

Quarterly Energy Dynamics

Q1 2019

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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 2019 (1 January to 31 March 2019). This quarterly report compares results for the quarter against other recent quarters, focussing on Q4 2018 and Q1 2018. 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	07/05/2019	Initial release

Executive summary

National Electricity Market (NEM) Q1 highlights

Hot summer increased electricity demand

- Q1 2019 across Australia was the warmest quarter on record, marked by persistent widespread heat, with extreme temperatures across many parts of South Australia on 24 January 2019, including Adelaide (47.7°C) and Port Augusta (49.5°C).
- Hot summer conditions increased the cooling load, leading to increased NEM average underlying demand¹ (+515 MW) and operational demand² (+243 MW) compared to Q1 2018.
 - Queensland set a new all-time maximum demand record of 10,044 MW on 13 February 2019 at 1730 hrs, 246 MW higher than the previous record.

Record high spot wholesale electricity prices in Victoria and South Australia

- Victoria and South Australia's quarterly average spot wholesale electricity prices of \$166/MWh and \$163/MWh were their highest on record. These results were not only driven by the electricity price volatility but underlying energy prices (that is, prices below \$300/MWh) were also high.
 - Q1 2019 quarterly cap returns were \$51.28/MWh in Victoria – its highest quarter on record – and \$49.41/MWh for South Australia. This volatility largely occurred on 24 and 25 January due to high coincident temperatures across both states increasing demand, a series of unplanned thermal unit outages, and comparatively low wind output.
 - Extreme conditions on these days also led to AEMO activating Reliability and Emergency Reserve Trader (RERT) contracts and, when these were insufficient, instructing load shedding on both 24 and 25 January to balance demand with available supply.
- Victoria and New South Wales recorded their highest underlying energy price on record, while Queensland, South Australia and Tasmania recorded their seconded highest energy prices on record. Drivers of high underlying energy prices included:
 - Dry conditions which resulted in a reduced output from hydro generators.
 - A continuation of comparatively high wholesale gas prices.
 - An increase in the price of offers from black coal-fired generation, with some generators citing coal conservation and/or quality issues.
 - Increased demand resulting from hot summer conditions.
- Forward wholesale prices also continued their upward climb: the price of calendar year (Cal) 2020 electricity swap contracts traded on the ASX rose between 12-23% over Q1 2019 and have risen by 49% in Victoria since July 2018.

Increased solar generation due to new capacity; hydro output reduced due to dry conditions

- Key changes in the NEM supply mix compared to Q1 2018 included:
 - An increase in average solar generation (both rooftop photovoltaic [PV] and grid solar) of approximately 700 MW, due to increased installed capacity.
 - Continued dry conditions in the south led to average hydro output decreasing by around 200 MW.
 - Gas-powered generation (GPG) rebounded from the record low quarterly output in Q4 2018, increasing by 143 MW on average compared to Q1 2018. This increase in GPG occurred predominantly in the evening peak period, corresponding with higher demand, higher spot electricity prices and declining solar output.

Wholesale gas prices remained high as gas-powered generation and oil prices rebounded

- Wholesale gas prices remained comparatively high at around \$9-10/GJ, increasing across all markets by an average of 15% compared to Q1 2018.
- The driver of the price increases was increased demand (largely from GPG and increased LNG exports), as well as higher priced gas injection offers.
- International Brent (oil) prices reversed the price fall that occurred over Q4 2018, increasing by 27% in Q1 2019 to finish at \$US68/bbl.

¹ Underlying demand is consumers' total demand for electricity from all sources, including the grid and distributed resources such as rooftop PV.

² 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.

Western Australia Wholesale Electricity Market (WEM) Q1 highlights

- The WEM has traditionally been summer peaking, however, during Q1 2019 summer peak demand fell to winter peak demand levels. This was due to mild summer conditions and increased penetration of rooftop PV.
- Average Load Following Ancillary Service (LFAS) Up and LFAS Down prices converged for the first time since LFAS market start.
- Non-scheduled generation in the WEM reached its highest ever proportion of underlying system demand at 47.8%.

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1. NEM market dynamics

1.1 Weather

Q1 2019 across Australia was the warmest quarter on record. Compared to both Q1 2018 and the 10-year average, average maximum temperatures were around 1°C higher across all capital cities (Figure 1). There were also multiple periods of prolonged heatwaves during the quarter, particularly in January³. For example, record-breaking temperatures were recorded across many parts of South Australia on 24 January 2019, including Adelaide (47.7°C) and Port Augusta (49.5°C).

The start of 2019 was also notable for dry conditions, with below average rainfall across most of the country except northern Queensland. The dry conditions have been most persistent in the Murray-Darling basin, which has recorded below average rainfall for almost two years⁴. Tasmanian rainfall for the quarter was again below average, making it six months of dry conditions.

Figure 1 Average max temperature variance by capital city – Q1 2019 vs Q1 2018 and 10-year Q1 average

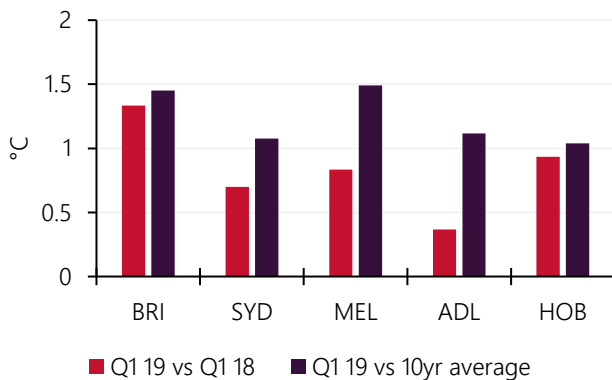
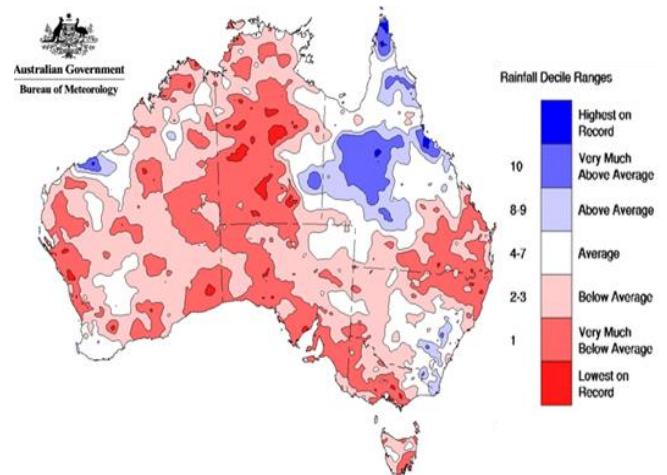


Figure 2 Rainfall deciles – Q1 2019



Source: Bureau of Meteorology

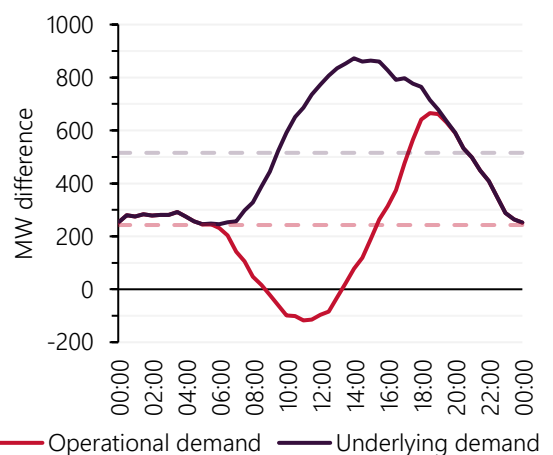
1.2 Electricity demand

Warmer summer conditions increased the cooling load, leading to increased electricity demand across all parts of the day compared to Q1 2018. Average NEM operational demand⁵ in Q1 2019 was up 243 MW (+1%) compared to Q1 2018, while underlying demand⁶ was up 515 MW on average. This difference between underlying and operational demand (Figure 3) highlights the impact of rooftop PV generation on the demand curve.

Compared to Q1 2018:

- The largest increase in average operational demand was in New South Wales (+216 MW), while Queensland also increased (+111 MW, Figure 4). The driver in these regions was the hot weather which increased cooling load in the major population centres.
- Operational demand reduced in Victoria (-50 MW) and South Australia (-1 MW) due to increased generation from rooftop PV more than offsetting increases in the underlying demand.
- Operational demand in Tasmania (-33 MW) slightly decreased, partly driven by small changes in industrial consumption.

Figure 3 Change in NEM demand by time of day – Q1 2019 vs Q1 2018



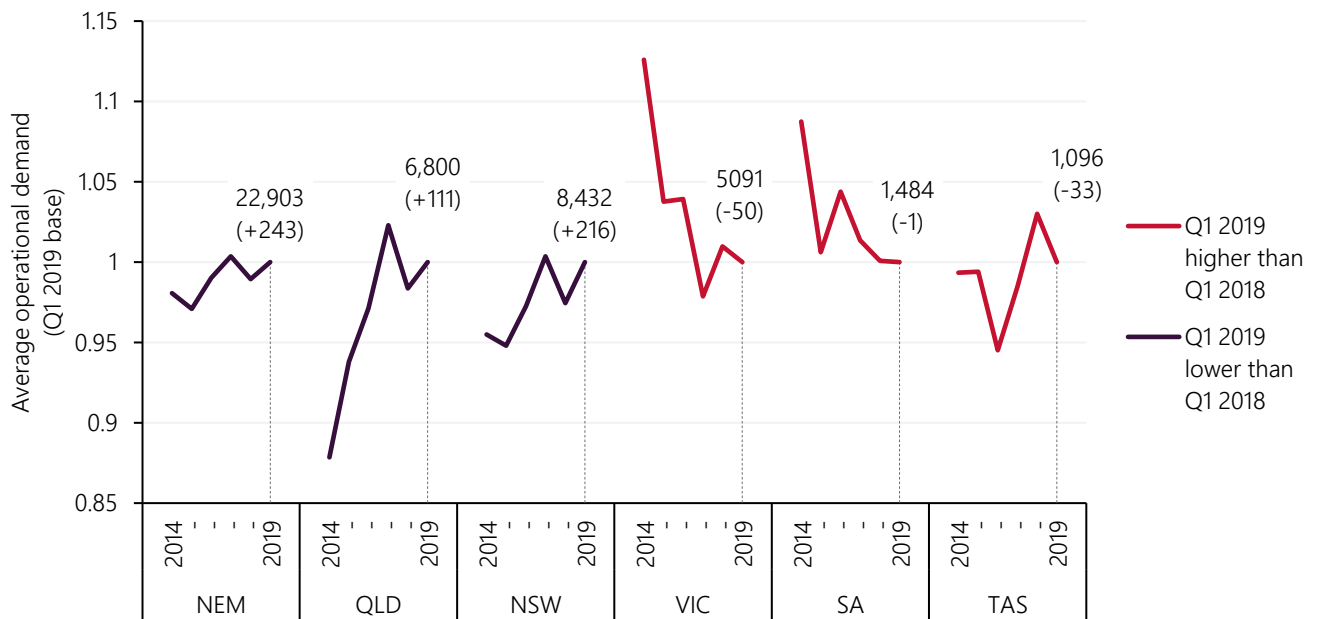
³ For further information see BOM [Special Climate Statement 68 - widespread heatwaves during December 2018 and January 2019](#)

⁴ For further information see BOM [Special Climate Statement 70—drought conditions in eastern Australia and impact on water resources in the Murray-Darling Basin](#)

⁵ 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.

⁶ Underlying demand is consumers' total demand for electricity from all sources, including the grid and distributed resources such as rooftop PV.

Figure 4 Average operational demand for Q1 (2014 to 2019)



Note: Demand by region has been normalised with Q1 2019 as the base. Values greater than 1 indicate that demand was higher than in Q1 2019 while values less than one represent the opposite. Units within the columns are in MW.

Maximum and minimum demand

The seasonal profile of demand tends to manifest in Q1 being the quarter where maximum demand records occur, with the exception of Tasmania which is winter peaking. Table 1 outlines the maximum and minimum demands which occurred in Q1 2019 and the respective regional records⁷. During the quarter, two demand records were broken:

- Queensland continued a trend of increasing maximum demands, setting a new all-time maximum demand record of 10,044 MW on 13 February 2019 at 1730 hrs, 246 MW higher than the previous record⁸. The new record occurred during a period of high temperatures
 - Despite hot weather, maximum demands in other regions did not reach record levels due, in part, to increased output from rooftop PV.
- South Australia set a new Q1 minimum demand record of 695 MW on 6 January 2019 at 1300 hrs, 25 MW lower than the previous record. The drivers of this are the same as previous records, with increased rooftop PV capacity lowering midday operational demand – a trend that has occurred for the past two years and is expected to continue.

Table 1 Maximum and minimum operational demand (MW) by region – Q1 2019 vs records

	Queensland		New South Wales		Victoria		South Australia *		Tasmania	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q1 2019	10,044	4,847	13,821	5,773	9,328	3,601	3,240	695	1,363	756
All Q1	9,798	3,260	14,744	4,642	10,576	3,311	3,399	720	1,499	552
All-time	9,798	3,102	14,744	4,642	10,576	3,217	3,399	599	1,790	552

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

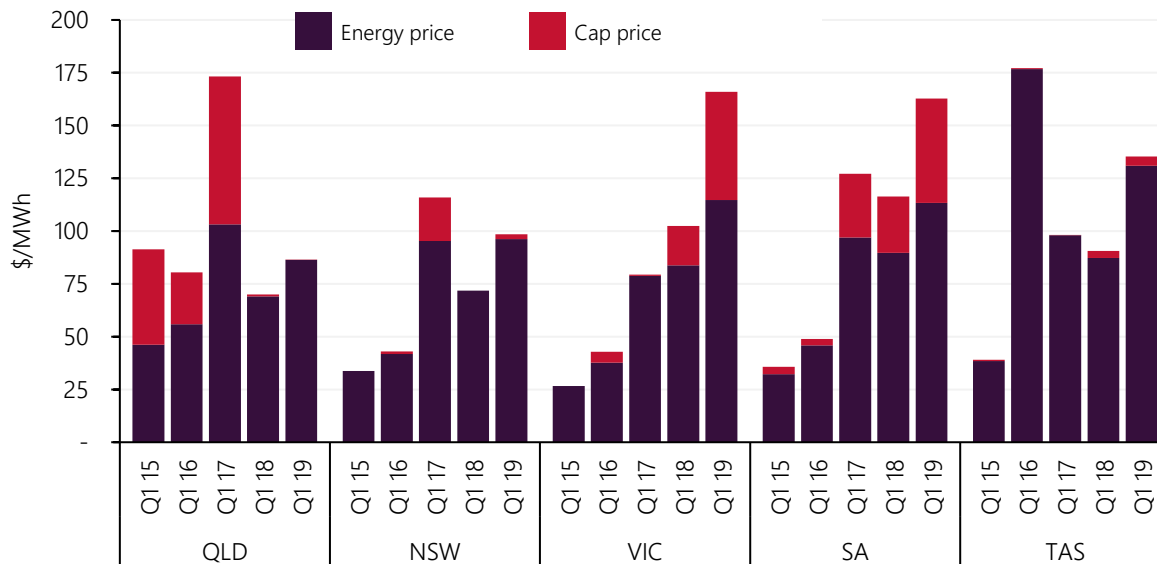
⁷ Table records refer to those prior to the commencement of Q1 2019. Instances where the previous record has been broken are shown with red text. The records go back to when the NEM began operation as a wholesale spot market in December 1998. Tasmania joined in May 2005.

⁸ <http://energylive.aemo.com.au/Energy-Explained/Queensland-breaks-demand-record>

1.3 Wholesale electricity prices

Q1 2019 was notable for the high spot wholesale electricity prices recorded in all NEM regions (Figure 5).

Figure 5 Average wholesale electricity price by region



This was a result of spot price volatility in Victoria and South Australia, as well as high underlying energy prices⁹ (that is, prices below \$300/MWh) in all NEM regions.

- Victoria and South Australia’s quarterly average spot electricity prices of \$166/MWh and \$163/MWh were their highest on record.
- Victoria and New South Wales recorded their highest underlying energy price on record, while Queensland, South Australia and Tasmania recorded their seconded highest energy prices on record. Spot prices were consistently above \$100/MWh for much of the quarter. For example, Victoria’s price was above \$100/MWh for 58% of the quarter, compared to 19% of the quarter in Q1 2018.

Drivers of high energy prices are discussed in the table below, while price volatility results are discussed in Section 1.3.1.

Wholesale electricity price drivers in Q1 2019

Dry conditions	Compared to Q1 2018, hydro generators shifted approximately 800 MW of capacity to prices above \$100/MWh, resulting in reduced dispatch at lower prices. This reflects recent dry conditions and the need to conserve dam storage levels (see Section 1.4.3).
High gas prices	Wholesale gas prices remained at comparatively high levels during Q1 2019 (see Section 2.2), which was reflected in comparatively higher GPG offers. Compared to the previous three Q1s, approximately 250 MW of GPG offers on average was shifted to prices above \$100/MWh (from prices below \$100/MWh).
Shifts in black-coal fired generator offers	In Q1 2019, there was a further shift in offers from black coal-fired generators. Approximately 800 MW offered below \$100/MWh in Q1 2018, was moved to prices above \$100/MWh in Q1 2019. Some generators highlighted coal conservation and/or quality issues as reasons for their changed offers over the quarter. See Section 1.4.2 for further details.
Increased demand	Hot summer conditions increased NEM average operational demand by 243 MW compared to Q1 2018. The largest increase in operational demand occurred in the late afternoon and evening peak demand periods (1600-2200 hrs), resulting in higher prices during these periods.

⁹ ‘Energy price’ is used in electricity pricing to remove the impact of price volatility (that is, prices above \$300/MWh).

1.3.1 Price volatility

During Q1 2019, there was high spot price volatility in Victoria and South Australia, but low volatility in New South Wales and Queensland, consistent with outcomes in Q1 2018.

Victoria and South Australia

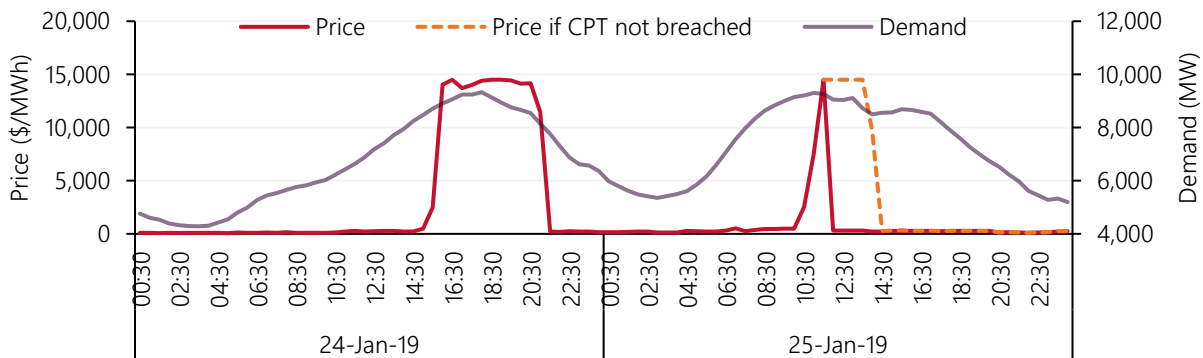
Q1 2019 quarterly cap returns¹⁰ were \$51.28/MWh in Victoria – its highest quarter on record – and \$49.41/MWh for South Australia. This volatility largely occurred on two days due to a confluence of events in the two regions. Victoria and South Australia’s daily average prices of \$3,378/MWh and \$3,360/MWh on 24 January 2019 were their highest on since NEM-start (Figure 6). The continuation of price volatility into 25 January resulted in the Cumulative Price Threshold (CPT)¹¹ being triggered, limiting the maximum price to \$300/MWh once it came into effect.

Contributors to these pricing outcomes included:

- Temperatures in South Australia broke new records on 24 January 2019, while parts of country Victoria experienced extreme heat (close to record levels). Simultaneous high temperatures in South Australia and Victoria resulted in high electricity demand across both regions, with coincident maximum operational demand of 12,463 MW on 24 January 2019 (representing the highest result since Q1 2014).
- A series of brown coal outages on these days reduced thermal capacity in Victoria by up to 1,600 MW.
- Wind capacity factors were comparatively low during the high-priced periods (average of 15% during the high prices, compared to average capacity factors of 30% during high demand periods in Victoria).

Extreme conditions on these days also led to AEMO activating Reliability and Emergency Reserve Trader (RERT) contracts and (as a last resort) AEMO instructing load shedding on both 24 and 25 January to balance demand with available supply. AEMO’s report on *Load Shedding in Victoria on 24 and 25 January 2019*¹² provides more details on the events of these two days.

Figure 6 Victorian spot electricity price and operational demand on 24 and 25 January 2019



Queensland and New South Wales

Despite hot weather and record demand in Queensland, Q1 2019 quarterly cap returns were comparatively low in Queensland and New South Wales (less than \$0.01/MWh and \$2.33/MWh, respectively). This represents a continuation of the lack of price volatility in these two regions which has occurred since Q1 2017. Even record high Queensland operational demand on 13 February 2019 only resulted in maximum spot prices of \$143.68/MWh. Contributors to this trend include:

- Comparatively high availability of the black coal fleet at prices below \$300/MWh over the last two summers. For example, there was an additional 814 MW on average offered below \$300/MWh in Q1 2019 compared to Q1 2017.
- The Queensland Government’s instruction to its state-owned generators to “undertake strategies to place downward pressure on wholesale prices”.¹³
- The return at the end of 2017 of Swanbank E (380 MW), which has run over the peak summer periods since then.

¹⁰ 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 half hourly 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.

¹¹ The cumulative price threshold imposes a limit on sustained high prices in the wholesale market. For further details on the CPT, see Reliability Panel 2018, *Reliability standard and setting review 2018*. Available at: www.aemc.gov.au/sites/default/files/2018-04/Reliability%20Panel%20Final%20Report.pdf

¹² AEMO 2019. *Load Shedding in Victoria on 24 and 25 January 2019 – An operating incident report for the National Electricity Market*, at www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf

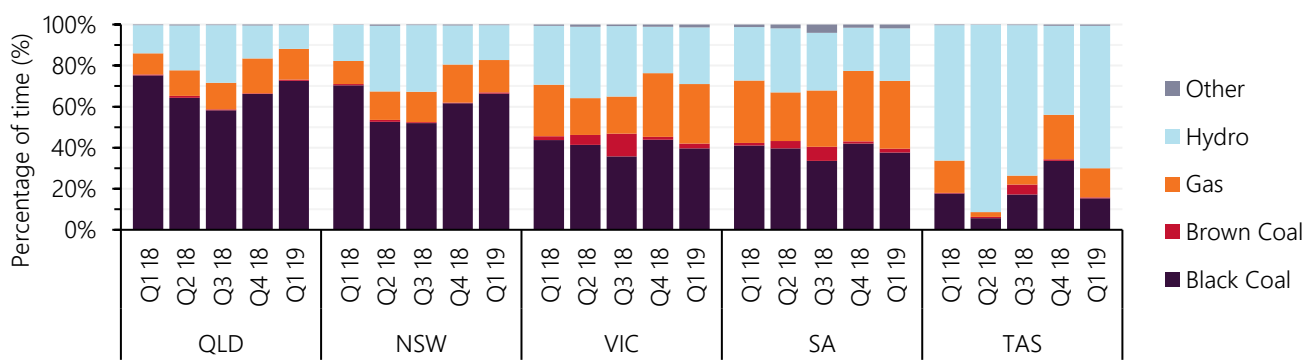
¹³ <https://dnrme.qld.gov.au/energy/initiatives/powering-queensland>

1.3.2 Price-setting trends

Despite the significant increase in NEM spot wholesale electricity prices (Section 1.3), price setting outcomes during Q1 2019 were relatively similar to Q1 2018 with minor changes amongst the fuel types. By region:

- **Queensland and New South Wales** – black coal continued to be the primary price setter in Queensland and New South Wales, setting the price approximately 70% of the time (predominantly in the off-peak periods). Compared to Q1 2018, there was a small reduction in black coal price setting, which was offset by increases in gas as the marginal unit.
- **Victoria and South Australia** – the marginal fuel source in Victoria and South Australia remained balanced between black coal (around 40%), gas (around 30%) and hydro (around 30%). These proportions tend to fluctuate subtly depending on changes in generation and availability across periods. Black coal’s price setting role decreased when compared to both Q1 2018 and Q4 2018, with small increases in the price setting role for gas and hydro. The reduction in black coal as the marginal unit was coincident with constraints on flows south over the VIC-NSW interconnector (see Section 1.6).
- **Tasmania** – Tasmania’s price was set by local units 61% of the time, in line with Q1 2018 results, with the marginal fuel sources remaining relatively similar to this quarter. The main price setting units were Gordon and Poatina.

Figure 7 Price-setting by fuel type – Q1 2019 versus prior quarters



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

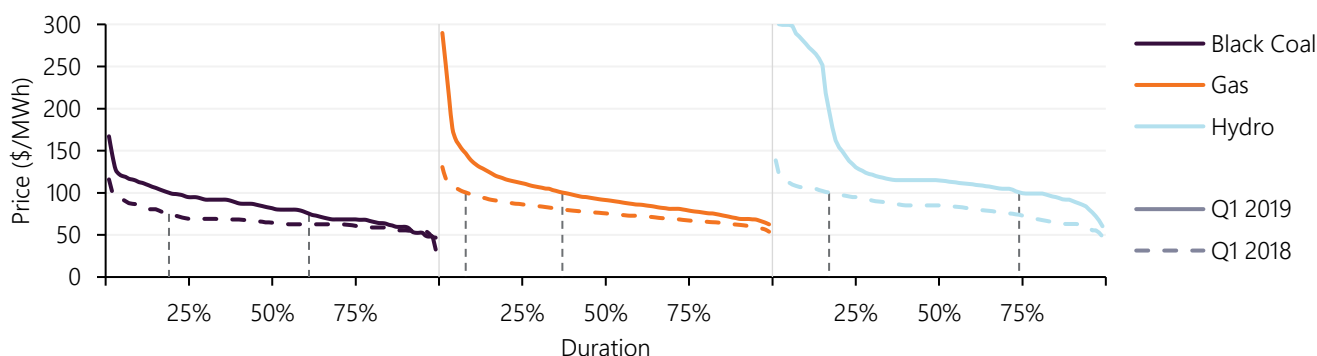
Case study: New South Wales – Q1 2019 versus Q1 2018

While the price setting share by fuel types remained similar between Q1 2019 and Q1 2018, the point at which the marginal units (and respective fuels) set the price increased across almost all percentiles this quarter. Figure 8 shows the price setting curves for the major price setting fuel types in New South Wales, which had a significant increase in the underlying price of energy this quarter compared to Q1 2018 (see Section 1.3).

In Q1 2018, gas and hydro were interchangeable in their role as the marginal unit, setting the price at comparable prices. This dynamic shifted in Q1 2019, with hydro setting price at comparatively higher prices than gas units.

- When hydro was marginal, it set the price above \$100/MWh 74% of the time compared to just 17% of the time in Q1 2018. This reflects the shift in offers from hydro units to higher priced bands due to low water storage levels (Section 1.4.3).
- For gas units, the increase was reflective of higher wholesale gas prices flowing through into increased electricity price offers (Section 1.3). Gas also played a more frequent price setting role than hydro, typically setting price lower than hydro units.
- Black coal-fired generators also set the price at higher levels than in Q1 2018: setting the price above \$100/MWh 19% of the time during the quarter versus 2% of the time in Q1 2018. This reflects higher priced offers from black-coal fired generators (Section 1.4.2), which also coincides with higher-priced offers from the other key price setting fuel types.

Figure 8 Price-setting duration curve by fuel type – New South Wales – Q1 2019 versus Q1 2018



1.4 Electricity generation

During the quarter the changing demand profile, capacity additions, and the pricing of dispatchable generation induced shifts in the supply mix. Figure 9 shows the average change in generation by fuel type compared to Q1 2018 and Figure 10 illustrates the changes by time of day. Key shifts included:

- An increase in rooftop and grid solar generation of approximately 700 MW on average, with 2,173 MW of new grid scale capacity commencing generation since Q1 2018.
- Black coal-fired generation reduced by 133 MW on average, reflecting: displacement by solar during the daytime; shifts into higher priced bands; and a 217 MW reduction in average availability.
- Hydro output decreased by 200 MW on average, due to dry conditions over the quarter and low storage levels.
- GPG rebounded from record low quarterly output in Q4 2018, increasing by 143 MW on average compared to Q1 2019. This increase occurred predominantly in the evening peak period, coinciding with higher spot electricity prices and declining solar output.

Figure 9 Change in supply – Q1 2019 versus Q1 2018

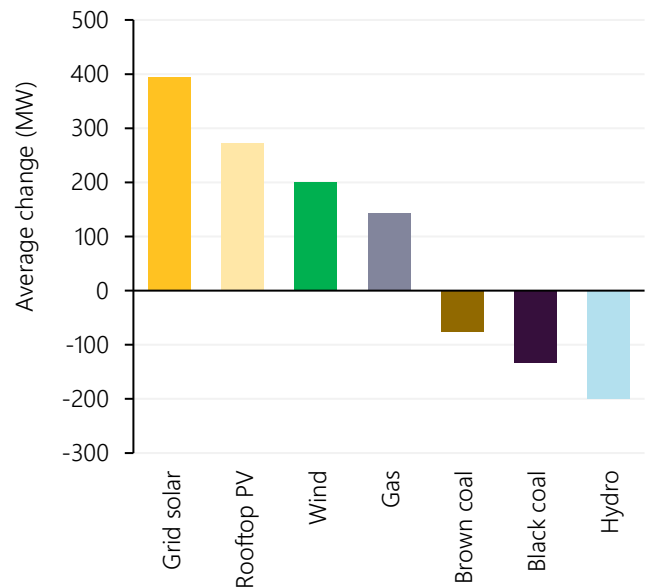
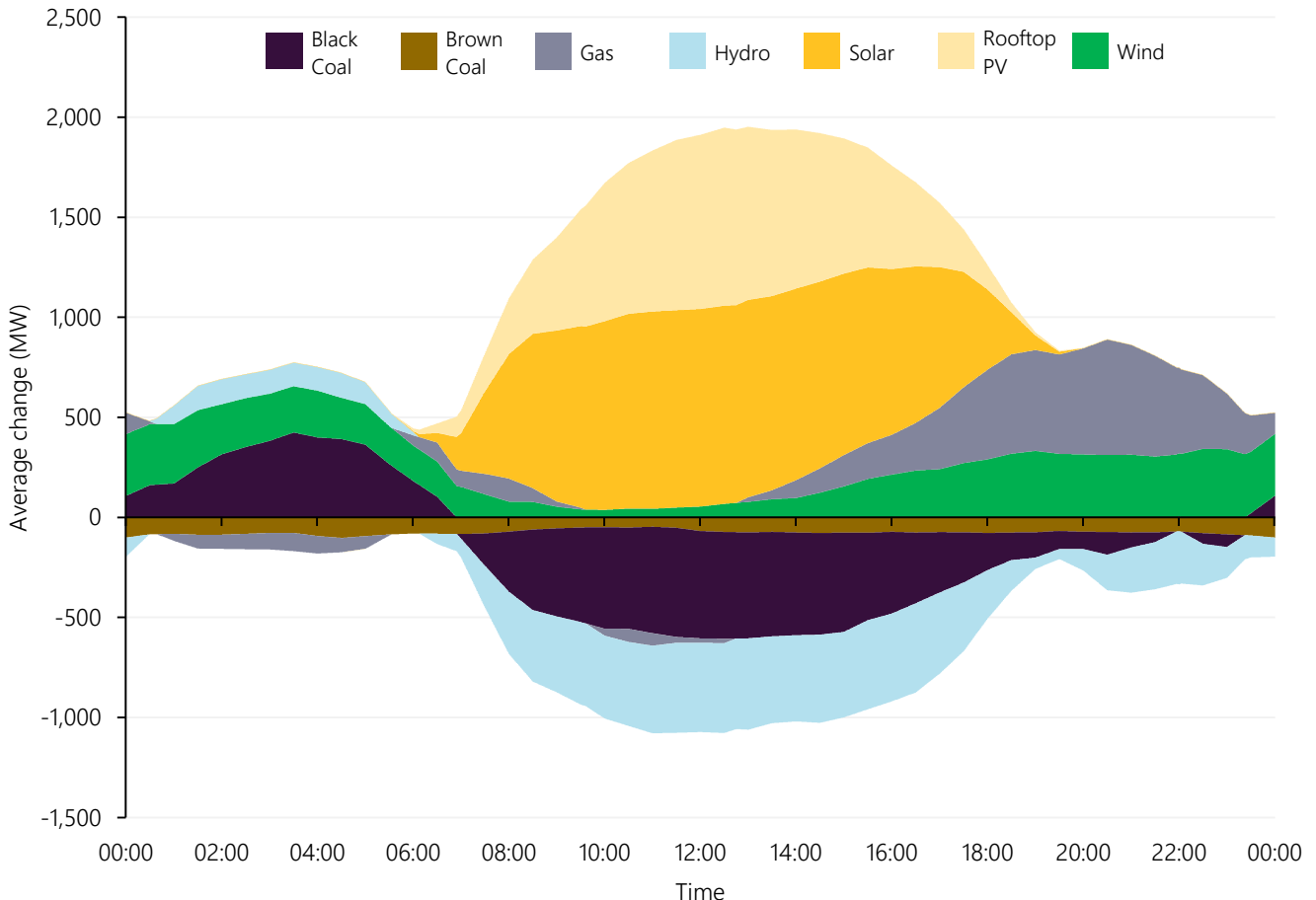


Figure 10 Change in supply – Q1 2019 versus Q1 2018 by time of day



1.4.1 Wind and solar generation

Compared to Q1 2018, average large-scale wind and solar generation increased from 1,521 MW to 2,116 MW (+39%) (Figure 11). Average wind generation increased by 201 MW and large-scale solar generation increased by 394 MW, as additional capacity was brought online.

The rapid deployment of large-scale solar generation has continued with five new solar farms totalling 326 MW capacity commencing generation in Q1 2019 (Table 2). Of this new large-scale solar capacity, four solar farms commenced generation in Queensland (231 MW), and one in South Australia (95 MW).

Figure 11 NEM wind and solar generation by region

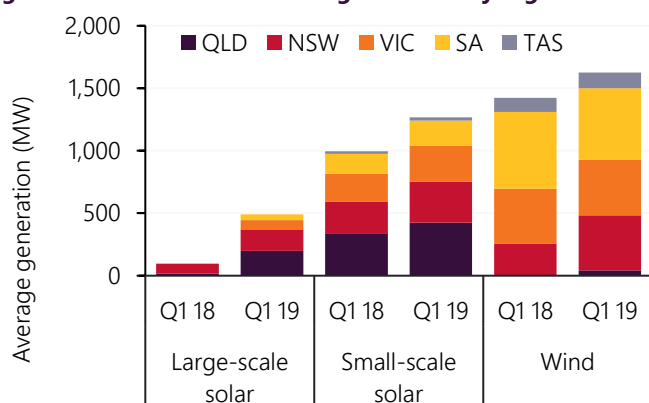


Table 2 New entrants in the NEM in Q4 2018

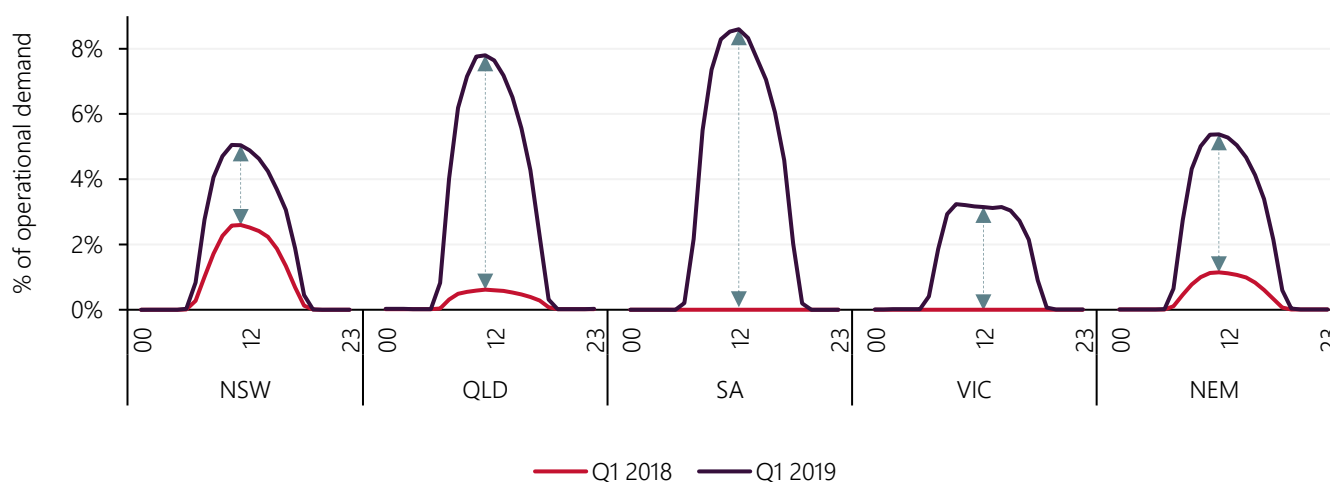
Technology	New entrant	Capacity (MW)	Region
Solar	Childers Solar Farm	56	QLD
	Hayman Solar Farm	50	
	Lilyvale Solar Farm	100	
	Oakey 1 Solar Farm	25	
	Tailem Bend Solar Project 1	95	SA

Note: Table includes new entrants that began generating during the quarter. Several of these projects are still undergoing testing and have yet to commence generating at full capacity.

In Q1 2019, large-scale solar met 5% of total midday operational demand, contrasting its contribution of 1% in Q1 2018 (Figure 12). The growing contribution is due to more than 2 GW of large-scale solar capacity commencing generation since the beginning of 2018 and was particularly marked in South Australia and Queensland, with around 8% of demand met by large-scale solar, compared to almost no contribution in Q1 2018.

Of note, the shape of Victoria’s large-scale solar generation profile illustrates the impact of solar tracking technology¹⁴: During summer tracking systems capture more direct solar radiation for longer periods of the day. This combined with the sizing of the inverter results in a flatter generation profile and higher capacity factors. In 2018, more than two-thirds of new grid solar capacity came from systems utilising single-axis tracking.

Figure 12 Percentage of Q1 2018 and Q1 2019 operational demand met by large-scale solar generation by time of day



Between Q1 2018 and Q1 2019 average rooftop PV generation increased from 995 MW to 1,268 MW (+27%). The largest increase was in New South Wales (30%), with substantial increases also occurring in Victoria (28%) and South Australia (28%). Increases in generation correspond with a record amount of installed rooftop PV capacity over 2018, and 2019 so far.

¹⁴ Unlike conventional, fixed axis systems, tracking solar has panels that tilt around a north-south axis to follow the sun – they face east in the morning, are horizontal at solar noon and face west in the evening.

1.4.2 Coal-fired generation

Total coal-fired generation reduced output by 209 MW on average compared to Q1 2018, despite higher NEM spot prices (Figure 13). By region, Queensland black coal-fired generation decreased by 132 MW on average, while New South Wales black coal-fired generation remained unchanged. The largest changes in average output between quarters were at Liddell (+232 MW), Mt Piper (-279 MW), Gladstone (-125 MW) and Stanwell (-74 MW) power stations. Drivers of these changes are outlined in the table below.

Brown coal-fired generation reduced by 76 MW on average when compared to Q1 2018, largely due to reduced availability and output at Loy Yang A and Yallourn power stations.

Figure 13 Coal availability and generation

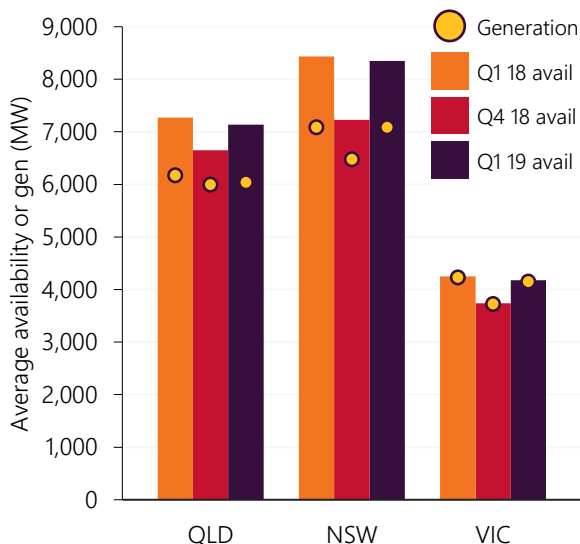
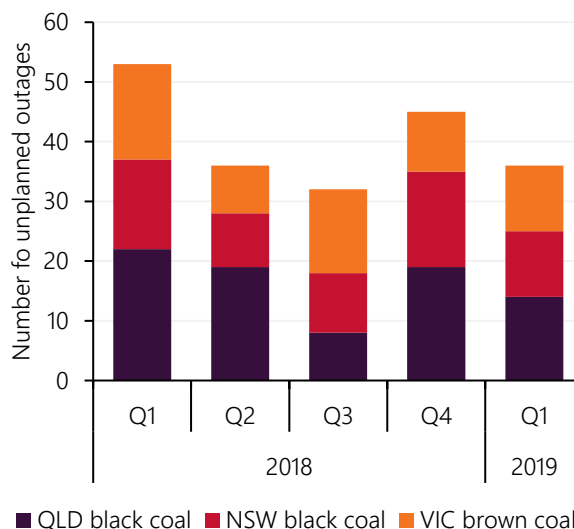


Figure 14 Coal fleet – unplanned outages

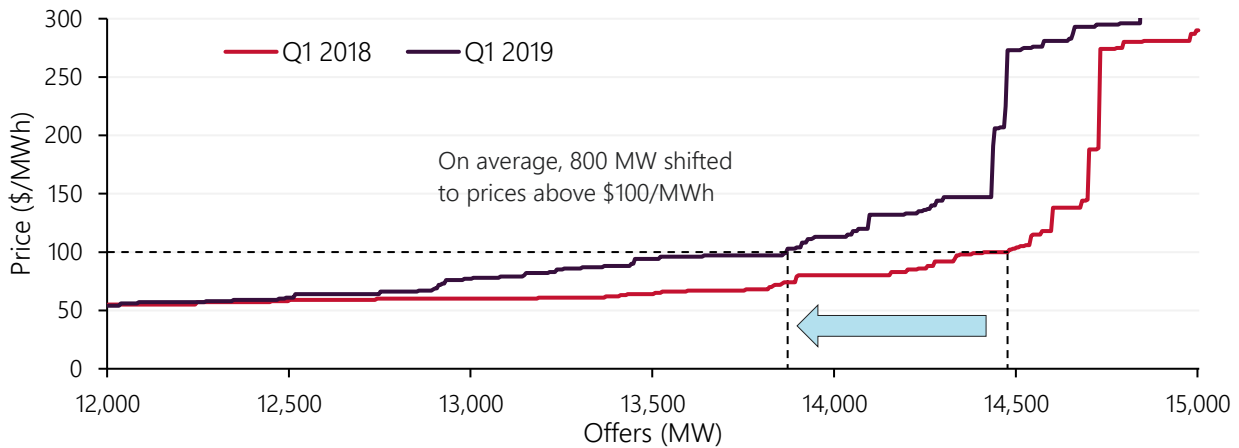


Drivers of reduced black-coal fired generation despite higher spot prices

<p>Capacity shifted into higher priced bands</p>	<p>Compared to Q1 2018, an additional 800 MW of capacity was shifted to prices above \$100/MWh (Figure 15). This resulted in reduced dispatch of the black coal fleet at prices below \$100/MWh.</p> <p>Some coal supply constraints may have contributed to the shift in offers. For example, during the quarter EnergyAustralia regularly rebid capacity at Mt Piper Power Station due to coal conservation and/or quality issues.</p>
<p>Reduced availability</p>	<p>Despite a 32% reduction in the number of unplanned outages compared to Q1 2018 (Figure 14¹⁵), average black coal availability reduced by 217 MW. This was due to an increase in the amount of time returning from these outages, taking an average of 3.6 days to return to service following an unplanned outage.</p>
<p>Displacement by solar</p>	<p>The largest reduction in black-coal fired generation by time of day occurred in the middle of the day, coinciding with an average increase in solar generation of 1,500-2,000 MW (Figure 10).</p>

¹⁵ This report uses a different metric to previous reports. While previous reports focussed on 'sudden unit trips' (when a generator falls from above minimum generation to 0 MW in under 10 minutes), this report includes all unplanned outages.

Figure 15 Bid supply curve – NEM black coal-fired generation



1.4.3 Hydro generation

Hydro generation across the NEM in Q1 2019 was lower than both Q1 2018 and Q4 2018 (-201 MW and -306 MW respectively – see Figure 16). By region:

- Tasmania’s quarterly average hydro output was consistent with historical Q1 results, but 56 MW lower than Q1 2018. There was also further contraction in output however when compared to Q4 2018. Average output decreased by 392 MW, with the largest reductions in generation from Gordon and Poatina. This reduction coincided with below average rainfall across most of Tasmania which meant their total energy in storage reduced from around 40% at the start of the quarter to 31% at quarter end (Figure 17).
- New South Wales hydro generation also reduced in both comparison periods, particularly when compared to Q1 2018. On average, output from New South Wales hydro units was 244 MW lower predominantly due to reduced output from Upper Tumut – a product of around 350 MW shifted to higher price bands above \$100/MWh compared to Q1 2018 which coincided with dry conditions.
- Victoria was higher than both Q1 2018 and Q4 2018 (26 and 41 MW, respectively) however the unit drivers varied slightly. The increase in Q1 was due to increased Dartmouth output while the shift from Q4 2018 was due to more output from Murray. These changes were primarily a function of record high spot electricity prices in Victoria (Section 1.3).
- Queensland hydro output was at its highest level since Q2 2007, although it remained a comparatively small portion of Queensland generation (2%). The key increases were from Barron Gorge and Kareeya, which were also operating at record levels.

Figure 16 Quarterly hydro output

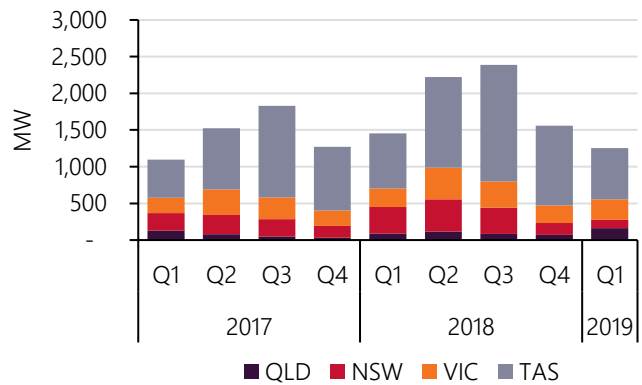
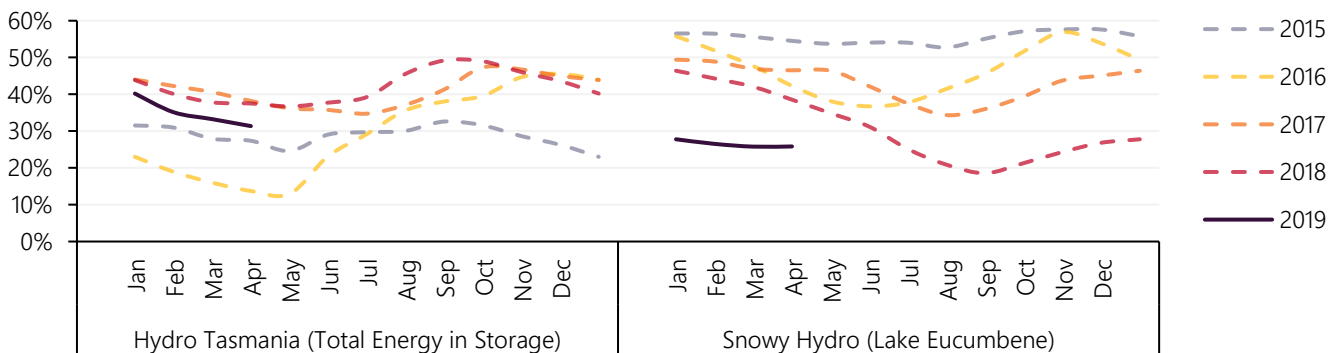


Figure 17 Hydro storage levels



Source: Hydro Tasmania¹⁶ & Snowy Hydro¹⁷

¹⁶ <https://www.hydro.com.au/water>

¹⁷ <https://www.snowyhydro.com.au/our-energy/water/storages/lake-levels-calculator/>

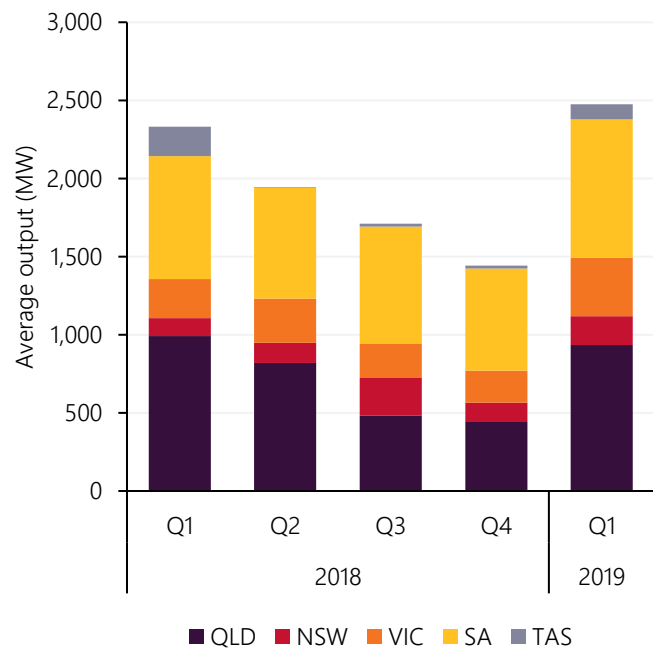
1.4.4 Gas-powered generation

In Q1 2019, GPG was dispatched at comparatively high levels, reversing the downward trend in 2018 (Figure 18). By region, average GPG increased in Victoria, South Australia and New South Wales (+126, 96 and 68 MW, respectively), and decreased in Tasmania and Queensland (-92 MW and -56 MW, respectively). Tasmania's reduced requirement was facilitated by increased electricity imports from Victoria (Section 1.6).

Contributors to GPG's rebound included:

- High NEM spot prices resulting from periods of high demand coinciding with coal generator outages.
 - Participants with both coal and gas-powered generators in their portfolio increased output at their gas-powered generators during coal outages. For example, EnergyAustralia ran Newport during Yallourn outages and AGL ran Somerton more during Loy Yang A outages.
- Comparatively low hydro output due to dry conditions. GPG and hydro generation typically play a peaking-generation role in the NEM, providing flexible capacity and generating at comparatively higher levels during peak periods.

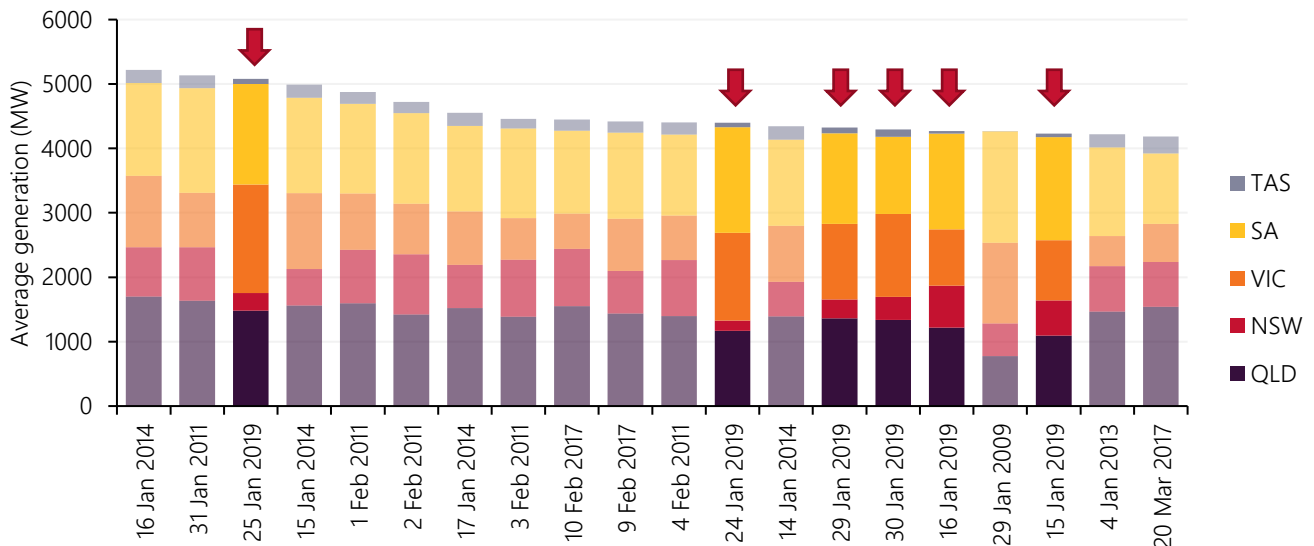
Figure 18 Quarterly gas-powered generation



These factors also necessitated an increased peaking role for GPG, which was particularly evident during January 2019:

- Six of the NEM's top 20 NEM GPG days occurred in January 2019 (Figure 19).
- 25 January 2019 was:
 - The third highest NEM GPG day on record.
 - The highest Victorian GPG day on record (23% higher than the next highest day).
 - The sixth highest South Australian GPG day on record.
- 24 January 2019 was:
 - The twelfth highest NEM GPG day on record.
 - The second highest Victorian GPG day on record.
 - Third highest South Australian GPG day on record.

Figure 19 Top 20 NEM GPG days (by average output)



1.4.5 Storage

The amount of charging or pumping by energy storage facilities in the NEM during Q1 2019 was 245 GWh, approximately 204 GWh higher than in Q1 2018 (Figure 20¹⁸). The increase was driven by increased pumping from Tumut 3, Wivenhoe, and Shoalhaven, coinciding with dry conditions, low dam storage levels, and relatively high spot electricity prices during peak periods. The contribution from batteries remained relatively stable relative to the prior quarter.

Batteries recorded park spreads¹⁹ of approximately \$21/MWh, a slight increase over the prior quarter (Figure 21²⁰). The composition of spot revenues for batteries changed over the quarter with:

- A greater contribution from energy revenues driven by high and volatile prices in South Australia and Victoria.
- Offset by reduced FCAS revenues, driven by lower FCAS prices with the commencement of participation in FCAS markets from newer battery installations.

Park spreads for the pumped hydro facilities were at \$1/MWh, increasing slightly over the quarter²¹.

Figure 20 Quarterly charging/pumping in the NEM

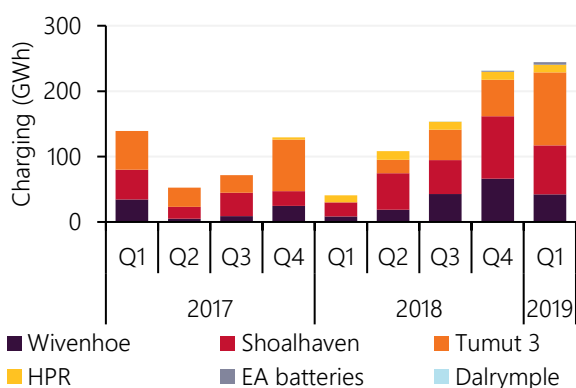
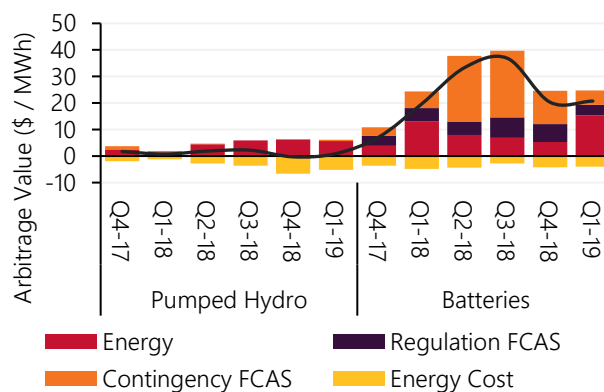


Figure 21 Revenue sources by storage technology



Dispatch patterns for storage in Q1 2019 have also changed relative to Q1 2018. In addition to a higher amount of charging and discharging, both pumped hydro and batteries increased charging/pumping during the middle of the day, especially during the solar noon (Figure 22 and Figure 23). Batteries also discharged more on average during the morning (around 0600-0700 hrs), with pumped hydro increasing generation during the evening peak.

Figure 22 Pumped Hydro - Intraday dispatch²⁰

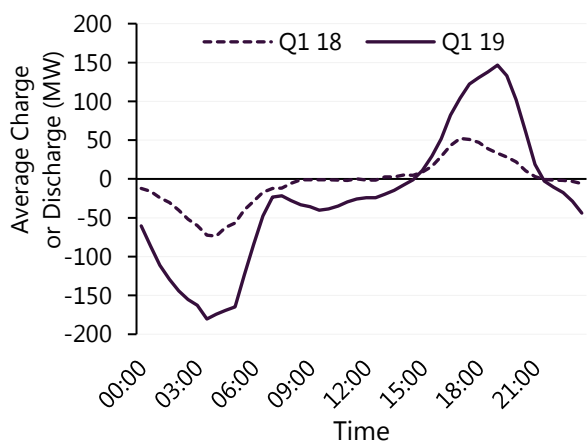
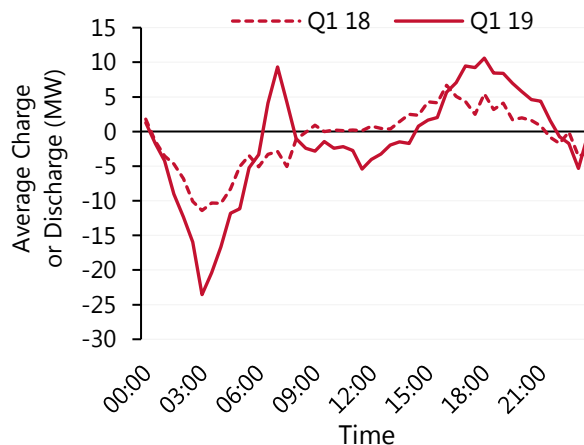


Figure 23 Batteries - Intraday dispatch



¹⁸ The EA batteries refer to the Gannawarra and Ballarat Battery Energy Storage Systems that are contracted to Energy Australia, who holds the rights to charge and dispatch energy from the battery storage systems into the National Electricity Market until 2030 and 2033 respectively. Further information available [\[here\]](#)

¹⁹ Storage arbitrage value is calculated as the estimated average spot value of energy and ancillary services (spot price x energy charged/discharged) over the period relative to the amount of charging capacity in the NEM. The 'park spread' is calculated as the difference between (i) estimated spot revenues of energy discharge and ancillary services enabled (i.e. the price of energy or FCAS x the MWh dispatched or enabled for the period) and (ii) the estimated energy costs of charging (i.e. the price of energy multiplied by the MWh purchased for the period). The 'park spread' is measured as a proportion of the charging capacity (in MW) of storage facilities in service in the NEM.

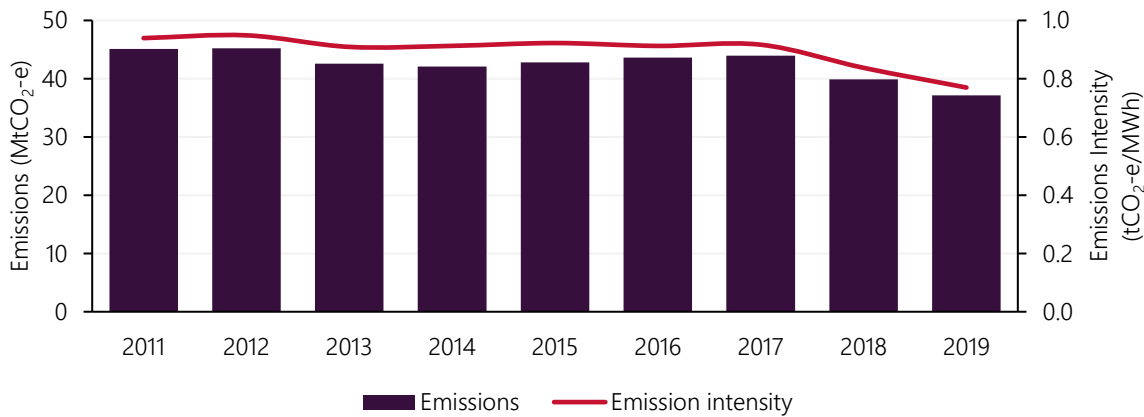
²⁰ The calculation of storage arbitrage value for pumped hydro excludes Tumut 3 facility as its sources of water include both pumped water from Jounama Pondage and inflows from Tumut 1 and Tumut 2 underground power stations and into Talbingo Reservoir. Further information available [\[here\]](#).

²¹ Storage operating within a portfolio and/or with forward contracts face different incentives for capturing spot electricity revenue than storage operating purely under an energy arbitrage model.

1.4.6 NEM emissions

The large increase in renewable output compared to Q1 2018, coupled with reduced coal-fired generation led to Q1 2019 being the lowest Q1 for NEM emissions on record (Figure 24). Total emissions were 2.77 MtCO₂-e lower than in Q1 2018 and the grid average emissions intensity of 0.77 tCO₂-e/MWh represents the lowest quarterly average emissions intensity on record.

Figure 24 Quarterly NEM emissions and emissions intensity (Q1s)



1.5 Other NEM-related markets

1.5.1 Electricity futures markets

The price of calendar year (Cal) 2020 electricity swap contracts traded on the ASX rose in all regions over Q1 2019 (Figure 25). This included increases of between 12-23% for calendar year Cal 2020 swap products and 13-21% for Cal 2021 swap products over the quarter (Table 3). Approximately 90% of this increase has occurred in the underlying energy pricing component (prices <\$300/MWh).

Overall price increases across all regions in both Cal 20 and 21 swaps were influenced by:

- Gas – sustained high wholesale gas prices (Section 2.2).
- Coal – market sentiment is for thermal coal prices to remain comparatively high into 2020, which has the potential to influence offers from coal-fired generators (Section 1.5.2).
- Low hydro storage levels on the mainland and Tasmania – Lake Eucumbene closed the quarter at around 25% which is below the typical end-of-year closing balance and Tasmanian storage levels closed at around 30% (Section 1.4.3).
- Renewables – concerns over delays to connection of new renewable projects as well as the impact of grid congestion.²²

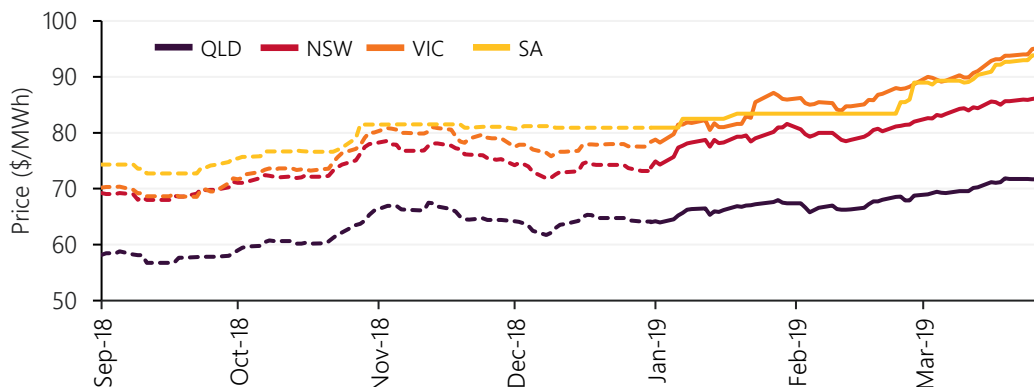
Q1 2020 cap prices were up in Victoria (+55%), New South Wales (20%) and South Australia (+18%), with a small decrease in Queensland (-2%). The large price increase in Victorian cap prices likely reflect concerns relating to the return of price volatility (Section 1.3.1).

Table 3 Change over Q1 2019 for Cal 2020 and Cal 2021 swap prices

Region	Cal 20	Cal 21
QLD	▲ \$7.55 (12%)	▲ \$10.12 (18%)
NSW	▲ \$12.98 (18%)	▲ \$10.75 (16%)
VIC	▲ \$17.59 (23%)	▲ \$13.34 (21%)
SA	▲ \$12.93 (16%)	▲ \$8.55 (13%)

²² See for example: <https://reneweconomy.com.au/wind-and-solar-plants-hit-by-massive-de-ratings-in-congested-grid-96404/>

Figure 25 ASX energy – Calendar year 2020 swap prices by region



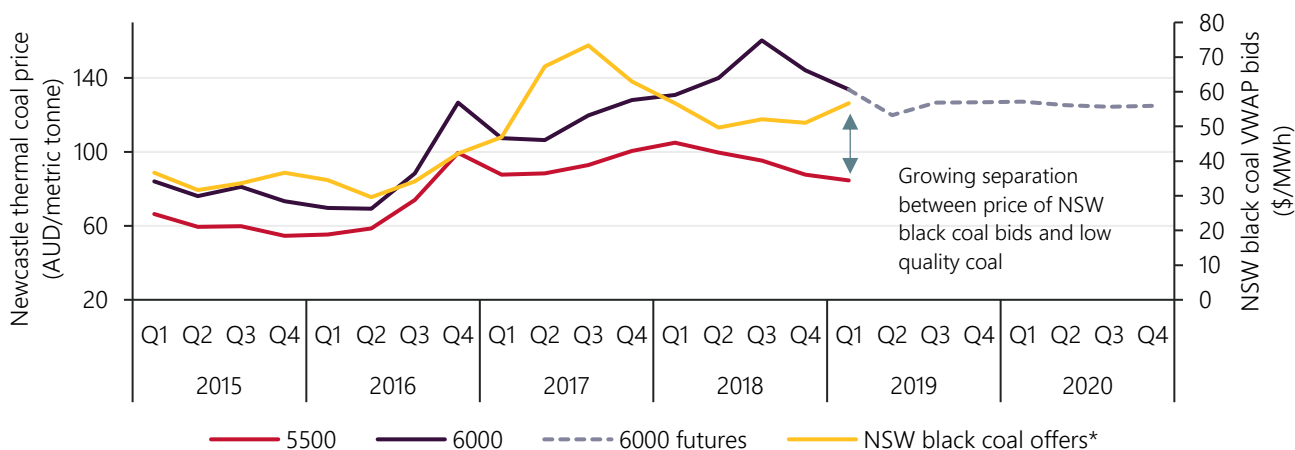
1.5.2 International coal prices

The average Q1 2019 spot price for high quality Australian Newcastle thermal coal (6000 kcal) was 7% lower than in Q4 2018, averaging \$134/tonne (AUD). The decreasing price of premium coal was matched by the price of lower quality coal (5500 kcal), which reduced by 4% over the quarter. These changes were driven by a reduction in Chinese demand, resulting from recovering domestic production and changes to import policies²³. While weakening somewhat, ongoing underlying demand continued to be reflected in the forward market, where coal futures prices remained above \$120/tonne for 2019 and 2020²⁴.

As illustrated in Figure 26, despite the reduction in international coal prices, there was a small increase in the price of offers from black coal-fired generators in New South Wales compared to recent quarters. This suggests that increasing black coal offers were not a direct result of higher input costs due to the procurement of incremental coal but more likely due to coal conservation and/or quality issues (see Section 1.4.2).

While much of Australia’s coal fleet remain on legacy fuel contracts, any requirement for incremental coal (for example, due to contract expiration or to support increased production) could expose a coal-fired generator to prices linked to the Newcastle spot price.

Figure 26 Quarterly average international black coal spot, futures and contract prices



Source for Newcastle thermal spot and futures prices: Bloomberg

*Black coal offers are the volume weighted average price of NSW black coal generators priced between \$20-\$120/MWh.

²³ Department of Industry. 2019. *Resources and Energy Quarterly*. ONLINE. Available at: <https://publications.industry.gov.au/publications/resourcesandenergyquarterlymarch2019/documents/Resources-and-Energy-Quarterly-March-2019-Thermal-Coal.pdf>. Accessed 11 April 2019.

²⁴ Assuming the exchange rate at the end of Q1 2019 remains constant – AUD/USD: 0.7087

1.5.3 Environmental Markets

The Large-scale Generation Certificate (LGC) spot price decreased by 30% to just over \$33/certificate in Q1 2019 (Figure 27, Table 4). The LGC spot price has now fallen \$53/certificate (-61%) since the beginning of 2018. Prices in the forward market were also lower, with Calendar Year 20 prices reducing to just over \$20/certificate.

As with the price reductions in Q4 2018, changes likely reflect:

- A growing supply of LGCs as new renewable generation commences (Section 1.4.1).
- The use of shortfall provisions provided under the Large-scale Renewable Energy Target (LRET) impacting demand for LGCs.²⁵ In February the CER published the results of the 2018 LRET certificate surrender, announcing that there was a total shortfall of 3.9 million LGCs (approximately 14% of total liability).²⁶
- Repeated communication from the Clean Energy Regulator (CER) that the 2020 LRET will be met.²⁷

Small-scale Technology Certificate (STC) prices finished the quarter at \$36.68/certificate, with prices steady despite the setting of the small-scale technology percentage at a record high of 21.73%.²⁸ The lack of downward pressure on price associated with the high STP reflects a large existing supply of STCs and high expected rooftop PV installations over 2019.²⁹

Figure 27 LGC spot and forward prices over Q1 2019

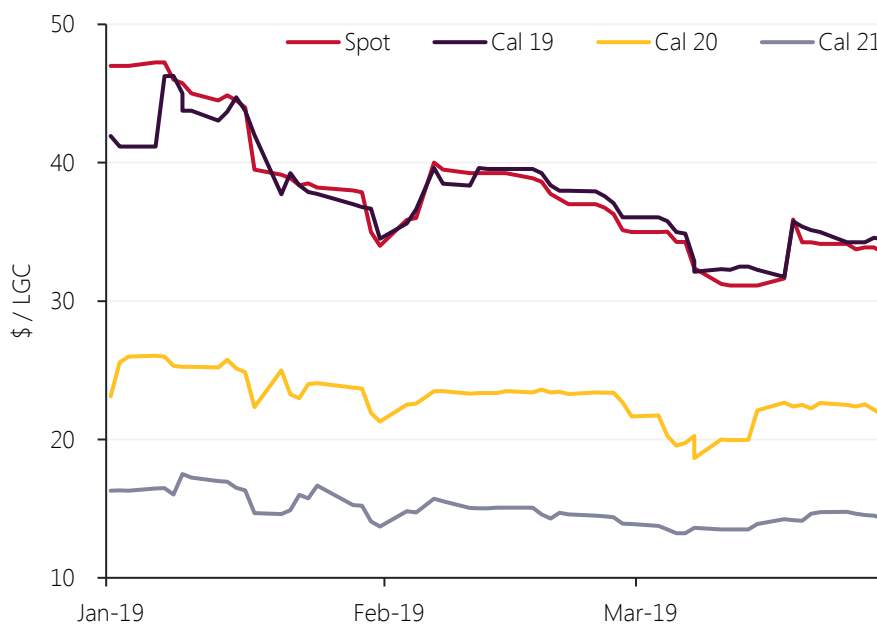


Table 4 LGC prices

Product	Change over Q1 19
Spot	▼ \$14.5 (30%)
Cal 19	▼ \$7.45 (18%)
Cal 20	▼ \$1.65 (7%)
Cal 21	▼ \$2.25 (14%)

Source: Mercari

²⁵ CER. 2019. *Surrender of large-scale renewable energy certificates and payment of shortfall charges*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Renewable-Energy-Target-liable-entities/Refunds-of-large-scale-generation-shortfall-charges#Surrender-of-largescale-renewable-energy-certificates-and-payment-of-shortfall-charges>. Accessed 10 April 2019.

²⁶ CER 2019. *Certificate shortfall register*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/RET/Pages/Scheme%20participants%20and%20industry/Renewable%20Energy%20Target%20liable%20entities/Scheme%20compliance/Certificate-shortfall-register.aspx>. Accessed 10 April 2019.

²⁷ CER 2019. *The 2018 Renewable Energy Target Annual Statement – Progress towards the 2020 target*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/About/Pages/Accountability%20and%20reporting/Administrative%20Reports/The-2018-Renewable-Energy-Target-Annual-Statement-%E2%80%93-Progress-towards-the-2020-target.aspx>. Accessed 10 April 2019.

²⁸ CER 2019. *2019 RPP and STP set*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/RET/Pages/News%20and%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96f6c&ItemId=622>. Accessed 10 April 2019.

²⁹ CER 2019. *Small-scale technology percentage modelling report*. ONLINE. Available: <http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage/small-scale-technology-percentage-modelling-reports>. Accessed 11 April 2019.

1.5.4 Frequency control ancillary services

In Q1 2019, frequency control ancillary services (FCAS) costs were \$36.5 million³⁰, representing an \$18 million (-33%) reduction on Q4 2018 levels (Figure 28). By market:

- Contingency Raise – most of the cost reductions occurred in these markets, down \$15.4 million (-46%) compared to Q4 2018.
- Regulation FCAS costs reduced by \$2.3 million.
- Contingency Lower costs remained at comparatively low levels.

Drivers of reduced costs included:

- Increased supply from:
 - **Batteries** – over the quarter, batteries increased their share of the Raise FCAS markets from 10% in Q4 2018 to 17% in Q1 2019 (Figure 29). Hornsdale Power Reserve’s share of the market has remained relatively stable, with increased FCAS provision coming from: Dalrymple North BESS (5% of Raise FCAS) and Ballarat BESS (3% of Raise FCAS). This additional supply displaced higher-priced supply from other technologies, largely coal.
 - **Hydro** – in addition to new supply from the two batteries, there was also a reduction in the price of offers (or return to the market) from some existing hydro providers, resulting in increased dispatch. For example, Wivenhoe Power Station returned to the Raise 5min FCAS market, offering approximately 150 MW more at prices below \$10/MWh than in Q4 2018.
- Reduced demand – compared to Q4 2018 there were reductions in demand across the Contingency Raise and Regulation FCAS markets:
 - Contingency Raise FCAS demand reduced by 7%, which was largely a function of increased average electricity demand.
 - Regulation FCAS demand decreased by approximately 10% following a trial period³¹ of increased Regulation FCAS in Q4 2018. However, on 22 March, to ensure ongoing compliance with the requirements of the Frequency Operating Standards, AEMO increased the Regulation FCAS across the mainland regions by 50 MW. This took the minimum quantities procured to 180 MW of Raise Regulation and 170 MW of Lower Regulation³².

Figure 28 Quarterly FCAS costs by service

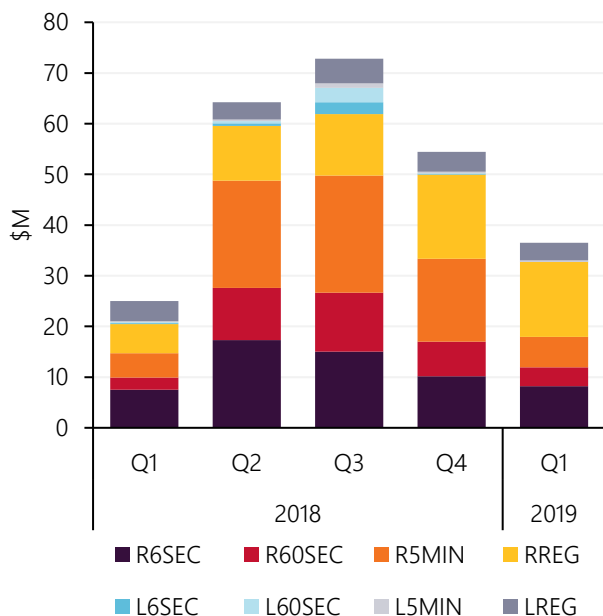
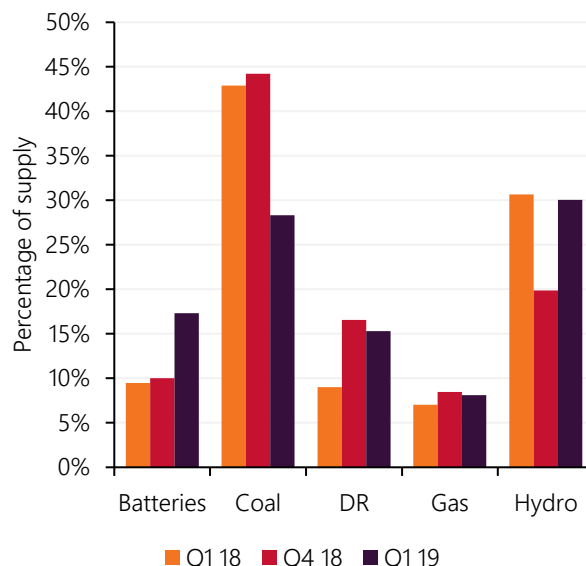


Figure 29 FCAS supply mix



³⁰ Represents preliminary data and subject to minor revisions.

³¹ The trial was intended to: 1. Determine the impact of revised regulation FCAS market volumes for managing frequency performance and arresting the current degrading trend; 2. Inform recommendations for optimal management of regulation FCAS and time error. See: <http://aemo.com.au/Market-Notices?searchString=64715>

³² At the time of publication, AEMO will review power system frequency performance every four weeks, and decide whether to further increase or hold the amount of regulation FCAS procured. AEMO’s decision will take into account whether frequency has remained in the NOFB for at least 99.5% of the time over the previous four weeks, together with any other relevant factors.

1.6 Inter-regional transfers

Total inter-regional transfers during the quarter increased by 5% compared to Q4 2018, but were 7% lower than in Q1 2018 (Figure 30).

Victoria to New South Wales Interconnector

During the quarter, the prevailing flow on the interconnector was 52 MW north on average, representing a 203 MW swing compared to Q1 2018. Notably, this change in transfers occurred despite record spot electricity prices in Victoria. Higher prices in Victoria would typically result in net flows south on the interconnector. However, despite a nominal southerly transfer limit of 1,350 MW, the average limit for flows south during the quarter was less than 300 MW (Figure 31). This contributed to:

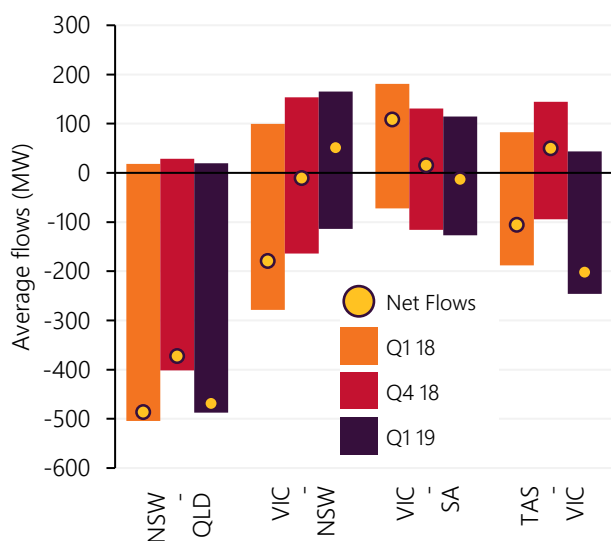
- The VIC-NSW interconnector binding at its limits for 32% of the quarter.
- Around \$16/MWh to the price spread between Victoria and New South Wales (the remaining \$51/MWh of price spread was during pricing volatility).

The primary driver of restricted transfers south on the VIC-NSW interconnector was changes in Snowy Hydro’s generation patterns resulting from dry conditions. Flows south on the interconnector were limited by the N[^]V_NIL_1 constraint³³, which bound more for 25% of the time in Q1 2019 (compared to 14% of the time in 2018). The constraint is largely a function of Snowy Hydro’s dispatch decisions. It is mainly eased by generation from Upper Tumut (and then Lower Tumut and Uranquinty), and is exacerbated by generation at Murray in Victoria. A 78% drop in generation from Tumut and comparatively higher Murray output compared to Q1 2018 contributed to limited flows south on the interconnector.

Other interconnectors³⁴

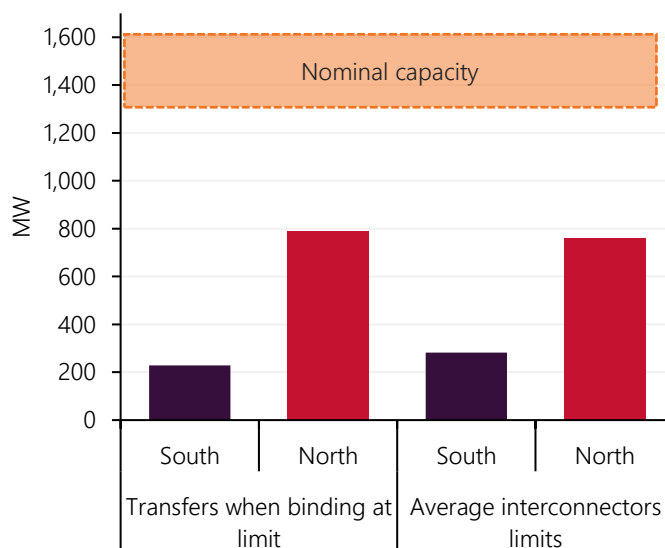
- **Tasmania to Victoria (Basslink)** – reduced hydro output due to dry conditions resulted in a prevailing flow south on Basslink (202 MW south on average), representing an 92% increase on Q1 2018 levels. This contributed to higher Victorian electricity spot prices over the quarter when compared to Q1 2018.
- **Victoria to South Australia** – total quarterly inter-regional transfers were comparable to previous quarters, and remained evenly balanced on a directional basis, with net average flows of 13 MW into Victoria. This contributed price convergence between the two regions: Victoria and South Australia’s prices were set by a common marginal unit for more than 90% of the quarter.
- **New South Wales to Queensland** – inter-regional transfer was almost exclusively south at net 468 MW on average, consistent with Q1 2018 results.

Figure 30 Quarterly inter-regional transfers



Positive transfers are denoted for: New South Wales transfers into Queensland; Victorian transfers into New South Wales and South Australia; Tasmanian transfers into Victoria.

Figure 31 Limits on the VIC-NSW interconnector – Q1 2019



³³ To avoid collapse for loss of the largest Victorian generating unit.

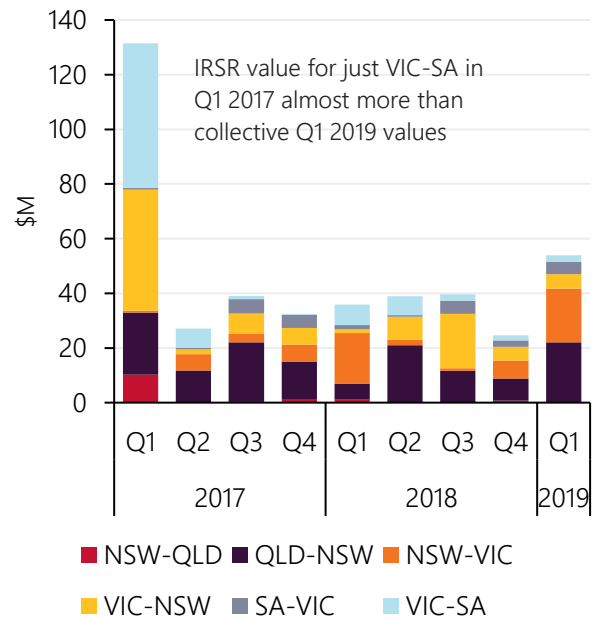
³⁴ For simplicity, where there are multiple interconnectors between two regions results for these interconnectors are taken in aggregate.

1.6.1 Inter-regional settlement residue

With an increase in inter-regional price separation and inter-regional transfers, there was a resulting 129% increase in inter-regional settlement residue³⁵ (IRSR) for the quarter compared to Q4 2018 (Figure 32). IRSR value totalled \$54 million – the highest since Q1 2017³⁶, where combined IRSR was \$131.4 million (Figure 32). Key outcomes for IRSR in Q1 2019 compared to recent quarters included:

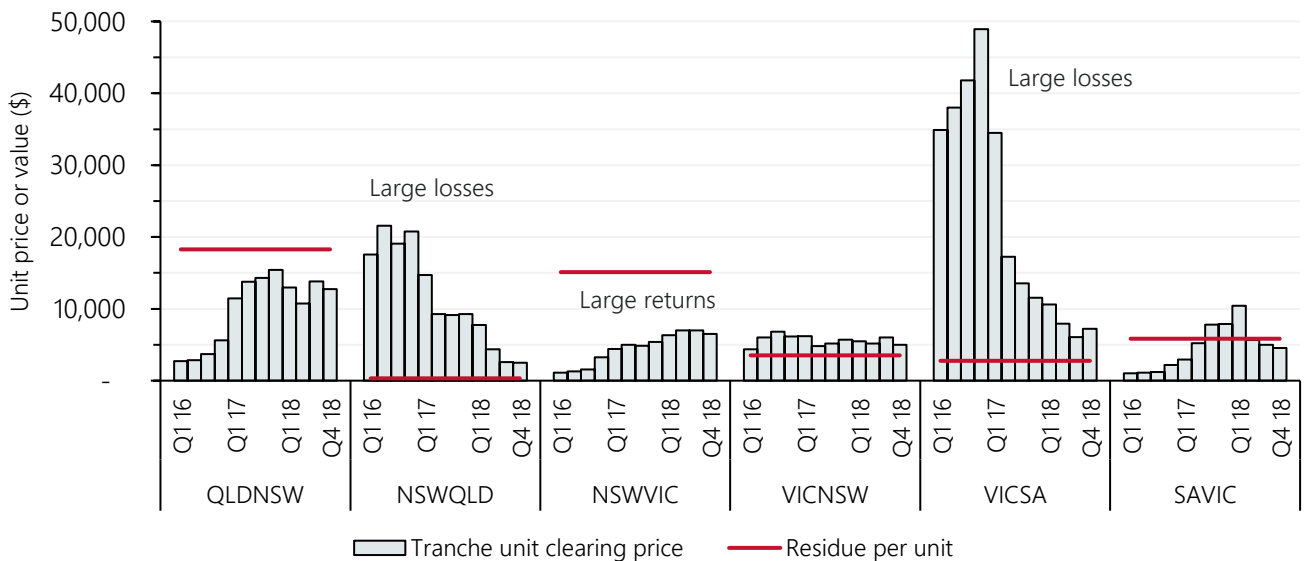
- **NSW-VIC** – the return of price volatility in Victoria led to comparatively high IRSR value for flows from New South Wales into Victoria. The IRSR value for these flows was \$19.7 million or 36% of total IRSR value for the quarter. However, restricted flows south on the interconnector – particularly during high Victorian spot prices – somewhat diminished the value of these units (relative to a situation with higher flows).
- **QLD-NSW** – with Queensland the lowest priced NEM region, flows remained predominantly into New South Wales, resulting in IRSR value of \$21.9 million. There were low transfers from New South Wales (and low price spread during these flows), resulting in minimal value for IRSR associated with these transfers.
- **VIC-SA** – Price separation between Victoria and South Australia has been relatively small in recent quarters, leading to comparatively low value for accumulated residues between the two regions.

Figure 32 Quarterly positive IRSR value



There were mixed results on returns for units purchased at settlement residue auctions. By directional interconnector, there were positive returns for flows from Queensland to New South Wales, New South Wales to Victoria, and South Australia to Victoria. Large negative returns were recorded for SRA units for flows from Victoria to South Australia, and New South Wales to Queensland, particularly for units purchased prior to closure of Hazelwood Power Station in March 2017³⁷. In general, the price paid for SRA units and their actual value converged the closer they were purchased to Q1 2019 (that is, units purchased at the March 2019 auction were closer to the actual value than units purchased in 2016 and 2017 auctions).

Figure 33 SRA tranche analysis – price paid for units versus actual value (Q1 2019)



³⁵ For further details on IRSR see: AEMO. 2018, *Guide to the Settlements Residue Auction*. ONLINE. Available at: www.aemo.com.au/-/media/Files/Electricity/NEM/Settlements_and_Payments/Settlements/2018/Guide-to-the-Settlements-Residue-Auction.pdf. Accessed 15 January 2019.

³⁶ The major difference between the two periods is the status of Hazelwood power station. While Hazelwood was in service, Victoria operated as a net exporter of energy (and predominantly at cheaper prices than neighbouring regions).

³⁷ Noting that SRA units may be used in a broad portfolio of risk management products, so SRA unit losses may be made up by gains from other futures products

1.7 Power system management

System security

During Q1 2019, AEMO issued directions to generators to maintain system security in the NEM. The level of directions for system security in South Australia declined relative to prior quarters, with directions in place for 4.4% of the time, compared to 13% during Q4 2018 (Figure 34). This represents the least time directing (for a quarter) since the South Australian system strength arrangements were introduced and contributed to total direction costs³⁸ reducing from approximately \$3.2 million in Q4 2018 to approximately \$1.3 million for the quarter. The reduced time directing was a function of higher synchronous generator availability, influenced by periods of high demand (which is typical for summer) and expectations of comparatively higher spot prices.

During the quarter, curtailment of non-synchronous generation in South Australia reduced to around 1% of the unconstrained intermittent generation forecast (UIGF, Figure 35). This was driven by:

- Increased availability of synchronous generation in the region.
- Comparatively fewer periods of high wind conditions
- Changes to operating guidance which allows dynamic levels of non-synchronous generation (ranging from 1,000 MW to 1,460 MW) based on the synchronous unit combinations available³⁹.

Figure 34 Directions for system security in South Australia and Victoria

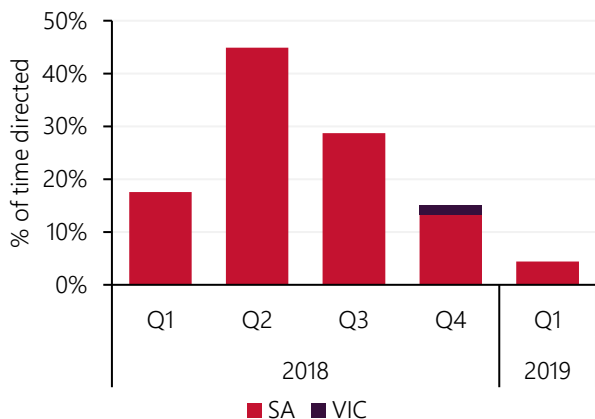
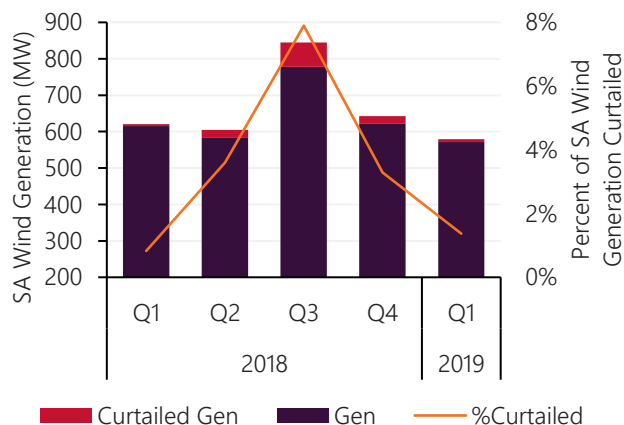


Figure 35 Curtailment of SA wind generation



³⁸ Based on Compensation Recovery Amount (provisional amount).

³⁹ AEMO. 2018. *Transfer Limit Advice – South Australia System Strength, December 2018*. ONLINE. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf. Accessed 24 April 2019.

2. Gas market dynamics

2.1 Gas demand

Total gas demand⁴⁰ was 7% (28 PJ) higher than in Q1 2018, due to a 22 PJ increase in Curtis Island demand for liquified natural gas (LNG) and a 5 PJ increase in GPG demand (Table 5). The increase in GPG demand reverses a trend of reduced GPG which occurred over 2018 (see Section 1.4.4). There was no material change in residential, commercial and industrial demand.

Table 5 Gas demand – quarterly comparison

Demand	Q1 2019 (PJ)	Q4 2018 (PJ)	Q1 2018 (PJ)	Percentage change from Q1 2018
AEMO Markets *	59	114	58	1%
GPG **	47	28	42	13%
QLD LNG	329	309	307	7%
TOTAL	435	451	407	7%

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

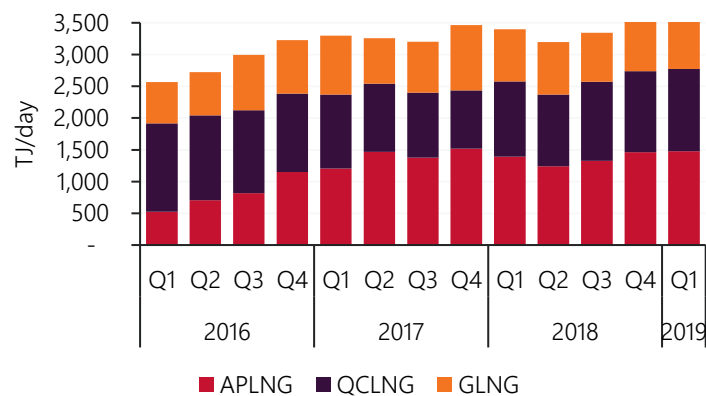
** Includes demand for GPG usually captured as part of total DWGM demand. Excludes Yabulu Power Station.

2.1.1 LNG demand

Record high average daily pipeline deliveries of 3,657 TJ/d were directed to Curtis Island during Q1 2019. This represents an increase of 258 TJ/d compared to Q1 2018 and an increase of 74 TJ/d compared to the prior quarter (Figure 36). Increased flows of gas to Curtis Island in Q1 2019 compared to Q4 2018 were predominantly due to higher GLNG demand (+5%). The increase in LNG demand comes despite the ACCC's LNG Netback price (Figure 40) falling below domestic Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM) prices (see Section 2.2.1).

The number of LNG cargoes exported during Q1 2019 (83 in total) was consistent with Q4 2018 and Q1 2018 exports.

Figure 36 Average daily pipeline flows to Curtis Island



2.1.2 Meeting gas demand on high GPG days

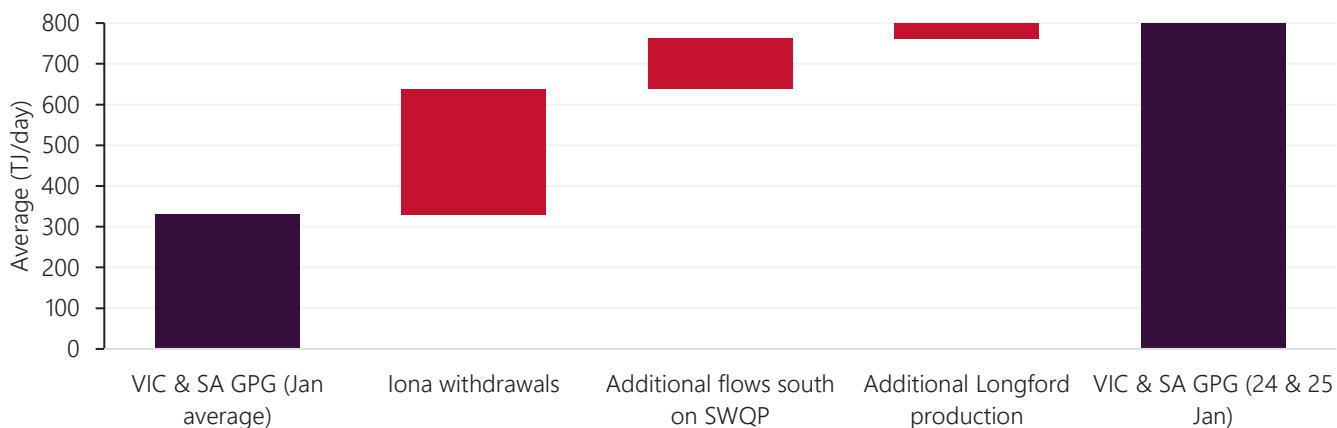
On 24 and 25 January 2019, Victorian daily average GPG demand reached its highest level on record, with comparatively high GPG also recorded in South Australia. Drivers of high GPG demand on these days included very hot weather leading to comparatively high electricity demand in Victoria and South Australia, coupled with brown coal outages (Section 1.4.4). With a reduced contribution from hydro generation over the quarter, there was an increased requirement for GPG over these high demand periods.

Meeting the spike in gas demand on high GPG days required:

- An average of 265 TJ/d was withdrawn from Iona on the 24 and 25 January, as compared to an average injection of 44 TJ/d for the remainder of the January (Figure 37).
- A reduction in gas delivered to GLNG over the two days of 222 TJ corresponded with an almost identical increase in delivery of gas flowing south on the South West Queensland Pipeline (SWQP, 225 TJ). Outages at APLNG may also have contributed to increase availability of gas.

⁴⁰ AEMO's wholesale gas markets, gas demand for gas-powered generation and pipeline deliveries to the Curtis Island LNG projects. Total demand does not include regional demand i.e. demand that is not captured by one of the markets.

Figure 37 Source of additional gas on high GPG days in Victoria and South Australia



Note: Data compares January 2019 average results (excluding 24 and 25 January) to results for 24 and 25 January 2019.

2.2 Wholesale gas prices

Q1 2019 wholesale gas prices remained comparatively high (\$9-10/GJ), increasing across all markets by an average of 15% compared to Q1 2018 (Figure 38). The largest increases occurred in the Brisbane STTM (+25%) the Adelaide STTM (+19%) and the Gas Supply Hub (GSH, +15%). Price increases were driven by increased demand (Section 2.1), coupled to higher priced gas injection offers. In Q1 2019 the quantity of gas offered at prices below \$8/GJ reduced by 10% compared to Q1 2018 (Figure 39). The changed price of offers coincided with the following changes:

- Increased GPG demand for electricity, up 5 PJ compared to Q1 2018.
- Rebounding oil prices, following a reduction in Q4 2018 (see Section 2.2.1)
- Expectations of continuing tightness in the gas supply-demand balance in the short to medium term⁴¹, which could influence participant pricing and operational decisions in the lead up to winter.
- Record high daily average pipeline deliveries to Curtis Island for export (+7%).

Prices reduced slightly in the DWGM and STTMs compared to record high prices recorded in Q4 2018 (-2%). The largest reductions occurred in the GSH (-8%) and the Brisbane STTM (-6%).

Figure 38 GSH, DWGM and STTM average prices

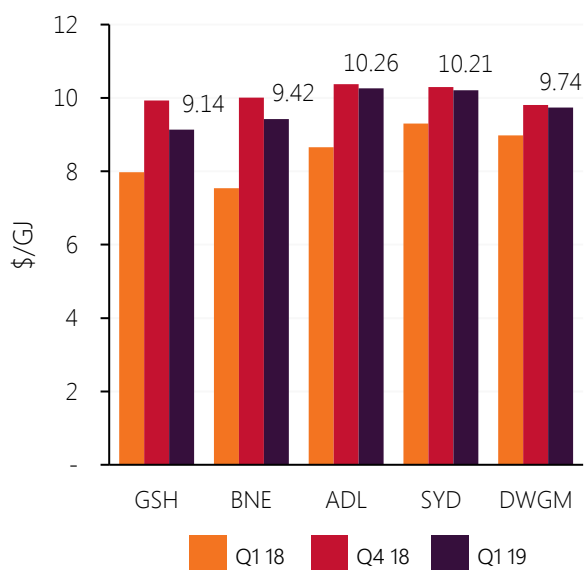
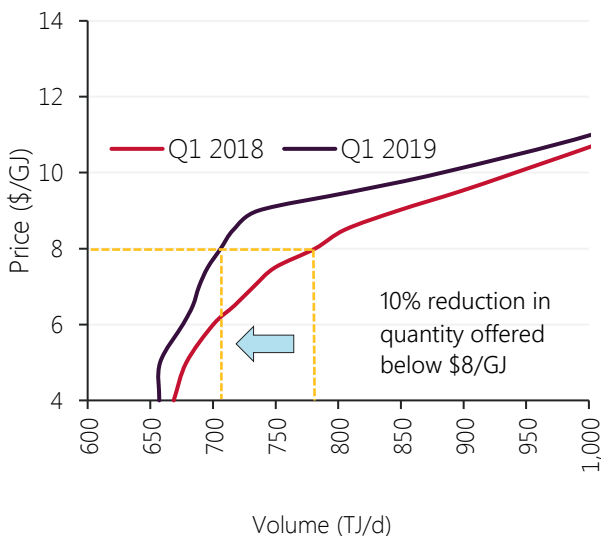


Figure 39 DWGM and STTM injection bid supply curve



⁴¹ AEMO 2019. Gas Statement of Opportunities. Available at: www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2019/2019-GSOO-report.pdf

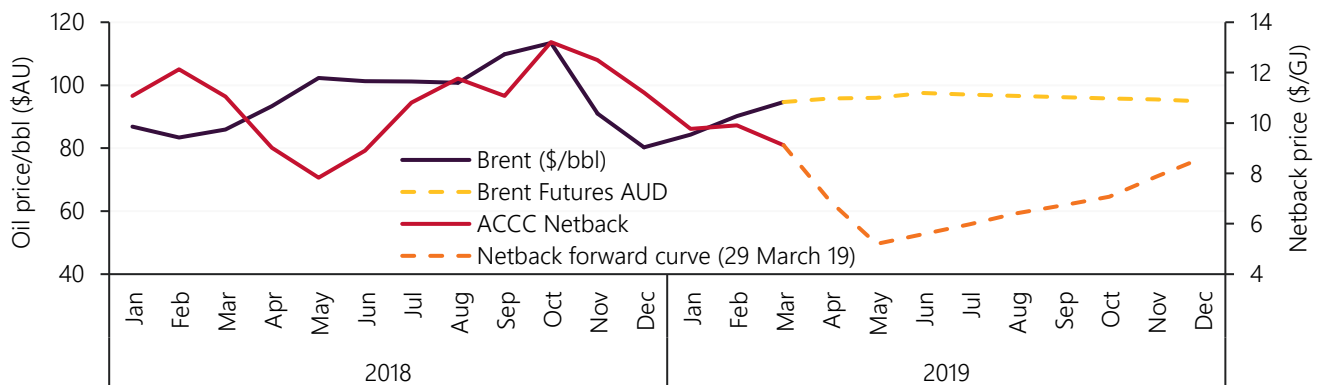
2.2.1 International gas and oil prices

International Brent prices partially reversed the reduction that occurred over Q4 2018, increasing by 27% in Q1 2019 to finish at US\$68/bbl (or AU\$97/bbl, Figure 40). Increasing oil prices were a function of falls in production, driven by reduced output from the Organization of Petroleum Exporting Countries (OPEC) and Russia, American sanctions on Iran and Venezuela, and conflict in Libya.⁴² Forward crude oil prices at the end of the quarter were tracking at around AU\$100/bbl for the rest of 2019.

The ACCC continued the publication of a historical and forward LNG netback price – a theoretical export parity price that a gas supplier can expect to receive for exporting its gas.⁴³ Figure 40 shows the ACCC LNG netback price continuing to fall over Q1 2019, finishing the quarter at \$9.12/GJ. The reduced price was influenced by softening demand due to rising LNG supply, warmer north Asian weather and nuclear restarts in Japan⁴⁴.

The end of quarter ACCC LNG netback forward price fell sharply to below \$6/GJ for mid-2019. A low netback price relative to domestic prices could incentivise the diversion of uncontracted gas that otherwise would have been exported via spot cargoes.

Figure 40 Spot and forward monthly average ACCC LNG netback and Brent crude oil prices



Source: ACCC and Bloomberg

2.3 Gas supply

2.3.1 Gas production

Q1 2019 east coast gas production⁴⁵ increased compared to Q1 2018 (+5%) and reduced slightly (-1%) compared to Q4 2018 (Figure 41).

Table 6 Changes in gas production

Production increase against Q1 2018	<ul style="list-style-type: none"> • Increase in Queensland production (+16 PJ), with increases in Woleebee Creek (+9 PJ) and Ruby Jo (+5 PJ) somewhat offset by reduced production at Condabri South (due to outages) and Fairview – (due to consistent lower production), both 3 PJ lower. • Increase in Longford production, (+3 PJ) due to higher gas prices resulting from increased demand. • Increases in Otway (+0.8 PJ) and Moomba (+0.6 PJ) offset by reductions at BassGas & Minerva (-1.3 PJ).
Production decrease against Q4 2018	<ul style="list-style-type: none"> • Reduced Longford production, down 6.5 PJ (-11%). The fall coincided with a 20% reduction in production over most of March due to planned maintenance (Figure 42). • Rise in Queensland production, up 7 PJ (+2%). The increase occurred at the same time as record high daily average flows to Curtis Island.

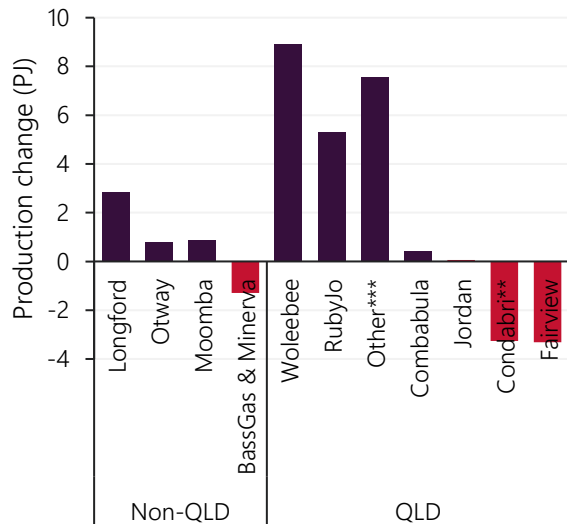
⁴² Bloomberg 2019. *Oil Leaps to 6-Month High as U.S. Vows to Strangle Iran Exports..* ONLINE. Available at: www.bloomberg.com/news/articles/2019-04-21/oil-rises-on-signs-of-slowing-u-s-drilling-supply-disruption. Accessed 09 April 2019.

⁴³ ACCC 2018, *LNG netback price series*. ONLINE. Available at: www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series. Accessed 09 April 2019.

⁴⁴ FT. 2019, *Asian LNG prices drop to near three-year lows*. ONLINE. Available at: <https://www.ft.com/content/9c485852-4cb6-11e9-bbc9-6917dce3dc62>. Accessed 09 April 2019.

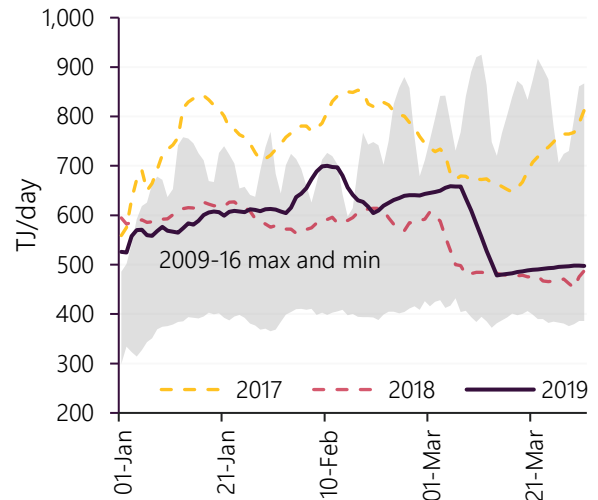
⁴⁵ Excludes facilities which recently began reporting production on the Gas Bulletin Board such as Tipton and Daandine. These facilities will be include once their data has been reported for a full year (which will be in the Q4 2019 QED report).

Figure 41 Change in quarterly gas production by plant – Q1 2019 versus Q1 2018



* Queensland production is based on grouping all production facilities in the Roma Zone of the Gas Bulletin Board.
 ** Condabri is the grouping of North, Central and South production facilities.
 *** Plant not explicitly stated are grouped as "Other".

Figure 42 Q1 2019 Longford production



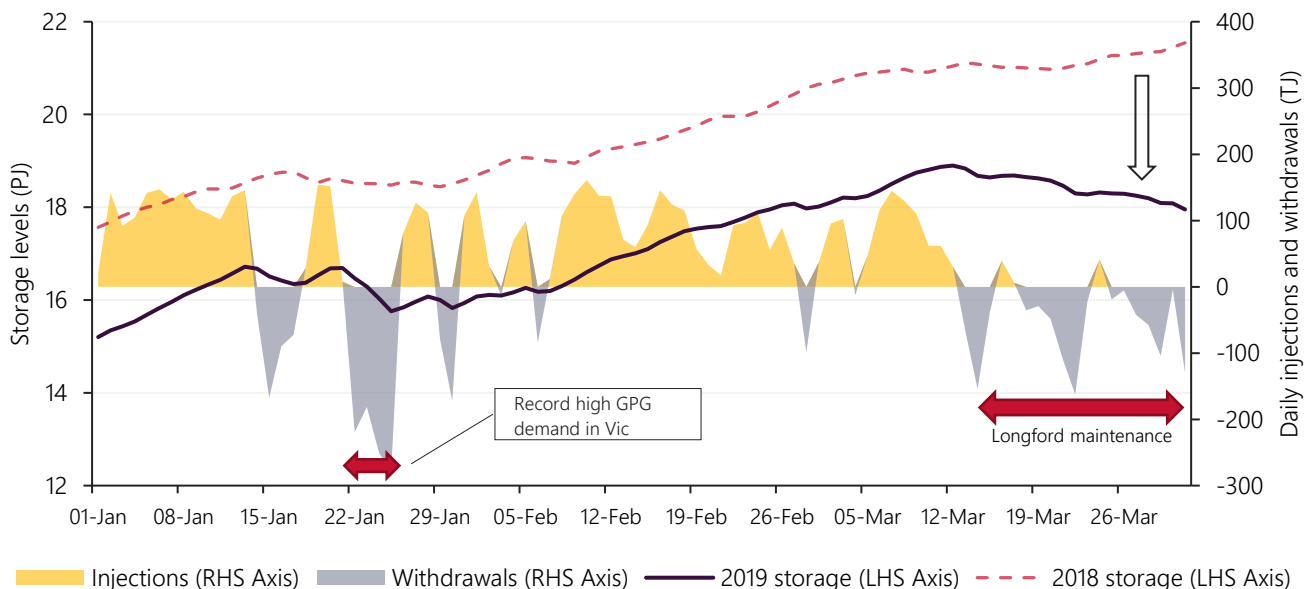
Seven day rolling average of production.

2.3.2 Gas storage

A gas balance of 18 PJ was recorded at the Iona Underground Storage Facility (Victoria) as at 31 March 2019, the lowest end of Q1 storage levels since records commenced in Q4 2016. During the quarter, gas filling exceeded gas emptying (net filling) by 2.8 PJ, representing 31 % less net filling than in Q1 2018 (Figure 43). Reduced filling rates corresponded with:

- Very high GPG demand days at the end of January due to hot weather, high demand and brown coal-fired generator outages.
- Reduced Longford production over much of March 2019 (Figure 42).
- Reduced gas flows from Queensland to Victoria (Section 2.4).

Figure 43 Iona Storage



2.4 Pipeline flows

2019 has continued 2018 trends, with Victorian net gas exports well below 2017 levels (Figure 44). Q1 2019 exports were lower than in Q1 2018 and Q4 2018, reducing by 1.4 PJ and 2.1 PJ, respectively. Contributors included:

- Increased Victorian GPG demand (Section 1.4.4).
- Decreased flows to Tasmania due to lower GPG demand from Tamar Valley CCGT.
- Decreased flows to South Australia despite an increase in GPG demand in that state, with increased imports into South Australia via the Moomba to Adelaide Pipeline (MAP) and less imported via SEA Gas.

Despite the overall decrease, flows to New South Wales increased by 1.35 PJ (8%) compared to Q1 2018, due to higher GPG demand in New South Wales.

The amount of gas flowing north to Wallumbilla on the South West Queensland Pipeline (SWQP) during Q1 2019 has continued to increase, despite increased GPG demand in the southern regions. In Q1 2019 there was a net flow north of 2.9 PJ, contrasting with Q1 2018 where 4.8 PJ flowed south. This represents a change of 7.6 PJ. Contributors included:

- Recording daily average flows to Curtis Island for LNG export
- The commissioning of the Northern Gas Pipeline (NGP) on 3 January 2019, connecting the Northern Territory to the east coast gas market for the first time. Approximately 6 PJ flowed from Northern Territory to Mt Isa, displacing gas that previously flowed north up the Carpentaria Gas Pipeline to supply Mt Isa.
- Increased Longford production (+3 PJ) compared to Q1 2018.

Figure 44 Victorian net gas exports to other states

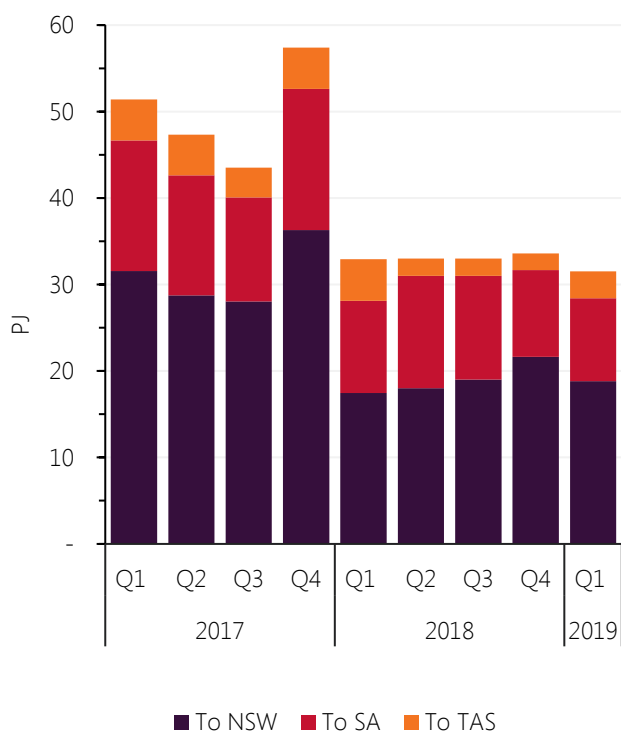
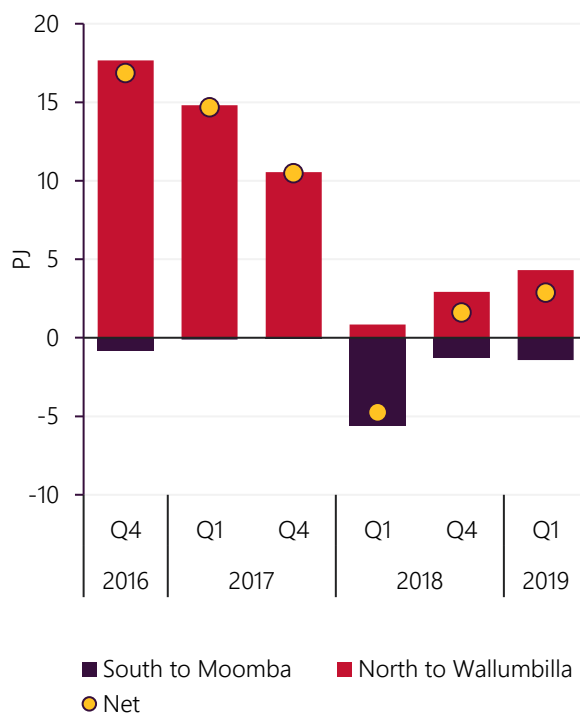


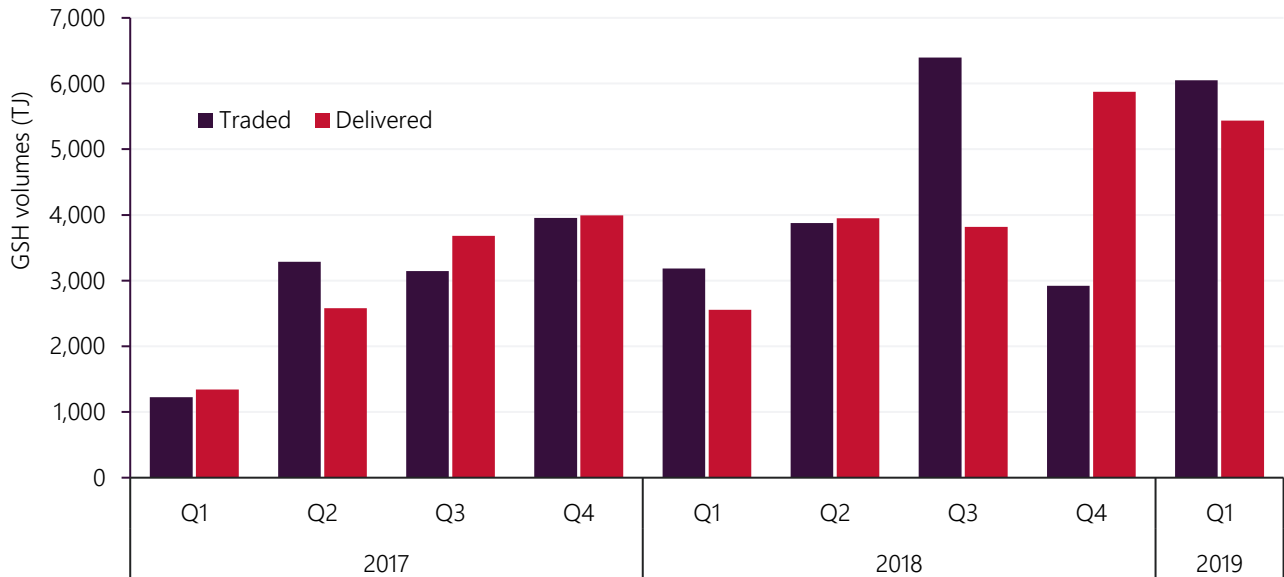
Figure 45 South West Queensland Pipeline at Wallumbilla



2.5 Gas Supply Hub

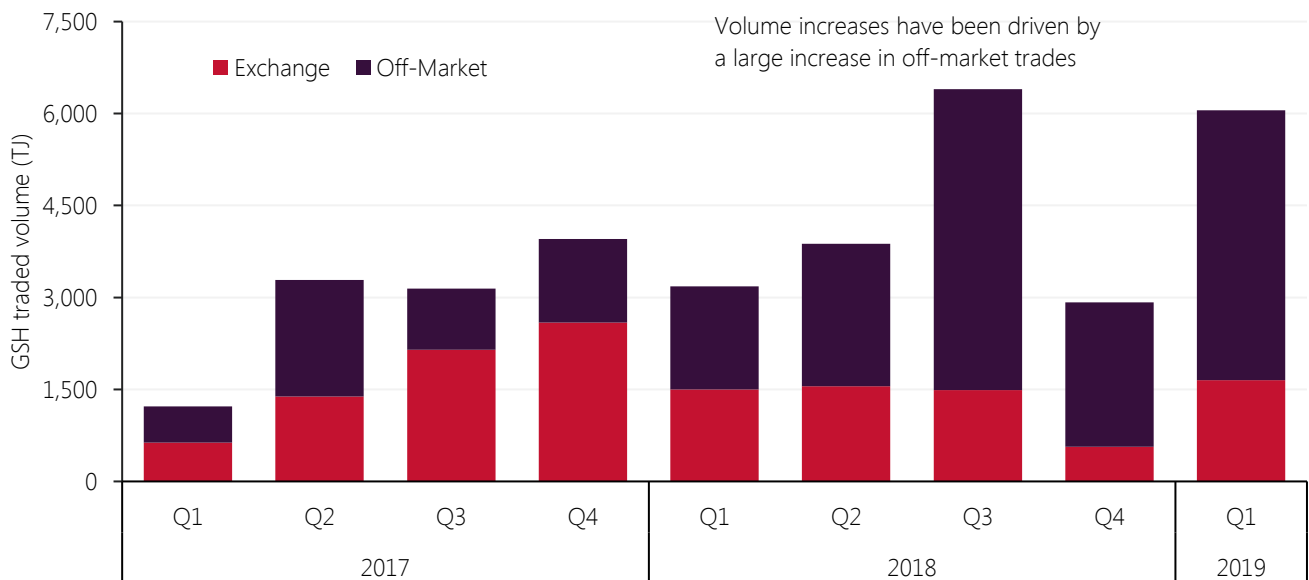
Q1 2019 continued the recent trend of comparatively high volumes traded on the GSH (Figure 46). Traded volumes increased by 2.9 PJ (+90%) when compared to Q1 2018 and by 4.8 PJ (+394%) when compared to Q1 2017.

Figure 46 Gas Supply Hub – quarterly trades and deliveries



The driver of this trend was increased utilisation of the GSH for off-market bilateral trades⁴⁶, while exchange trades have remained relatively flat (Figure 47).

Figure 47 GSH exchange and off-market volumes



⁴⁶ The GSH allows trading participants to either trade on-screen through the exchange, where buyers and sellers are matched on price, or they can use the GSH for trades where the buyer and seller have already agreed to the price, volume and length of the trade (an off-market trade).

2.6 Gas – Western Australia

In Q1 2019 total gas consumption reduced by 5% (or 4.5 PJ) compared to Q4 2018 (Figure 48), largely driven by decreases from distribution (-1 PJ) and large industrial users (-2 PJ).

There was a corresponding reduction in gas supply over the quarter, reducing by 3.9 PJ (or 4%, Figure 49). Gas production was lower at all production facilities, except Pluto. The most significant decreases came from Karratha (-3.1 PJ) and Varanus Island (-1.5 PJ). During Q1 2019 the Wheatstone production facility came online, producing 3.5 PJ during the quarter.

In Q1 2019 gas transferred into Storage Facilities⁴⁷ increased by 5% (or 0.3 PJ) compared to Q4 2018. The net effect – of reduced demand by 4.5 PJ, reduced supply by 3.9 PJ and increased storage by 0.3 PJ – indicates minor impact on linepack.

Figure 48 WA gas demand

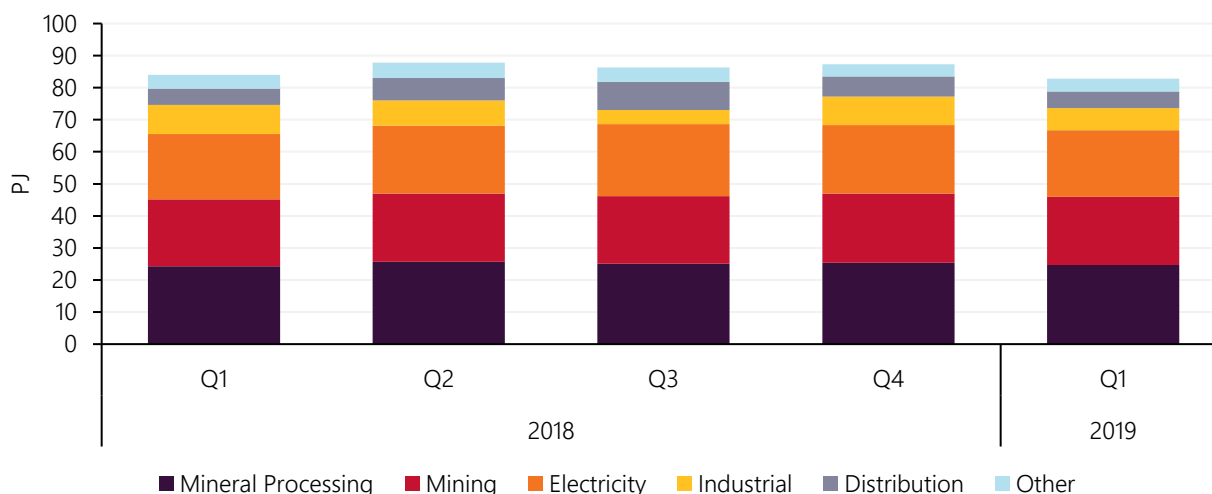
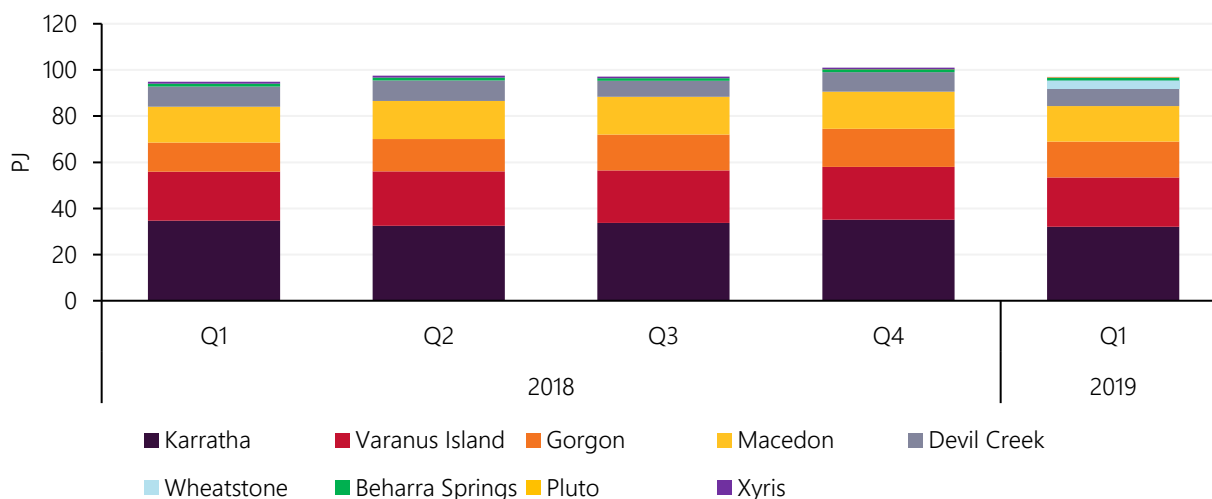


Figure 49 WA gas supply



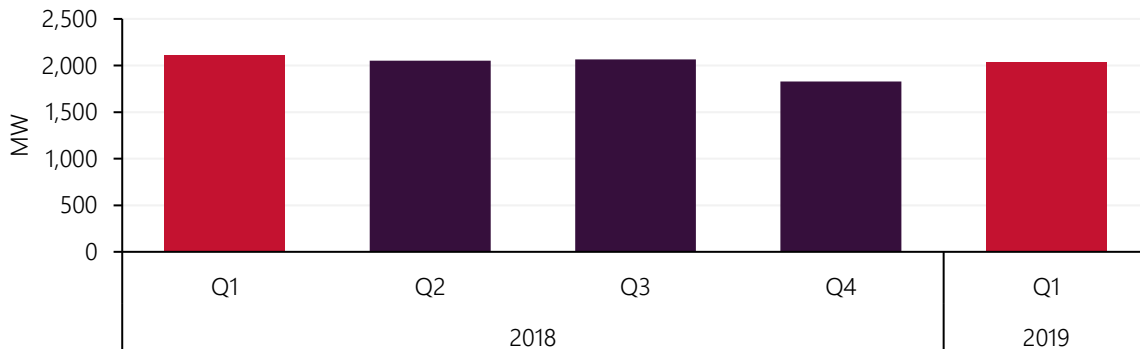
⁴⁷ Mondarra and Tubrudgi Storage Facilities

3. WEM market dynamics

3.1 Electricity demand and weather

Perth's average and maximum temperatures during Q1 2019 were lower than the 10-year Q1 average by 0.82°C and 0.70°C, respectively. This, coupled with increased penetration of rooftop PV, contributed to an average reduction in operational demand⁴⁸ of 70 MW (or 3.3%) compared to Q1 2018 (Figure 50).

Figure 50 WEM average operational demand



3.1.1 Peak demand intervals

The WEM recovers costs of the Reserve Capacity Mechanism through consumption during peak intervals in the Hot Season⁴⁹. Peak demand for the 2018-19 Hot Season (Table 7), which ended at the end of Q1 2019, was only 2 MW higher than peak demand during the previous winter (Figure 51). This was driven by the comparatively mild summer conditions and increased penetration of rooftop PV. In addition, the summer peak continued a trend of occurring later in the day⁵⁰.

Figure 51 WEM Hot Season and Winter peak demand

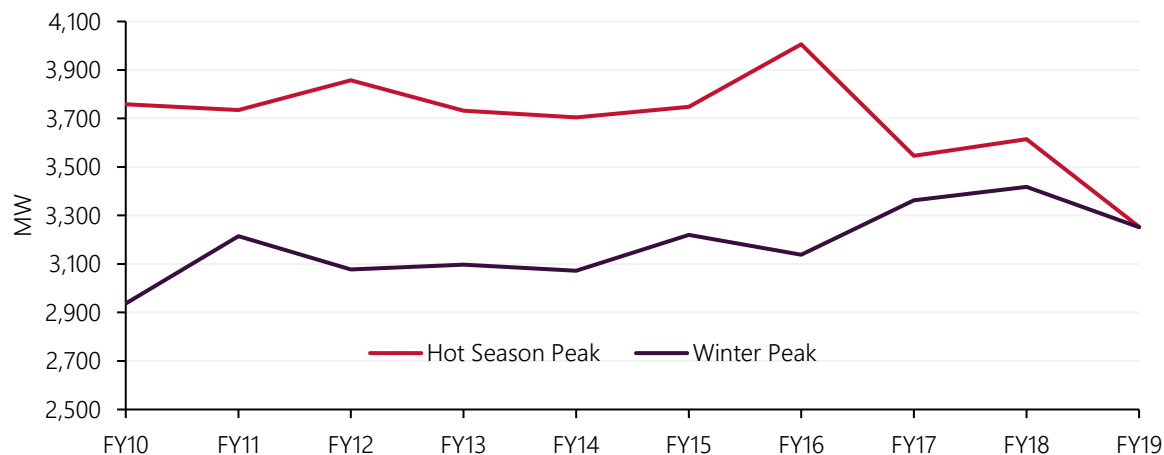


Table 7 WEM maximum and minimum demand (MW) – Q1 2019 vs records

Maximum demand (MW)			Minimum demand (MW)		
Q1 2019	All-time	All Q1	Q1 2019	All-time	All Q1
3,253	4,006	4,006	1,320	1,173	1,214

⁴⁸ 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.

⁴⁹ The period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April.

⁵⁰ 2018 ES00: pg. 5 – 6 - <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities>

3.2 Wholesale electricity pricing

3.2.1 Balancing and STEM prices

In Q1 2019, average Balancing Prices were 2% higher than Q4 2018 and 1% higher than Q1 2018, while Short Term Electricity Market (STEM) prices were 10% lower than Q4 2018 and 5% lower than Q1 2018 (Figure 52). The increase in the average balancing price in Q1 2019 compared to Q4 2018 was due to increased demand. The decrease in the average STEM price relative to Q4 2018 was largely driven by participant bidding behaviour.

The trend of increasing occurrences of daytime negative balancing prices continued in Q1 2019, with 106 (or 3.6%) intervals clearing at a negative price during on-peak periods (Figure 53).⁵¹ The lowest balancing price in Q1 2019 was -\$29.99/MWh.

Figure 52 WEM wholesale electricity prices

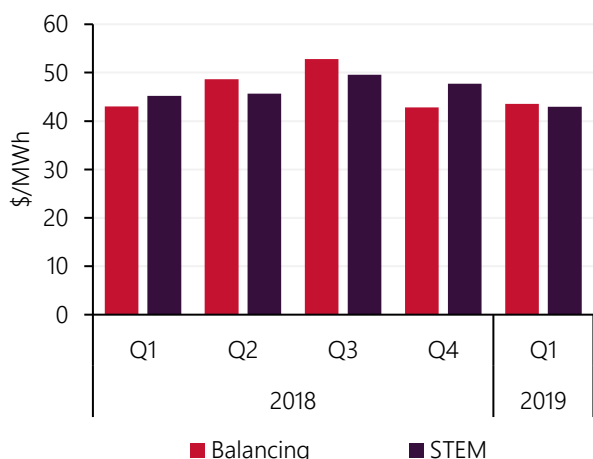
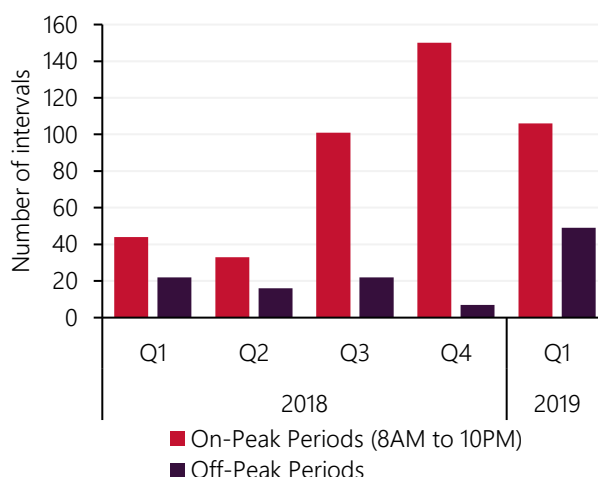


Figure 53 WEM negative Balancing Price intervals



3.2.2 Load Following Ancillary Service prices

In Q1 2019, the average LFAS Up and LFAS Down⁵² prices over the quarter converged for the first time since LFAS Market commencement. Compared to Q4 2018, the average LFAS Up price increased by 19% while the average LFAS Down price fell by 21% (Figure 54).

Figure 54 WEM average LFAS Prices

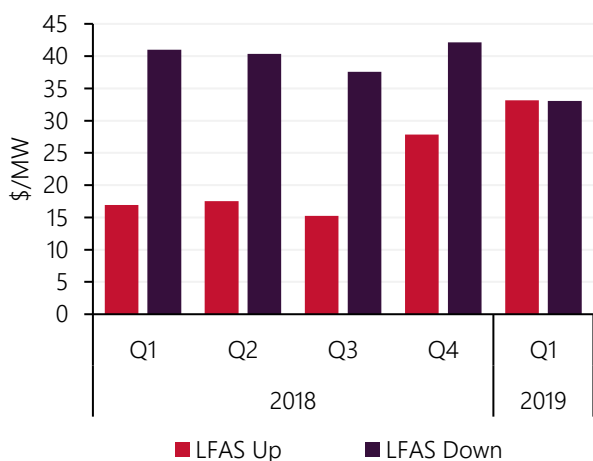
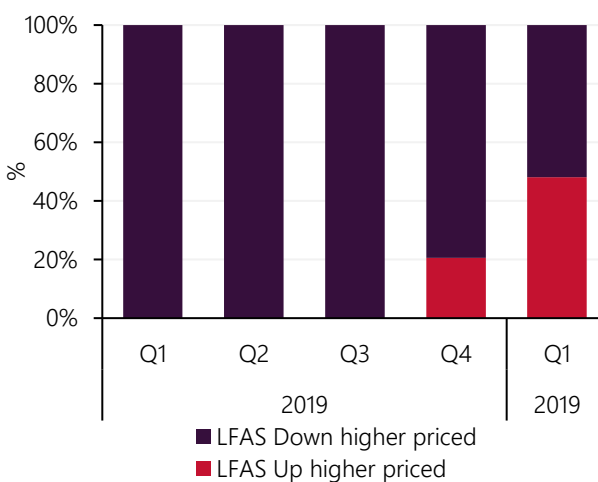


Figure 55 Percentage of Intervals where LFAS Up prices are greater than LFAS Down Prices



⁵¹Defined as 0800 to 2200 hrs

⁵² LFAS is used to continuously balance supply and demand. LFAS accounts for the difference between scheduled energy (what has been dispatched), actual load, and intermittent generation. LFAS Up requires the provision of additional generation to increase frequency in real-time and LFAS Down requires the reduction in generation to decrease frequency.

During the quarter, LFAS Up prices were higher than LFAS Down prices during 2085 (or 48%) of total intervals: this is an increase from 910 in Q4 2018 and only two intervals prior to Q3 2018 (Figure 55). The convergence of average LFAS Up and Down prices to an average of \$33.1/MW reverses the historical trend of LFAS Down prices being higher than LFAS Up prices, due to energy foregone in the provision of LFAS Down (which is not compensated at the Balancing Price).

There has been no change to the approved LFAS requirement of 72 MW⁵³. These price changes could be influenced by the changing pricing dynamics in the Balancing Market, particularly the increased occurrences of negative price intervals affecting participant bidding behaviour⁵⁴.

On 6 Feb 2019 a third participant, Alinta⁵⁵, commenced participating in the LFAS market. This resulted in lower LFAS Up and Down average prices for the remainder of the quarter, with average LFAS Up and Down prices for February falling by 26% following the entry of new supply. Prior to the addition of a third participant into the LFAS market, LFAS prices had been trending upwards, particularly over Q4 2018 and January 2019.

Synergy has historically set the clearing price in the LFAS Up and LFAS Down markets for the majority of time. The introduction of a third participant in the LFAS markets reduced the price setting role of Synergy over the quarter, mostly in the LFAS Down market during the middle of the day. In total, there were 142 intervals in which Synergy was not the price setter, with the price being set by Alinta during 125 of these intervals.

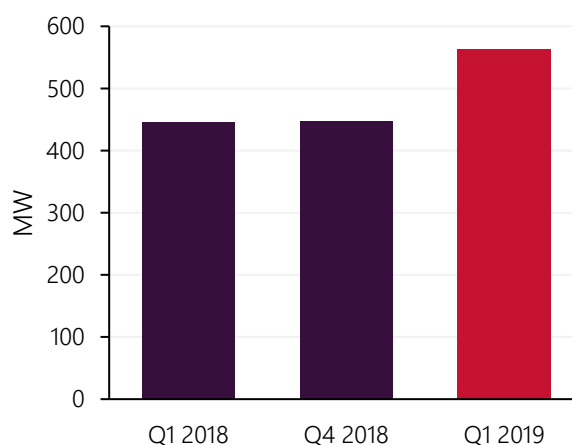
3.3 Non-scheduled generation

At 0730 hrs on 3 February 2019 the WEM reached its highest ever level of generation from grid-scale renewable Non-scheduled Generation (NSG), reaching 564 MW. This represents a 21% increase from the highest level of grid-scale NSG online during a single interval in both Q4 2018 and Q1 2018 (Figure 56).

Increasing NSG on the system was primarily driven by the connection of a new 130 MW wind generation facility during the quarter (Badgingarra Wind Farm).

Additionally, during the quarter total NSG (including estimated rooftop PV generation) reached its highest level as a proportion of underlying system demand. This occurred at 1145 hrs on 3 February 2019, when 47.8% of underlying demand was met by NSG. This trend of increasing NSG as a percentage of underlying demand is expected to continue as more NSG facilities register in the WEM and increasing capacity of rooftop PV is installed.

Figure 56 WEM maximum interval of NSG



⁵³ Refer to the 2018 Ancillary Services Report - <https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf>

⁵⁴ Negative Balancing Prices result in generators being charged for any electricity generated relative to their Net Contract Position.

⁵⁵ The other two participants are Synergy and NewGen Power Kwinana

Abbreviations

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