Wholesale Markets Quarterly Q3 2019

November 2019

AUSTRALIAN ENERGY REGULATOR

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Contents

Summary

Electricity markets

The third quarter of 2019 (Q3 2019) saw lower average wholesale prices than in Q3 a year ago in most National Electricity Market (NEM) regions. Notably, prices fell in Queensland and South Australia, but increased in Victoria and Tasmania (but Tasmania was from a lower base).

Average wholesale prices ranged from $66 per MWh in Queensland to $103 per MWh in Victoria. Prices in Queensland largely reflected the availability of significant amounts of low priced generation, with the supply of black coal generation now increasingly being supplemented with large amounts of large scale solar. The higher prices in Victoria reflected unplanned generator outages at Loy Yang A and Yallourn, and the outage of the Basslink interconnector, which limited imports from Tasmania into Victoria. While wholesale prices in Q3 2019 were generally lower, financial markets indicate there are expectations of high prices for the coming summer, particularly in Victoria and South Australia. This in part reflects ongoing uncertainty around generation outages in Victoria.

An interesting feature of Q3 2019 was the record number of negative wholesale prices in South Australia and Queensland. These prices reflected high levels of wind generation and very low demand in South Australia, and significant amounts of low priced coal and solar generation in Queensland.

Q3 2019 highlighted a change in the composition of generation output. There was a significant increase in wind and large scale solar generation, continuing the ongoing trend. Output from both brown and black coal generation was down considerably from levels a year ago, largely due to coal generation outages. Brown coal generation output in Victoria was at its lowest levels since the commencement of the NEM in 1998. Gas generation increased in all mainland regions, particularly Victoria.

Gas markets

Movements in wholesale gas market spot prices continued to align with the Asian LNG spot price movement, an observable trend since early 2017. As Asian LNG spot prices declined sharply over the quarter, so too did domestic spot prices—although not falling as low as the Asian LNG spot netback price to Wallumbilla.

Spot gas prices in Adelaide, Brisbane, Sydney and Victoria ranged from $7.28 per GJ to $8.89 per GJ and on average were around $1.50 per GJ lower over the quarter compared to Q2.

Historically, spot prices have increased over winter as southern demand increases. However, recent trends have been different. Southern spot prices declined over winter 2017 as Asian LNG spot prices fell, while in 2018 southern spot prices did not fall when Asian LNG spot prices did not notably decline. Spot gas price trends throughout the year appear to be changing to reflect Asian LNG market impacts, with winter no longer likely to be the highest priced period.

Recent growth in spot market trade continued during the quarter, along with increased market participation. Spot prices, reported over the quarter, would have flagged potential savings when compared to recent reports of long-term contract prices. The lower spot prices would have assisted active spot market participants, including industrial customers, in downstream markets.

Flows of gas from northern to southern markets reached record levels over winter, as gas production reached new highs. In addition, the new Day Ahead Auction (DAA) of pipeline capacity provided access to cheap transportation for new participants. Increased use of the DAA, combined with growing short-term trade at the Wallumbilla and Moomba gas supply exchanges resulted in lower prices in the downstream Sydney and Victorian markets, as a number of participants sought price arbitrage between northern and southern prices.

Quarterly gas production was at record levels, driven by output from Queensland gas fields. Export volumes across Q2 and Q3 2019 have been steady but were down from Q1 volumes when gas demand for heating is typically higher in the northern hemisphere winter.

About this report

A core function of the AER is to monitor and report on the performance of the national wholesale electricity and gas commodity and capacity markets. This quarterly report bridges the gap between our shorter term high price event reports and our longer-term performance reports, including the annual *State of the energy market* report and the biennial performance report. The quarterly report draws on our online industry statistics and allows us to identify significant trends in the electricity and gas markets, and independently evaluate market developments as they emerge.

From Q1 2020 the requirement to report into outcomes and trends in ancillary services markets will be incorporated in this report. In preparation for this role, this quarterly report contains a focus piece on ancillary services markets and publishes some of the measures we will be required to report on from next year.

Electricity markets at a glance
Q3 2019

Spot prices

Prices have fallen
in most regions

Negative prices

Record number of negative prices
in Queensland and SA

Fuel costs

Coal and gas costs
have fallen

Demand

Falling minimum demand
in all mainland regions

Generation

Reduced coal generation largely
due to outages. Continued increase
in renewable generation

Frequency control

Cost of maintaining system
frequency has increased

Gas markets at a glance
Q3 2019

Gas commodity spot prices

Fell by a range of 13% to 22% from Q2

Gas powered generation

High gas powered generation in VIC, SA and NSW

Gas production

Record production driven by QLD

LNG export

Steady with Q2 volume levels

Net gas flow

Record gas flows from North to South

Market utilisation rate

Spot trade increasing in STTM and DWGM

Gas storage level

Volumes at RUGS* storage now higher than at the start of year

* RUGS is the Roma Underground Gas Storage

Auction of pipeline capacity

Auction reducing cost of transportation

1. Electricity

1.1 Quarterly spot prices

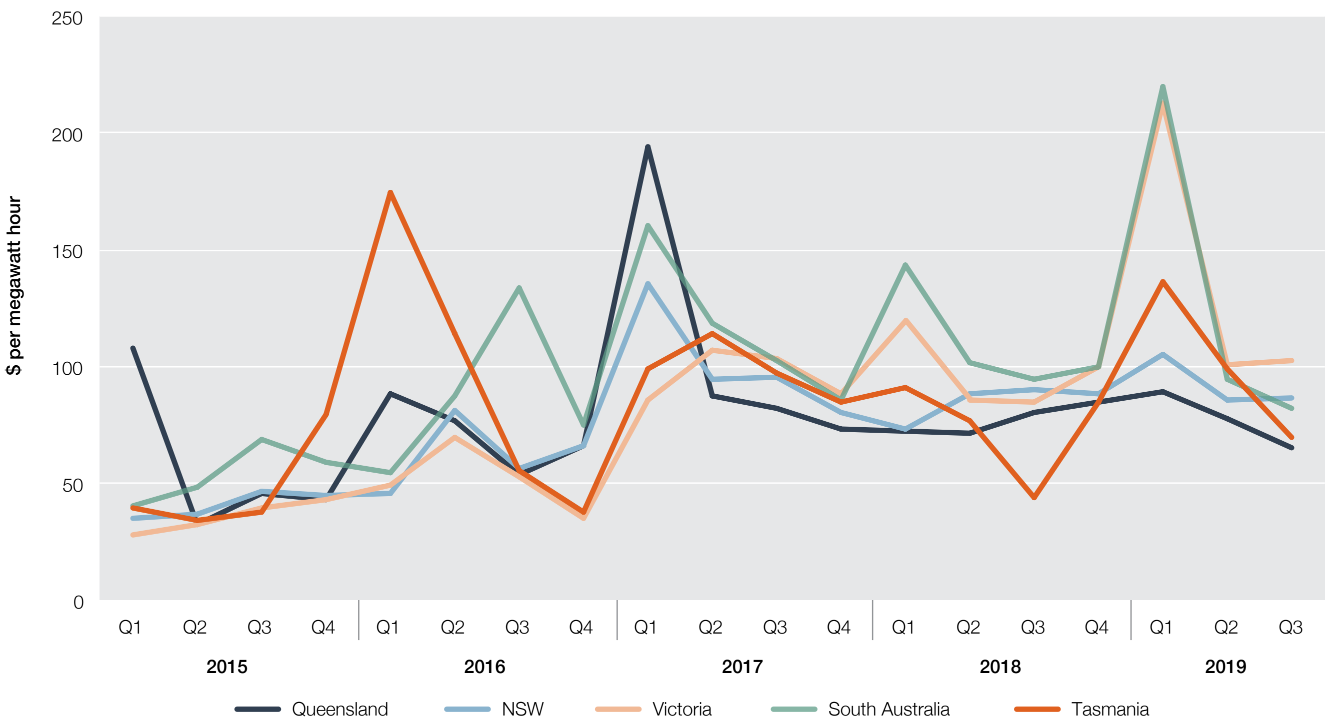
- Spot prices were lower in Q3 2019 than they were in Q3 2018, except in Victoria and Tasmania.
- Average Q3 2019 prices ranged between $66 per MWh in Queensland and $103 per MWh in Victoria.

Average quarterly spot prices were lower in Q3 2019 than in Q3 2018 in most regions, particularly in Queensland and South Australia (figure 1.1). The main exception was Victoria where quarterly prices increased compared to Q3 2018. Prices were also higher in Tasmania but from a very low base.

In recent years, volume weighted average (VWA) quarterly prices have followed a consistent pattern—peaking in summer and returning to levels averaging around $70 to $100 per MWh for the remainder of the year.

Average prices in Q3 2019 ranged from $66 per MWh in Queensland to $103 per MWh in Victoria. Prices in Queensland and South Australia were the lowest they have been since Q3 2016, while prices in Victoria were almost $20 per MWh higher than any other region.

Figure 1.1 Quarterly spot prices (VWA)



Source: AER analysis using NEM data.

1.2 Negative prices

- There were a record number of negative prices in the NEM in Q3 2019, largely driven by a record number of negative prices in South Australia and Queensland.
- Negative prices contributed to a $6.70 per MWh reduction in the average quarterly spot price in South Australia and a $2.40 per MWh reduction in Queensland.

Wholesale spot prices can vary between -$1000 and $14 700 per MWh. There were a record number of negative half hour spot prices in the NEM in Q3 2019 (figure 1.2). This was largely driven by a record number of negative spot prices in South Australia (359 or around 8 per cent of the time) and Queensland (157 or around 4 per cent of the time). The number of negative prices in Queensland for the quarter was more than six times the previous record for the region.

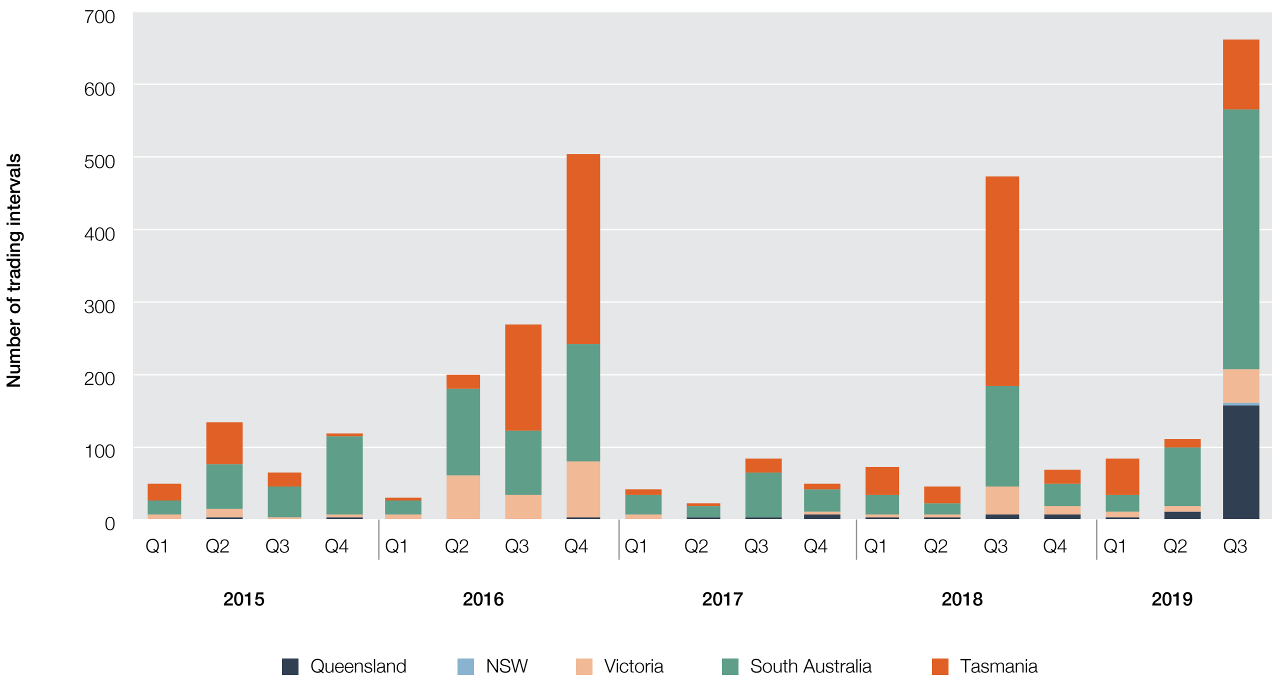
In South Australia, these negative prices contributed to a reduction in the average quarterly spot price of $6.70 per MWh. In Queensland, this contribution amounted to a reduction of $2.40 per MWh.

For Q3 2019, the drivers of negative prices included:

- high renewable generation—we explore generation outcomes in section 1.5
- low demand—we discuss demand further in section 1.4
- restricted interconnector flows—we analyse interconnector flows in section 1.10.

Generally, there are a number of factors that can drive negative prices and we discuss this further in our focus story on negative prices.

Figure 1.2 Number of negative prices in each region



Source: AER analysis using NEM data.

1.3 Price expectations

> - The financial markets are expecting higher wholesale prices in the coming year than they were a year ago.
> - High wholesale prices are expected again this summer, in particular in Victoria and South Australia.
> - Price expectations for this quarter were mostly met, except in Victoria.

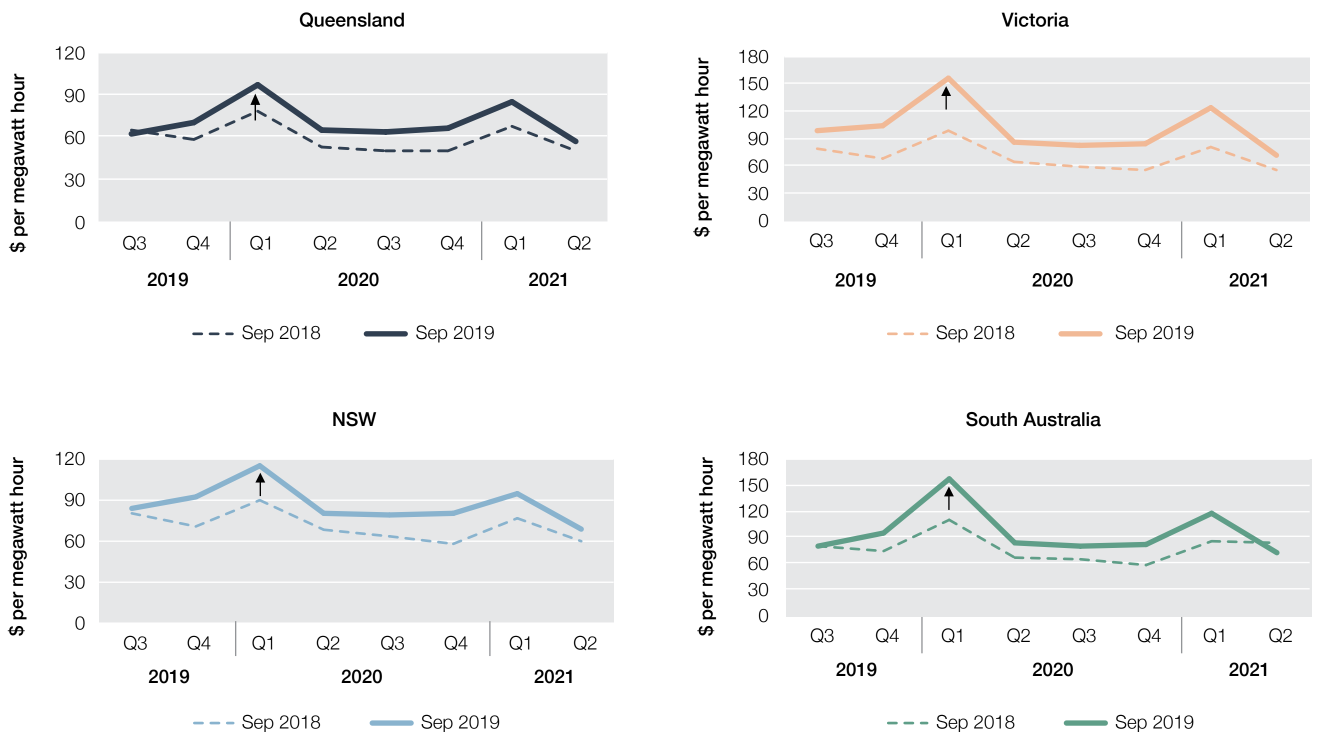
The financial markets are expecting higher spot prices in 2020 than they were 12 months ago. This is reflected in the price increase for base future products for the next six quarters, compared to a year ago (the upward shift from the dashed line to the solid line in figure 1.3).

In particular, base future prices for Q1 2020 in Victoria and South Australia which were around $100 per MWh a year ago are now over $150 per MWh. This shift in expectations reflects in part the high prices in those states last summer and continuing concerns over generator outages.

As is typical in the NEM, prices are expected to fall after summer, to between $60 and $90 per MWh for the remainder of 2020.

Last year's expectations for price outcomes this quarter were mostly met. Electricity base future prices for Q3 2019 at the close of this quarter were similar to a year ago, except in Victoria where the base future price increased by around $20 per MWh. This was influenced by the unplanned generator outages over winter.

Figure 1.3 Base future prices, Q4 2019 to Q2 2021



Source: AER analysis using NEM data.

1.4 Demand

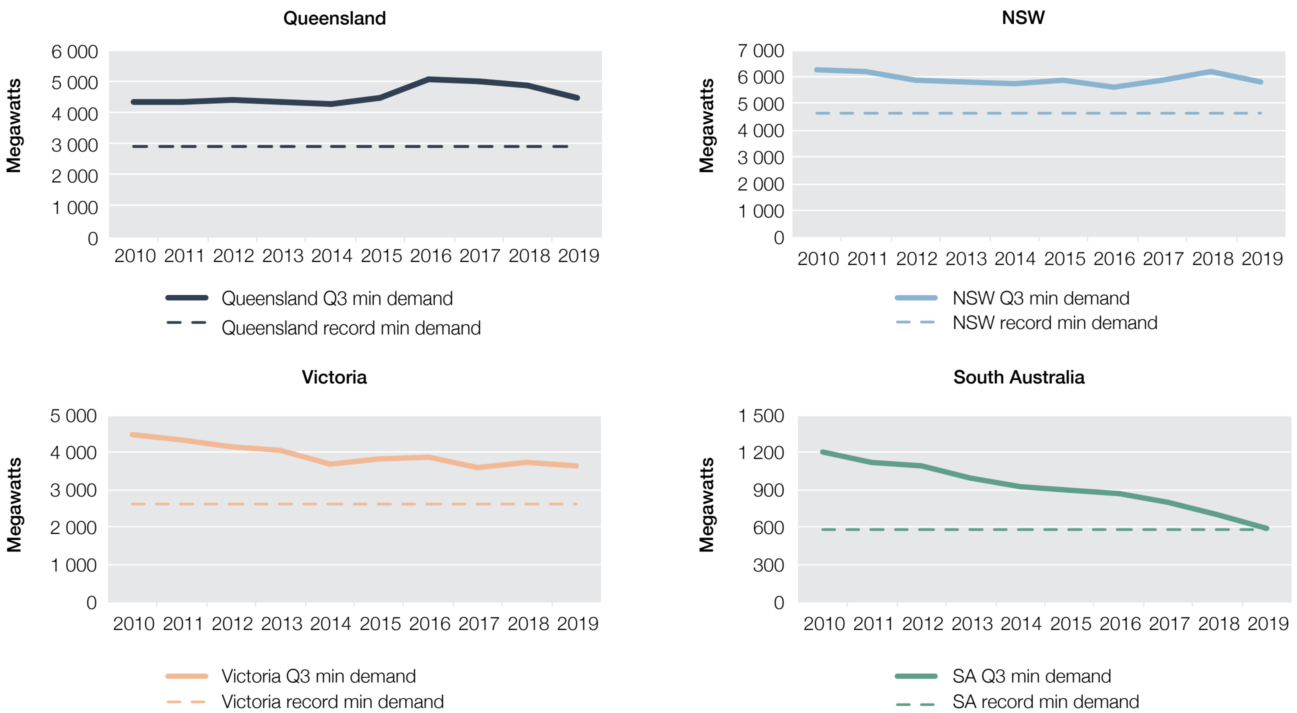
- South Australia not only experienced record minimum Q3 demand, but demand fell to within 4 MW of its lowest minimum demand since market start.
- Minimum Q3 demand has been falling recently in all mainland regions.

Q3 is a quarter of relatively low demand on the mainland, and as a result we do not traditionally see high wholesale prices.

There were, however, some interesting trends in Q3 demand. Minimum Q3 demand has recently been falling in all mainland regions, with a particularly strong fall in South Australia (figure 1.4).[1] Not only did South Australia experience its lowest ever minimum Q3 demand, on 29 September 2019 it was within 4 MW of its record minimum demand.[2]

A key driver for falling minimum demand is the continued growth in rooftop solar generation. Rooftop solar offsets the demand that must be met by grid supplied electricity particularly in the middle of the day. In regions like Queensland, which has a high penetration of roof top solar, it has contributed to negative prices at these times.

Figure 1.4 Minimum Q3 demand



Source: AER analysis using NEM data.

Note: Uses native demand.

1 Minimum daily demand is the lowest level of demand over all 30-minute trading intervals during a trading day. Minimum Q3 demand is the lowest level of demand over all trading intervals during the quarter.

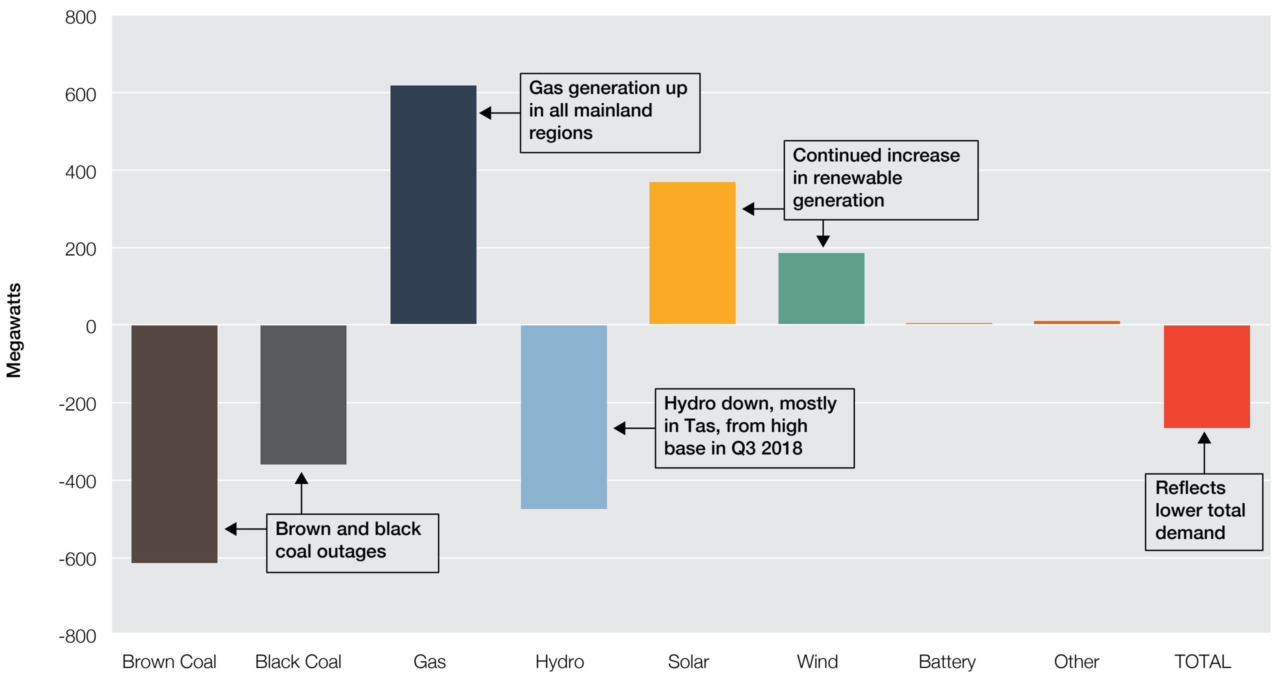
2 Subsequently, on 20 October 2019, South Australia set a new record minimum demand of 480 MW.

1.5 Generation

- Q3 2019 highlighted a change in the composition of generation output in the NEM.
- Output from both brown and black goal generation was down considerably from Q3 levels a year ago, largely reflecting coal generation outages. Brown coal generation output in Victoria was at its lowest levels since the commencement of the NEM.
- Renewable generation continues to increase in all mainland regions, particularly large scale solar generation in Queensland.
- The decrease in generation due to outages was partially met by increased gas generation, especially in Victoria.

Q3 2019 saw a shift in the generation output mix across the NEM compared to Q3 2018 with lower coal and hydro, and more gas and renewable generation output (figure 1.5).

Figure 1.5 Change in average NEM generation output by fuel type, Q3 2019 to Q3 2018

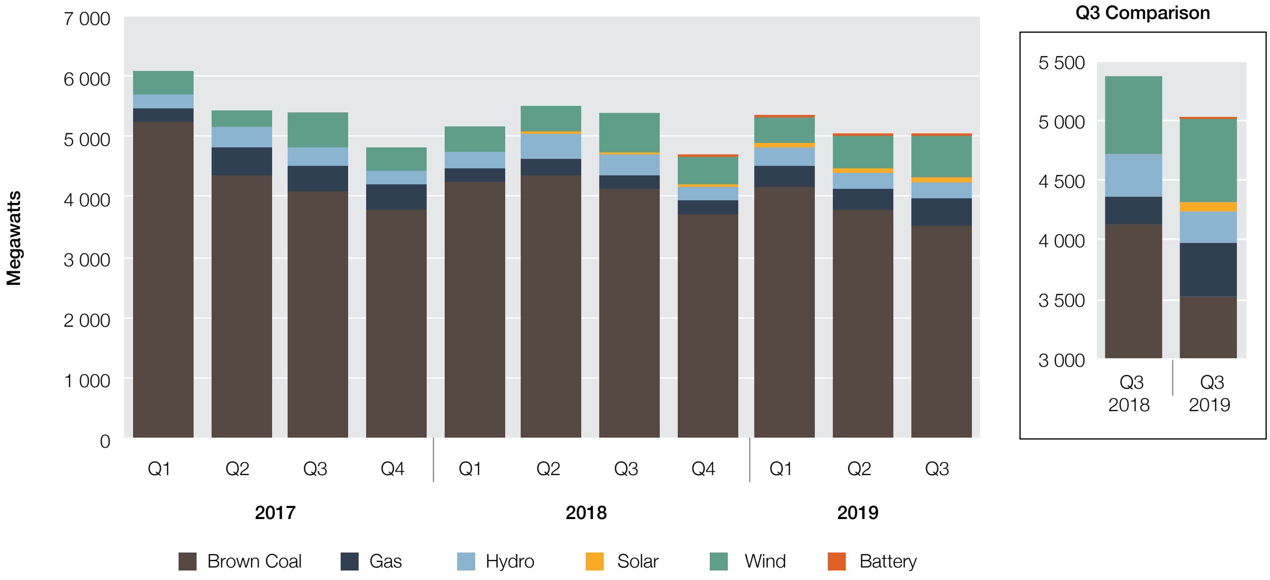


Source: AER analysis using NEM data.

Note: Figure compares quarterly average metered generation output by fuel type in Q3 2019 and Q3 2018. Solar generation includes large scale generation, it does not include rooftop solar PV. Rooftop solar PV impacts demand.

Victoria experienced its record lowest quarterly average brown coal generation since NEM start of around 3520 MW. This reflects the exit of significant brown coal capacity (including Hazelwood in early 2017) and more recent unplanned outages (figure 1.6). Unplanned outages, particularly at Loy Yang A, Loy Yang B and Yallourn power stations (table 1.1), was the key driver of average quarterly brown coal generation being around 600 MW less in Q3 2019 than in Q3 2018.

Figure 1.6 Average generation in Victoria



Source: AER analysis using NEM data.

Note: Figure uses quarterly average metered generation output in Victoria by fuel type.

Black coal generation continues to provide around half of the generation in the NEM despite quarterly average generation being almost 400 MW lower than in Q3 2018. The main drivers of lower average black coal generation were planned generator outages, particularly at Kogan Creek in Queensland and Mt Piper in NSW (table 1.1). In the lead up to summer market participants will often take the opportunity to undertake planned maintenance.

The impact of these outages was partially offset by increased black coal generation from other NSW generators suggesting that some coal supply issues that were present in recent years are being resolved. Table 1.1 lists the major planned and unplanned outages across the NEM during the quarter.

There was an increase in average quarterly gas generation in Q3 2019, which partly offset the lower levels of brown and black coal generation. Gas generation increased in all mainland regions, particularly in Victoria, where average gas generation was up around 200 MW relative to Q3 2018. Gas powered generation is discussed further in section 2.2.

Hydro generation was lower in Q3 2019 relative to Q3 2018. In Tasmania, quarterly average hydro generation decreased by 300 MW from levels in Q3 2018 when there was unseasonably high rainfall. Exports from Tasmania were also limited by the Basslink outage.

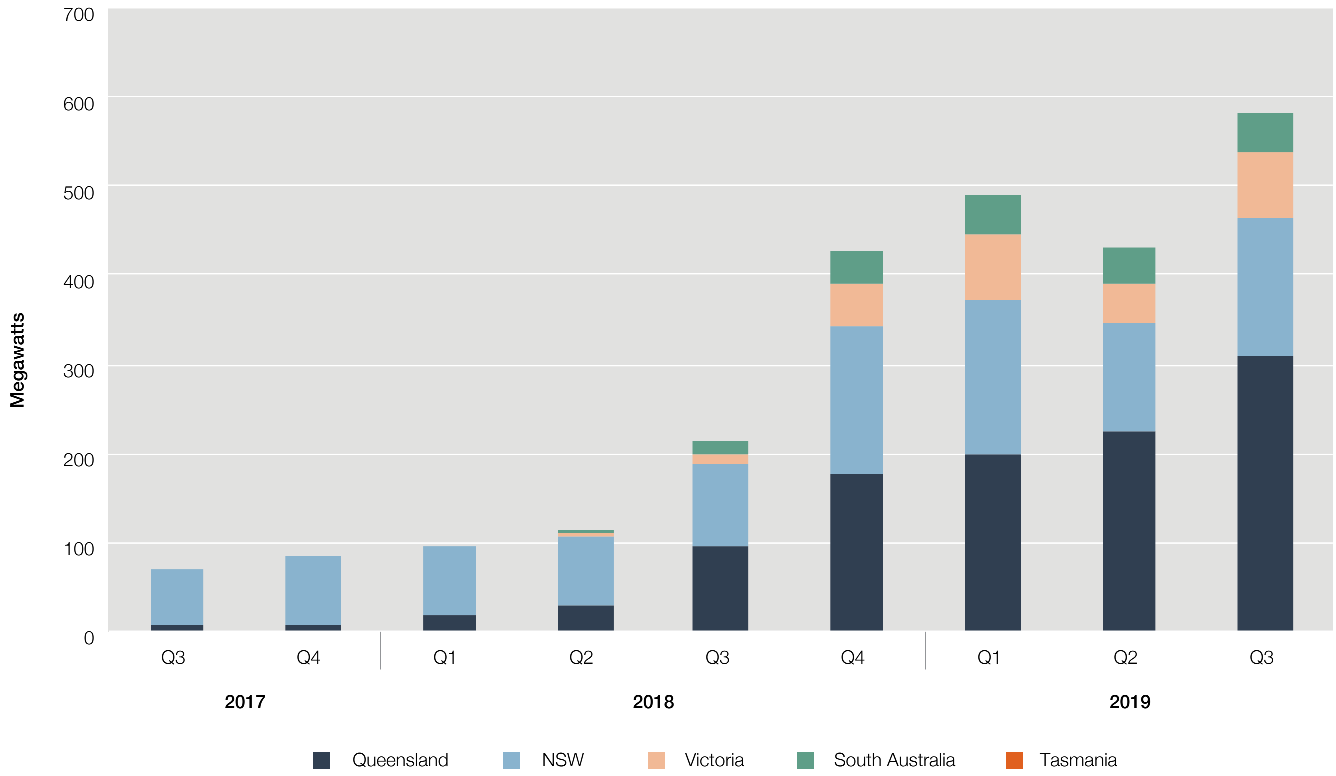
Table 1.1 Generator outages

STATION, COMPANY	FUEL TYPE, CAPACITY (WINTER RATING)	NUMBER OF DAYS OFFLINE IN Q3 2019	NOTES
Queensland			
Kogan Creek, CS Energy	Black Coal 1 unit, 744 MW	80 days	Planned—Major overhaul completed in October
Gladstone, CS Energy	Black Coal 6 units, 280 MW each	Unit 1: 20 days	Planned
		Unit 2: 34 days	Planned
		Unit 3: 19 days	Planned
Stanwell, Stanwell Corporation	Black Coal 4 units, 365 MW each	Unit 1: 61 days	Planned
New South Wales			
Mt Piper, EnergyAustralia	Black Coal 2 units, 700 MW each	Unit 1: 22 days Unit 2: 40 days	Planned—Managing coal supply issues
Liddell, AGL Energy	Black Coal 4 units, 450 MW each	Unit 2: 22 days	Planned
Bayswater, AGL Energy	Black Coal 4 units, 660 MW each	Unit 4: 60 days	Planned
Eraring, Origin Energy	Black Coal 4 units, 720 MW each	Unit 1: 6 days	Unplanned—‘fan issues’
		Unit 2: 10 days	Unplanned—‘valve replacement’ (forced outage)
		Unit 3: 50 days	Planned (44 days) Unplanned (6 days)—‘mill management’, ‘suspected tube leak’
Vales Point, Delta Electricity	Black Coal 2 units, 660 MW each	Unit 1: 17 days	Planned
		Unit 2: 25 days	Unplanned—‘unit trip’, ‘air heater problems’
Victoria			
Loy Yang A, AGL Energy	Brown Coal 4 units, 552 MW each	Unit 2: 92 days	Unplanned—Electrical issues due back mid-December
Loy Yang B, Alinta Energy	Brown Coal 2 units, 535 MW each	Unit 1: 14 days	Unplanned—Tube leak
Yallourn, EnergyAustralia	Brown Coal 4 units, 382 MW each	Unit 2: 27 days	Unplanned—Tube leak
		Unit 3: 24 days	Unplanned—Tube leak
		Unit 4: 34 days	Unplanned—Tube leak
Mortlake, Origin Energy	Gas 2 units, 292 MW each	Unit 1: 15 days	Planned
		Unit 2: 88 days	Unplanned—Electrical issues but doesn’t run often in Q3. Due back mid-December

Source: AER analysis using NEM data.

Wind and solar generation continue to increase across all mainland regions of the NEM. In particular, large scale solar output in Queensland in Q3 2019 was more than triple the level of Q3 last year reflecting the significant number of new entrants in the region. The increase of large scale solar output in NSW and Victoria has also been rapid (figure 1.7).

Figure 1.7 Solar generation by region



Source: AER analysis using NEM data.

Note: Figure uses quarterly average metered generation output.

1.6 New entry

- Two new generators entered the market this quarter, both large scale solar farms.
- Over the past two years, more than 5000 MW of renewable generation capacity entered the market.
- A further 3000 MW of committed renewable generation capacity is scheduled to enter the market this financial year.

Two new generators entered the market this quarter, one large scale solar farm in Queensland and another in NSW (table 1.2). Both of these generators are still commissioning, with their offered capacity expected to ramp up and reach full capacity over the coming months.

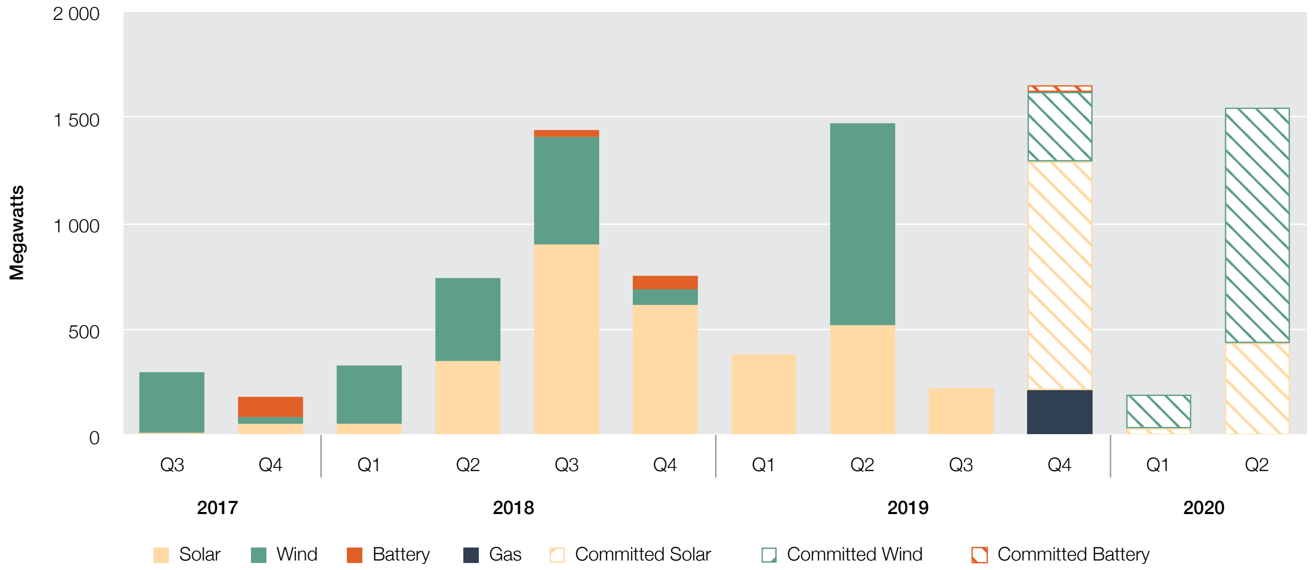
Table 1.2 New market entry

STATE	STATION	FUEL TYPE	SCHEDULE TYPE	HIGHEST CAPACITY OFFERED IN Q3 2019 (MW)	REGISTERED CAPACITY (MW)	COMMENCED OPERATIONS
Queensland	Oakey 2	Solar	Semi-scheduled	10	65	September 2019
NSW	Finley	Solar	Semi-scheduled	44	162	August 2019

Since July 2017, more than 3000 MW of large scale solar and 2500 MW of wind generation capacity has entered the market (figure 1.8). Of the new solar capacity, over half is located in Queensland.

Figure 1.8 also shows another 3000 MW of large scale solar and wind generation capacity scheduled to enter the market this financial year. AGL Energy's Barker Inlet gas-fired power station in South Australia is currently being commissioned.

Figure 1.8 New and committed investment in the NEM



Source: AER analysis using NEM data.

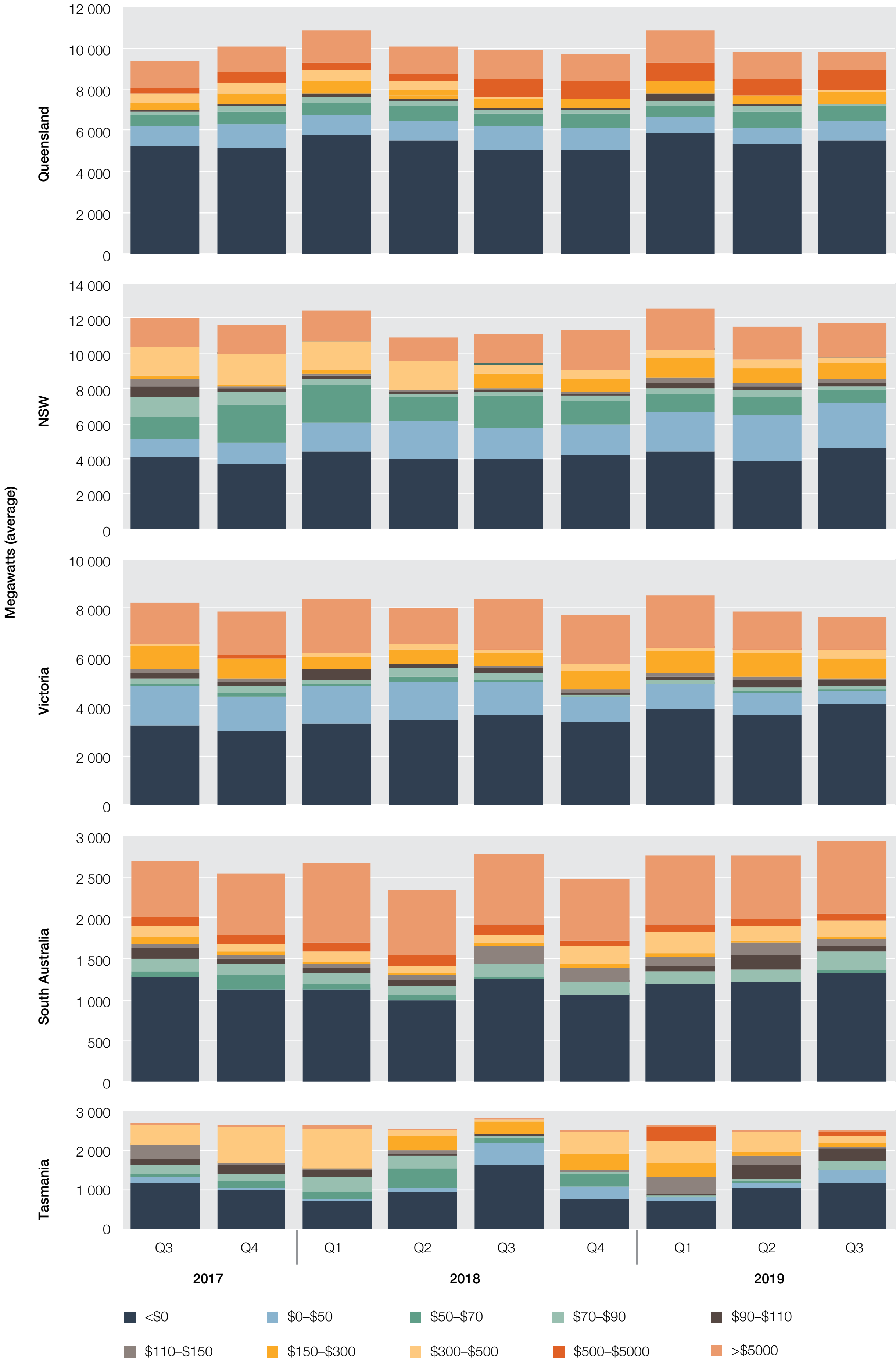
1.7 Participant offers

- Average capacity offered by brown coal generators in Q3 2019 in Victoria decreased by almost 700 MW, compared to Q3 2018.
- The amount of capacity offered by black coal generators in NSW fluctuated throughout Q3 2019, partly due to coal supply issues at EnergyAustralia's Mt Piper generator.
- A 100 MW increase in average capacity offered in Queensland was largely due to new solar generation coming online.

The AER monitors participant offers because how capacity is offered into the market, and at what price and amount, can significantly impact market outcomes.

Despite generator outages and supply issues in NSW and Queensland throughout Q3 2019, the average amount of capacity offered was close to the previous quarter and the same time last year (figure 1.9). Less capacity was offered in Victoria largely due to ongoing outages, while in South Australia more capacity was offered mainly due to increased wind generation as a result of weather conditions. In Tasmania, less capacity was offered compared to Q3 2018 reflecting high rainfall last year.

Figure 1.9 Regional offered capacity, by price thresholds



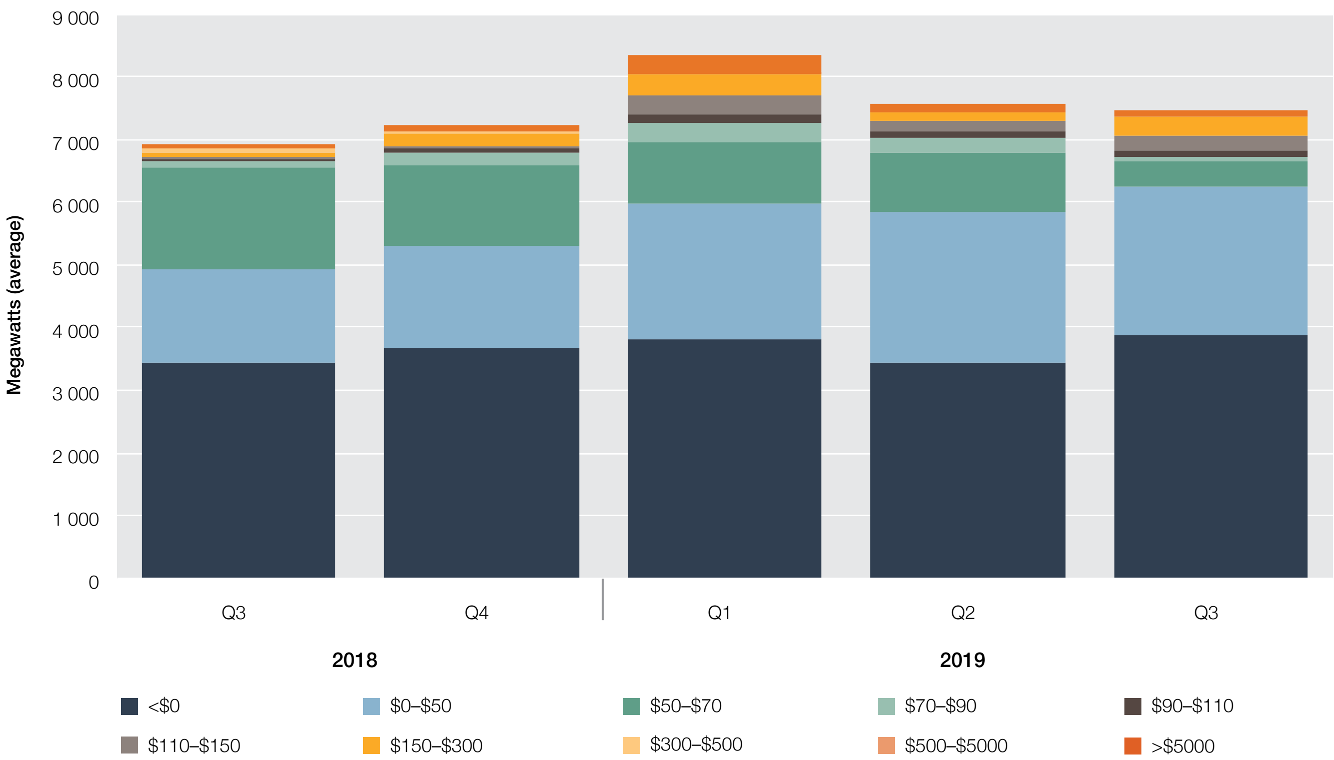
Source: AER analysis using NEM data.

The average capacity offered by brown coal generators in Victoria in Q3 2019 decreased by 686 MW compared to Q3 2018. As discussed in section 1.5, this lower level of capacity was primarily due to significant brown coal generator outages during Q3 2019.

The average amount of capacity offered below $50 per MWh increased in Queensland, NSW and South Australia, in part reflecting falls in coal and gas fuel prices (discussed in section 1.9) and an increase in renewable generation.

In NSW, coal supply issues at EnergyAustralia's Mt Piper generator impacted the average amount of capacity offered by black coal generators in Q3 2019. Despite this, the amount of capacity offered below $50 per MWh was at its highest level since 2016 (top of pale blue bar in figure 1.10). There was over 1000 MW more capacity offered by NSW generators below $50 per MWh in Q3 2019 than in Q3 2018. This is likely due to an increase of capacity offered in these price bands by other generators such as AGL Energy's Bayswater and Liddell generators, and the fall in coal prices. This increase in low priced offers reduced the average price at which black coal and gas generators set price.

Figure 1.10 NSW black coal offered capacity, by price thresholds



Source: AER analysis using NEM data.

The average amount of total capacity offered in Q3 2019 in Queensland was similar to the previous quarter and Q3 last year, despite a major outage to upgrade Kogan Creek power station. The reduction in Kogan Creek's offered capacity was largely offset by an increase in gas and solar offers. Solar generation that came online within the last year offered around 640 MW of capacity during daylight hours, the majority of which was offered below $0 per MWh. This contributed to the lower prices in Queensland and higher counts of negative prices.

1.8 Price setter

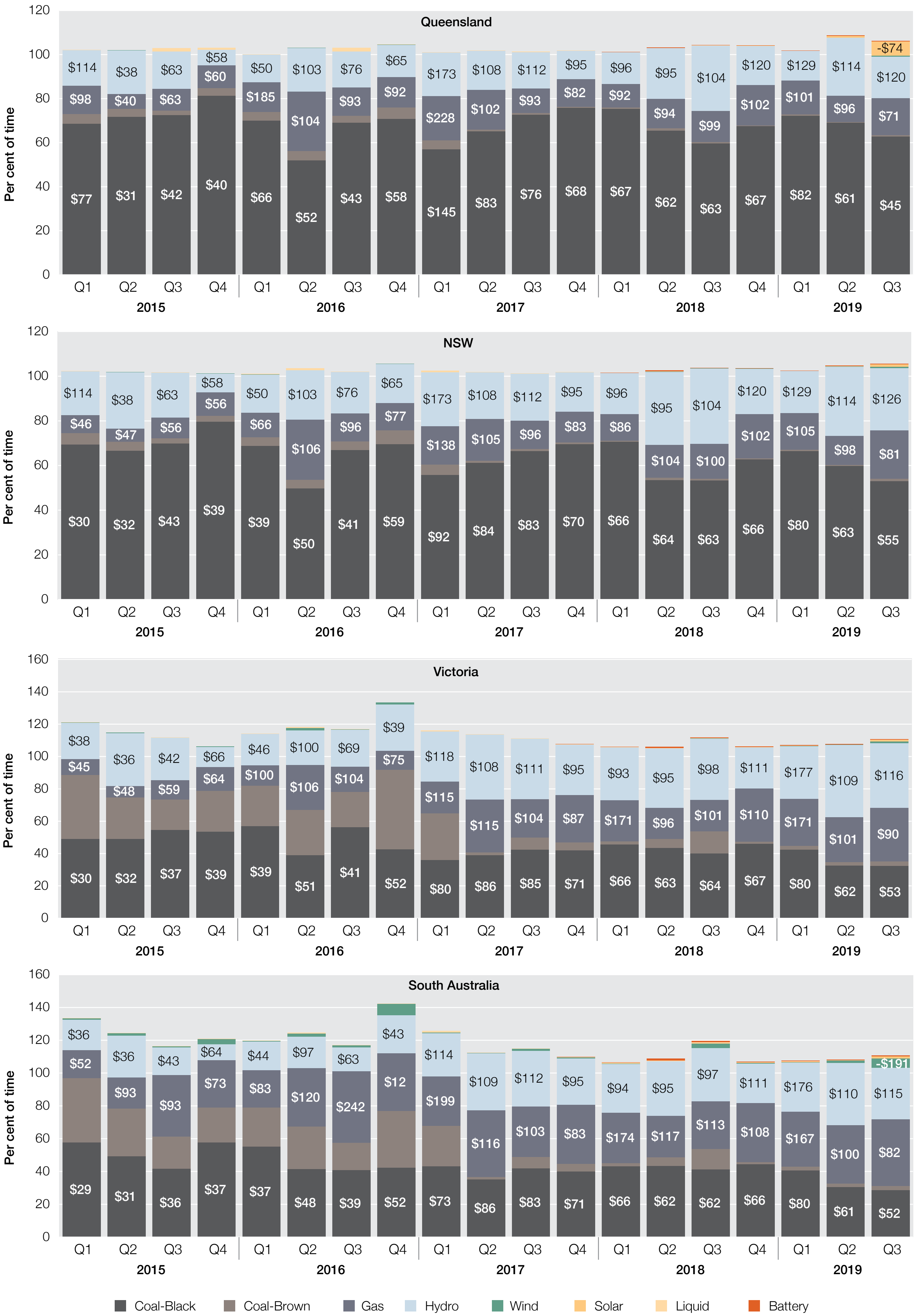
- The average prices set by black coal and gas generators fell this quarter.
- Gas generators set price more often this quarter and coal less often.
- Large scale solar generators in Queensland and wind generators in South Australia both set price around 6 per cent of time this quarter, generally at prices below zero.

Price setter information over time highlights the interaction between the price offered by generators and market conditions, for example, changes in input costs, contracting trends and evolving market dynamics.

The average price set by black coal generators fell to around $50 per MWh in all regions this quarter, except in Queensland where it was even lower (figure 1.11). This was around $10 per megawatt hour less compared to last quarter or Q3 last year. Similarly, the average price set by gas generators fell in every region by around $10 per megawatt hour compared to last quarter and Q3 last year, with the exception of Queensland and South Australia where it fell further.

An interesting feature of Q3 2019 is that renewable energy generators set price more frequently than ever before in Queensland and South Australia. Solar generators and wind generators set price for around 6 per cent of time in Queensland and South Australia, respectively. The average wholesale prices set by renewable generators in these two regions were extremely low at -$74 per MWh and -$191 per MWh, respectively. We discuss this in more detail in our focus story on negative prices.

Figure 1.11 Price setter by fuel type and region



Source: AER analysis using NEM data.

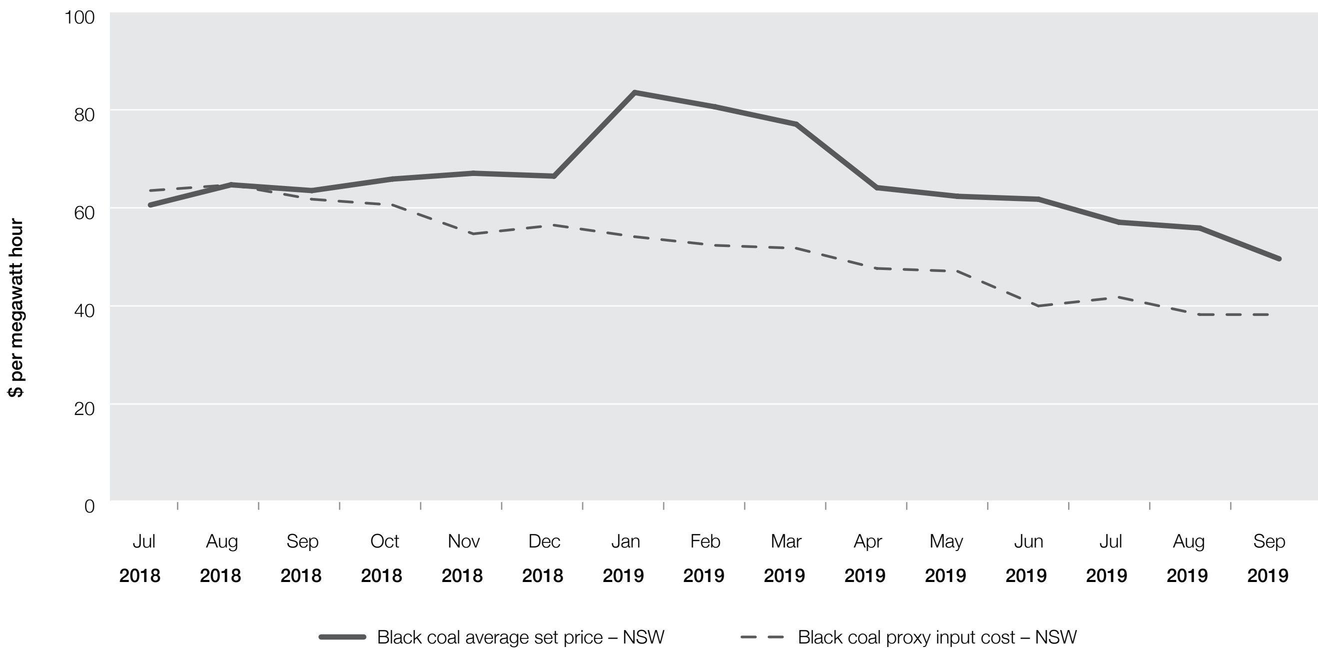
1.9 Fuel costs

- Black coal and gas fuel prices declined this quarter.
- The drop in fuel prices coincides with a decrease in the average prices set by black coal and gas.

To assess how changes in fuel prices affected the wholesale electricity market, we compared the price of electricity when black coal or gas generators were the marginal generator against prices for those fuels. Fuel such as coal and gas is typically sourced under a range of short and long term contracts, and therefore an approach that relies on spot prices alone has its limitations. In the absence of detailed generator cost data, commodity prices can be used as a reasonable proxy and enables a comparison to the average prices set by coal and gas generators.[3]

The international reference price for thermal coal in Newcastle (converted to AUD$ per MWh) has been declining since mid-2018 (figure 1.12).[4] The average monthly price set by black coal generators (solid line) has tracked the falling international coal prices (dashed line), with the exception of the summer months where they were higher. The decline in coal prices is consistent with NSW black coal generators offering more capacity at low price bands in Q3 2019.

Figure 1.12 International reference price for Newcastle spot thermal coal and average monthly price when black coal generators set the price in NSW



Source: AER analysis using NEM data, globalCOAL data.

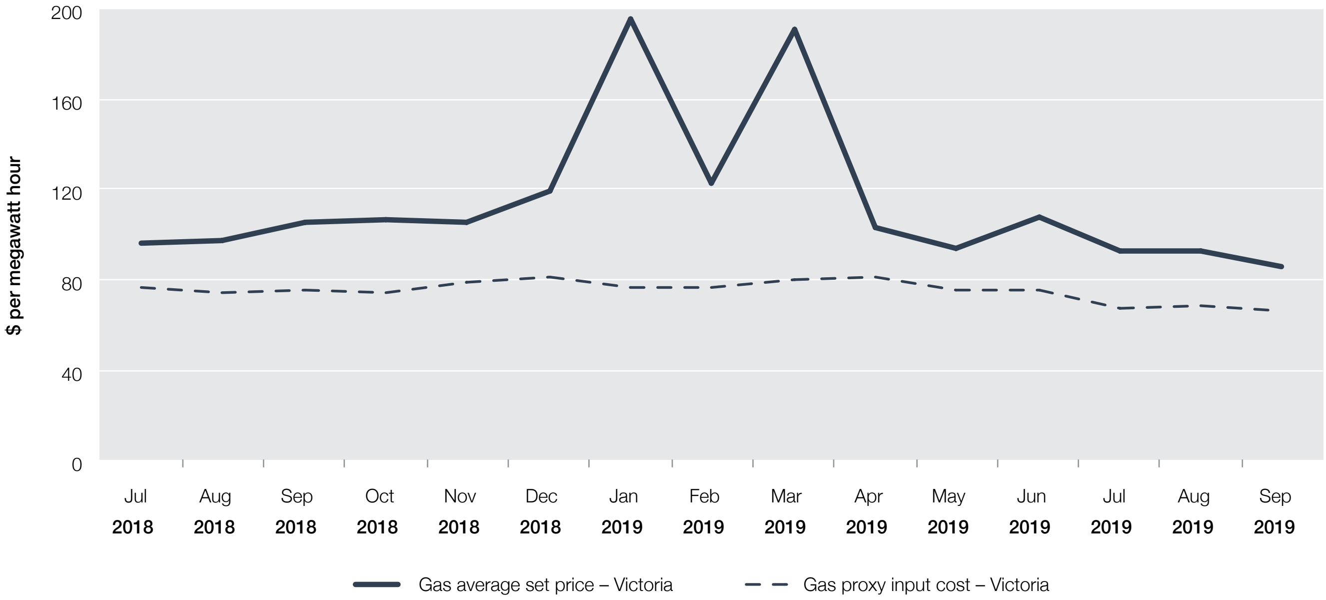
Note: Black coal proxy input cost derived from Newcastle coal index (USD$ per tonne), converted to AUD$ per MWh with RBA exchange rate, and average heat rate for coal generators.

Average wholesale gas spot prices dropped to below $8 per GJ across all five markets this quarter (section 2.1). Using the average spot price in the Victorian wholesale gas market as a proxy for the marginal cost of gas generators, the average price set by gas generators in Victoria (solid line in figure 1.13) has recently declined along with declining gas fuel prices (dashed line), again with the exception of the summer months where they were higher.

3 We also applied this method in the *Wholesale electricity market performance report* in December 2018. The methodology is described in the [Methods and assumptions paper](#).

4 The globalCOAL Newcastle coal price index is a reference price for spot thermal coal at Newcastle Port in NSW. The globalCOAL methodology is available at www.globalcoal.com.

Figure 1.13 Victorian spot gas market price and average monthly price when gas generators set the price in Victoria



Source: AER analysis using NEM data.

Note: Gas proxy input cost derived from Victorian Declared Wholesale Gas Market price (AUD$ per GJ), converted to AUD$ per MWh with average heat rate for gas generators.

We will undertake a more detailed assessment of the relationship between participant costs and market price outcomes, including examining why input costs and prices diverge over summer months, as part of our next *Wholesale electricity market performance report* due in December 2020.

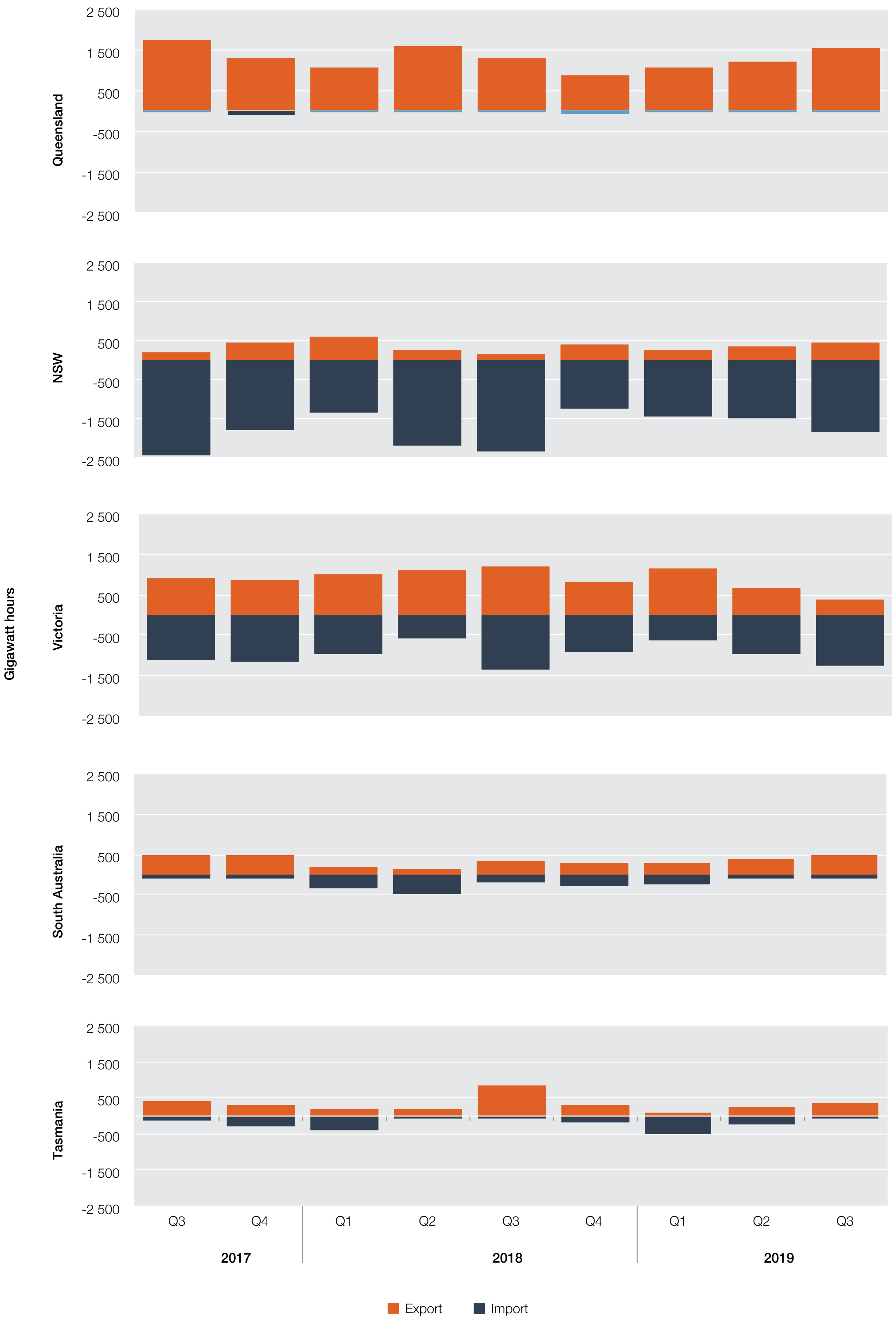
1.10 Interconnectors

- Net exports from Queensland were at their highest levels for the year.
- The Basslink interconnector was out of service from 24 August to 29 September.
- Exports from Victoria were at their lowest in three years due to high spot prices.

Figure 1.14 illustrates levels of trade between the regions of the NEM. Trade between regions over interconnectors provides some competition between participants across regions. Overall, flows between regions in Q3 2019 have not significantly changed from Q2 2019 with the exceptions of Queensland and Tasmania.

Queensland continues to be a net exporting region, with its highest level of exports for the year occurring in Q3 2019, reflecting its lower prices.

Figure 1.14 Regional interconnector flows—exports and imports

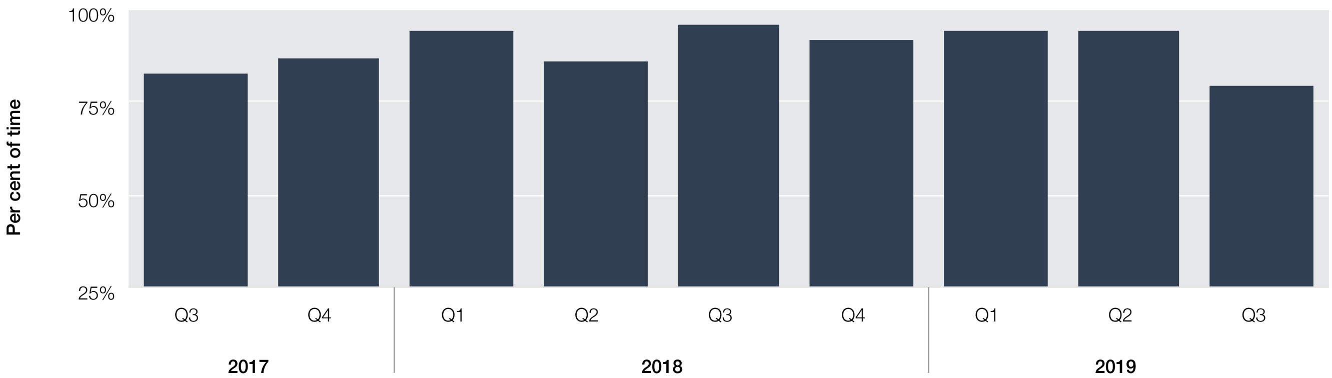


Source: AER analysis using NEM data.

When flows across interconnectors are not at their limits, neighbouring regions act as one and share the same price (altered only by network losses). We refer to this as price alignment. Price separation between regions generally occurs when interconnectors reach their physical limits. It can also occur because of network outages, upgrades or limitations put in place to maintain system security.

Prices in Queensland and NSW were aligned 79 per cent of the time in Q3 2019 compared to 96 per cent of the time in Q3 2018 (figure 1.15). In Q3 2019, lower prices in Queensland drove exports into NSW at interconnector limits more often than in previous quarters. Energy typically flows from regions with lower prices to regions with higher prices, subject to physical limitations on the interconnectors.

Figure 1.15 Per cent of time Queensland was price aligned with NSW



Source: AER analysis using NEM data.

Victoria was a net importer in Q3 2019 with exports being at their lowest in three years. Flows between Victoria and Tasmania during Q3 2019 were limited due to the unplanned outage of the Basslink interconnector from 24 August to 29 September 2019.[5] Price alignment between Tasmania and Victoria was accordingly low for Q3 2019, occurring only 25 per cent of the time.

Despite the prolonged outage, average exports from Tasmania were greater than the two previous quarters, reflecting the higher spot prices in Victoria.

1.11 Frequency control ancillary services

- The cost of regulation services increased to record levels in Q3 2019.
- We will start regular analysis of the FCAS markets from Q1 2020.

Frequency control ancillary services (FCAS) are used to maintain the frequency of the system. There are two categories of FCAS:

- regulation services (raise and lower), which continuously balance small changes in frequency6
- contingency services (6 second, 60 second and 5 minute, each with raise and lower), which are called upon to respond to major changes in frequency.[7]

5 Basslink media statement: http://www.basslink.com.au/wp-content/uploads/2019/09/20190929_Basslink_Media-statement_RTS_on-29-Sept1.pdf.

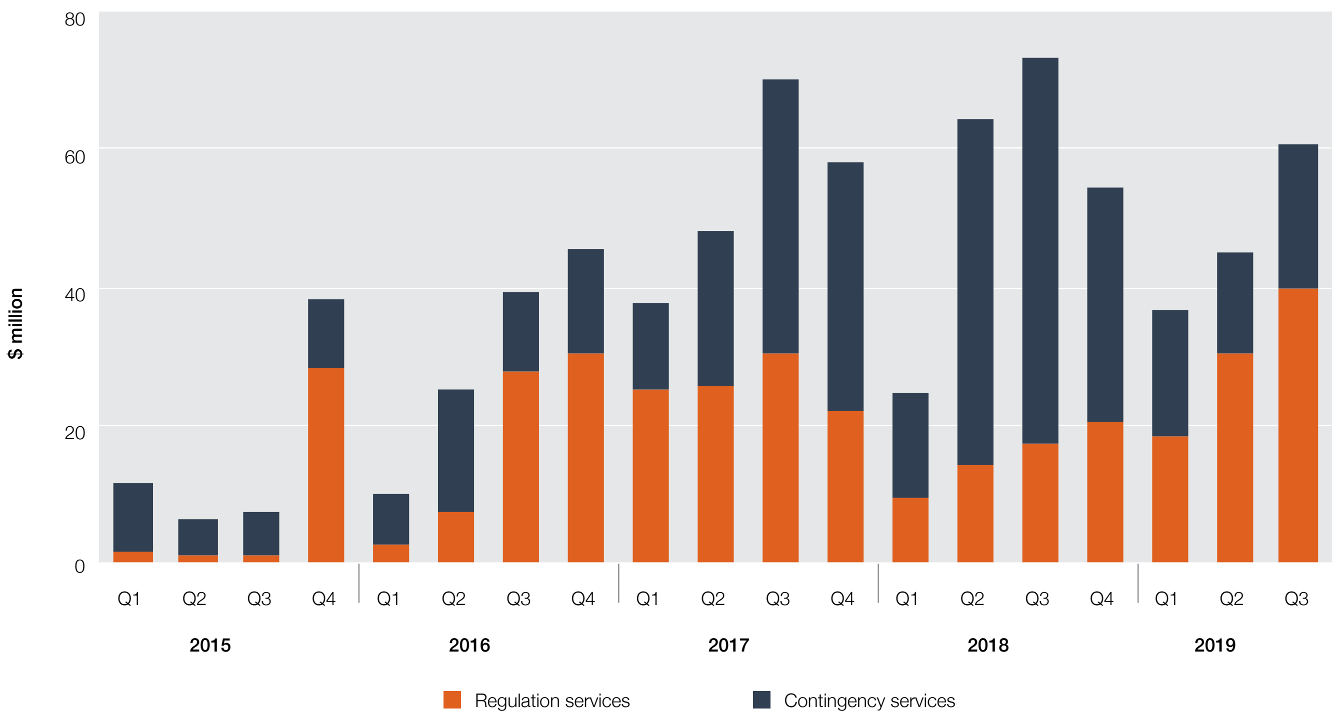
6 Participants receive dispatch targets every 5 minutes from AEMO. They are paid in accordance with their offered volumes. Costs are recovered on a causer pays basis.

7 There are three contingency services to increase the frequency and three to decrease the frequency. Raise services respond to a reduction in supply and are paid for by generators. Lower services respond to a reduction in demand and are paid for by consumers. Participants will not be supplying these services until a contingency occurs but are paid according to their enablement.

While they are a small proportion of energy costs, the cost of these services has been increasing since 2016 (figure 1.16).

Total FCAS costs in Q3 2019 were lower than Q3 2017 and Q3 2018. However, while the cost of contingency services was lower, the cost of regulation services (orange bar) increased to record levels. This has largely been because the Australian Energy Market Operator (AEMO) increased base regulation FCAS volumes by 90 MW across mainland regions.

Figure 1.16 Total FCAS costs



Source: AER analysis using NEM data.

From Q1 2020 the AER will commence regular reporting on outcomes and trends in ancillary services markets. This quarterly report contains a focus piece on ancillary services markets and publishes some of the measures we will be required to report on from next year, including prices and the amount of FCAS enabled. It also explains how the FCAS markets work in more detail.

Focus—Negative prices

A record number of negatively priced trading intervals occurred NEM-wide in Q3 2019, which in turn reduced average quarterly prices, particularly in South Australia and Queensland. All negative prices in Queensland occurred during daylight hours.

Negative prices are part of the normal functioning of the market

The NEM design allows generators to offer in capacity at negative prices, to a price floor of -$1000 per MWh. As AEMO dispatches generators using cheapest-priced offers first, generators offer capacity at the price floor to ensure dispatch, and this forms a large part of the capacity offered into the market.

Why do generators offer at negative prices?

Generators offer to supply the market at negative prices for a number of reasons. Generators that rely on intermittent, renewable fuel sources, like solar and wind, have near zero running costs as their fuel source is free. They also have access to non-market forms of compensation, such as the large-scale generation certificates created under the Renewable Energy Target, which provide an income regardless of the spot price. These factors allow them to offer capacity at negative prices and still receive enough revenue to cover their costs.

Conversely, it is more efficient for large, baseload generators (like coal-fired generators) to operate continuously due to high start-up and shut down costs, low operating costs, and minimum generating levels. This motivates baseload generators to offer a portion of their generation capacity at negative prices. For example, black coal generators in Queensland offered on average around 71 per cent of their capacity at negative prices during Q3 2019.

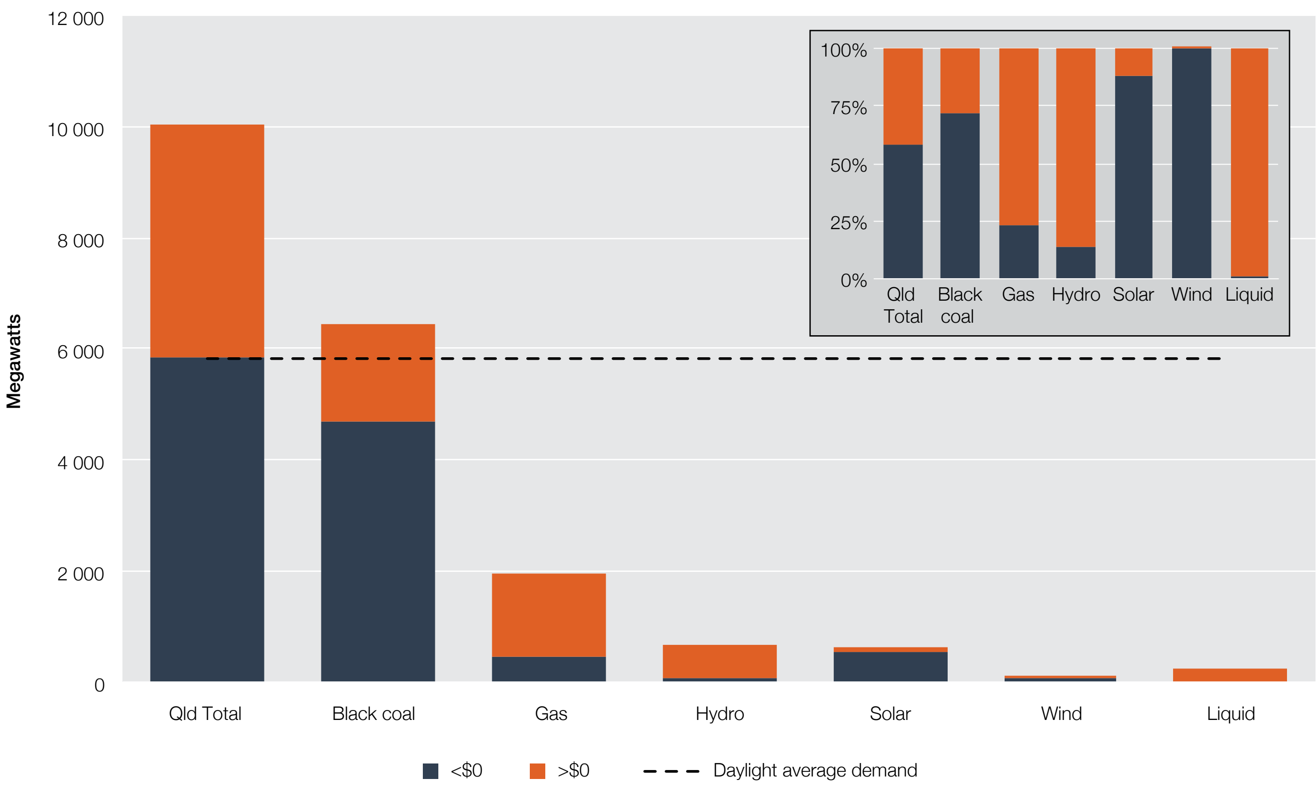
Other incentives, such as bilateral contracts settled outside the market, can motivate a generator to offer at negative prices by insulating it from the impact of changes in the spot price. Some of these contracts guarantee a fixed price for a portion of that generator's output, encouraging it to offer in at negative prices to guarantee dispatch.

Why does the spot price go negative?

Importantly, while generators may offer their generation in at negative prices, the price they receive is determined by the marginal generator—the highest priced offer used to meet demand. While generators may offer at negative prices they often receive positive spot prices for their output.

Sometimes the mechanics of supply and demand can result in negative spot prices. If demand conditions are low, fewer higher priced offers are required to meet demand, driving the spot price down. Similarly, an abundance of negative priced supply can be enough to meet demand on its own and push spot prices negative. The dashed line in figure 1.17 shows that in Queensland for Q3 2019, on average, enough capacity (60 per cent) was offered at negative prices to almost meet demand. Therefore, even small changes in demand or supply resulted in negative prices.

Figure 1.17 Capacity offered above and below $0 per MWh in Queensland during daylight hours, Q3 2019



Source: AER analysis using NEM data.

In recent years, almost all investment in new capacity has been in intermittent fuel types, namely wind and solar. This has further increased the amount of negative priced capacity in the market. Furthermore, weather conditions can affect the amount renewables can generate, and therefore the amount of negative priced capacity in the market. Given many of these generators are grouped together geographically, when one generates others also generate, increasing negatively priced capacity.

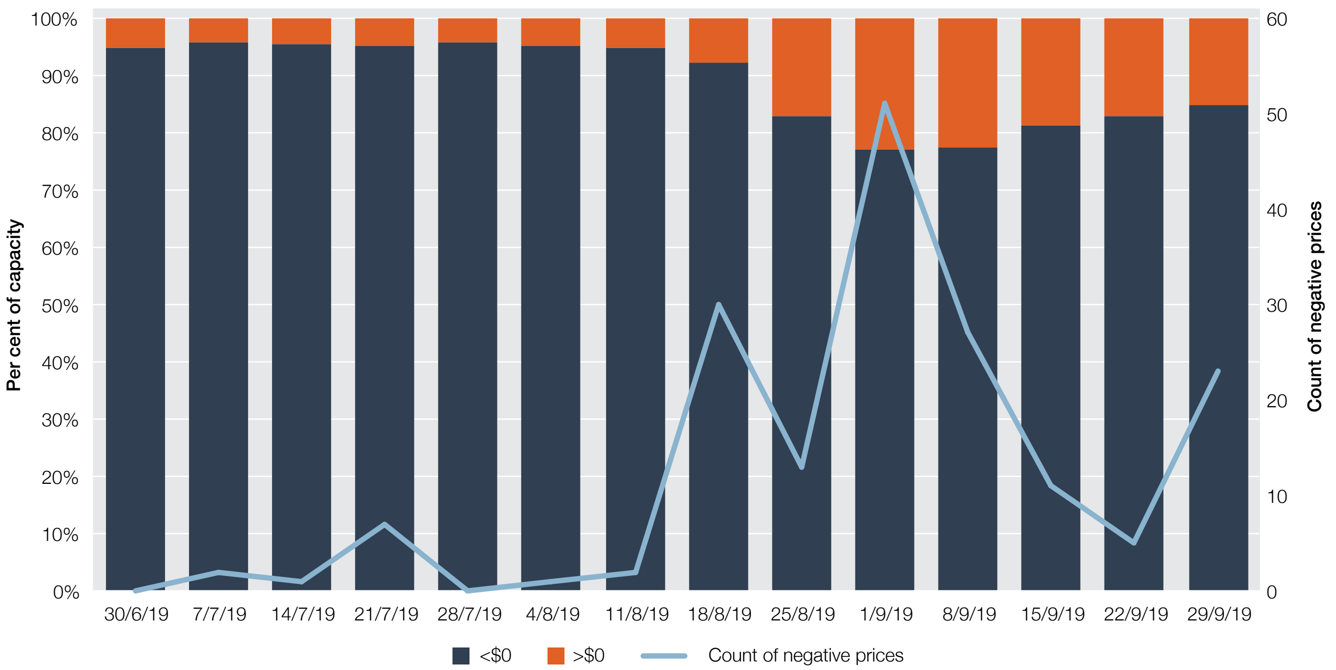
Non-market solar PV (such as residential rooftop solar) also acts to reduce demand at the same time large scale solar generators are producing. Queensland currently has around 2700 MW of rooftop solar installed, which decreases demand from the market during daylight hours.

The market allows generators to respond to changing market conditions, but not all generation types can respond in the same way. Flexible generation types, like hydro, gas, solar and wind, are able to rapidly change their plant output when faced with an unexpected event or negative prices. Inflexible generation types, such as coal-fired generation, are unable to do so to the same extent and might choose to endure an unexpected period of negative prices to avoid greater costs or to meet contracted loads.

What are we seeing?

The increase in negative prices has led to some generators changing their offers to reduce output and avoid uneconomical dispatch of their plant.

Figure 1.18 Weekly average Queensland solar offers as instances of negative prices increase



Source: AER analysis using NEM data.

Figure 1.18 illustrates average weekly solar generation closing offers for Q3 2019 in Queensland. As instances of negative prices increased, solar generators shifted capacity from negative to above $0 per MWh to avoid being dispatched. Wind generators in South Australia also exhibited similar behaviour. This demonstrates the flexibility of these generation types: rebidding as negative prices emerge or are forecast, and adjusting offer strategies as instances of negative prices continue.

While a rapid response to commercial drivers is anticipated, the response of participants to extended periods of negative prices is presenting a number of new challenges for AEMO and participants alike. The operation of the rules framework may also need to be reviewed to see whether it remains fit for purpose to accommodate these changed generator behaviours. We will work with AEMO and other stakeholders to ensure that changes are made if there are weaknesses in the existing rules framework.

We have also observed participants rebidding capacity to low prices in Queensland at the time of negative prices, citing ‘FCAS/Energy co-optimisation’ as the reason. Participants who offer capacity into the FCAS markets in Queensland are mainly coal-fired generators. When the price of energy is negative these generators may have incentives to increase dispatch in FCAS markets where the prices may be higher. For example, on 4 September 2019 the price for some lower services was above $300 per MWh at the time energy prices were negative.

Are negative prices positive for the market?

Spot prices form an important part of the market-based signals that drive commitment, technology investment and exit decisions. As instances of negative spot prices increase, we would expect to see a variety of responses such as new investment, changes in participant behaviour or exit from the market. Operational and policy responses are also important.

Sustained negative prices improves the business case for storage technologies that would, during a period of negative prices, be paid to store energy. Demand side participants may also investigate shifting consumption from higher priced periods into negative priced periods, while older, less flexible technologies, may become unprofitable and exit.

If instances of negative prices persist or increase, generators may drive the spot price higher during periods where the price is positive in order to recover lost revenue. For those with contracts in place that insulate them from negative spot prices, the nature of these agreements may evolve over time as counter parties react to the changing market environment.

For end consumers however, negative wholesale spot prices do not necessarily immediately translate to lower retail prices, as wholesale costs form just one part of a retail electricity bill. Also, risk hedging strategies by electricity retailers insulate consumers from the volatility of the wholesale market. This means changes in wholesale prices typically take some time to flow through to the end consumer.

Overall, negative prices can be a normal part of a functioning market. The appearance of negative prices are not, on their own, a sign of underlying problems. Normally, negative prices act as a signal for participants and investors. Participant, operational and regulatory responses to longer periods of negative prices will continue to be observed and reported on, to assist in understanding the underlying drivers and implications for any future design.

Focus—FCAS market performance

- FCAS costs are small compared with the cost of energy but they have been increasing since 2016.
- The cost and amount enabled of regulation services has increased to record levels over the last two quarters.
- Average prices for raise regulation services increased to record levels in Q3 2019.

The market operator, AEMO, uses frequency control ancillary services (FCAS) to maintain the frequency of the power system at 50 Hertz. FCAS is managed as part of the dispatch process. Participants register to provide FCAS and make offers to provide these services in a similar way as they provide energy offers. AEMO determines which generators provide both energy and FCAS at lowest cost (known as co-optimisation).

A changing market requires closer monitoring

In 2018, the Australian Energy Market Commission (AEMC) reviewed the frequency control frameworks in light of the changing generating mix. To improve the transparency and consistency of information provided to the market, the AEMC subsequently made a rule requiring the AER to report quarterly on the performance of the FCAS markets. We formally commence this role in 2020.

An explanation of FCAS

Frequency control ancillary services are used to maintain the frequency of the power system close to 50 Hertz (Hz). To do this, AEMO must balance the supply of electricity with consumption at all times. They raise system frequency by increasing generation (or reducing load) and lower system frequency by decreasing generation (or increasing load).

There are two general categories of FCAS:

- regulation services
- contingency services.

Regulation services continuously adjust to small changes in demand or supply (changes that cause the frequency to move by only a small amount away from 50 Hz). Costs are recovered from the participants who contribute to the frequency deviating from 50 Hz.

Contingency services manage large changes in demand or supply that occur relatively rarely and move the frequency by a large amount. There are three contingency services:

- fast services, which stop a frequency deviation within the first six seconds of a contingent event
- slow services, which stabilise frequency deviations within sixty seconds of the event
- delayed services, which stabilise frequency deviations within five minutes of the event.

Raise contingency FCAS are required to be available to correct frequency deviations that have arisen from a contingency event that leads to a decrease in frequency. As these contingency events usually involve step reductions in supply side, the rules stipulate that generators pay for these services. Lower contingency FCAS are the services required to be available to correct the frequency deviations that arise from a contingency event that leads to an increase in frequency. As these contingency events usually involve step reductions in customer demand, the rules stipulate that customers pay for these services.

FCAS costs have been increasing

FCAS costs have been increasing since the start of 2016 (figure 1.16). In Q1 2016, total FCAS costs averaged 0.3 per cent of NEM energy costs but they are now four times that, at 1.5 per cent. In Q3 2019, total FCAS costs were $61 million. This was higher than in Q3 2016, but lower than in Q3 2017 and Q3 2018. These costs are recovered from generators and consumers, in part through a causer pays mechanism.

Figure 1.16 shows regulation FCAS costs reached record levels in Q3 2019. The main drivers for the increased cost of regulation services were:

- on the demand side, AEMO increased mainland base regulation FCAS volumes in the first half of 2019
- on the supply side, a reduction in FCAS was offered by Tasmania due to the Basslink outage.

The amount of regulation services enabled has increased and the amount of contingency services enabled is expected to increase.

While the total amount of FCAS enabled (the amount AEMO says participants need to provide of a service) has remained relatively stable since 2015, over the last two quarters the amount of regulation services enabled has increased (figure 1.19).

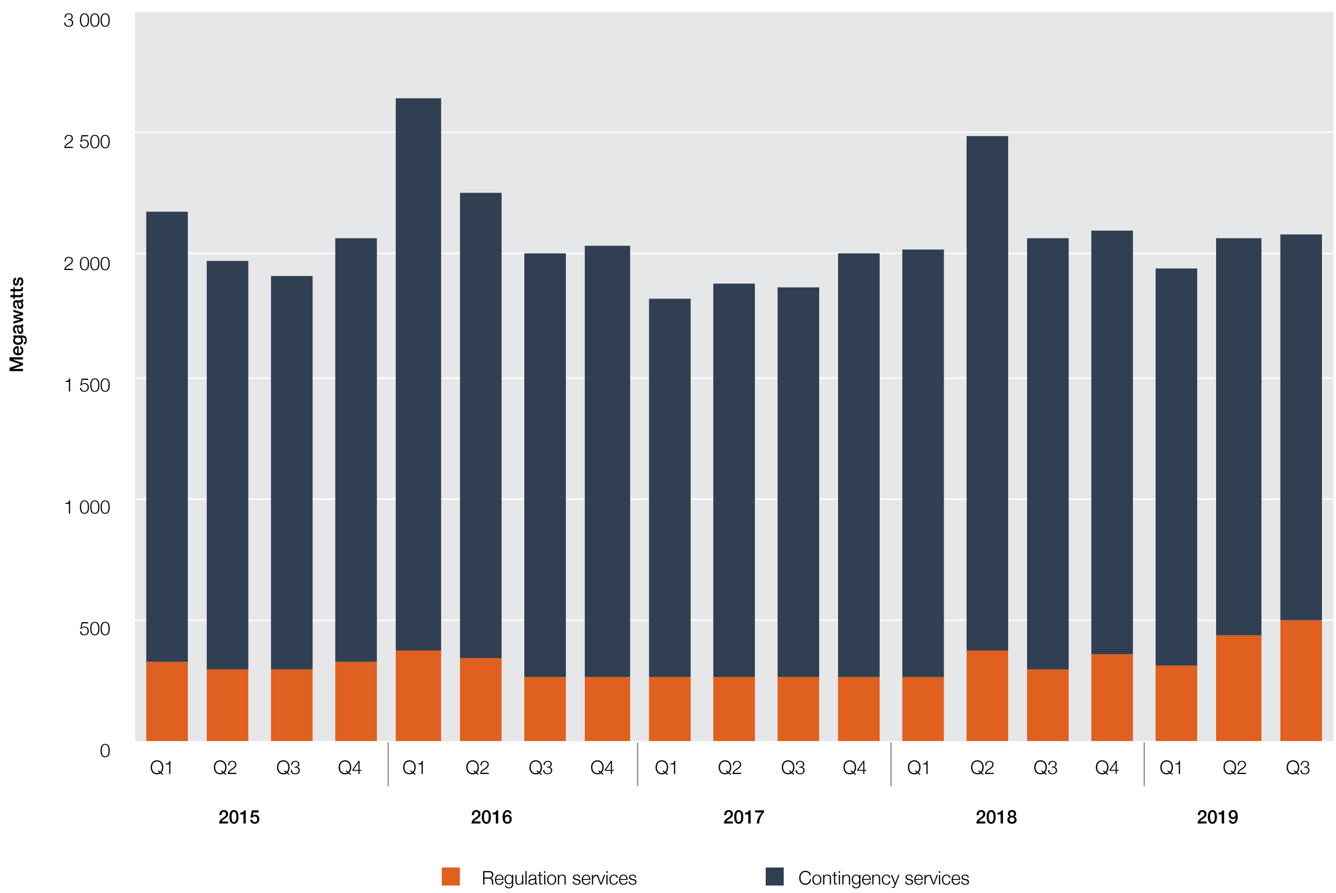
AEMO increased mainland base regulation FCAS volumes, by 50 MW in March, and a further 20 MW in April and 20 MW in May 2019, due to deteriorating frequency performance. Since then, the amount and cost of regulation services enabled has reached record levels. AEMO advised it may further increase the regulation FCAS volumes should frequency performance degrade.

The amount of contingency services enabled is three times that of regulation services. The volume of contingency services enabled has decreased recently but is expected to increase from September 2019.

AEMO changed the way it calculates contingency FCAS requirements and stated the change will materially increase contingency FCAS volumes. AEMO proposes to progressively reduce the mainland load relief assumption in the calculation, from 1.5 per cent to 0.5 per cent. In the first phase, where the load relief will be reduced from 1.5 per cent to one per cent, AEMO estimates, for example, fast raise FCAS will increase by an average of around 100 MW or 26 per cent.

At a regional level, the amount of FCAS enabled in South Australia has increased four-fold over the last two years with the entry of the Hornsdale Power Reserve (battery) and Wind Farm into the market, while the amount of FCAS enabled in NSW has fallen. In Queensland, Victoria and Tasmania, the amount of FCAS enabled has remained largely unchanged.

Figure 1.19 Total FCAS enabled



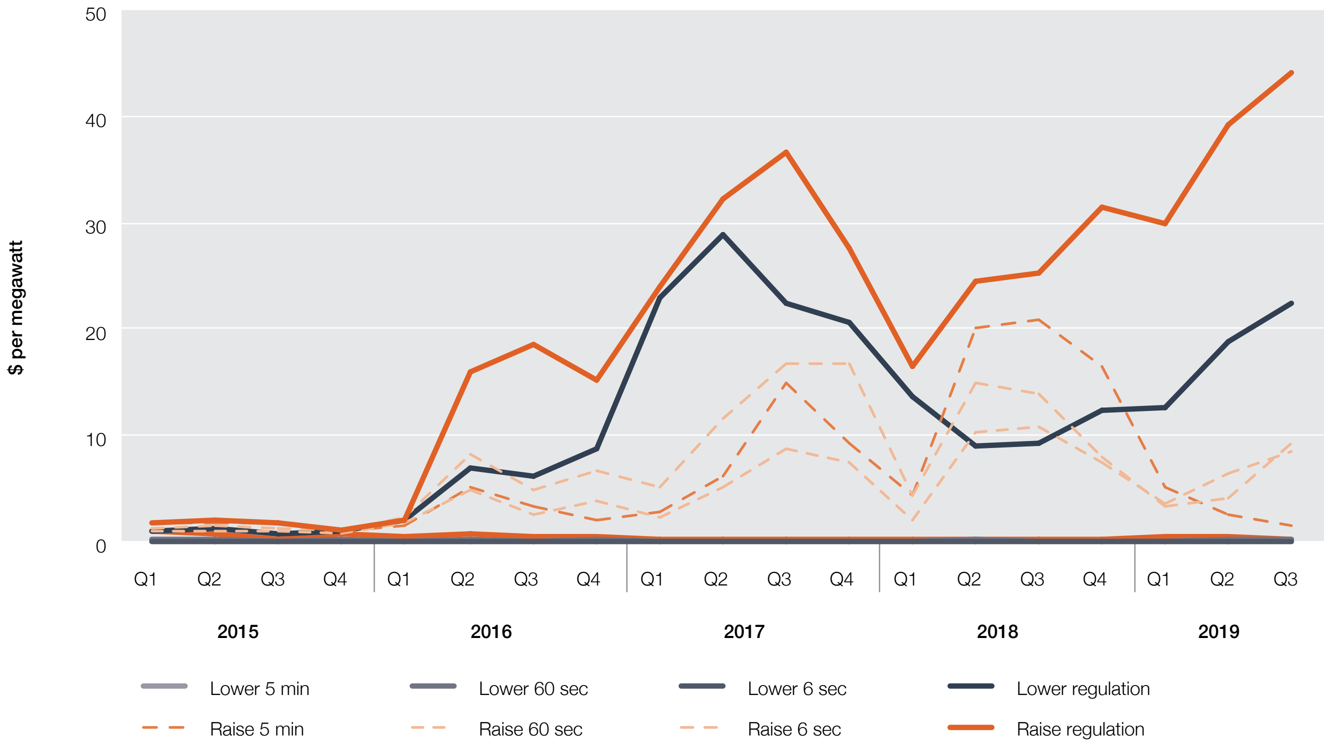
Source: AER analysis using NEM data.

FCAS prices

Average prices for raise and lower regulation services have increased over the last year (figure 1.20, orange and dark blue lines). In particular, average quarterly prices for raise regulation services reached record levels in Q3 2019. They increased 22-fold since the start of 2016, from $2 to $44 per MW.

Average quarterly prices for lower regulation services have doubled over the last five quarters, from $10 to $22 per MW. Average prices for contingency services are significantly lower than for regulation services.

Figure 1.20 Average FCAS prices



Source: AER analysis using NEM data.

New participants are providing FCAS

There are not as many participants in the FCAS markets as in the energy market. There are seven major providers of FCAS in NSW, nine in Queensland, eight in South Australia, seven in Victoria, and one in Tasmania (table 1.3).

Some new participants are providing FCAS. In recent years we have seen demand response aggregators enter the market to provide FCAS. However, for every ancillary service, only a small per cent of capacity is offered by renewable generators or demand responders.

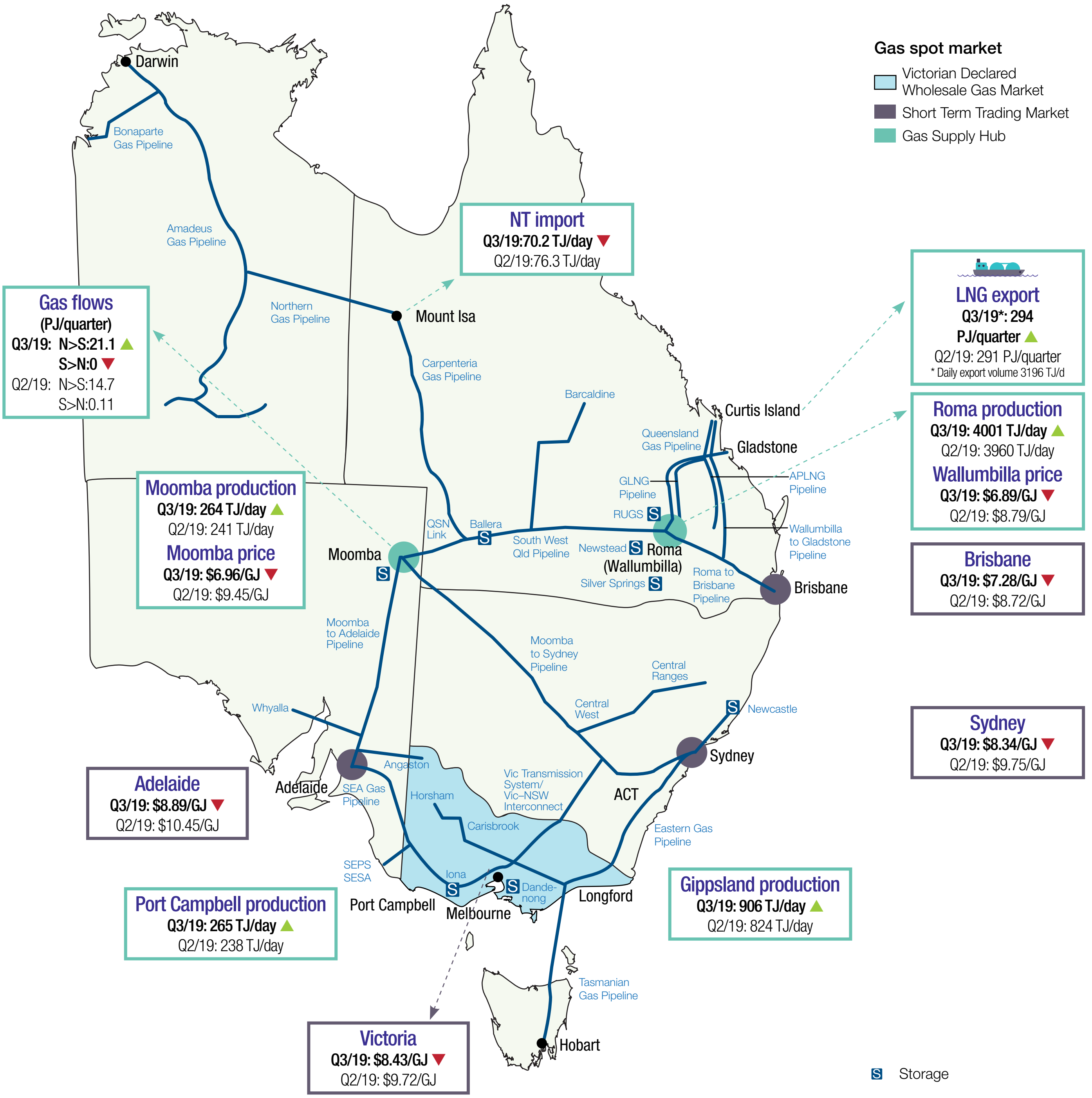
Table 1.3 Participants and number of units providing FCAS, by region

	PARTICIPANT	LOWER 5MIN	LOWER 60SEC	LOWER 6SEC	LOWER REG	RAISE 5 MIN	RAISE 60SEC	RAISE 6 SEC	RAISE REG	TYPE
Qld	AGL Energy		1	1	1		1	1	1	gas
	Alinta Energy	3	3	3	3	3	3	3	3	gas
	CS Energy	8	8	8	8	9	8	8	8	black coal
	CleanCo		1		1	4	5	2	1	hydro, pump, gas
	EnerNOC					1	1	1		demand aggregator
	ERM Power	2	2	2	2	2	2	2	2	gas
	Millmerran				2				2	black coal
	Origin Energy				3				3	gas, liquid
	Stanwell	8	8	8	8	5	8	8	8	black coal, gas
NSW	AGL Energy	8	8	8	8	8	8	8	8	black coal
	Delta	2	2	2	2	2	2	2	2	black coal
	EnergyAustralia	2	2	2	2	2	2	2	2	black coal
	EnerNOC					1	1	1		demand aggregator
	ActewAGL	1	1	1						virtual power plant
	Origin Energy	4	4	4	4	4	5	5	4	black coal, hydro
	Snowy Hydro	4	3	3	3	4	4	4	3	hydro
Vic	AGL Energy	4	10	10	10	8	10	10	10	brown coal, hydro
	Alinta Energy	2	2	2	2	2	2	2	2	brown coal
	EnergyAustralia	5	6	6	9	5	6	6	9	brown coal, gas, battery
	EnerNOC					1	1	1		demand aggregator
	Origin Energy				2				2	gas
	SECV	1	1	1		1	1	1		load (smelter)
	Snowy Hydro	2	1	1	1	2	2	2	1	hydro, pump, gas
SA	AGL Energy	4	8	8	8	4	8	8	8	gas
	Enel X Australia					1	1	1		demand aggregator
	Energy Locals	2	2	1		2	2	1		virtual power plant
	Engie		1	1	1		1	1	1	gas
	Greentricity	2	2	2		2	2	2		battery
	Neoen	2	2	1	5	2	2	1	5	battery, wind
	Origin Energy	1	1	2	2	1	1	2	2	gas
	Snowy Hydro				1				1	liquid
Tas	Hydro Tasmania	18	18	19	17	17	17	18	17	hydro, pump, gas

Source: NEM data.

2. Gas

Figure 2.1 Eastern gas markets, major production, pipelines and storage



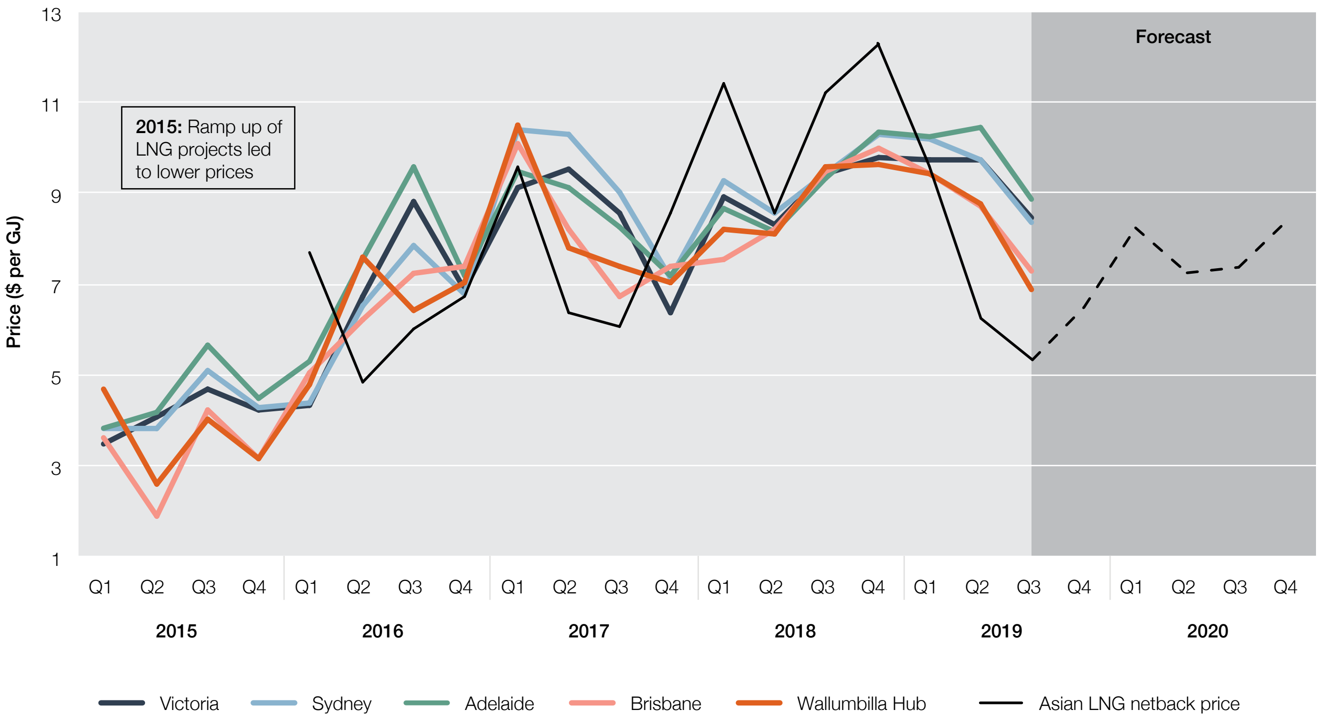
Note: Northern markets consist of Wallumbilla, Moomba and Brisbane (including gas imported from NT). Southern markets include Adelaide, Sydney, Victoria.

2.1 Quarterly spot prices

- Quarterly wholesale gas spot prices averaged across five markets dropped to $7.96 per GJ (or 16 per cent).
- The decrease was consistent with a sharp fall in Asian LNG spot prices, increased northern supply and use of the new pipeline capacity auction.

Figure 2.2 shows that spot prices dropped sharply from Q2 2019 prices by an average of $1.55 per GJ, to $7.96 per GJ, across the five domestic markets, commensurate with a large drop in the Asian LNG netback price (at Wallumbilla).[8] Notably, although prices fell in all markets, a north-south price gap opened, with spot prices in the three southern markets $1.47 per GJ higher than in the northern markets.

Figure 2.2 Domestic spot prices and Asian LNG spot netback price



Source: DWGM, STTM, WGSH and ACCC netback price series.

Note: Wallumbilla hub is the exchange traded day ahead price at the Wallumbilla location. Victoria is daily imbalance price calculated at 6:00 am schedule. Sydney, Adelaide and Brisbane are the ex-ante schedule prices.

A number of factors may affect domestic spot prices (see appendix). However, three inter-linked factors appeared to drive spot price falls in Q3 2019: lower Asian LNG spot prices, a surplus of production in the north, and access to cheap gas transportation through the pipeline Day Ahead Auction (DAA):

- Asian LNG netback prices were 52 per cent lower at $5.30 per GJ this quarter, when compared to Q3 2018. Figure 2.2 shows the recent trend of Asian LNG netback prices and domestic spot prices moving in the same direction.
- Gas production increased in the north (Moomba and Roma), while exports from Gladstone stayed steady (figure 2.1). Accordingly, significant northern supply was brought south to meet winter peak demand in South Australia, NSW, and Victoria.
- The DAA, which commenced on 1 March 2019, facilitated shippers moving gas from northern to southern markets at near zero auction costs, with the Moomba Sydney Pipeline being the most used auction route.

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8 Asian LNG netback prices are a measure of the export parity price that a domestic supplier can expect to receive for exporting its gas. Here, it is the receipt price for LNG minus the cost of conversion to LNG and shipment, netted back to Wallumbilla. For further information: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series.

Figure 2.3 shows the north-south commodity price differences since 2015.

Figure 2.3 North-south commodity price gap

Source: DWGM, STTM and WGSH data.

Price separation has often occurred but not due to divergent price movement between southern and northern markets. Prices across markets have generally followed the same path up or down over quarters, but at a different magnitude, as illustrated above. No price gap existed in Q3 2018, as Asian spot prices reached an uncharacteristic seasonal high, which raised the price in northern markets. Price gaps this winter (Q3 2019) were narrower ($1.47 per GJ) than previous winters ($1.94 per GJ and $1.65 per GJ in Q3 2016 and Q3 2017, respectively). This is likely attributable in part to the role of the DAA in lowering the cost of transporting gas between spot markets.

2.2 East coast outcomes

- Production increased to meet winter heating and high mainland gas powered generation demand.
- Record gas flows between the north and the south.
- Iona storage was heavily utilised to meet peak demand over winter, whilst RUGS increased its storage levels in the north.

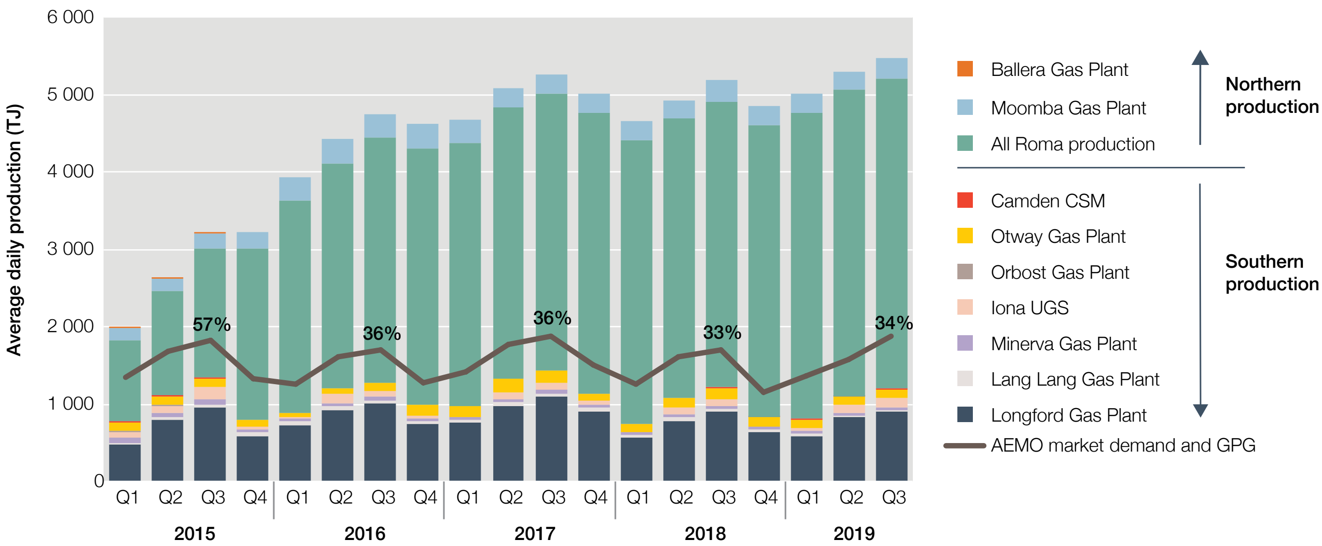
EAST COAST WIDE SNAPSHOT												
	Eastern States Combined[c]				BRI	VIC	SYD	ADL	BRI	VIC	SYD	ADL
	2015	2016	2017	2018	Q3 2018				Q3 2019			
average spot market price, $/GJ	$4.03	$6.73	$8.56	$9.11	$9.49	$9.43	$9.44	$9.33	$7.28	$8.43	$8.34	$8.89
					$9.42				$8.24			
total net market trade volume, PJ[a]	25.2	24.2	33.6	30.8	0.3	4.7	3.2	1.2	0.2	7.4	4.4	0.9
					9.4				12.9			
spot trade as a proportion of scheduled demand (%)	8.2%	7.1%	9.2%	10.5%	3.3%	5.9%	12.3%	16.1%	3.0%	8.7%	16.7%	13.2%
total GPG, PJ	185	146	187	140	9	6	4	16	10	11	6	18
					35				45			
total production, PJ	974	1600	1811	1772	466				491			
LNG export, PJ	317	950	1101	1119	282				294			
(+) total import from North, PJ	+22.4	+1	+9	+19	+8.6				+21			
(-) total export to North, PJ	-7.2	-72.4	-48.4	-15.9	-0.5				0			
average underground gas storage level, PJ	N/A	N/A	N/A	N/A	100.3[b]				93.6			

a January 2015 net market trade volume for Victoria was estimated due to unavailability
b Roma UGS Q3 2018 was estimated using Q4 2018 figures
c Eastern states include Queensland, Victoria, NSW and South Australia

Production

Figure 2.4 shows east coast gas production grouped into the north and south.

Figure 2.4 East coast production



Source: Natural Gas Services Bulletin Board data, NEM data, DWGM and STTM data.

East coast gas production averaged 5,467 TJ per day over Q3 2019. This was a record level as strong demand emerged for gas powered electricity generation in southern states. The demand represented a 41 per cent increase from Q3 2018.

To date, gas production has typically peaked in Q3, coinciding with peak residential heating demand during winter (June, July and August) in southern states. Despite LNG spot prices typically being higher during the northern hemisphere winter (December, January and February), this has not led to peak east coast production during Q4 or Q1.

In Q3 2019, production from Roma accounted for approximately 4000 TJ per day, around 73 per cent of east coast production. Gas production is dominated by facilities operated by the three LNG exporters and production located around Roma. Table 2.1 shows the composition of the largest production fields in Roma.

Table 2.1 Gas production in Roma, Queensland in Q3 2019

PRODUCTION FACILITY	PRODUCTION VOLUME (TJ/DAY)	NAMEPLATE CAPACITY (TJ/DAY)
Wolleebee Creek (QGC)	644	757
Ruby Jo (QGC)	409	503
Fairview (Santos)	402	430
Jordan (QGC)	332	507
Combabula (APLNG)	262	286
Bellevue (QGC)	194	243
Orana (APLNG)	186	197
Reedy Creek (APLNG)	184	190
Condabri (APLNG)	178	190
Eurombah Creek (APLNG)	152	190
Total top 10 production	**2 943**	**3 493**

Source: Natural Gas Services Bulletin Board data.

Note: QGC is the name of an upstream entity operated by Shell.

Outside of Queensland, the Longford Gas Plant is the most significant source of supply. The plant averaged 906 TJ per day production over Q3 2019, slightly higher than in Q3 2018.

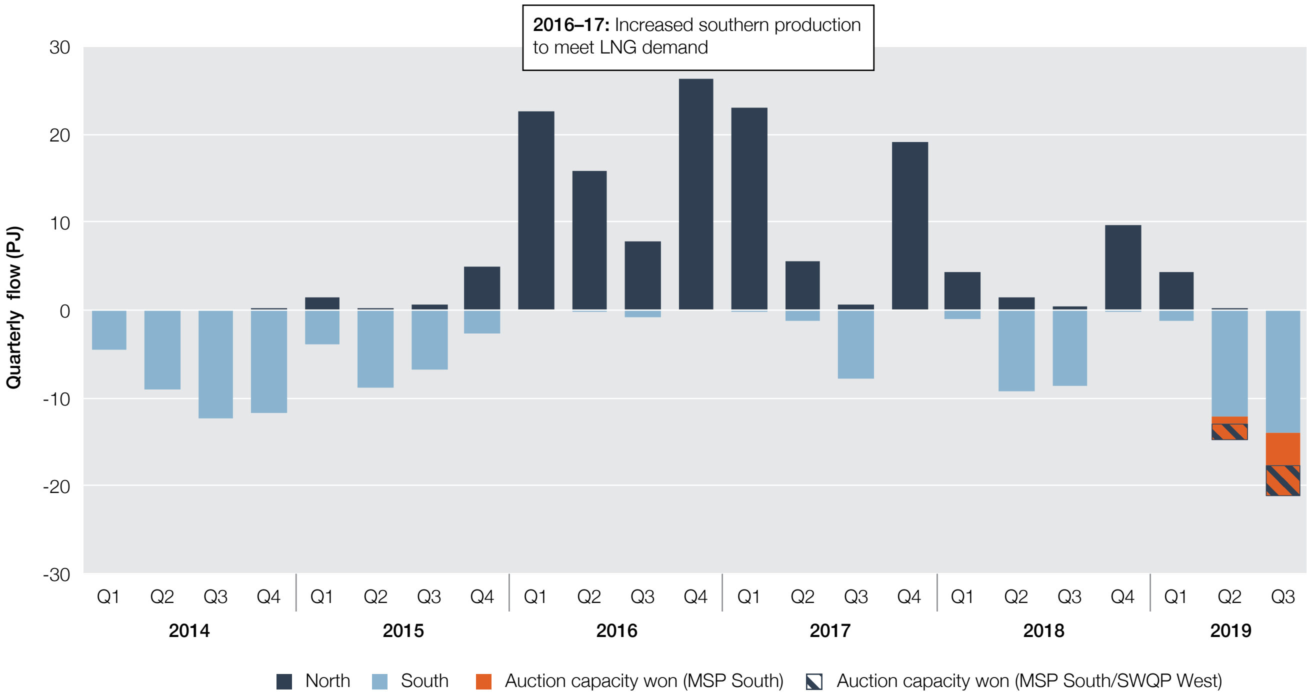
During Q3 2019, a number of new gas production facilities in Queensland and the Northern Territory registered to report production volumes on the Natural Gas Services Bulletin Board. These were Kincora (QLD), Mereenie (NT) and Palm Valley (NT) gas plants, collectively having a nameplate capacity of 79 TJ per day.

On 9 August 2019, there was record demand in the Victorian gas market. On this day, Longford ran at high production to meet Victorian and NSW demand (994 TJ combined) while Iona's value in meeting high Victorian demand was reflected in 353 TJ of injections. There were also sizeable interconnected pipeline contributions via NSW imports at Culcairn (which was limited by constraints to 79 TJ), through the VicHub (51 TJ) and from gas stored on the Tasmanian gas pipeline (25 TJ).

Flows between north and south

Figure 2.5 depicts gas flows since 2014 when gas began to move more dynamically between the northern and southern markets (markets are shown in figure 2.1) in greater volumes. More recent increases in gas flows south correspond with a trend, commencing across 2018, toward decreased southern production.

Figure 2.5 North-south gas flows



Source: DWGM, STTM, DAA data.

Note: North/South flows depict net physical flows around Moomba–North or South.

Since 2016, production in Queensland has risen, resulting in less gas needing to be sourced from southern states to produce LNG for Queensland exports (as played out in 2016).

Strong production in Queensland over Q3 2019 coincided with record flows of approximately 233 TJ per day to southern markets. Flows to southern states from Queensland more than doubled, growing by 144 per cent from Q3 2018.

Additionally, the commissioning of the Northern Gas Pipeline in early 2019 has enabled gas imports from the Northern Territory to Queensland, reaching an average of 70 TJ per day in Q3 2019. This has enhanced the capability for gas flows from northern markets to NSW, South Australia and to a lesser extent, Victoria.

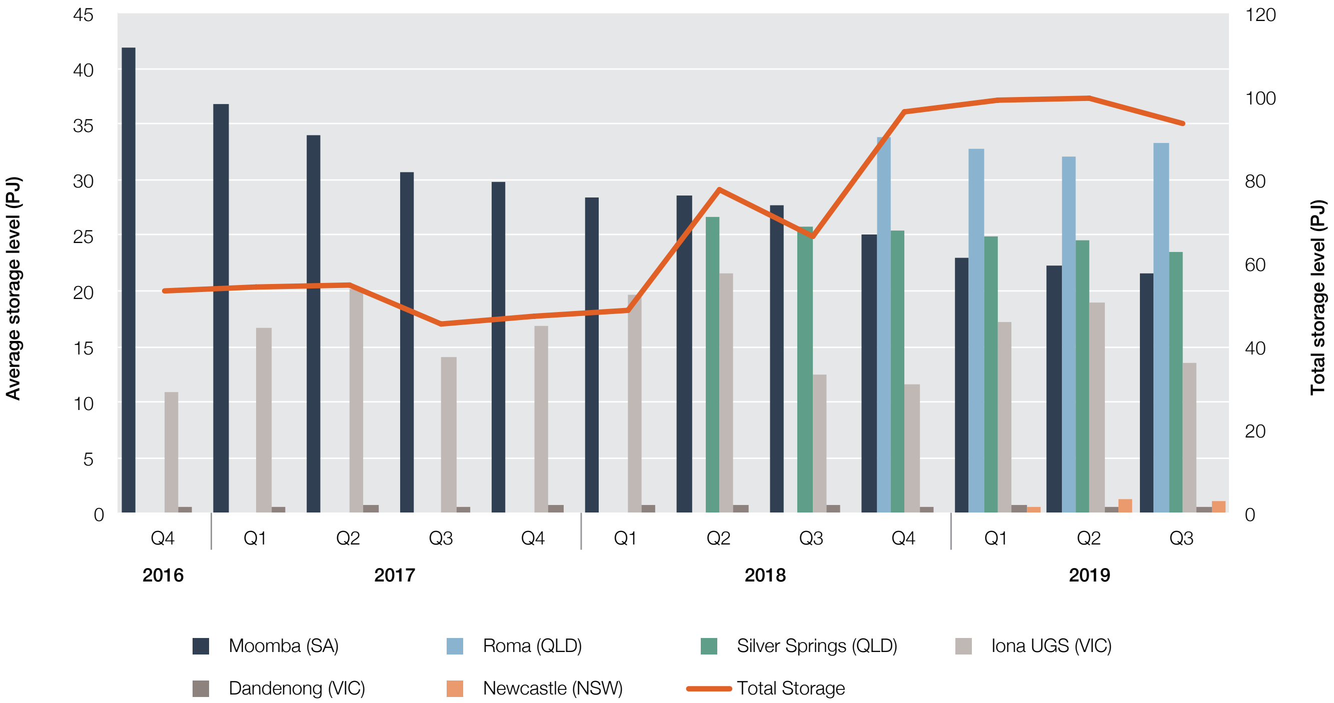
In Q2 and Q3 2019, there has also been significant cheap auction capacity won through the DAA for routes south on the SWQP and MSP shown by the orange colouring in the bars. The vast majority of this capacity is likely to have been used the subsequent day to transport gas south (DAA outcomes are discussed in section 2.3) and reflects a benefit to further trade and gas movement via the introduction of the auction.

Storage

Expansions to the Victorian gas transmission system and the Iona Underground Gas Storage facility has allowed gas to move in greater volumes in and out of storage.[9] [10] During Q3 2019, gas storage provided critical support, supplying Victoria during winter demand peaks, particularly when gas was used for high levels of electricity generation. This occurred on 30 and 31 July, and on 9, 12 and 13 August.

Figure 2.6 shows average storage levels for large underground gas storage facilities and smaller LNG storage facilities.

Figure 2.6 Storage levels



Source: Natural Gas Services Bulletin Board data.

Note: Roma, Silver Springs underground storage facilities are long established facilities but only commenced reporting of storage data pursuant to legislation in 2018.

In states outside of Victoria, a number of large storage facilities have been consistently drawn down, particularly as LNG export facilities were commissioned from 2015. The use of these storage facilities appears to be less influenced by seasonal trends, with lower injection and withdrawal capabilities compared to the Victoria's Iona Underground Storage facility. Against this trend, storage levels in RUGS have increased from the start of 2019. This may in part be linked to GLNG export plant outages over Q3 2019.

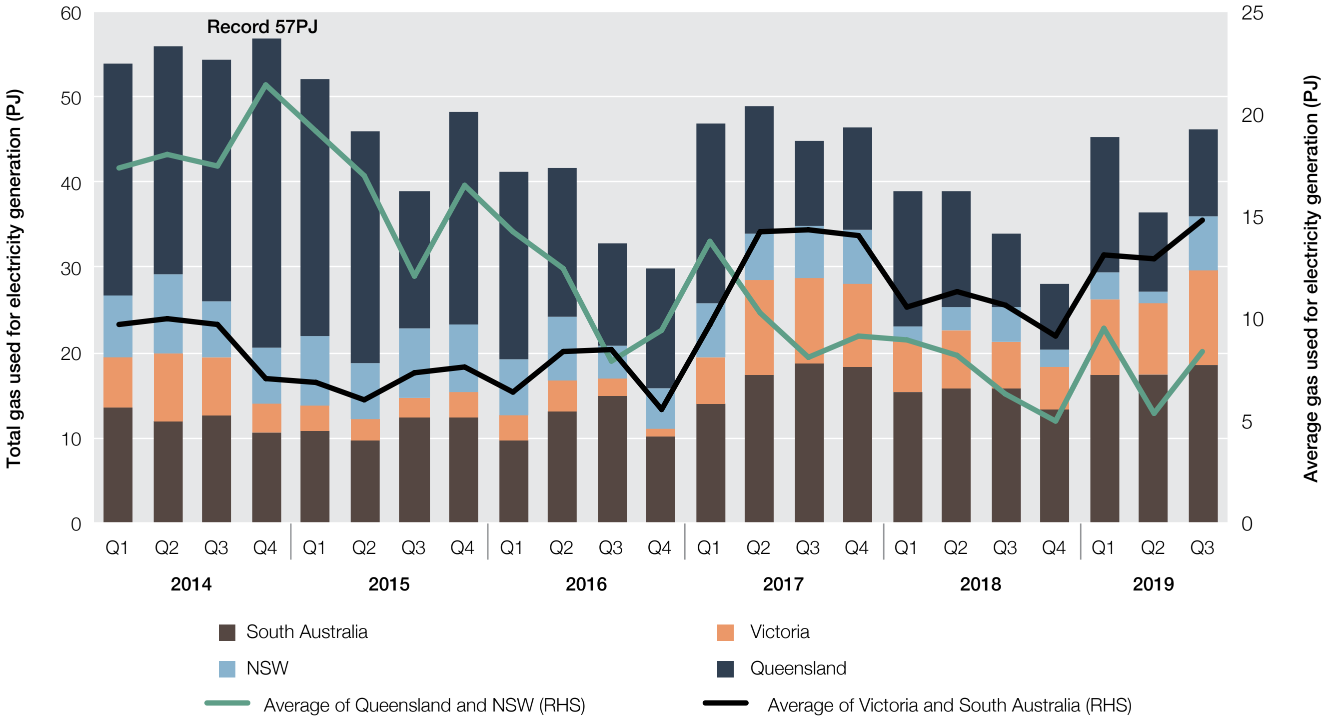
9 AEMO, *Vic gas planning report 2018*: https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2017/2018---Victorian-Gas-Planning-Report-Update.pdf, pp. 42–43.

10 AEMO, *Vic gas planning report 2019*: https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/VGPR/2019/2019-VGPR-Full-Report.pdf, p. 57.

Gas powered generation (GPG)

Figure 2.7 shows the gas used by gas power generation in the NEM (except Tasmania) since 2014. The combined NSW and Queensland levels are shown for comparison against the combined Victorian and South Australian levels.

Figure 2.7 Gas powered generation



Source: NEM data, ACIL Allen data.

Elevated levels of gas demand for electricity generation occurred in Q3 2019 across NSW, Victoria and South Australia. As outlined in the electricity component of this report (section 1.5), this corresponds with lower gas prices, less hydro generation and significant coal power plant outages.

There has been increased output from gas powered electricity generators in the NEM's southern markets since the closures of the Northern power station (South Australia) in 2016 and Hazelwood power station (Victoria) in 2017. This is in contrast to Queensland, which historically consumed the most gas for electricity generation but has progressively reduced its usage, particularly as gas has become more scarce and expensive since LNG export projects have been commissioned. South Australia has overtaken Queensland as the largest consumer of gas for electricity generation. Collectively, southern states have used close to record volumes of gas for electricity generation in Q3 2019.

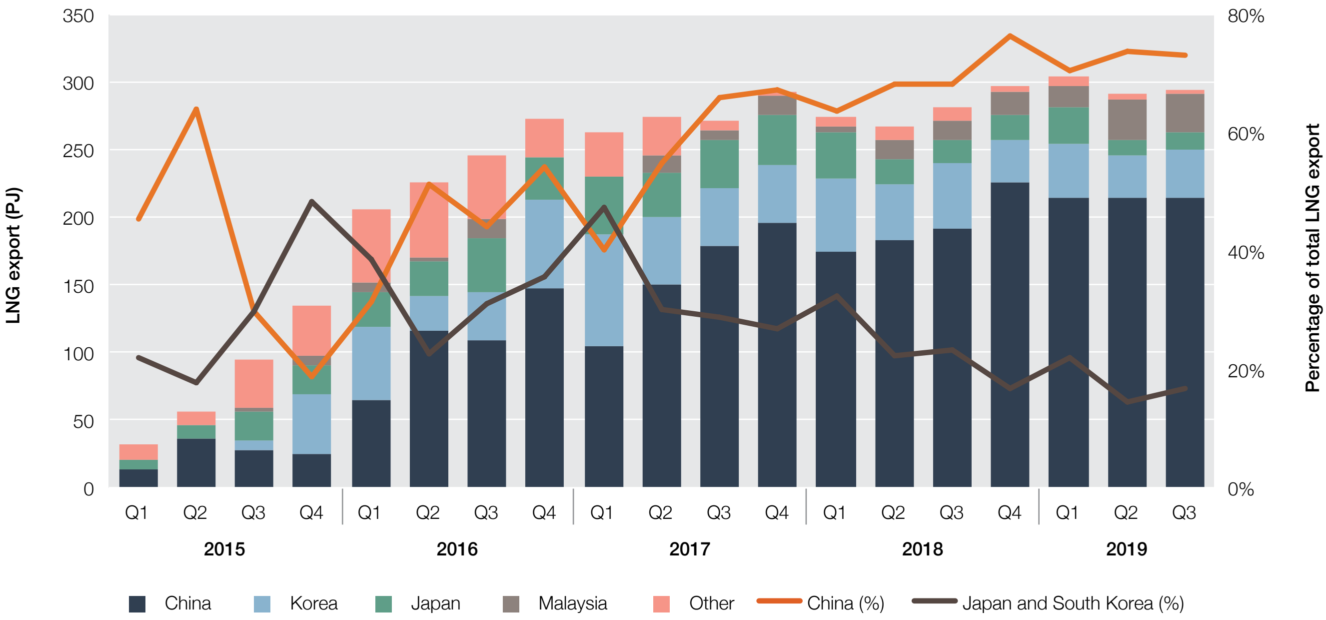
2.3 Upstream market outcomes

- LNG export levels were steady from Q2 to Q3 2019 and down from Q1 2019, when LNG spot prices were higher.
- Gas Supply Hub exchange trade volumes maintained near record levels with a skew towards off screen trade as brokers continue to finalise deals.
- Day Ahead Auction volumes increased this quarter along with participation.

LNG exports

Figure 2.8 shows LNG exports along with a breakdown of the intended destination port. The orange and black lines show the percentage of total LNG exports going to China, and to Japan and South Korea combined.

Figure 2.8 LNG shipped from Gladstone Port by destination



Source: Gladstone Ports Corporation data.

LNG export volumes were effectively unchanged compared to the previous quarter being only 4 PJ higher.

The majority of Roma (and Moomba) gas production is contracted to Asian customers in Japan, South Korea and China through long-term contracts, explaining the high export volumes to these countries. Cargoes marked for export to China were slightly higher but cargoes marked for export to Japan and South Korea declined by 25 per cent (down from 65 PJ in Q3 2018 to 49 PJ this quarter). This may be explained by the restarting of nuclear power generation, replacing gas, to meet electricity demand in Japan.

Without legislation that requires information on whether cargoes leaving Gladstone are sold under contract or as spot cargoes in place, it is impossible to be sure that there were no spot cargoes this quarter. However, spot cargo sales seem unlikely given low spot prices. The public reporting of information on LNG shipments and prices is currently being considered by the Council of Australian Governments' Energy Council.

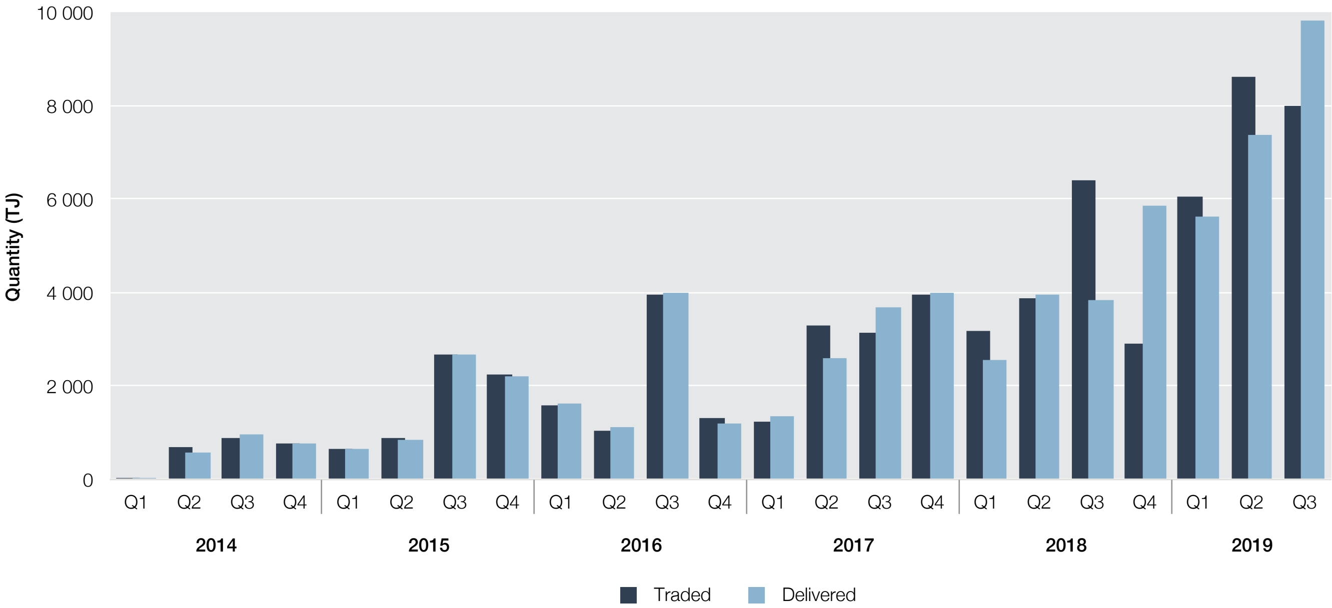
Gas Supply Hub outcomes

GAS SUPPLY HUBS SNAPSHOT	2014	2015	2016	2017	2018	2019 YTD
number of trades	481	875	798	1638	1919	2932
trade volume, PJ *% of trade by top 3 buyers : sellers*	2.4 *67% : 89%*	6.4 *71% : 75%*	7.9 *66% : 56%*	11.6 *51% : 59%*	16.4 *53%: 52%*	22.7 *54% : 66%*
trade value, $million	5	24	57	89	148	185
volume weighted average price, $/GJ	2.01	3.66	7.20	7.68	9.02	8.18
number of trading participants *number of active participants on-screen vs. off-screen*	8 *7:0*	12 *11:7*	12 *11:11*	13 *12:9*	13 *12:12*	14 *12:14*
% traded through exchange (sum bought divide by regional demand)	N/A	N/A	N/A	4.3%	6.1%	9.4%

Source: GSH trades data, Natural Gas Service bulletin board.

Figure 2.9 shows volumes traded or settled through the Gas Supply Hub (GSH) exchanges (Moomba and Wallumbilla).

Figure 2.9 Traded and delivered quantities in GSH

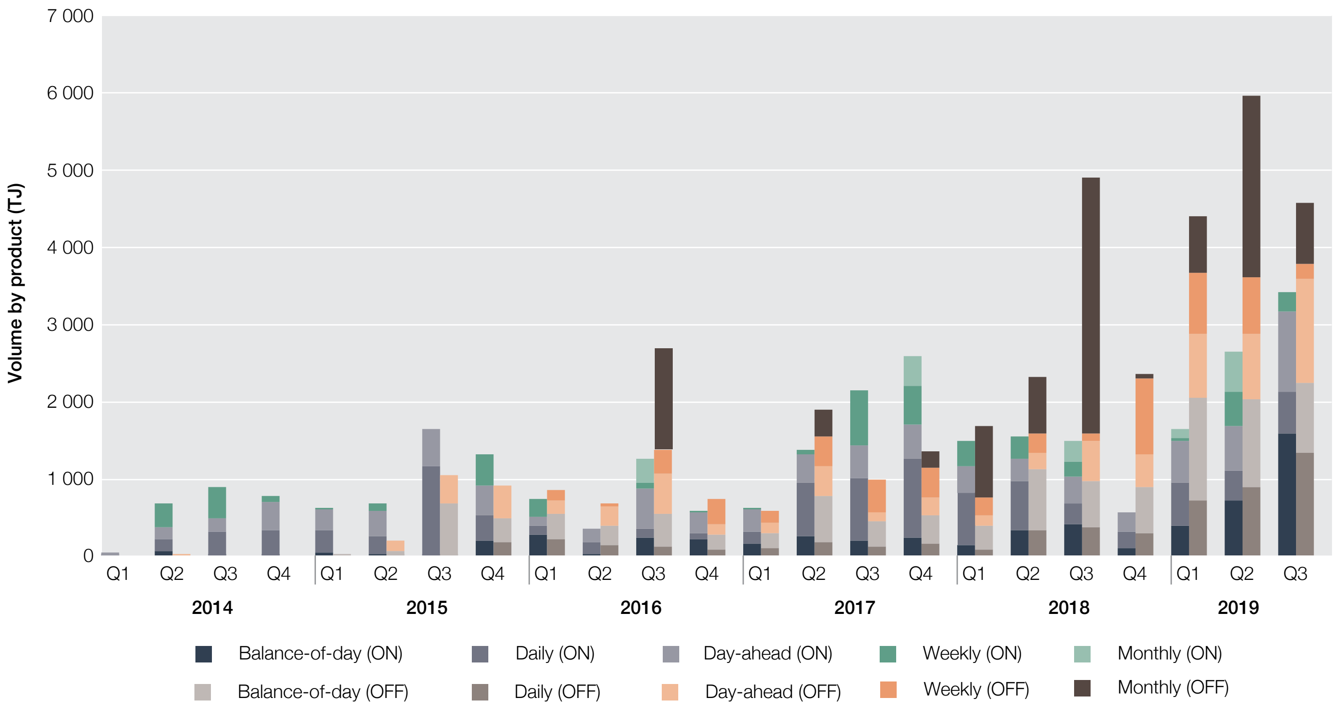


Source: WGSH, MGSH data.

Trade at the GSH continued to remain high in Q3 2019 after increases in previous quarters. There were a record number of quarterly trades through the GSH in Q3 2019, with 1007 transactions. There was just over 8000 TJ of gas traded, falling short of the Q2 2019 record of 8617 TJ (figure 2.9). The extra volumes traded in Q2 2019, however, reflected increased use of monthly products, which traded into Q3 2019, resulting in record quantities delivered for the quarter (figure 2.10).

Figure 2.10 shows the distribution of trade by product and whether the trade was done on screen through the anonymous bidding platform or off screen via bilaterally priced deals and then placed on the exchange for settlement.

Figure 2.10 GSH—On and off screen trade volumes by product



Source: WGSH, MGSH data.

Participants, both on and off screen, continued to make more use of balance of day and day ahead products in Q3 2019 (figure 2.10). In part, this is likely reflecting an opening of transportation routes as a result of the pipeline capacity trading and DAA reforms. These reforms have improved access to key transportation routes, such that buyers can more easily bring gas from northern to southern markets.

More broadly, trade at the GSH has increased since Q3 2018, with off screen trades doubling in volume from 2017–18 levels. Participants have indicated that this may reflect the greater involvement of brokers matching trades on behalf of participants, accelerating market activity. Participants can also leverage pre-existing bilateral arrangements to facilitate spot trades, entering transactions directly over the phone and then lodging these through the hub. This may also accelerate market activity when on screen bids and offers are not matching. Notably, these products often involve larger volumes of gas than on screen alternatives.

More recently, some off screen products can now be traded 24 hours a day, providing even greater access to the market. However, this primarily benefits those participants who use brokers, or have pre-existing bilateral arrangements. Other participants may be more reliant on the anonymous offers and bids, which are matched on screen.

While the increase in trade is positive, the trend towards more active participants off screen—participation has risen above on screen in 2019 for the first time—warrants further monitoring and investigation of the impacts on different participants, small and large.

The number of participants trading in the GSH has risen to 14 for 2019 to date, as one participant has returned to trade primarily off screen. The balance of trade through the GSH this year has become slightly more concentrated, with the top three buyers and sellers now accounting for 54 and 66 per cent respectively, up from just over 50 per cent each in 2018. Traders now account for 12 per cent of gas traded through the GSH, compared with seven per cent in 2018.[11]

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11 Participant categories include Export/producers (participants who export or produce gas), Gentailer/GPG (participants who retail gas or generate electricity using gas), Industrial (participants who use gas for industrial purposes), and Trader (participants who trade on the hub as a trader). There are 16 participants currently registered for the GSH including: AGL Energy, Arrow Energy, Australia Pacific LNG, Braemar Power Project, CleanCo, EnergyAustralia, ERM Power, GLNG, Incitec Pivot, Macquarie Bank, Origin Energy, Santos QNT, Stanwell, Strategic Gas Market Trading, Walloons Coal Seam Gas Company and Westside.

Table 2.2 shows the hub churn rate by quarter, reflecting the ratio of volume of trade to regional demand going through the hub.

Table 2.2 Churn rate by Gas Supply Hub[12]

QUARTER	MOOMBA	WALLUMBILLA	QUARTER	MOOMBA	WALLUMBILLA
Q4 2016	-	1.6%	Q2 2018	0.0%	6.0%
Q1 2017	-	2.0%	Q3 2018	0.1%	5.6%
Q2 2017	-	4.4%	Q4 2018	0.1%	8.3%
Q3 2017	0.0%	5.3%	Q1 2019	0.1%	8.0%
Q4 2017	0.0%	5.6%	Q2 2019	1.3%	8.7%
Q1 2018	-	4.1%	Q3 2019	0.9%	11.6%

Source: WGSH and MGSH data, Natural Gas Services Bulletin Board data.

The churn rate has increased to 9.4 per cent this year. When treated separately, the Wallumbilla hub reached a record level of 11.6 per cent in Q3 2019 (table 2.2). While comparatively lower, the Moomba hub remained higher than historic levels, achieving 0.9 per cent churn rate for this quarter.

Day Ahead Auction outcomes

DAY AHEAD AUCTION SNAPSHOT	MAR	APR	MAY	JUN	JUL	AUG	SEP
number of trades	142	132	260	279	413	449	419
capacity traded, TJ	2548	1747	2853	2010	5315	5590	4040
maximum auction price, $/GJ	0.10	0.28	0.70	0.61	0.65	1.00	1.05
number of active participants	1	2	4	3	4	5	6
% traded at $0/GJ	82%	95%	89%	79%	74%	53%	91%
% traded at ≥$0.10/GJ	0%	1%	9%	13%	19%	32%	4%

Source: DAA auction results data.

Notes: Each trade reflects a leg acquired through the auction. So, if capacity is acquired from Wallumbilla to Sydney on a day this could involve two legs—SWQP and MSP—or up to as many as four legs if capacity on the RBP and Wallumbilla compressors has also been involved to move gas south.

The DAA commenced on 1 March 2019 along with the pipeline capacity trading reforms to facilitate two new ways of purchasing pipeline capacity (see the background to the reforms in the appendix). Fourteen organisations have registered to participate in the DAA to the end of Q3 2019, with seven taking part to date. Monthly participation increased from a sole participant in the first month the auction was run, to six participants in September.[13]

The highest number of trades and total quantities won were observed in August, closely followed by July, largely driven by capacity won on the Moomba to Sydney Pipeline (MSP) and the desire to move gas south during the

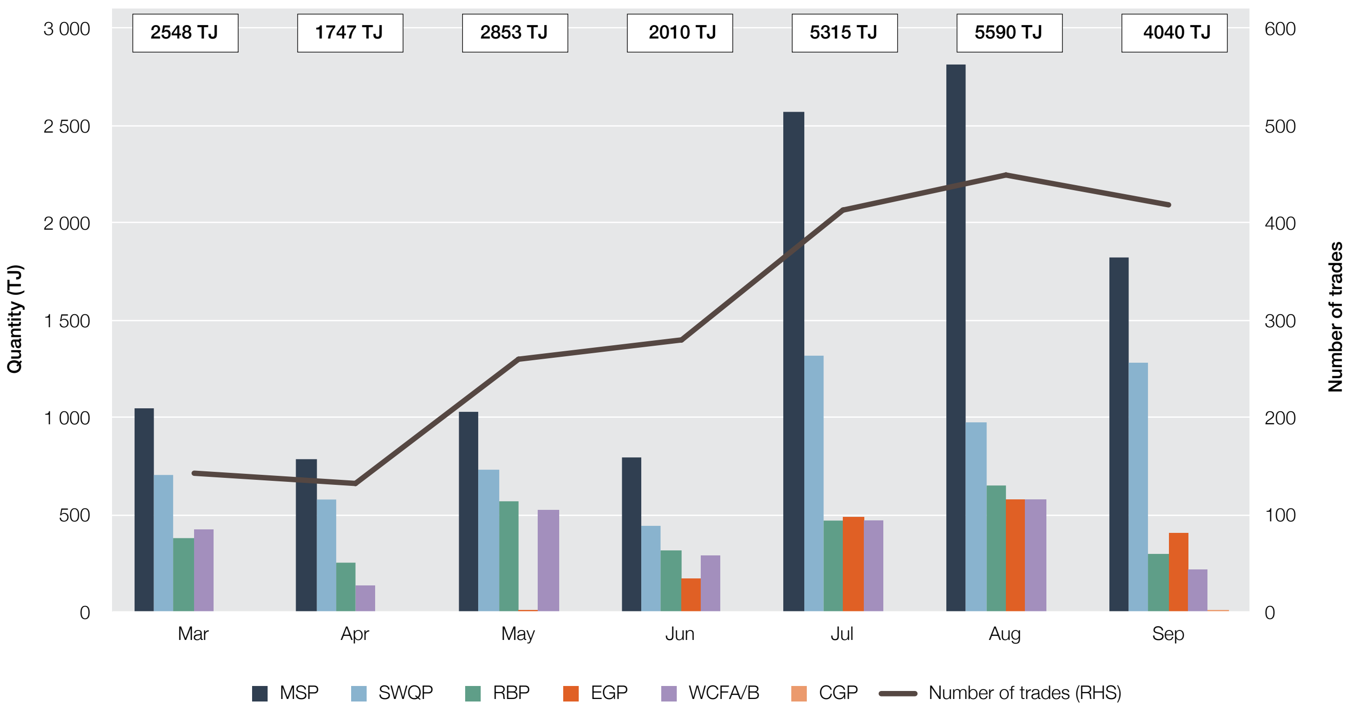
12 No results are those quarters where there was no gas traded on the Moomba Hub.

13 Registered DAA participants include: CleanCo Queensland Limited, EnergyAustralia Pty Ltd, ERM Power Retail Pty Ltd, Esso Australia Resources Pty Ltd, Incitec Pivot Limited, Macquarie Bank Ltd, Origin Energy Retail Ltd, Qenos Pty Ltd. Santos QNT Pty Ltd, Shell Energy Australia Pty Ltd, Stanwell Corporation Limited, Strategic Gas Market Trading Pty Ltd, Tarac Technologies Pty Ltd and Walloons Coal Seam Gas Company Pty Limited.

winter months (figure 2.11).[14] The frequency of trades at $0 per GJ increased in September as more auction capacity became available and quantities won decreased. An exception was available auction capacity west on the Roma to Brisbane Pipeline (RBP), which was 100 per cent utilised during this period and a record high price of $1.05 per GJ was observed.

All trades on the Eastern Gas Pipeline (EGP), Carpentaria Gas Pipeline (CGP) and Wallumbilla Compression Facilities A and B (WCFA and WCFB) were won at $0 per GJ, while trades on the MSP in April, May, June, July and September were also won at $0 per GJ. The demand for auction capacity on heavily contracted pipelines (to move gas south) was highlighted by prices on the South West Queensland Pipeline (SWQP) being greater than or equal to $0.10 per GJ for more than 60 per cent of quantities won in July and August, more than 40 per cent of quantities won in June, July and September on the RBP and more than 35 per cent of quantities won in August on the MSP. Low auction prices have to some extent contributed to lower southern spot prices, putting downward pressure on prices in delivery zones where auction capacity was won (See Focus—North-south gas price separation).

Figure 2.11 Pipeline capacity won on the DAA



Source: DAA auction data.

Notes: Quantities shown are the monthly sum of auction products allocated on each pipeline and do not necessarily represent the physical volumes of gas that actually flowed for each gas day.

The DAA has resulted in over 24 PJ of unused contracted pipeline capacity being won across seven facilities in the seven months since its commencement on 1 March 2019, with the majority of capacity won facilitating low-cost transport of gas from northern to southern markets in Victoria and NSW via the heavily contracted SWQP and MSP. These two pipelines have accounted for approximately 70 per cent of auction capacity won to date, with the most popular delivery zones being Culcairn (MSP-DZ-08), Moomba (SWQP-DZ-01) and Sydney (MSP-DZ-06). Capacity has also been won on the RBP, on the majority of days it has been available, with the delivery predominately into Wallumbilla (RBP-DZ-01).

Increased participation has seen total capacity won increase by more than 58 per cent by the end of September compared to the first month of the auction (March 2019). The number of trades has also increased almost three times over the same period. In addition, increased competition has also resulted in the percentage of trades won

14 A trade is defined as the auction transaction in which auction capacity was won by a participant from a given receipt point to delivery point, it is inclusive of pipeline segments.

at $0 per GJ decreasing from a monthly high of 95 per cent in April to 53 per cent in August, with auction products priced greater than $0 per GJ observed on pipelines when auction limits were reached.[15]

Unsurprisingly, June to August saw a reduction in auction capacity available on the SWQP and RBP as contract holders shipped closer to their contractual rights. This resulted in high levels of available auction capacity utilisation as shown in table 2.3. September saw an increase in available auction capacity on the SWQP, resulting in a considerable decrease in utilisation.

Table 2.3 Capacity availability and utilisation on the DAA[16]

	MAR	APR	MAY	JUN	JUL	AUG	SEP
RBP							
Number of days capacity available	30	30	30	30	31	31	25
Number of days capacity won	26	23	30	30	31	31	25
Number of days auction limit reached	11	4	14	27	26	26	25
Available auction capacity utilised (%)	76	68	79	98	95	94	100
SWQP							
Number of days capacity available	31	30	31	30	31	31	30
Number of days capacity won	29	24	31	28	31	31	30
Number of days auction limit reached	0	0	6	12	24	26	1
Available auction capacity utilised (%)	19	23	56	60	92	95	38
EGP							
Number of days capacity available	27	30	31	30	31	30	24
Number of days capacity won	0	0	1	9	22	29	18
Number of days auction limit reached	0	0	0	0	1	3	4
Available auction capacity utilised (%)	-	-	3	41	56	56	61

Source: DAA auction data.

The dominant routes for which the tabled calculations have been made are as follows: RBP (Receipt Zone-03/04 to Delivery Zone-01), SWQP (Receipt Zone-02/03 to Delivery Zone-01), EGP (Receipt Zone-01 to Delivery Zone-05). MSP, WCFA/B and CGP calculations have not been included due to complexities surrounding the dominant routes and bi-directional flow of the MSP, low levels of utilisation at WCFA/B and low trade volume on the CGP.

We will look at the degree to which demand for auction routes has been higher than the quantities available in future wholesale market quarterly reports.

15 This price represents the cost of capacity won through the auction. Additional cost pass-through provisions also apply to recoup administrative costs related to traded capacity. These costs can vary depending on usage as fixed costs apply; indicatively, if the auction is being used to transport capacity from Wallumbilla to Victoria or Sydney then charges could equal around 40 cents a day, if 1 TJ a day of auction services are being bought.

16 Percentages have been calculated using data from days when auction capacity was won on the dominant pipeline route. Days where capacity was available, but nothing won, were not included.

2.4 Downstream market outcomes

- Participation continues to increase in downstream markets.
- Volumes traded are growing, especially in Sydney and Victoria.
- ASX futures trade continues to build for the gas market in Victoria.

Participation

As shown below, in 2018, four organisations already participating in east coast gas market trading became active in new regions, with a further eight entirely new participants entering one or more markets that year. These new entrants were predominantly industrial users. So far, in 2019, eight participants have commenced trading in at least one new market, with four being entirely new participants: two gas traders (Macquarie Bank, Strategic Gas Market Trading), an industrial in Adelaide (Michell Wool) and one producer selling into Sydney (Shell).

PARTICIPANT LIST IN EASTERN GAS MARKET

	Market participant	Victoria	Sydney	Adelaide	Brisbane
Gentailer	AGL	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017
	Alinta Energy	Entered before 2017	Entered in 2017	Entered before 2017	Entered before 2017
	Aurora Energy		Entered before 2017		
	Delta Electricity		Entered before 2017		
	EnergyAustralia	Entered before 2017	Entered before 2017	Entered before 2017	
	Engie	Entered before 2017			
	ERM	Entered before 2017	Entered before 2017		Entered before 2017
	HydroTas	Entered before 2017			
	Origin	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017
	Snowy Hydro	Entered before 2017	Entered before 2017		
	Stanwell				Entered before 2017
Exporter/ Producer	BHP Billiton	Entered in 2019	Entered before 2017		
	Esso	Entered before 2017	Entered before 2017		
	Lochard Energy	Entered in 2017			
	Santos	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017
	Shell		Entered in 2019		
Retailer	Click Energy	Entered before 2017	Entered in 2017		
	Covau	Entered before 2017	Entered before 2017		
	Dodo	Entered before 2017	Entered before 2017		
	GloBird Energy	Entered in 2018			
	GOEnergy		Exit or inactive		Exit or inactive
	GridX		Entered before 2017		
	Lumo Energy	Exit or inactive	Entered before 2017	Entered in 2018	
	Powershop	Entered in 2018			
	Red Energy		Entered before 2017	Entered in 2017	Entered in 2018
	Simply Energy		Entered in 2017	Entered before 2017	
	Sumo Gas	Entered in 2017			
	Visy	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017
	Viva Energy	Entered in 2018			
	Weston Energy	Entered in 2018	Entered before 2017	Entered in 2017	Entered in 2018
Industrial	Adelaide Brighton Cement			Entered before 2017	
	BlueScope		Entered before 2017		Entered in 2018
	BP				Exit or inactive
	Caltex				Entered before 2017
	Cargill Malt	Entered in 2019	Entered in 2018	Entered in 2018	
	Com Steel		Entered in 2017		
	Coogee Energy	Exit or inactive			
	Coopers			Entered in 2017	
	CSR Building	Entered in 2018		Entered in 2019	Entered in 2018
	Incitec Pivot				Entered before 2017
	Michell Wool			Entered in 2019	
	Mobil Oil	Entered in 2018			
	Norske	Entered in 2018			
	Paper Australia	Entered in 2018			
	O-I International	Entered in 2018	Entered in 2018	Entered in 2018	Entered in 2019
	OneSteel	Entered before 2017	Entered before 2017	Entered before 2017	
	Orica		Entered in 2017		
	Qenos	Entered in 2017	Entered before 2017		
	SA water			Entered before 2017	
	Tarac Technologies		Entered in 2017	Entered before 2017	
Trader	Macquarie Bank	Entered in 2019	Entered in 2019		
	Strategic Gas Market Trading	Entered in 2019	Entered in 2019		
	Total active market participants	32	31	19	15

● Entered before 2017 ● Entered in 2017 ● Entered in 2018 ● Entered in 2019 ● Exit or inactive

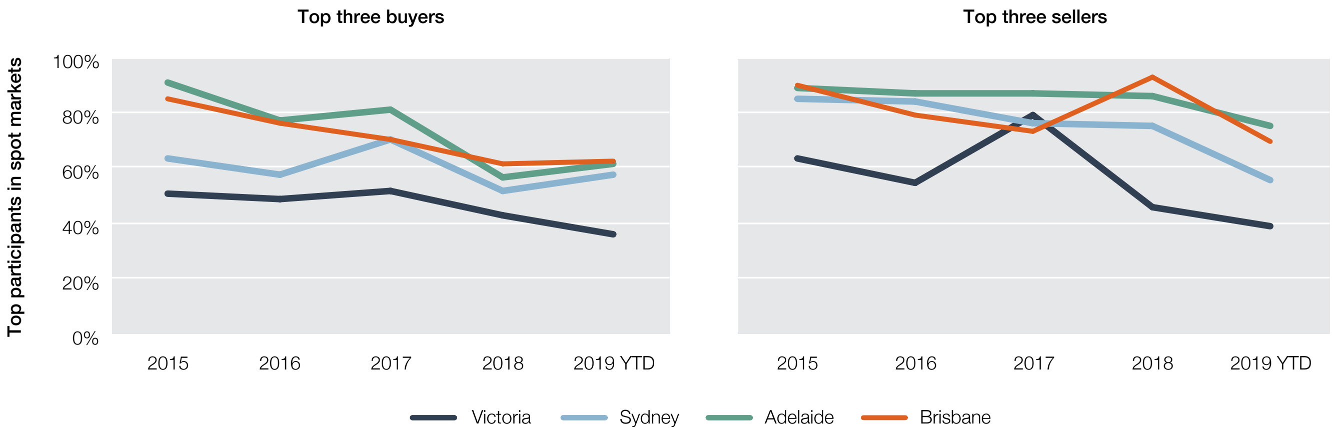
Note: The year represents when participant commenced trading (not registered).

Trade volumes and liquidity in spot market

Spot trade occurring in the east coast gas markets is dominated by the top three buyers and sellers in each region (figure 2.12). These participants account for around 50 to 90 per cent of the net quantities traded at the spot price since 2015.

However, the general trend over the past few years shows that the proportion of spot trading amongst the top three buyers and sellers, in each of the regions, is declining. Market concentration based on this metric has reduced with the top three buyers and sellers in Victoria falling below 50 per cent across 2018 and this year.

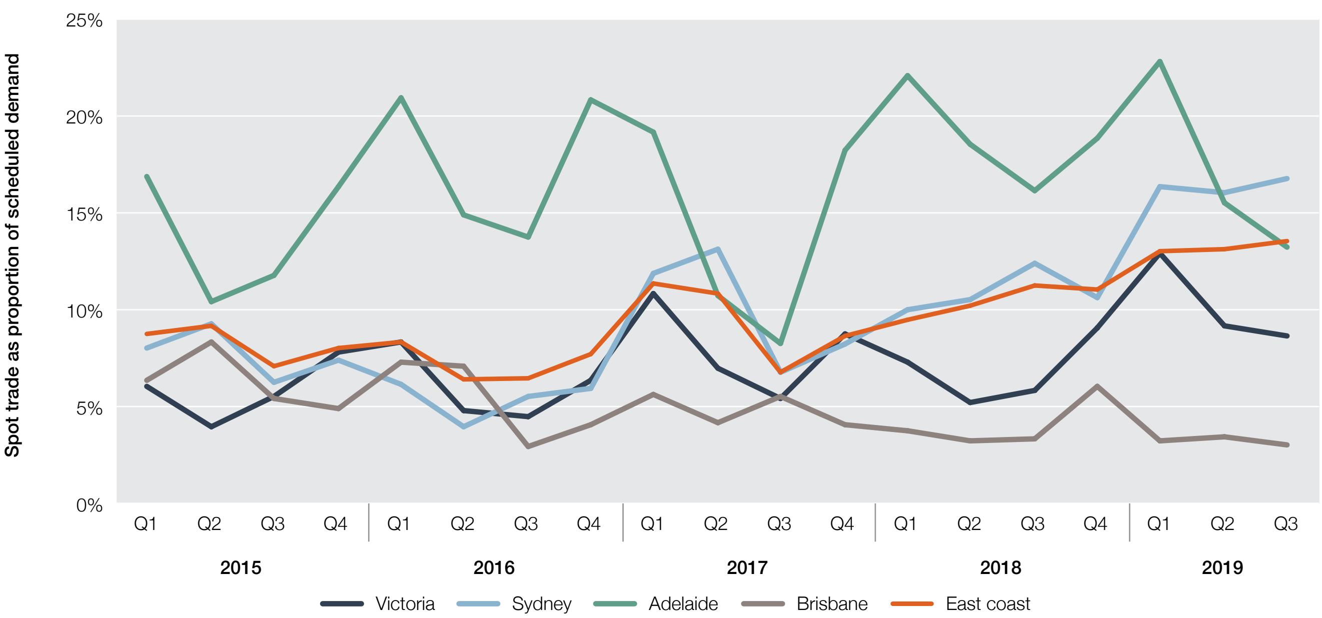
Figure 2.12 Top three buyers and sellers in spot markets



Source: DWGM, STTM data.

While the majority of trade for gas supply across the east coast demonstrates a significant reliance on bilateral contracts, net trading through spot markets has increased since 2016. As shown in figure 2.13, trading for Q3 2019 has risen to around 13.6 per cent of total demand across the four downstream gas markets.

Figure 2.13 Spot trade liquidity



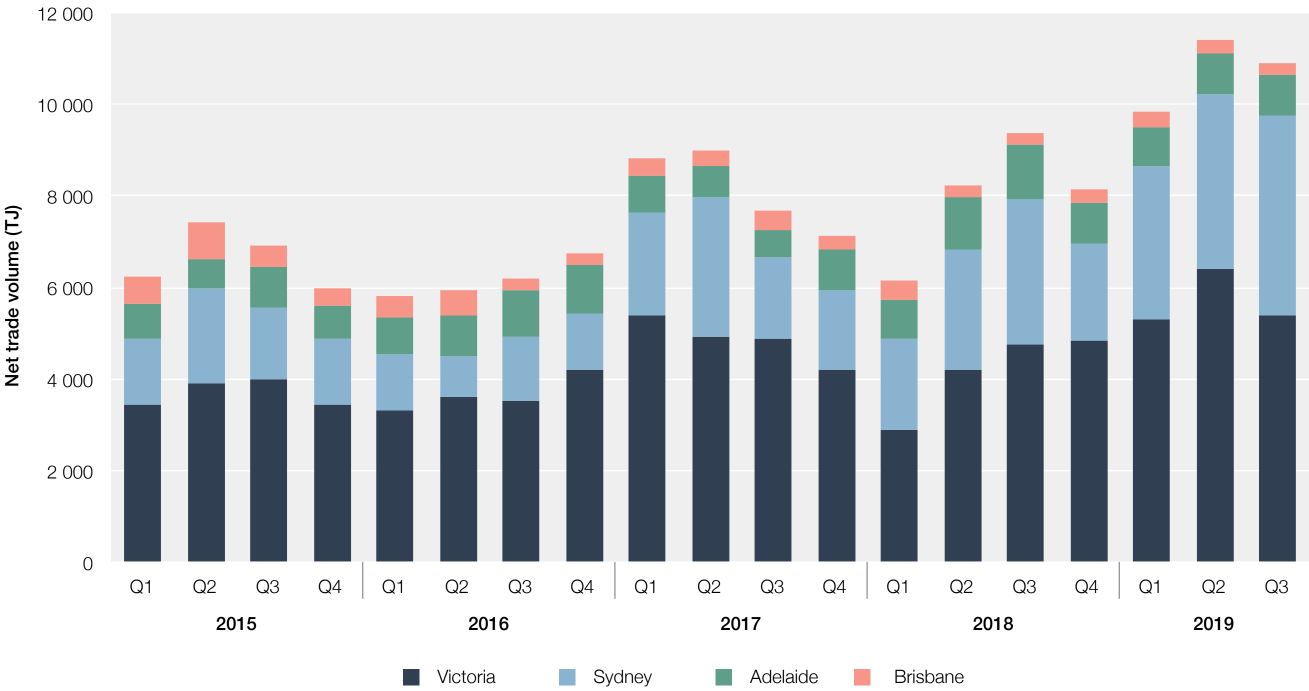
Source: DWGM, STTM data.

Adelaide has the highest proportion of gas purchases occurring through the market, typically peaking over the summer periods (Q4–Q1). However, long term liquidity in that STTM has remained relatively flat over the years. The largest increases in net trading happened in Victoria and Sydney, with the latter overtaking Adelaide in Q3 2019.

A few notable changes in the range of participants trading have occurred in southern markets in recent years. Around 90 per cent of the net purchases in Adelaide were concentrated around three players in 2015. This changed to up to nine participants in 2018 and 2019. In Victoria and Sydney, the traditional sellers have seen increased competition from producers like ExxonMobil and BHP Billiton selling more gas into the markets across 2018–19 along with the emergence of traders arbitraging market prices.

Figure 2.14 shows the net trade through gas markets in volume terms rather than as a percentage of scheduled demand.

Figure 2.14 Total net trade quantity



Source: DWGM, STTM data.

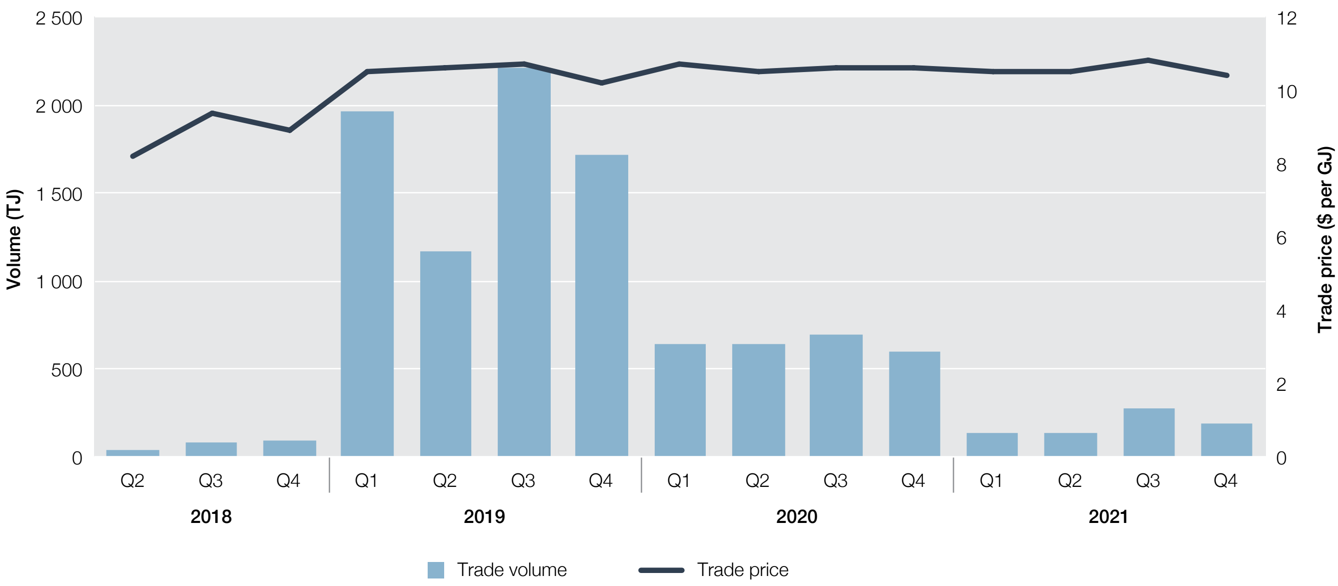
This highlights the trend of increasing volumes traded through the Sydney and Victorian markets, with Adelaide fairly flat and Brisbane having slightly declined.

Trade in financial markets

Quarterly and yearly (strip) products are available for participants in the Victorian gas market to limit their exposure to the spot price by setting a price for future financial transactions. The ASX launched the Victorian gas futures product in 2013, with little subsequent trade until Q2 2018. Since then activity and trade volumes have increased significantly from the start of 2019. While the amounts traded only equate to a very small proportion of the total physical volume traded through the gas market (around five per cent or less), an increasing level of open interest, alongside increased spot trading in short-term markets in general, present some encouraging signs.

Figure 2.15 shows the rise in gas futures trade from 2019.

Figure 2.15 ASX Victorian futures



Source: ASX data.

Note: Quantities traded are volumes for any future period in each quarter.

Focus—North-south gas price separation

Short-term gas prices across the east coast markets can vary significantly between northern and southern markets. Since 2016, a trend has emerged toward spot prices in the southern markets being higher than northern markets, especially in recent quarters.

General trend to higher prices in south

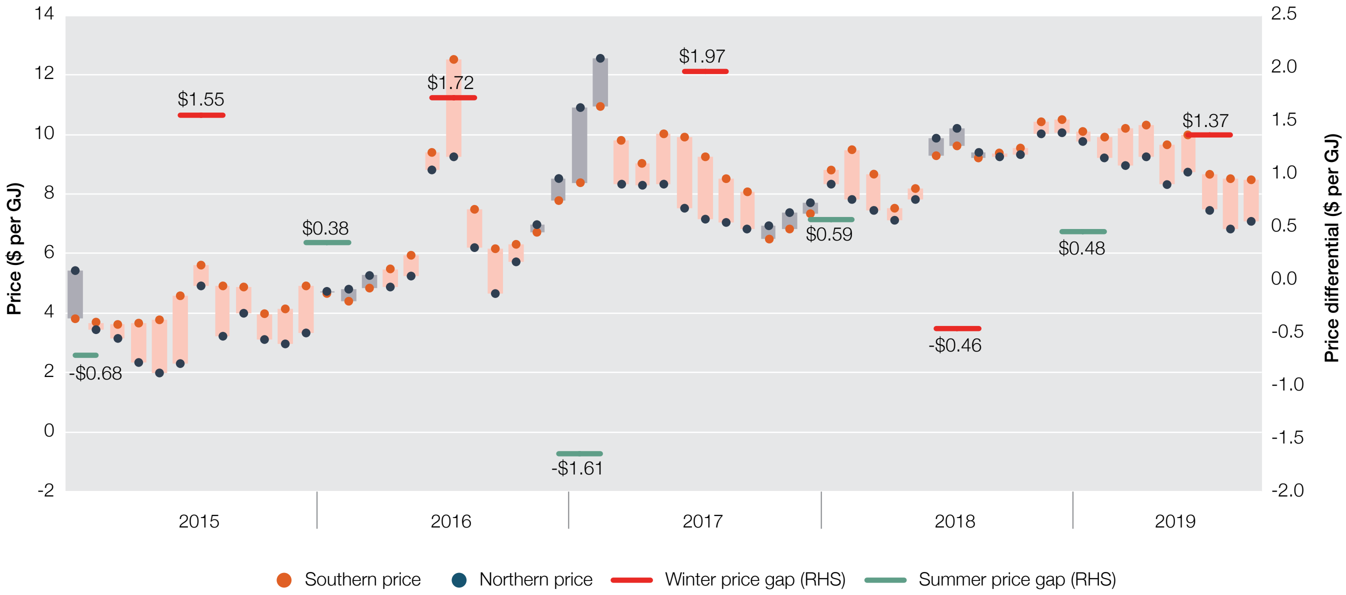
Northern prices are the simple average of the Brisbane daily ex ante price and the day-ahead price at the Wallumbilla Gas Supply Hub exchange.[17] Southern prices were calculated as the simple average of the daily Adelaide, Sydney and Victorian (6.00 am) ex ante prices. During the period 2016–2019, the north-south price gap has tended to be highest in quarters two and three (except 2018) as shown in figure 2.16.[18] These quarters cover the Australian winter and are associated with high gas demand for heating in southern markets.

Price separation has not been due to diverging north-south price movements. Prices across markets have generally followed the same path up or down over quarters, but at a different magnitude. This is shown in figure 2.16 by the southern and northern monthly price 'dots' moving in the same direction.

17 Volume weighted day ahead price of the WAL product at the Wallumbilla Gas Supply Hub Exchange.

18 Asian spot prices were highest in Q2 and Q3 2018 compared to 2015, 2016, 2017 and 2019 pushing up the northern domestic spot prices.

Figure 2.16 North-south prices highlighting winter and summer price gaps



Source: DWGM, STTM data.

Note: Winter covers June to August. Summer covers December to February.

The north-south price gap, with southern prices higher, has reached up to $3.30 per GJ (June 2016) and is typically wider over winter, than summer, as represented by red (winter) and green (summer) bars. The winter price gap, however, narrowed in recent years ($1.37 per GJ in 2019, compared to $1.72 per GJ and $1.97 per GJ in 2016 and 2017).

North-south price separation over 2019

Consecutive periods of record production in the north in Q2 and Q3 2019 has not translated to greater international gas exports. Falling export levels, from Q1 2019, meant surplus northern gas has been available to transport to southern markets.

In southern markets, there has been high winter demand for GPG (increasing 18 per cent, 10 per cent and three per cent in Sydney, Victoria and Adelaide respectively since Q1 2019). As a result, more northern gas has flowed through the SWQP (9 PJ) and MSP (7 PJ) pipelines to southern markets.[19]

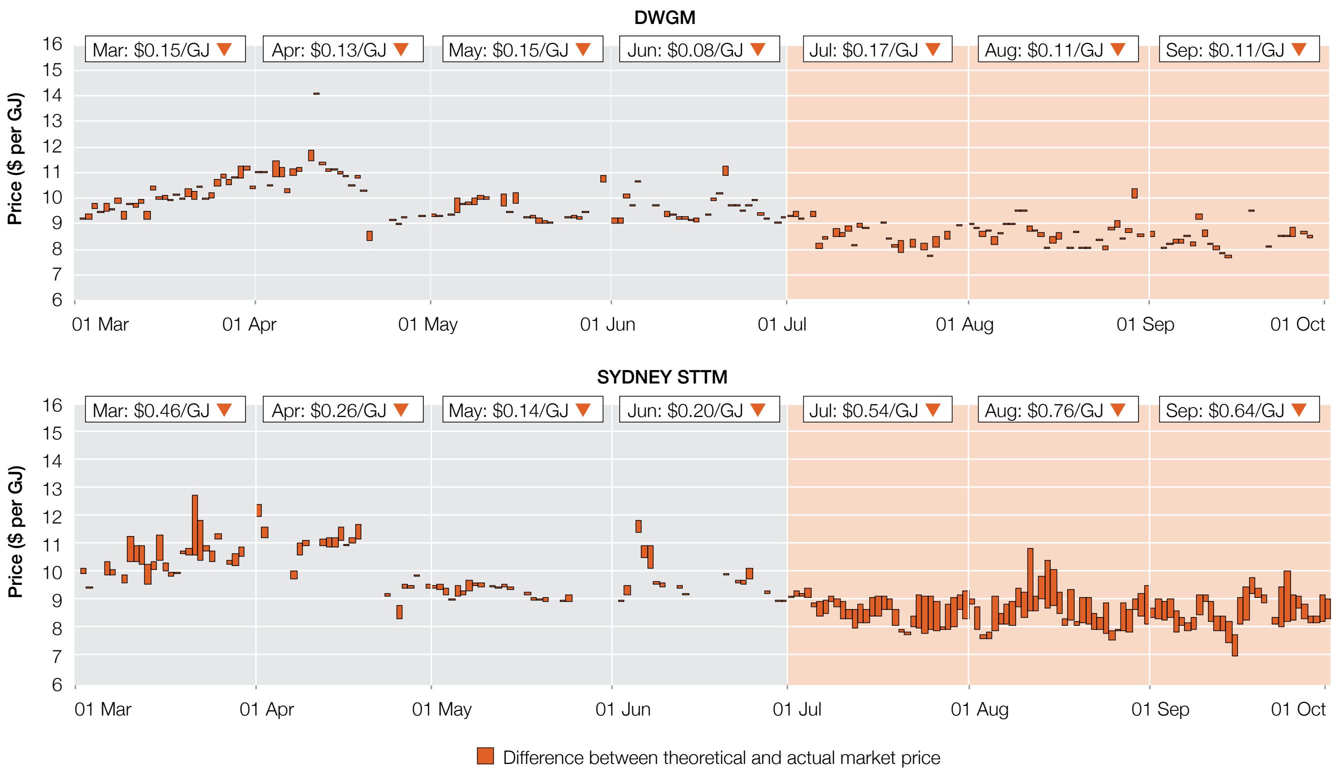
Southern spot market prices have reflected the cost of gas bought in the north plus transportation costs to bring south from Wallumbilla (which can typically be around $2 per GJ under long term contracts).

19 Gas Bulletin Board flows at Moomba on the SWQP and MSP, total of daily net flows south for winter months (June to August), 2018 vs 2019.

Arbitrage opportunities with north-south price separation

The strong flow of gas south, and the north-south commodity price separation has created opportunities to arbitrage prices. Participants have used the new DAA to purchase transportation, at near zero auction costs, and bring gas south. In figure 2.17, auction capacity won to market 'gates' has been matched to corresponding commodity offers into the Victorian and Sydney markets to measure the potential price impacts in those regions. The analysis indicates the possibility of prices in the hubs being reduced by as much as 10 cents per GJ in Victoria and 76 cents per GJ in Sydney from March to September 2019 by auction backed offers.[20] Moreover, the positive impact of the auction in lowering southern market prices appears to be growing in Sydney as more participants utilise the auction path to the Wilton trade point. Estimating future possible southern price gains for consumers due to the DAA will be a focus of our analysis in 2020.

Figure 2.17 Market price impact due to DAA capacity



Source: DWGM, STTM data, DAA auction data.

20 This represents the maximum price impact assuming all offers placed for specific participants in those markets are reliant on capacity being won through the DAA. In practice, offers would be submitted before auction quantities are cleared, and as such the actual market price impacts could often be lower than the range shown (as these quantities also do not consider the upstream cost of gas and its impact on offer price ranges).

Appendix

Domestic spot market prices

There are many influences on spot gas prices including seasonal demand, unplanned outages and changes over time in the number of sellers and buyers. Some important enduring drivers of gas spot contract prices are noted below.

Long-term contract prices: The majority of gas is sold under long-term contract including by producers to retailers who then can sell excess volumes (under contract) into spot markets. Average prices invoiced by Victoria gas producers increased from around $4 per GJ in 2014 to around $8 per GJ by Q4 2018 and this is influencing the price at which excess contracted gas is bid into spot markets.[21]

Global (Asian) LNG prices: The Queensland LNG exporters participate as both exporters and sellers of gas to the domestic market. Given perfect arbitrage, domestic prices and international prices (e.g. netted back to Wallumbilla) could settle to an equilibrium price. The ACCC Gas Inquiry, in its September 2017 Interim report, found that the majority of Gas Exporters and Producers considered the Asian spot price as the relevant comparator for assessing likely domestic prices.[22] This was supported by a prevailing view that there would be sufficient production in Queensland for exporters to meet long term foundation LNG contracts (oil price linked) and sell opportunistic spot LNG export cargoes. The ACCC reported that 13 LNG spot cargoes were sold over 2018.[23] Our analysis shows that the Asian spot netback relationship appears particularly strong for gas sold through domestic spot markets.

Production Cost Floor: If the Asian LNG netback price became lower than production costs, then LNG exporters may seek to reduce production rather than sell spot cargoes internationally or domestically at a loss. The floor price for exporters has been reported to be around $4 to $6 per GJ in Queensland depending on the project.

National Electricity Market: In summer 2017 high gas prices followed high NEM prices in Queensland.[24] Further, when gas prices fall significantly—such as happened in the LNG ramp up phase in 2015—fuel substitution in the NEM from coal back to gas can occur supporting the price of gas.

Domestic spot transport prices

On 1 March 2019, two new secondary capacity trading markets were introduced into the east coast gas market. Both are designed to encourage access to contracted pipeline capacity by secondary buyers, when contracted capacity along a pipeline is not being utilised. Historically, some pipelines have been fully contracted across a year to gas shippers, meaning a pipeline's capacity can be under-utilised by those shippers (when they do not require it in the year) and there might be interest in the pipeline capacity from other shippers. The new markets are designed to facilitate easier access to any unused capacity on the east coast across through a co-ordinated trading platform.

There are two means of trading within this new market:

1. In the first instance, a voluntary trading platform, the Capacity Trading Platform (CTP), is available. All shippers can choose to either use their contracted capacity or sell forward any capacity they don't expect to use on the trading platform. Sale revenue from trades on the CTP go to the selling shipper.
2. If shippers decide not to sell their unused capacity, any unused capacity quantity will be offered into a mandatory auction platform: the Day Ahead Auction (DAA). Any shipper can bid for this capacity and, in contrast to the CTP, all proceeds from the auction pass to the pipeline (or compression) facility operators, rather than shippers.

This new market is intended to open up access to key transport bottlenecks, where contracted capacity is held by only a few shippers. A key example is the heavily contracted South West Queensland Pipeline, which is strategically important for north-south flows and is the only pipeline connecting Queensland with the southern states.

Up to the end of Q3 2019, there was negligible use of the CTP. However the DAA has been widely used with six participants in September 2019 buying spot capacity day ahead.

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21 ACCC, Gas inquiry, April 2019 Interim Report, p. 41.

22 ACCC, Gas inquiry, September 2017 Interim Report, p. 67.

23 ACCC, Gas Inquiry, April 2019 Interim, p. 15.

24 AER, State of the Energy Market report, 2018, p. 196.