AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Quarterly Energy Dynamics Q3 2019

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 Q3 2019 (1 July to 30 September 2019). This quarterly report compares results for the quarter against other recent quarters, focusing on Q2 2019 and Q3 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	12/11/2019	

Executive summary

National Electricity Market (NEM) Q3 2019 highlights

Wholesale gas prices fall for the first time in a year

- After averaging $9-10/gigajoule (GJ) for the last year, average prices on AEMO's gas markets[1] fell in Q3 2019. Wholesale gas prices averaged $7.95/GJ over the quarter, 16% lower than in Q2 2019 and Q3 2018. Overall, prices were at their lowest level since Q4 2017, with Queensland prices recording the largest falls.
- East coast gas demand this quarter was higher than Q3 2018, driven by increased gas flows to Curtis Island for liquified natural gas (LNG) export and increased gas-powered generation (GPG), with the balance of mass market commercial and industrial demand similar to this time last year.
- Gas supply was boosted by record coal seam methane production, with QCLNG's Woleebee Creek expansion contributing an additional 9 petajoules (PJ). New gas supply from the Northern Territory through the Northern Gas Pipeline added another 6.1 PJ.
- Lower gas prices were a function of increased supply coinciding with low international LNG prices and greater competition at Longford, with BHP gas offers around $1.50/GJ below Esso for much of the quarter.

Negative spot electricity prices hit record levels in Queensland and South Australia

- In Q3 2019 there were record levels of negative electricity prices in parts of the NEM. Queensland's spot price was zero or negative 4.5% of the time, compared to 0.1% of the time in Q3 2018, with most negative intervals occurring during the daytime. In South Australia, the spot price was zero or negative 8.4% of the time, compared to 3.4% of the time in Q3 2018. Negative spot electricity prices reduced the Queensland average quarterly price by $2.74/megawatt hour (MWh) and the South Australia average by $8.22/MWh.
- Negative spot price periods in these regions coincided with high variable renewable energy (VRE) output (Queensland's solar penetration has increased significantly in the last year), low operational demand[2] and interconnector constraints which restricted electricity exports.
- Gas prices reductions, coupled with negative spot electricity prices, contributed to decreased spot electricity prices in Queensland and South Australia. Queensland's average price of $62/MWh was its lowest since Q3 2016, while South Australia's average of $75/MWh was its lowest since Q1 2016[3].
- An interesting consequence of negative spot prices was that some renewable generators rebid to avoid having to pay to generate. This was a factor in comparatively high levels of VRE curtailment – approximately 4.5% of VRE output was curtailed in Q3 2019 compared to 2% in Q2 2019.

[1] AEMO manages the spot gas markets in Victoria (Declared Wholesale Gas Market), Sydney, Adelaide and Brisbane (Short Term Trading Markets) and the Gas Supply Hub in Queensland.

[2] Operational demand is demand met by local scheduled generation, semi-scheduled generation and non-scheduled wind/solar generation of aggregate capacity ≥ 30 MW, and by generation imports to the region, excluding the demand of local scheduled loads. For definitions, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

[3] Excluding Q4 2016 which had its spot price outcomes significantly affected by the South Australian system black event.

Outages affect the Q3 supply mix

- Brown coal-fired generation declined to its lowest level since the start of the NEM due to a high number of planned and unplanned outages (most notably Loy Yang A2, which has been unavailable since May).
- These outages, coupled with ongoing water conservation from hydro generators due to dry conditions and an unplanned outage of Basslink, contributed to Victoria's average spot electricity price of $98/MWh, its fifth highest quarter on record.
- Gas-powered generators operated at elevated levels to cover coal-fired generator outages, with quarterly average gas-powered generation reaching its highest Q3 level in five years.
- The Basslink Interconnector experienced an unplanned outage between 24 August 2019 and 29 September 2019. This contributed to reduced Tasmanian hydro generation (excess hydro output could not be transferred to the mainland), as well as comparatively high NEM-wide Frequency Control Ancillary Service (FCAS) demand and costs.

Other east coast highlights

- Despite mostly lower spot prices, ASX electricity futures continued to rise. Calendar year 2020 swaps reached record average levels in all NEM regions, coinciding with concerns about the timing of the return to service of units at Loy Yang A and Mortlake power stations.
- On 24 August 2019, grid-scale VRE output met more than 30% of NEM operational demand for the first time, contributing to low and/or negatively priced intervals across the NEM on that day.
- South Australia set a new all-time minimum demand record of 574 megawatts (MW) at 1230 hrs on 29 September 2019[4]. This represents a continuation of decreasing average daytime demand, primarily driven by increasing rooftop photovoltaic (PV) uptake.

Western Australia Wholesale Electricity Market (WEM) Q3 highlights

- Minimum demand reached 1,176 MW, which was the WEM's lowest Q3 minimum demand on record and only 3 MW higher than the all-time minimum.
  - During this trading interval, output from rooftop PV reached 971 MW, with 45% of underlying system demand fulfilled by rooftop PV.
- Wind generation increased 27% compared to Q3 2018, resulting in 590 MW of non-scheduled generation on the system, which is an all-time record high.
- The average Balancing Price decreased by 22% compared to Q3 2018, with the largest decrease occurring during evening peak demand periods. This decrease was driven by:
  - Lower demand during evening peaks.
  - GPG offering an additional 120 MW on average at the floor price, causing a shift in the supply curve.
- The total cost of Load Following Ancillary Service (LFAS) decreased by 3% ($558,000) in Q3 2019 compared to Q2 2019, driven by a revised LFAS requirement introduced in August 2019.

[4] This record has since been exceeded in Q4 2019. At 12:30 PM AEST on Sunday 20 October 2019, favourable conditions for renewable energy resources, coupled with low weekend demand, saw South Australia reach a new record for lowest operational demand at 475 MW. At the time of the new record, rooftop PV was generating approximately 821 MW, equalling 64% of the total demand required in South Australia. This, combined with power generated by utility solar and wind generation, meant that approximately 90% of the state's native demand (demand met by local scheduled, semi-scheduled, non-scheduled, and exempt generation, and by generation imports to the region) was met by renewable sources.

Contents

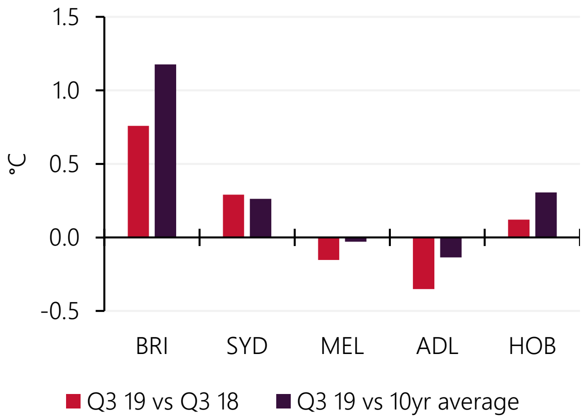
1. NEM Market Dynamics

1.1 Weather

During Q3 2019, warmer than average temperatures led to reduced heating requirement in Brisbane and Sydney (Figure 1, Figure 2). Colder than average temperatures increased heating requirements in Adelaide, while Melbourne and Hobart conditions were close to the 10-year average.

Figure 1 Mild winter in the northern regions

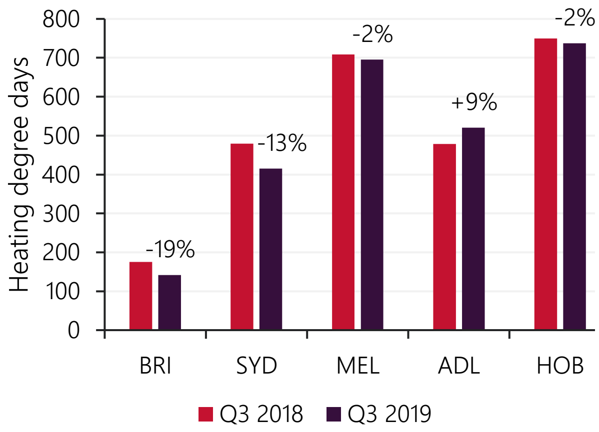
Average maximum temperature variance by capital city – Q3 2019 vs 10-year Q3 average



Source: Bureau of Meteorology

Figure 2 Reduced heating requirements in Brisbane and Sydney

Heating degree days[5]



1.2 Electricity demand

Compared to Q3 2018, NEM average operational demand reduced by 314 MW, primarily driven by increased output from rooftop PV, which led to lower average midday operational demand (by around 700 MW, Figure 3). Underlying demand[6] also reduced compared to Q3 2018, reflecting milder winter conditions which decreased heating requirements across most regions.

Compared to Q3 2018, by region:

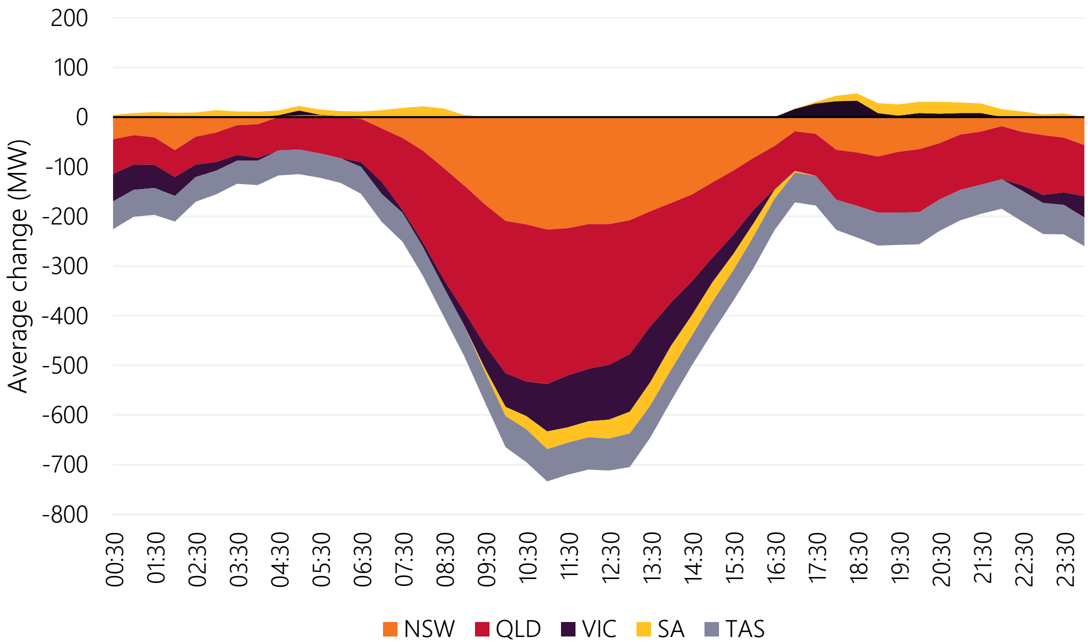
- **Queensland** – mild winter conditions and increased rooftop PV output (+78 MW on average) reduced average operational demand by 142 MW.
- **New South Wales and Victoria** – underlying demand was consistent with Q3 2018 results in these regions, with increased rooftop PV output reducing average operational demand by 82 MW in New South Wales and 29 MW in Victoria.
- **South Australia** – increased heating requirements offset increased rooftop PV penetration (+14 MW) and decreased industrial load, leading to steady operational demand (-2 MW).
- **Tasmania** – reduced industrial load in the region as well as warmer winter conditions contributed to a 59 MW decrease in average operational demand.

[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).

[6] Underlying demand = operational demand with rooftop PV added back in.

Figure 3 Increased rooftop PV output continues to impact daytime demand

Change in NEM-average operational demand by region and time of day (Q3 2019 versus Q3 2018)



Maximum and minimum demand

Table 1 outlines the maximum and minimum demands which occurred in Q3 2019, and the regional records[7].

Of note, South Australia set a new all-time minimum demand record of 574 MW on 29 September 2019[8] at 1230 hrs, 25 MW lower than the previous record. During this trading interval, South Australia rooftop PV output was approximately 750 MW. This represents a continuation of the decreasing daytime demand trend in the region, primarily driven by increasing rooftop PV uptake.

Table 1 Maximum and minimum operational demand (MW) by region – Q3 2019 vs previous records

	Queensland		***New South Wales***		***Victoria***		***South Australia ****		***Tasmania***	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q3 2019	7,898	4,211	11,430	5,803	7,477	3,635	2,356	574	1,626	887
All Q3	8,212	2,972	14,289	5,112	8,351	3,601	2,530	661	1,790	792
All-time	10,044	2,894	14,744	4,636	10,576	3,217	3,399	599	1,790	552

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

[7] Table records refer to those prior to the commencement of Q3 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] This record has since been exceeded in Q4 2019. At 1230 hrs (AEST) on Sunday 20 October 2019, favourable conditions for renewable energy resources coupled with low weekend demand saw South Australia reach a new record for lowest operational demand at 475 MW. At the time of the new record, rooftop PV was generating approximately 821 MW, equalling 64% of the total demand required in South Australia. This combined with power generated by utility solar and wind generation meant that approximately 90% of the state's native demand as met by renewable sources.

1.3 Electricity generation

Thermal unit outages and increased variable renewable energy (VRE) penetration shaped the generation mix in Q3 2019. Figure 4 shows the average change in generation by fuel type compared to Q3 2018 and Figure 5 illustrates the change by time of day.

Quarter highlights included:

- Average coal-fired generation (combined black and brown coal-fired generation) dropped to its lowest quarterly level since NEM start, primarily driven by a high number of planned and unplanned outages of brown coal-fired generators.
- Average GPG output of 2,337 MW represented the highest Q3 level since 2014, with Newport, Tallawarra and Jeeralang power stations running at elevated levels to cover coal-fired generator outages.
- On 24 August 2019, grid-scale VRE output met more than 30% of NEM operational demand for the first time, contributing to low and/or negative prices across the NEM on that day.

Figure 4 GPG running hard to cover coal unit outages

Change in supply – Q3 2019 versus Q3 2018

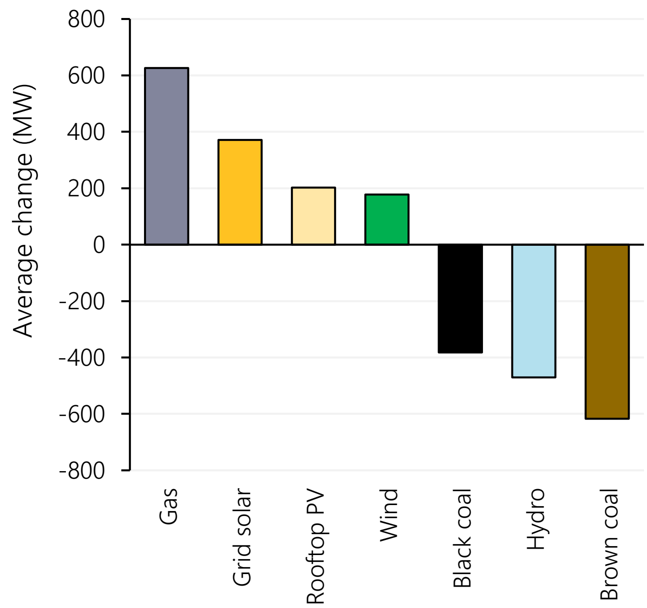
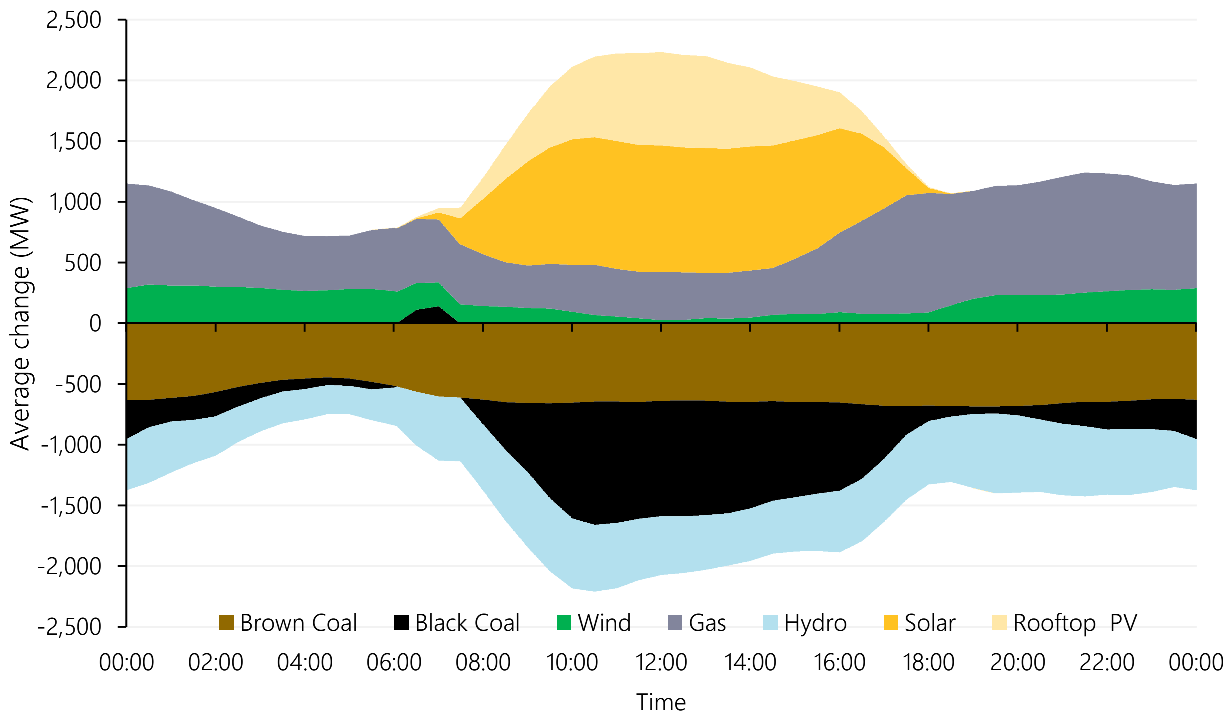


Figure 5 Reduced coal across the day; increased overnight GPG and daytime solar

Change in supply – Q3 2019 versus Q3 2018 by time of day



1.3.1 Coal-fired generation

Brown coal fleet

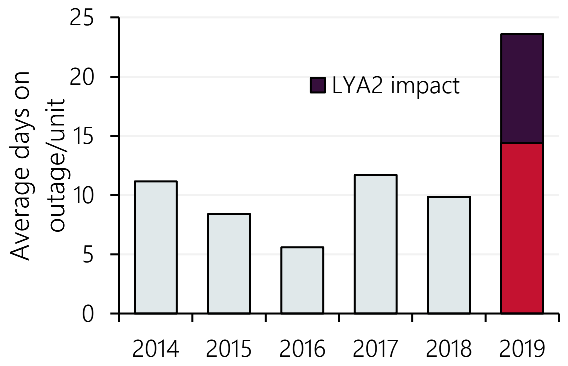
Brown coal-fired generation dropped to average 3,520 MW, its lowest quarterly average since NEM start. This was a function of the ongoing outage of Loy Yang A2 (from May 2019), combined low availability across other units (Figure 6).

There were 19 occurrences of unit outages during the quarter – five were planned, 14 were unplanned – resulting in more than double the average number of days on outage per unit recorded in Q3 2018.

Loy Yang A's average output of 1,426 MW was its second lowest quarter since NEM start, and Yallourn was affected by a comparatively high number of unplanned outages, leading to a reduction in average output of 226 MW compared to Q3 2018.

Figure 6 Brown coal fleet outages increase[9]

Brown coal-fired generators – days on outage (Q3s)



Black coal fleet

Results varied for black coal-fired generators in Q3 2019 compared to Q3 2018, with the New South Wales fleet increasing average generation by 113 MW, while the Queensland fleet's output fell by almost 500 MW.

AGL ran Bayswater and Liddell power station at elevated levels (combined +616 MW on average) which more than offset lower output at Loy Yang A Power Station (Figure 7). In contrast, Energy Australia's Mt Piper Power Station continued to be severely affected by coal supply/quality issues, resulting in its lowest quarterly average output since NEM start (434 MW).

A planned outage of Kogan Creek Power Station reduced Queensland black coal-fired generator average output by 655 MW compared to Q3 2018. In addition, increased penetration of solar (both grid-scale and rooftop PV) induced more flexible operation of some black-coal fired generators in the region. Figure 8 shows this, with Gladstone Power Station ramping down to around half its capacity over the middle of the day, before ramping up to near-full capacity during the peak evening period.

Figure 7 Varied response to outages across portfolios

Change in supply mix by participant and fuel type – Q3 2019 versus Q3 2018

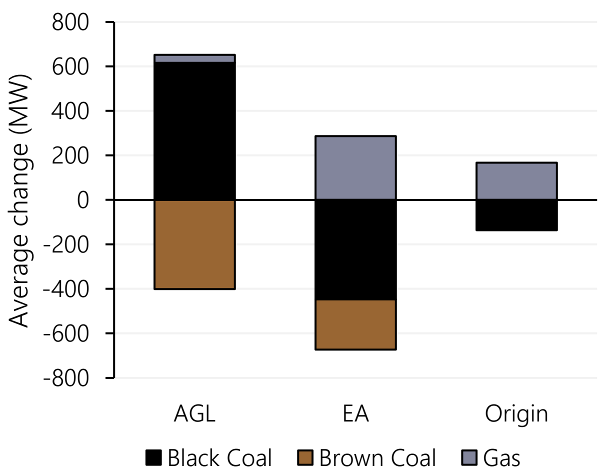
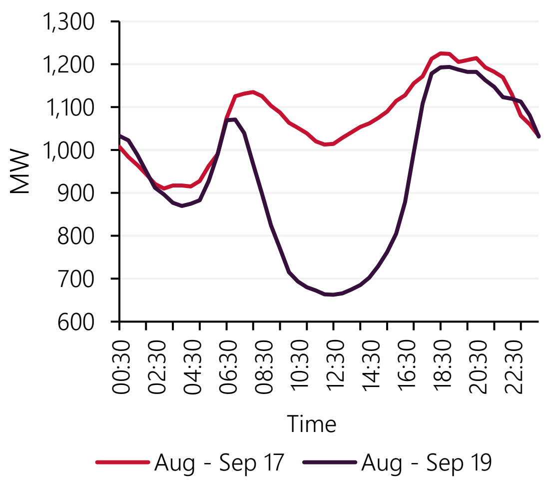


Figure 8 Solar induced flexibility at Gladstone

Gladstone Power Station daily generation profile – August-September 2019 and August-September 2017



[9] Historically data excludes generators which have closed.

1.3.2 Gas-powered generation (GPG)

NEM-average GPG increased sharply by around 630 MW (+37%) compared to the same period last year, reaching its highest Q3 level since 2014 (when gas prices began rising).

This was due to GPG running at elevated levels to cover coal-fired generator outages (Figure 9), as well as a reduction in wholesale gas prices. These factors were reflected in GPG market offers – on average, there was around 700 MW more capacity offered at prices below $100/MWh than in Q3 2018 (Figure 10).

Noticeable changes in output by unit compared to Q3 2018 included:

- Energy Australia's Newport increased by 156 MW on average (around 68% of Victoria's increase), while its Tallawarra plant was up around 90 MW (75% of New South Wales' increase). These increases were in response to outages at Yallourn Power Station in Victoria and Mount Piper Power Station in New South Wales.
- Engie's Pelican Point in South Australia increased by around 60 MW on average, continuing its high running pattern in 2019.
- QGC's Condamine increased by 105 MW on average (accounting for 70% of Queensland's increase) due to increased availability following an extended outage in Q3 2018.
- Origin Energy's Victorian Mortlake Unit 12 experienced an electrical fault on 8 July taking the power station down to one operational unit. Mortlake Unit 12, which generated around 85 MW on average in 2019 before the outage, is not expected to return to service until 20 December 2019[10].

Figure 9 GPG up in Q3 2019

Change in GPG Q3 2019 versus Q3 2018

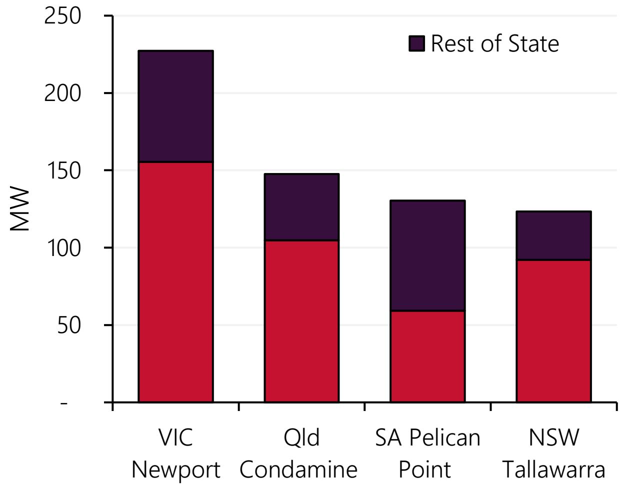
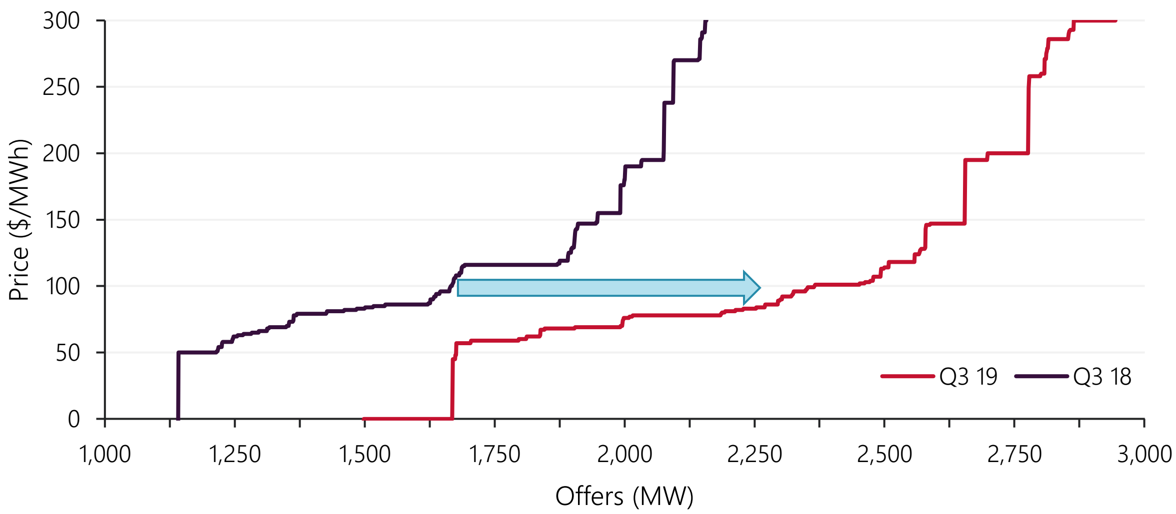


Figure 10 GPG bid into the market at lower prices

NEM GPG bid supply curve – Q3 2019 versus Q3 2018



[10] Origin Energy, 2019, at www.originenergy.com.au/about/investors-media/media-centre/statement_on_mortlake_power_station.html

1.3.3 Hydro

Hydro generation was approximately 475 MW lower (-20%) in Q3 2019 than the same period last year, resulting in its lowest Q3 output since 2014 (Figure 11). The largest decline occurred in Tasmania (around -310 MW), following the Basslink outage in September which restricted the ability to export excess hydro generation to Victoria.

Snowy reduced output by an average of around 190 MW, with historically low dam levels continuing through 2019 (Figure 12). Upper Tumut was down by approximately 70 MW and Murray 85 MW on average. Hydro Tasmania's storages were replenished over the quarter, increasing from 35% to 47%.

According to the Bureau of Meteorology[11], year to date (January-September) rainfall has been below average to very much below average, across most of Australia, as is reflected in the nine-month rainfall deficiencies. For Australia as a whole, this was the fourth-driest January-September on record, and the driest since 1965.

Figure 11 Tasmania leads hydro decrease

Change in hydro generation by region – Q3 2019 versus Q3 2018

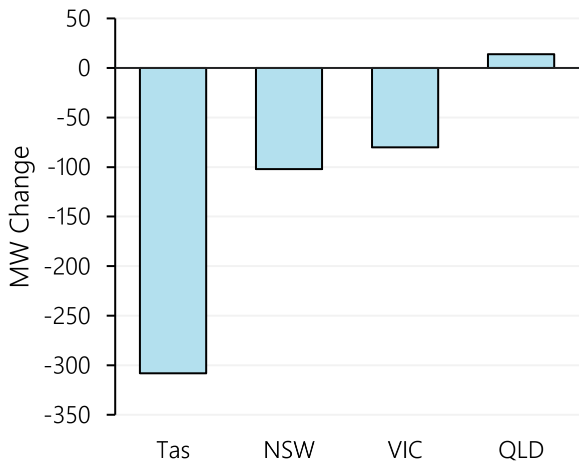
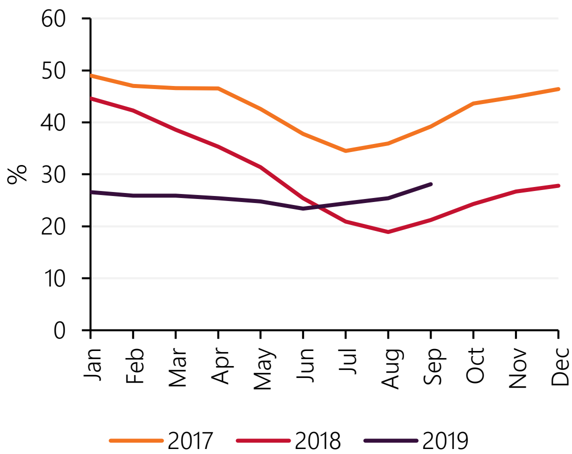


Figure 12 Snowy dam levels remain low[12]

Weekly gross storage levels in percentage



1.3.4 Wind and solar

Several grid-scale VRE records were set during Q3 2019, with new projects from previous quarters continuing to ramp up to full output, leading to the highest quarterly average wind and solar output on record. The third quarter is also typically the windiest quarter across most NEM regions. Trading interval records[13] included:

- Highest grid-scale VRE share of NEM operational demand – NEM VRE output met 30% of NEM operational demand for the first time on record at 1300 hrs on 24 August 2019.
- Highest VRE output on record – NEM VRE output reached 5,896 MW at 1300 hrs on 9 August 2019 (Figure 13).
- Highest wind output on record – NEM wind output reached 4,738 MW at 2000 hrs on 10 August 2019.
- Highest grid-solar output on record. NEM grid-solar output reached 2,210 MW at 1400 hrs on 28 September 2019.

Periods of elevated VRE output contributed to increased frequency of zero and/or negative spot prices, which is covered in more detail in Section 1.4.2.

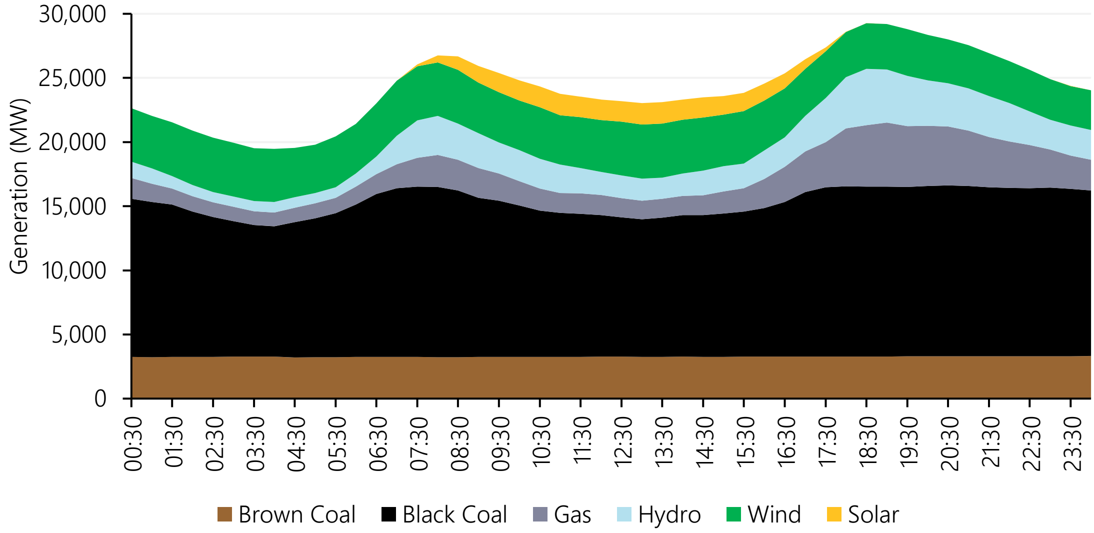
[11] See www.bom.gov.au/climate/drought/

[12] https://www.snowyhydro.com.au/our-energy/water/storages/lake-levels-calculator/

[13] Several of these records have since been broken.

Figure 13 VRE output reaches record levels

NEM supply mix on 9 August 2019



NEM average wind output was up by 185 MW, mostly driven by higher wind output in New South Wales (+137 MW). South Australian wind output reduced by 60 MW on average despite increased installed capacity, due to lower wind speeds.

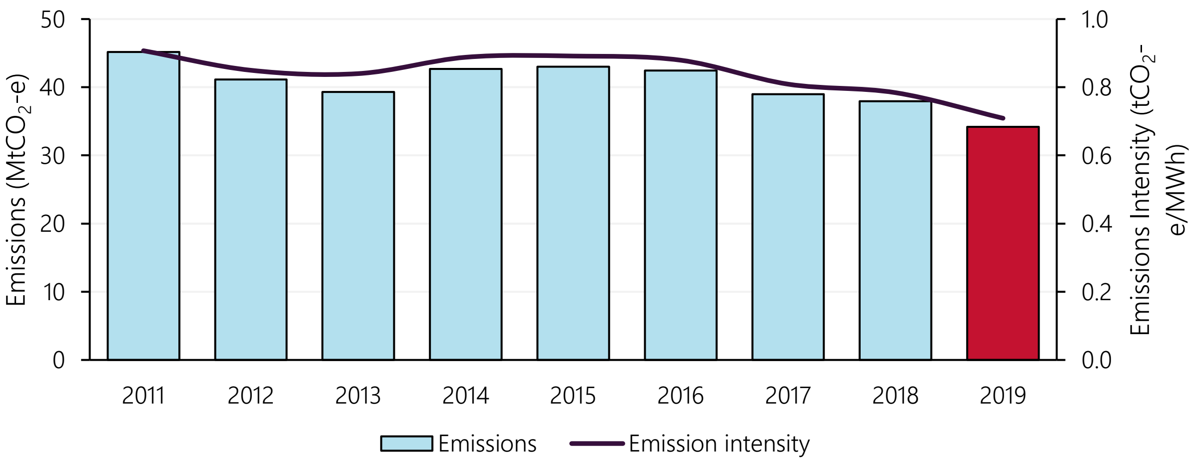
Growth in grid-scale solar capacity slowed over the quarter, with only two projects commencing generation (Finley Solar Farm in New South Wales, 133 MW; Oakey 2 Solar Farm in Queensland, 55 MW). However, there was still a 369 MW increase in average generation compared to Q3 2018, as projects which commenced generation in previous quarters continued to ramp up to full capacity. Almost 60% of this year-on-year growth occurred in Queensland.

1.3.5 NEM emissions

NEM emissions for the quarter continued the recent downward trend, reaching the lowest level on record, both in terms of absolute emissions and emissions intensity (Figure 14). The NEM average emissions intensity of 0.71 tonnes of carbon dioxide equivalents/MWh (tCO_2-e/MWh) was around 5% lower than the previous lowest quarter (Q2 2019). This downward trend in emissions is due to record low brown coal-fired generation, increased VRE output, and lower NEM operational demand.

Figure 14 Record low quarterly NEM emissions

Quarterly NEM emissions and emissions intensity (Q3s)



1.3.6 Storage

The amount of charging or pumping by energy storage facilities in the NEM during Q3 2019 was 221 gigawatt hours (GWh), 82 GWh higher than in Q2 2019 and 68 GWh higher than Q3 2018. This was due to increased pumping from pumped hydro stations Tumut 3 and Shoalhaven, coinciding with the fourth driest winter on record in New South Wales. The contribution from batteries remained relatively stable compared to the prior quarter.

Battery net revenues for the quarter were approximately $12 million, representing the highest level on record since the first grid-scale battery entered the market at the end of 2017 (Figure 15). Drivers included:

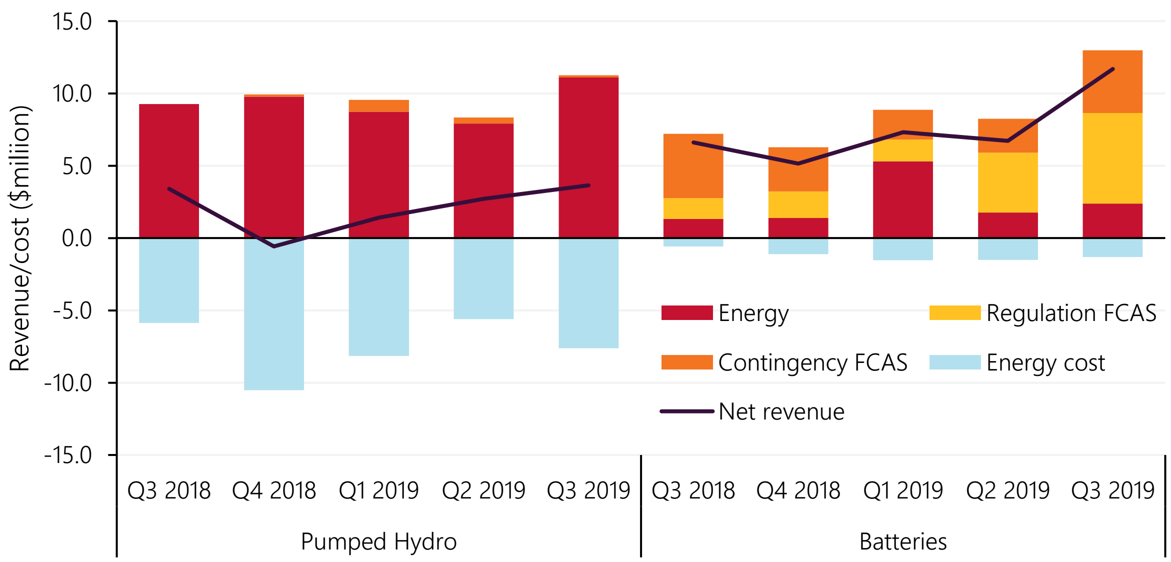
- Increased FCAS revenues (around +$4 million), due to a 20% increase in Regulation FCAS prices compared to Q2 2019 and greater participation in FCAS markets from the two grid-scale batteries in Victoria.
- Increased energy revenues compared to Q2 2019 (+$0.6 million), which was a function of increased dispatch of Victorian batteries into the spot electricity market.
- A decrease in energy costs compared to Q2 2019 (-$0.22 million), largely due to lower charging costs in South Australia associated with charging during negative or low spot prices.

Net revenue for the pumped hydro facilities also increased, reaching $3.65 million. This was driven by a 31% increase in dispatch of pumped hydro facilities, as well as the average energy arbitrage value increasing from $67/MWh in Q2 2019 to $82/MWh in Q3 2019.[14]

Increased energy arbitrage was largely due to Wivenhoe pumping at lower prices than in Q2 2019 (volume-weighted pumping price of $28/MWh in Q3 2019 versus $53/MWh in Q2 2019). However, this arbitrage would have been higher if Wivenhoe had pumped more during negatively priced intervals – Wivenhoe only pumped during 18% of these intervals. A combination of environmental, technical and commercial considerations is likely to have influenced this behaviour.

Figure 15 NEM battery market revenue hits record levels

Revenue sources by storage technology[15]



[14] 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. The calculation also excludes potential value from the stored water through its sale outside of the energy sector.

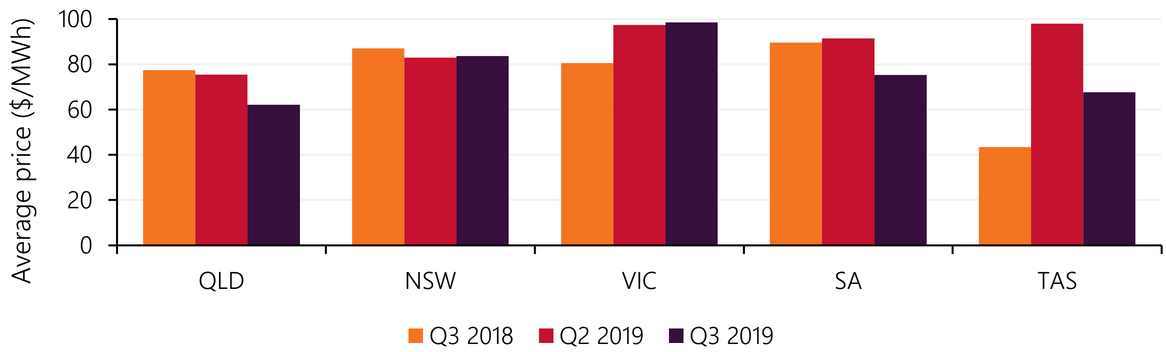
[15] The calculation of storage arbitrage value for pumped hydro excludes Tumut 3 facility as its sources of water include both pumped water from Jounama Pondage and inflows from Tumut 1 and Tumut 2 underground power stations and into Talbingo Reservoir...

1.4 Wholesale electricity prices

Queensland and South Australian wholesale electricity prices fell in Q3 2019 compared to Q3 2018, with Queensland's average spot price of $62/MWh representing the lowest quarterly average mainland NEM price since Q3 2016 (Figure 16). South Australia's average of $75/MWh was its lowest since Q1 2016[16]. In contrast, Victoria's average price rose to $98/MWh – its fifth highest quarter on record – despite higher GPG and reduced wholesale gas prices. New South Wales' average price was consistent with recent quarters.

Figure 16 Mixed results for spot electricity prices

Average wholesale electricity price by region

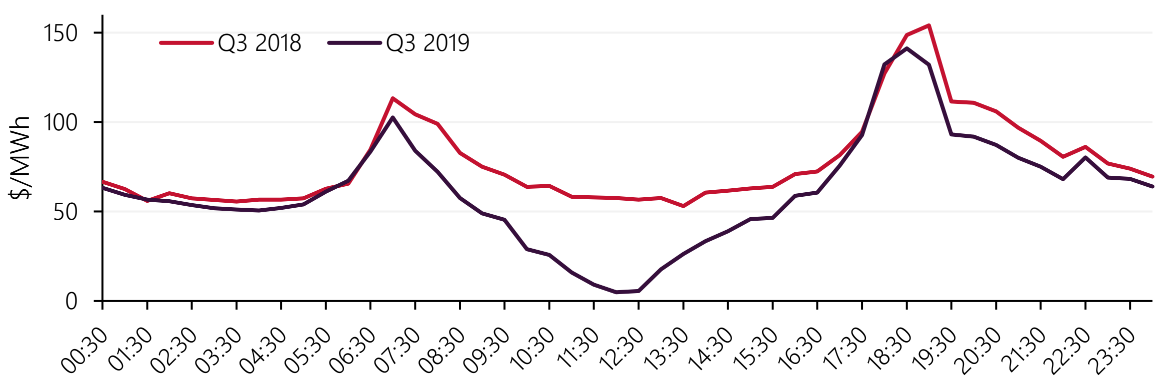


Wholesale electricity price drivers: Q3 2019 compared to Q3 2018

Increased prices in Victoria despite lower gas prices	Record low brown coal-fired generation (see Section 1.3.1). Water conservation – continued dry conditions, combined with an outage on the Basslink Interconnector outage reduced availability of lower-priced hydro generation. Hydro generation set Victoria's price 35% of the time at an average of $128/MWh (up from $101/MWh in Q3 2018).
Reduced Queensland and South Australia prices	High levels of negative and zero spot prices – negative prices directly reduced the Queensland average by $3/MWh and the South Australian average by $8/MWh. Negative price drivers are discussed in more detail in Section 1.4.2. The large increase in Queensland solar generation was a key factor in Queensland's average midday price reducing to almost 0/MWh (Figure 17). Reduced wholesale gas prices were reflected in lower-priced offers from gas-powered generators. For example, GPG units set South Australia's price at an average of $83/MWh over the quarter, compared to $112/MWh in Q3 2018.

Figure 17 Large reduction in Queensland's daytime spot prices

Queensland average spot electricity price by time of day



[16] Excluding Q4 2016, in which spot price outcomes were significantly affected by the South Australian black system event.

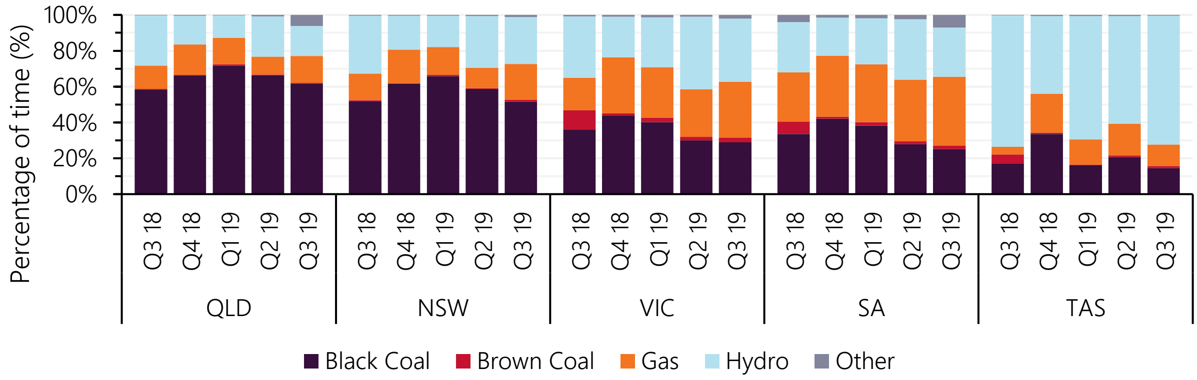
1.4.1 Price-setting dynamics

Figure 18 and Figure 19 show price setting results compared to recent quarters. Key outcomes included:

- Increased price setting role for gas – across the NEM, gas was the marginal fuel type 23% of the time, representing the third-highest quarterly level since 2010.
  - Gas units set the price at lower levels than in recent quarters, reflecting lower wholesale gas prices. For example, in Queensland GPG set the price at an average of \$65/MWh (compared to \$89/MWh in Q3 2018) and in South Australia GPG set the price at an average of \$83/MWh (compared to \$112/MWh in Q3 2018).
- Renewable projects setting the price more often – periods of oversupply in Queensland and South Australia (see Section 1.4.2) led to VRE units setting the price more frequently than in any other quarter on record.
  - Solar farms set Queensland's price approximately 5% of the time.
  - Wind farms set South Australia's price approximately 5% of the time.
- Increased local price setting – generators set the price in their home region more often than recent quarters in four out of five NEM regions (Victoria was the exception). The largest shift was in Queensland, with local units setting the price 53% of the time compared to 35% in Q3 2018.
  - This was driven by interconnectors reaching capacity limits more often than in recent quarters (see Section 1.6), contributing to increased price spreads.

Figure 18 Gas setting the price more frequently

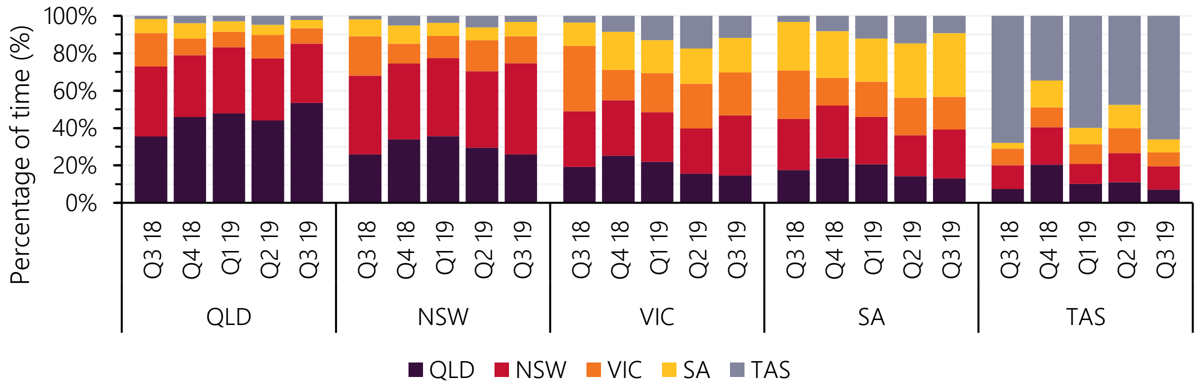
Price-setting by fuel type – Q3 2019 versus prior quarters



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

Figure 19 Increased local prices setting across most NEM regions

Price-setting by region – Q3 2019 versus prior quarters



1.4.2 Negative prices

This quarter, the frequency of negative and zero spot prices in South Australia and Queensland reached record levels (Figure 20). Queensland's spot price was negative or zero 4.5% of the time, compared to 0.1% of the time in Q3 2018, with the majority of negative intervals occurring during the daytime.

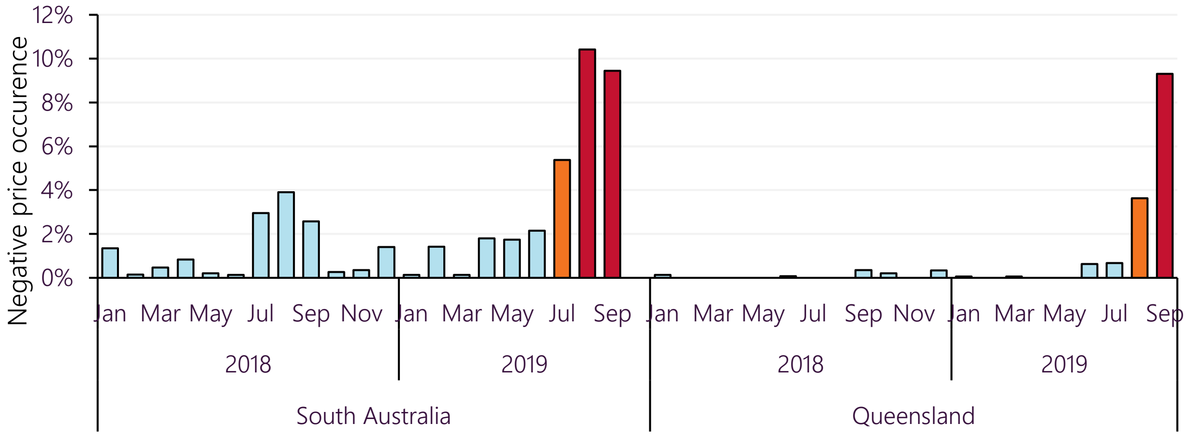
In South Australia, the spot price was negative or zero 8.4% of the time, compared to 3.4% of the time in Q3 2018. Drivers of these results are discussed below. The frequency of negative spot prices in New South Wales, Victoria, and Tasmania remained comparatively low.

Negative and zero prices over the quarter contributed to:

- Average spot price reductions in Queensland and South Australia (Section 1.4).
- Comparatively high curtailment of VRE output (Section 1.7). This was due to some wind and solar farms re-bidding output to higher prices and subsequently not being dispatched during negative intervals.
- Flexible operation of some coal-fired generators in Queensland (Section 1.3.1).
- Comparatively high value of inter-regional settlement residue associated with flows from Queensland to New South Wales and flows from South Australia to Victoria (Section 1.6.1).

Figure 20 Record occurrence of negative prices in South Australia and Queensland

Frequency of negative or zero spot prices in South Australia and Queensland.



Drivers of negative prices in Queensland included:

- Seasonally-low (and falling) daytime demand[17]. Due to Queensland's mild winter conditions, which limit heating requirements, Q3 is typically its lowest demand quarter (Figure 21).
  - In addition, increasing rooftop PV penetration has reduced daytime operational demand – in Q3 2019, Queensland's average daytime operational demand was around 260 MW lower than in Q3 2018.
- More daytime supply offered at low prices – between July 2018 and September 2019, around 1,250 MW of grid-scale solar capacity and approximately 500 MW of wind capacity commenced generation in Queensland. In August and September 2019, this increased the average daytime VRE output by approximately 600 MW compared to the corresponding months in 2018.
- Interconnector constraints and outages:
  - On September 4 and 5, transmission line outages resulted in significant de-rating of the Queensland to New South Wales interconnector (QNI, import limit reduced by more than 800 MW, Figure 22).

[17] 0900 – 1500 hrs

- With low operational demand and high daytime solar output, de-rating of the interconnector led to excess Queensland supply and several trading intervals reaching prices below -$400/MWh.
- This contributed more than 50% of the negative price impact over the quarter.

– Under a voltage constraint introduced in early 2019[18], output from the Sapphire Wind Farm limits flows south on QNI. This constraint contributed to a 11% reduction on the QNI's southerly transfer limit compared to Q3 2018.

Figure 21 Queensland daytime demand has reduced

Average operational demand in Queensland 0900-1500 hrs

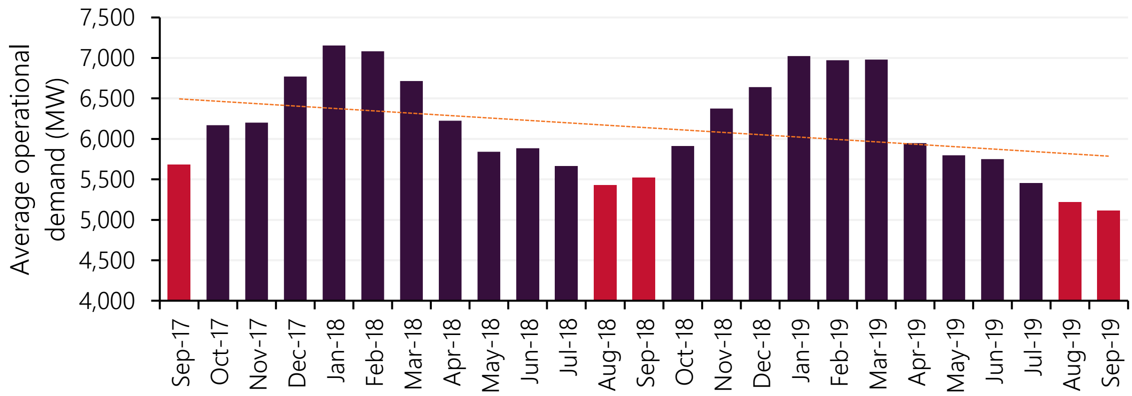
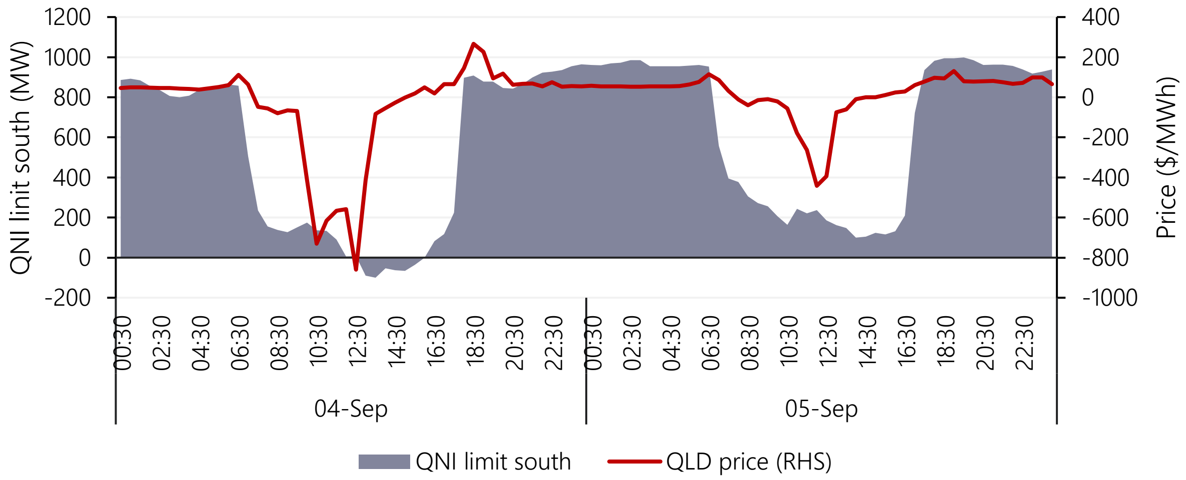


Figure 22 September transmission outages cause record negatives

The impact of Tamworth-Armidale line outage on 4 and 5 September 2019



Drivers of negative prices in South Australia included a combination of:

- High VRE output – approximately 54% of the negative intervals over the quarter occurred when South Australian VRE output exceeded 1,100 MW.
- Interconnector constraints – around 66% of the negative intervals over the quarter occurred when the Heywood interconnector's import limit was below 300 MW (from 500 MW). This included periods where AEMO invoked discretionary constraints to limit transfer on the VIC-SA interconnectors (to 50-250 MW)[19] due to increased risk of non-credible contingencies in South Australia and/or Victoria associated with abnormal weather conditions.

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[18] Q^^NIL_QNI_SRAR, introduced to avoid voltage instability on trip of Sapphire - Armidale (8E) 330 kV line.

[19] Examples include the VS_100 and VS_250 constraints.

- Low operational demand – around 32% of the negative intervals over the quarter occurred when operation demand was below 1,100 MW.

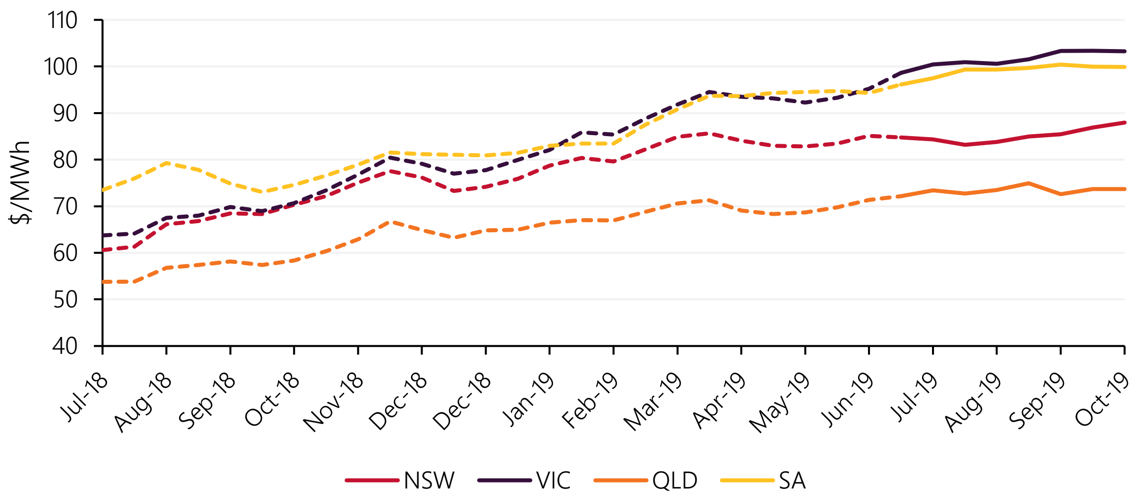
1.5 Other NEM-related markets

1.5.1 Electricity future markets

ASX Electricity futures continued to rise in Q3 2019, with Calendar 2020 (Cal20) swaps reaching record average highs across all regions (Figure 23).

Figure 23 ASX Futures continue to rise

ASX Energy – Cal20 swap prices by region

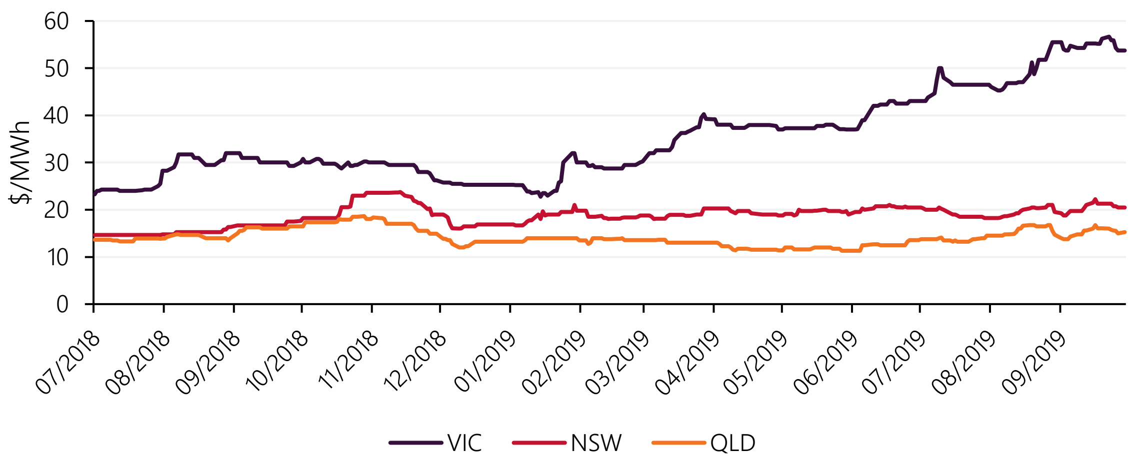


Victoria's Cal20 price averaged $102/MWh in Q3 2019, an increase of approximately $7.50/MWh compared to Q2 2019, while the Q1 2020 cap product was up around $11/MWh to $50/MWh compared to Q2 2019. These price movements indicate concerns regarding the expected return to service for AGL's Loy Yang Unit 2 and Origin's Mortlake Unit 12, as well as the general performance of the coal-fired fleet.

Victoria's price spread between Cal20 and Cal21 swaps widened to approximately $22/MWh, while the Victoria and New South Wales Cal20 spread increased to around $15/MWh.

Figure 24 ASX Caps – Victoria continues to rise

ASX Energy – Q1 2020 Cap prices by region



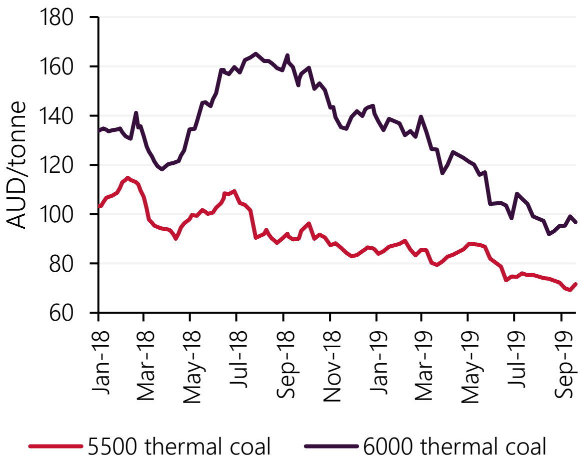
1.5.2 International coal prices

Newcastle thermal coal prices continued to trend downward over the quarter (Figure 25). Since Q3 2018, thermal coal prices (6,000 kcal) have fallen from a quarterly-average of AUD$160/tonne to AUD$98.75/tonne in Q3 2019. Key drivers include:

- Lower year-on-year imports from Japan, South Korea, and the European Union. While Chinese imports have been resilient, the prospect of tighter import controls have influenced buying sentiment.
- Low spot LNG prices, which also encouraged some coal-to-gas switching – predominantly in Europe – further dampening import demand for thermal coal. Concurrently, large volumes of thermal coal have entered the seaborne market since 2018, predominately from Atlantic suppliers, resulting in an oversupplied market[21].

Figure 25 Thermal coal prices remain subdued[20]

Newcastle thermal coal prices



To date, the falling international coal price has not significantly affected domestic energy market outcomes. In New South Wales, some coal-fired generators have reduced the price of their offers (Bayswater and Eraring power stations). However, in Q3 2019 coal-fired generators in the region set the average spot price at a similar level as in Q3 2018 (at around $65-70/MWh).

1.5.3 Environmental markets

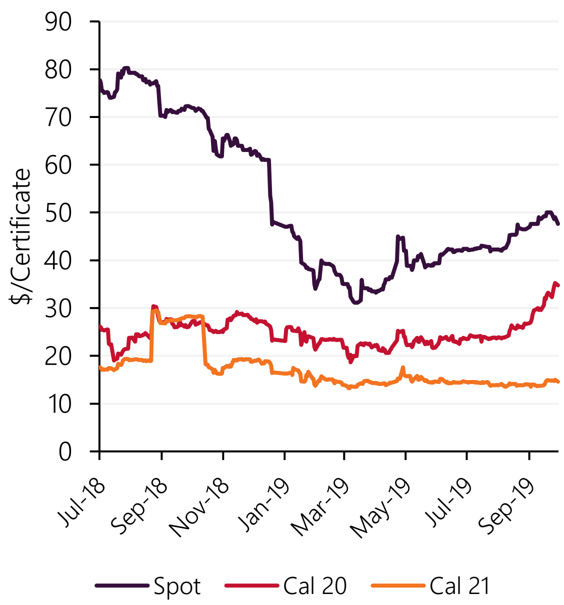
Spot Large-scale Generation Certificate (LGC) prices increased on average by $6/certificate throughout Q3 2019 (Figure 26). Spot prices reached a high of $50/certificate, while Cal20 peaked at $35.25/certificate and Cal21 was flat at around $15/certificate.

The rally from around the beginning of August to late September for spot LGC prices coincided with:

- A low hydro generation year – from Q1-Q3 2019, hydro generation was around 20% lower than the same period last year, which will likely result in limited LGC creation from hydro generation this year.
- The Basslink outage from 24 August to 29 September 2019, which contributed to a reduction in Tasmania's hydro generation to average 1,278 MW for Q3 2019 versus 1,586 MW in Q3 2018.
- Increased curtailment of VRE output associated with negative prices and network constraints (see Section 1.7).

Figure 26 LGC price rally continues[22]

LGC spot and forward price over time



[20] Source: Bloomberg

[21] https://publications.industry.gov.au/publications/resourcesandenergyquarterlyseptember2019/documents/Resources-and-Energy-Quarterly-September-2019.pdf page 45.

[22] Source: Mercari

1.5.4 Frequency control ancillary services

In Q3 2019, FCAS costs were $59.5 million, representing a $14 million (32%) increase on Q2 2019, reaching similar levels as in 2018 (Figure 27). FCAS costs were up across most markets, with a $9 million (+30%) increase in Regulation FCAS costs contributing the majority of the increase.

Most of the comparatively higher FCAS costs occurred during September 2019, due to high FCAS requirements over the month. Drivers of increased requirements included:

- Basslink outage – during the Basslink outage AEMO was required to enable local FCAS in Tasmania in addition to the usual FCAS requirements, increasing total FCAS demand (Figure 29).
- Changes to Contingency FCAS requirements – as part of a review of load relief[23], AEMO determined that the changing nature of load means load relief for FCAS should be assumed to be 0.5% (down from 1.5%). From 12 September 2019, AEMO began to slowly decrease the assumed level of mainland load relief (reducing by 0.1% per fortnight), which had the practical effect of increasing Contingency FCAS requirements.

Batteries and hydro increased supply compared to recent quarters (Figure 28), providing 20% and 25% of Raise FCAS market share, respectively.

Figure 27 Regulation FCAS costs increase

Quarterly FCAS costs by service

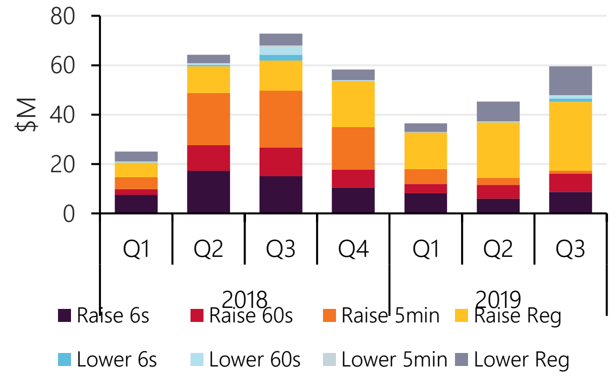
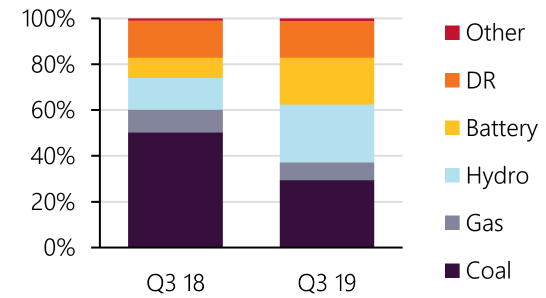


Figure 28 Batteries and hydro capture larger share of FCAS market

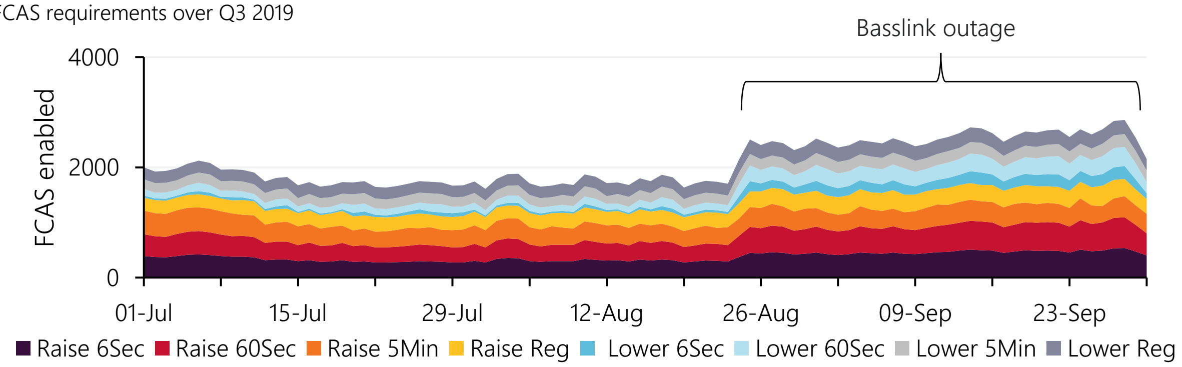
Raise FCAS supply mix by fuel type



In addition, a virtual power plant (VPP) was enabled to provide FCAS as part of AEMO's VPP Demonstrations. As part of the trial, Energy Locals registered a VPP to deliver 1 MW of FCAS across the six contingency FCAS markets. The VPP was first enabled to provide FCAS on 13 September 2019 and was enabled across the FCAS markets around 75% of the time for the remainder of the month, benefiting from comparatively high FCAS prices over the period.

Figure 29 Basslink outage increases FCAS requirements

FCAS requirements over Q3 2019



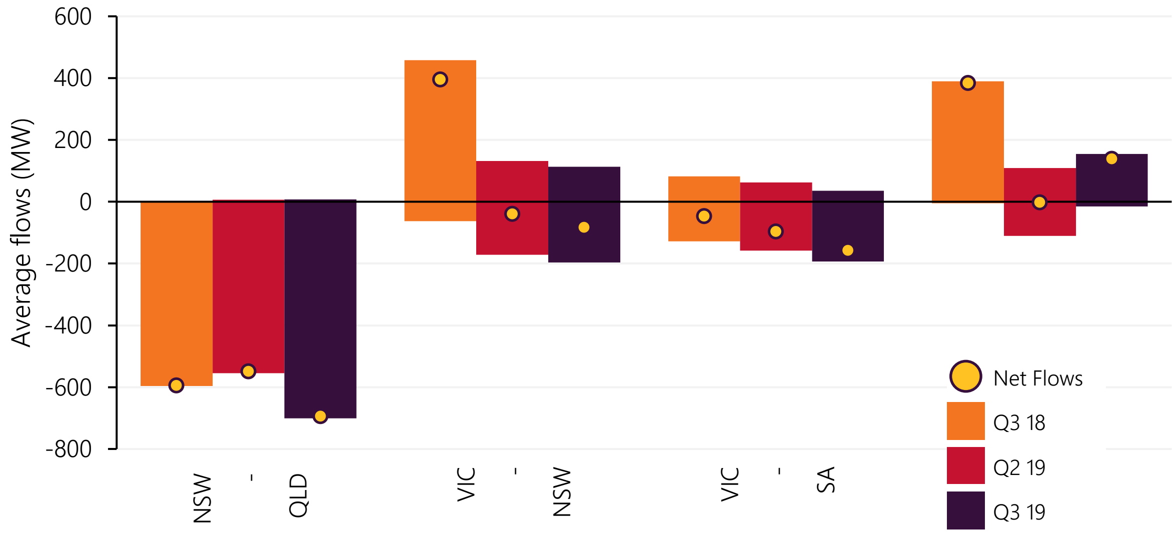
[23] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf

1.6 Inter-regional transfers

Generator outages, changes in the supply mix, and an unplanned outage of Basslink influenced inter-regional transfers over the quarter. Total inter-regional transfers reduced by 18% compared to Q3 2018, largely due to the Basslink outage (Figure 30)

Figure 30 Comparatively high electricity transfers into Victoria

Quarterly inter-regional transfers



By regional interconnector:

- Reduced Queensland demand, as well as increased solar output, led to a large excess of Queensland generation, particularly in the middle of the day. This resulted in almost exclusive southerly transfers on the New South Wales to Queensland interconnectors, increasing by 100 MW on average compared to Q3 2018.
  – QNI was binding at its limits for approximately 29% of the quarter (compared to 6% in Q3 2018), which contributed to an inter-regional price spread of $22/MWh between Queensland and New South Wales.
- A comparatively high number of outages of brown-coal fired units in Victoria, led to net imports from all three neighbouring regions:
  – Victoria imported 83 MW on average from New South Wales, representing a swing of almost 500 MW compared to Q3 2018. The VIC-NSW interconnector was binding at its limits for approximately 35% of the quarter (compared to 25% in Q3 2018), which contributed to an inter-regional price spread of $15/MWh. Similar to H1 2019, changes in Snowy Hydro's generation patterns resulting from dry conditions contributed to restricted flows south on the interconnector.
  – Victorian imports from South Australia also increased, reaching 158 MW on average, representing a 111 MW increase on Q3 2018 levels.
- The Basslink interconnector was on an unplanned outage between 24 August 2019 and 29 September 2019. This outage was a key driver of the 246 MW average reduction on transfers north into Victoria compared to Q3 2018.
  – The outage contributed to reduced Tasmanian hydro generation (excess output could not be transferred to the mainland), as well as comparatively high NEM-wide FCAS demand and costs (see Section 1.5.4).

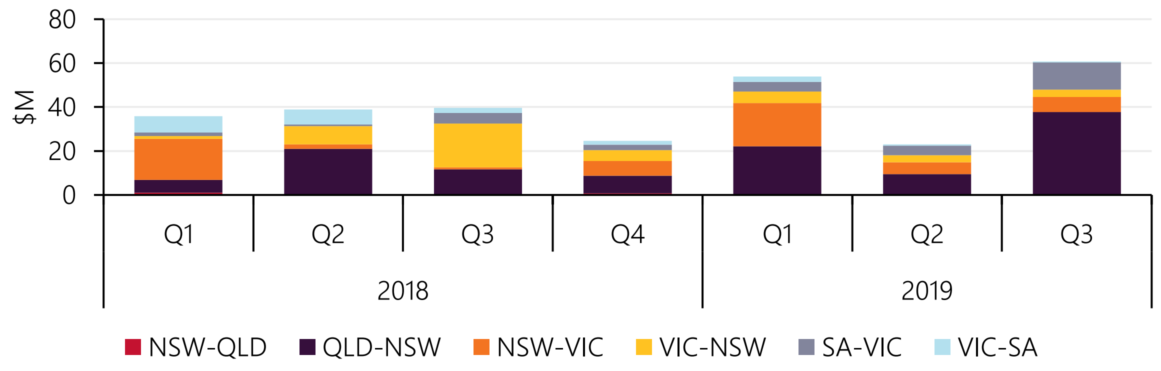
1.6.1 Inter-regional settlement residue

Total inter-regional settlement residue[24] (IRSR) for the quarter increased to $61 million, its highest value since Q1 2017 (Figure 31). The main driver of this result was an increased IRSR value for the Queensland to New South Wales and South Australia to Victoria interconnectors compared to recent quarters, which was a function of:

- Increased priced separation with neighbouring regions, including during negative spot prices in Queensland and South Australia. Negatively-priced intervals contributed to approximately 20% of the total IRSR value, despite only making up around 5% of total intervals in these regions.
- Increased transfers on these interconnectors (see Section 1.6).

Figure 31 Highest IRSR value since Q1 2017

Quarterly positive IRSR value



There were mixed results on returns for units purchased at settlement residue auctions (SRAs), with large positive returns occurring for units relating to Queensland to New South Wales flows and South Australia to Victoria flows across all tranches (Figure 32). The positive returns suggest larger than expected price separation between Queensland and New South Wales, and between South Australia and Victoria, likely associated with unexpected generator outages and interconnector constraints.

Large negative returns occurred for SRA units for flows from Victoria to South Australia, particularly for units purchased prior to closure of Hazelwood Power Station in March 2017[25].

Figure 32 Large positive returns for units purchase for exports from Queensland and South Australia

SRA tranche analysis – price paid for units versus actual value (Q3 2019)

[24] For further details on IRSR see: AEMO 2018, *Guide to the Settlements Residue Auction*.

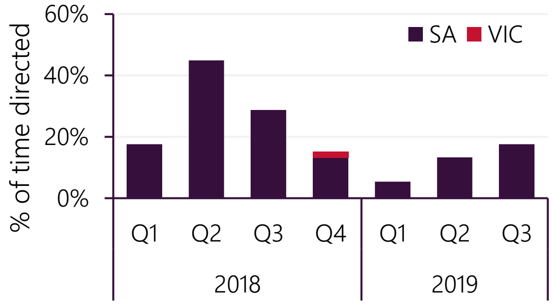
[25] Noting that SRA units may be used in a broad portfolio of risk management products, so SRA unit losses may be made up by gains from other futures products

1.7 Power system management

Directions

During the quarter, AEMO issued directions to gas-powered generators in South Australia to maintain system security. The time on direction rose relative to Q2 2019, due to windier conditions, but continued the trend of lower directions compared to 2018 (Figure 33). Reduced time directing was driven by higher synchronous unit availability – Osborne and Pelican Point's combined availability[26] was 22% higher than in Q3 2018.

Figure 33 Directions for system security



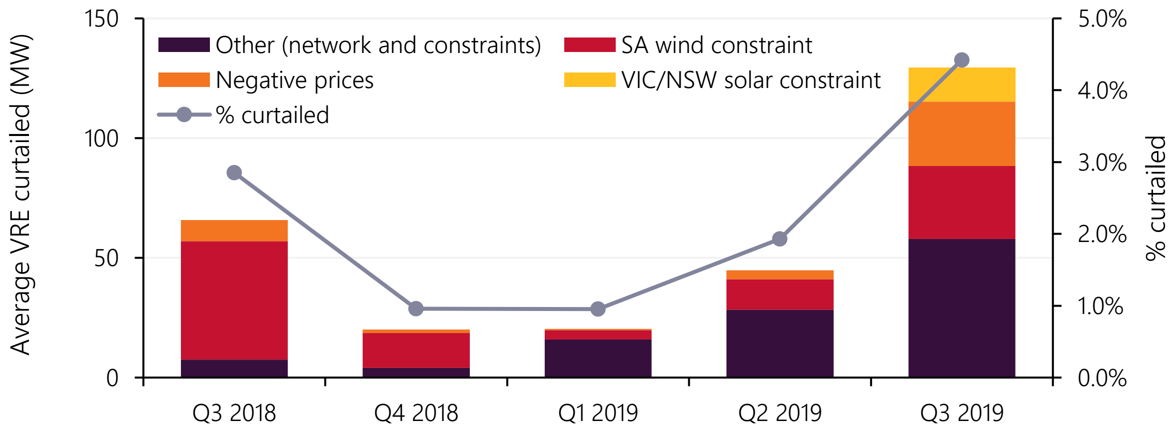
Despite reduced time on direction, total direction costs were slightly higher than Q3 2018 at around $8.5 million. This was partly due to an increase in the 12-month 90th percentile spot price (which is used to compensated directed participants) from an average of $126/MWh in Q3 2018 to $143/MWh this quarter.

VRE Curtailment

During Q3 2019, NEM-wide VRE curtailment increased to approximately 4.5% of total VRE output, the highest amount on record (Figure 34). Drivers of increased curtailment compared to Q3 2018 included:

- Increased occurrence of negative prices led to higher self-curtailment from wind and solar farms to avoid paying to generate. On average, 27 MW of VRE output was self-curtailed in response to negative prices, compared to 9 MW in Q3 2018.
- New constraints on five solar farms in Victoria and New South Wales reduced average solar output by approximately 14 MW on average over the quarter.
  - These constraints, which commenced on 13 September 2019, were introduced to manage identified voltage fluctuations in north-west Victoria and south-west New South Wales.
- Heightened impact of transmission outages and other network constraints which contributed to around 58 MW of curtailment on average compared to 8 MW in Q3 2018.

Figure 34 NEM VRE curtailment increases to record levels[27]



[26] Availability adjusted to remove the effect of directions.

[27] Curtailment amount based on combination of market data and AEMO estimates.

2. Gas Market Dynamics

2.1 Gas demand

Total east coast gas demand was 6% higher than in Q3 2018, due to increased GPG demand and higher LNG exports from Curtis Island. There was a small aggregate reduction in combined residential, commercial and industrial demand (Table 2, Figure 35).

Table 2 Gas demand – quarterly comparison[28]

Demand	Q3 2019 (PJ)	Q2 2019 (PJ)	Q3 2018 (PJ)	Change from Q3 2018 (PJ)
AEMO Markets *	112.6	93.9	113.7	-1.2 (1%)
GPG **	46.7	37.5	33.8	12.9 (38%)
QLD LNG	324.0	323.2	308.6	15.2 (5%)
TOTAL	483.2	454.1	456.2	26.8 (6%)

* AEMO Markets demand is the sum of customer demand in each of the Short-Term Trading Markets (STTMs) and the Declared Wholesale Gas Market (DWGM) and excludes GPG.
** Includes demand for GPG usually captured as part of total DWGM demand. Excludes Yabulu Power Station.

Average daily pipeline deliveries of 3,526 terajoules a day (TJ/d) flowed to Curtis Island during Q3 2019, an increase of 185 TJ/d compared to Q3 2018 and a slight decrease of 26 TJ/d compared to the previous quarter. Q3 2019 is the fourth consecutive quarter in which flows have exceeded 3,500 TJ/d. Prior to Q4 2018 no quarter had exceeded this level. There were 78 LNG cargoes exported during Q3 2019, slightly higher than Q2 2019 (77 cargoes).

GPG demand increased significantly in all states except Tasmania, which saw minimal changes. Q3 2019 was the highest Q3 GPG demand since 2014. Factors for the higher demand include an increase in coal-fired generator outages and lower hydro generation (see Section 1.3.2).

On 9 August 2019, a new daily gas demand record was set for the DWGM in Victoria. Very cold weather on this day drove demand to 1,308 TJ, which was 17 TJ higher than the previous record (set on 17 July 2007).

Figure 35 LNG and GPG drive east coast gas demand increase

East coast gas demand – Q3 2019 versus Q3 2018

[28] Some entries in this table may have minor variations to numbers published in QED reports, due to changed accounting of several gas-powered generators.

2.2 Wholesale gas prices

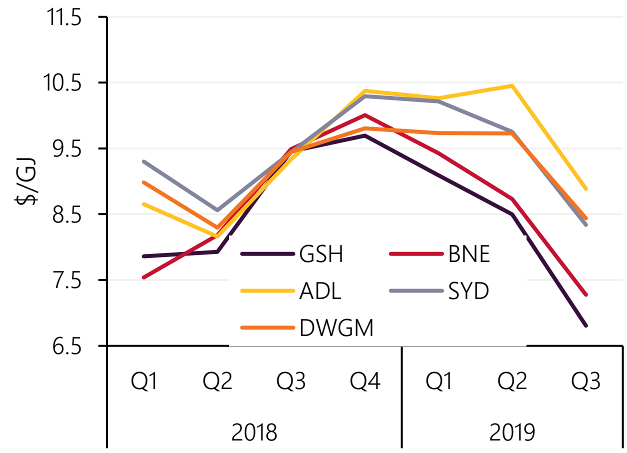
Wholesale gas prices reduced across all markets for the first time in more than a year, down by an average of 16% compared to Q3 2018 (Figure 36). The largest decreases occurred in Brisbane STTM (-23%) and the Gas Supply Hub (GSH, -28%)[29]. Decreases also occurred in Sydney STTM (-12%), the DWGM (-11%), and Adelaide STTM (-5%). The Brisbane STTM and the GSH recorded their lowest average prices since Q4 2017, and the other markets their lowest price since Q2 2018.

These gas price decreases occurred despite increased demand, with more gas being offered at lower prices into the markets:

- There was a significant shift in offers into the GSH – more than 90% of marginal bids were at prices below $8/GJ; in Q2 2019 only around 10% of marginal bids were at prices below $8/GJ (Figure 37).
- In the DWGM, an additional 163 TJ/day was offered below $9/GJ compared to Q3 2018 (Figure 38)

Figure 36 Wholesale gas prices decrease across all markets

GSH, DWGM and STTM quarterly average prices



The lower-priced offers coincided with the following:

- Falling international LNG netback price and comparatively low oil prices – the falling international LNG prices during the northern hemisphere summer and a period of oversupply has influenced some domestic pricing arrangements over the quarter.
- More competition in gas bids from Longford producers[30] – in previous quarters, Longford producers had offered gas into the domestic markets at very similar prices (at around $9-10/GJ). However, this quarter BHP shifted the price of its offers to around $8/GJ, while Esso offers remained at $9-10/GJ.
- Increased gas supply – Q3 2019 represents the highest gas production quarter on record, driven by Queensland increases (see Section 2.3.1).

Figure 37 Significant shift in GSH bids

GSH – proportion of marginal bids by price band

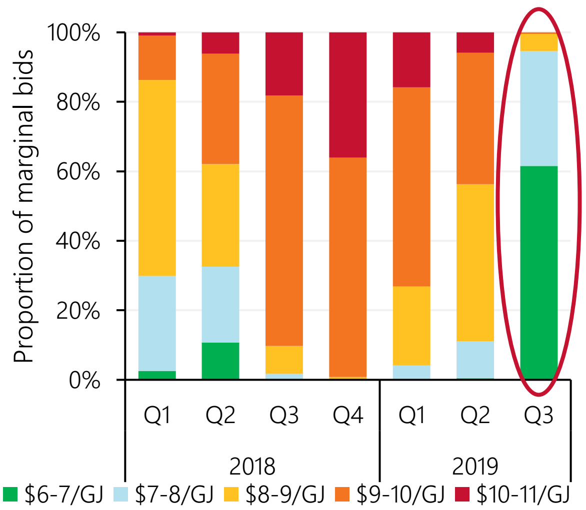
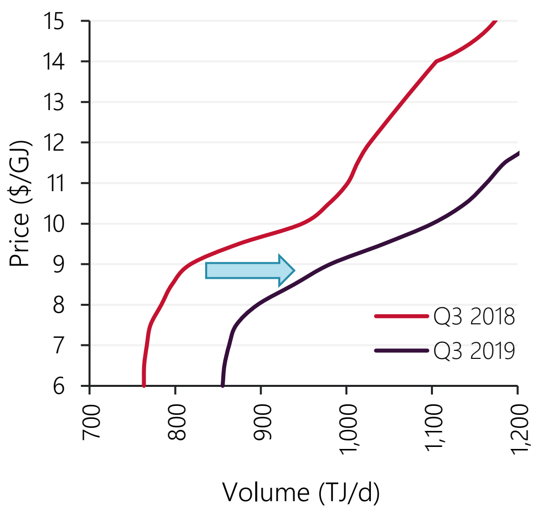


Figure 38 DWGM – more gas bid at lower prices

DWGM bid supply curve – Q3 2019 versus Q3 2018



[29] Some GSH prices may vary from previous published prices due to the exclusion of monthly and weekly prices for this quarterly report.

[30] Joint marketing ended on 1 January 2019.

2.2.1 International gas and oil prices

The world economy outlook remained uncertain in Q3 2019. Global cutbacks in manufacturing production and a deteriorating world industrial production also influenced international energy commodity prices.

After rallying to a high of around US$75/bbl during the first half of 2019, Brent Crude oil was flat in Q3 2019, tracking between US$55-65/bbl (A$85-95/bbl). Not even a drone attack on the world's largest crude oil processing facility in Saudi Arabia on 14 September 2019 (which briefly took out around 5% of global oil supplies) shifted the sideways trend.

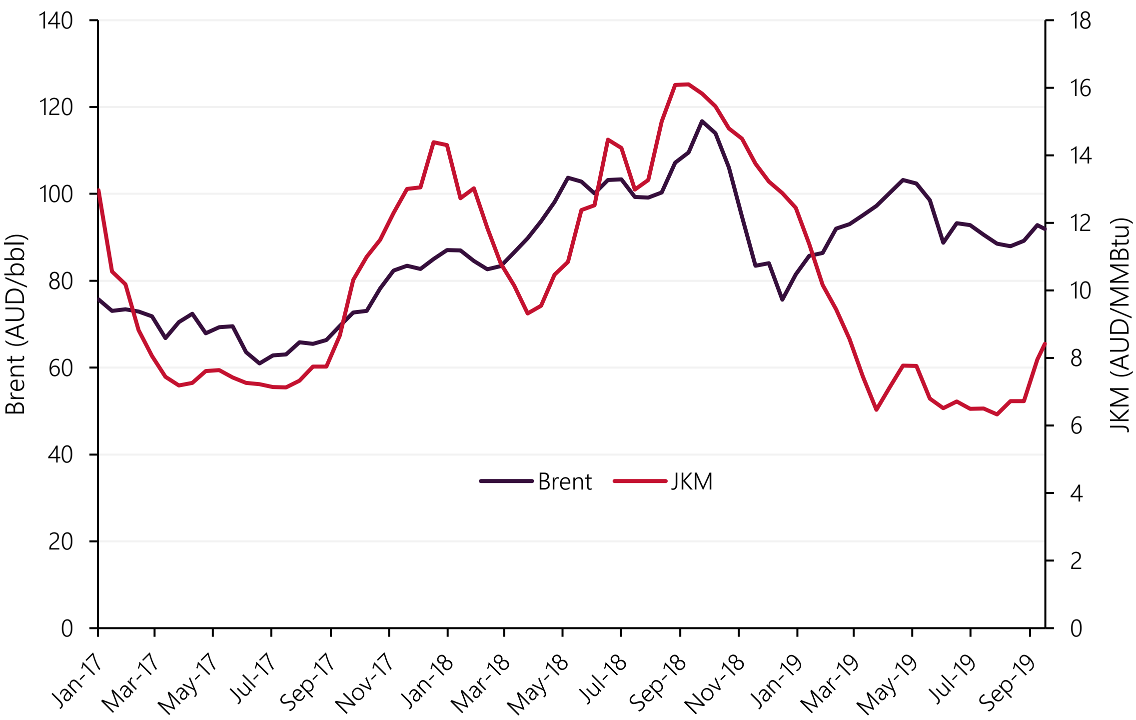
JKM LNG prices continued their downward trend, hitting a low of US$4.25/Metric Million British thermal unit (MMBtu) in early September 2019. Over the quarter, the JKM price averaged US$4.73/MMBtu (or A$6.91/MMBtu), around 53% lower than Q3 2018's average price.

The fall in spot prices has been driven by a combination of growing supply capacity and weak demand from major consumers in Asia. On the supply side, the ramp up of new capacity in the United States, Australia and Russia has put downward pressure on prices. Meanwhile, growth in China's LNG purchases has slowed, and the imports to Japan and South Korea – the world's largest and third largest LNG buyers respectively – have declined[31].

The international price separation between the lower JKM LNG and higher Brent Crude oil prices, which emerged during 2019, was one contributing factor towards domestic average wholesale gas prices being comparatively lower in Queensland than in Victoria (Figure 39).

Figure 39 Oil and LNG spot price separation continues

Brent Crude oil and JKM LNG prices in Australian dollars[32]



[31] Bloomberg & https://publications.industry.gov.au/publications/resourcesandenergyquarterlyseptember2019/documents/Resources-and-Energy-Quarterly-September-2019.pdf page 56 onwards

[32] Source: Bloomberg. Prices in 14 day averages.

2.3 Gas supply

2.3.1 Gas production

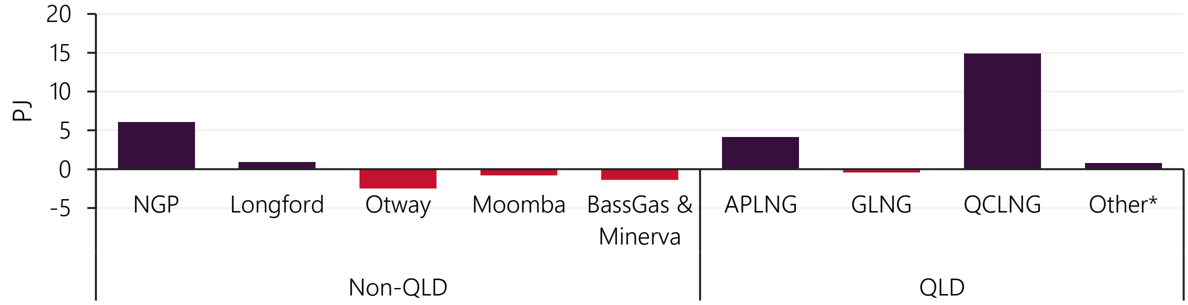
Q3 2019 east coast gas production increased compared to Q3 2018 (+3%) and Q2 2019 (+5%), resulting in the highest production quarter on record and follows on from a record production year in 2018-19. Increases in production occurred in Queensland and production in South Australia and Victoria slightly decreased (Table 3, Figure 40). Compared to Q3 2018, supply was boosted by 6.1 PJ of production from the Northern Territory which supplied the Mt Isa region (Section 2.4).

Table 3 Changes in gas production

Production increase against Q3 2018	Higher Queensland production (+19.4 PJ), driven by increases at Woleebee Creek (+8.9 PJ), Jordan (+3.4 PJ), Condabri Central (+3.6 PJ) and Eurombah Creek (+2.6 PJ). Slightly higher Longford production (+0.9 PJ, 1%).
Production decrease against Q3 2018	Reduced production elsewhere; Otway production (-2.5 PJ, -21%), Bass Gas and Minerva (-1.4 PJ, -22%) and Moomba (-0.8 PJ, -3%). Minerva ceased production in September 2019.

Figure 40 Queensland increases drives highest quarterly east coast gas production on record

Change in east coast gas production – Q3 2019 versus Q3 2018



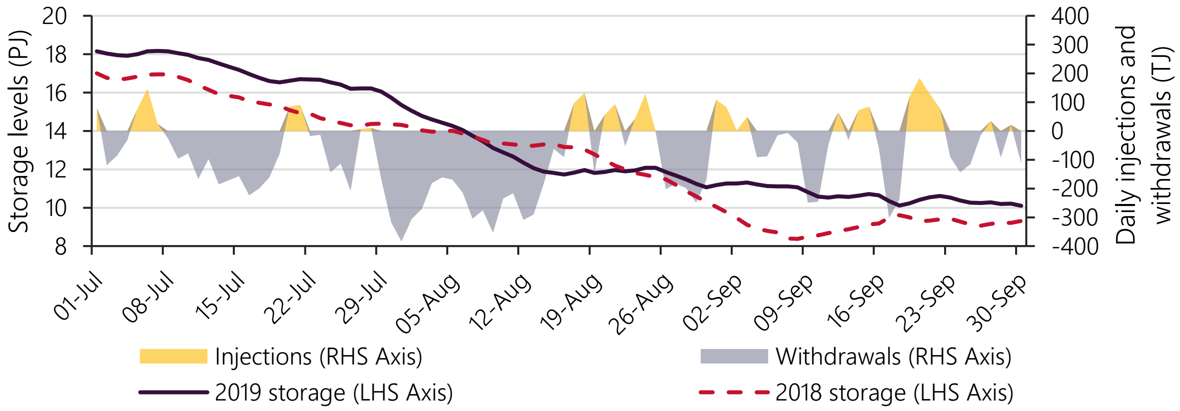
* Plant not explicitly stated are grouped as 'Other'

2.3.2 Gas storage

A gas balance of 10.1 PJ was recorded at the Iona Underground Storage Facility in Victoria at 30 September 2019, 0.78 PJ higher than at the end of Q3 2018 (Figure 41). This is despite Iona dropping below the August 2018 level in early August 2019. However, after that, storage levels reduced more slowly than in 2018 due to increased imports from Queensland into Victoria, and lower Victorian exports to South Australia, New South Wales and Tasmania (see Section 2.4).

Figure 41 Iona Storage finished the quarter above 2018 levels

Iona storage levels



2.4 Pipeline flows

Victorian net gas exports in Q3 2019 continued to decrease, reducing in Q3 2018 and Q2 2019 by 13.2 PJ and 4.7 PJ respectively (Figure 42). This was replaced by increased Queensland production, which led to increased South West Queensland Pipeline (SWQP) flows to Moomba (Figure 43). This trend began in Q2 2019 and increased further in Q3 2019. This was due to:

- A 6.4 PJ decrease in Carpentaria Gas Pipeline (CGP) flows to the Mt Isa region compared to Q3 2018, displaced by Northern Gas Pipeline (NGP) flows from the Northern Territory.
- Continued higher Queensland production. While LNG demand increased by 0.6 PJ for the quarter compared to Q2 2019, Queensland production increased by 11 PJ.

This led to:

- Decreased flows from Victoria to New South Wales compared to Q3 2018, with Victoria importing a net 7.9 PJ via Culcairn. Exports to New South Wales via the Eastern Gas Pipeline (EGP) decreased by 3 PJ.
- Decreased flows from Victoria to South Australia by 4.6 PJ compared to Q3 2018, despite a demand increase in that state. Supply was instead met by increased imports into South Australia via the Moomba to Adelaide Pipeline (MAP).
- Flows from Victoria to Tasmania decreased (-0.4 PJ) compared to Q3 2018, due to a decrease in Tasmanian GPG demand.

Figure 42 Victorian gas exports continue to decline

Victorian net gas exports to other states

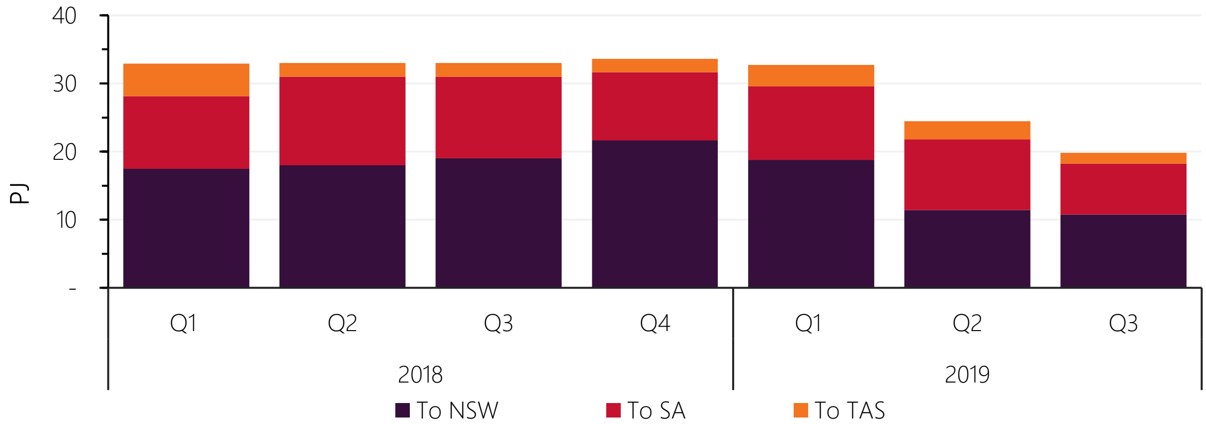
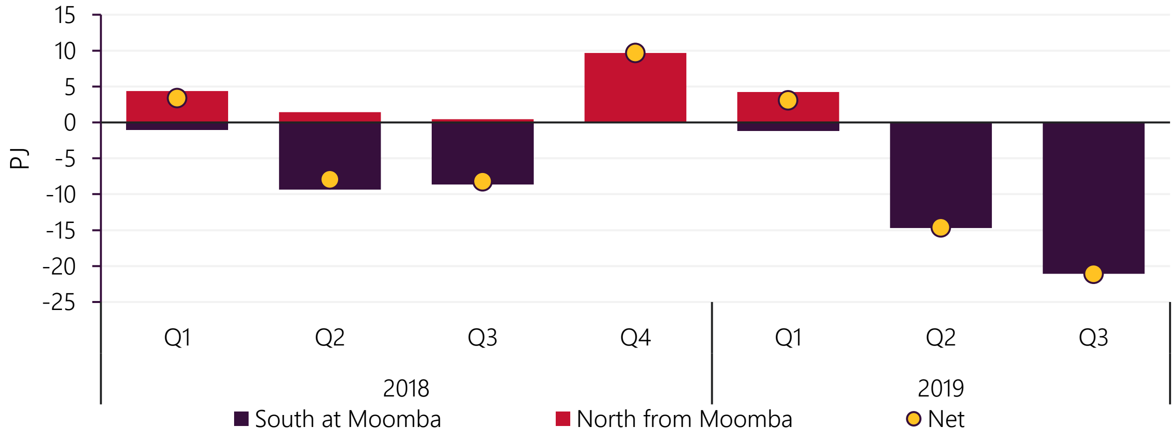


Figure 43 Queensland gas exports increase

Flows on the South West Queensland Pipeline at Moomba



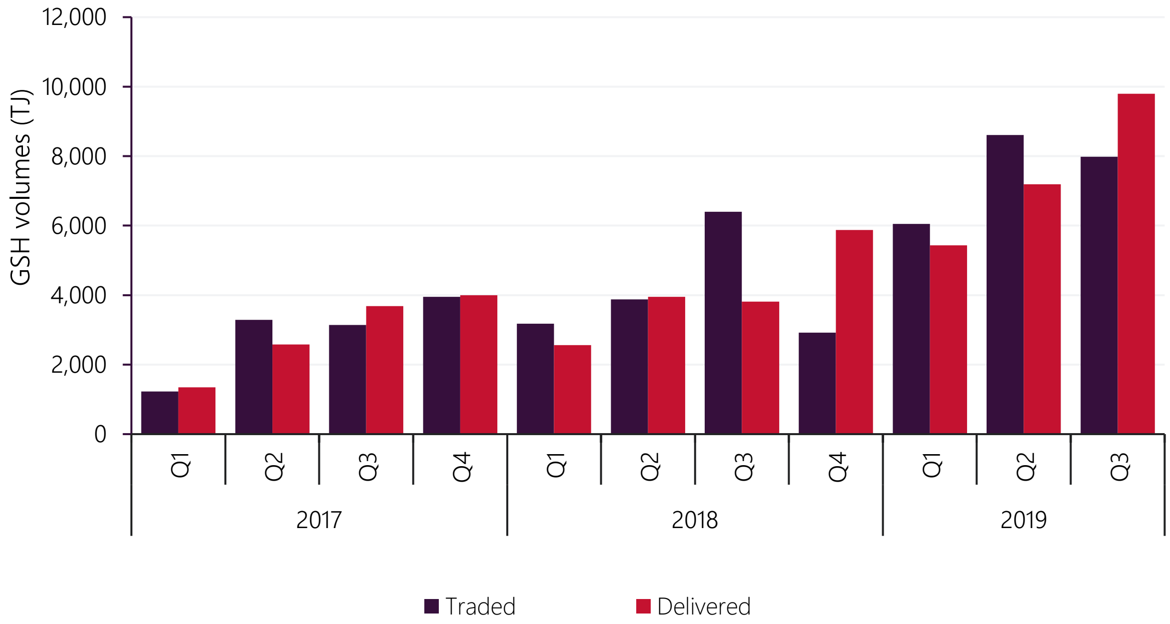
2.5 Gas Supply Hub

In Q3 2019, the GSH reached record high quarterly levels for delivered volume. Compared to Q3 2018, traded volume increased by 1.6 PJ (+25%) and delivered volume increased by 6 PJ (+157%).

The number of trades also increased, from 516 in Q3 2018, to 1,003 in Q3 2019. This marks the first time a quarter has exceeded 1,000 trades.

Figure 44 GSH continues to break trading records

Gas Supply Hub – quarterly trades and deliveries



2.6 Pipeline Capacity Trading and Day Ahead Auction

A new market for trading and auctioning unused pipeline transmission capacity began on 1 March 2019.

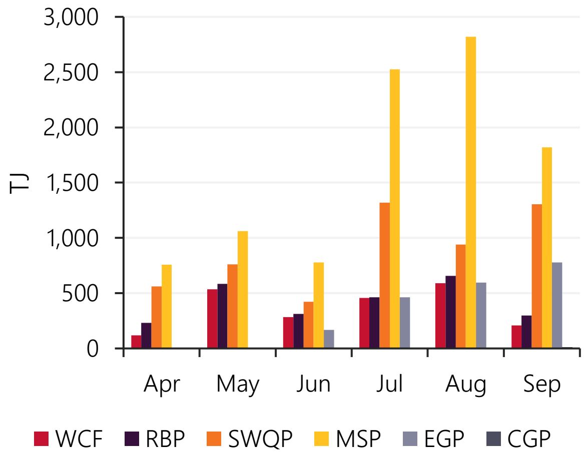
Compared to Q2 2019, in Q3 2019 there was a large increase in day ahead auction (DAA) utilisation. In particular, the largest increase in activity occurred on the Moomba to Sydney Pipeline (MSP) and SWQP. This coincided with an uptick in the number of market participants utilising the auction. The CGP also began trading in September.

Average auction clearing prices ranged from $0/GJ on EGP and Wallumbilla Compressor (WCF), $0.06/GJ on the MSP, $0.16/GJ on the Roma to Brisbane Pipeline (RBP), and $0.17/GJ on the SWQP.

While the auction was utilised every day, no capacity trades through the capacity trading platform (CTP) have yet occurred.

Figure 45 Day Ahead Auction use increases

Day Ahead Auction Results by Month



2.7 Gas – Western Australia

In Q3 2019, total gas consumption was 100.2 PJ, an increase of 4% (or 3.5 PJ) compared to Q2 2019 (Figure 46), largely driven by increases from industrial users (2.1 PJ) and GPG (1.3 PJ). This represents the highest total quarterly gas consumption recorded since GBB (WA) commencement in 2013. The growth in industrial use was mainly due to a 1.4 PJ increase in use from the Yara Pilbara Liquid Ammonia Plant which was on an outage for part of Q2 2019. Despite a 1.3 PJ increase compared to Q2 2019, gas consumption for GPG was still 1.2 PJ lower than in Q3 2018.

There was a corresponding increase in gas supply over the quarter of 2% (2.5 PJ). This was driven by a 7.5 PJ increase in production at the Devil Creek facility (Figure 47).

Over the quarter, 1.7 PJ less gas was transferred into Storage Facilities[33] compared to last quarter. The net effect of increased demand of 3.5 PJ, increased supply of 2.5 PJ, and a 1.7 PJ reduction in the net amount transferred into storage indicates a small increase in overall linepack.

Figure 46 Highest Western Australia gas demand since Market Start

Western Australia gas demand by sector

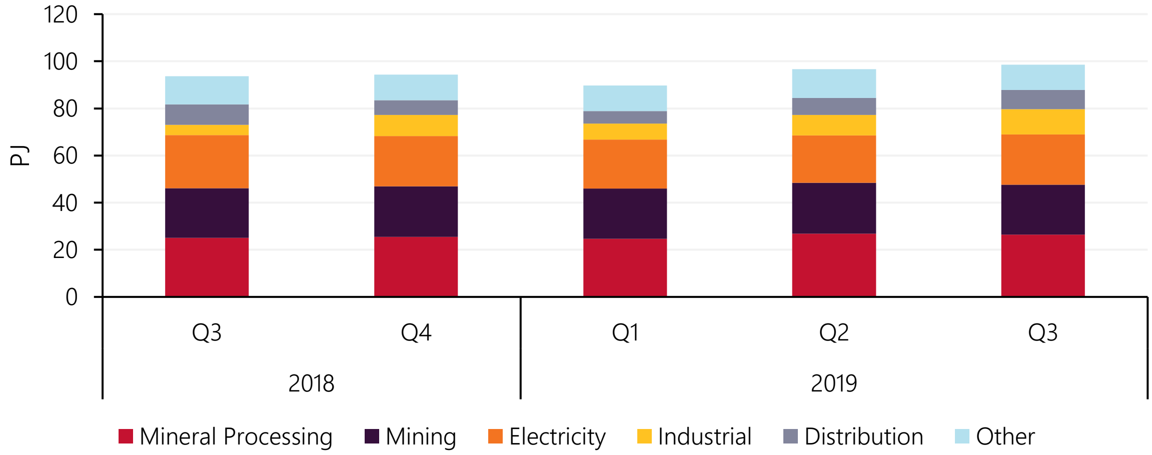
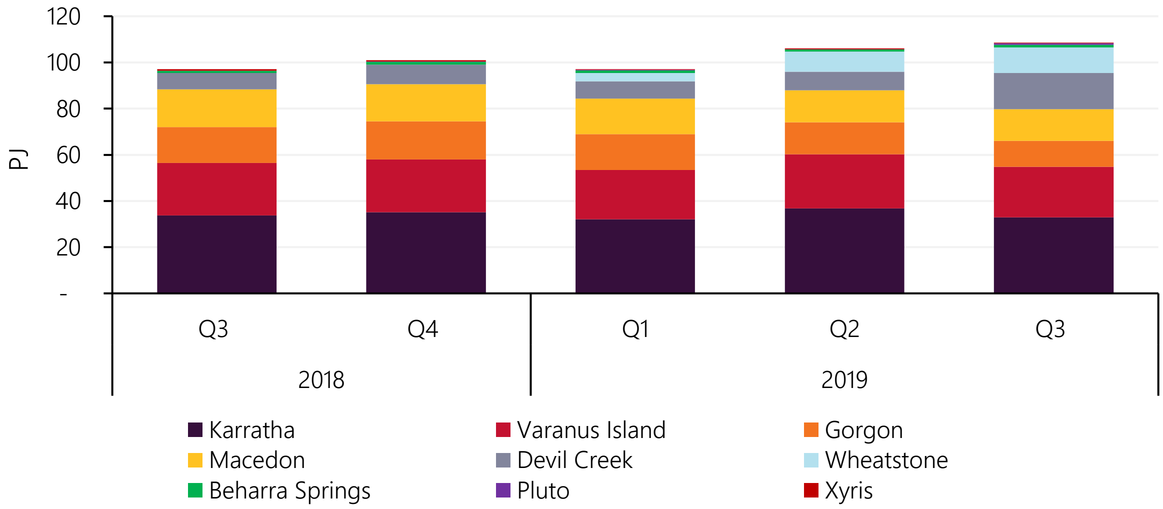


Figure 47 Western Australia gas supply increases

WA gas supply by production facility



33 Mondarra and Tubrudgi Storage Facilities

3. WEM Market Dynamics

3.1 Electricity demand and weather

Perth temperatures over Q3 2019 were very warm for a Q3. The average maximum temperature of 20.9°C was the highest Q3 on record and the average temperature was 0.4°C higher than the 10-year Q3 average. Additionally, average solar exposure was 7% higher than the 10-year Q3 average.

This mild and sunny weather, coupled with increased penetration of rooftop PV, contributed to an average reduction in operational demand[34] of 67 MW (3.3%) compared to Q3 2018 (Figure 48). A 2 MW decrease compared to Q2 2019 meant that for the first time since WEM market start[35], average operational demand was lower in Q3 than in Q2.

3.1.1 Minimum demand

A new Q3 WEM minimum demand record was set at 1130 hrs (AWST) on Sunday 29 September 2019, when average operational demand was 1,176 MW, only 3 MW above the WEM's record low operational demand experienced on 15 October 2006. At the time, output from rooftop PV was approximately 971 MW, fulfilling 45% of underlying demand.

Table 4 WEM maximum and minimum demand (MW) – Q3 2019 vs records

Maximum demand (MW)			Minimum demand (MW)		
Q3 2019	All-time	All Q3	Q3 2019	All-time	All Q3
3,055	4,006	3418	1,176	1,173	1,177

Increasing rooftop PV is continuing to shift minimum demand from the early morning to middle of the day. For the first time in Q4 2018, and again in Q3 2019, there were more instances where minimum demand occurred during the day rather than overnight (Figure 49).

Figure 48 WEM demand falls

WEM average operational demand

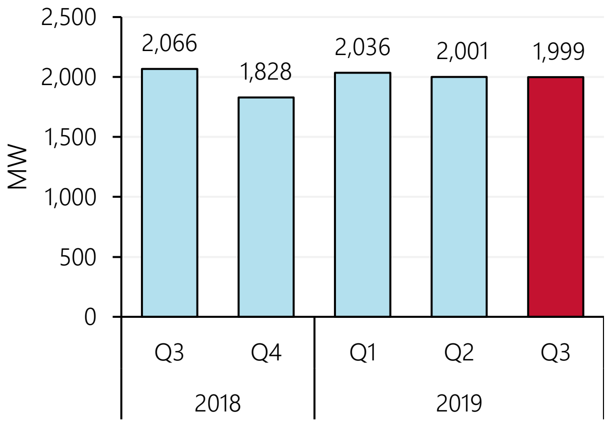
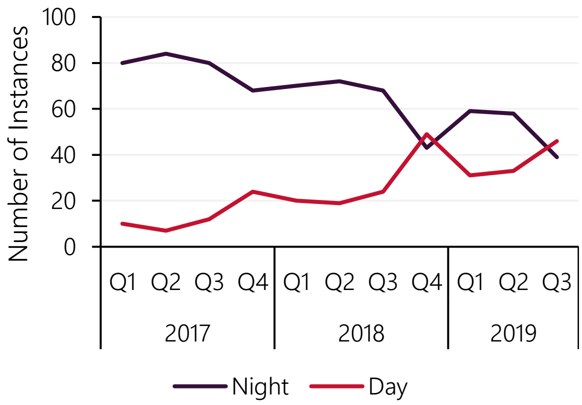


Figure 49 WEM minimum demand increasingly occurs during the day

Instances of min demand



[34] 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.

[35] The Wholesale Electricity Market of Western Australia commenced on 21 September 2006.

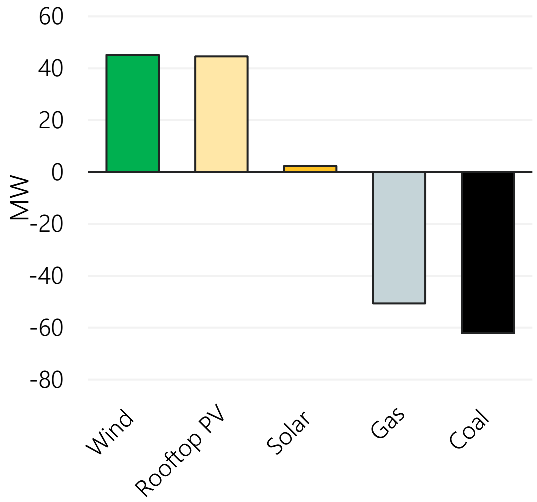
3.2 Electricity generation

Figure 50 shows the average quarterly change in generation by fuel type compared to Q3 2018, while Figure 51 shows the average changes by time of day. These changes highlight the supply-mix transformation occurring in the WEM. Key shifts include:

- An average increase in wind output of around 45 MW (27%), largely due to the connection of Badgingarra Wind Farm (130 MW) at the beginning of 2019, and Beros Road Wind Farm (9.9 MW) during Q3 2019. Wind generation in the middle of the day was impacted by lower midday wind speeds.
  - The connection of the new wind farms has resulted in a new record level of grid-scale non-scheduled generation (NSG) of 590 MW.

Figure 50 Increased wind output in the WEM

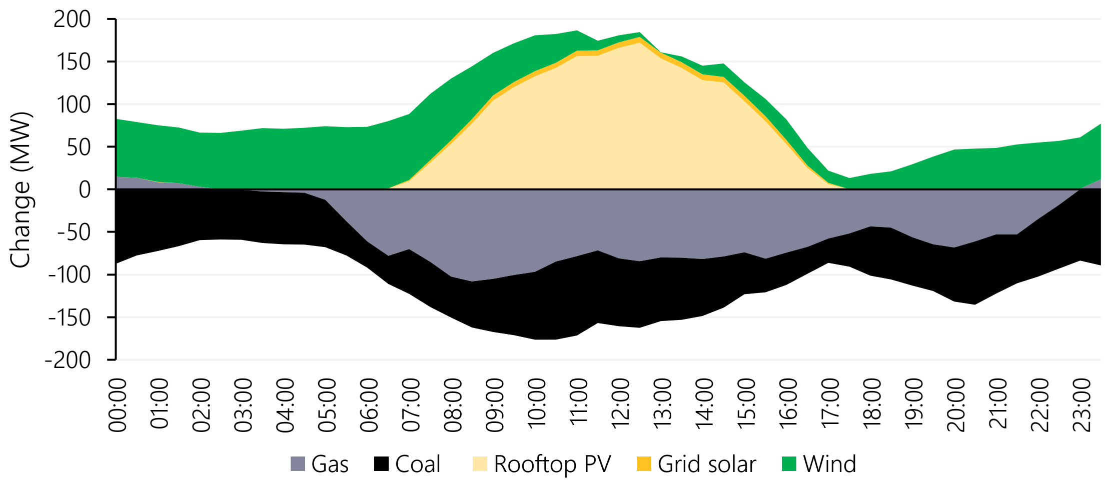
Change in WEM supply – Q3 2019 versus Q3 2018



- An average 45 MW increase in rooftop solar generation, with an increase of up to 172 MW at 1230 hrs. AEMO estimates[36] that between end Q3 2018 and end Q3 2019, an additional 215 MW of rooftop PV capacity was installed in the SWIS.
- Coal-fired generation reduced by 62 MW (7%) on average and GPG by 51 MW (5%) on average. This occurred mainly in the middle of the day when they were displaced by solar generation.
  - Coal units were run in a more cyclical fashion with the baseload Collie Power Station cycled off more often. The facility was cycled off seven times in Q3 2019, compared to only twice in Q3 2018 (Figure 52). Only two instances this quarter were due to outages. The remaining five occurred when the facility was available but not required due to low demand over weekend periods.
  - Average GPG fell compared to Q3 2018, but increased between 2300 hrs and 0200 hrs, due to reduced coal-fired generation overnight.

Figure 51 WEM supply mix changing throughout the day

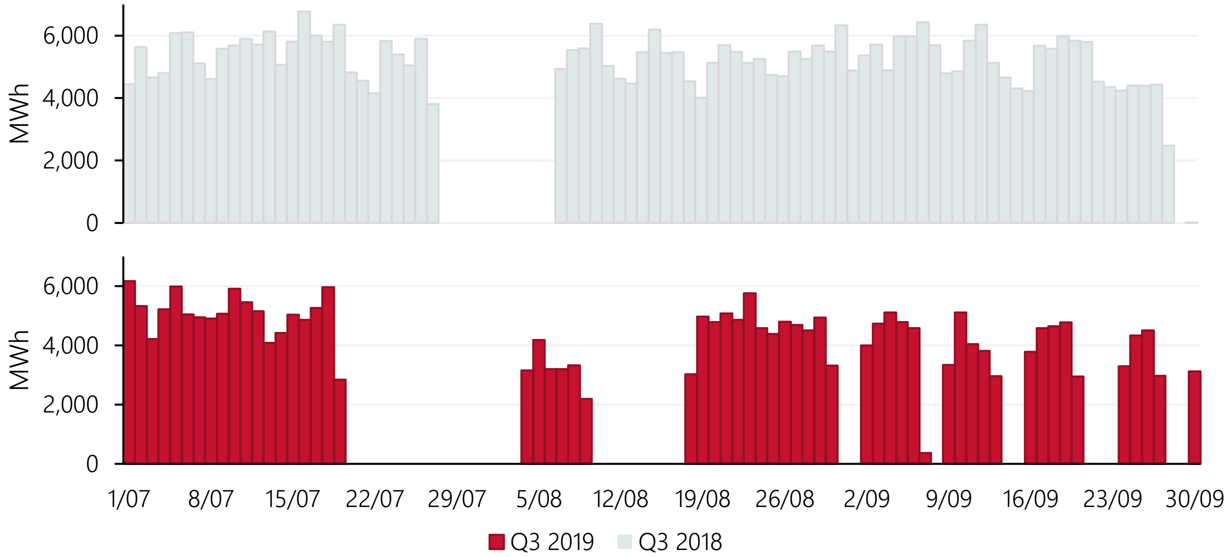
Change in supply – Q3 2019 versus Q3 2018



[36] Forward estimates are based on Clean Energy Regulator small-scale solar data found here.

Figure 52 The Collie Power Station coal facility was cycled more frequently

Daily Q3 output of COLLIE_G1



3.3 Wholesale electricity pricing

3.3.1 Average Balancing and Short Term Electricity Market prices

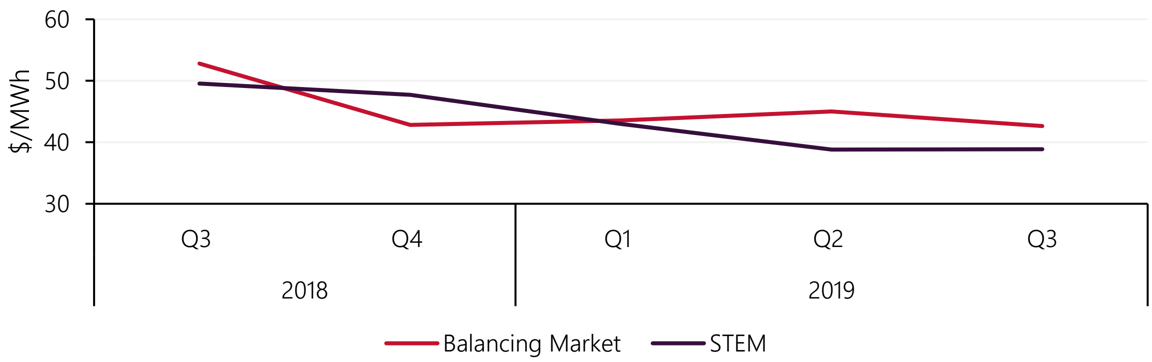
Wholesale electricity prices reduced compared to Q3 2018, with average Balancing Prices decreasing by 19% and Short Term Electricity Market (STEM) prices decreasing by 22% (Figure 53). Contributing factors included:

- A 3.3% decrease in average operational demand.
- Small increases in baseload and non-scheduled generation (NSG) availability.
- A 27% increase in average wind generation due to connection of Badgingarra and Beros Road wind farms.

These factors also contributed to an increase in the number of negatively-priced intervals, which was also partially the result of an increase in generation offered at the price floor by 51 MW compared to Q3 2018. Expectations of low Balancing Prices also facilitated increased trading of energy in the STEM, with generators offering an average 30% more energy at negative prices compared to Q3 2018.

Figure 53 WEM prices reducing

WEM wholesale electricity prices



3.3.2 Negative prices

During the quarter, there was increased occurrence of negative Balancing Prices, with 5% of intervals negatively-priced (Figure 54). Most negatively-priced intervals occurred in the middle of the day due to low operational demand. WEM average Q3 operational demand between 1100 hrs and 1400 hrs has fallen 8% each year since 2017 (Figure 55). Rooftop PV capacity in the WEM has grown 22% since Q3 2018, with an estimated installed capacity of just under 1.2 GW by the end of Q3 2019.

Negative prices occurring in the early hours of the morning were largely the result of increased overnight wind generation (+38% compared to Q3 2018) and low demand.

The number of negatively-priced intervals in the STEM also increased in Q3 2019, often occurring on days with low or negative Balancing Prices. In expectation of low load and therefore low prices, demand in the STEM decreased by an average of 23% for days which cleared at a negative Balancing Price. This caused low or negative prices to also clear in the STEM.

Figure 54 High number of WEM negatively-priced intervals

WEM negative Balancing Price intervals

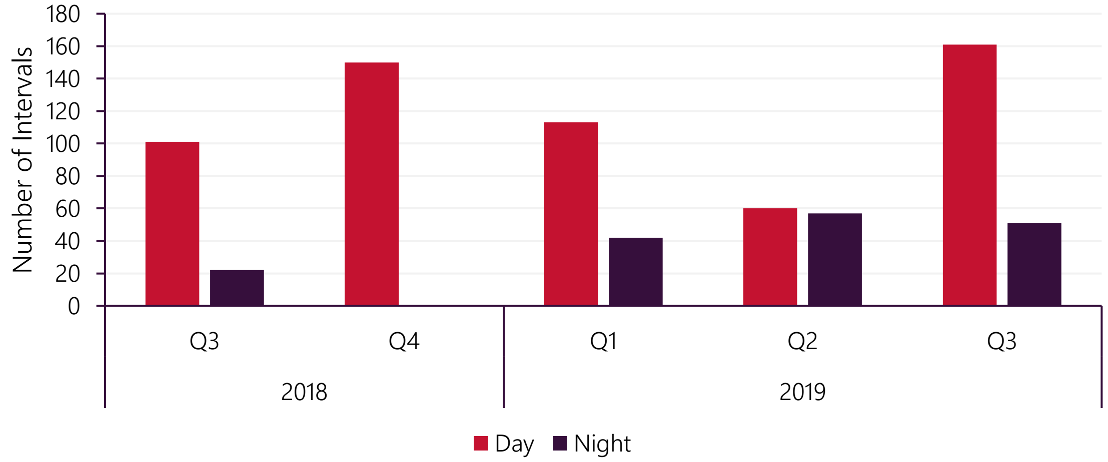
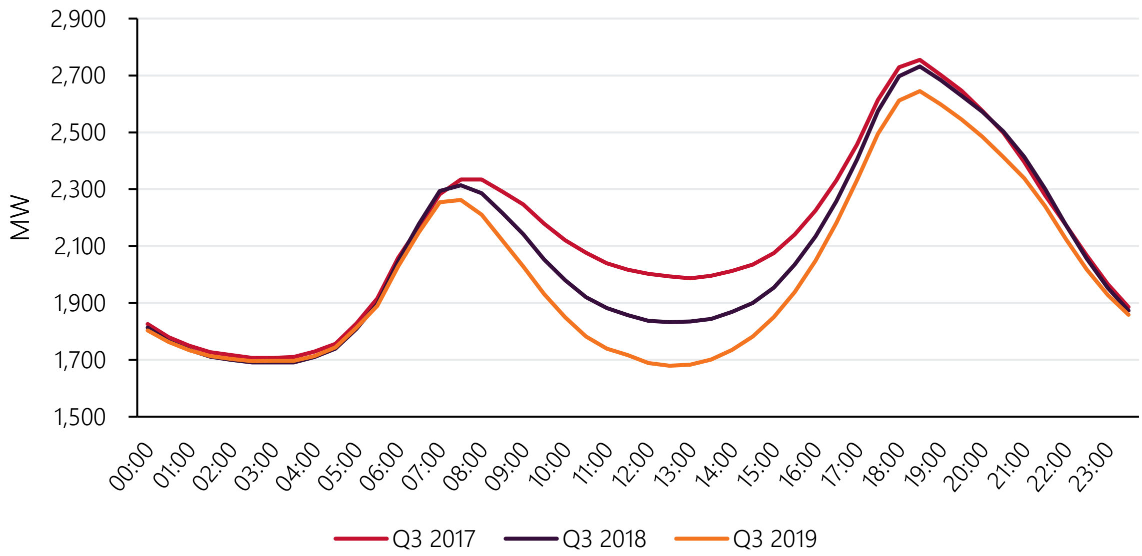


Figure 55 Falling daytime demand

Average WEM operational demand by time of day



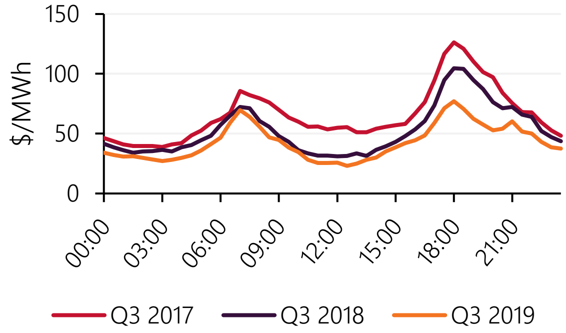
3.3.3 Average prices by time of day

Figure 56 shows the average Balancing Price by time of day, demonstrating that, compared to Q3 2018, reduced average prices in Q3 2019 occurred across almost all times of the day. Daytime prices decreased due to increased rooftop PV output reducing demand.

The largest price drop occurred during evening peak demand periods, with prices at 1800 hrs falling by an average of 26% compared to Q3 2018. This was the result of lower peak evening demand (-85 MW) as well as increased supply. Figure 57 shows the average Q3 supply and demand curves in the WEM at 1800 hrs compared to Q3 2018:

Figure 56 Falling prices during evening peak demand

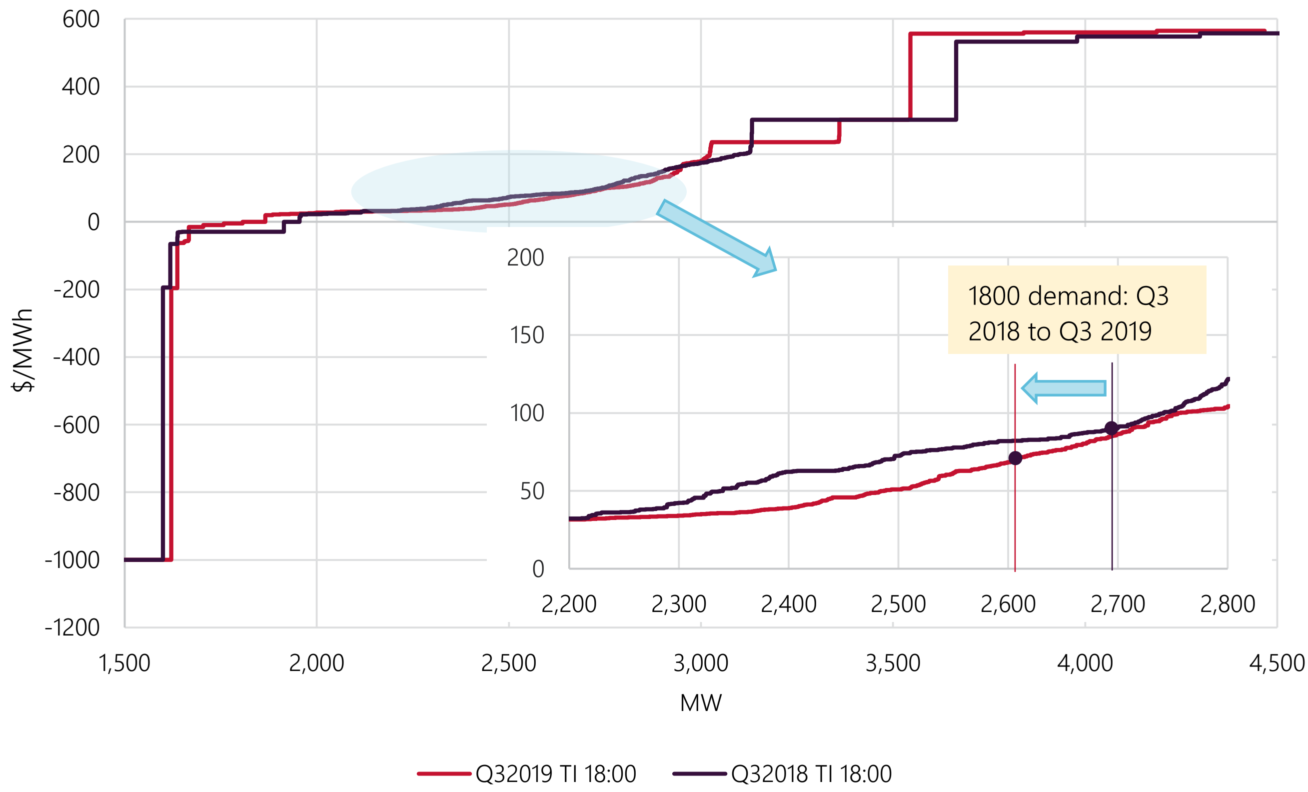
Average Balancing Price by time of day



- At the floor price of -$1,000/MWh, an additional 20 MW was offered during the peak demand interval.
- The bottom right of Figure 57 shows where average demand and supply meet. At average demand levels, supply was offered at lower prices, shifting this part of the supply curve outwards.
- Most of the change in bidding behaviour has come from GPG, with an average 120 MW increase in GPG bid at the floor[37] compared to Q3 2018[38].

Figure 57 Average supply curves during evening peak demand shift

Average supply curve at 1800 hrs



[37] The WEM price floor is -$1,000/MWh, the price ceiling changes annually and is currently $235/MWh, and the alternative price ceiling for liquid fuelled generators changes monthly.

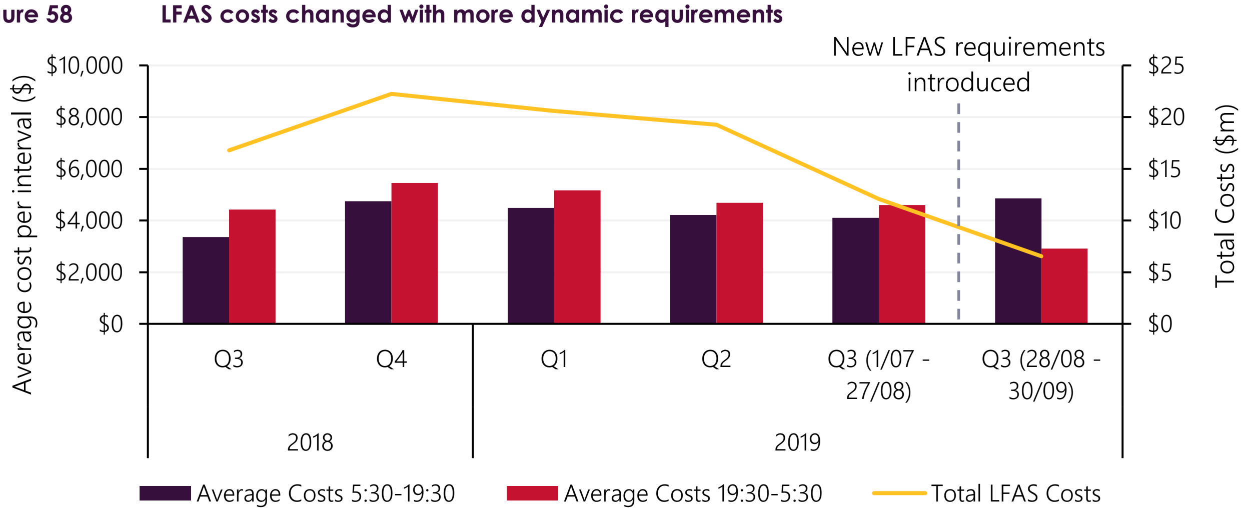
[38] Load Following Ancillary Service (LFAS) facilities must bid at the price floor to ensure they are dispatched. During Q1 2019 a third Market Participant began participating in the LFAS market., increasing the quantity of gas-powered generation offered at the floor compared to 2018.

3.4 Load Following Ancillary Services

3.4.1 Changes to LFAS requirements

New Load Following Ancillary Service (LFAS)[39] requirements came into effect on 28 August 2019, requiring that 85 MW of LFAS Up/Down capacity be procured between 0530 and 1930 hrs, and 50 MW from 1930 to 0530 hrs, an average of 70.4 MW. The previous LFAS requirement was 72 MW for all intervals[40]. Following these changes, average LFAS Up and Down prices were stable, however overall costs have decreased. Average LFAS costs per interval increased for intervals with the higher 85 MW requirement and fell for other intervals (Figure 11). Excluding Backup LFAS, total LFAS costs for Q3 2019 were $18.6m, a 3% decrease from Q2 2019.

Figure 58 LFAS costs changed with more dynamic requirements



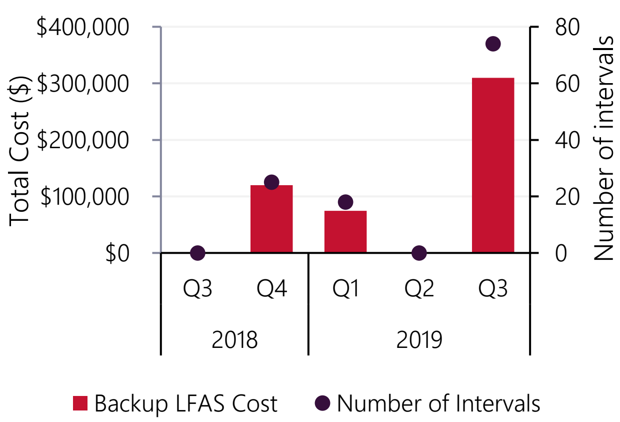
3.4.2 Backup Load Following Ancillary Services

Backup LFAS[41] was activated for a record 74 intervals in Q3 2019, resulting in total costs of $310,000 (Figure 13). This equates to approximately 1.6% of total LFAS costs. Backup LFAS was largely used in response to VRE variability, and 82% of activations occurred during daylight hours (Figure 15).

Even after the introduction of the new LFAS requirements[42] on 28 August 2019 – which increased the amount of LFAS capacity available during the day – Backup LFAS was still activated relatively frequently.

Figure 59 Record amount of Backup LFAS used in Q3

Backup LFAS cost and activation



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[39] 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.

[40] New LFAS requirements were introduced to reflect increased variability during the day due to higher PV penetration. See AEMO, Ancillary Services Report for the WEM 2019, at https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2019-Ancillary-Services-Report.pdf.

[41] Backup LFAS is contingency capacity bid into the LFAS market in addition to the standard LFAS requirements.

[42] 85 MW of LFAS Up/Down between 0530 and 1930 hrs, 50 MW from 1930 to 0530 hrs.

Abbreviaions

Abbreviation	Expanded term
AEMO	Australian Energy Market Operator
ASX	Australian Stock Exchange
AUD	Australian dollars
BBL	Barrel
CER	Clean Energy Regulator
CTP	Capacity trading platform
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FY	Financial year
GJ	Gigajoule
GPG	Gas-powered generation
GSH	Gas Supply Hub
GW	Gigawatt
GWh	Gigawatt hour
HDD	Heating degree day
IRSR	Inter-regional settlement residue
Kcal	kilocalories
LFAS	Load Following Ancillary Services
LGC	Large-scale Generation Certificates
LNG	Liquefied natural gas
MAP	Moomba to Adelaide Pipeline
MMBtu	Metric Million British thermal unit
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatt

Abbreviation	Expanded term
MWh	Megawatt hour
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NSG	Non-scheduled generation
PJ	Petajoule
PV	Photovoltaic
QNI	Queensland to New South Wales Interconnector
RBP	Roma to Brisbane Pipeline
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