Quarterly Energy Dynamics

Q2 2018

August 2018

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Important notice

PURPOSE

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q2 2018 (1 April to 30 June 2018). This quarterly report compares results for the quarter against other recent quarters, focussing on Q1 2018 and Q2 2017. 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	15 August 2018	
1a	30 October 2018	Corrected time of directions in the Executive Summary.

Executive summary

Highlights for Q2 2018 include:

- Wholesale electricity and gas prices decreased across most regions and markets compared to Q1 2018.
  - Queensland continued the recent trend of recording the lowest wholesale electricity ($70/MWh) and gas prices ($8.18/GJ) in the east coast.
  - New South Wales electricity prices increased by $12/MWh to $84/MWh due to a reduction in black coal generator availability (1,250 MW lower on average) and associated price volatility in early June.
  - Whilst gas prices were generally lower across most AEMO gas markets during the quarter, prices peaked above $10/GJ in late-June following an unplanned outage at Longford which coincided with a period of high gas-powered generation (GPG) demand in the National Electricity Market (NEM).
- Electricity price reductions were driven by: reduced volatility in Victoria and South Australia; increased renewable output (including hydro) and reduced demand associated with seasonal temperature decreases. In the gas markets, lower GPG – driven by lower electricity prices and reduced LNG exports – contributed to the gas price reductions.
- The weather for Q2 2018 was warmer than average than other second quarters, particularly during April. This, coupled with increased industrial output, contributed to a 2% increase in NEM operational demand compared to Q2 2017.
- Key changes in the electricity supply mix compared to Q2 2017 included:
  - Hydro generation increased across the NEM by approximately 650 MW: Q2 2018 was the highest Q2 on record. This was driven by:
    - Increased output from Tasmania's hydro generators driven by: high rainfall in the hydro catchment areas; outage of Basslink for 72% of the quarter; and unavailability of Tamar Valley CCGT.
    - Mainland hydro generators reducing the price of their market offers to increase dispatch.
  - GPG decreased to its lowest quarterly output since Q4 2016 as it was displaced by higher renewable output.
  - Wind and solar increased output by approximately 700 MW reflecting windier conditions (Q2 2017 was a very low wind quarter) and newly installed capacity. During Q2 2018 there was a continuation of downward price movements for Large-scale Generation Certificate (LGC) spot and forward prices, with the price of calendar year 2020 forward contracts decreasing by 24%.
- AEMO applied directions for system strength in South Australia, to ensure the system remained in a secure operating state, for approximately 60% of time during April and May due to a combination of high wind, low demand and generator outages. Since September 2017, there have been directions in South Australia for approximately 26% of the time.
- Frequency control ancillary service (FCAS) market costs were 157% ($39 million) higher than in Q1 2018, primarily driven by the outage of Basslink for 72% of the quarter.
- Planned maintenance at two of the three Curtis Island LNG facilities reduced quarter LNG exports to their lowest levels since Q3 2016. The South West Queensland Pipeline flowed almost exclusively south, and there were increased flows south along the Moomba to Sydney Pipeline.
- The supply mix in the Wholesale Electricity Market (WEM) in Western Australia remained steady with GPG and black coal continuing to dominate (approximately 90% of total generation).
  - The average wholesale electricity prices in both the Short Term Energy Market (STEM) and Balancing Market decreased in Q2 2018 when compared to Q2 2017 (by $7/MWh and $8/MWh) due to fewer generator outages.
  - In the South West Interconnected System (SWIS), there was a significant (>50%) increase in Constrained Off compensation in Q1 and Q2 2018 compared to Q2 2017 due to planned network outages.

Contents

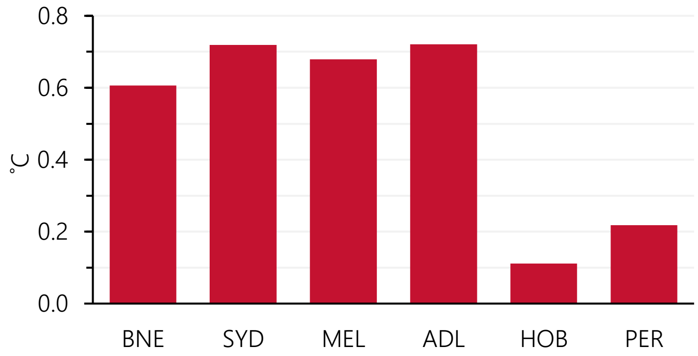
1. Electricity market dynamics

1.1 Weather

Average maximum temperatures in Q2 2018 were warmer than the long-term average[1] for each of the capital cities (Figure 1), driven by the warmest April on record.

Q2 2018 was also a dry quarter, with rainfall across the country 56% lower than the Q2 long-term average. Despite this, key catchment areas for hydro generation in New South Wales and Tasmania received average to above average rainfall.

Figure 1 Variation in Q2 average maximum temperature from the long-term average



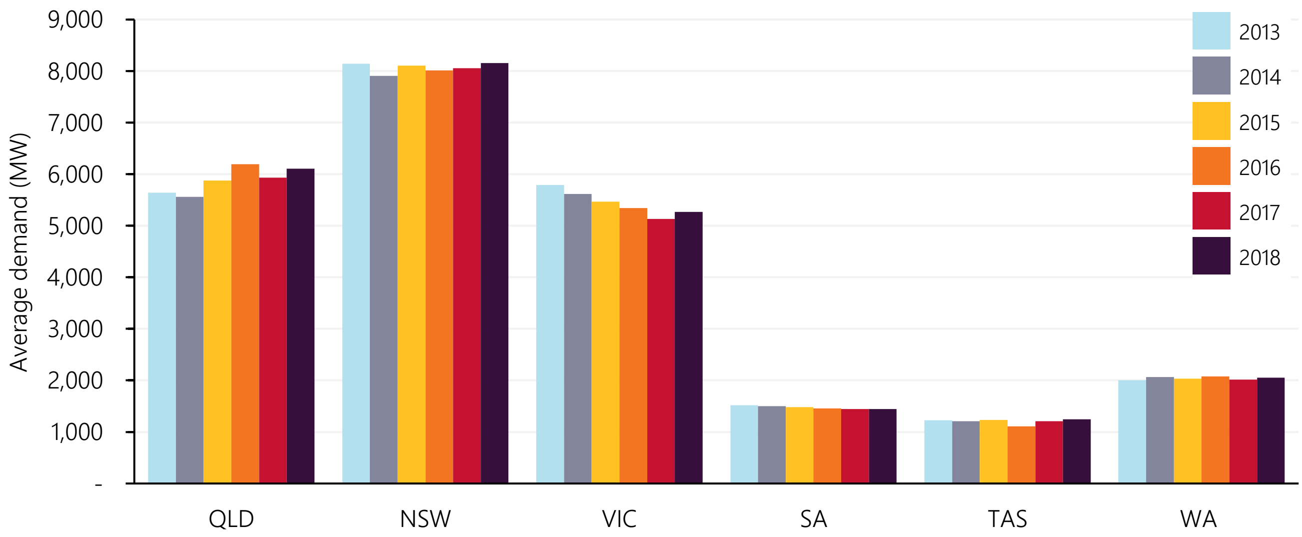
Source: Bureau of Meteorology

1.2 Electricity Demand

In Q2 2018, average electricity operational demand[2] across the NEM increased by 450 MW (or +2.1%) relative to Q2 2017 (Figure 2). From a regional perspective, average operational demand increased in every region except for South Australia.

The increases in Queensland (+174 MW, +2.9%) and New South Wales (+99 MW, +1.2%) were primarily due to warmer temperatures during April which led to increased cooling requirements in both regions. Average operational demand in Victoria increased by 141 MW (+2.8%) compared to Q2 2017, with the main driver being Portland Aluminium Smelter operating at full load compared to Q2 2017 (where its capacity was progressively being restored).[3] Tasmania and Western Australia's WEM recorded slight increases in average operational demand, up 37 MW and 34 MW respectively.

Figure 2 Average operational demand for Q2 (2013 to 2018)



[1] For this report, long-term average is the average of Q2 maximum temperatures over the previous 10 years. For rainfall, long-term average is the average rainfall recorded between 1961 and 1990.

[2] Operational demand refers to the electricity used by residential, commercial and large industrial customers, as supplied by the scheduled, semi-scheduled and significant non-scheduled generating units. More information on demand terms can be found here: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

[3] During Q2 2017, the plant was operating at reduced levels after a power outage in December 2016 curtailed their capacity. A media release from Alcoa referring to the restart of capacity can be found here: http://news.alcoa.com/press-release/corporate/portland-aluminium-smelter-victoria-australia-restart-capacity-lost-after

1.2.1 Maximum and minimum demand

Table 1 outlines the quarter's maximum and minimum demands. Notable events included:

- Queensland recorded its highest Q2 operational demand of 8,171 MW on 18 June 2018 at 1900hrs. This new record was 154 MW higher than the previous Q2 record.
- South Australia recorded its lowest Q2 operational demand on 29 April 2018 at 1230hrs when operational demand fell to 793 MW, 51 MW (-6%) lower than the previous Q2 record. This continues a trend of reduced demand in the middle of the day driven by increased uptake of rooftop PV.[5]

Table 1 Maximum and minimum demand by region – Q2 2018 vs records[4]

Region	Maximum Demand (MW)			Minimum Demand (MW)		
	Q2 2018	All Q2	All-time	Q2 2018	All Q2	All-time
QLD	**8,171**	8,017	9,796	4,709	3,102	2,894
NSW	12,128	13,458	14,744	5,682	4,862	4,636
VIC	7,515	8,267	10,576	3,677	3,401	3,217
SA	2,376	2,498	3,399	**793**	844	584 *
TAS	1,648	1,752	1,790	945	756	552

** Excluding system black event in South Australia (28th September 2016)*

1.2.2 Power system management

Over Q2 2018, AEMO was required to intervene in the market to direct synchronous generation units in order to maintain system strength in South Australia and ensure the grid was in a secure operating state.[6] During April and May, directions were in place for 62% and 70% of the time respectively (Figure 3) driven by high wind, lower operational demand and generator outages, including at Pelican Point. Since September last year, there have been directions in South Australia for approximately 26% on the time on average.

During Q2 2018, curtailments of non-synchronous generation in South Australia increased to around 4.8% of the unconstrained intermittent generation forecast (UIGF, Figure 4).[7] This was driven by high wind conditions and insufficient synchronous generators being available to meet system strength requirements.

Figure 3 Directions for system strength in South Australia

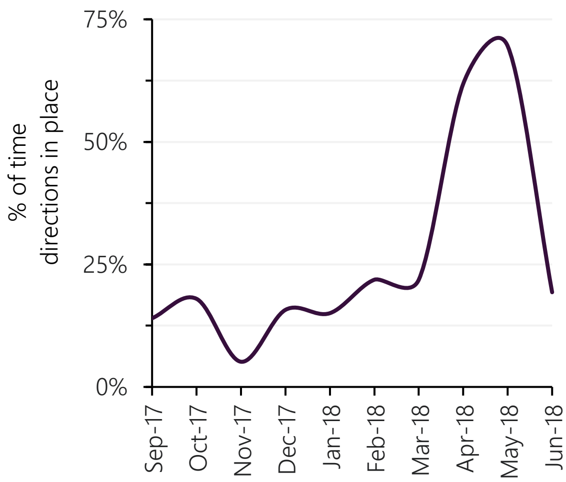
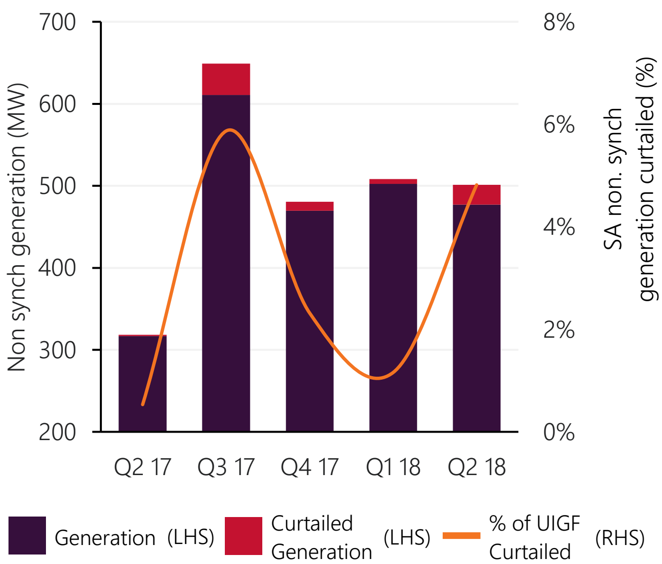


Figure 4 Curtailment of non-synchronous generation



[4] Table records refer to those prior to the commencement of Q2 2018. 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 from May 2005.

[5] More discussion on the changing demand profile can be found: http://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations.pdf

[6] AEMO has specified combinations of synchronous generation units that would provide sufficient system strength. This is available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice

[7] Under National Electricity Rules Clause 3.7B, AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators, in order to schedule sufficient generation in the dispatch process. This is known as the as the UIGF. AEMO estimates UIGF based on the outputs of the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). Further information is available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

A key driver of higher directions in Q2 2018 has been reduced availability at existing synchronous generation units in South Australia (Figure 5). The amount of the time units were online dropped across most of the synchronous generation facilities, especially Pelican Point which was online 77% of the time in Q1 2018 but only 27% in Q2 2018. This has reduced the combinations available to meet minimum system strength requirements and has resulted in directions being required across a wider range of pricing conditions. Figure 5 indicates that during Q1 2018 around 32% of directions occurred at dispatch prices[8] above $70/MWh, with this increasing to 48% in Q2 2018.

Figure 5 SA synchronous generation online[9]

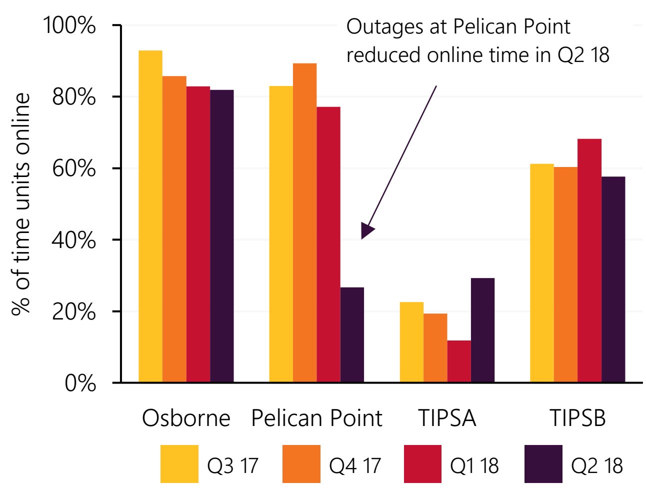
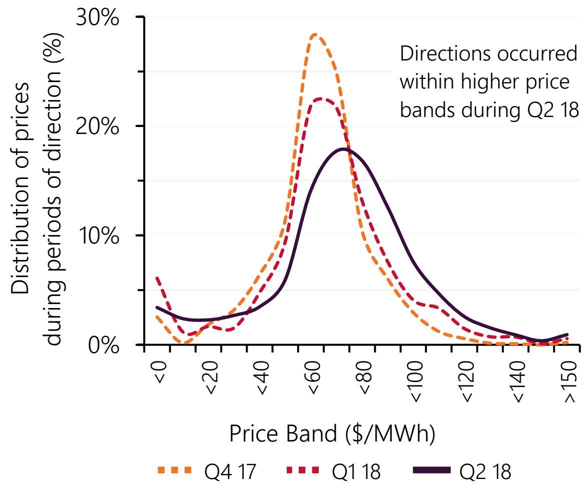


Figure 6 Dispatch prices during periods of direction



1.3 Electricity generation

Q2 2018 was notable for large increases in hydro generation (+663 MW) and variable renewable energy[10] (+703 MW) when compared to Q2 2017 (Figure 7 and Figure 8) which led to the lowest Q2 emissions on record in the NEM. Increased renewable output (including hydro generation) also contributed to a slight decrease in black coal-fired generation (-53 MW) and a considerable decrease in GPG (-697 MW).

Figure 7 Quarterly electricity supply mix

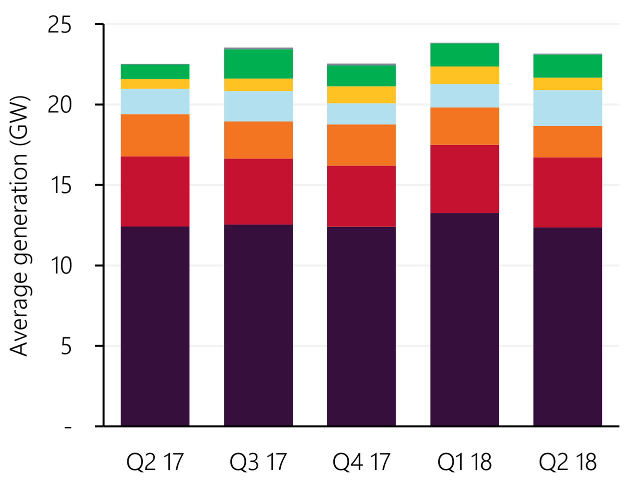
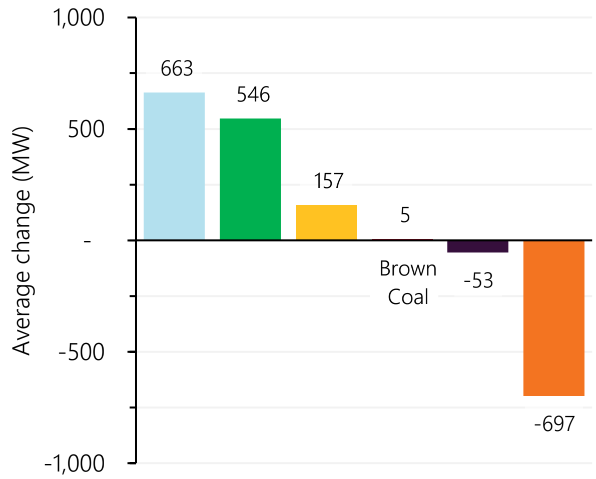


Figure 8 Change in supply – Q2 2018 vs Q2 2017



** Solar includes both large-scale solar and rooftop PV.*

[8] Dispatch prices refers to what the price would have been if the directed units had been committed (i.e. it backs out the impact of intervention pricing). It is represents the opportunity cost or lost spot revenue of not committing the units on a commercial basis.

[9] The percent of time online for fast-start synchronous units in SA (Mintaro, Dry Creek and Quarantine Power Station 5) have not been shown as these units have not been directed for any significant period of time (comprising less than 0.1% of all energy directed to date in SA). The percent of time plants were online has been adjusted to remove the effect of directions.

[10] Includes large-scale wind and solar, and rooftop PV.

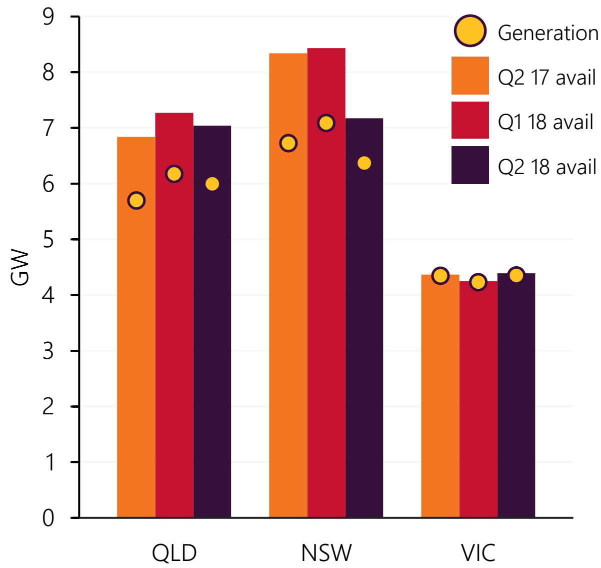
1.3.1 Coal

During the quarter, average black coal-fired generation reduced compared to recent quarters, driven by a large number of planned and unplanned outages of the black coal fleet in New South Wales (Figure 9). The New South Wales fleet recorded its lowest availability since Q4 2016, largely due to extended unit outages at Bayswater and Eraring power stations.[11] Average output at these power stations reduced by 314 MW and 282 MW respectively compared to Q2 2017.

A combination of planned and unplanned outages across the fleet during the week of 4-10 June resulted in very low black coal-fired generator availability. Tight supply conditions during this week contributed to electricity price volatility and higher New South Wales prices over the quarter (see Section 1.4).

Results for the Queensland black coal-fired fleet were mixed, recording increased availability and generation compared to Q2 2017, but a slight reduction in generation compared to Q1 2018. The largest increases in generation compared to Q2 2017 were at Gladstone and Millmerran power stations (+297 MW and 288 MW, respectively), reflecting increased availability at lower prices.

Figure 9 Coal availability and generation

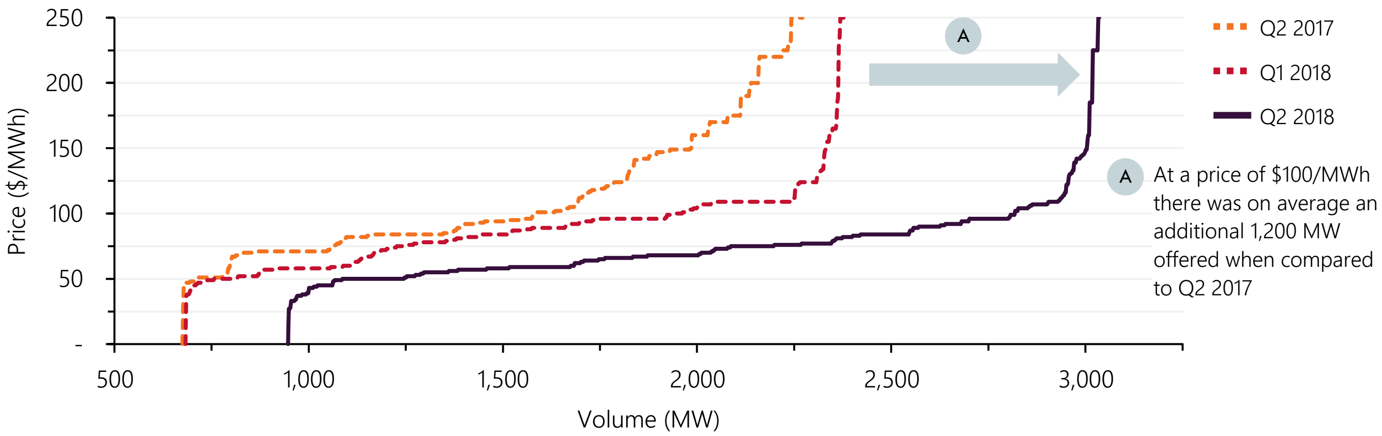


Brown coal-fired generation was steady compared to Q2 2017, reflecting few outages during the quarter. The one exception was at Yallourn Power Station which had at least one unit on a planned outage for 75% of the quarter.

1.3.2 Hydro

Hydro generation substantially increased in Q2 2018, 663 MW higher (+43%) on average than in Q2 2017, representing the highest average hydro generation since Q4 2016. This is due to the significant shift in the supply curve for hydro units with an additional 1,200 MW offered below $100/MWh compared to Q2 2017 (Figure 10). The additional supply meant that this quarter was the highest Q2 hydro output on record and the fifth highest quarter since NEM start.

Figure 10 Bid supply curve – NEM Hydro



The largest increase in hydro generation occurred in Tasmania (+370 MW), due to the outage of the Basslink interconnector during April and May, which meant that Tasmania was reliant on local generation. In addition, withdrawal of Tamar Valley CCGT (Section 1.3.3) from the market for the whole quarter increased reliance on local hydro capacity to meet demand. In line with local rainfall patterns, the majority of increased hydro generation came from the Gordon, Mersey Forth and Pieman schemes.

New South Wales and Victoria also recorded increased hydro generation (175 MW and 81 MW respectively) driven predominantly by increased availability of lower priced capacity from Snowy Hydro – Upper Tumut increased generation by 124 MW and Murray increased by 62 MW. Cumulative hydro generation from Snowy Hydro in 2018 to date is only slightly behind the levels of generation recorded in 2016 – a year of record generation from Snowy where they created 1.9 million Large-scale Generation Certificates (LGCs).[12]

[11] It is typical for a greater number of planned outages to be scheduled for the lower demand 'shoulder' seasons of Autumn and Spring.

[12] Snowy Hydro Annual Report 2017: https://drive.google.com/file/d/1CEPDcrCzq6ydxCTrTzXo6GCT6idj2Cm_/view

1.3.3 Gas-powered generation

GPG output has reduced markedly from its elevated levels in 2017, with Q2 2018 recording the lowest GPG output in the NEM since Q4 2016. Compared to Q2 2017, GPG reduced by approximately 700 MW, with reductions occurring in all NEM regions (Table 2). Drivers of reduced GPG included: reduced availability due to outages; lower wholesale electricity prices (Section 1.4) and increased hydro output. Compared to Q2 2017 there was a 587 MW reduction in GPG capacity offered below $100/MWh.

Table 2 GPG output – Q2 2018 vs Q2 2017

Region	Q2 2017 (MW)	Q2 2018 (MW)	Change (MW)
QLD	886	821	▼ 65
NSW	295	127	▼168
VIC	462	284	▼ 178
SA	831	708	▼122
TAS	168	5	▼163
TOTAL	**2,642**	**1,945**	**▼697**

By station, the largest output reductions were at:

- Mortlake Power Station (-163 MW), with a 36% reduction in availability compared to Q2 2017 due to outages.
- Tamar Valley CCGT (-157 MW), due to Hydro Tasmania withdrawing it from the market at the end of summer.[13] This is consistent with recent operation of the plant, which is typically only available over summer (a drier period in Tasmania).
- Pelican Point (-127 MW), driven by a planned full station outage for almost half the quarter.

1.3.4 Wind and solar

Compared to Q2 2017, average large-scale[14] wind and solar generation in Q2 2018 increased from 954 to 1551 MW (+63%), making up 7% of the supply mix over the quarter compared to 4% in Q2 2017.

Wind generation was up an average of 546 MW (+61%): 392 MW of this increase came from existing wind farms due to improved wind conditions (Q2 2017 had comparatively low wind conditions), with the remainder (154 MW) coming from new capacity which has commenced generation since Q2 2017.

Large-scale solar generation increased by 51 MW (+82%) as additional capacity was brought online. Since Q2 2017 580 MW of capacity has commenced generation, with 450 MW starting generation in Q2 2018 (Table 3).

Figure 11 Average wind and solar generation by region

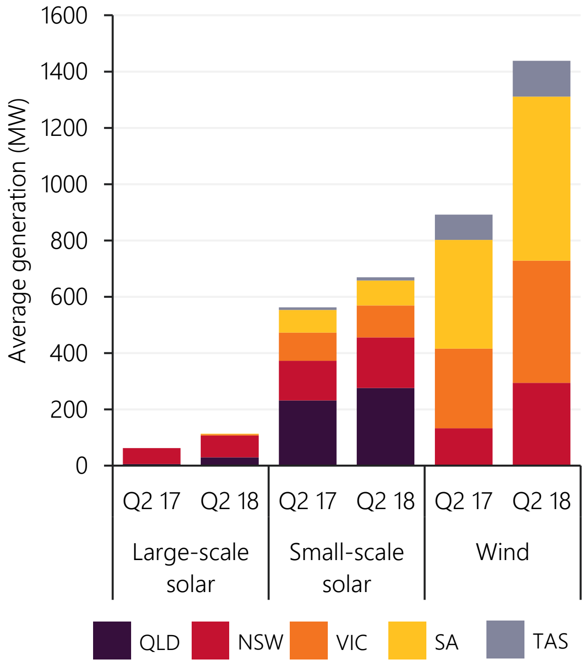


Table 3 New entrants[15] in the NEM in Q2 2018

Region	New entrant	Capacity (MW)	Fuel Source
NSW	Manildra Solar Farm	46.7	Solar PV
	Silverton Wind Farm	193	Wind
	Griffith Solar Farm	27	Solar PV
QLD	Sun Metals Solar Farm	107	Solar PV
	Clare Solar Farm	100	Solar PV
	Longreach Solar Farm	14	Solar PV
SA	Bungala One Solar Farm	110	Solar PV
VIC	Gannawarra Solar Farm	50	Solar PV
	Mt Gellibrand Wind Farm	132	Wind
	Salt Creek Wind Farm	54	Wind

[13] Tamar Valley CCGT remains available for recall at less than three months' notice.

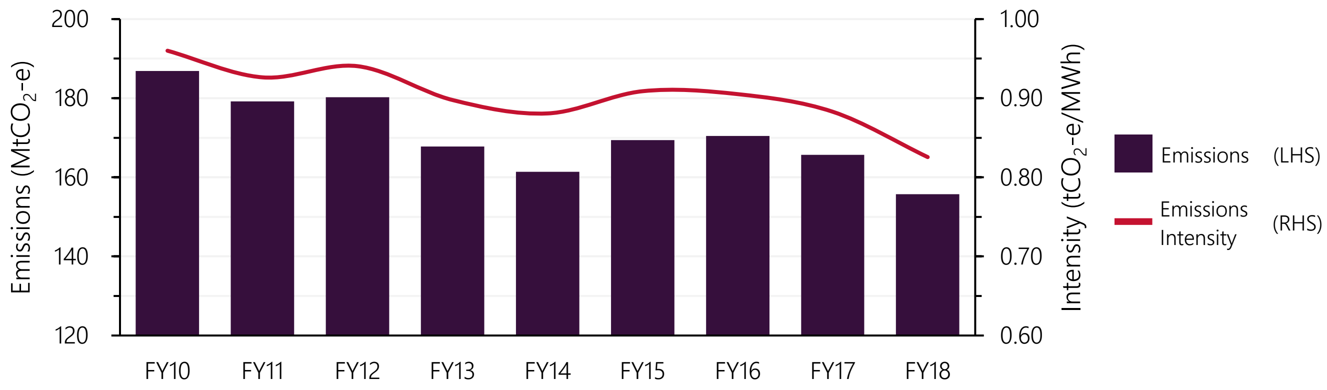
[14] Large-scale generation includes market generators (a generator which sells all of its sent-out electricity through AEMO's market) and non-market generators with registered capacity equal to or greater than 30 MW.

[15] 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.

Average Q2 2018 rooftop PV generation increased from 562 MW to 669 MW (+19%) when compared to Q2 2017 (Figure 11). The largest increase was in New South Wales (+27%), with Queensland (+19%), Tasmania (+18%), Victoria (+13%), and South Australia (12%) also experiencing large increases. The daily maximum average generation[16] increased from 2,216 MW to 2,637 MW (+19%) between quarters. These changes correspond with a record amount of installed rooftop PV capacity over 2017 (+1.06 GW) and an additional estimated 500 MW installed as at the end of Q2 2018.[17]

Annual NEM emissions for the 2018 financial year were the lowest on record[18], in terms of both absolute emissions and emissions intensity (Figure 12). Drivers behind the downward trend in annual emissions include the closure of Hazelwood Power Station and increased renewable generation.

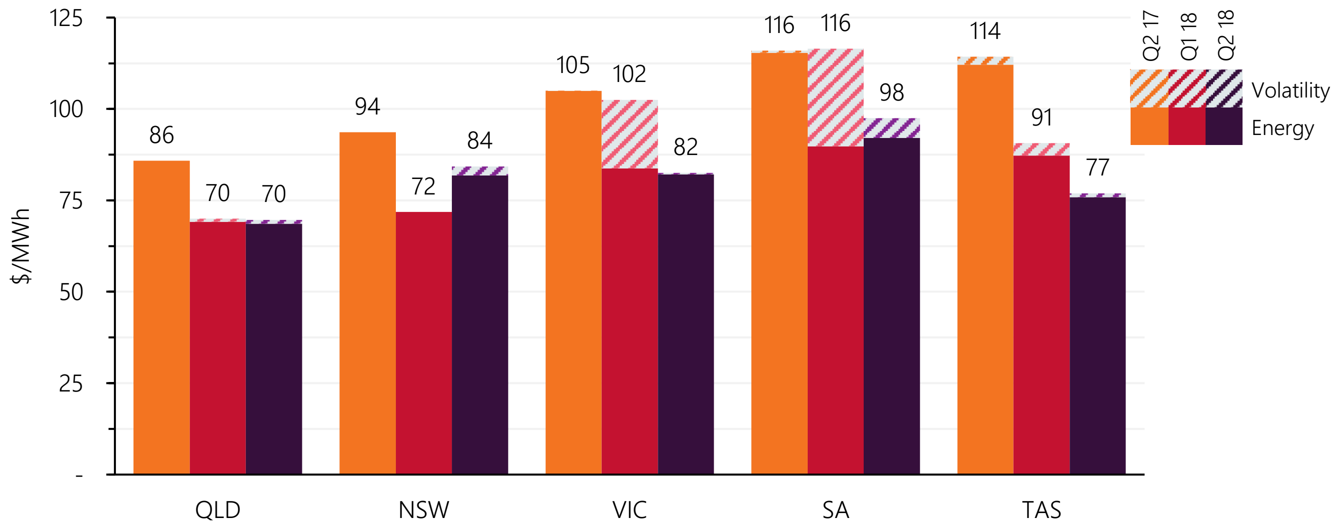
Figure 12 NEM annual emissions and emissions intensity



1.4 Wholesale electricity prices

During Q2 2018, wholesale electricity prices reduced across most NEM regions compared to previous quarters reflecting increased availability of comparatively lower priced supply. Queensland was the lowest priced region for the fifth consecutive quarter with an average wholesale electricity price of $69.69/MWh, while the highest priced region was South Australia at $97.50/MWh (Figure 13). Overall, average prices in Victoria, South Australia and Tasmania reduced by $13-20/MWh when compared to Q1 2018, but increased in New South Wales (+$12/MWh). Table 4 provides a summary of the price drivers during the quarter.

Figure 13 Average wholesale electricity price by region



Note: The average quarterly price is broken up into two parts, energy and volatility. Volatility refers to the contribution of high priced events (above $300/MWh) to the average price more commonly known as cap returns. 'Energy' is therefore the remainder.

[16] The maximum rooftop PV generated across a 30-minute trading interval each day averaged across the quarter.

[17] CER 2018. http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations - As a 12 month creation period for small-scale technology certificates applies, Q2 installed capacity figures will continue to rise for up to 12 months.

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

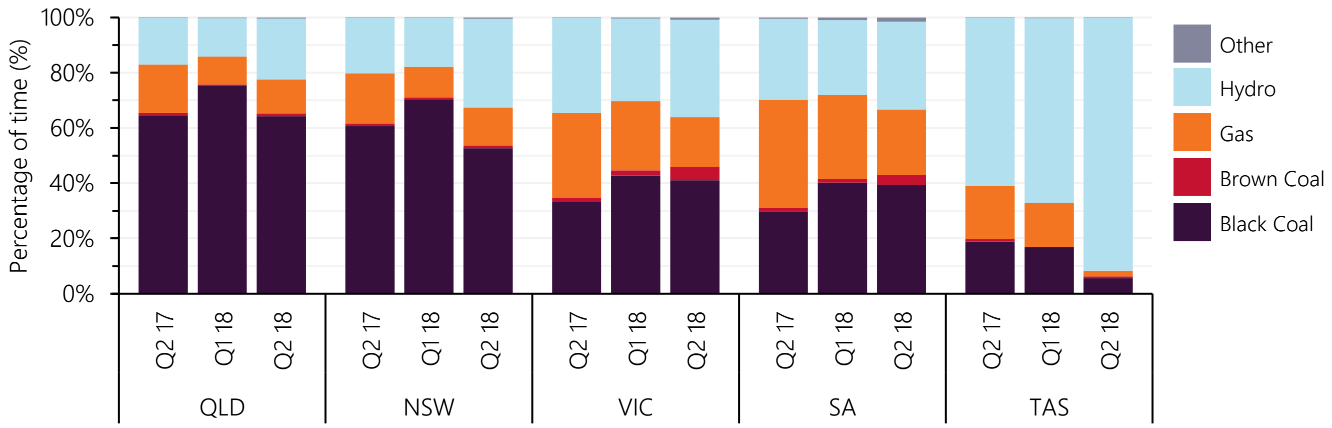
Table 4 Wholesale electricity price drivers in Q2 2018

Consistently lower prices in QLD	The main contributor to this trend was continuation of the impact of the Queensland Government's instruction to state-owned generators to "undertake strategies to place downward pressure on wholesale price"[19] . During the quarter the Queensland black coal-fired fleet maintained comparatively high generation and availability – see Section 1.3.1 for further details.
Lower prices in VIC, SA and TAS	The key drivers for this were: • Increased availability of lower-priced hydro capacity – see Section 1.3.2 for further details. • Increased wind generation compared to Q2 2017 (and a slight increase on Q1 2018 levels) – see Section 1.3.4 for further details. • The price volatility during Q1 2018 was largely absent during the quarter, with combined cap returns[20] decreasing from $45/MWh in Q1 2018 to $6/MWh due to fewer periods of high demand in Victoria and South Australia. The majority of cap returns in South Australia in Q2 2018 occurred in only a small number of trading intervals[21] where wind generation was low (or following a sudden decrease in wind output).
Higher prices in NSW	Higher prices during the quarter were a function of reduced black coal-fired generation and availability, particularly in June (Section 1.3.1). Prices in June were above $150/MWh for 8.6% of the month compared to about 2% in April and May.

1.4.1 Price setting trends

The wholesale price setting dynamics in Q2 2018 were representative of the shifts in the supply mix, with hydro generation setting the price more often than in previous quarters in all NEM regions. Figure 14 highlights the changes in price setting outcomes compared to Q1 2018 and Q2 2017.

Figure 14 Price setting by fuel type – Q2 2018 vs prior quarters



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

Compared to Q1 2018, greater hydro availability resulted in an increase in the price setting role for hydro. The largest mainland increase was in New South Wales where price setting by hydro increased from 18% to 32%. This corresponded with black coal's reduced role as the marginal fuel type, dropping from 70% to 53%. In Victoria and South Australia, increased price setting from hydro was offset by reduced GPG as the marginal fuel type. Black coal remained the dominant price setting fuel type in the NEM despite its reduced role compared to Q1 2018.

In Tasmania, the Basslink outage (Section 1.5) meant that Tasmania's wholesale price was set locally 88% of the time compared to previous quarters where its price was set inter-regionally around half the time. Given Tasmania's supply mix, with Basslink out and Tamar Valley CCGT out of service for the entire quarter, hydro generation set the price 92% of the time in Q2 2018 compared to 60% of the time in previous quarters.

[19] More details on the Queensland instruction can be found here: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland

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

[21] The cap returns from 10 trading intervals contribute to 95% of the total quarterly cap returns in South Australia.

1.4.2 Electricity futures markets

Over Q2 2018 ASX Energy calendar year (Cal) 2019 swap prices recorded small increases in most NEM regions (Table 5), reversing recent downward price trends. Over the same period Cal 2020 products continued to fall in price.

This resulted in a growing separation between ASX Energy Cal 2019 and 2020 swap contract prices. In Victoria the price gap between products grew from $4 to $16/MWh over the quarter (Figure 15) with similar changes occurring in New South Wales and Queensland.

The growing separation between years has coincided with:

- Increased market sentiment that a significant amount of new renewable capacity will enter the market by 2020. This is reflected in falling Large-scale Generation Certificate forward prices (Section 1.4.4).
- High hydro output in the first half of 2018 which could see reduced dam levels in the lead in to 2019 (Section 1.3.2).

Table 5 Change over Q2 2018 for Cal 19 and Cal 20 swap prices

Region	Cal 19	Cal 20
QLD	▲ $0.98 (2%)	▼ $8.14 (13%)
NSW	▲ $1.98 (3%)	▼ $9.37 (13%)
VIC	▲ $0.58 (1%)	▼ $11.90 (16%)
SA	▼ $2.84 (3%)	▼ $12.72 (15%)

Q1 2019 cap prices were up in Victoria (+28%), New South Wales (+22%) and South Australia (+16%), despite falls in volatility in most regions over the quarter (Figure 16). The price increases reflect market sentiment that volatility may increase over the upcoming summer.

Figure 15 ASX energy – VIC swap prices

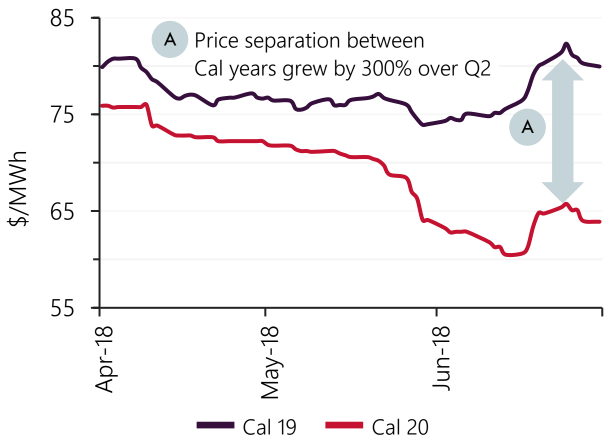
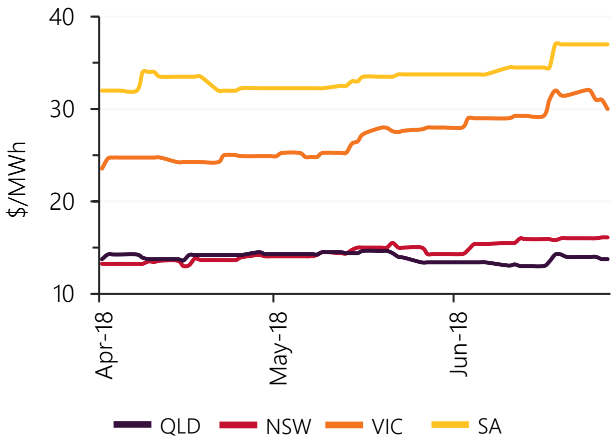


Figure 16 ASX Energy Q1 2019 cap prices



1.4.3 International coal and prices

The spot price for Australian Newcastle thermal coal continued to climb over Q2 2018, averaging AUD$140/tonne, its highest level since early 2012. High prices continue to be driven by strong Asian demand due to a combination of strong economic growth, supply constraints in China and peak North Asian demand over a hot summer.[22]

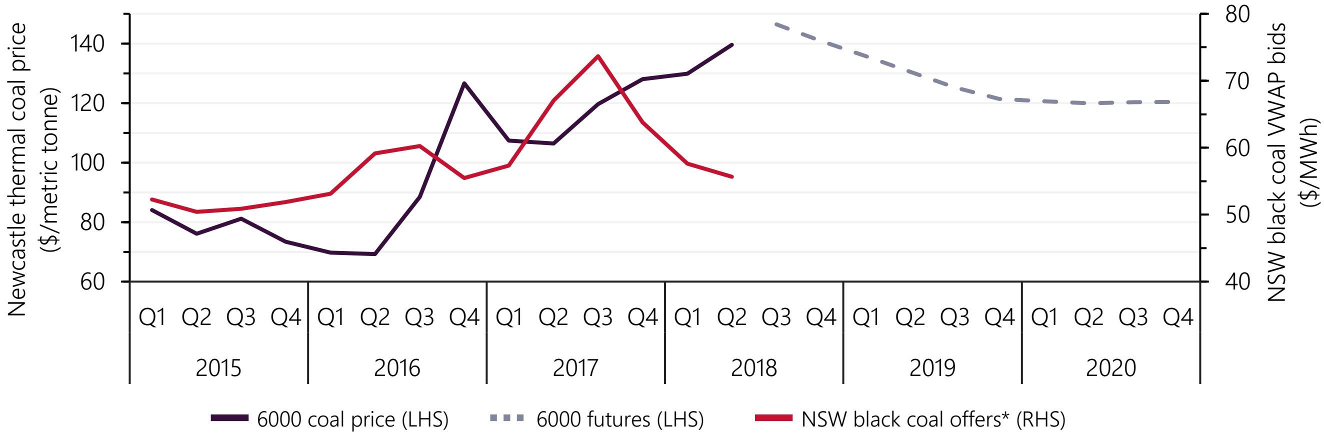
Strong underlying demand is also showing in the forward market, where coal futures prices remain above $100 per tonne beyond 2018. The increase in thermal coal prices appears to be impacting some large domestic energy consumers, with Rio Tinto reporting in its Q2 production results that "*higher than expected power costs have been experienced in Australia due to higher coal prices impacting power contracts*".[23]

Continuing the Q1 2018 trend, high international coal prices were not correlated with higher electricity price offers from black coal-fired generators and in fact they fell during the quarter (Figure 17).

[22] Reuters 2018. Available online: https://www.reuters.com/article/us-coal-asia-australia/australian-coal-prices-hit-6-year-high-as-asia-demand-spikes-idUSKCN1J40C9

[23] Rio Tinto 2018. Pg 4. Available online: https://www.riotinto.com/documents/180717_Rio_Tinto_releases_second_quarter_production_results.pdf

Figure 17 Quarterly average international black coal spot and futures prices and domestic coal-fired generators' offers

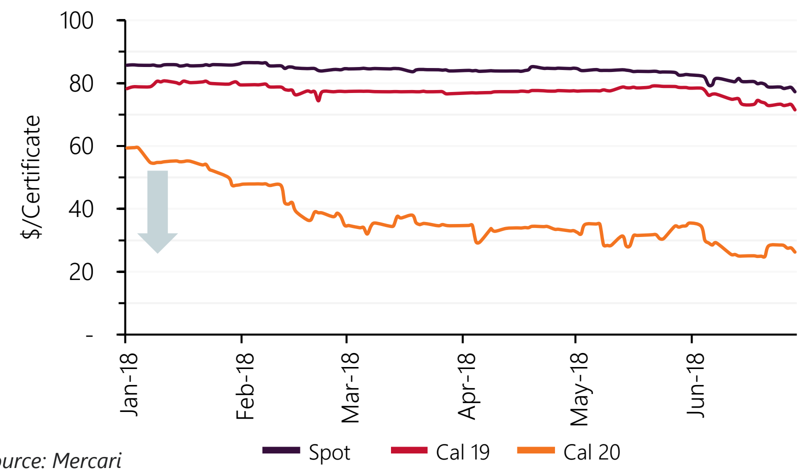


Source for Newcastle thermal spot and futures prices: Bloomberg
** Black coal offers are the volume-weighted average price of offers priced between $40-$120/MWh*

1.4.4 Environmental Markets

During Q2 2018 there was a continuation of downward price movements for LGC spot and forward prices. The largest price drops were in Cal 2020 (-24%) and Cal 2021 (-44%) forward contracts (Figure 18).[24] Falling prices over Q2 2018 are part of longer term trend with Cal 2020 and 2021 forward contracts down 56% and 65% respectively since the beginning of the year. These falling prices reflect growing market certainty that new renewable build will lead to sufficient LGC supply to meet demand required under the Large-scale Renewable Energy Target (LRET) by 2020.

Figure 18 LGC spot and forward prices since January 2018



Source: Mercari

Table 6 LGC prices

Product	Change over Q2 18
Spot	▼ $6.63 (8%)
Cal 18	▼ $7.55 (9%)
Cal 19	▼ $5.13 (%)
Cal 20	▼ $8.38 (24%)
Cal 21	▼ $14.00 (44%)

1.4.5 Frequency control ancillary services

In Q2 2018, FCAS costs increased by $39m (+157%) compared to Q1 2018, returning to above Q4 2017 levels (Figure 19). Of the increases, the majority occurred in the contingency raise markets, increasing from $15m to $49m. Total FCAS costs were the second highest quarter on record and the highest quarter on record in the Raise 60 Second and Raise 5 Minute markets.

While previous cost changes were primarily supply-side driven,[25] a confluence of supply- and demand-side factors contributed to the Q2 2018 results (Figure 20). Of note, the cost increases were despite new supply entering the markets during the quarter – Hydro Tasmania registered 105 MW of demand response in the Raise 6 Second market.

[24] The forward price curve is based on a 'Mid-Point Index' - the mid-point between a recorded bid and offer. The gap between bid and offers for 2021 LGC forward contracts can be large and the product infrequently traded.

[25] AEMO 2018. Quarterly Energy Dynamics – Q1 2018. www.aemo.com.au/Media-Centre/AEMO-publishes-Quarter-Energy-Dynamics---Q1-2018

Figure 19 Quarterly FCAS costs by service

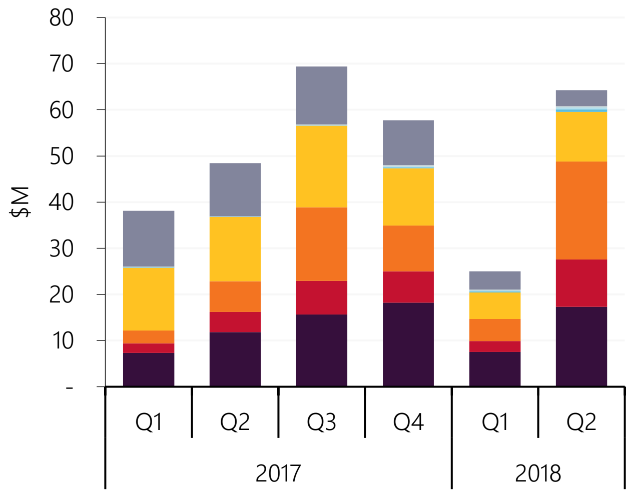


Figure 20 FCAS demand – March to June 2018

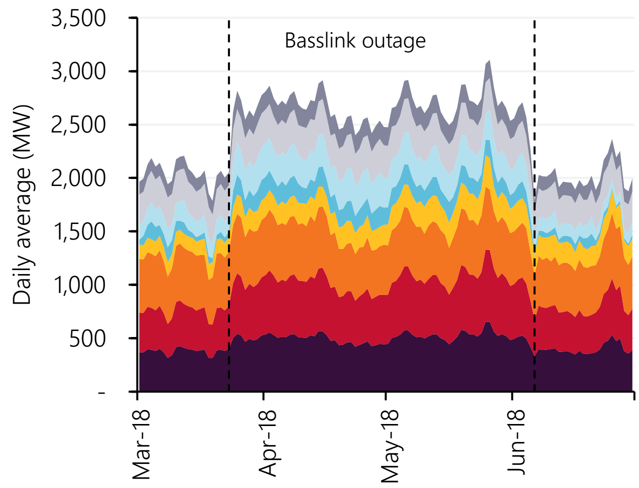


Table 7 FCAS price drivers in Q2 2018

Increased demand	AEMO's total FCAS demand increased by 472 MW (+23%) in Q2 2018 compared to Q1 2018. The largest increases were in the Raise 6 Second and Raise 60 Second markets. Drivers included: • Basslink outage – during the Basslink outage AEMO was required to enable local FCAS in Tasmania in addition to the usual FCAS requirements. This had the practical effect of increasing total FCAS demand by 32% during the outage (Figure 20). • Pelican Point credible contingency – for four days AEMO reclassified the simultaneous loss of Pelican Point GT 12 with any other generating unit as a credible contingency event. This increased demand for contingency Raise FCAS by around 10% during these periods. • Increased time error resulting in increased enablement of Regulation FCAS.[26]
Reduced supply	In Q2 2017 there was a reduction in availability of lower priced FCAS supply, particularly in the Raise markets. For example, in the Raise 5 Minute market there was a 119 MW reduction in offers below $10/MWh compared to Q1 2018. Contributors to reduced FCAS supply included: • Basslink outage – Hydro Tasmania typically supplies about 10-20% of the NEM's total Raise FCAS requirements. The extended outage of Basslink during the quarter (see Section 1.5) meant that Tasmania's supply was not available to mainland regions. • Wivenhoe maintenance – Wivenhoe Hydro Power Station typically provides the second largest amount (approximately 80 MW or 20%) of Raise 5 Minute FCAS in the NEM. Wivenhoe was unavailable to provide FCAS for most of the quarter, which coincided with a major overhaul of one of its two units.[27] • Outages of units at key FCAS providing power stations, including Bayswater, Eraring and Vales Point power stations.

1.5 Inter-regional flows

Total electricity flows during the quarter increased by 5% compared to Q1 2018, despite extended outages of Basslink and Murraylink (for 72% and 31% of the quarter, respectively). This was primarily a function of decreased black coal-fired generator availability in New South Wales which reduced generation in the region and consequently increased New South Wales' electricity imports by 63%.

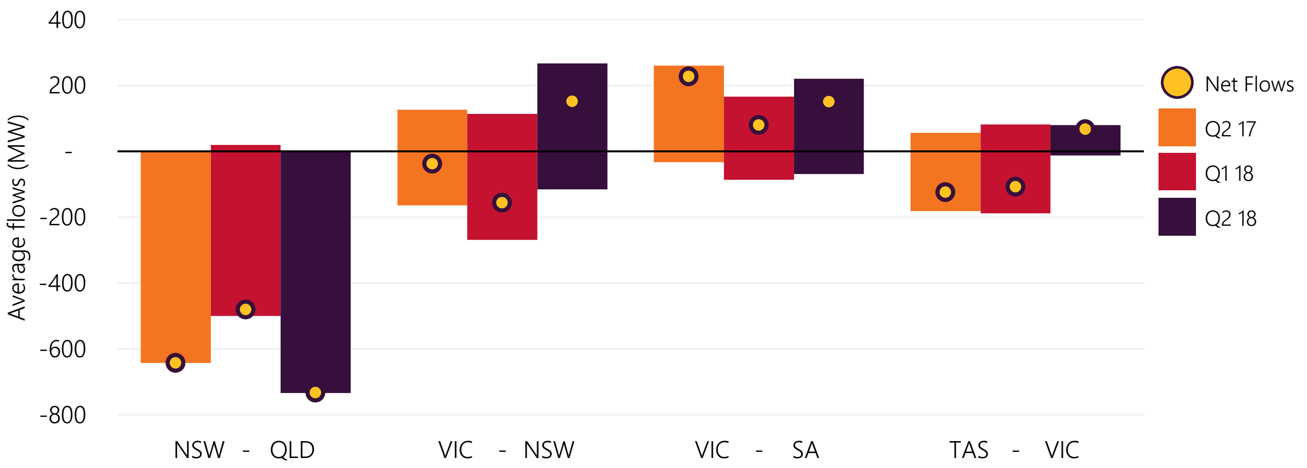
[26] Constraint equations are used to control mainland accumulated time error by varying the amount of Regulation FCAS enabled. Accumulated time error means in respect of a measurement of system frequency that AEMO uses for controlling system frequency, the integral over time of the difference between 20 milliseconds and the inverse of that system frequency, starting from a time published by AEMO.

[27] www.csenergy.com.au/news/cs-energy-services-queensland-s-largest-battery

On a regional basis (Figure 21):

- Average flows from Queensland to New South Wales in Q2 2018 increased by 252 MW (52%) compared to Q1 2018.
- The prevailing flow on the Victoria to New South Wales interconnector during the quarter was into New South Wales (152 MW), representing a 308 MW swing in transfers when compared to Q1 2018 results.
  – Wind output is increasingly a driver of flows on the Victoria to New South Wales interconnector. During Q2 2018, at times of high Victorian wind output (greater than 500 MW), there was a flow north of 400 MW north on average. This reduced to 0 MW (net average) when Victorian wind output was below 500 MW.
- In Q2 2018 average flow was from Victoria to South Australia, which also reflects prevailing flow in Q2 2017 and Q1 2018. Average flow increased by 72 MW compared to Q1 2018.
- The Basslink interconnector was on an outage for 72% of the quarter, with flows reduced to zero during the outage. During the period Basslink was in service, flows were heavily north, primarily driven by high output from hydro generation in Tasmania (see Section 1.3.2).

Figure 21 Quarterly inter-regional transfers in the NEM

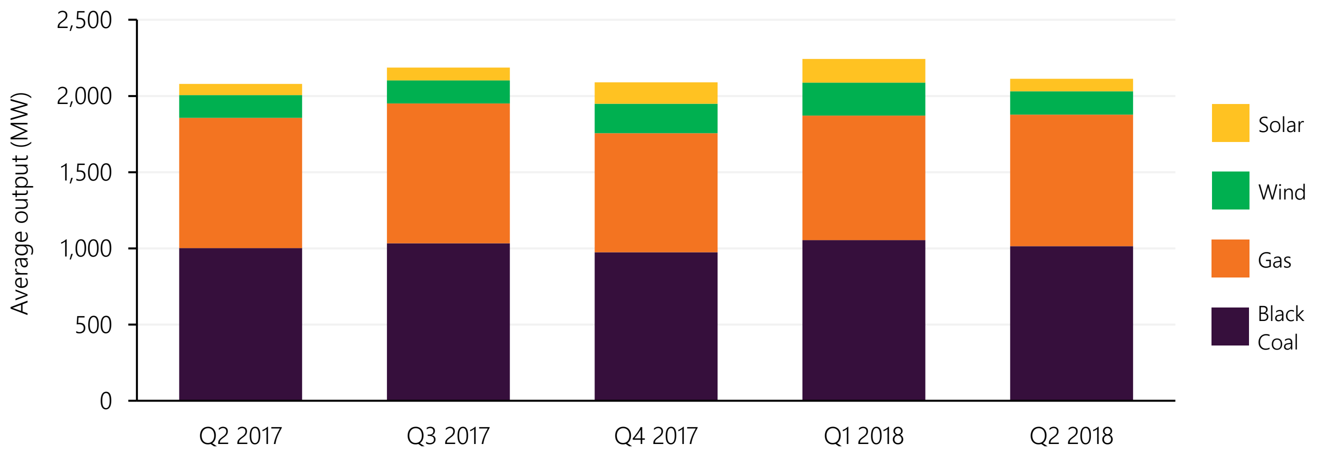


1.6 Wholesale Electricity Market in Western Australia

1.6.1 WEM generation

In the Wholesale Electricity Market (WEM), the electricity fuel mix in Q2 2018 remained in line with Q1 2018 and Q2 2017 results, with black coal-fired generation and GPG dominating the supply mix (approximately 85% of the total, Figure 22). Coal-fired generation was steady with reduced generation from Muja and Collie power stations offset by increased generation at Bluewaters Power Station. The remaining supply largely consisted of wind (7%) and rooftop PV (3.6%) output, both of which increased slightly compared to Q2 2017.

Figure 22 WEM electricity supply mix



1.6.2 WEM wholesale electricity prices

The average wholesale electricity prices in both the Short Term Energy Market (STEM) and Balancing Market decreased in Q2 2018 when compared to Q2 2017 by $7/MWh and $8/MWh, respectively (Figure 23). This was due to fewer outages in Q2 2018, with increased availability of lower cost generation. During Q2 2018, the Synergy balancing portfolio[28] set the Balancing Market price for 71% of the trading intervals, compared to 84% of the trading intervals in Q2 2017 (Figure 24).

Figure 23 WEM wholesale electricity prices

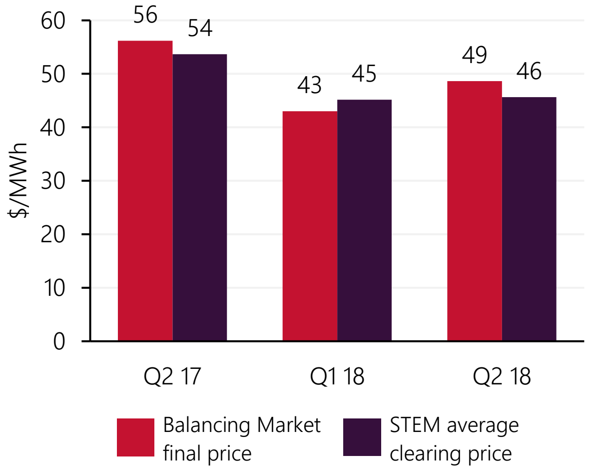
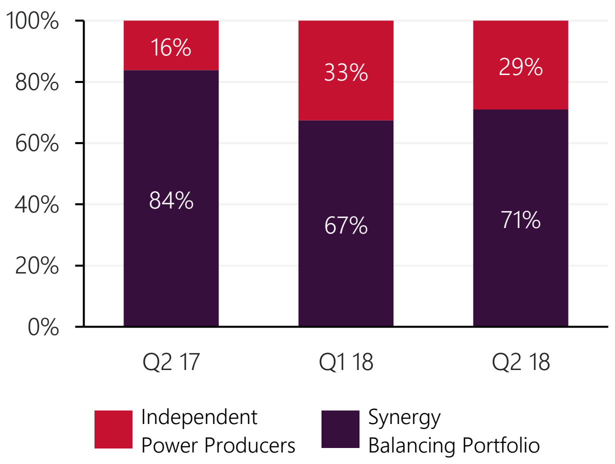


Figure 24 WEM balancing market price setters



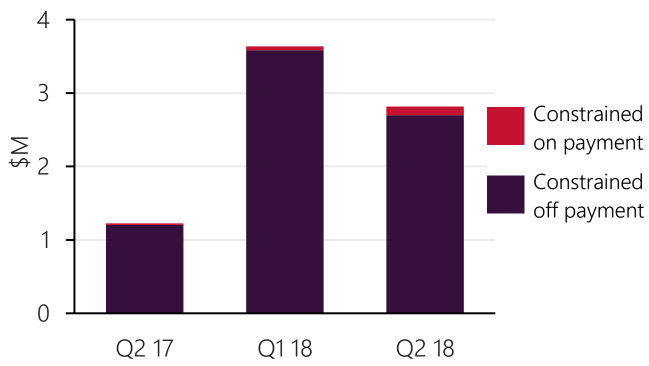
The majority of electricity traded in the WEM is through bilateral contracts and variation between quarters tends to be minimal. In Q2 2018, the quantity traded bilaterally was 6% higher than in Q2 2017, with corresponding decreases in self-consumption (-4%) and Balancing Market trades (-2%).

1.6.3 Constrained payments

There has been a significant (>50%) increase in Constrained Off compensation in Q1 and Q2 2018 compared to Q2 2017 (Figure 25). Constrained compensation is paid to Market Generators who are dispatched out of merit by AEMO and is calculated based on their offer price, the Balancing Price and constrained quantity.

In Q2 2018, there were 24% of intervals in which at least one generator was constrained on or off compared to 10% in Q2 2017. This increase was due to planned network outages in the North Country region of the South West Interconnected System occurring over March and April 2018. In Q2 2018, there were 12 consecutive days of planned network outage impacting six generation facilities in the region.

Figure 25 WEM constrained payments



[28] Synergy is owned by the Government of Western Australia, represented by the Minister for Energy and is registered in the WEM as a Market Customer and a Market Generator. Synergy has 30 registered generation Facilities in the WEM representing a total nameplate capacity of 2,824 MW or 51%. Synergy bid their Facilities into the market as a consolidated portfolio. Synergy is the largest retailer operating in the WEM and is the default retailer for non-contestable customers (i.e. those consuming less than 50 MWh annually).

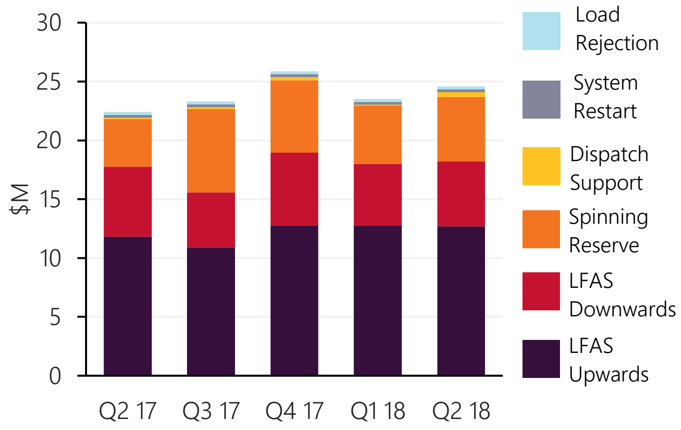
1.6.4 Ancillary Services payments

In the WEM, total Ancillary Services payments increased by $1.1M in Q2 2018 compared to Q1 2018 (Figure 26).

The total payments for Load Following Ancillary Services (LFAS)[29] in Q2 2018 has increased from Q1 2018 by $209,000, with the procured quantity of both services remaining at 72 MW. Compared to Q2 2017, there was an 8% decrease in the average LFAS Upwards price ($18/MWh) and a 7% increase in the average LFAS Downwards price ($40/MWh).

Spinning Reserve service is capacity held in reserve which can respond rapidly should an online generator experience a sudden outage[30]. The payments for Spinning Reserve in Q2 2018 has increased from Q1 2018 by $531,000 due to increases in Balancing Price from Q1 2018 to Q2 2018 for both peak and off-peak intervals.

Figure 26 WEM ancillary service payments



1.6.5 Reserve Capacity refunds

WEM Reserve Capacity refunds were significantly lower in Q2 2018 when compared to Q2 2017 due to a reduction in forced outages (Table 8). Comparatively high Reserve Capacity refunds in Q2 and Q3 2017 were driven by the trip of Bluewaters Power Station in January 2017 and subsequent extended outage until July 2017.

Table 8 WEM Reserve Capacity Refunds

WEM Reserve Capacity refunds	Q2 2017	Q2 2018	Change to Q2 2017
Scheduled Generator refunds	$6.36M	$407k	▼ -$5.95M
Intermittent Load refunds	$25.5k	$180k	▲ +$155k
Net STEM Shortfall refunds	$65.5k	$0	▼ -$65.4k
TOTAL	**$6.45M**	**$588k**	**▼-$5.86M**

[29] LFAS Downwards and Upwards service is frequency control services provided by generators which can respond within 5 seconds.

[30] Spinning Reserve is provided Synergy as the default provider of ancillary services and by Independent Power Producers which are contracted at a discount to Synergy's administered price payments. Synergy's administered payments are relative to the energy prices in the Balancing Market and the Spinning Reserve quantities settled to Synergy based on fixed quantities determined by the Economic Regulation Authority in the Margin Values Review.

2. Gas market dynamics

2.1 Gas demand

Total gas demand[31] decreased by 19 PJ during the quarter compared to Q2 2017 and increased by 24 PJ compared to Q1 2018, consistent with typical seasonal demand profiles (Table 9). Table 10 provides a summary of the drivers of demand changes.

Table 9 Total Gas Demand – Quarterly comparison

Total Demand	Q2 2018 (PJ)	Q1 2018 (PJ)	Q2 2017 (PJ)	Volume Change to Q2 2017 (PJ)
AEMO Markets *	96	54	97	▼ -1
GPG **	38	41	50	▼ -12
QLD LNG	292	307	298	▼ -6
TOTAL	426	402	445	▼ -19

** 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.*

Table 10 Changes in gas demand

Demand *increases* against Q1 2018	• 42 PJ increase in residential, commercial and industrial demand from AEMO's wholesale gas markets, driven by increased heating load requirements consistent with typical seasonal demand profiles. • 15 PJ reduction in demand for export LNG driven by planned maintenance across multiple LNG projects (Section 2.1.1). • 3 PJ decrease in GPG demand, as hydro generation and variable renewable energy displaced GPG.
Demand *decreases* against Q2 2017	• 12 PJ decrease in GPG demand across all regions, driven by large increases in hydro generation and variable renewable energy (Section 1.3.3). • 6 PJ reduction in pipeline deliveries for export LNG. • Residential, commercial and industrial demand for gas from AEMO's wholesale gas markets remained consistent.

2.1.1 LNG

Average daily pipeline deliveries of 3,210 TJ/d flowed to Curtis Island during Q2 2018, a decrease of 61 TJ/d compared to Q2 2017 and a reduction of 202 TJ/d compared to the previous quarter (Figure 28).

Planned maintenance across multiple LNG projects was completed during the quarter, resulting in average daily pipeline flows to Curtis Island reaching their lowest levels since Q3 2016 and two-fewer LNG export cargoes compared to the previous quarter. However, despite this period of planned maintenance, record quarterly gas production from APLNG[32] contributed to more than 3,600 TJ/d of total gas production in Queensland for the quarter. This resulted in 405 TJ/d of total Queensland gas incremental to LNG pipeline deliveries being consumed by the domestic market – an increase from 303 TJ/d during Q1 2018 – which contributed to reduced prices across most of the gas markets.

Planned maintenance during the quarter included:

- APLNG decreased total LNG production capacity by 50% during late April.
- QCLNG decreased LNG production capacity by between 25% and 50% for most of May.

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

[32] https://www.originenergy.com.au/content/dam/origin/about/investors-media/180731_June-18-QPR_Final.pdf

Co-ordination between LNG proponents was exhibited during the planned maintenance periods, as maintenance-driven decreases in pipeline deliveries were matched by corresponding increases in deliveries to GLNG (Figure 27):

- APLNG decreased average pipeline flows by 568 TJ/d during their planned maintenance in April, compared to the prior week. A corresponding increase in average pipeline flows of 412 TJ/d was recorded by GLNG.
- QCLNG decreased average pipeline flows by 637 TJ/d during their planned maintenance in May, compared to the prior week. A corresponding increase in average pipeline flows of 200 TJ/d was recorded by GLNG.

Figure 27 Pipeline deliveries to Curtis Island

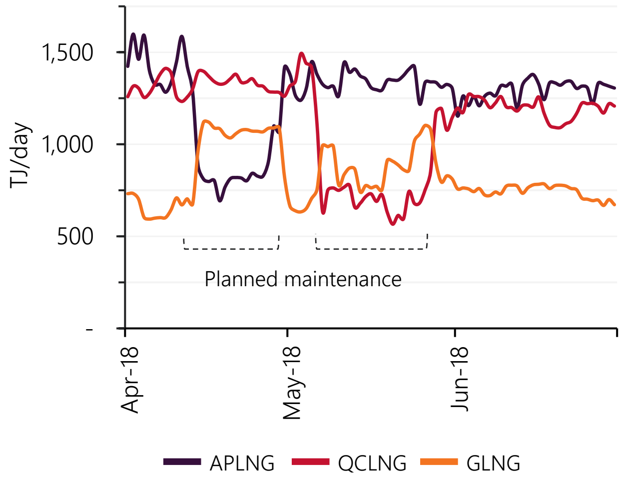
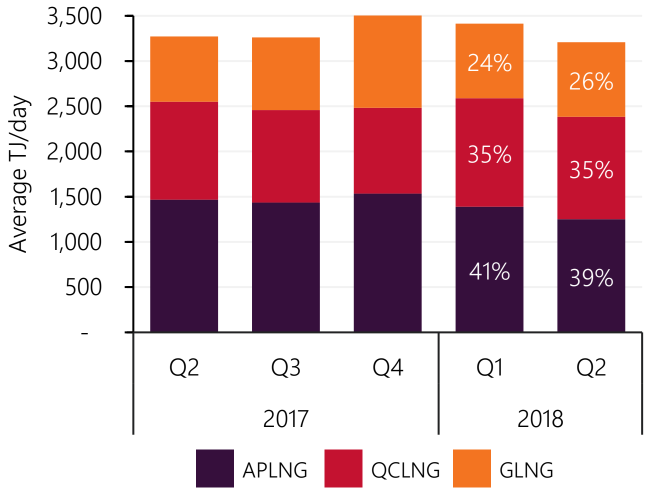


Figure 28 Average daily pipeline deliveries to Curtis Island



2.2 Wholesale gas prices

Average quarterly prices decreased across most AEMO gas markets during Q2 2018 compared to the previous quarter (Figure 29), reflecting reduced GPG in all NEM regions and reduced LNG exports. Lower GPG demand was a function of reduced electricity prices in most NEM regions (Section 1.4), as well as reduced availability (Section 1.3.3).

The Gas Supply Hub (GSH) ($7.93/GJ) was the lowest priced gas market during the quarter due to reduced LNG export cargoes and steady upstream production. These factors also contributed to the GSH recording its second-highest ever monthly delivered volumes of 1,524 TJ during May 2018.

The Sydney STTM recorded the largest absolute and percentage decrease to end the quarter, but remained the east coast's highest priced gas market at $8.56/GJ (a decrease of $0.74/GJ or 8% compared to Q1 2018).

Figure 29 Average wholesale gas prices by market

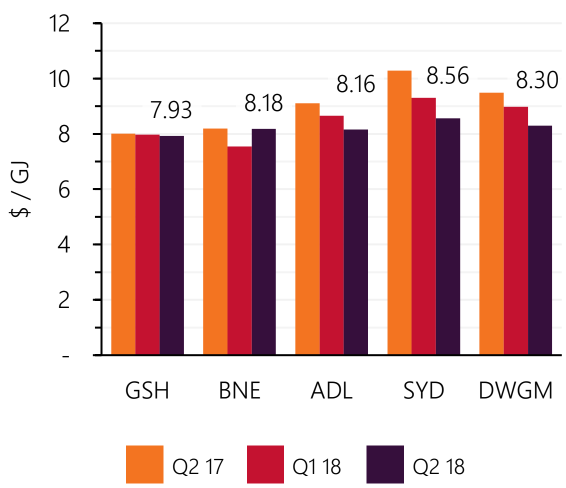
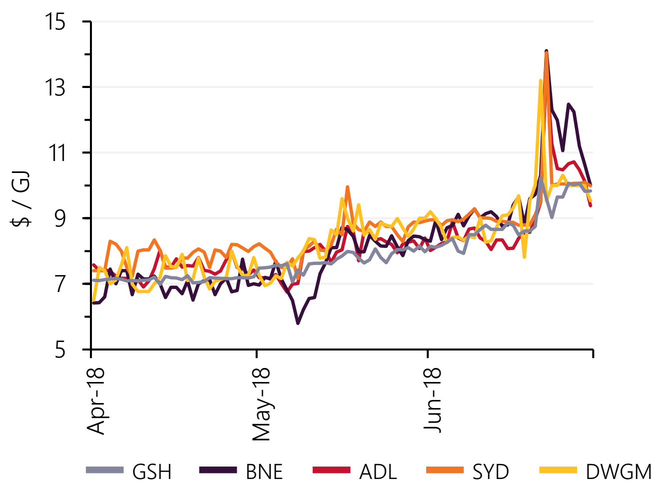


Figure 30 Average daily wholesale gas prices per market



A focus on daily average prices (Figure 30) highlights the following:

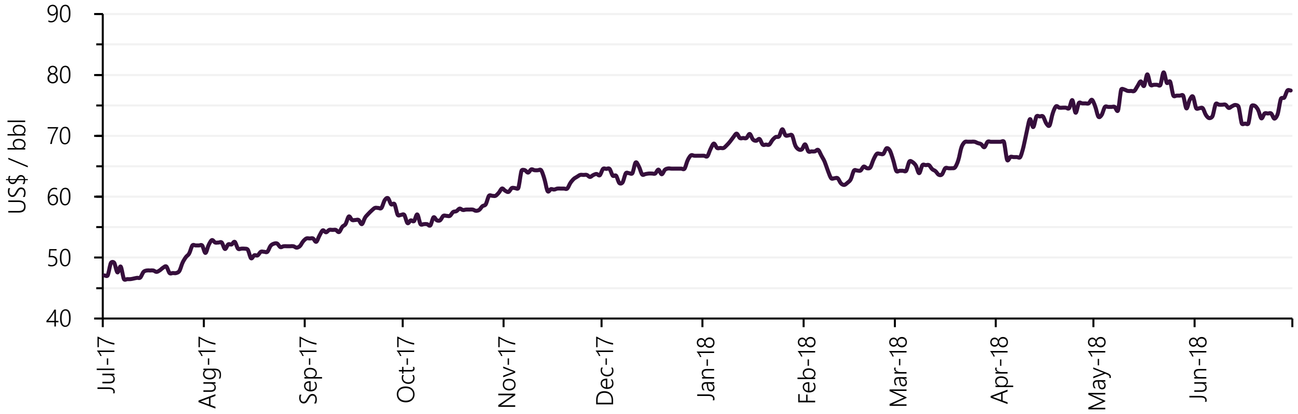
- On 8 May 2018, average prices on the Brisbane STTM were $5.80/GJ, as 59 TJ of additional supply was offered at prices below $6/GJ. Increased supply to the Brisbane STTM coincided with lower priced gas offered into the market by Stanwell.
- Prices across all AEMO gas markets peaked above $10/GJ in late-June following an unplanned partial outage at Longford on 21 June, which coincided with a period of high GPG demand in the NEM. During this period, market participants shifted offers from $9-11/GJ to $12-15/GJ, which also contributed to the first trade above $10/GJ on the GSH since May 2017.
- Wholesale gas prices progressively increased during the quarter, coinciding with colder weather and increased gas demand.

2.2.1 International gas prices

Brent Spot traded at US$69.02/bbl at the start of Q2 2018 and ended the quarter at US$77.44/bbl (Figure 31). Supported by strong demand, OPEC-led production cuts, and the prospect of renewed U.S. sanctions on Iran[33], the price climbed during Q2 2018 and peaked in late-May at US$80.42/bbl, the highest Brent Spot has traded since November 2014.

The relationship between oil price and east-coast gas market dynamics softened during the quarter as reduced LNG exports and lower domestic gas prices were recorded despite the highest Brent oil prices for 3.5 years.

Figure 31 Brent spot price



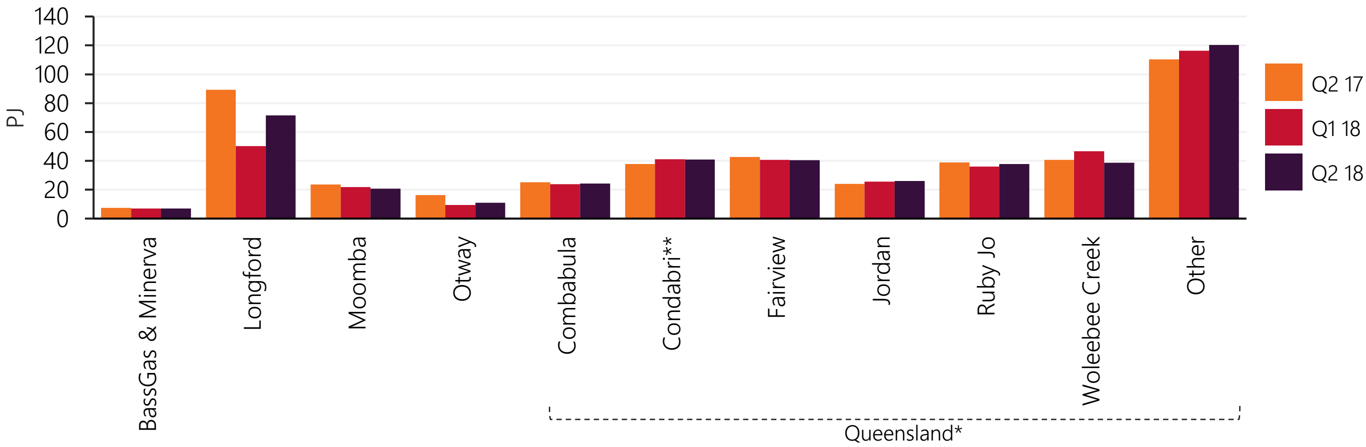
Source: EIA for Brent oil price (USD/bbl)

2.3 Gas supply

2.3.1 Gas production

East coast gas production of 439 PJ was recorded during Q2 2018, a 20 PJ (or 4.7%) increase on the previous quarter (Figure 32).

Figure 32 Production by gas plant by quarter

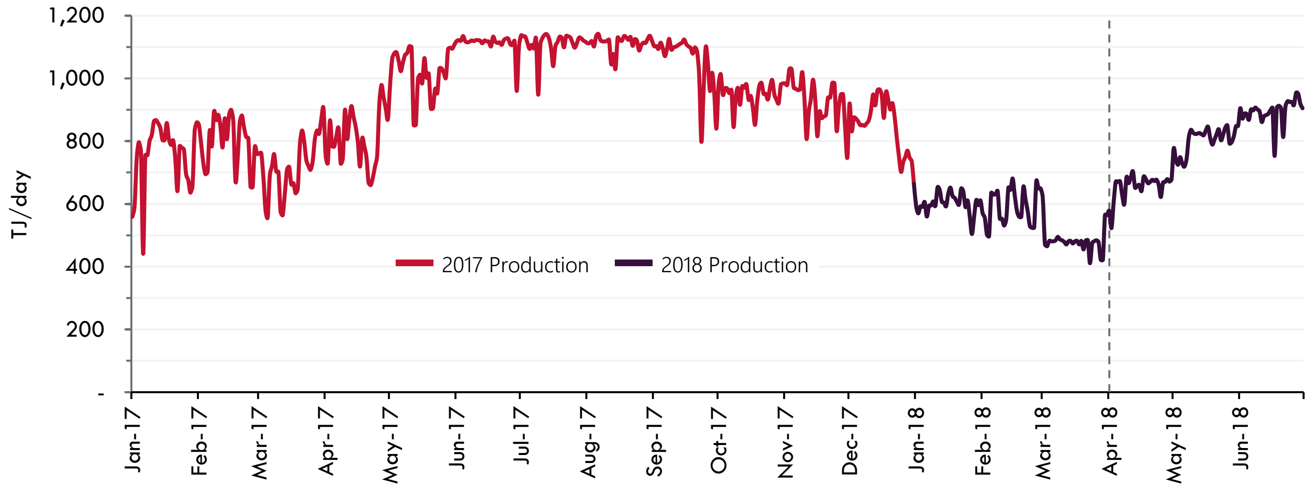


* *Queensland production is based on grouping all Gas Bulletin Board production facilities in the Roma Zone of the Gas Bulletin Board. Those not explicitly stated are grouped as "Other".*
** *Condabri is the grouping of North, Central and South production facilities.*

[33] https://www.cnbc.com/2018/04/24/reuters-america-update-7-oil-steadies-after-brent-tops-75-on-supply-cuts-iran-sanctions-threat.html

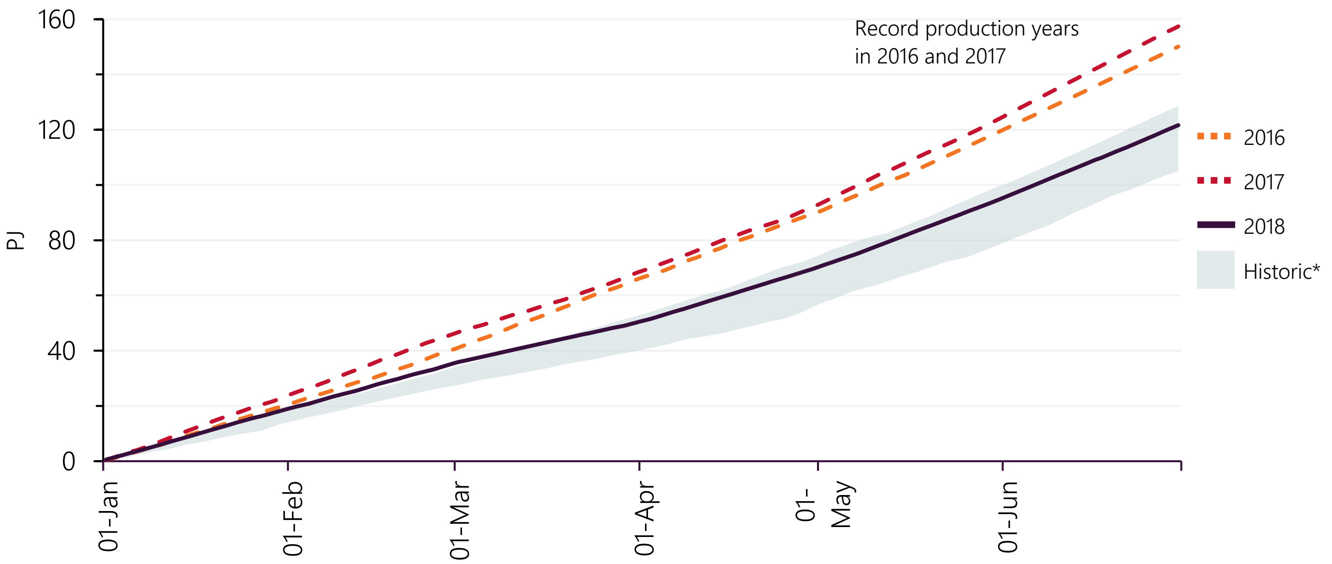
Compared to Q1 2018, production increases of 23 PJ from the Otway and Longford gas facilities (Figure 33) were driven by seasonal demand profiles which increase in line with heating load requirements during winter. The production increase from the south was partially offset by a 1 PJ reduction in output from Moomba and a 2 PJ decrease in Queensland production driven by planned maintenance across various LNG-operated gas facilities during April and May.

Figure 33 Longford gas plant daily production



Whilst lower than 2016-17, Longford production is tracking consistently with historical averages (Figure 34). However, the maximum daily delivery of 954 TJ is significantly less than the 1142 TJ achieved in 2017 and the 2015 maximum of 1043 TJ.

Figure 34 Longford Gas Plant | Quarter 1 & 2 cumulative production | 2009 to 2018



** The shaded series represents the highest and lowest cumulative production levels occurring between 2009 and 2015*

2.3.2 Gas storage

A gas balance of 17.2 PJ was recorded at the Iona Underground Storage Facility (Victoria) as at 30 June 2018. Gas withdrawals exceeded gas injections ('net withdrawals') by 4.5 PJ during the quarter, compared to net withdrawals of 3.2 PJ during Q2 2017 (Figure 35 and Figure 36). Reduced Q2 2018 gas production from Otway and Longford compared to Q2 2017 contributed to an increased reliance on gas from storage to meet quarterly demand.

Figure 35 Iona Daily Injections & Withdrawals

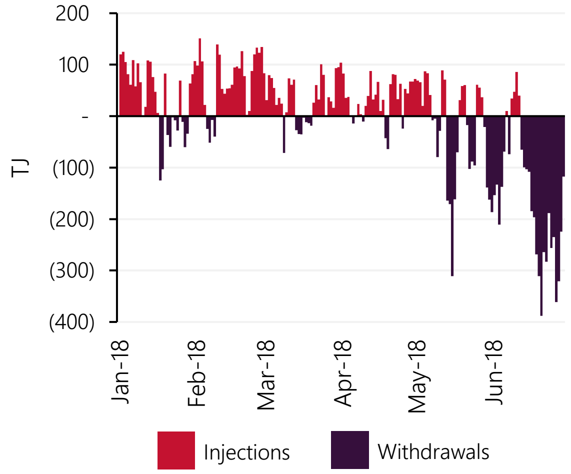
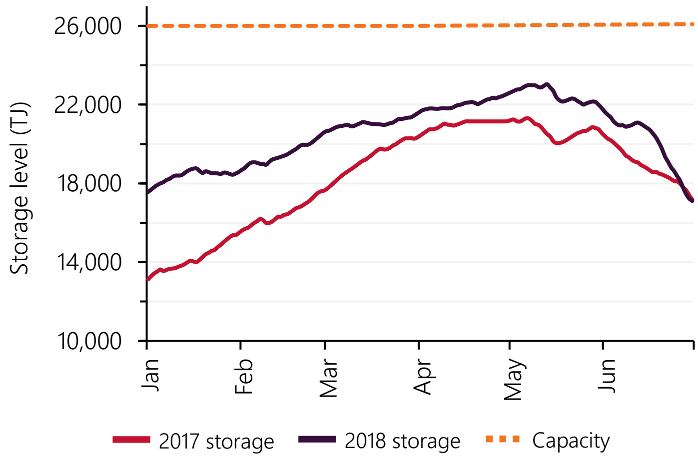


Figure 36 Iona Underground Storage Facility – storage levels



2.4 Pipeline flows

Quarterly gas exports from Victoria to other states totalled 34 PJ and were consistent with exports during Q1 2018. Tamar Valley CCGT did not run during the quarter and the resulting decrease in flows along the Tasmanian Gas Pipeline were offset by an increase in gas deliveries to South Australia along the SEAGas Pipeline.

Following record production in 2017, decreased output from the Otway and Longford gas facilities during 2018 (Figure 32 and Figure 34) has reduced Victorian exports by 15 PJ (or 31%) when compared to Q2 2017 (Figure 37).

Figure 37 Victorian gas exports to other states

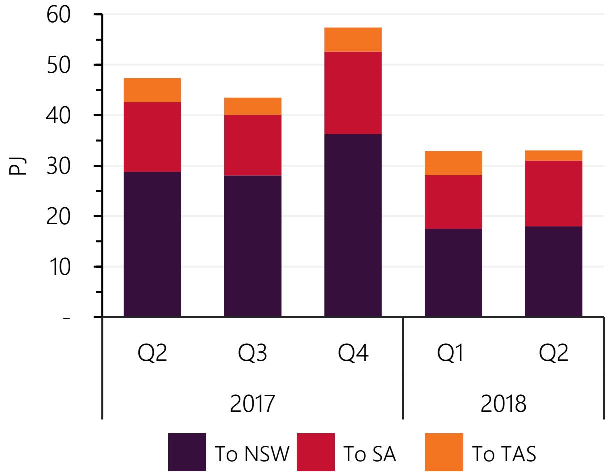
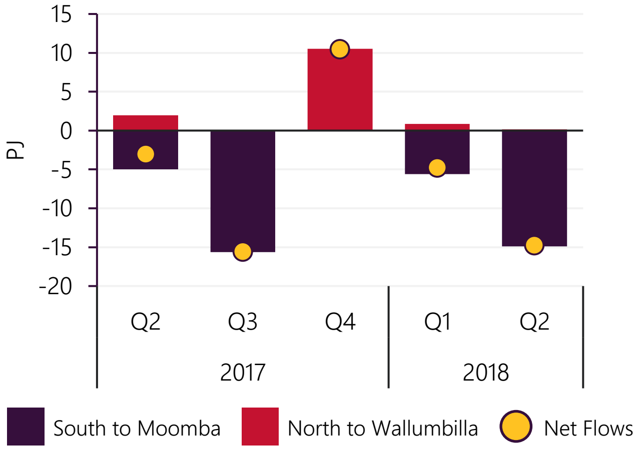


Figure 38 South West Queensland Pipeline at Wallumbilla



The South West Queensland Pipeline (SWQP) flowed almost exclusively south during Q2 2018, recording a southerly net flow of 15 PJ (Figure 38). There was a corresponding increase in flows recorded along the Moomba to Sydney Pipeline, which increased by 71 TJ/d and the Moomba to Adelaide Pipeline, which increased by 9 TJ/d when compared to the previous quarter.

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
BBL	Barrel
CER	Clean Energy Regulator
CCGT	Combined cycle gas turbine
DWGM	Declared Wholesale Gas Market
FCAS	Frequency control ancillary services
GJ	GigaJoule
GPG	Gas-powered generation
GSH	Gas Supply Hub
LFAS	Load Following Ancillary Services
LGC	Large-scale Generation Certificates
LNG	Liquefied natural gas
MW	MegaWatt
MWh	MegaWatt hour
NEM	National Electricity Market
PJ	PetaJoule
PV	Photovoltaic
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
TJ	TeraJoule
UIGF	Unconstrained intermittent generation forecast
USD	United States dollars
WEM	Wholesale Electricity Market