Quarterly Energy Dynamics Q2 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 Q2 2019 (1 April to 30 June 2019). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2019 and Q2 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	9/8/2019	Initial release

Executive summary

National Electricity Market (NEM) Q2 highlights

High wholesale electricity and gas prices continue

- Wholesale spot electricity prices remained high over the quarter, averaging $89/megawatt hour (MWh) across the NEM, up 8% compared to Q2 2018.
  - Despite a large increase in solar photovoltaic (PV) generation, the impact on NEM prices was limited. Midday prices averaged $70-80/MWh and remained higher than overnight prices which average $60-70/MWh.
  - In Victoria and South Australia there was an increased price-setting role from gas-powered generation (GPG) and hydro generation, setting the price approximately 70% of the time (the highest level of record in Victoria).
- The price of financial year (FY) 2019-20 electricity swap contracts traded on the ASX rose in all regions, with Victoria reaching $110/MWh – exceeding the state's previous actual annual spot price record of $92/MWh in 2017.
- Wholesale gas prices remained comparatively high, increasing across all markets to an average of $9.67/gigajoule (GJ), up 16% compared to Q2 2018. The quarterly-average gas price of $10.48/GJ in Adelaide's Short-term Trading Market (STTM) represents the highest on record for that market.

Brown coal-fired generator outages drive reduced output

- Average brown coal-fired generation was 573 MW lower than in Q2 2018 due to increased planned and unplanned outages.
  - Following a forced outage of its Loy Yang A2 unit, AGL announced that this unit would not return to service until late 2019.
  - Loy Yang B2 was on extended planned outage in Q2 2019 to undergo a major upgrade which was completed by the end of the quarter. The upgrade increased the unit's capacity from 535 MW to 580 MW and improved its emissions intensity.
- NEM emissions for the quarter fell to their lowest on record, both in terms of absolute emissions and emissions intensity, driven by low brown coal-fired generation; increased variable renewable energy (VRE) output; and lower NEM demand.

East coast gas supply hits new records

- East coast gas supply increased compared to Q2 2018 and reached a new record for the financial year 2018-19. This was primarily driven by increased output from QCLNG's Woleebee Creek production facility, with the new supply enabling a 6% increase in Curtis Island LNG exports for the financial year.
  - Longford production whilst lower than the previous financial year was up for the quarter, with maximum daily production of 1,075 terajoules (TJ) in Q2 2019, compared to 954 TJ in Q2 2018. Esso and BHP – which are in their first year of separately marketing gas – injected 2.1 petajoules (PJ) of gas into the market at prices of around $9-10/GJ over the quarter.
- The commissioning of the Northern Gas Pipeline (NGP) resulted in 6 PJ of Northern Territory flow to Mt Isa, which contributed to an increase in gas flowing from Queensland to the southern states.
- The Day Ahead Auction – which commenced in March 2019 – enabled participants to buy 72 TJ/day of unused pipeline capacity at prices between $0/GJ to $0.07/GJ.

Other east coast highlights included:

- NEM-average operational demand was 362 MW lower than in Q2 2018, with demand reductions across all regions. Drivers included increased rooftop PV output and mild weather in Sydney and Melbourne.
- New projects making up almost 1.5 GW of capacity began generating over the quarter, with around 50% of this new capacity located in Queensland.
- Increased GPG availability in South Australia reduced the amount of GPG time on direction for system security purposes to 13%, compared to 45% of the time in Q2 2018.
- New South Wales GPG was at its lowest quarterly level on record due to GPG outages, comparatively high coal-fired generation in the region, and a lack of price volatility.

Western Australia Wholesale Electricity Market (WEM) Q2 highlights

- Compared to Q2 2018, changes to the WEM electricity supply mix included a 56% increase in wind output, while coal and GPG both decreased by 7%.
- Compared to Q1 2019, prices in the Balancing Market increased by 3%, while prices in the day-ahead Short-Term Electricity Market (STEM) reduced by 10%. Additionally, the number of high Balancing Prices increased by 34% with a maximum price of $292.68/MWh.
- On 19 April 2019 (Good Friday) difficult to forecast cloud cover and wind conditions meant that the WEM experienced:
  - Large changes in wind and rooftop solar PV generation, which resulted in large variation between forecast and actual Balancing Prices.
  - High price variability: the Balancing Price cleared as negative in 19 intervals, and for a further eight intervals the price cleared at over $100/MWh.

Contents

1. NEM market dynamics

1.1 Weather

Warmer than average weather continued in Q2 2019 with all capital cities recording temperatures above the 10-year average (Figure 1). With the exception of Adelaide, weather conditions were also generally milder compared to Q2 2018, resulting in lower heating requirements than this time last year (Figure 2).

Most of the east coast recorded below average rainfall over the quarter, whilst rainfall in Tasmania's major catchment zones was in line with the long-term average.

Figure 1 Warmer than average Q2

Average maximum temperature variance by capital city – Q2 2019 vs 10-year Q2 average

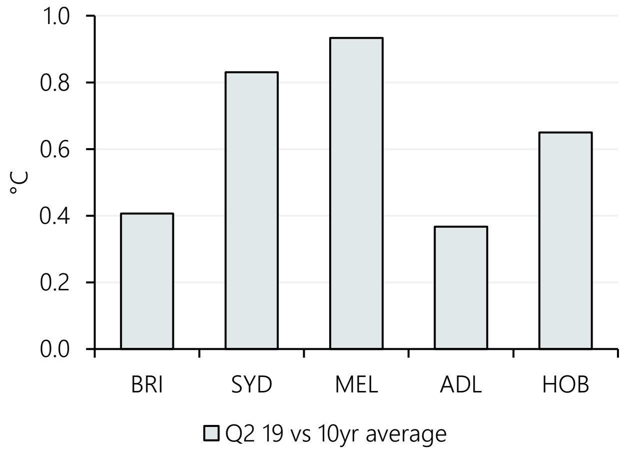
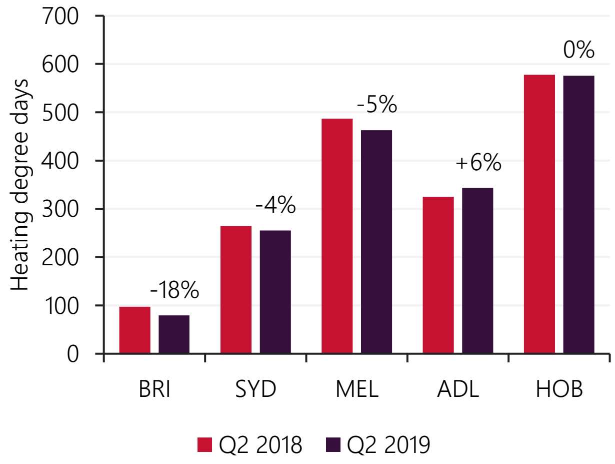


Figure 2 Reduced heating requirements vs Q2 2018

Heating degree days[1]



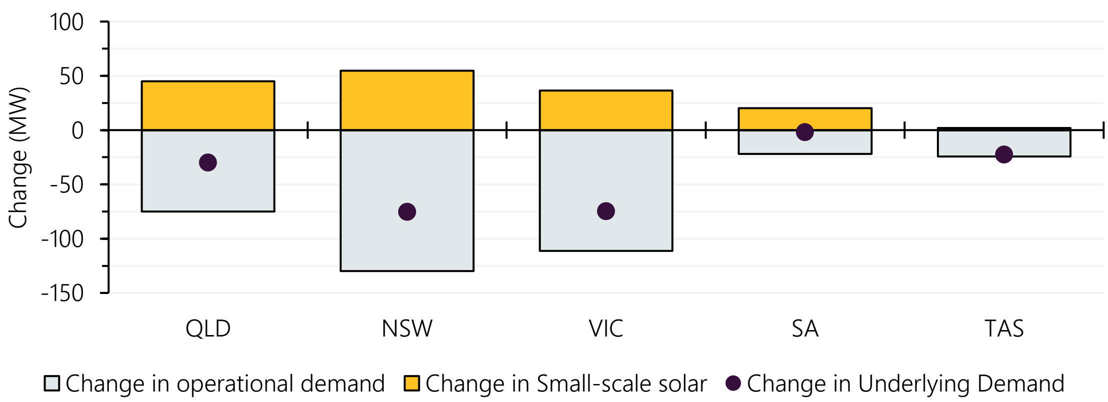
Source: Bureau of Meteorology

1.2 Electricity demand

NEM average operational demand reduced by 362 megawatts (MW) in Q2 2019 compared to Q2 2018, with reductions experienced across all NEM regions. The largest reductions were in New South Wales (-130 MW) and Victoria (-111 MW), driven by additional rooftop photovoltaic (PV) output and mild peak-time temperatures which reduced peak heating requirements. Reduced demand in Queensland (-75 MW) and South Australia (-22 MW) was a function of continued growth in rooftop PV output over the middle of the day.

Figure 3 Demand reduced across all NEM regions in Q2 2019

Change in average operational demand and underlying demand (Q2 2019 versus Q2 2018)



[1] 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).

Maximum and minimum demand

In Q2 2019, South Australia set a new Q2 minimum demand record at 1330 hrs on 27 April 2019, when operational demand dropped to 749 MW (44 MW lower than the previous Q2 record last year). At this time, rooftop PV provided approximately 600 MW of output.

As Figure 4 shows, this minimum demand levels in South Australia have been declining for almost a decade, largely driven by increasing uptake of rooftop PV in the region. According to the Clean Energy Regulator (CER), as at the end of June 2019, South Australia had approximately 1 gigawatts (GW) of small-scale solar capacity installed[2]. This has driven a considerable reduction in operational demand over the middle of the day, shifting the time of minimum demand from the early morning to the middle of the day (Figure 5). Reduced commercial and industrial load in the region has also contributed to this trend. This shift in the time of demand is limited to South Australia at present. For other NEM regions, the overnight period remains the lowest demand part of the day.

Figure 4 SA minimum demands are declining

SA minimum demand over time

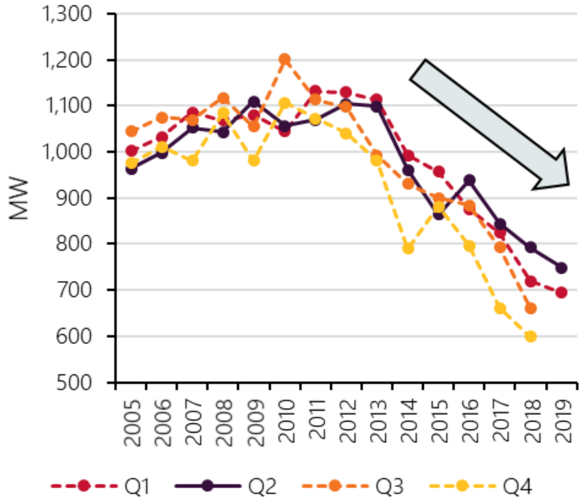
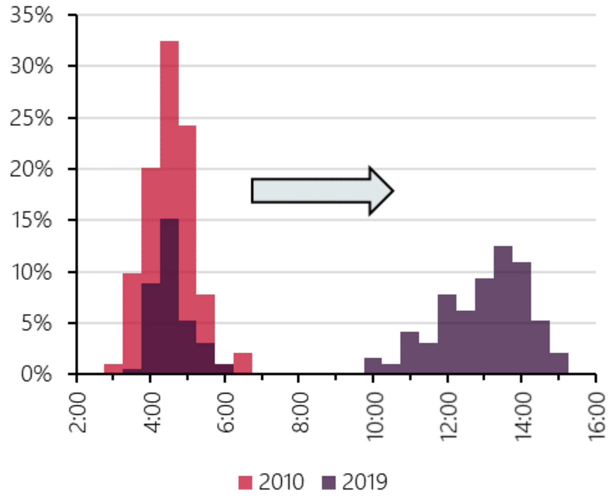


Figure 5 The time of SA minimum demand has shifted

Per cent of time minimum demand occurs by time of day (Jan-Jun)



In addition to the Q2 minimum demand record, South Australia also surpassed its Q2 maximum demand record. At 1830 hrs on 24 June 2019, operational demand reached 2,564 MW, 66 MW higher than the previous Q2 record (in 2010). Cold weather across the state was the main driver with increased heating requirements boosting demand.

Table 1 outlines the maximum and minimum demands which occurred in Q2 2019 and the respective regional records[3].

Table 1 Maximum and minimum operational demand (MW) by region – Q2 2019 vs records

	Queensland		New South Wales		Victoria		South Australia *		Tasmania	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q2 2019	8,073	4,661	12,130	5,733	7,620	3,500	**2,564**	**749**	1,724	884
All Q2	8,172	3,102	13,458	4,862	8,267	3,401	2,498	793	1,752	756
All-time	10,044	2,894	14,744	4,636	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).

[2] Due to the 12-month creation period of small-scale technology certificates, the actual figure at the end of Q2 2019 is likely higher than this reported figure.

[3] Table records refer to those prior to the commencement of Q2 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.

1.3 Electricity generation

During the quarter a combination of outages, dry conditions, and capacity additions induced shifts in the supply mix. Figure 6 shows the average change in generation by fuel type compared to Q2 2018 and Figure 7 illustrates the changes by time of day.

Key shifts included:

- Brown coal – planned and unplanned outages reduced average brown coal-fired generation by 573 MW compared to Q2 2018. A key driver was the 50-day planned outage of Loy Yang B2 to upgrade the unit.
- Hydro – continued dry conditions and comparatively low dam levels led hydro generators to conserve water during Q2 2019. This resulted in an average reduction in output of 463 MW, with the largest decrease occurring at midday. In Q2 2018, hydro generation was above average, so the underlying move was closer to 76 MW.
- An increase in variable renewable energy (VRE) output of approximately 890 MW on average, with 3,700 MW of new grid-scale capacity commencing generation since Q2 2018.

Figure 6 Large reductions in brown coal and hydro output

Change in supply – Q2 2019 versus Q2 2018

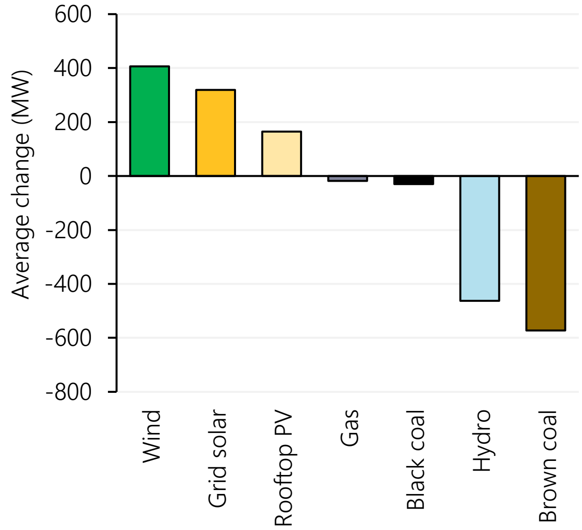
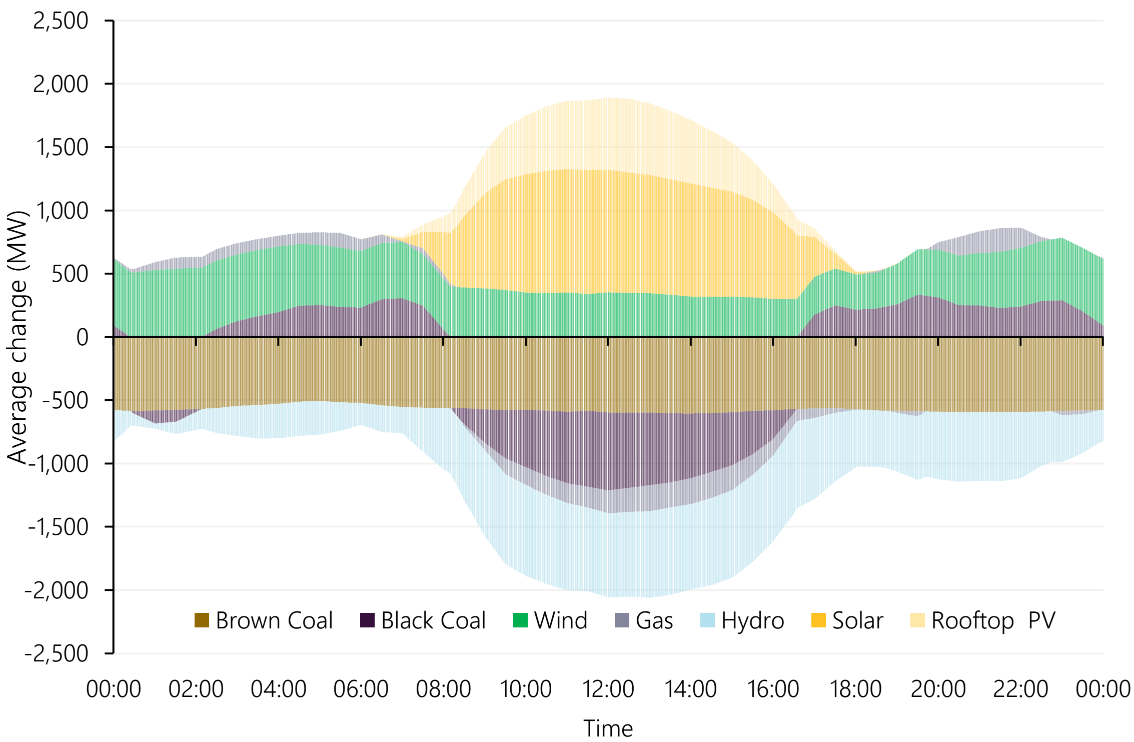


Figure 7 Increased solar changing the shape of the generation profile

Change in supply – Q2 2019 versus Q2 2018 by time of day



1.3.1 Coal-fired generation

Brown coal fleet

In Q2 2019, average brown coal-fired generation was 573 MW lower than in Q2 2018 due to an increase in planned and unplanned outages (Figure 8). This culminated in the average availability factor[4] for the current brown coal fleet[5] in 2018-19 being at its second lowest level on record (Figure 9), with generation for the financial year at its lowest point since repeal of the carbon price. By station:

- Loy Yang (LY) A – Q2 2019 generation was 324 MW lower on average than in Q2 2018, due to a greater amount of time on planned and unplanned outages. Following a forced outage of its LYA2 unit in May, AGL announced that this unit would not return to service until the end of 2019.
- Loy Yang B – average output was 277 MW lower than in Q2 2018. LYB2 was on an extended planned outage in Q2 2019 as part of a major upgrade which was completed by the end of the quarter. The upgrade increased the unit's capacity from 535 MW to 580 MW and improved its emissions intensity. A similar upgrade is planned for LYB1 in 2020.
- Yallourn – average generation increased by 28 MW compared to Q2 2018, reflecting increased availability.

Figure 8 Brown coal fleet outages increase

Brown coal-fired generators - days on outage (Q2s)

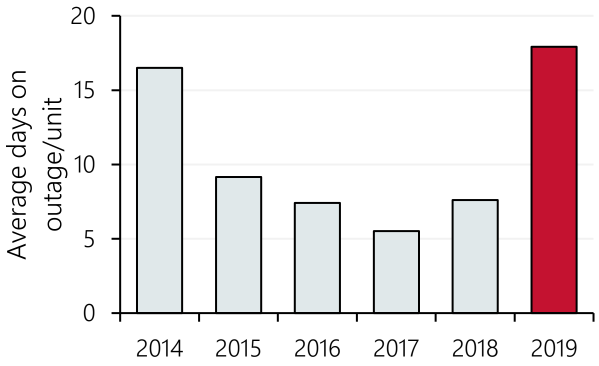
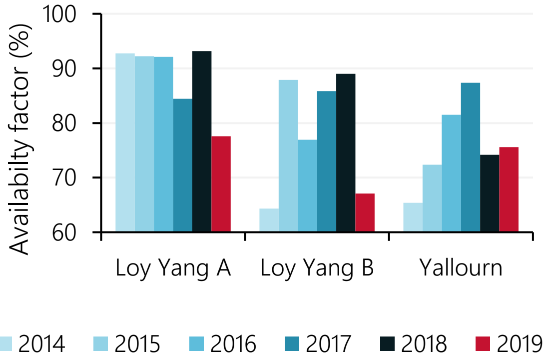


Figure 9 Low availability quarter for brown coal fleet

Brown coal fleet availability factor (Q2s)



Black coal fleet

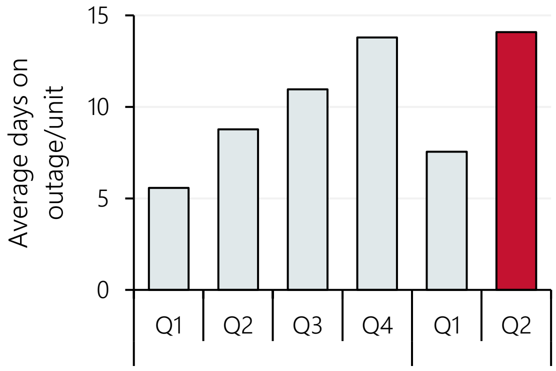
Compared to Q2 2018, black coal-fired generation was relatively flat, with an average increase of 273 MW in New South Wales offset by a decrease of 303 MW in Queensland.

The New South Wales result was largely driven by increased generation and availability at Bayswater (+466 MW) and Eraring (+428 MW) power stations. Eraring's average output of 2,263 MW was its highest quarterly output on record. Coal constraints significantly affected Mt Piper Power Station, which reduced its average output by 558 MW (-50%).

At 5,693 MW, Queensland recorded its lowest quarterly-average output of 5,693 MW in the last three years. Drivers of reduced Queensland output included:

Figure 10 Queensland coal fleet outages increase

Queensland coal-fired generators – days on outage



- An increase in planned and unplanned outages compared to Q2 2018 (Figure 10). This included long planned outages at Callide and Tarong North power stations, and a comparatively long unplanned outage at Gladstone Power Station.
- A shift in offers from Gladstone Power Station, coupled with unplanned outages, contributed to a 240 MW reduction in output. Between Q2 2018 and Q2 2019 around 400 MW priced below $60/MWh was shifted to prices between $60 to $100/MWh.
- Daytime displacement by solar generation (Figure 7).

[4] Availability factor is average availability for the quarter divided by the maximum capacity of the unit.

[5] Loy Yang A, Loy Yang B and Yallourn power stations

1.3.2 Hydro generation

In line with the usual seasonal patterns, hydro generation increased by around 500 MW when compared to Q1 2019, with Tasmania experiencing the largest increase.

Compared to Q2 2018, however, hydro output was 463 MW lower on average (Figure 11). From a regional perspective:

- Tasmania – Hydro generation in Q2 2019 was slightly lower than historical Q2 averages, but 182 MW lower when compared with Q2 2018. This was largely due to on a two-month Basslink outage in Q2 2018 which necessitated increased hydro output. There was a small increase in storage levels with the quarter ending at 35%.
- New South Wales and Victoria – Storage levels at Lake Eucumbene fell slightly over the quarter to 23% (from 26%), the lowest end-of-June levels since 2010, reflecting 18 months of below average rainfall in the region (Figure 12). Compared to Q2 2018, hydro output in New South Wales and Victoria reduced on average by 173 and 145 MW respectively. The main driver of the reduced output was a shift in offers from Snowy Hydro to manage dispatch (and by extension, storages). On average, around 500 MW priced at $75/MWh or below in Q2 2018 was shifted to higher priced bands this quarter.

Figure 11 Hydro slightly down on five-year Q2 average

Quarterly hydro output

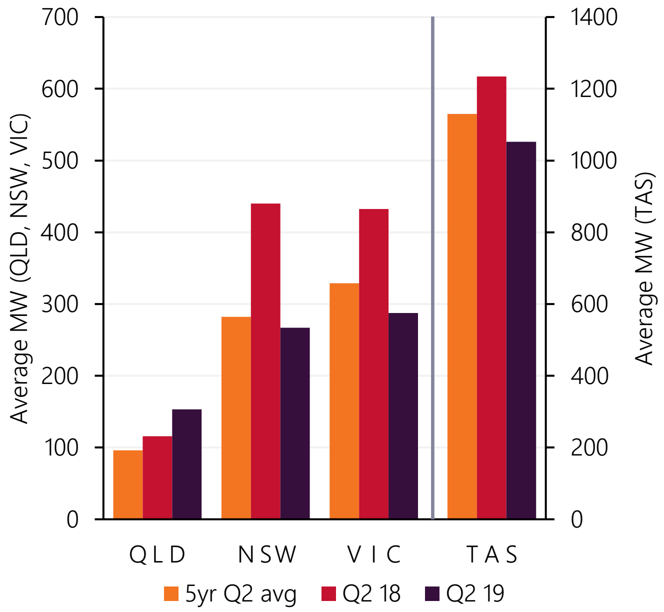
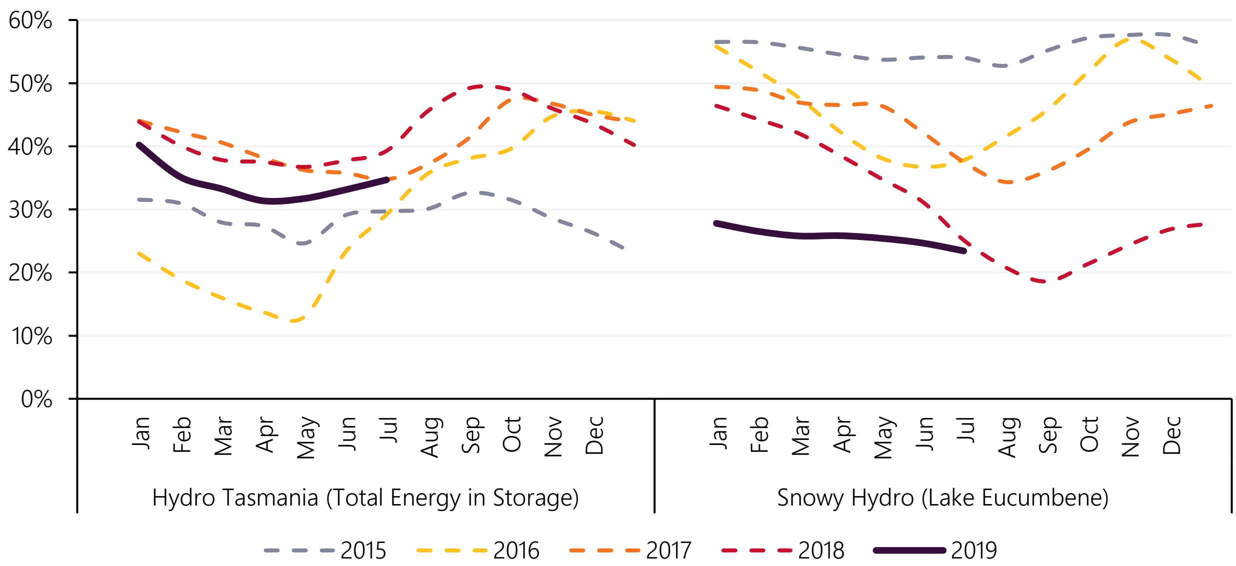


Figure 12 Snowy water storages remain low

Hydro storage levels



Source: Hydro Tasmania https://www.hydro.com.au/water and Snowy Hydro https://www.snowyhydro.com.au/our-energy/water/storages/lake-levels-calculator/.

1.3.3 Gas-powered generation (GPG)

Compared to Q2 2018, GPG was relatively flat, with average increases of 292 MW in the southern regions (Victoria, South Australia and Tasmania) offset by decreases of 310 MW in the northern regions (Queensland and New South Wales). The main driver of reduced Queensland GPG was lower output at Darling Downs (-338 MW) due to a long duration on planned outage.

New South Wales' quarterly average GPG of 72 MW represents its lowest level on record and was due to:

- Record high output from Eraring Power Station which, coupled with a lack of price volatility, enabled lower utilisation of Uranquinty Power Station by Origin.
- Comparatively low availability of Tallawarra Power Station, with an average availability factor of 9.8% for the quarter. Tallawarra was on outage for the first two months of the quarter following an unplanned outage in Q1 2019.

Figure 13 GPG up in the south and down in the north

Quarterly GPG by region

Drivers of increased GPG in the southern regions included:

- Increased availability, particularly at Pelican Point combined cycle gas turbine (CCGT) which increased its availability factor from 24% to 77% (Pelican Point was on a major outage in Q2 2018).
- Brown coal outages – several Victorian and South Australian gas-powered generators – including Newport and Torrens Island power stations – operated at comparatively high levels following brown coal-fired generator outages.
- Dry conditions – to assist in maintaining water storage levels, Hydro Tasmania ran Tamar Valley CCGT longer into the shoulder season compared to 2018 to assist in maintaining water storage levels, resulting in an output increase of 68 MW.

1.3.4 Wind and solar generation

Between Q2 2018 and Q2 2019, average large-scale[6] wind and solar generation increased from 1,551 MW to 2,275 MW (+47%), making up 10% of the supply mix compared to 7% in Q2 2018 (Figure 14). Over the quarter, new projects representing almost 1,500 MW of capacity began generating (Table 2). Of this new capacity, 1,020 MW was from wind and 427 MW from solar, with almost 50% of this capacity addition occurring in Queensland.

Wind generation increased by an average of 406 MW, due to new capacity which has commenced generation since Q2 2018. The NEM-wide average wind capacity factor was 31% compared to 32% in Q2 2018.[7]

Large-scale solar generation increased by 318 MW (+281%) as additional capacity was brought online. Most of the increase in large-scale solar output was in Queensland (195 MW, 61% of the increase). Average Q2 2019 rooftop PV generation increased from 669 MW to 827 MW (+19%) compared to Q2 2018.

Figure 14 Significant solar increase in Queensland

NEM wind and solar generation by region

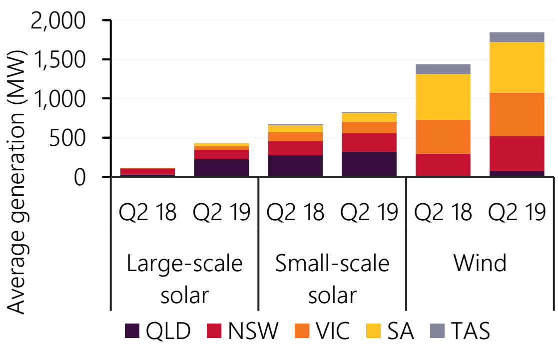


Table 2 New entrants in the NEM in Q2 2019[8]

Technology	New entrant	Capacity MW)	Region
Solar	Beryl	87	NSW
	Clermont	75	QLD
	Haughton Stage 1	100	
	Rugby Run	65	
	Numurkah	100	VIC
Wind	Coopers Gap	440	QLD
	Lincoln Gap	212.4	SA
	Murra Warra	225.7	VIC
	Yendon	142	

[6] Large-scale generation includes market generators (a generator which sells all of its sent-out electricity through AEMO's market) and non-market generators with registered capacity equal to or greater than 30 MW.

[7] Excludes wind farms undergoing commissioning and/or yet to reach high output levels.

[8] 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

1.3.5 Storage

The amount of charging or pumping by energy storage facilities in the NEM during Q2 2019 was 140 GWh, 31 GWh higher than in Q2 2018 but lower than in recent quarters (Figure 15). The increase was due to increased pumping from Tumut 3, Wivenhoe, and Shoalhaven. The contribution from batteries remained relatively stable compared to the prior quarter. On the mainland regions the average spread between peak and off-peak periods was $53/MWh, slightly lower than $56/MWh in Q2 2018.[9]

Battery net revenues for the quarter were approximately $6.7 million, a slight decrease compared to Q1 2019 (Figure 17). The composition of spot revenues for batteries changed over the quarter with:

- A lower contribution from energy revenues due to reduced price volatility South Australia and Victoria (-$3.5 million, Figure 16).
- Increased frequency control ancillary service (FCAS) revenues, driven by high Regulation FCAS prices and greater participation in the FCAS markets by Ballarat Battery Energy Storage System (BESS, +$2.9 million).

Net revenue for the pumped hydro facilities was $2.7 million, slightly more than Q1 2019 due to decreased energy costs associated with lower spot electricity prices at times of pumping.[10]

Figure 15 Pumping remained at comparatively high levels over the quarter

Quarterly charging/pumping in the NEM[11]

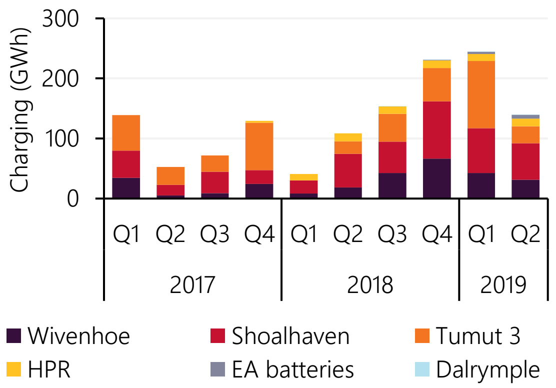


Figure 16 Batteries' energy arbitrage drops due to lower price volatility

Average energy arbitrage by storage type

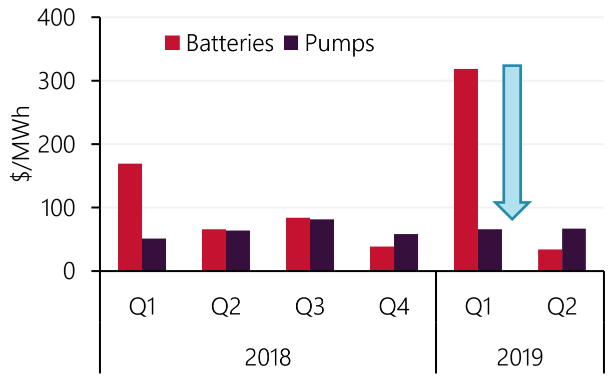
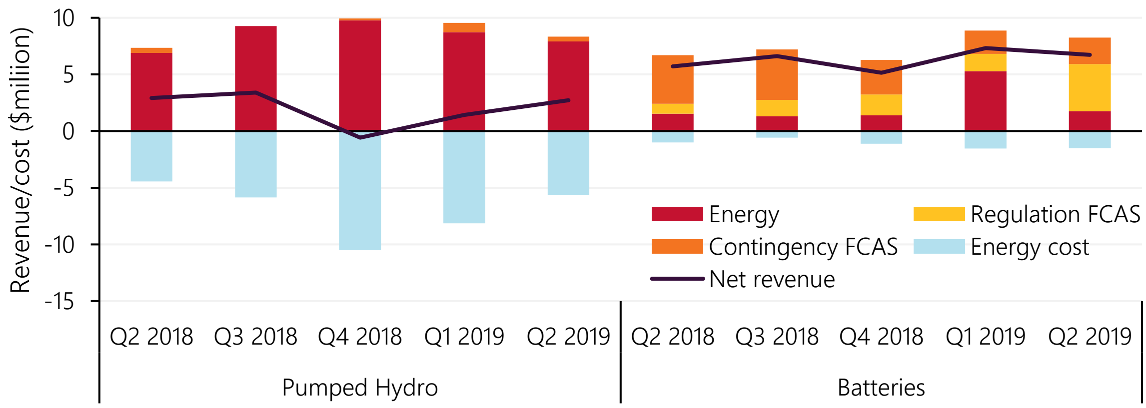


Figure 17 Regulation FCAS revenue drives batteries' profitability in Q2

Revenue sources by storage technology[12]



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

[10] 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. In addition, the calculation excludes potential value from the stored water through its sale outside of the energy sector.

[11] 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 NEM until 2030 and 2033 respectively. Further information available [here]

[12] 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].

1.3.6 NEM emissions

NEM emissions for the quarter fell to their lowest on record[13], both in terms of absolute emissions and emissions intensity, with absolute emissions 4.1 million tonnes of carbon dioxide equivalents (MtCO2-e) lower than in Q2 2018 (Figure 18). Drivers of the downward trend included comparatively low brown coal-fired generation, increased VRE output, and lower NEM demand.

Figure 19 shows the NEM-average emissions intensity by time of day for Q2 2019 and Q2 2018. The largest decrease occurred at midday due to increased penetration of solar PV. The lowest emissions intensity continued to occur in the morning and evening peak periods, due to the high amount of GPG and hydro generation at these times.

Figure 18 Record low quarterly NEM emissions

Quarterly NEM emissions and emissions intensity (Q2s)

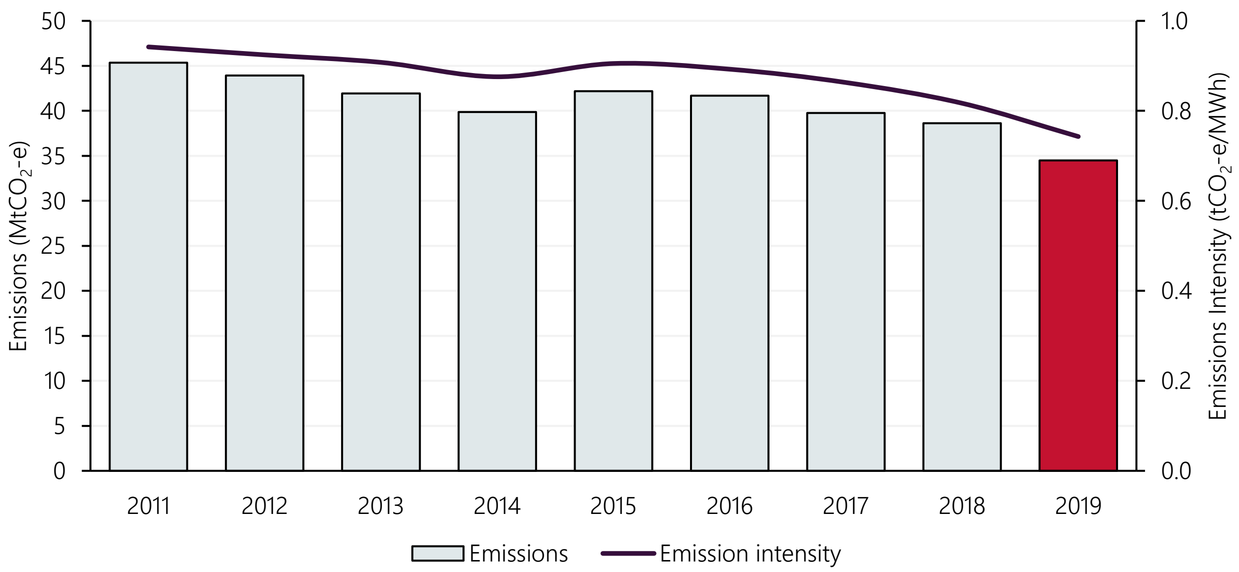
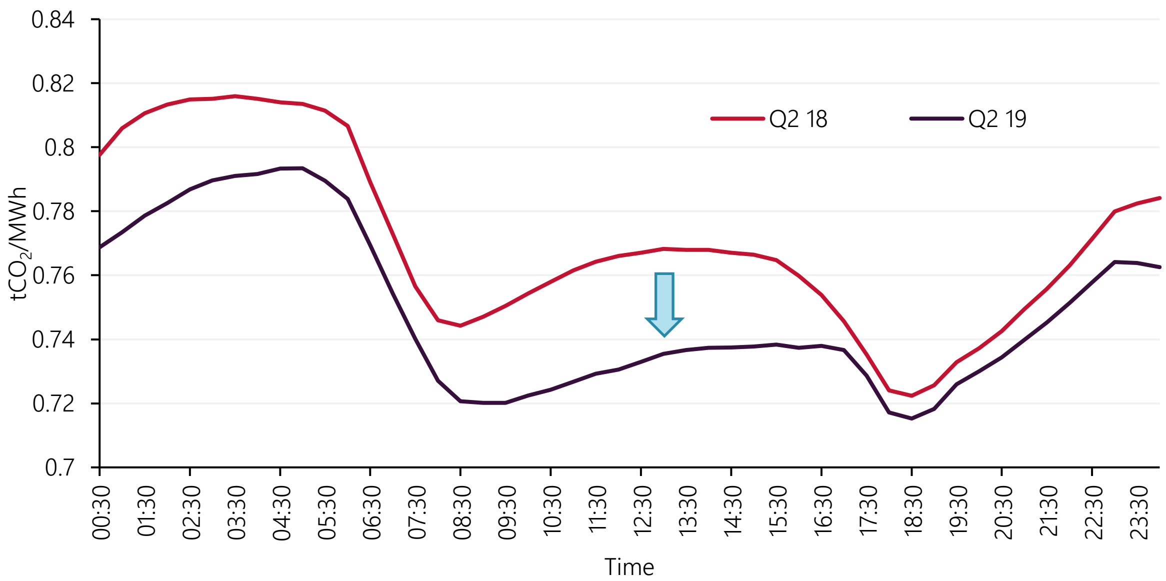


Figure 19 Solar reduces daytime emissions intensity

NEM emissions intensity by time of day (quarterly averages)



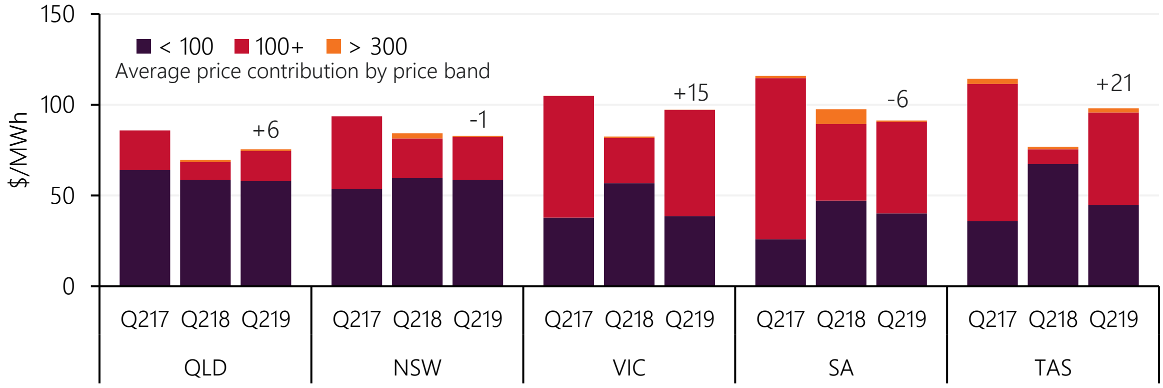
[13] NEM emissions are only estimated from 2001 onwards, whereas the NEM commenced in 1998.

1.4 Wholesale electricity prices

During Q2 2019, wholesale electricity prices remained at comparatively high levels, increasing across most NEM regions compared to Q2 2018, largely due to reduced brown coal and hydro generation, and higher gas prices. The largest increases occurred in Tasmania (+$21/MWh) and Victoria (+$15/MWh). These higher prices occurred despite demand reductions, increased VRE output and a lack of price volatility (i.e. there was an absence of prices above $300/MWh).

Figure 20 Prices up in most NEM regions compared to last year

Average wholesale electricity price by region



Wholesale electricity price drivers: Q2 2019 compared to Q2 2018

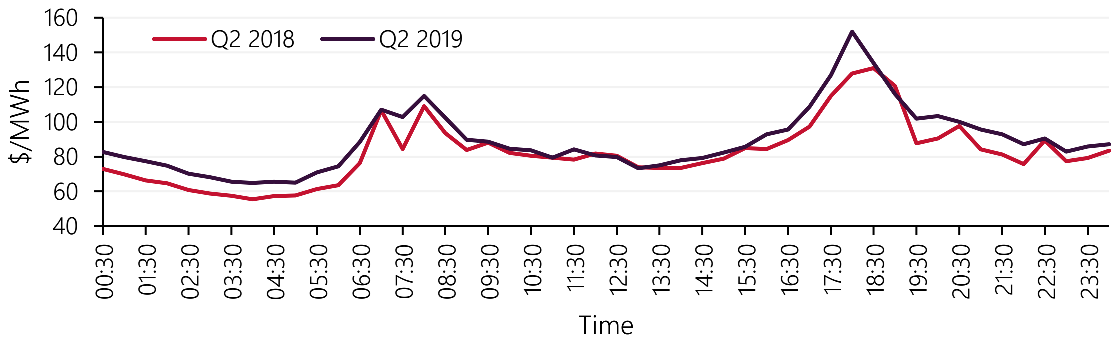
Increased prices in Victoria and Tasmania	• Planned and unplanned outages of brown coal-fired generators in Victoria reduced generation priced below $100/MWh by almost 600 MW on average compared to Q2 2018. • Dry conditions reduced availability of lower-priced hydro generation (Section 1.3.2). • Wholesale gas prices remained at comparatively high levels (Section 2.2), which was reflected in higher GPG offers. Since Q2 2017, the average availability of GPG priced below $100/MWh has fallen by approximately 750 MW.
Reduced prices in South Australia	• Reduced price volatility, due in part to greater availability of the VIC-SA interconnectors. • Increased periods of negative pricing in the region (Section 1.4.2).
Flat prices in Queensland and New South Wales	The price impact of increased VRE output was offset by reduced hydro output, as well as higher prices when set on an inter-regional basis. Queensland's price when set by a southern region (Victoria, South Australia or Tasmania) averaged $94/MWh, compared to $77/MWh in Q2 2018.

Figure 21 shows the NEM-average price by time of day, revealing that the largest uplift in the spot electricity price in the quarter occurred in the evening peak and early morning hours. Higher early morning prices were largely a result of reduced brown coal-fired generation.

Daytime prices were comparable to Q2 2018, with increased solar output balancing out the price-increasing factors discussed above. Despite the large increase in solar PV penetration (Section 1.3.4), average midday prices (around $70-80/MWh) remained higher than early morning prices (around $60-70/MWh) over the quarter.

Figure 21 Midday prices still higher than early morning prices

NEM average spot electricity price by time of day



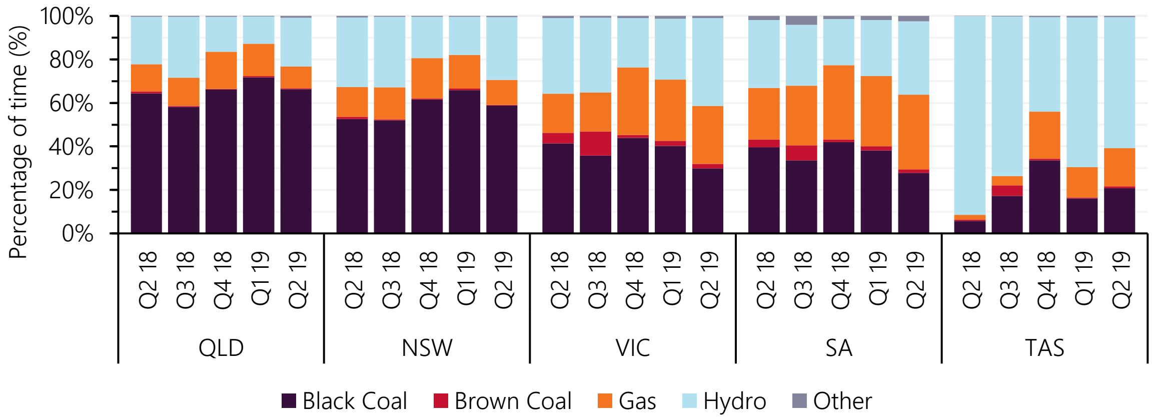
1.4.1 Price-setting dynamics

Changes in the supply mix shifted the price-setting dynamics this quarter, both in terms of the fuel type setting the price, as well as the regional location of the marginal unit. Compared to Q2 2018, regional results include:

- Queensland and New South Wales – Black coal remained the dominant price setter this quarter, setting the price around 60% of the time. Compared to Q2 2018, black coal set the price more often in the off-peak periods and in the middle of the day. This was, however, this was partially offset by increased hydro price setting in the evening peak.
- Victoria and South Australia – This quarter represented the highest percentage of time on record that gas and hydro were involved in setting the price in these regions, with prices set higher than a year ago (+$12-15/MWh). Gas and hydro set Victoria's price 67% of the time (compared to 53% of the time in Q2 2018), with a large portion of this increase occurring in the evening peak. This was largely due to the shift in offers from Snowy Hydro (as mentioned in Section 1.3.2) and restricted flows south on the VIC-NSW interconnector (Section 1.6). The main price-setting units were Torrens Island (16%), Murray (12%) and Gordon (8%).
- Tasmania – The local price in Tasmania was set inter-regionally 52% of the time this quarter compared to 12% in Q2 2018 (Figure 23). This was largely due to change in offers from Hydro Tasmania, which shifted around 450 MW priced below $100/MWh to higher priced bands, and also a fully operational Basslink[14].

Figure 22 Gas and hydro setting the price more frequently in the southern regions

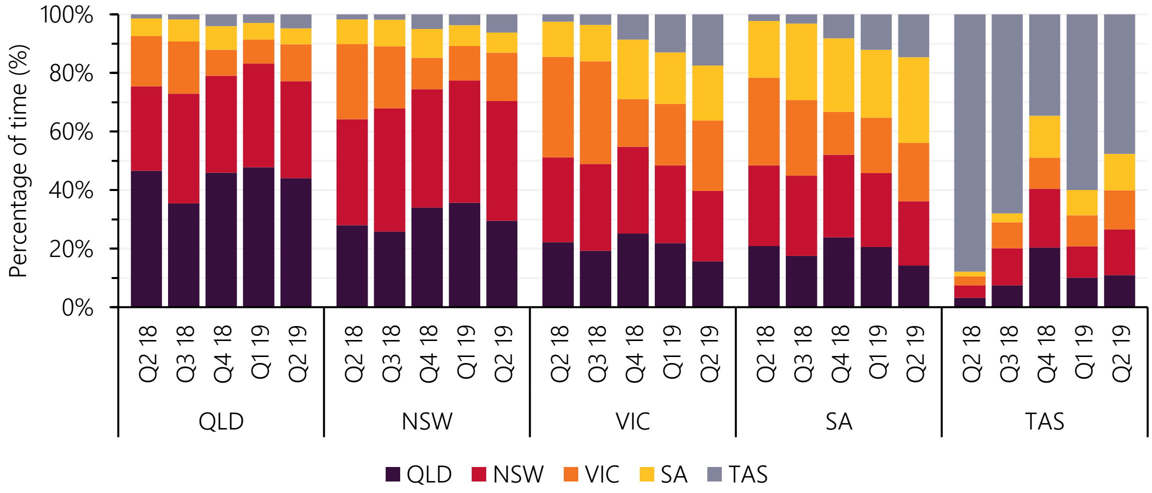
Price-setting by fuel type – Q2 2019 versus prior quarters



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

Figure 23 Shifting regional price setting dynamics

Price-setting by region – Q2 2019 versus prior quarters



[14] In Q2 2018, Basslink was on a two-month outage meaning that Tasmania could only utilise local generation to meet demand and by extension, set the price.

1.4.2 Negative prices

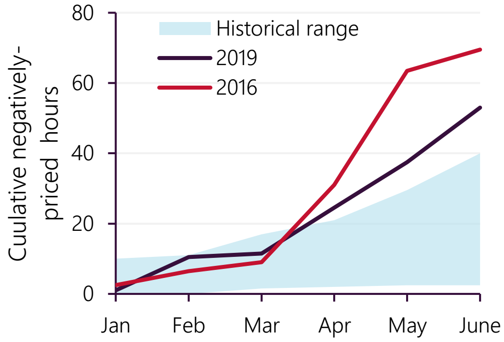
In South Australia, negative prices were at comparatively high levels for the first half of 2019, with almost 53 negatively-priced hours (although still only 1.2% of the time), the second highest year-to-date level on record (Figure 24). Negative prices over Q2 2019 contributed to South Australia's average spot price being $6/MWh lower than Victoria's.

Typical drivers of negative prices include:

- Comparatively VRE output. Since the start of 2018, 709 MW of new VRE capacity has commenced generation in South Australia, which has led to increased incidence of high VRE output.
- Comparatively low operational demand (<1,200 MW). Minimum operational demands in South Australia continue to decline, driven by uptake of rooftop PV.
- Constraints which restrict flows on the VIC-SA interconnectors.

Figure 24 Comparative high prevalence of negative pricing this year

Cumulative negative prices in South Australia – YTD[15]



Wind and solar respond to negative prices

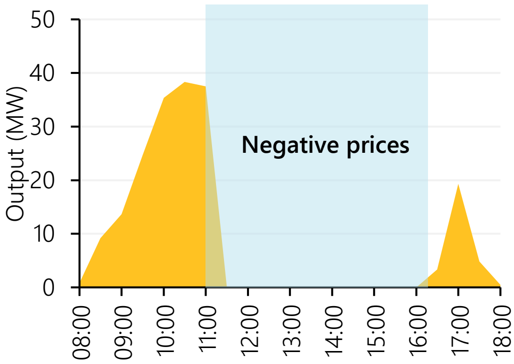
VRE generators have traditionally been bid to maximise output regardless of price. However, recent negative price events in South Australia have highlighted a shift in behaviour from some wind and solar farms.

An example of this was on 30 April 2019, when low demand, high VRE output and network constraints drove negative prices for more than five hours. On this day, more than half of SA's VRE generators reduced their output due to the negative prices. Semi-scheduled VRE achieved the reduction in output by re-bidding output to higher prices and subsequently not being dispatched by AEMO, while some non-scheduled VRE opted to self-curtail its output.

An example of this is shown in Figure 25, with Tailem Bend Solar Farm curtailing its output over the negative price period by re-bidding capacity from -$1,000/MWh to $14,500/MWh to avoid being dispatched at negative prices.

Figure 25 VRE is responding to negative prices

Tailem Bend response to negative prices (30 Apr 2019)



1.5 Other NEM-related markets

1.5.1 Electricity future markets

The price of financial year 2019-20 (FY20) electricity swap contracts traded on the ASX rose in all regions over Q2 2019 (Figure 26). The largest increases occurred in Victoria and South Australia, and coincided with the announcement that Loy Yang A Unit 2 would not return to service until the end of 2019 (Section 1.3.1). At the end of the quarter, Victoria's FY20 swap price reached $110/MWh, its highest level on record for that product.

Prices of FY21 swaps were relatively flat, with small increases in Victoria and South Australia (+2-3%) and decreases in Queensland and New South Wales (Table 3). Q1 2020 cap prices were up in all regions, with the largest increases in Victoria (+10%), and South Australia (+5.6%), reflecting continued concerns regarding the return of price volatility.

Figure 26 Victorian futures prices reach record levels

ASX energy – FY20 swap prices by region

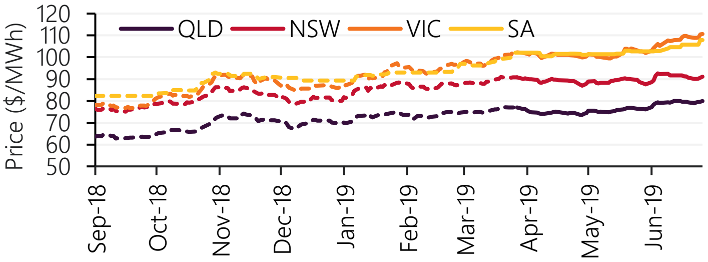


Table 3 Change over Q2 19 for FY20 and FY21 swap prices

Region	FY 20	FY 21
QLD	▲ $2.88 (3.7%)	▼ $1.23 (1.8%)
NSW	▲ $0.43 (0.5%)	▼ $3.52 (4.4%)
VIC	▲ $8.41 (8.2%)	▲ $1.65 (2%)
SA	▲ $5.83 (5.7%)	▲ $2.41 (3%)

[15] Historical range is for years 2010 to 2018, excluding 2016 (the highest year).

1.5.2 International coal prices

Newcastle coal prices continued to decline, with the spot price for high quality thermal coal (6,000 kilocalories [kcal]) reducing 16% to AU$98/metric tonne by the end of the quarter. Similarly, the price of lower quality coal (5,500 kcal) decreased by 8% over the quarter (Figure 27). Drivers of these recent price reductions include lower northern hemisphere demand, Chinese import restrictions and comparatively lower LNG spot prices encouraging some fuel switching in Asia[16].

Despite the reduction in international coal prices, domestic wholesale electricity prices have remained at comparatively high levels. As shown in Figure 28, recent New South Wales wholesale spot electricity prices have been more closely correlated with estimated marginal gas costs than marginal coal costs[17].

Figure 27 Steep fall in international coal prices

Newcastle thermal coal price

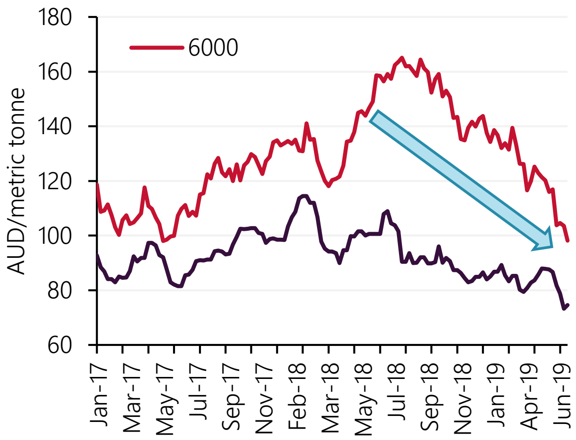
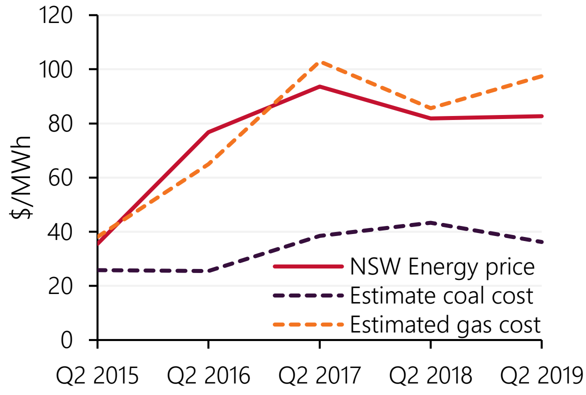


Figure 28 New South Wales wholesale electricity prices remain closer to gas costs

Relationship between electricity, coal and gas pricing



Source: Bloomberg

1.5.3 Environmental Markets

The Large-scale Generation Certificate (LGC) spot price increased to $42/certificate over Q2 2019 after falling as low as $31/certificate in March 2019 (Figure 29, Table 4). This price rebound ended the trend of LGC spot price reductions from October 2018, when the CER published an industry update changing their position on the use of shortfall provisions[18]. With the CER confirming that the 2020 target will be exceeded[19], certificate demand effectively shifted to future years where prices are lower.

The increase in spot and calendar year 2019 (Cal19) prices over the quarter coincided with:

- Dry conditions and comparatively low hydro output over the 1H 2019, which may limit hydro generators' LGC creation this year.
- Renewable project delays, coupled with increased grid congestion, as reflected in the recently updated marginal loss factors[20].

Figure 29 LGC spot price rebounds in Q2 2019

LGC spot and forward prices over time

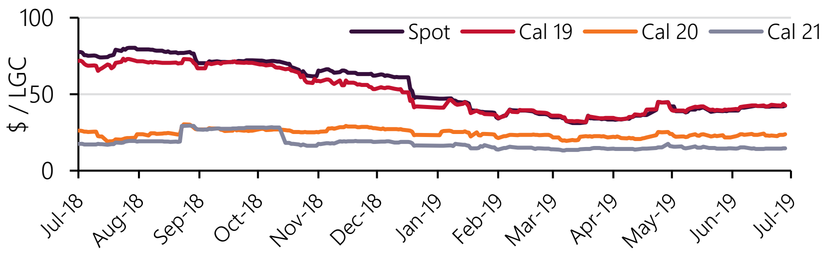


Table 4 LGC prices

Product	Change over Q2 19
Spot	+ $8.88 (26%)
Cal 19	+ $8.28 (24%)
Cal 20	+$1.55 (7%)
Cal 21	+ $0.33 (2%)

Source: Mercari

[16] Department of Industry 2019, Resources and Energy Quarterly - June 2019

[17] Estimated gas cost based on the quarterly average gas price in the Sydney Short-term Trading Market and a heat rate of 10 GJ/MWh. Estimate coal cost based on the 5500 Newcastle thermal coal price (in AUD/tonne), energy content of 23 GJ/tonne, and a heat rate of 10 GJ/MWh.

[18] CER 2018, Industry update on surrender of large-scale generation certificates

[19] CER 2019, The 2018 Renewable Energy Target Annual Statement

[20] AEMO 2019, Loss factors and regional boundaries.

1.5.4 Frequency control ancillary services

In Q2 2019, FCAS costs were $45 million[21], representing an $8.7 million (24%) increase on Q1 2019 levels, but a reduction on 2018 levels (Figure 30). By market:

- Regulation FCAS costs increased by $12 million (+66%), driving the overall cost increases.
- Contingency Raise costs reduced by $3.5 million (-19%), somewhat offsetting the increases in the Regulation markets.
- Contingency Lower costs remained at comparatively low levels.

Figure 30 Regulation FCAS costs increase
Quarterly FCAS costs by service

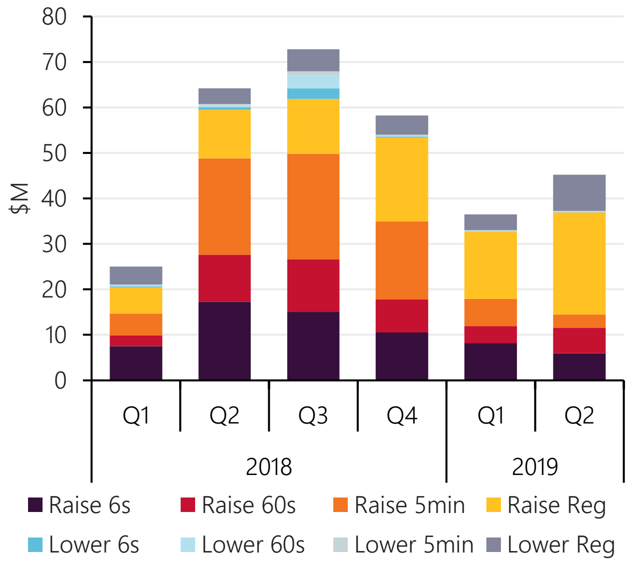
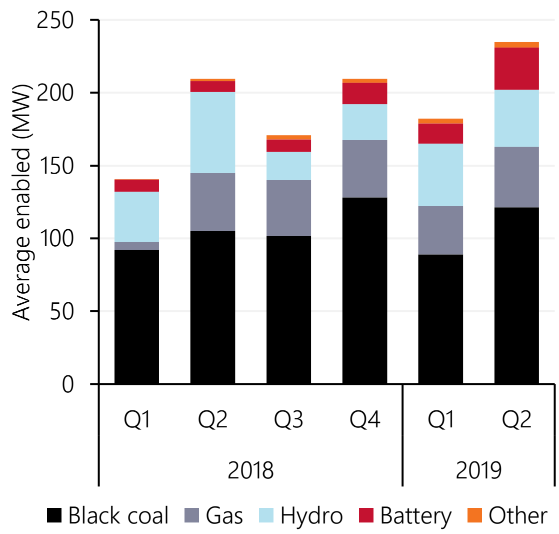


Figure 31 Regulation FCAS demand increased
Raise Regulation FCAS enabled by fuel type



FCAS price drivers: Q2 2019 compared to Q1 2019

Increased Regulation FCAS costs	• Increased demand – on 22 March, to ensure ongoing compliance with the requirements of the Frequency Operating Standards, AEMO increased the Regulation FCAS across the mainland NEM regions by 50 MW[22]. Since then, AEMO has further increased the minimum quantities to 220 MW of Raise Regulation and 210 MW of Lower Regulation. – This resulted in a 29% and 52% increase in average Raise and Lower Regulation enablement over the quarter, driving increased Raise Regulation supply from black coal-fired generation (+38%), GPG (+27%) and batteries (+112%, Figure 31). • A shift in offers from some providers to higher-priced bands – compared to Q2 2018, there was a 50 MW reduction in offers below $20/MWh. Providers shifting offers into higher-priced bands included Gladstone, Gordon and Poatina power stations. This shift was somewhat offset by increased supply from Ballarat BESS, Torrens Island and Upper Tumut.
Reduced Contingency Raise costs	• Cost reductions in these markets were a function of an increase in supply offered at comparatively low prices. – For example, Gladstone, Demand Response assets operated by Enel X[23] and Hydro Tasmania, and the Snowy Pump at Guthega all substantially increased their availability in the Raise 6 Second FCAS market. This resulted in supply from these providers increasing from a combined average of 63 MW to 131 MW (+107%).

[21] Represents preliminary data and subject to minor revisions.

[22] At the time of publication, AEMO stated that it would 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 assess whether frequency has remained in the Normal Operating Frequency Band for at least 99.5% of the time over the previous four weeks, together with any other relevant factors.

[23] Formerly EnerNOC.

1.6 Inter-regional transfers

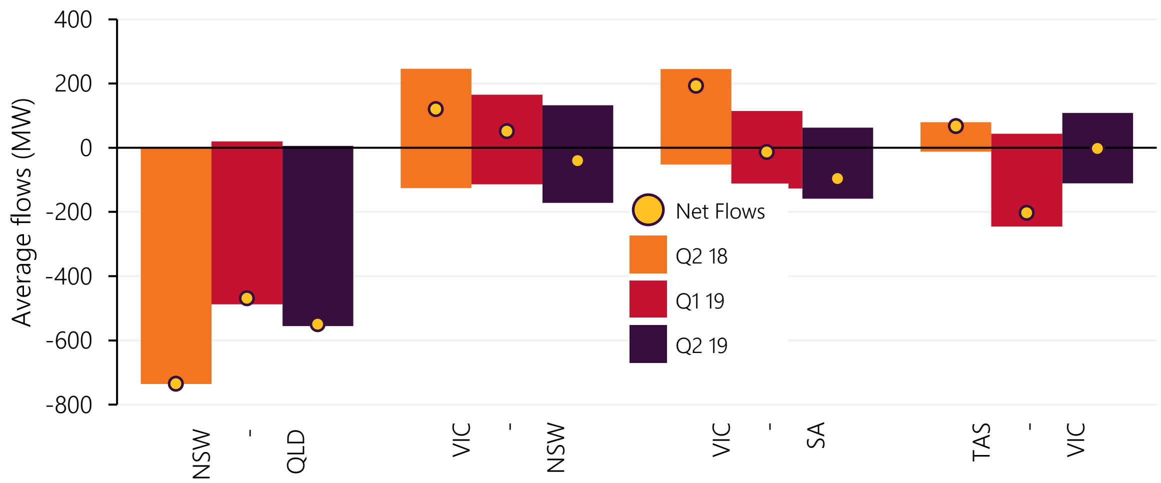
Total inter-regional transfers decreased to approximately 2,851 GWh (-13% compared to Q2 2018), largely due to reduced flows south on the Queensland to New South Wales Interconnector (QNI, Figure 32).

Compared to Q2 2018, by regional interconnector[24]:

- New South Wales to Queensland – Inter-regional transfer was almost exclusively south at net 549 MW on average, but reduced by 186 MW from Q2 2018. This reduction was due to an increase in output from black coal-fired generation in New South Wales and a decrease in output from black coal-fired generation in Queensland (see Section 1.3.1).
- Victoria to New South Wales – there was a 410 MW average decrease in net transfers north on the interconnector. This change was a function of reduced hydro and brown coal-fired generation in the southern regions. The VIC-NSW interconnector was binding at its limits for 34% of the quarter (compared to 14% in Q2 2018), which contributed to an inter-regional price spread of $14/MWh. Similar to Q1 2019, changes in Snowy Hydro's generation patterns resulting from dry conditions contributed to restricted flows south on the interconnector[25].
- Victoria to South Australia – there was a 289 MW swing on the interconnectors, with net transfers of 96 MW into Victoria, driven by brown coal-fired generator outages. The Heywood interconnector continued to rarely reach its limits; it only bound at its limit for 8% of the quarter, contributing to continuing price convergence between the two regions.
- Tasmania to Victoria (Basslink) – brown coal-fired generation outages, coupled with water conservation by Hydro Tasmania, resulted in an even balance in transfers on Basslink (net 2 MW into Tasmania). Due to increased interconnector availability compared to Q2 2018 (when it was on outage for much of the quarter), there was a greater amount of inter-regional price setting by Tasmania units (17% this quarter compared to 2% in Q2 2018).

Figure 32 Inter-regional electricity transfers reduce

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.

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

[25] AEMO 2019, *Quarterly Energy Dynamics – Q1 2019*.

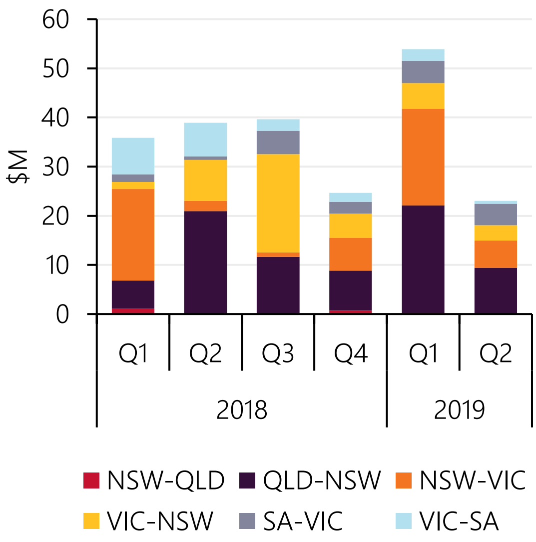
1.6.1 Inter-regional settlement residue

Total inter-regional settlement residue[26] (IRSR) for the quarter reduced to $23 million, its lowest value since Q2 2014 (Figure 33). The main driver of this result was a $11.5 million (55%) reduction in IRSR value on the QLD-NSW interconnectors compared to Q2 2018, which was a function of reduced flows and reduced price separation between the two regions. Other outcomes compared to Q2 2018 included:

- NSW-VIC – despite continued price separation between the two regions, IRSR value on the VIC-NSW interconnector reduced by $1.8 million. This was due to restricted flow south on the interconnector – particularly during higher Victorian spot prices – which somewhat diminished the IRSR value (relative to a situation with higher flows).
- VIC-SA – fewer periods of price volatility in South Australia led to a $2.6 million reduction in IRSR value.

Figure 33 Lowest IRSR for four years

Quarterly positive IRSR value



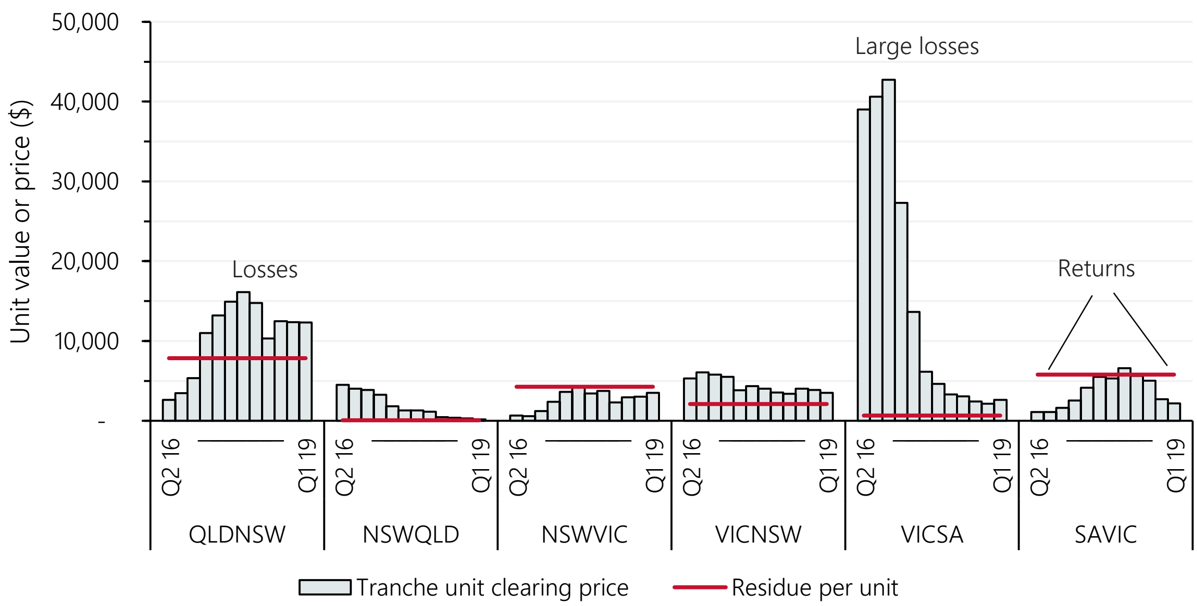
There were mixed results on returns for units purchased at settlement residue auctions (SRAs), with positive returns only occurring for units relating to NSW-VIC flows and SA-VIC flows (Figure 34). The positive returns may have been influenced by higher than expected flows into Victoria resulting from brown coal-fired generator outages.

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[27]. There were also losses on units for QLD-NSW flows, likely driven by price convergence between the two regions.

In general, the price paid for SRA units and their actual value converged the closer they were purchased to Q2 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 34 Mixed results for returns on units purchased at Settlement Residue Auctions

SRA tranche analysis – price paid for units versus actual value (Q2 2019)



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

[27] 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 Q2 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 Q2 2018, with directions in place for 13% of the time, compared to 45% during Q2 2018 (Figure 35). Total direction costs[28] reduced from approximately $6.5 million in Q2 2018 to approximately $3.2 million for the quarter. The reduced time directing was a function of higher synchronous generator availability; Pelican Point CCGT's availability factor increased from 24% to 77% (it was on a major outage in Q2 2018) and Torrens Island generated at elevated levels following an outage of LYA2.

During the quarter, curtailment of non-synchronous generation in South Australia increased slightly compared to Q2 2018, to around 4% of the unconstrained intermittent generation forecast (UIGF as Figure 36 shows). This was despite a 7% reduction in high wind periods (South Australian wind output >1,200 MW), and was largely driven by network constraints which limited output from the Lake Bonney wind farms for several days, as well as VRE self-curtailment in response to negative prices (Section 1.4.2).

Figure 35 System strength directions reduce in 2019
Directions for system security in South Australia and Victoria

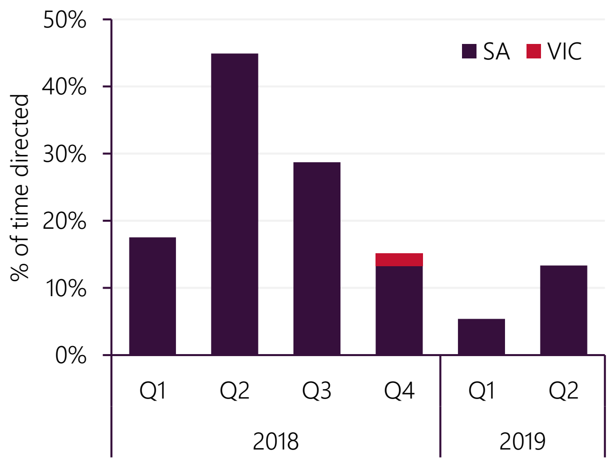
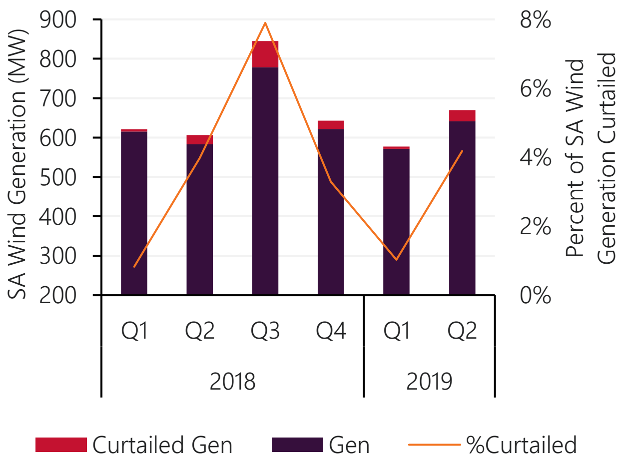


Figure 36 Four per cent of SA wind curtailed over Q2
Curtailment of SA wind generation



[28] Based on Compensation Recovery Amount (provisional amount).

2. Gas market dynamics

2.1 Gas demand

Total east coast gas demand was 7% higher than in Q2 2018 (Table 5), solely due to an increase in demand at Curtis Island for liquified natural gas (LNG). There was no material change in GPG, residential, commercial and industrial demand; all experienced slight decreases.

Table 5 Gas demand – Quarterly comparison[29]

Demand	Q2 2019 (PJ)	Q1 2019 (PJ)	Q2 2018 (PJ)	Change from Q2 2018 (PJ)
AEMO Markets *	93.4	54.8	95.1	-1.7 (2%)
GPG **	37.5	47.7	38.4	-0.9 (2%)
QLD LNG	323.2	329.0	292.0	+31 (11%)
TOTAL	454.1	431.5	425.5	+29 (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.

LNG demand

Total deliveries of 323 PJ were directed to Curtis Island during Q2 2019, the third highest quarter on record (with the preceding quarters being the two highest, Figure 37). This represents an increase of 31 PJ compared to Q2 2018, and a decrease of 5.8 PJ compared to the prior quarter. The decrease was due to maintenance activities conducted on all three facilities at different times during the quarter.

There were 77 LNG cargoes exported during Q2 2019, lower than Q1 2019 (83 cargoes).

GPG demand

While aggregate Q2 2019 GPG demand was comparable to Q2 2018, significant differences occurred at a state level (Figure 38). Queensland demand decreased by 4.4 PJ, whereas South Australia increased by 1.8 PJ and Victoria increased by 1.3 PJ. Section 1.3.3 provides more detail on drivers of these regional-based differences.

Figure 37 High gas flows to Curtis Island for LNG export

Total quarterly pipeline flows to Curtis Island

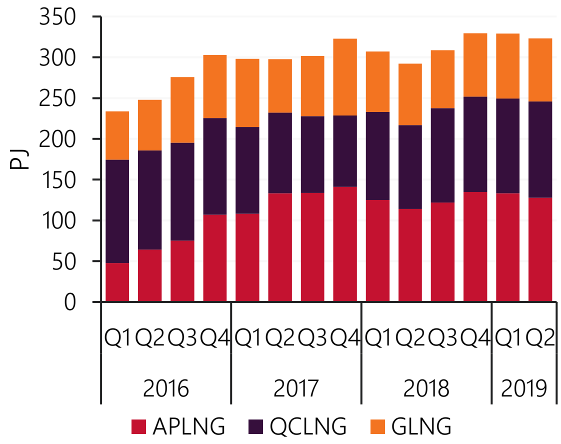
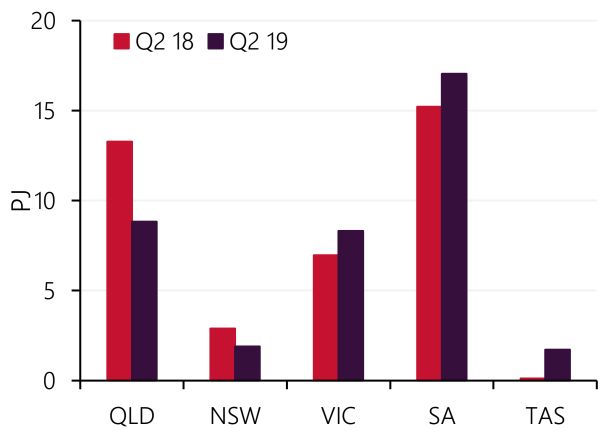


Figure 38 GPG demand up in the south and down in the north

GPG demand for electricity by region



[29] 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

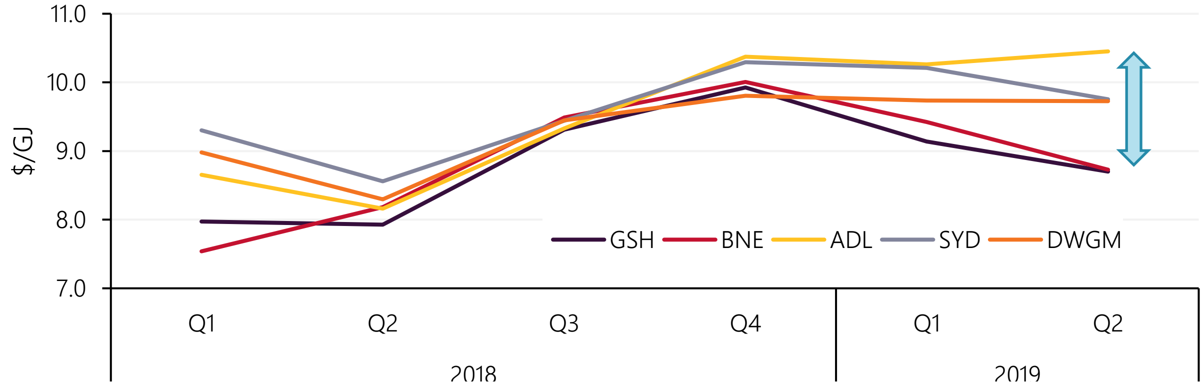
Q2 2019 wholesale gas prices remained comparatively high, increasing across all markets by an average of 16% compared to Q2 2018 (Figure 39). The largest increases occurred in the Adelaide STTM (+28%), the DWGM (+17%) and the Sydney STTM (+14%). Price increases also occurred in the Brisbane STTM (+7%) and the Gas Supply Hub (GSH, +10%). Adelaide recorded its highest quarterly average gas price on record.

In recent quarters, a distinct price separation between Queensland and the southern markets has emerged. This separation has coincided with the following changes:

- Increased Queensland production, up 23 PJ compared to Q2 2018.
- Introduction of the Northern Gas Pipeline in January 2019, which has released around 6 PJ of Queensland gas previously flowing to Mt Isa (Section 2.4).
- Increased GPG demand for electricity in South Australia, Victoria and Tasmania, up 4.8 PJ compared to Q2 2018.
- Decreased GPG demand for electricity in Queensland, down 4.4 PJ compared to Q2 2018.

Figure 39 Price separation emerges between the northern and southern markets

GSH, DWGM and STTM average prices

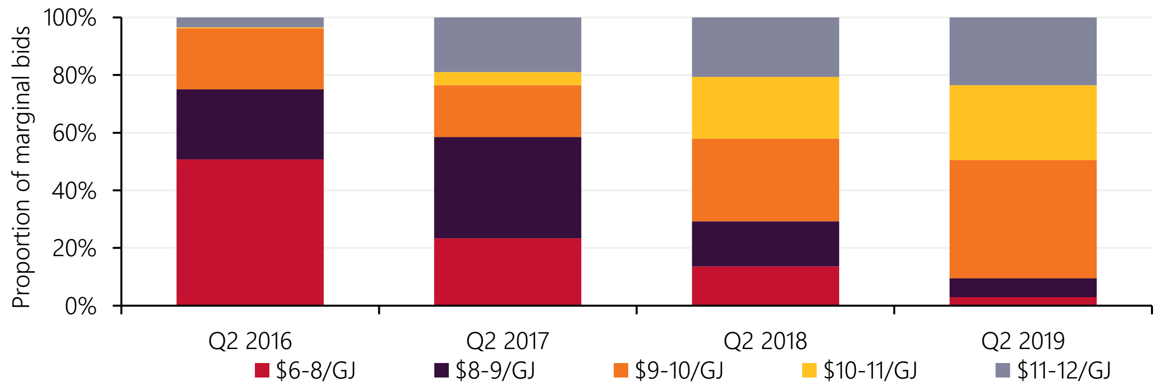


Gas price increases were driven by increased demand, coupled to higher-priced gas injection offers. In Q2 2019, the quantity of gas offered at prices below $9/GJ reduced by 12% compared to Q2 2018. In the DWGM, less than 10% of marginal injection offers[30] were bid in at prices below $9/GJ (Figure 40). The change of prices offered coincided with the following:

- Comparatively high electricity prices in the southern regions of the NEM (Section 1.4).
- Increase in scheduled gas from Longford producers into the DWGM and Sydney STTM (Section 2.3.2).
- An increase in the price of newly signed gas supply agreements (GSAs). In April 2019, the ACCC reported that: "range of agreed prices for gas supply in all regions has increased relative to the ranges previously reported (from $0.89 to $2.37 for Queensland and from $2 to $2.05 for the Southern States), due to the inclusion of newer, higher priced GSAs[31]."

Figure 40 Shift in gas injection offers to higher prices

DWGM – proportion of marginal injections offers by price band



[30] Offers between $6/GJ and $12/GJ.

[31] ACCC 2019, *Gas inquiry 2017–2020 Interim report April 2019*, p.34

2.2.1 International gas and oil prices

The Brent crude oil price continued its recovery over April and May, supported by the curtailment of supply under a production agreement between OPEC+ members. However, by June, the oil price fell sharply amidst changing sentiment driven by US trade tensions with China and Iran leading to fears over the state of the global economy[32]. This flowed into forward price expectations which tracked lower at around AU$90/bbl over the near term.

The ACCC LNG netback price[33] dropped significantly from levels in Q1 2019 to approximately $6/GJ, significantly lower than domestic gas price outcomes (Section 2.2). The forward price reflects the seasonal demand for LNG in the northern hemisphere.

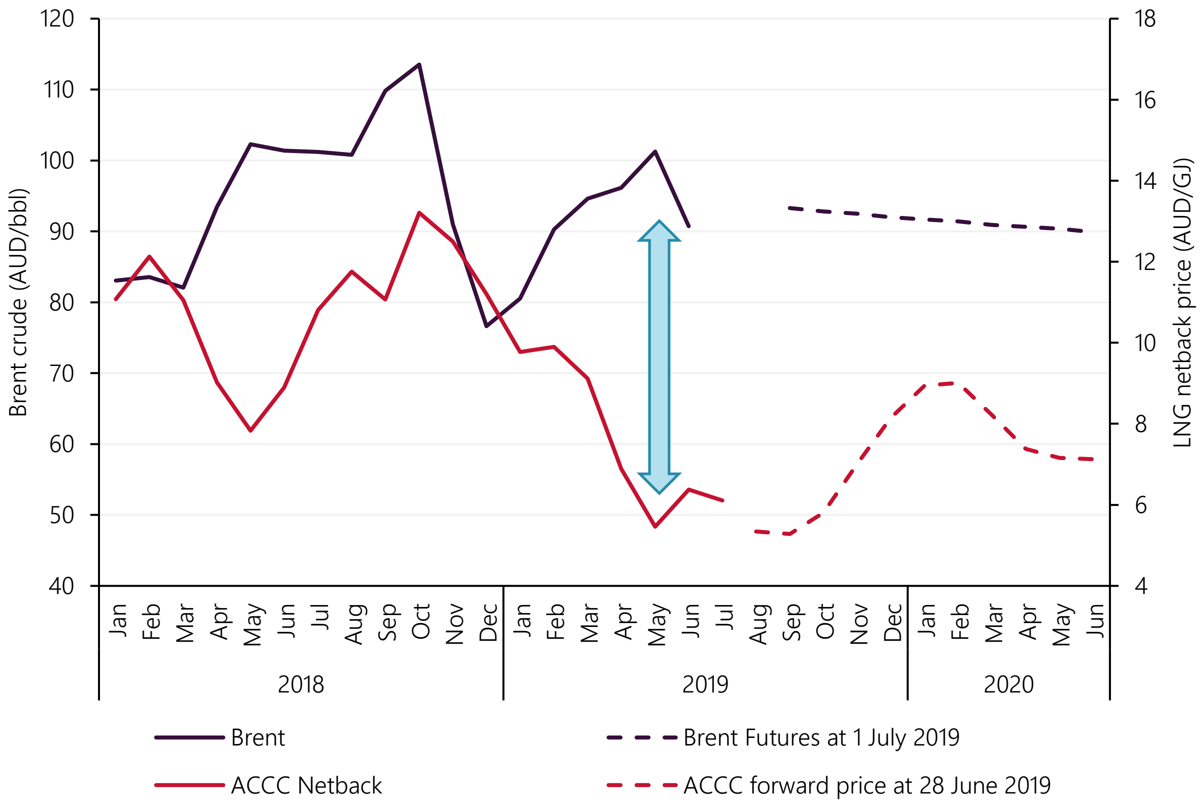
Since the beginning of 2019, there has been a growing separation between the spot price of oil and LNG prices. This matters because some LNG contracts are oil-linked[34] meaning that the current conditions are favourable for sellers. As noted by the Department of Industry,

> *"A key question is what the implications of this decoupling might be, especially if decoupling endures for a sustained period. Previous periods of low spot prices have encouraged buyers to push for shorter, more flexible contracts and gas-based pricing, and away from traditional oil-linked pricing arrangements."*

With the oil futures price remaining high, even with the expected seasonal rebound in spot LNG prices, the market expects that price separation will continue into 2020.

Figure 41 Oil and LNG spot prices have diverged, mirroring winter 2018 results

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



Source: ACCC and Bloomberg

[32] Department of Industry 2019, Resources and Energy Quarterly - June 2019

[33] A theoretical export parity price that a gas supplier can expect to receive for exporting its gas. ACCC 2019, LNG netback price series.

[34] ACCC, Inquiry into the east coast gas market , April 2016

2.3 Gas supply

2.3.1 Gas production

Q2 2019 east coast gas production increased compared to Q2 2018 (+5%) and Q1 2019 (+5%) (Figure 42). This resulted in record high east coast gas production over financial year 2018-19, increasing by 22 PJ compared to 2017-18.

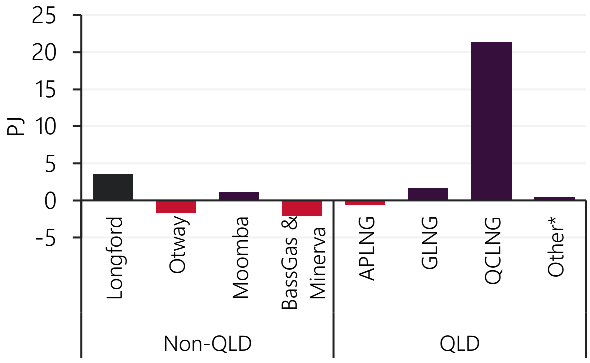
Table 6 Changes in gas production

Production increase against Q2 2018	• Higher Queensland production (+23 PJ), driven mostly by increases in Woleebee Creek (+19.5 PJ) and Ruby Jo (+5 PJ). • Increase in Longford production (+3.5 PJ), offsetting decreases at Otway, Bass Gas and Minerva (-3.7 PJ). Of this increase, 1.5 PJ came from Esso and BHP directly selling into the DWGM and Sydney STTM from Longford (Section 2.3.2). • Increase in Moomba production (+1.2 PJ).

QCLNG's Woleebee Creek gas plant has been a key factor in elevated east coast gas production (Figure 43). An expansion dubbed 'Charlie Project'[35] has enabled additional processing of up to 220 TJ/day, an increase from the previous capacity of 450TJ/day.

Figure 42 Queensland producers drive production increases

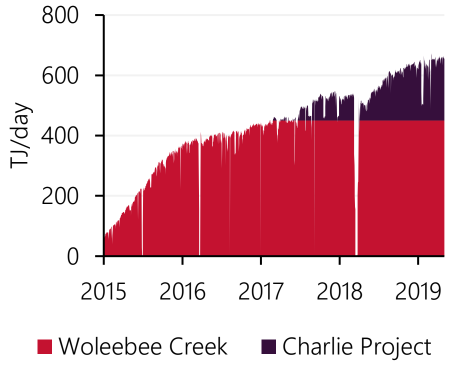
Change in quarterly gas production by plant – Q2 2019 versus Q2 2018



* Plant not explicitly stated are grouped as "Other"

Figure 43 Large increase in Woleebee Creek production

Woleebee Creek daily production



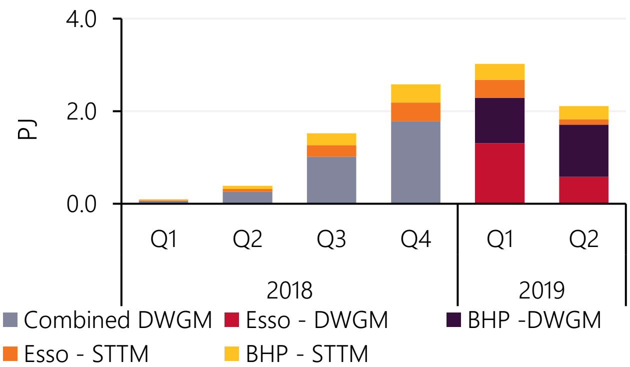
2.3.2 Supply from Longford producers

From 1 January 2019 Esso and BHP have separately marketed gas produced at Longford under the Gippsland Basin Joint Venture (GBJV)[36]. Prior to this, gas was sold into the DWGM under one combined gas participant. This change has coincided with increased volumes supplied into the DWGM and Sydney STTM hub from Esso and BHP (Figure 44). Compared to Q2 2018 gas volumes have increased by 1.72 PJ.

When offering gas into the DWGM during the quarter, BHP and/or Esso set the price 34% of the time at prices ranging from $9.11 to $9.70/GJ. When offering gas into the Sydney STTM, BHP and/or Esso set the price 14% of the time, at prices ranging from $9.20 to $9.84/GJ[37].

Figure 44 Longford producers selling gas in the DWGM and Sydney STTM

Esso/BHP Longford volume bid into DWGM and STTM at prices at or below market price



[35] QGC Charlie Natural Gas Project.

[36] BHP and Esso to separately market Gippsland Basin gas.

[37] Esso and BHP did not offer any gas into the market between 7 March and 19 April 2019 due to maintenance at Longford causing a capacity reduction.

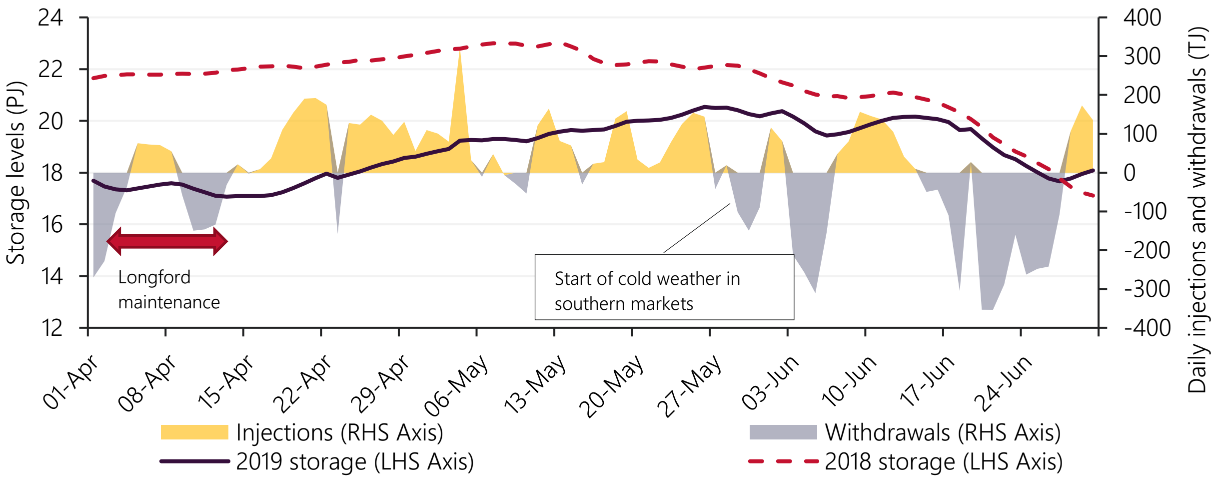
2.3.3 Gas storage

A gas balance of 18.1 PJ was recorded at the Iona Underground Storage Facility (Victoria) at 30 June 2019, 0.97 PJ higher than at the end of Q2 2018, and 0.39 PJ higher than at the start of the quarter (Figure 45). This is despite Iona beginning the quarter almost 4 PJ lower than at the start of Q2 2018. Differences to Q2 2018 correspond with:

- Increased Longford production (Section 2.3.1).
- Increased imports from Queensland into Victoria via Culcairn and lower exports to South Australia (Section 2.4).
- Milder weather leading to lower heating requirements (Section 1.1), which was partially offset by higher gas demand for GPG in the southern regions.

Figure 45 Iona Storage increases over the quarter

Iona storage levels



2.4 Pipeline flows

Victorian net gas exports in Q2 2019 were lower than in Q2 2018 and Q1 2019, reducing by 8.4 PJ and 6.9 PJ respectively (Figure 46). The key driver of this was increased South West Queensland Pipeline (SWQP) flows to Moomba (Figure 47). This was due to a 6 PJ decrease in flows to the Mt Isa region over the quarter, resulting from the introduction of the Northern Gas Pipeline (NGP) in January 2019, which enabled flows from the Northern Territory to displace gas previously supplying that region. This led to:

- Decreased flows from Victoria to New South Wales compared to Q2 2018, with Victoria importing 4.7 PJ via Culcairn. Exports to New South Wales via Eastern Gas Pipeline (EGP) remained steady at around 16 PJ.
- Decreased flows via SEAGas from Victoria to South Australia by 2.7 PJ, despite an increase in GPG demand in that state. Instead, supply was met by increased imports into South Australia via the Moomba to Adelaide Pipeline (MAP).

Flows from Victoria to Tasmania increased (+0.7 PJ) compared to Q2 2018 due to an increase in Tasmanian GPG demand.

Figure 46 Victorian gas exports decrease

Victorian net gas exports to other states

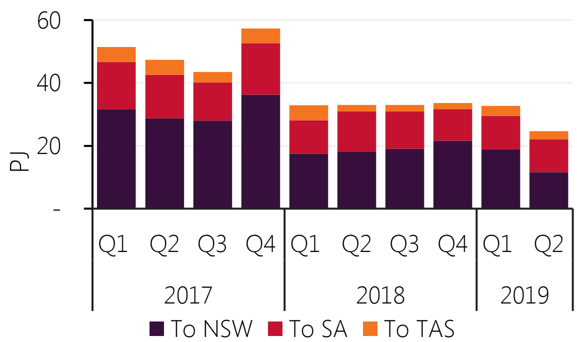
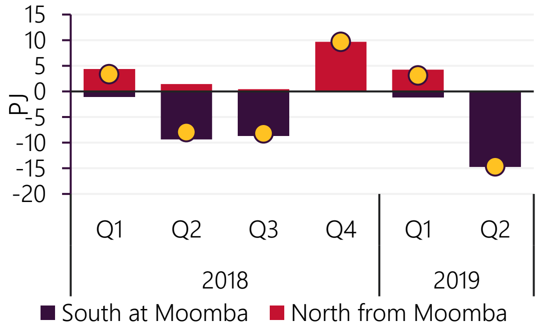


Figure 47 High flows south on the SWQP[38]

Flows on the South West Queensland Pipeline at Moomba



[38] Some historical numbers in this chart different to those in previous QEDs, due to the introduction of the Northern Gas Pipeline (gas flowing to Mt Isa was previously included, but no longer is in the historical numbers).

2.5 Gas Supply Hub

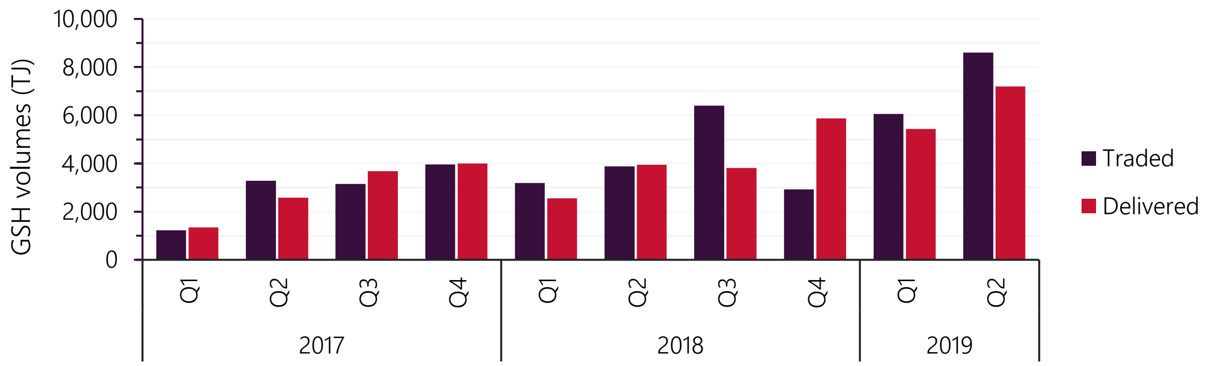
In Q2 2019, the GSH continued its upward trading volume trend, reaching record high quarterly levels (Figure 48). Traded volumes increased by 4.7 PJ (+122%) when compared to Q2 2018.

A key shift during the quarter was the first significant volumes traded at Moomba, reaching 1 PJ, up from the previous record of 33 TJ. This reflected increased participant interest in trading at that location, due to:

- The introduction of the Day Ahead Auction (DAA) on 1 March 2019 has resulted in greater access to pipeline capacity (see Section 2.6). AEMO has observed participants purchasing both capacity and commodity on the Moomba to Sydney Pipeline (MSP).
- This increase in trading has resulted in additional participants placing bids and offers at Moomba.

Figure 48 Gas Supply Hub hits another record

Gas Supply Hub – quarterly trades and deliveries



The continued driver of record trading was increased utilisation of the GSH for off-market bilateral trades. The ACCC Gas Inquiry Interim report[39] published in May 2019 stated that 96% of all short-term trades in Queensland in 2018 were conducted through the GSH.

2.6 Pipeline Capacity Trading and Day Ahead Auction

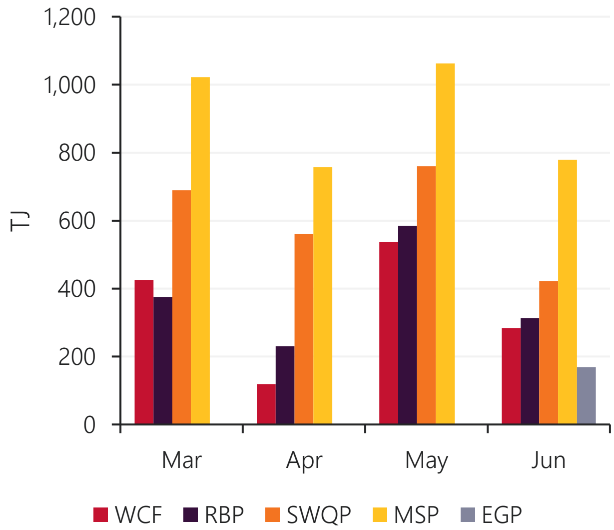
A new market for trading and auctioning unused pipeline transmission capacity began on 1 March 2019. This included the development of:

- A capacity trading platform (CTP) that shippers can use to trade secondary capacity ahead of the nomination cut-off time and provides for exchange-based trading of commonly traded products and a listing service for bespoke products.
- A day-ahead auction (DAA) of contracted but un-nominated capacity, conducted shortly after nomination cut-off and subject to a reserve price of zero.

No CTP trades occurred up to 30 June, however the DAA however was utilised on most days. The pipelines most frequently traded were the Moomba to Sydney Pipeline (MSP), the South West Queensland Pipeline (SWQP), Roma to Brisbane Pipeline (RBP), and the Wallumbilla Compressor (WCF). The Eastern Gas Pipeline (EGP) began to be traded from late May (Figure 49).

Figure 49 Day ahead pipeline trading capacity commences

Day Ahead Auction Results by Month



Average auction clearing prices ranged from $0/GJ on WCF, EGP and MSP, $0.04/GJ on SWQP, and $0.07/GJ on RBP.

39 39 https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2020/gas-inquiry-april-2019-interim-report.

2.7 Gas – Western Australia

In Q2 2019, total gas consumption was 96.7 PJ, an increase of 12% (or 6.9 PJ) compared to Q1 2019 (Figure 50), largely driven by increases from mineral processing (2.1 PJ) and distribution (2 PJ). This represents the highest total quarterly gas consumption since Q3 2017, when consumption totalled 97.6 PJ.

There was a corresponding increase in gas supply over the quarter of 9% (Figure 51). This was largely driven by a 5PJ increase in gas production at the Wheatstone facility which came online towards the end of Q1 2019.

Over the quarter, 3 PJ of gas was transferred into Storage Facilities[40]. The net effect of increased demand of 6.9 PJ, increased supply of 9.1 PJ, and increased storage of 3.0 PJ indicates a small reduction in overall linepack.

Figure 50 Highest Western Australia gas demand since Q3 2017

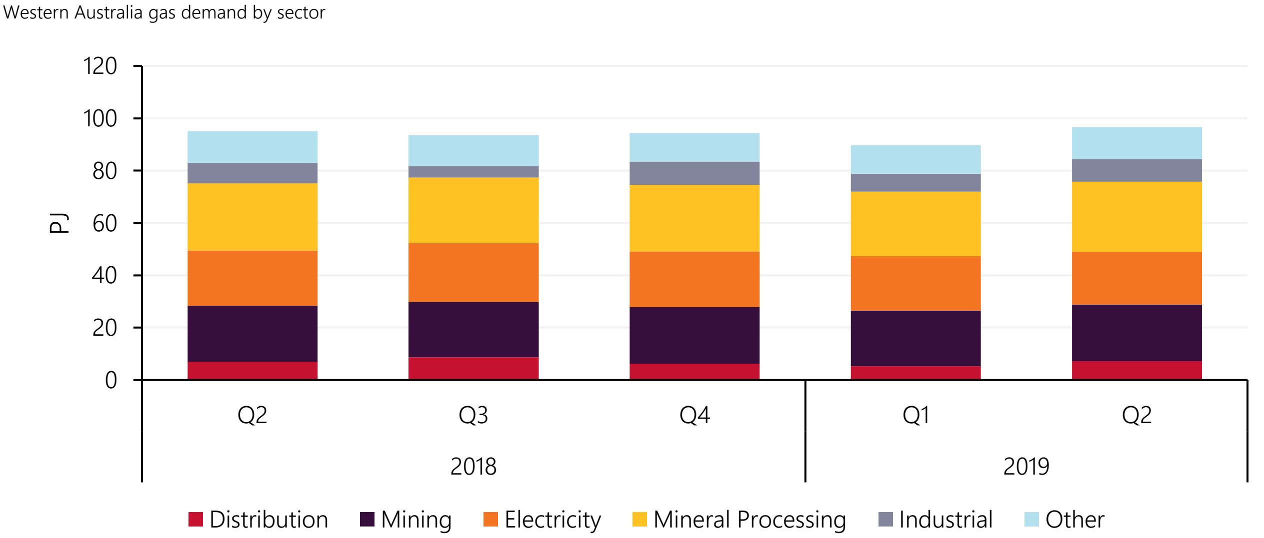
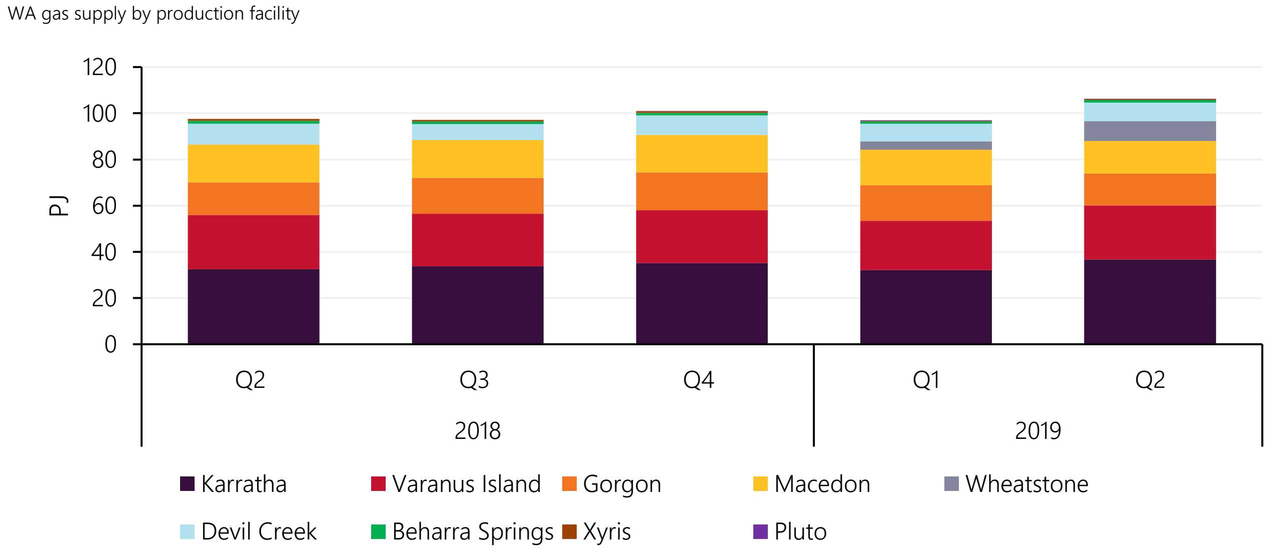


Figure 51 Large production increase at the Wheatstone facility



[40] Mondarra and Tubrudgi Storage Facilities.

3. WEM market dynamics

3.1 Electricity demand and weather

Perth's average and minimum temperatures during Q2 2019 were lower than the 10-year Q2 average by 0.46°C and 0.74°C, respectively. This, coupled with increased penetration of rooftop PV, contributed to an average reduction in operational demand[41] of 50 MW (2.5%) when compared to Q2 2018 (Figure 52).

The minimum demand interval during the quarter was 1,235 MW[42], a reduction of 145 MW (or 10%) compared to minimum demand in Q2 2018. This was also the lowest minimum demand interval for Q2 since 2008 (Figure 53) and the lowest for 2019 so far. Conversely, maximum demand during the quarter was consistent with Q2 2018 results, only increasing slightly (4 MW).

Figure 52 WEM demand reduces

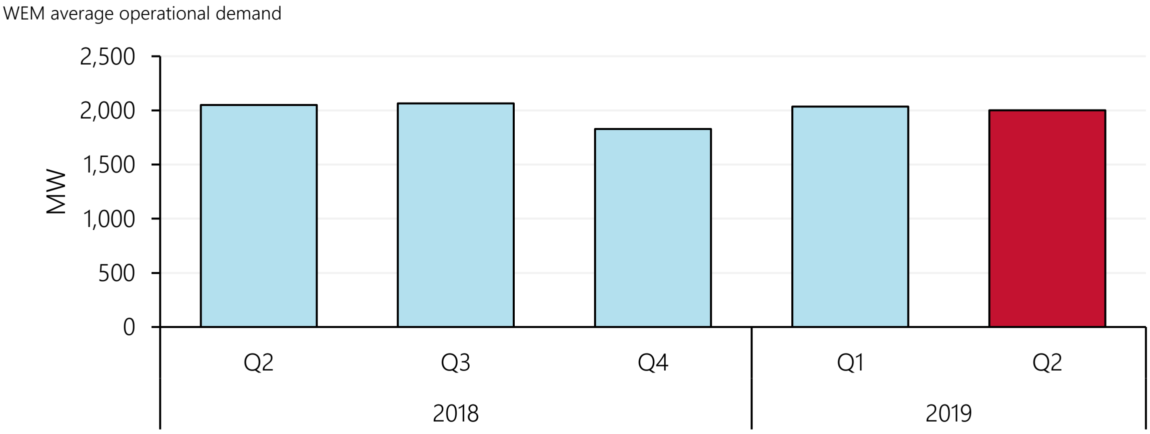


Figure 53 Q2 minimum demands reducing over time

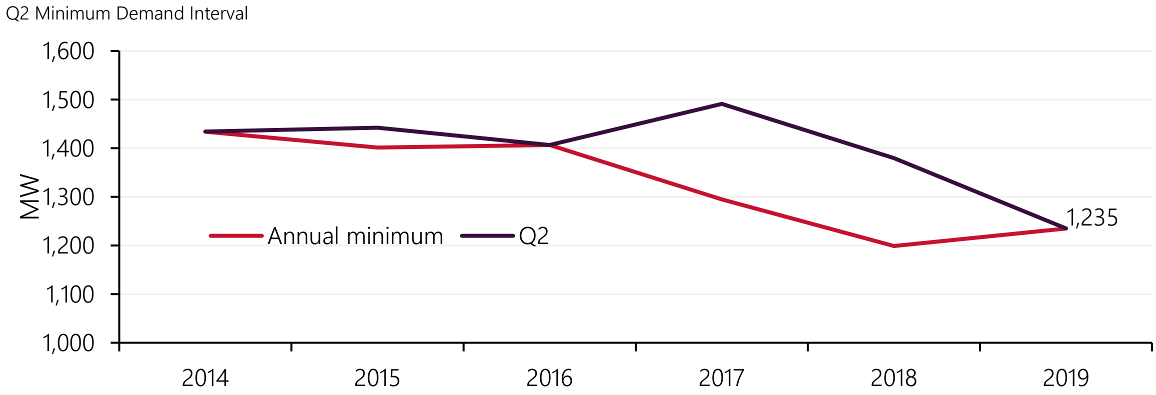


Table 7 WEM maximum and minimum demand (MW) – Q2 2019 vs records

Maximum demand (MW)			Minimum demand (MW)		
Q2 2019	All-time	All Q2	Q2 2019	All-time	All Q2
3,197	4,006	3,362	1,235	1,173	1,176

[41] 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.

[42] 6 April 2019 at 1330 hrs

3.2 Electricity generation

Figure 54 shows the average change in generation by fuel type compared to Q2 2018 by time of day, while Figure 55 shows the average changes. These changes highlight the supply-mix transformation which has begun to occur in the WEM. Key shifts included:

- An average increase in wind generation of approximately 90 MW (56%). This is largely due to the connection of the 130 MW Badgingarra Wind Farm at the beginning of 2019. Additionally, all wind farms increased output this quarter compared to Q2 2018 due to stronger wind conditions.
- An average 2 MW increase in large-scale solar generation due to the connection of two solar farms, Ambrisolar Solar Farm (0.9 MW) and Northam Solar Farm (10 MW), in the second half of 2018.
- Coal generation reduced by 75 MW (7%) on average and GPG by 60 MW (7%) on average, particularly throughout the middle of the day when they were displaced by solar, and overnight when wind generation peaked.
  - There was a comparatively lower reduction in GPG during evening peak periods, which coincided with declining solar output.
- Rooftop PV increased by an average of 19.4 MW. The majority of the increase occurred in the afternoon, due to an increase in installed rooftop capacity in the South West Interconnected System (SWIS) and changes in the half-hourly average capacity factor in 2019 compared to 2018 (Figure 56).

Figure 54 Variable renewable energy inducing changes in the WEM supply mix

Change in supply – Q2 2019 versus Q2 2018 by time of day

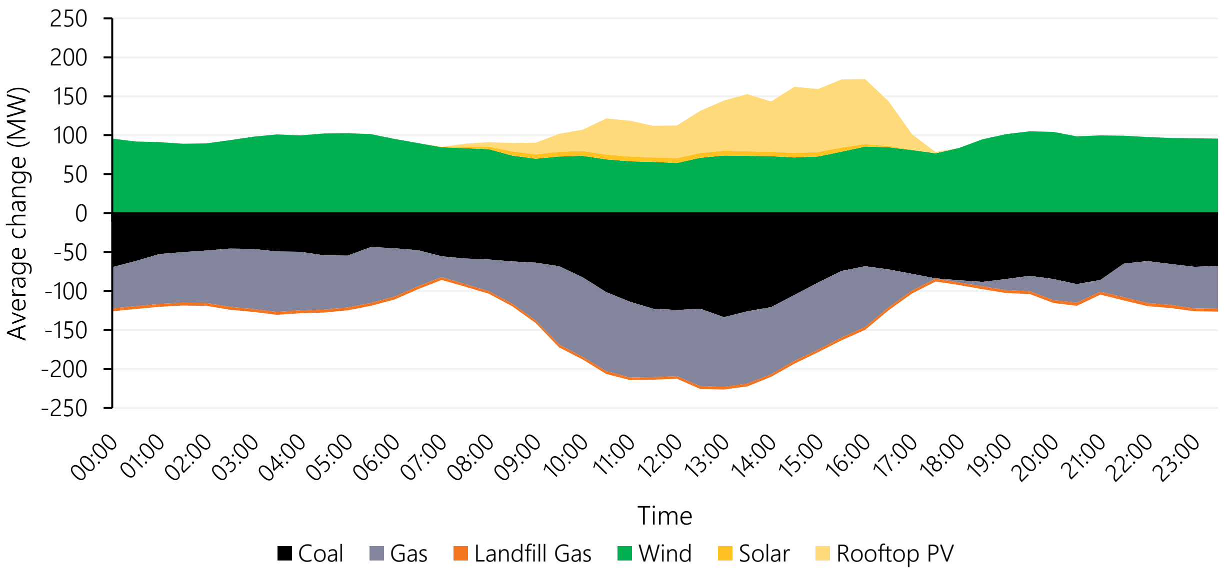


Figure 55 Large increase in wind output in the WEM

Average MW change by fuel type

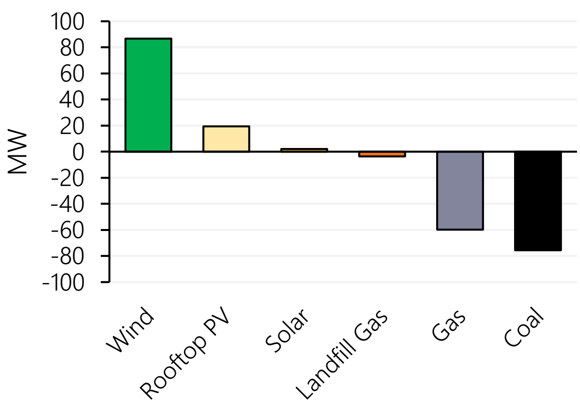
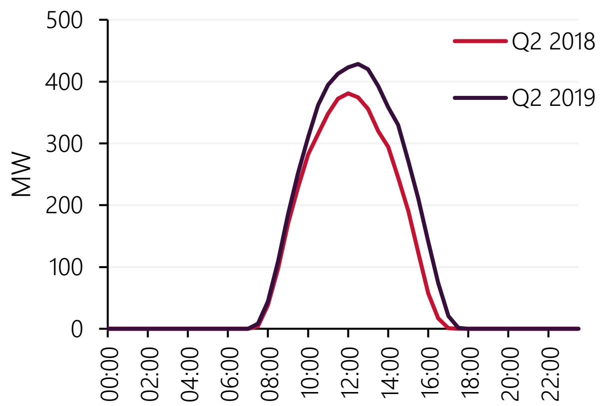


Figure 56 Solar PV increases, mostly in the afternoon

Average solar PV generation throughout the day



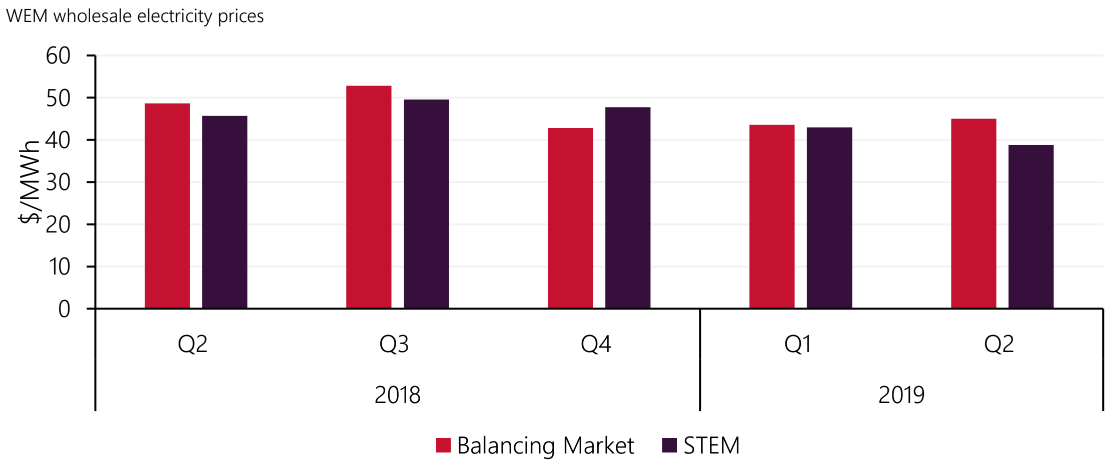
3.3 Wholesale electricity pricing

3.3.1 Balancing and STEM prices

There was a small increase in average Balancing Prices this quarter, which were up 3% compared to Q1 2019. Short Term Electricity Market (STEM) prices were, however, 10% lower than Q1 2019 (Figure 57). This decrease was largely driven by participant bidding behaviour, with STEM supply (offer quantities) increasing by 1%, while STEM demand (bid quantities) decreased by 6%.

When compared to Q2 2018, Balancing Prices were 7% lower, and STEM prices 15% lower. One contributor to these price reductions was fewer baseload generation outages: compared to Q2 2018, the average MW outage per interval of baseload generation facilities was down by 59%. Participant bidding behaviour also contributed to price changes in the past year. On average, the quantity of coal offered at the floor price[43] increased by 19%, while the quantity of gas offered at the floor price increased by 23%.

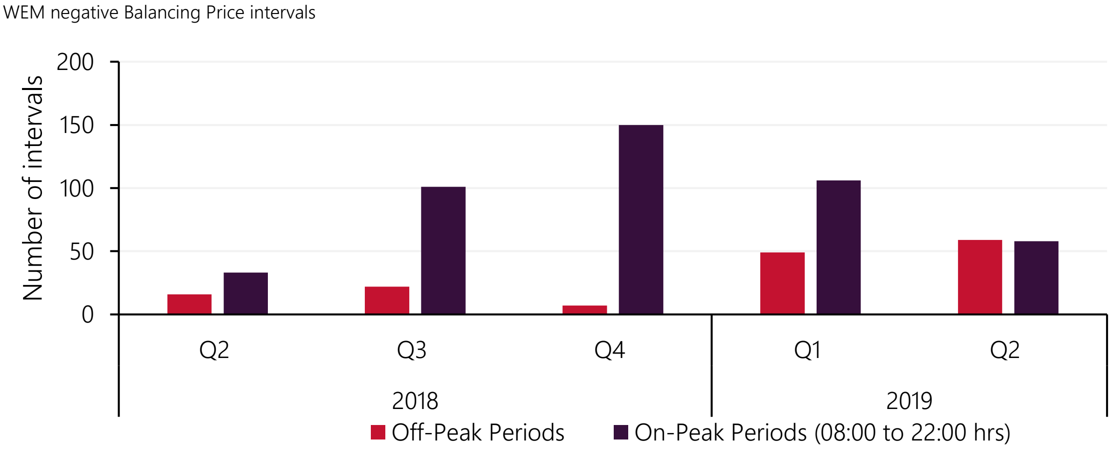
Figure 57 STEM prices reduce



The trend of increasing occurrences of daytime negative Balancing Prices weakened in Q2 2019, with 58 intervals clearing at a negative price during on-peak periods (Figure 58) [44]. This was a decrease of 48 intervals (or 45%) from Q1 2019 and likely due to the seasonal reduction in average solar PV output this quarter.

The lowest Balancing Price in Q2 2019 was -$43.57/MWh[45], and was sustained for two intervals around noon. Over these intervals, Non-Scheduled Generator (NSG) output was around 100 MW and demand relatively low at 1,600 MW.

Figure 58 Reduced negative prices during daytime hours



[43] -$1,000/MWh

[44] Defined as 0800 to 2200 hrs

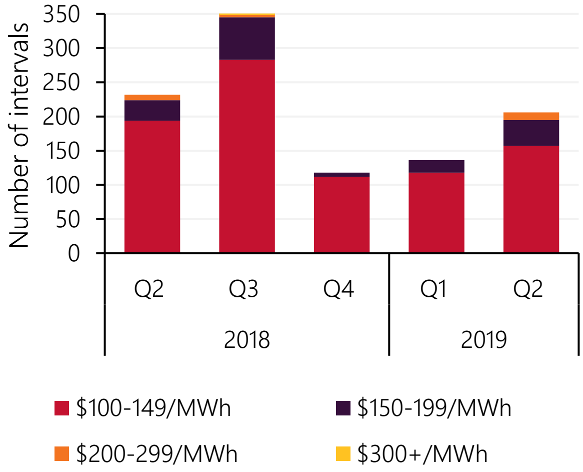
[45] Minimum price of -$43.57/MWh was sustained for two intervals: 1130 & 1200 hrs on Thursday 2 May.

3.3.2 High-priced intervals

During Q2 2019, there was an increased occurrence of high Balancing Prices in the WEM. Compared to Q1 2019, the number of times the Balancing Price cleared at and above $100/MWh increased by 34%, and the occurrence of prices above $150/MWh increased by 170% (Figure 59). Of these high prices, 40% occurred during the morning peak period between 0600 and 0900 hrs.

Figure 59 Increased occurrence of high balancing prices

High Balancing Prices in the WEM (>$100/MWh)



The maximum Balancing Price was $292.68/MW[46], which was the highest Q2 price since 2015 and the highest price so far in 2019. This price is only $10/MWh less than the WEM price cap for non-liquid fuel generators. This high Balancing Price was primarily driven by participant bidding behaviour, with small Price-Quantity Pair tranches (bids of less than 20 MW) in the Balancing Merit Order around the intersection point with the load forecast. When the load forecast intersects with these small Price-Quantity pair tranches, small variations in demand or fluctuations in NSG can cause significant price spikes. In this case, had demand been 100 MW lower, the price would have cleared at just $69/MWh.

The characteristics of this price spike included:

- Demand of 2,699 MW, approximately 35% higher than the average for Q2. This occurred at 0700 hrs during the morning peak demand period.
- Grid-scale NSG online during the interval was relatively low at 167 MW, fulfilling only 6% of demand.
- Coal was the largest fuel online, contributing 49% of generation, followed closely by gas which contributed 46%.
- Capacity was on outage (314 MW), reducing baseload generation capacity by 8% and mid-merit generation capacity by 2%.
- The interval prior cleared a price of only $71.07/MWh, while the following interval had an increase in demand of 30 MW and a decrease in price of $160/MWh.
- The initial price forecast produced at 1800 hrs the day prior forecast the price as $188.91/MWh, and it was not until 30 minutes prior to the interval that the $292/MWh price spike was forecast.

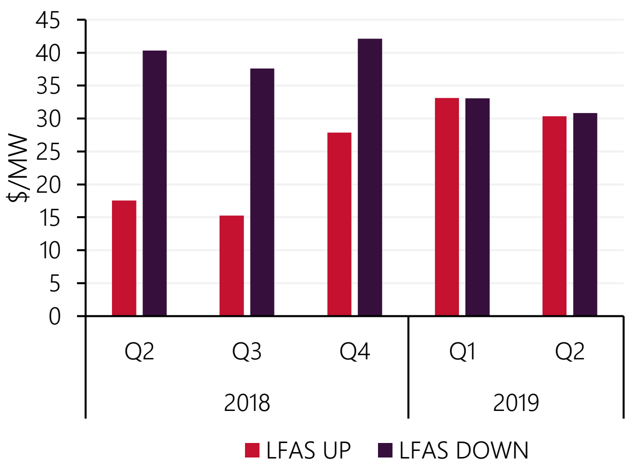
3.3.3 Load Following Ancillary Service prices

In Q2 2019, average LFAS Up and LFAS Down[47] prices both reduced compared to Q1 2018, by 8% and 7%, respectively (Figure 60).

In Q2 2019, LFAS Up and Down prices continued to converge (which occurred for the first time in Q1 2019), reversing the historic trend of LFAS Down being priced higher than LFAS Up. This may be an outcome of the increasing prevalence of negative prices in the Balancing Market, causing generators to pay for energy generated in the provision of LFAS Up.

Figure 60 LFAS price convergence continues

WEM average LFAS prices



[46] 0700 hrs on 28 June 2019

[47] 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.

3.4 Power System on 19 April 2019

On 19 April 2019 (Good Friday), the WEM experienced a period of high volatility, from both a demand and pricing perspective. The main drivers of this event included fast-moving bands of cloud cover and high levels of variable wind output.

As at the end of Q2 2019, one in four households connected to the South West Interconnected System (SWIS) have Distributed Energy Resources (DER)[48] installed, with small-scale PV capacity increasing by 20% in the past year to total over 1.1 GW. The maximum output from rooftop PV on 19 April was 500 MW. Intermittent cloud cover which moved rapidly across the Perth area meant that this DER output was highly variable throughout the day (Figure 61).

Wind speeds of up to 90km/hr led to maximum wind generation of 573 MW, or 94% of total wind generation capacity, making up 32% of system demand[49]. The stormy conditions also meant that wind generation was difficult to forecast and fluctuated significantly throughout the day, dropping to a minimum of 128 MW (Figure 62).

Figure 61 Good Friday solar PV fluctuations

Good Friday PV generation v sunny day

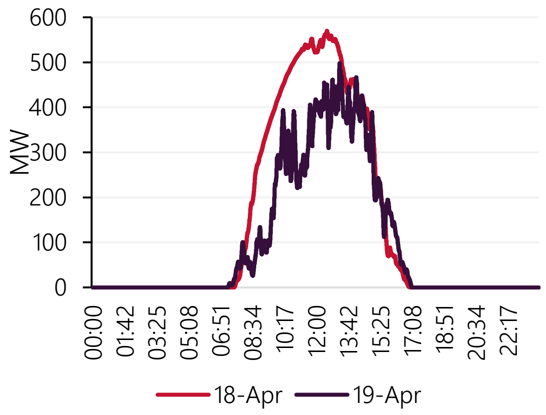
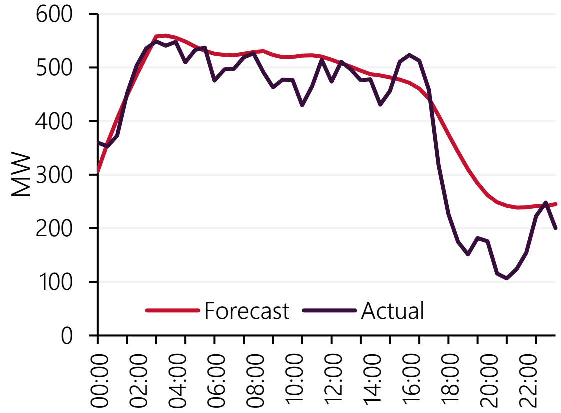


Figure 62 Good Friday wind fluctuations

Good Friday forecast v final wind generation

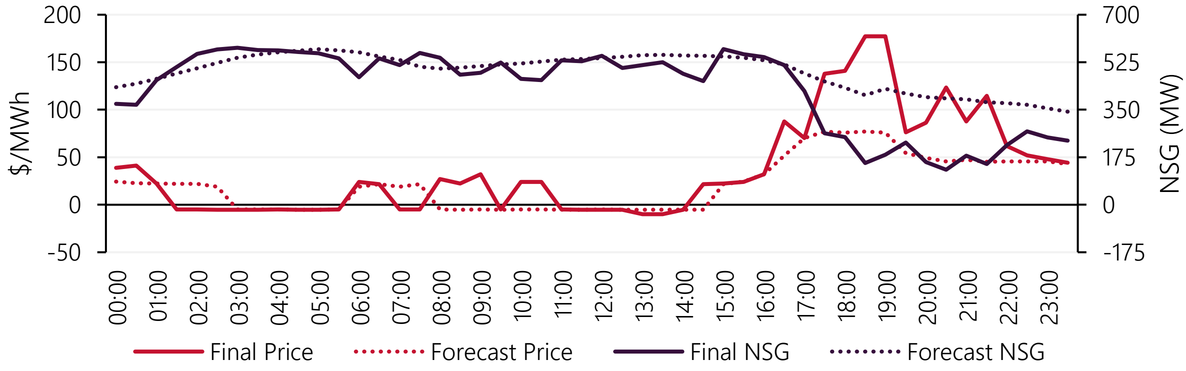


Most sunny days in Q2 2019 cleared with no negative price intervals and only two intervals with a price above $100/MWh. On Good Friday, however, the Balancing Price cleared at negative prices in 19 intervals, and a further eight intervals cleared at a price of over $100/MWh (0).

These variable market outcomes were largely the result of forecasting difficulties, with up to 263 MW less NSG output than forecast. This resulted in variances between forecast and actual Balancing Prices of up to $100/MWh[50]. The high variability between forecast and final prices and NSG meant that the ability of Scheduled Generators to respond to changing conditions was hampered.

Figure 63 Price volatility on Good Friday 2019

Forecast v Final Price and NSG Output 19 April 2019



[48] Primarily rooftop PV installed in the Perth metro area

[49] System Demand excludes behind the meter generation

[50] The Price Cap for non-liquid fuel generators in the WEM is $302/MWh

Abbreviations

Abbreviation	Expanded term
AEMO	Australian Energy Market Operator
ASX	Australian Stock Exchange
AUD	Australian dollars
BBL	Barrel
BESS	Battery energy storage system
CER	Clean Energy Regulator
CCGT	Combined cycle gas turbine
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
GBJV	Gippsland Basin Joint Venture
GJ	GigaJoule
GPG	Gas-powered generation
GSA	Gas supply agreement
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
LY	Loy Yang
MAP	Moomba to Adelaide Pipeline
MSP	Moomba to Sydney Pipeline
MtCO2-e	Million tonnes of carbon dioxide equivalents
MW	MegaWatt
MWh	MegaWatt hour
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NSG	Non-scheduled generation

Abbreviation	Expanded term
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
UIGF	Unconstrained intermittent generation forecast
VRE	Variable renewable energy
WCF	Wallumbilla Compressor
WEM	Wholesale Electricity Market
YTD	Year to date