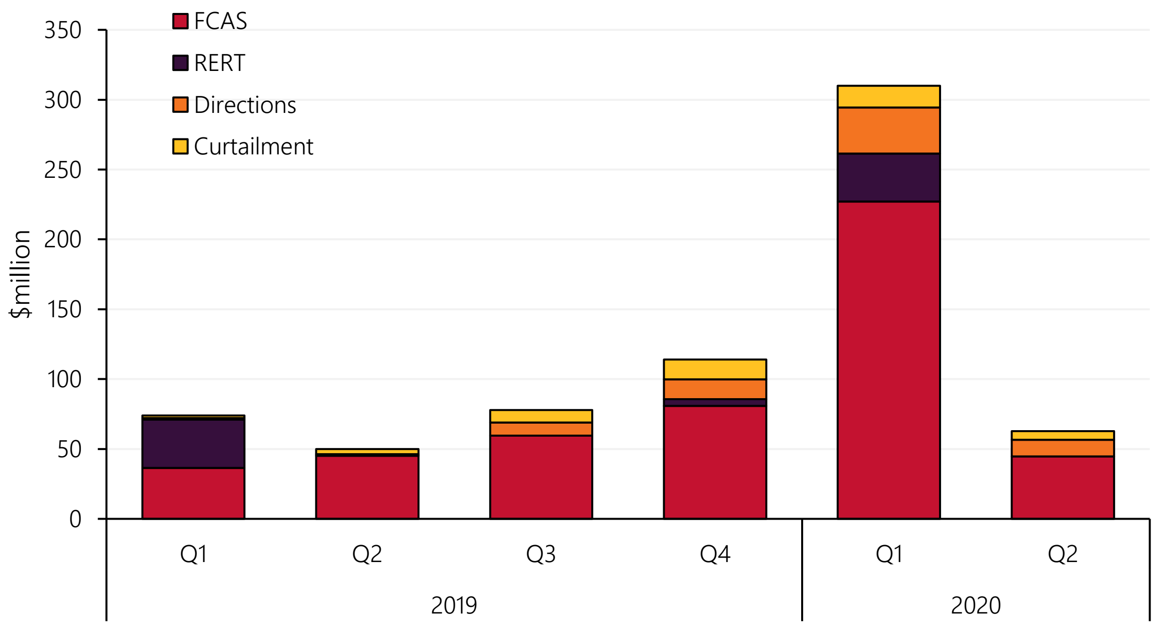
1.6 Power system management

Without any major power system separations this quarter, total system costs reduced from $310 million in Q1 2020, to $63 million in Q2 2020 (Figure 36). By component:

- FCAS costs returned to typical levels after the record levels of Q1 2020. FCAS continued to be the main contribution to system costs. Section 1.6.1 provides details on FCAS.
- The cost of **directing units** to maintain system security declined to $12 million, 65% lower than in Q1 2020, largely due to reduced directions of Victorian generators, with South Australian direction costs reducing slightly. Section 1.6.3 provides details on system security directions for the quarter.
- **Reliability and Emergency Reserve Trader (RERT)** was not required this quarter.
- Estimated **VRE curtailment costs**[16] decreased to $6 million, 59% lower than in Q1 2020. Section 1.6.2 provides details on VRE curtailment for the quarter.

Figure 36 System costs return to typical levels

Quarterly system costs by category



1.6.1 Frequency control ancillary services

Quarterly FCAS costs were $45 million, similar to Q2 2019 but down 80% from record levels in Q1 2020[17] (Figure 37), with the largest decrease occurring in the Contingency Raise markets (-$116 million). These cost reductions occurred despite AEMO's increased FCAS requirements (Figure 38), and were a function of:

- No power system separation events – these events typically lead to very high FCAS costs due to increased FCAS requirements, and the need for FCAS demand to be provided by local supply, which can lead to a tight supply/demand balance and/or increased market concentration.
- Decreased energy prices – Raise FCAS market prices often move in line with energy prices due to the opportunity cost of service provision. Energy prices in Q2 2020 were substantially lower than recent quarters (Section 1.3), contributing to reduced Raise FCAS prices.
- Reduction in the price of offers from FCAS providers.

[16] Excludes economic curtailment. The cost of curtailed VRE output estimated to be $40/MWh of output curtailed.

[17] The AER will provide a detailed analysis of the key drivers of the high price events from Q1 in its upcoming Wholesale Markets Quarterly.

AEMO's FCAS requirements increased substantially compared to recent quarters – compared to Q2 2019, combined Contingency Lower requirements increased by 417 MW (103%), Contingency Raise requirements by 377 MW (31%), and Regulation requirements by 23 MW (5%). The main driver was changes to the load relief component, which affect the Contingency requirements and were progressively introduced between August 2019 and January 2020.

Figure 37 FCAS costs decline from record highs

Quarterly FCAS costs by market[18]

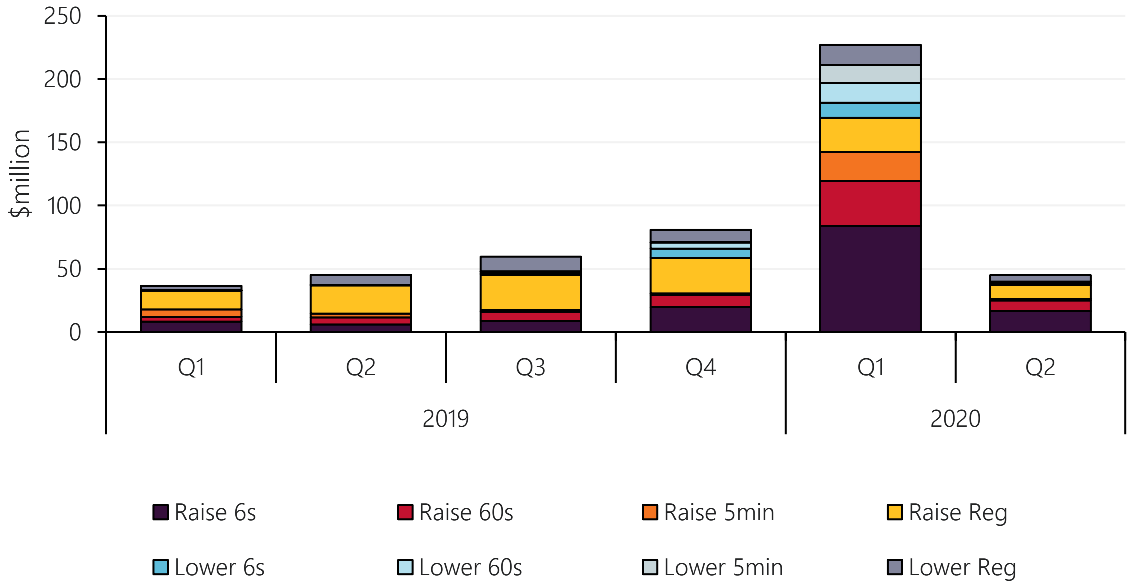
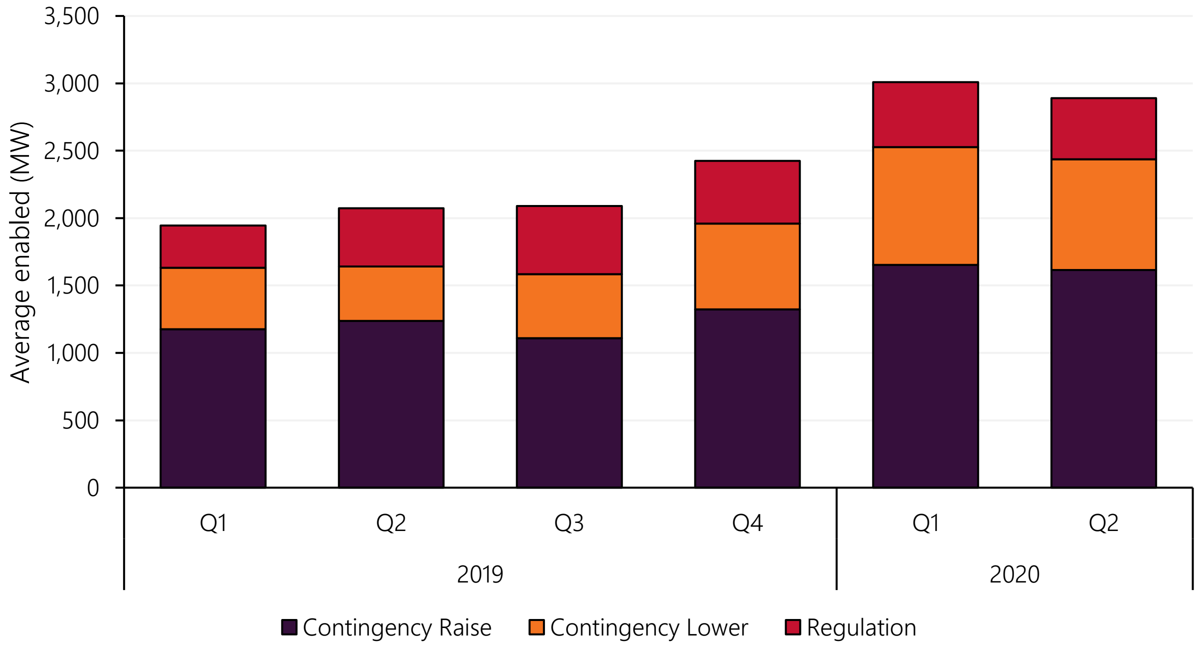


Figure 38 FCAS requirements increased in 2020

Quarterly average FCAS enabled by market



[18] Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

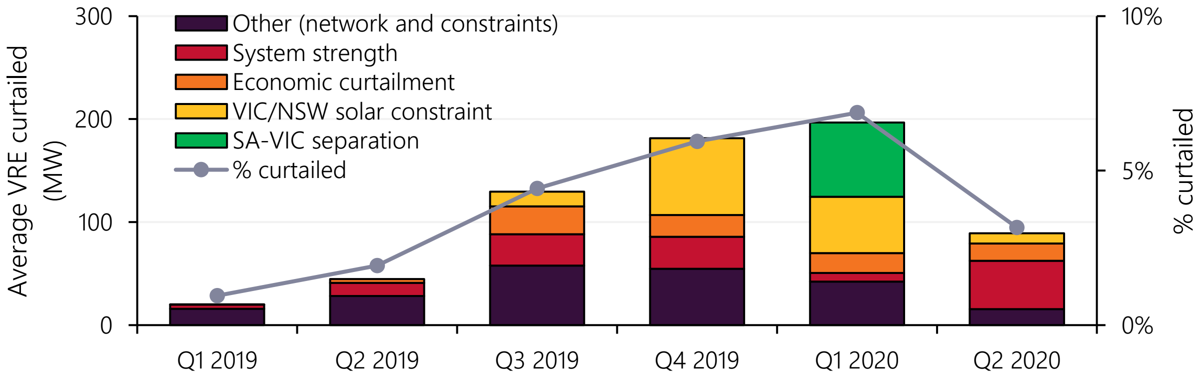
1.6.2 VRE curtailment

In Q2 2020, NEM-wide VRE curtailment dropped to 3.2% of VRE output, compared to 6.9% in Q1 2020. This reverses the trend of increasing curtailment during 2019 (Figure 39). By curtailment driver:

- **Removal of the Victorian and New South Wales solar constraint –** in late April, AEMO lifted generation constraints imposed on five solar farms in the West Murray Zone, following the successful testing of new tuned inverter settings. This substantially reduced estimated curtailment at these solar farms, with the quarterly average amount falling from 55 MW in Q1 2020 to 10 MW in Q2 2020. Figure 40 shows the impact of removing the solar constraint on output in the week it was removed.
- **Lack of power system separation events** – there were no major power system separation events, which contributed to a 72 MW curtailment reduction compared to Q1 2020.
- **Network-related** curtailment reduced to 15 MW on average, down from 42 MW in Q1 2020.
- **Economic curtailment –** despite the comparatively high occurrence of negative spot prices (Section 1.3.2), economically-induced curtailment of VRE output was relatively flat at 17 MW on average. This was due to 90% of negative spot prices ranging between $0 to -$50/MWh, with prices below -$50/MWh typically leading to much higher levels of VRE curtailment.
- **System strength curtailment** was the only contributor to increase, averaging 47 MW. Of this system strength curtailment, 42 MW occurred in South Australia, and 5 MW in Queensland.

Figure 39 VRE curtailment falls for first time in a year

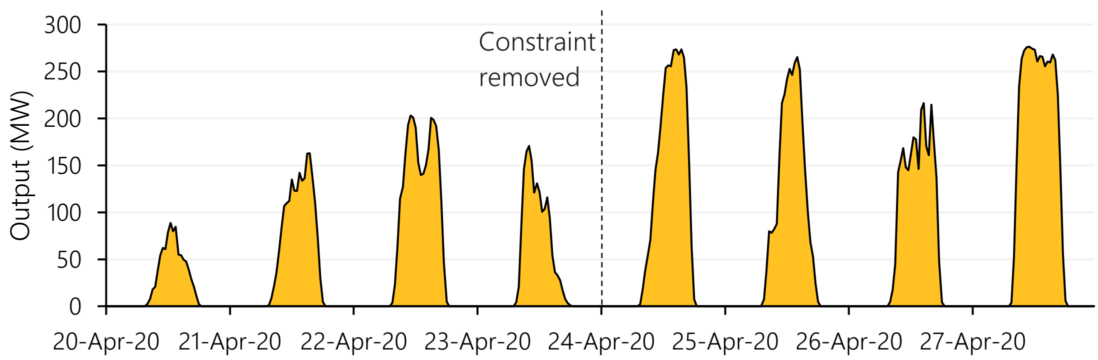
Average NEM VRE curtailed by curtailment type



Note: curtailment amount based on combination of market data and AEMO estimates[19].

Figure 40 Victoria and New South Wales solar constraint removed

Combined solar output at solar farms affected by the constraint – 20-27 April 2020



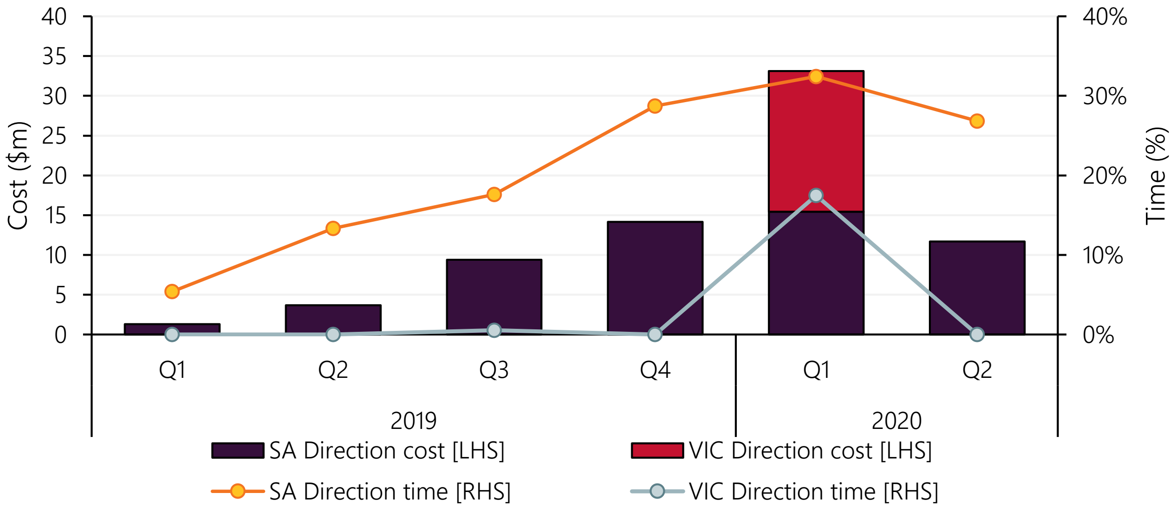
[19] For further information on the curtailment calculation, see: www.wattclarity.com.au/articles/2020/06/not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation/?utm_source=rss&utm_medium=rss&utm_campaign=not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation.

1.6.3 Directions

During Q2 2020, AEMO continued to issue directions to GPGs in South Australia to maintain system security in the region. Total NEM direction costs for energy were $11.7 million, up by $8 million compared to Q2 2019, but down by $21.4 million compared to Q1 2020 (Figure 41). In contrast to Q1 2020, and in line with most quarters, no Victorian directions were required this quarter.

Figure 41 South Australian directions cost remain comparatively high

Time 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.

While NEM direction costs were significantly lower than in Q1 2020, South Australia's direction costs remained comparatively high, due to low daytime operational demand and low spot prices driving GPGs to de-commit for economic reasons. To maintain system strength in the state, these GPG units were subsequently directed to remain in the market.

Compared to Q2 2019, increased directions costs in South Australia were a function of:

- Increased time on direction – South Australian GPGs were directed 27% of the time, up from 13%.
- Increased amount of GPG directed – 50 MW of GPG was directed on average, a 121% increase from Q2 2019.

2. Gas market dynamics

2.1 Gas demand

Total east coast gas demand for Q2 2020 decreased by 7 PJ compared to Q2 2019, due to lower LNG exports from Curtis Island and reduced GPG (Table 3). However, residential, commercial, and industrial demand increased, mostly due to colder than average conditions in Victoria.

Table 3 Gas demand – quarterly comparison[20]

Demand (PJ)	Q2 2020	Q1 2020	Q2 2019	Change from Q2 2019
AEMO Markets *	97	55	93	4 (4%)
GPG **	33	36	38	-4 (-11%)
QLD LNG	317	338	323	-7 (-2%)
TOTAL	447	429	454	-7 (-1%)

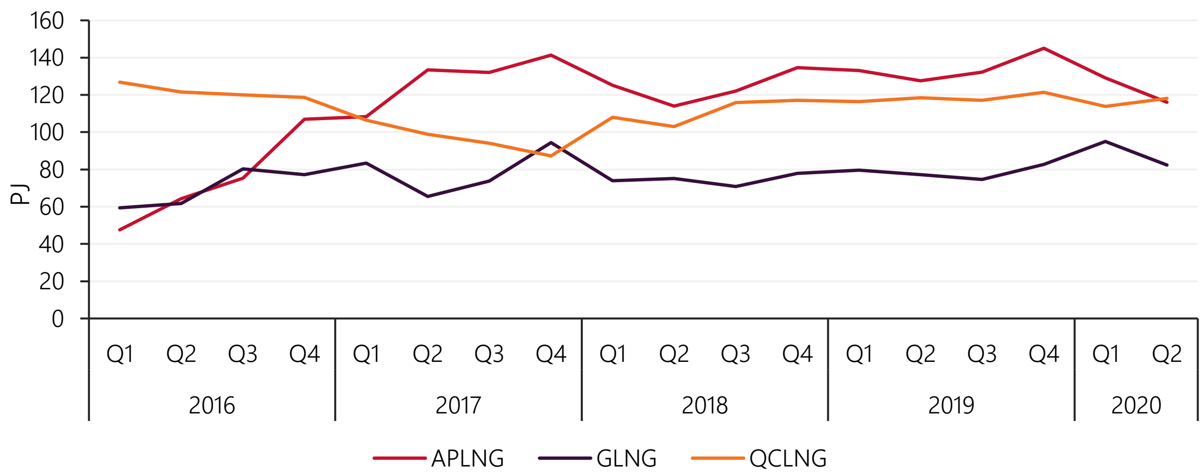
* AEMO Markets demand is the sum of customer demand in each of the STTMs and the DWGM and excludes GPG in these markets.
** Includes demand for GPG usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

A total of 317 PJ flowed to Curtis Island during Q2 2020, a decrease of 7 PJ compared to Q2 2019, and a decrease of 21 PJ compared to the Q1 2020 (Figure 42). This decrease comes after record flows in Q1 2020 and coincides with the continued decline in international oil and gas prices (contracted LNG can be benchmarked against a lagged oil price). There were also maintenance activities on all three facilities at different times during the quarter, contributing to the decrease.

During the quarter, there were 81 LNG cargoes exported, down from 85 in Q1 2020. Australia Pacific LNG (APLNG) and Gladstone LNG (GLNG) both reduced their cargoes, while Queensland Curtis LNG (QCLNG) increased from 27 to 30. This is reflected in a decrease in APLNG flows (-13 PJ) and GLNG flows (-12.7 PJ) to Curtis Island, while QCLNG slightly increased (+4.3 PJ).

Figure 42 LNG exports from Curtis Island decrease by 21 PJ (compared to Q1 2020)

Total quarterly pipeline flows to Curtis Island



[20] Some entries in this table may have minor variations to numbers published in prior QED reports, due to changed accounting of GPGs.

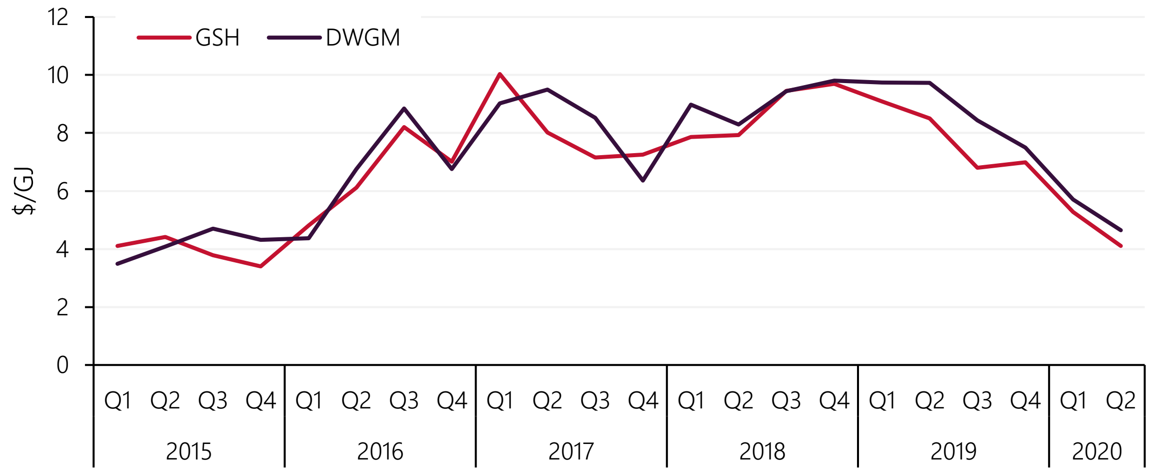
GPG demand decreased by 11% compared to Q2 2019, with reductions in South Australia, Victoria, and Tasmania offsetting a large increase in Queensland (Section 1.4.3). The main driver for reduced GPG was displacement by low-priced supply from other fuel-types (coal, hydro, and wind generation).

2.2 Wholesale gas prices

Wholesale gas prices continued the downward trend from Q1 2020, with the GSH reaching its lowest level since Q4 2015, and the DWGM since Q1 2016 (Figure 43). The largest decreases occurred in the Brisbane and Sydney STTMs (-55%). This was followed by the Gas Supply Hub (GSH, -52%), the DWGM (-52%), and Adelaide STTM (-50%).

Figure 43 Wholesale gas price fall continues

GSH and DWGM quarterly average prices

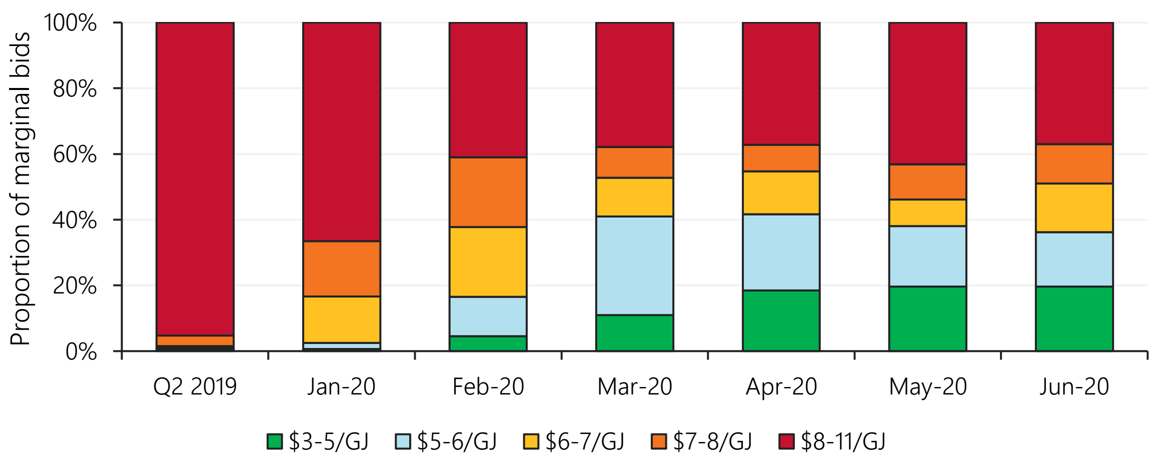


Price decreases were due to decreased demand (from LNG and GPG), and the continuation of more gas being offered at lower prices into the markets. In Q2 2020, 61% of bids in the DWGM were priced under $8/GJ, compared to 4.8% in Q2 2019 (Figure 44). These lower-priced offers continue to coincide with declining international oil and gas prices (Section 1.3.4), and lower NEM prices (Section 1.3).

There was also a continuation in competition in bids from Longford producers – during Q2 2020, BHP continued to offer marginally priced gas below $6/GJ, while Esso offered gas at $7-$8/GJ[21].

Figure 44 Low price gas offers into the DWGM continue into winter

DWGM – proportion of marginal bids by price band



[21] The AER will undertake a more detailed analysis of participant behaviour in its upcoming Wholesale Markets Quarterly.

2.2.1 Gas supply

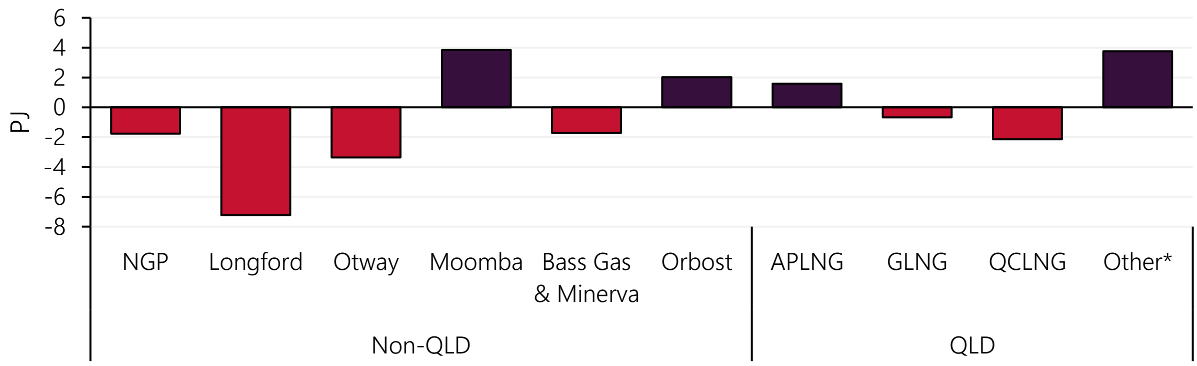
2.2.2 Gas production

Q2 2020 east coast gas production decreased by 1.1% compared to Q2 2019 (Figure 45) due to:

- Reduced Victorian production from Longford (-7.2 PJ) and Bass Gas and Minerva[22] (-1.7 PJ). Longford quarterly production (67.8 PJ) was its lowest Q2 total since 2014. These decreases were partially offset by:
  - Higher Moomba production (+3.8 PJ).
  - Orbost production in Victoria, which commenced on 25 March (+2 PJ). This facility previously processed gas from the Longtom field but has been recommissioned to process gas from Cooper Energy's Sole gas field. Once commissioning is complete it is expected to reach 68 TJ/day[23].
  - Higher Queensland production (+2.5 PJ); increases at APLNG and other QLD facilities were offset by decreases at GLNG and QCLNG.

Figure 45 East coast gas production down 1.1%

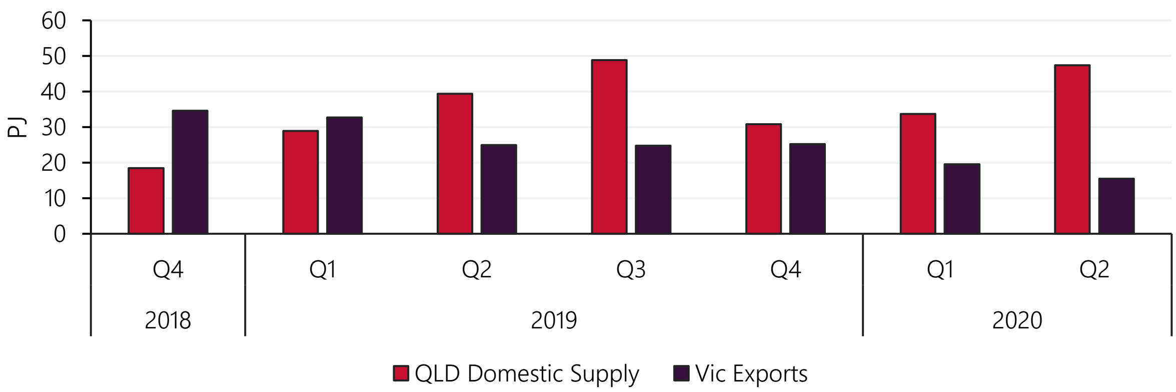
Change in east coast gas supply – Q2 2020 versus Q2 2019



2.2.3 Queensland excess production

Total net domestic supply into Queensland (aggregate Queensland supply minus aggregate demand from QLD LNG) was 47 PJ in Q2 2020, up 8 PJ on Q2 2019 levels (Figure 46). The Q2 increase was a function of reduced LNG exports, with Queensland gas production was unchanged. At the same time, flows from Northern Territory via the Northern Gas Pipeline (NGP) have decreased compared to 2019, and Victorian gas transfers to other states continue to decline (Section 2.3).

Figure 46 Queensland domestic supply increases while Victoria net exports decrease



[22] The Minerva Gas Plant ceased production on 3 September 2019.

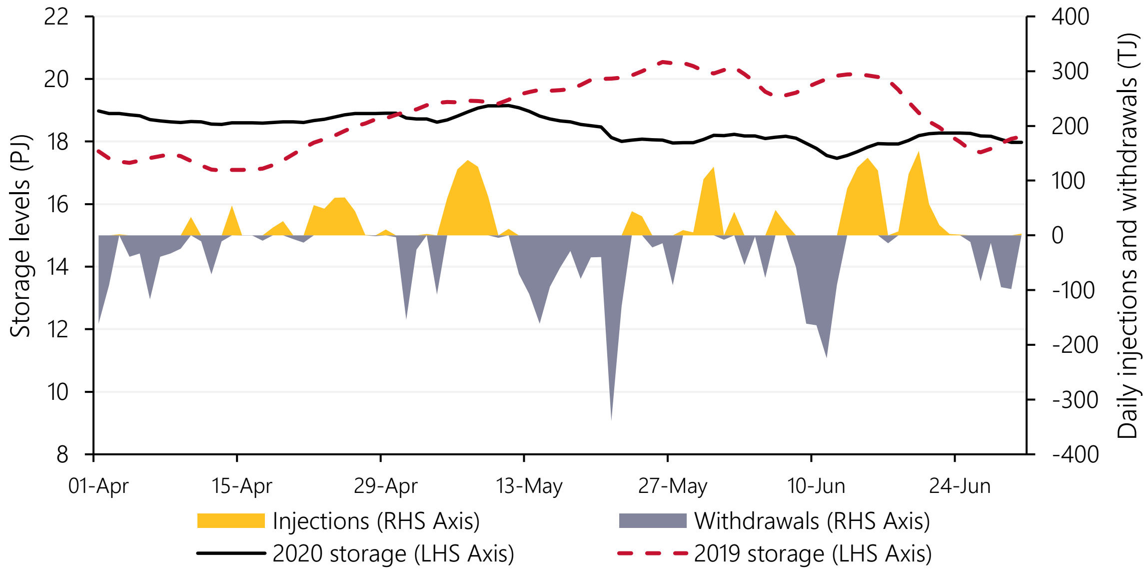
[23] APA 2020, Orbost gas plant upgrade: https://www.apa.com.au/about-apa/our-projects/orbost-gas-plant-upgrade/.

2.2.4 Gas storage

A gas balance of 18 PJ was recorded at the Iona Underground Storage Facility (UGS) in Victoria at 30 June 2020, 0.1 PJ lower than at the end of Q2 2019 (Figure 47). While storage levels were lower than the corresponding period in 2019 for much of May, some milder weather in June – as well as very high gas flow south from Queensland – allowed storage levels to increase, leaving it at a very similar level to 2019.

Figure 47 Iona end of quarter storage levels in line with 2019 results

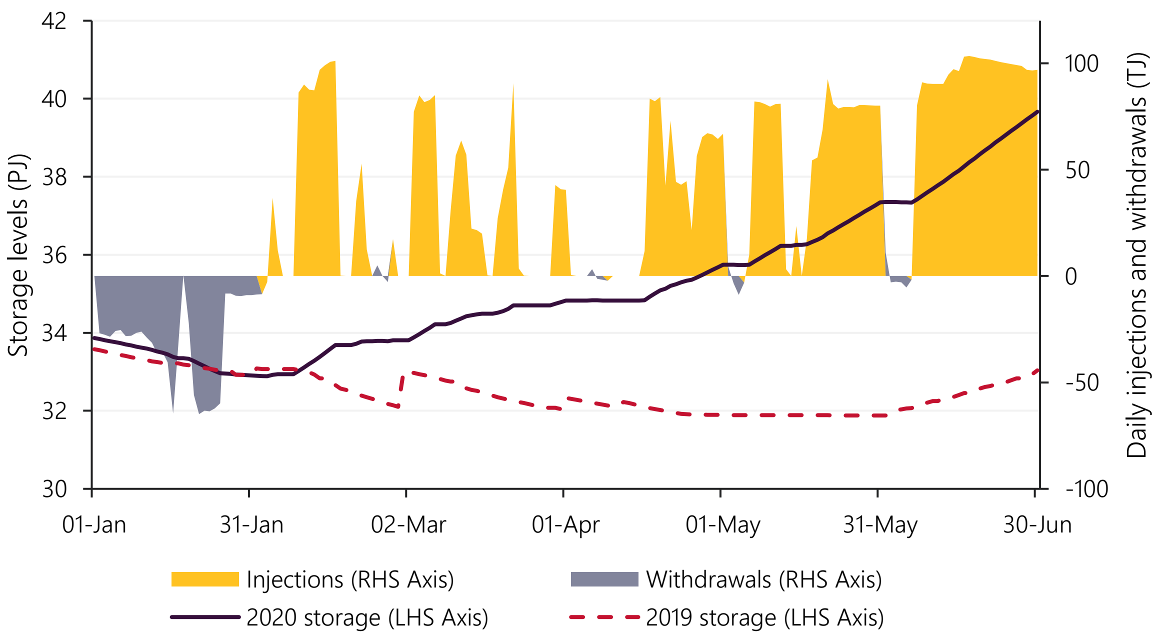
Iona storage levels



Since 9 February 2020, GLNG's Roma Underground Gas Storage (RUGS) has seen a steady increase in storage levels. During 2019 storage levels varied from 31.9 to 33.9 PJ. At 30 June, RUGS recorded a gas balance of 39.7 PJ, 6.6 PJ higher than for the corresponding period in 2019.

Figure 48 Roma storage levels continue to climb

RUGS storage levels



2.3 Pipeline flows

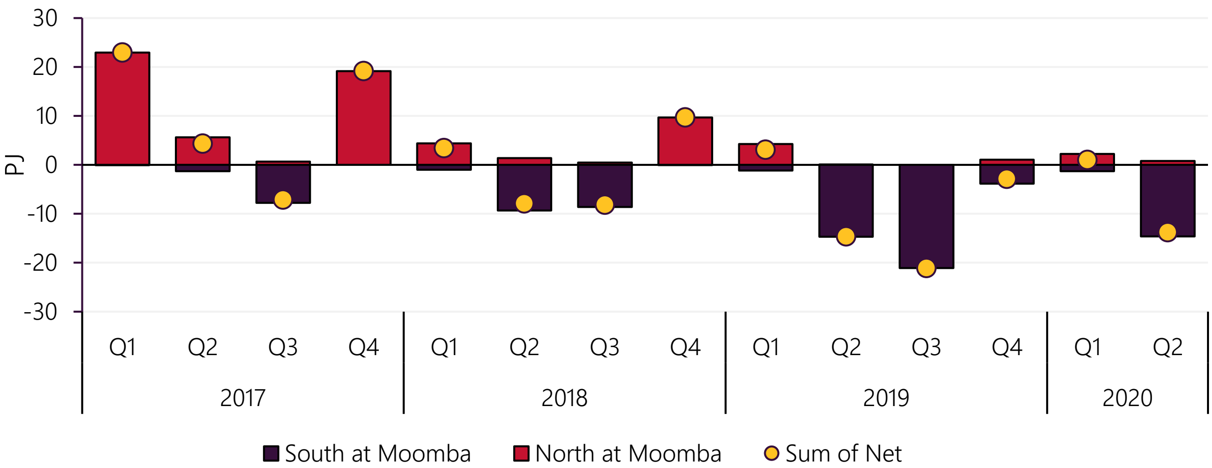
Compared to Q2 2019, there was a 0.8 PJ decrease on net transfers south on the South West Queensland Pipeline (SWQP) (Figure 49). This is despite continued decrease in Victorian gas production, particularly at the Longford Gas Plant.

Reasons for the slight decrease in Q2 2020 flows include:

- A decrease in non-Queensland demand by 4.5 PJ.
- An increase in Moomba production by 3.8 PJ.

Figure 49 Q2 southerly SWQP flows at comparatively high levels

Flows on the South West Queensland Pipeline at Moomba



Victorian net gas exports in Q2 2020 reduced by 9.5 PJ compared to Q2 2019 (Figure 50), due to a continued decrease in Victorian production. Compared to Q2 2019 there was decreased flow from:

- Victoria to New South Wales – Victoria imported a net 4.2 PJ via Culcairn, compared to a net import from New South Wales via Culcairn of 5 PJ in Q2 2019. Exports to New South Wales via the Eastern Gas Pipeline (EGP) decreased by 5 PJ.
- Victoria to South Australia, by 4 PJ.
- Victoria to Tasmania, by 1.2 PJ, due to lower GPG demand in Tasmania.

Figure 50 Victorian gas exports continue to decrease

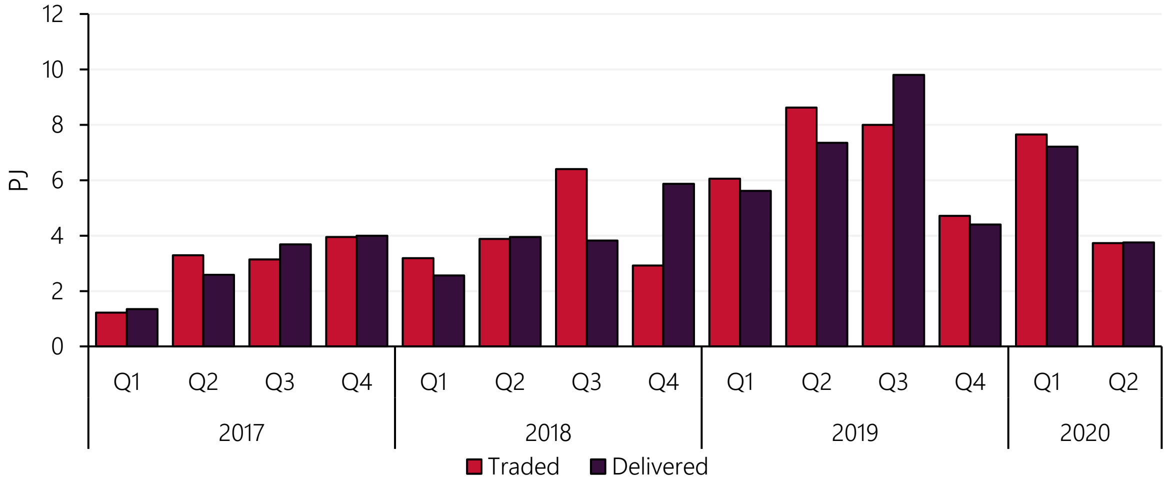
Victorian net gas exports to other states

2.4 Gas Supply Hub

In Q2 2020, the GSH experienced a decrease in trading volumes for both traded and delivered volume compared to Q1 2020 and Q2 2019 (Figure 51). Compared to Q2 2019, traded volume decreased by 4.9 PJ (-57%), and delivered volume decreased by 3.6 PJ (-49%). This represents the lowest delivered volume since Q2 2018.

Figure 51 Comparatively low trading on the Gas Supply Hub

Gas Supply Hub – quarterly trades and deliveries



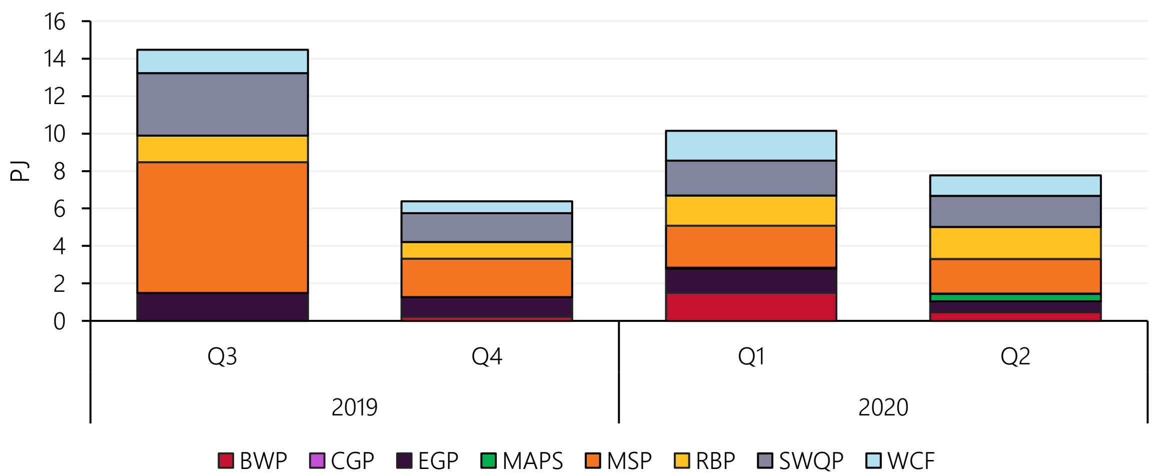
2.5 Pipeline capacity trading and day ahead auction

Compared to Q1 2020, there was a decrease in day ahead auction (DAA) utilisation (Figure 52). Only two pipelines saw an increase, being Moomba to Adelaide Pipeline (MAP) (+0.3 PJ), and Roma to Brisbane Pipeline (RBP) (+0.1 PJ). The AER will review the first year of operation of the DAA in its upcoming Wholesale Markets Quarterly.

Average auction clearing prices were $0/GJ – or close – to on most pipelines. The exception to this was the Moomba to Sydney Pipeline (MSP), which averaged $0.15/GJ for the quarter, however from 22 May to the end of the quarter averaged $0.61/GJ, peaking at $1.15/GJ. The higher MSP price was due to higher competition for capacity on that pipeline, compared to the amount of spare capacity.

Figure 52 Day Ahead Auction utilisation decreases

Day Ahead Auction Results by quarter



2.6 Gas – Western Australia

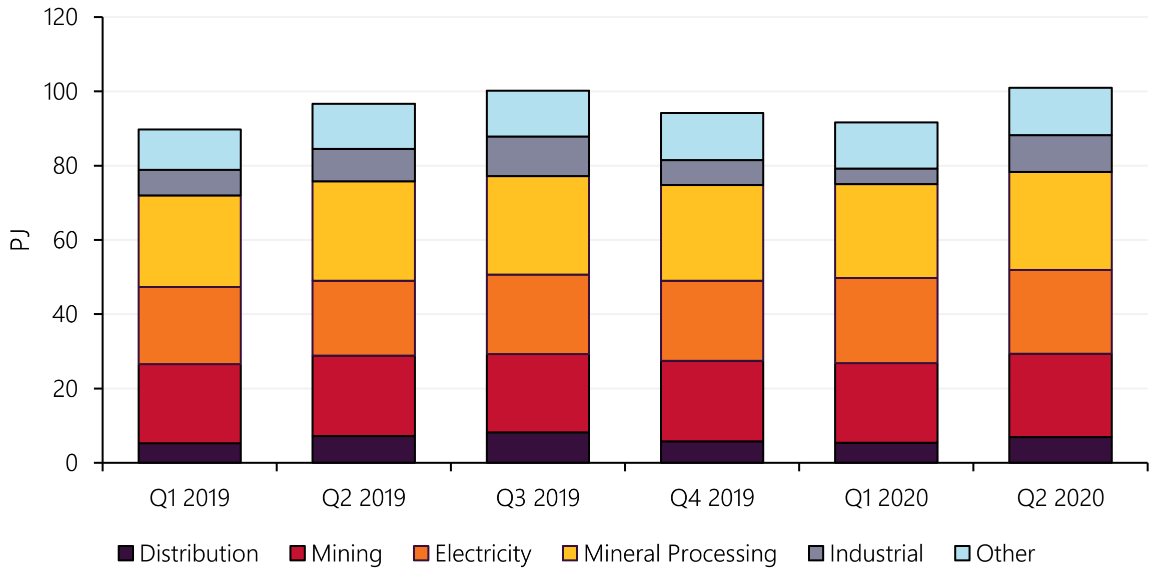
In Q2 2020, total Western Australian gas consumption was 101.0 PJ, representing a 10% increase on Q1 2020 levels (Figure 53). This reflects higher consumption by large users (7.7 PJ) and the distribution network (1.5 PJ).

Consumption by Industrial users increased by 133%, reflecting a return to normal operations after unplanned maintenance shutdowns significantly affected consumption in Q4 2019 and Q1 2020[24].

There was a reduction in consumption from electricity generation (-2%) between Q1 and Q2 2020, due to lower seasonal demand. In contrast, there was a 12% increase in gas consumption for electricity generation from Q2 2019: this can largely be attributed to the lower availability of coal facilities (73.5% in Q2 2020 compared to 98% in Q2 2019), resulting in increased consumption of gas for electricity generation.

Figure 53 Western Australia gas consumption up 10% compared to Q1 2020

WA quarterly gas consumption by industry



With increased gas demand, there was a corresponding increase in gas production. A total of 110 PJ was produced in Q2 2020, up 10% compared to Q1 2020 (Figure 54).

Wheatstone, Varanus Island, and Devils Creek accounted for the most significant increase in production, with 5.0 PJ, 4.3 PJ, and 3.3 PJ increases respectively. These facilities offset the decrease in Karratha Gas Plant's production (-4.7 PJ), which was due to planned maintenance throughout the quarter, and the Xyris facility (11.5 TJ/day nameplate capacity), which remains closed for maintenance and expansion[25] and did not produce gas for the second consecutive quarter. 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[26].

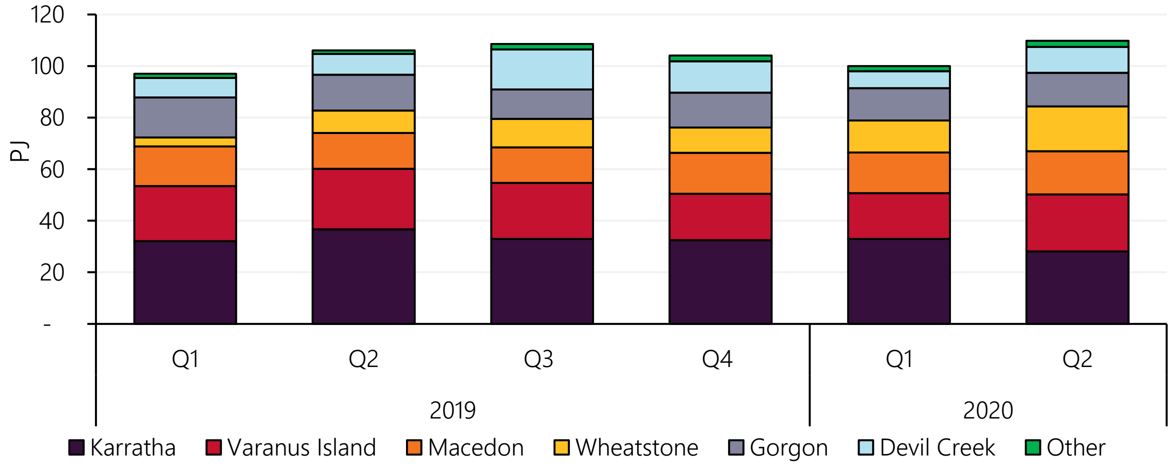
[24] Pilbara News 2019, Rupture shuts down Yara plant: https://www.pilbaranews.com.au/news/pilbara-news/rupture-shuts-down-yara-plant-ng-b881394640z.

[25] 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/.

[26] Mitsui E&P Australia, Stage 1 Expansion: https://mitsuiepmidwest.com.au/what-we-do/production/stage-1-expansion/.

Figure 54 Western Australia gas production up 10% compared to Q1 2020

WA quarterly gas production by facility



In the Q1 2020 QED, AEMO reported an increase in Linepack Capacity Adequacy (LCAs) alerts. An Amber LCA alert indicates likely curtailment of interruptible flows, while a Red LCA alert indicates likely curtailment of firm flows. This trend has continued in Q2 2020. The increase in events is attributable to a change in participant reporting behaviour, whereby planned maintenance events are more frequently being reported on Western Australia's Gas Bulletin Board GBB(WA) as an LCA event. The increase in LCA alerts is not necessarily due to a rise in incidents on the pipelines.

3. WEM market dynamics

3.1 Weather and electricity demand

Perth temperatures in Q2 2020 were 0.5 °C warmer than the 10-year Q2 average, with a quarterly average maximum of 23.2°C, which was 0.7°C warmer than Q2 2019. June 2020 also saw a monthly mean maximum temperature of 21.4°C, which was the highest in 26 years[27].

Average WEM operational demand[28] in Q2 2020 decreased by 8.2% compared to Q1 2020, in line with seasonal demand variation (Figure 55), while ongoing uptake of distributed PV continues to drive lower demand year-on-year, resulting in a decrease of 4.7% compared to Q2 2019 (Figure 56).

In general, demand in Q2 was lower throughout the day, and particularly during the morning peak and midday period, compared to previous years.

Decreases in the morning peak were driven by a combination of impacts from COVID-19 (Section 3.4) and high temperatures. Conversely, COVID-19 contributed to increased demand during the middle of the day and the evening peak, offsetting the impact of temperature, while decreasing demand through the middle of the day was driven primarily by increasing distributed PV uptake.

Higher than average overnight temperatures also resulted in slightly reduced off peak demands as demand for heating decreased.

Figure 55 WEM Q2 operational demand down 4.7%

WEM quarterly average operational demand

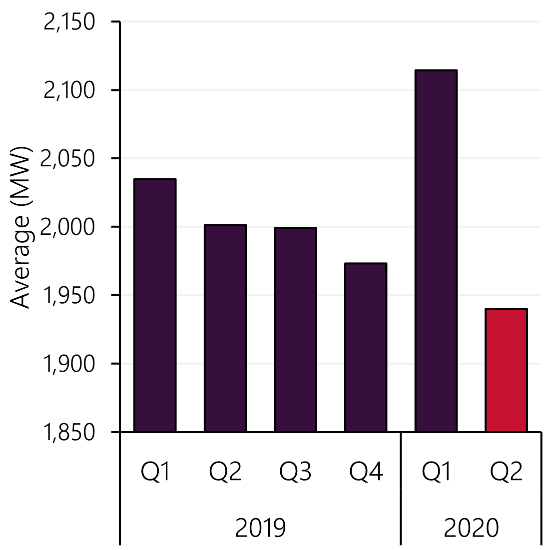
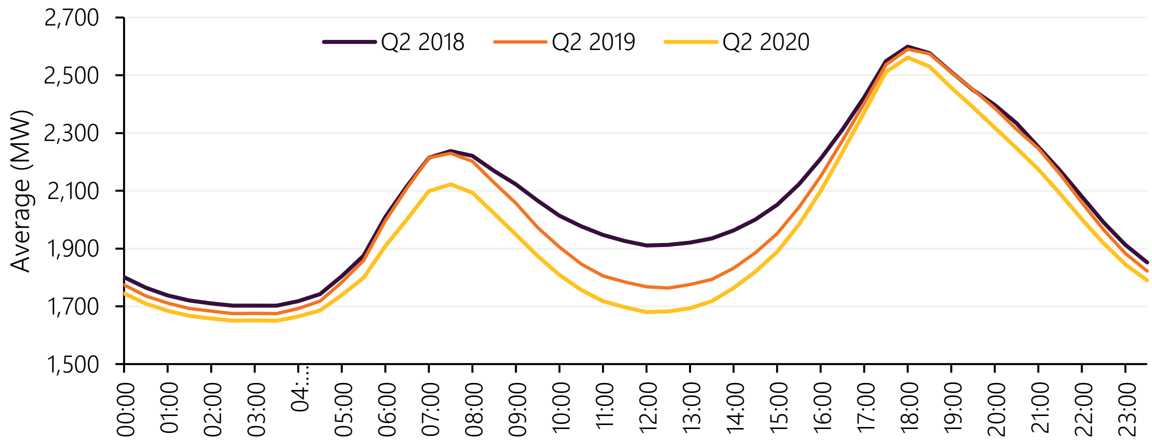


Figure 56 Changing demand patterns: reduced morning peak and daytime demand

WEM Q2 hourly average operational demand by year



[27] See: http://www.bom.gov.au/climate/current/month/wa/perth.shtml.

[28] All demand measurements use 'operational demand' which is the average measured total of all wholesale generation in the South West Integrated System (SWIS) and is based on non-loss adjusted sent out SCADA data.

Maximum and minimum demand

Operational demand reached 1,155 MW at 1100 hrs AWST on Sunday, 26 April 2020, setting a new quarterly record minimum demand for Q2 in the WEM, and breaking the record previously set in 2007 (Table 4). Distributed PV output was the main driver for this event, and was estimated to be 682 MW, or about 37% of the total underlying demand.

This was the fourth consecutive quarter in which a minimum quarterly demand record was set, of which two were all-time minimum demand records, highlighting the continuing impact of distributed PV on demand patterns and quantities in the WEM.

Table 4 WEM maximum and minimum demand records

Maximum demand (MW)			Minimum demand (MW)		
Q2 2020	All-time	All Q2	Q2 2020	All-time	All Q2
3,026	4,006	3,362	1,155	1,135	1,155

3.2 Electricity generation

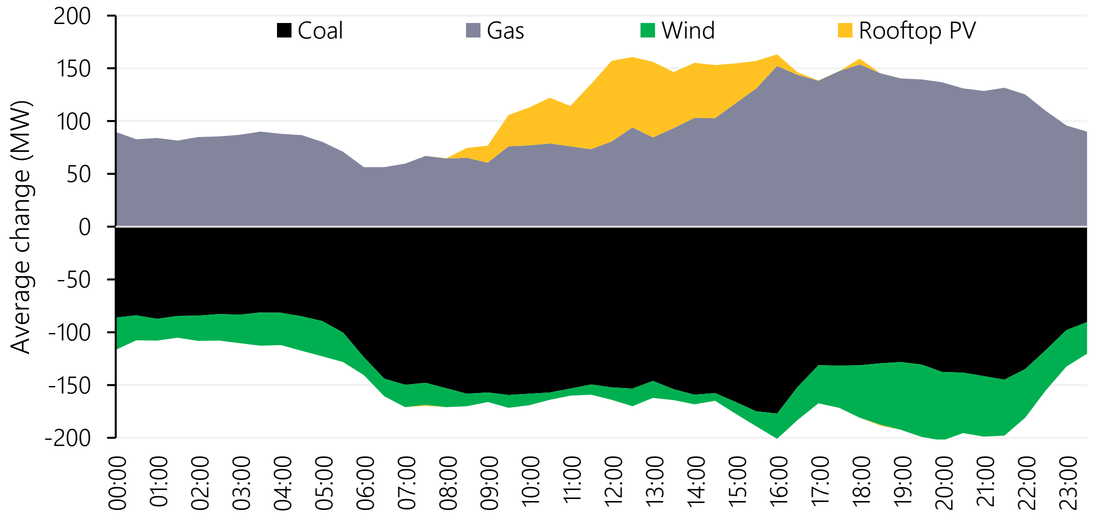
Figure 57 shows the average quarterly change in generation by fuel type compared to Q2 2019 by time of day. These changes highlight the supply mix transformation occurring in the WEM.

Key shifts compared to Q2 2019 include:

- Coal-fired generation saw a decrease by 129.5MW (-14%) on average. The decrease was due to lower coal power availability in Q2 2020 (83.9%) versus 2019 (99.7%), mainly due to planned outages.
- Average GPG significantly increased by 100 MW, to make up for the reduction in coal-fired generation.
- Distributed PV increased by 14 MW on average, with a maximum quarterly output of 900 MW, continuing the trend of rapidly increasing installed distributed PV capacity in the South West Interconnected System (SWIS).
- Wind generation decreased by 27.9 MW (-12%) on average, driven by poorer conditions for wind generation.

Figure 57 GPG covers for coal unit outages

Average change in WEM supply – Q2 2020 versus Q2 2019



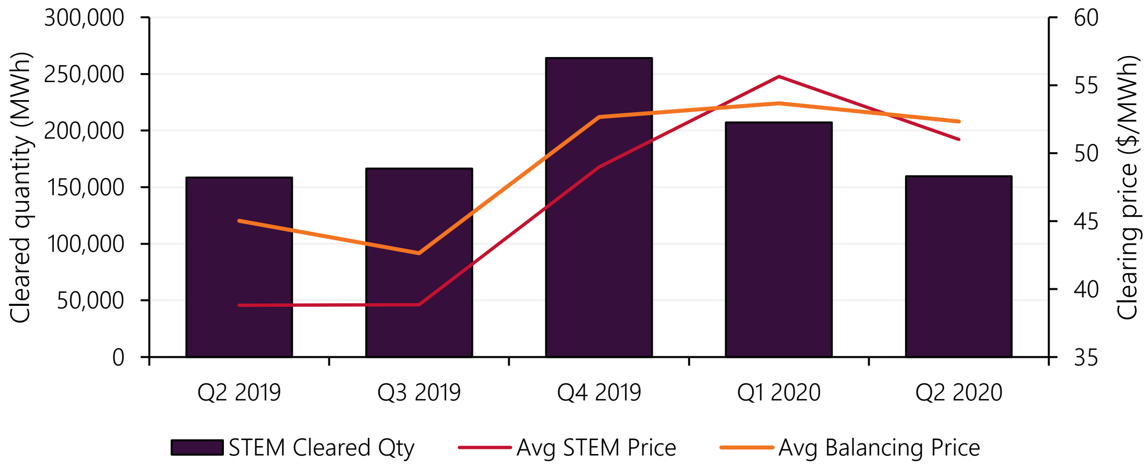
3.3 Wholesale electricity prices

Although there was a decrease in WEM demand, the average Balancing Price in Q2 2020 increased by 16.1% compared to Q2 2019 (Figure 58). The decrease was driven by the change in fuel mix, as greater comparatively low-cost coal-fired generation was on outage and was largely replaced by higher cost GPG (Section 3.2).

Average prices in the Short-Term Energy Marker (STEM) increased by 31.5% with a 0.8% increase in cleared quantity. This increased price was due to changing Market Participant bidding and hedging behaviour in response to the higher prices in the Balancing Market.

Figure 58 Increased outages led to higher Balancing Prices

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

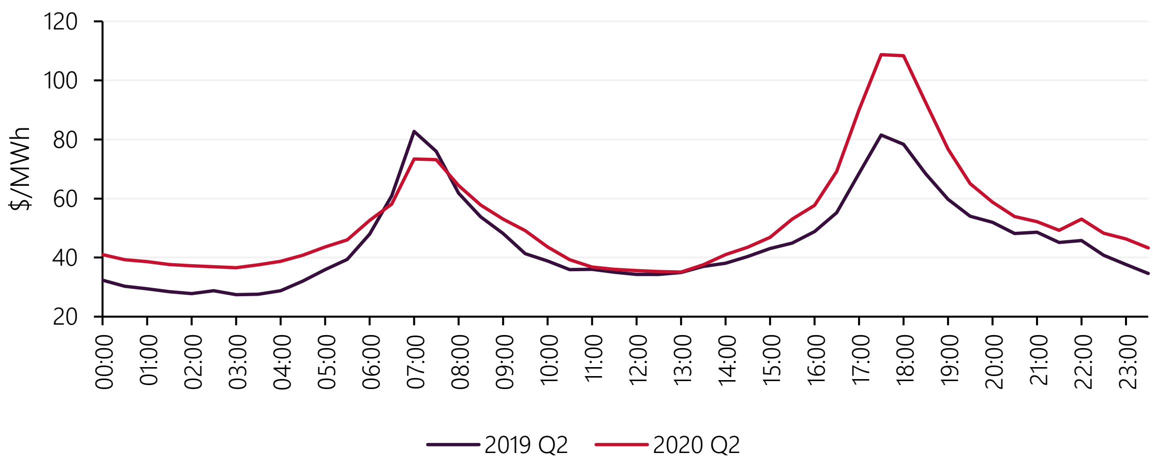


3.3.1 Intra-day pricing

Figure 59 compares the average balancing price by time of day between Q2 2019 and Q2 2020. Despite average operational demand decreasing throughout the day Section 3.1), there was an increase in price throughout most of the day due to increased generation by higher cost GPG. Prices decreased in the morning peak, as this period experienced both the largest decrease in operational demand and the lowest increase in GPG.

Figure 59 Average balancing prices increased throughout the day, except for the morning peak

Average Balancing Price by time of day, Q2 2020 vs Q2 2019



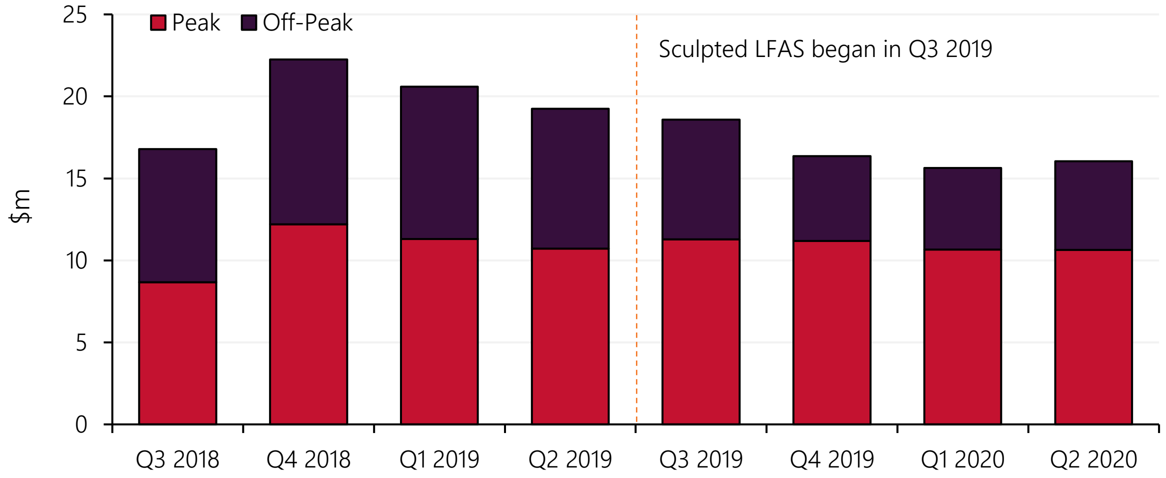
3.3.2 LFAS cost

Total Load Following Ancillary Services (LFAS) availability costs for Q2 2020 were $16.0 million compared to $19.2 million for Q2 2019, representing a 17% decrease (Figure 60). This decrease was driven by the following factors:

- AEMO introduced a 'sculpted' LFAS requirement in the 2019-20 Financial Year in its approved Ancillary Services Report[29]. 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 and Down between 0530 hrs and 1930 hrs (Peak) and 50 MW between 1930 hrs and 0530 hrs (Off-peak).
- Three additional facilities were certified to provide LFAS in 2019, leading to additional competition on the LFAS market.

These changes have led to more cost-effective procurement of LFAS, while ensuring sufficient LFAS is available for system security.

Figure 60 LFAS costs have declined since market start and new LFAS requirements
Quarterly peak and Off-peak LFAS costs since Q2 2019



3.4 WEM COVID-19 impacts

As outlined in Section 1.2.1, the response to the COVID-19 pandemic has had an impact on electricity demand in the NEM. While the response to the pandemic has been coordinated across Australia, there have been some differences in approach at the state level. Due to the isolated nature of the SWIS, and differing technical characteristics between the NEM and WEM, an in-depth examination of the COVID-19 impacts to demand in the WEM is presented here.

This analysis considers the period from 23 March, when initial restrictions were imposed by the Federal Government[30], to 25 May, when the Western Australian Government was relaxing from Phase 2 restrictions (18 May) to Phase 3 restrictions (6 June) under the COVID-19 roadmap[31]. This represents the period with the most significant restrictions on economic activities in Western Australia.

The analysis compares operational demand quantities and patterns during this period and the equivalent period in 2019 to identify any changes which cannot be accounted for by any other factors, such as weather or the impact of distributed PV.

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[29] 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.

[30] See: https://www.australia.gov.au/coronavirus-updates.

[31] See: https://www.wa.gov.au/organisation/department-of-the-premier-and-cabinet/covid-19-coronavirus-wa-roadmap.

In addition to COVID-19's impact on overall operational demand, AEMO has assessed the impact on large consumers (representing large commercial and industrial users) and smaller consumers across the WEM (representing both smaller commercial and industrial users and residential loads) independently.

Overall demand impact

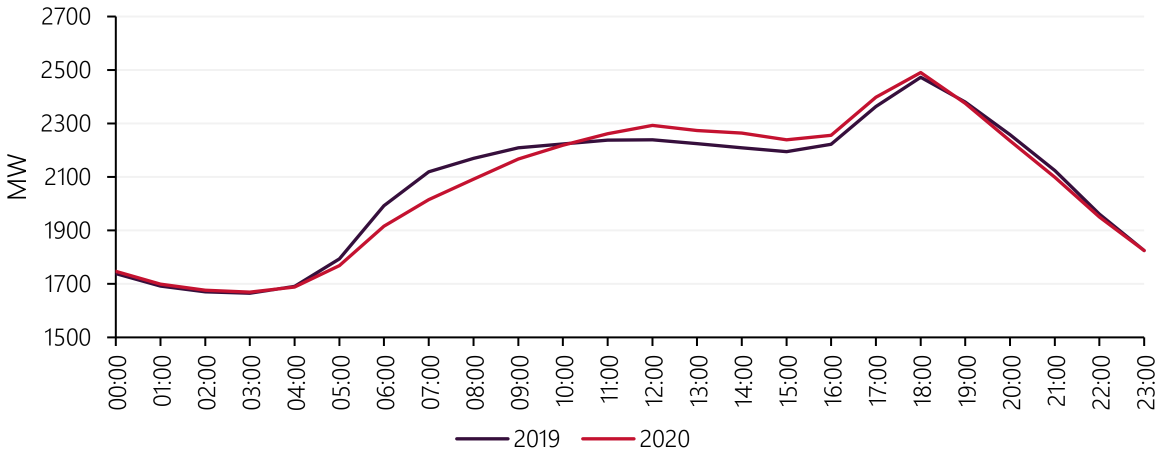
To account for the impact of distributed PV, this analysis considers estimated underlying demand, which is operational demand plus estimated distributed PV output.

Overall changes in average underlying demand were negligible from 2019 to 2020 (0.1% decrease). However, AEMO observed a change to the consumption patterns (Figure 61), with a shift of some consumption from the morning to the period between midday and the evening peak. During the morning (0500hrs to 1000hrs), underlying demand decreased by 3.1% on average, while during the midday to evening peak period (1100hrs to 1900hrs), underlying demand increased by 1.7% on average. Overnight, underlying demand was relatively unchanged.

The period of restrictions falls within the shoulder season between summer and winter. AEMO has assessed the weather trends in the period of restrictions in 2020 and compared to the same period in 2019. While there was an increase in average temperatures of 1.5°C, this are not expected to materially affect the overall average demand for the period, as increases in energy used for cooling are offset by decreases in energy used for heating. Therefore, for the purposes of this analysis it was assumed that the impact of weather on demand changes was negligible.

Figure 61 Overall underlying demand in the WEM was unchanged from 2019 to 2020, despite some minor changes to consumption patterns during the day

Average WEM underlying demand by time of day



Demand impact by segment

To determine whether, and how, varying segments were impacted differently, AEMO has also considered the following segments independently:

- Large users – consumers which consumed at least 160 MWh[32] in the 12 months prior to implementation of COVID-19 restrictions. This is largely representative of large commercial and industrial users.
- Smaller users – consumers which consumed less than 160 MWh in the 12 months prior to implementation of COVID-19 restrictions. This represents smaller commercial and industrial consumers plus all residential consumption.

Analysis was conducted using estimated underlying demand and, where this is not available, aggregated loss-factor-adjusted interval meter data.

[32] Section 47 of the Electricity Industry Act 2004 defines the 160 MWh per annum threshold between small and large end user sites.

Overall, average consumption by large users declined by 7.3% (Figure 62), whereas overall small user consumption increased by about 8.2% (Figure 63). While large user consumption decreases were fairly consistent throughout the day (though slightly larger during peak hours), smaller user increases were significantly larger between noon and the evening peak.

These observations indicate that decreases in morning peak consumption are mainly attributable to a reduction of consumption by large industrial and commercial users as economic activity declined. In contrast, afternoon and the evening peak consumption increases are mainly attributable to an increase in consumption by smaller industrial and commercial users plus residential loads; this is likely attributable to increased time spent at home associated social distancing measures such as working from home and limitations on recreational activities.

Figure 62 Consumption by large users in the WEM decreased by 7.3%

Change in WEM average large user consumption by time of day, Q2 2019 vs Q2 2020 (loss-factor adjusted net interval meter consumption).

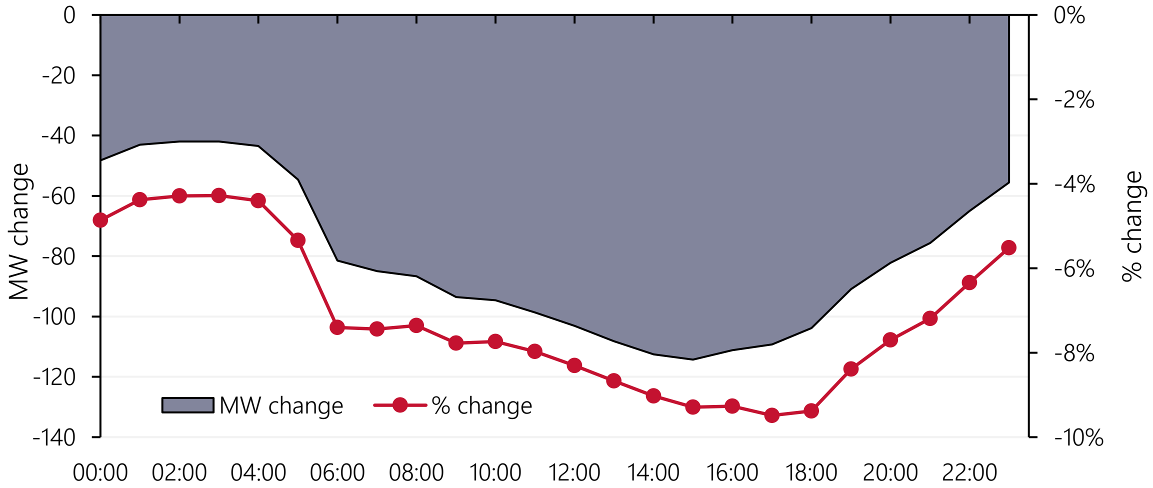
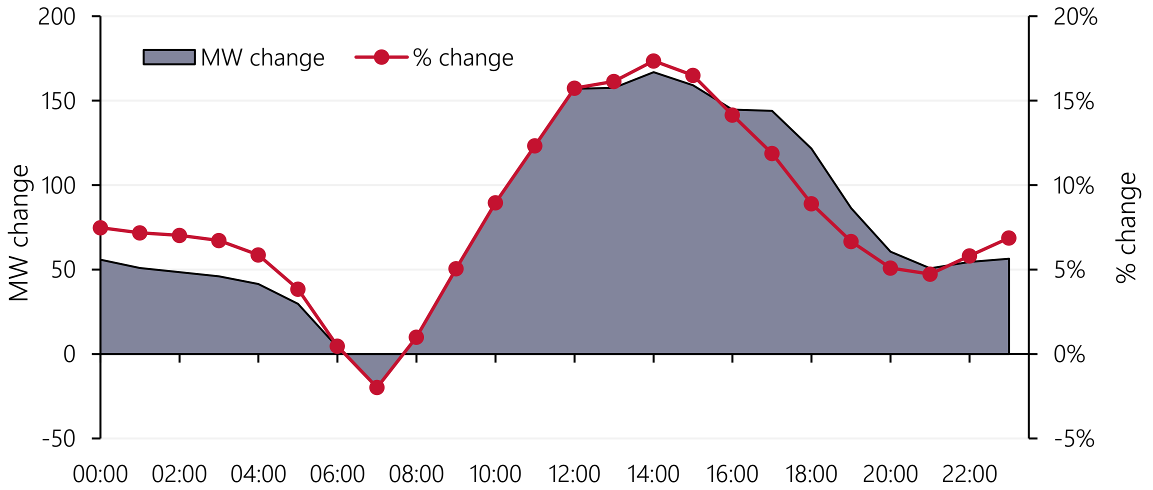


Figure 63 Overall consumption by small users in the WEM increased by 8.2%

Change in WEM average small user consumption by time of day, Q2 2019 to Q2 2020 (total WEM underlying demand less large user loss-factor adjusted net interval meter consumption).



Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Stock Exchange
APLNG	Australia Pacific LNG
AUD	Australian dollars
AWST	Australian Western Standard Time
BBL	Barrel
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
GBB	Gas Bulletin Board
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
LNG	Liquefied natural gas
MAPS	Moomba to Adelaide Pipeline System

Abbreviation	Expanded term
MMBtu	Metric Million British thermal unit
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NGP	Northern Gas Pipeline
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