Significant price variation report

East Coast Gas Markets July & August 2016

14 November 2016

AUSTRALIAN ENERGY REGULATOR

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Executive summary

The AER is required to publish a report whenever there is a significant price variation **(SPV)** in the Victorian gas market and the Short Term Trading Markets **(STTM)**.[1] The AER has published guidelines which set out what constitutes an SPV.[2]

When an SPV occurs it doesn't necessarily mean there has been a price 'spike'. An SPV can also occur, for example, when the gas price falls by a certain amount.

This report has been prepared following 12 SPVs across the domestic gas markets in July and August this year. This report follows an earlier report which addressed 12 SPVs that occurred in June this year.[3]

During winter this year, the domestic gas markets experienced tight supply and demand conditions.

This is often the case during the winter months as households increase their gas usage for heating, particularly in Victoria. This can mean small changes in supply and/or demand can have a relatively larger impact on price.

However this winter, the tight supply and conditions were brought about by a unique confluence of supply and demand conditions.

Some of the supply side factors include:

- gas fields which previously supplied only the domestic market are now also supplying export markets – including gas from South Australia's Moomba production facility, and from Victorian gas fields[4]
- the unexpected curtailment of a Queensland-based supply source for AGL. This resulted in AGL buying more gas from the spot markets
- lower production from the Port Campbell region into Victoria
- reduced supply available from Iona underground storage over July and August following high use over June
- Longford (in Victoria) operating at full capacity

Some of the demand side factors include:

- increased output from gas fired electricity generators, particularly in South Australia

1 The obligation is set out in the National Gas Rules. Rule 498(3)(b) relates to SPVs in the Short Term Trading Markets, and rule 355(1)(b) relates to SPVs in the Victorian market.

2 These thresholds are noted in Appendix A.

3 The June SPV report is available here: http://www.aer.gov.au/wholesale-markets/market-performance/significant-price-variation-report-june-2016

4 We note had it not been for a long term LNG contract, the investment to extend the Moomba field would not have happened.

- The commencement of three LNG export projects in Queensland. In total, the demand from these projects is forecast to reach around three times the level of domestic demand once fully operational
- relatively cold weather – although this winter was warmer than usual, residential demand for heating is still a significant factor particularly in Victoria

While the demand from the LNG export projects will be significant, the direct impact on the domestic market at a point in time can be difficult to determine precisely. All three projects source gas from the broader domestic market (i.e. outside their gas fields in the Roma region) but this varies over time. It has been reported that Santos' Gladstone LNG **(GLNG)** project sources a larger proportion of gas from sources outside Roma relative to Origin's Australia Pacific LNG **(APLNG)** and Shell/BG's Queensland Curtis LNG **(QCLNG)**.

However simply looking at the demand impact of the LNG projects doesn't give the full picture. The LNG export projects also provide another source of supply for the domestic market, and this seems unlikely to change anytime soon. As domestic gas prices have risen, so has the attractiveness of selling gas domestically. One of the SPVs noted in this report occurred when the price reduced from $19.97/GJ to $12.20/GJ. One of the key contributors to the price reduction was an increase in lower priced supply offers by Santos of over 12 TJ. We also understand some supply from the Roma region was sold into the domestic markets. This resulted in pipeline flows moving south instead of north on a number of days.

On most occasions prices were close to forecast. The tight supply and demand conditions were reflected in participants' offers to the market. While on most days there were generally enough supply offers priced at or under $10/GJ to meet forecast demand, offers for gas beyond this point were at increasingly higher prices and for lower quantities.

This report is structured as follows:

- Part one provides an overview of Australia's east coast gas markets
- Part two explains the market conditions across winter this year that contributed to the SPVs
- Part three examines the individual July and August SPVs
- Part four addresses the other market and compliance issues identified by the AER when preparing this report

1 The east coast gas markets

The Victorian gas market and the STTMs help determine the scheduling of gas to meet demand from residential customers, industrial users[5] and some gas-fired electricity generators.[6] These markets are compulsory for all gas users located within the defined physical boundaries of each market and are marked ‘M’ in Figure 1 below.

Figure 1: The east coast gas markets

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5 Some industrial participants, for example Qenos or AB Cement participate directly in the market. Others have another party – usually an energy retailer – participate on their behalf.

6 Unlike the Victorian gas market, where many gas fired electricity generators **(GFG)** sit within the physical boundaries of the market, no GFG sits within the physical boundaries of the Adelaide or Sydney STTM and therefore do not have to participate in the market. However, these GFGs can make offers to buy gas from the daily market for transport to their power station (withdrawal bids). Though more commonly they choose to bypass markets and buy gas directly under long term contracts.

There are also two upstream gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia) marked ‘H’ in Figure 1. Trading in these supply hubs is voluntary and there are no SPV reporting requirements. Markets and Hubs are connected by a number of key pipelines.

Recent changes to the east coast gas markets

In 2014, the first of three liquefied natural gas **(LNG)** export projects came online near Gladstone in Queensland. These projects have effectively connected Australia’s east coast domestic gas market to the global LNG market. While outcomes were once determined purely by domestic conditions, international supply and demand dynamics are growing in influence.

Once fully operational, the gas demand from the LNG export facilities is forecast to reach three to four times the level of domestic demand.[7] This has fundamentally changed all aspects of the east coast gas market.

The following investments have been made to facilitate the transportation of gas by participants across the network to where it is valued highest.

- Upgrades to pipelines to enable bidirectional flows, including:
    - the Moomba to Adelaide pipeline **(MAP)**
    - the Moomba to Sydney pipeline **(MSP)**
    - the South West Queensland pipeline **(SWQP)** including the Queensland South Australia and New South Wales link **(QSN link)**.
- Transmission pipeline connections to form new routes north and south:
    - the MAP and SEAGas pipeline **(SEAGas)**. This enables gas to flow between the two pipelines and avoid the Adelaide distribution system.
    - the MSP and the Eastern Gas pipeline **(EGP)**. This enables gas to flow between the two pipelines and avoid the Sydney distribution system.[8]

There has also been ongoing investment in the New South Wales – Victoria interconnect.

These investments have largely been made to enable participants to send gas north, primarily to supply LNG exports. However they also enable gas to flow south when circumstances dictate. This may occur, for example, when an LNG export facility is undergoing maintenance and additional gas becomes available.

This variability in supply and demand from the LNG export facilities has also increased the importance of gas storage. The ability to store gas allows participants to quickly respond and take advantage of short term supply and demand fluctuations.

7 In 2020, domestic demand (residential and commercial, industrial, and gas fired electricity generators) is forecast to be around 515 PJ a year, whereas the demand from LNG is forecast to reach nearly 2000 PJ.

8 Also, the EGP has been connected to the Wilton connection point in New South Wales. Previously only the MSP was connected to this point. The new connection enables Sydney’s demand to be supplied predominately by the EGP (which sources gas from Victoria) if required by participants.

AGL has recently built the Newcastle Gas Storage Facility **(NGSF)**, which has been providing gas to the Sydney STTM regularly this winter. The NGSF is discussed further in section 2.

1.1 Converging energy markets

Gas-fired generation

The national electricity market **(NEM)** is an energy-only mandatory market that schedules generators in order to balance supply and demand. The Victorian gas market and the STTMs are also mandatory markets, which were designed to schedule gas flows into, and out of, particular gas networks. The markets facilitate the trade of gas and/or electricity between market participants, based on their individual commercial requirements.

Gas-fired electricity generators in effect link the NEM and the east coast gas markets and some organisations participate in both markets. For example, an energy retailer might provide gas to residential customers and also operate a gas fired electricity generator. These dynamics help ensure gas is allocated to its most economic use.

Across winter 2016, the use of gas-fired electricity generators increased significantly following a number of planned outages of coal-fired generators across the NEM.[9] It particularly increased in South Australia in the wake of: coal plant closures; below average wind generation; and planned network outages.[10] This further increased the overall demand for gas and may have increased the value placed on gas by some participants, particularly during times of high electricity prices.

Table 1 below sets out examples of some of the larger participants with exposure to both the NEM and the east coast gas markets.

Table 1: Major players with interests in both gas and electricity*

Participant*	Market	National Electricity Market (Amount of gas fired electricity generation) Gas market Retailer			
		Victoria	SA/Adelaide	NSW/Sydney	QLD/Brisbane
AGL	NEM Gas Gas retail	162 MW Yes	1280 MW Yes	No Yes	243 MW Yes
EnergyAustralia	NEM Gas Gas retail	No Yes	206 MW Yes	460 MW Yes	N/A No
Engie	NEM Gas Gas retail	No Yes	465 MW Yes	No	No
Origin	NEM Gas Gas retail	584 MW Yes	484 MW Yes	664 MW Yes	724 MW Yes

9 It is noted that gas-fired generation decreased in Queensland and the AER understands this is because the ramp gas that made gas-fired generation cheap in previous winters was no longer available in 2016.

10 See AER Communication Winter Energy Prices, http://www.aer.gov.au/communication/winter-energy-prices-2016.

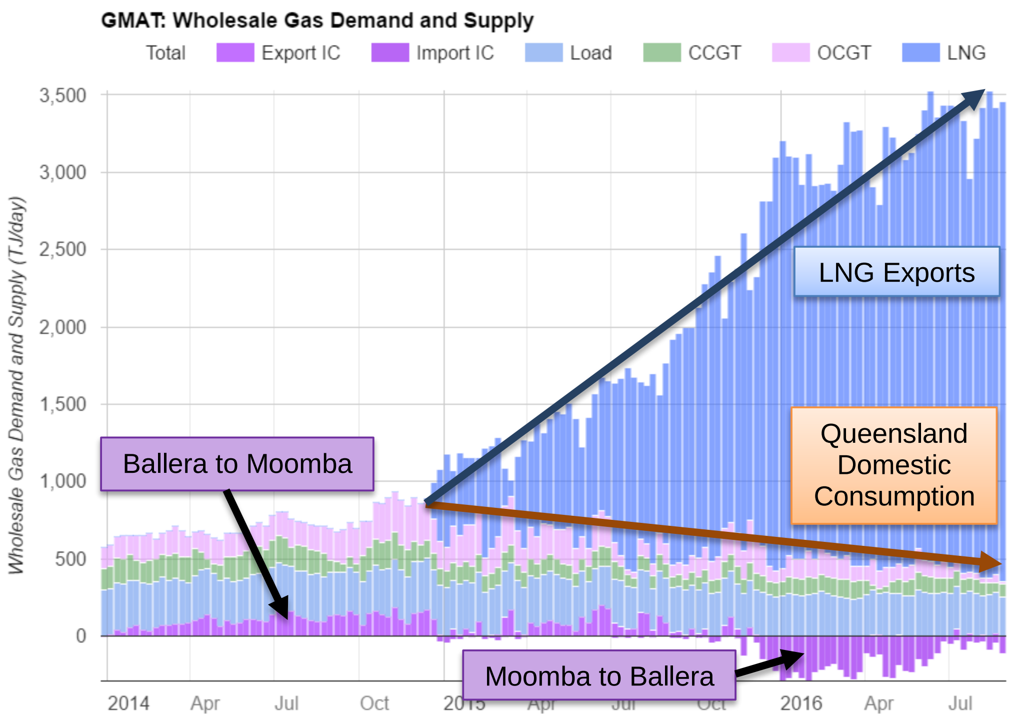
* Not showing all participants across the east coast energy markets. Engie's NEM gas value reflects reduced output from Pelican Point Power Station, which only has 1 of 2 units at Pelican Point Power Station in operation as per availability information provided to the market operator. Information provided by industry participants confirmed that although some generators can run on alternative fuels, the vast majority of energy generated by gas-fired generators this winter used gas as a fuel source.

LNG export markets

In late 2014, gas production in Roma began ramping up to cater for three new LNG export projects coming online at Curtis Island near Gladstone. These export projects have progressively brought online their first and second export 'trains' with the last and sixth train, owned by APLNG, shipping its first cargo in October 2016. Accordingly, the level of demand has steadily grown and is now around three times the level of previous consumption despite falling local demand for gas in Queensland.

Figure 2 shows the change in gas consumption patterns in Queensland from 2014. The increase in LNG exports has led to gas flowing in the direction of the LNG export projects (Moomba to Ballera) in 2016 whereas previously, and in the early stages of commissioning of the LNG trains, more Queensland gas was flowing to Southern markets (Ballera to Moomba). Given domestic supply is largely unchanged, this increase in demand applies upwards pressure on prices.

Figure 2: Queensland gas consumption by type



Source: Energy Edge - Gas Market Analysis Tool

LNG export demand factors and their interaction with local supply are discussed later in section 2.3.

2 Market conditions across winter 2016

This section sets out the overall market conditions during winter 2016 with a particular focus on the supply and demand factors that contributed to the high prices in July and August.

2.1 Prices and level of trade

Prices in STTMs (Adelaide, Brisbane and Sydney) and the Victorian Gas Market

Overall, prices were higher in winter 2016 compared with 2015 with the average price in:

- Adelaide up 91 per cent to $10.59/GJ
- Brisbane up 131 per cent to $8.23/GJ
- Sydney up 80 per cent to $8.82/GJ
- Victoria up 114 per cent to $10.02/GJ

We understand the costs of purchasing gas through long term gas supply agreements have increased in line with higher costs of production, limited new supply sources and suppliers, and domestic users having to compete with international demand.[11] These cost increases are reflected in the prices of gas offers submitted by participants.

While prices in winter this year were notably higher than the same period last year, the supply and demand factors at play are not all the same.

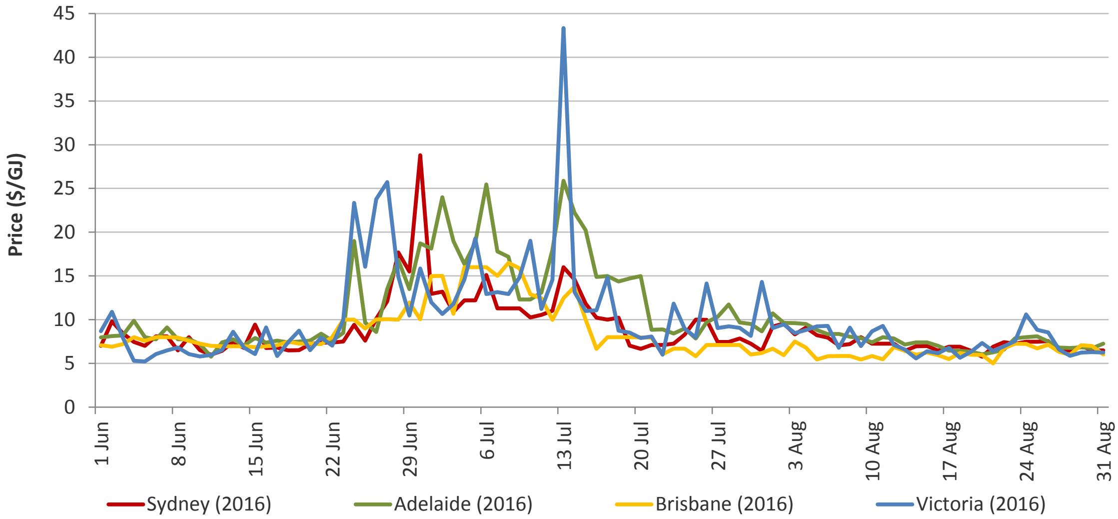
Demand during winter this year was generally lower than 2015.[12] However prices in winter 2015 did not exceed $7/GJ across the three markets. Prices were generally higher and more volatile in winter this year. Figure 3 illustrates this; particularly around the 23 June to 20 July gas days.

Supply of low priced ramp gas from the LNG projects was available to the domestic markets during the commissioning of the LNG trains in 2015. While the LNG projects continued to supply gas to the domestic market this year, it was likely at higher prices. Demand from gas fired generation, although a driver behind high prices in June this year, was lower overall than in winter 2015.

11 These factors were also discussed in the ACCC Gas Inquiry Report April 2016: http://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015

12 We calculated the top ten demand days across winter 2015 and 2016. Seven of the ten days high demand days occurred in 2015. The high demand days in 2015 ranged from around 1.56–1.63 PJ.

Figure 3: Daily Victorian Market and STTM gas prices over winter 2016



The higher prices in Figure 3 generally occurred on days of high demand in the southern markets. Large retailers such as Origin, AGL and Energy Australia optimise their gas positions across the daily Adelaide, Sydney and Victorian gas markets as well as running gas fired generation (GFG) in the NEM. Table 2 lists the top ten coincident southern market demand days in 2016 illustrating the impact of higher coincident demand and NEM conditions on prices.

Table 2: Coincident demand in the southern gas markets

Rank	Gas day	Coincident Adelaide, Sydney, Victorian gas market demand (TJ)	Highest market price across the three southern markets ($/GJ)	Notes on other factors including gas-fired generation
#1*	13 July	1670	$ 43.33 (Victoria)	Coincident market demand for 2016 exceeded the highest level in 2015 by close to 50 TJ. On this day there was around 308 TJ of demand from SA gas-fired generation (the 6th highest level across 2015 and 2016).
#2*	26 July	1557	$ 14.14 (Victoria)	High Victorian price despite supply from Culcairn reversing to flow into the region.
#3*	24 June	1554	$ 23.34 (Victoria)	High demand in Victoria, triggered by low temperatures, influenced higher prices in all three southern regions and set a record high price in Adelaide.
#4*	30 June	1526	$ 28.81 (Sydney)	Rebidding drove an inelastic supply curve in Sydney alongside a small increase to forecast demand.
#5*	27 June	1515	$ 25.74 (Victoria)	This day there was around 244 TJ of demand from SA gas-fired generation.
#6*	26 June	1505	$ 23.77 (Victoria)	Rebidding reduced low priced offers in Sydney resulting in a high ex ante price, alongside cold weather and high demand in Victoria.

Rank	Gas day	Coincident Adelaide, Sydney, Victorian gas market demand (TJ)	Highest market price across the three southern markets ($/GJ)	Notes on other factors including gas-fired generation
#7	14 July	1471	$ 22.22 (Adelaide)	This day there was around 328 TJ of demand from SA gas-fired generation (the 3rd highest level across 2015 and 2016).
#8	5 July	1466	$ 19.26 (Victoria)	High prices in Victoria and Adelaide. Participants revising up forecast demand and rebidding contributed to the 6 pm schedule price reaching $30/GJ in Victoria.
#9*	12 July	1447	$ 17.99 (Adelaide)	Inelastic supply curve in Adelaide.
#10	24 July	1444	$ 9.00 (Adelaide)	Cold weather drove higher demand in southern regions.

*These seven days are days which triggered SPV reporting across June and July

Trade through the STTMs and Victorian Gas Market

Over winter this year, there were periods of relatively high trade through the STTMs and Victorian Gas Market compared to previous years. This appears aligned in part with AGL's shortage of gas (see section 2.4) but also because gas from late July became available to the domestic market through the Wallumbilla Gas Supply hub. During the high price period between 23 June and 20 July there where as many as five participants on an average daily basis selling and/or buying between 15 and 20 TJ of gas including:

- LNG exporters selling gas at the Wallumbilla hub through the exchange for delivery on the SWQP
- Southern producers selling gas into the Southern STTMs and Victorian markets
- Large integrated electricity and gas retailers
- Medium-sized integrated electricity and gas retailers

This increase in traded volumes through the markets may be indicative that with the changed dynamics in the market there is increasing appetite from Southern gas producers (Santos and Esso) and LNG exporters (QCLNG, GLNG and APLNG) to trade gas into the domestic markets.[13] These observations are consistent with views shared by a range of participants in preparing this report. LNG exporters had also informed the ACCC Gas Inquiry that following achieving production for LNG trains they were looking for opportunities to trade into downstream markets.[14]

13 The historic dynamic has been that producers and LNG exporters have not participated in the traded markets. Trading of gas through the STTMs and Victorian Gas Market has been limited to smaller balancing volumes between gas retailers topping up long term supply contracts or to accommodate short term changes in demand.

14 See section 4.4.5 of the ACCC Gas Inquiry Report April 2016, www.accc.gov.au

2.2 Supply conditions

Historically, gas from the Moomba production facility (in the Cooper basin), the Victorian gas fields (the Otway, Bass, and Gippsland basins) and storage facilities has supplied demand located south of Moomba.[15]

Gas from the Roma production fields (the Surat and Bowen basins, north of Moomba) has predominately supplied demand in Queensland, in particular Mt Isa, Gladstone and Brisbane.

The gas basins across the east coast are illustrated in Figure 1.

Victorian gas fields

There are a number of important sources of supply located in Victoria. Table 3 sets out some of the key Victorian supply sources and the quantities of gas delivered across winter 2016 compared with 2015.

Longford is the largest supplier of gas in Victoria. Longford operated at nearly 100 per cent of its capacity for most of winter 2016. For the same period in 2015 Longford was operating at around 96 per cent.[16]

Participants used the Iona underground storage facility to provide supply throughout June resulting in average deliveries around 60 per cent higher than the previous year.[17] The high use of Iona throughout June limited its ability to sustain the same levels of supply throughout July with even less scheduled in August.

Other important sources of supply in Victoria include the Otway and Minerva gas plants.

The Otway gas plant was operating at reduced capacity. It provided an average of around 93 TJ a day during winter, compared to an average of 105 TJ for the same period in 2015.

The Minerva gas plant also supplied less gas this winter, with an average daily delivery of around 54 TJ, compared to an average of around 70 TJ for the same period last year.

Table 3: Key Victorian supply sources–winter 2016 vs 2015

Source	Measure	2016			2015		
		June	July	August	June	July	August
Longford	Daily average	1,024	1,022	1,020	957	993	967
	Maximum	1,059	1,056	1,050	1,036	1,043	1,043
	Minimum	968	984	993	775	882	825
	Total	30,732	31,673	31,620	28,697	30,785	29,962
Iona	Daily average	221	143	78	137	293	127

15 South Australia, New South Wales, and Victoria.

16 Source: Bulletin Board data; INT911, INT924, INT925, www.gasbb.com.au. Using capacities of 1,024 TJ for winter 2016 and 1,010 TJ for winter 2015.

17 In August, Lochard Energy (the owner/operator of Iona) informed the AER that Iona's recent storage is at historic lows.

Source	Measure	2016			2015		
		June	July	August	June	July	August
	Maximum	323	329	238	354	380	336
	Minimum	36	-54	-69	22	137	-37
	Total	6,636	4,447	2,421	4,103	9,069	3,923
Otway	Daily average	99	88	81	110	99	117
	Maximum	103	106	106	134	130	129
	Minimum	72	0	0	5	0	31
	Total	2,974	2,725	2,517	3,311	3,079	3,634
Minerva	Daily average	54	55	48	67	72	72
	Maximum	55	55	54	74	74	73
	Minimum	51	52	30	46	61	49
	Total	1,624	1,695	1,478	2,020	2,243	2,237

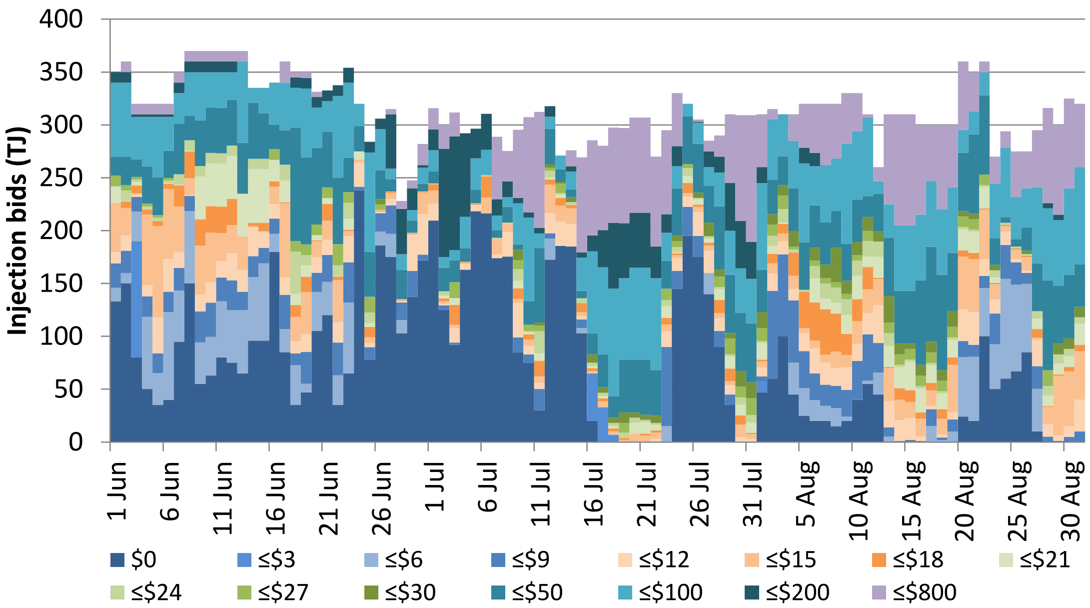
Source: Gas Bulletin Board Data, www.gasbb.com.au; Some numbers differ slightly from June report due to updating of GBB data.

Role of Iona Gas Storage and other balancing gas supply

As Iona capacity became scarce reaching near record minimum levels towards the end of July, the scarcity started to be reflected in participant offers for even small quantities of gas being over $10/GJ. In contrast across winter 2015 bids from Iona for at least the first 100 TJ were consistently below $10/GJ.

Figure 4 shows that participants began to price gas from Iona at higher prices in July and August. We understand this reflects the overall reduction in Iona's storage levels (which at one stage reached 30% of capacity) following high levels of supply throughout June.

Figure 4: Iona Gas Storage facility injections bids (supply offers)*



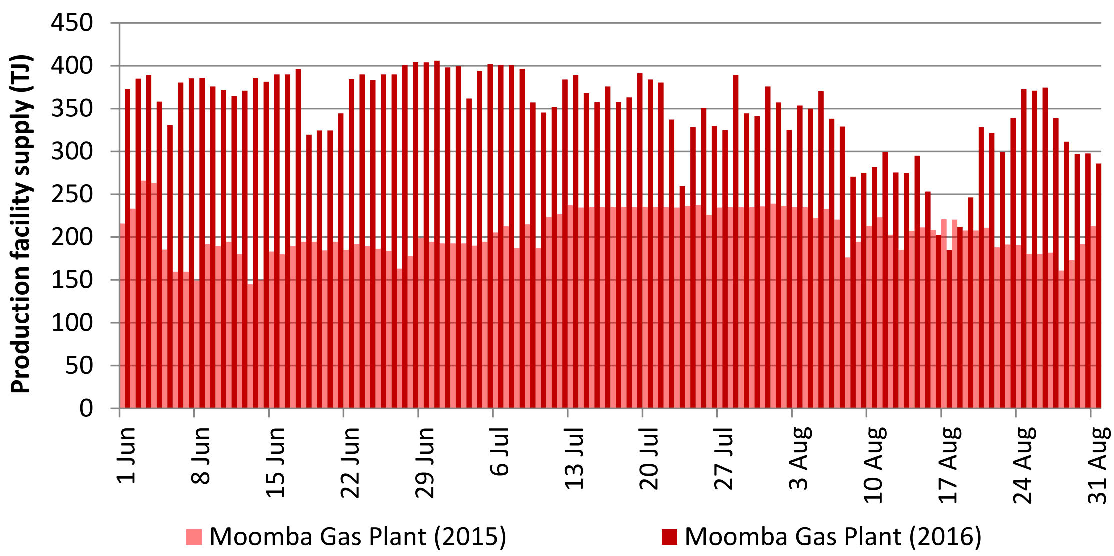
* 6 am (beginning of day) supply offers are shown for each gas day)

At the same time as the reduction in supply from Iona in July, there was an increase in net injections into Victoria through the Vic-NSW interconnect as northern gas supplies made their way south. This was reflected in the Victorian Gas Market through a large increase in offers to inject gas into the Victorian market from 18 July at below $9/GJ.

South Australian gas fields

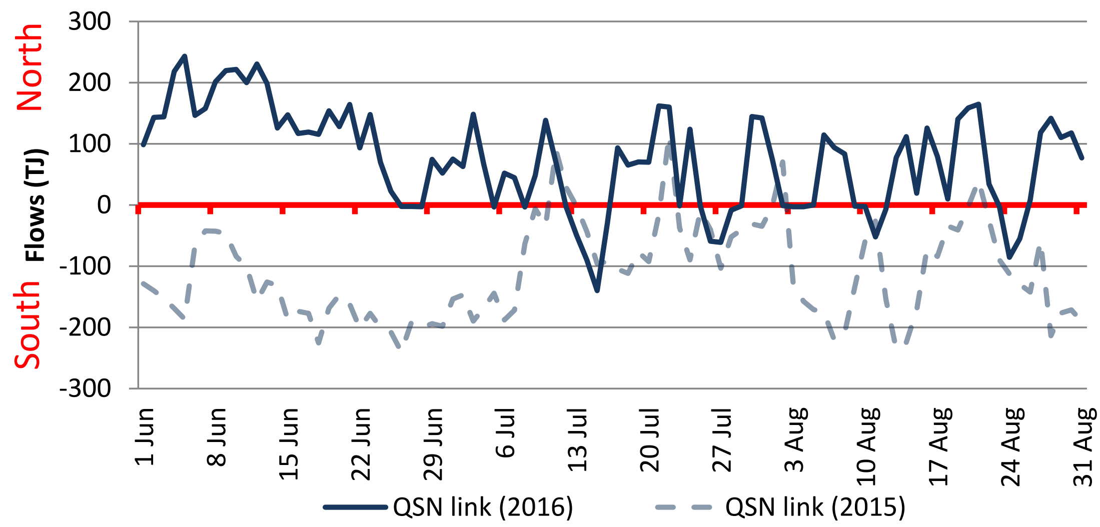
Figure 5 illustrates that in winter 2016, more gas was flowing from Moomba than in 2015. Figure 6 illustrates pipeline flow data, which suggests the extra gas may have been flowing into Queensland to supply demand from LNG exports, instead of domestic demand. Santos uses some of its Moomba gas to supply its Gladstone LNG export project.

Figure 5: Moomba Production



Source: Bulletin Board data, www.gasbb.com.au

Figure 6: QSN link flows*



* flow quantity has been adjusted to show northerly flows above the x-axis.

Source: Bulletin Board data, www.gasbb.com.au

New South Wales gas

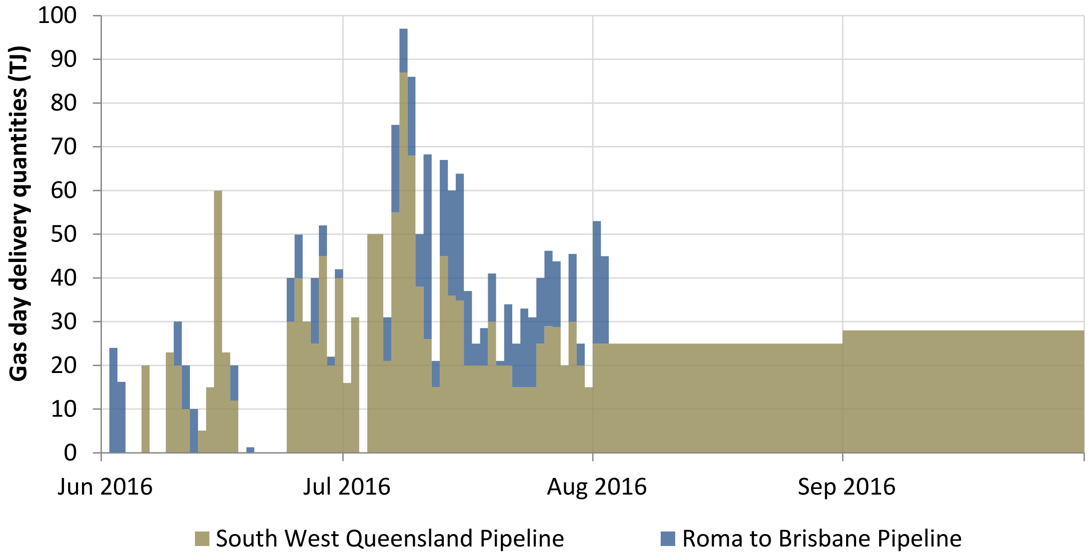
From the second week of June to the end of August, AGL used its Newcastle gas storage facility **(NGSF)** regularly to supply gas to the Sydney STTM. Over the period, the NGSF was scheduled on 20 gas days. Its quantities averaged nearly 25 TJ a day, with a maximum of 50 TJ and a minimum of 10 TJ.[18] This is the first winter that the NGSF has been a major source of supply for the Sydney STTM. In winter 2015 the NGSF was being commissioned, and first supplied gas on 23 July 2015.

Queensland gas (for domestic markets)

The AER identified multiple parties selling gas into the domestic markets in Queensland this winter. In July, QGC sent gas from the QCLNG export project to the domestic market.[19]

Figure 7 shows gas trades entered into on the Exchange increased markedly in July. Exchange based trades shown below are likely to reflect an increase in overall trade in July for both off market and on Exchange sales of 'LNG gas' in to the domestic market.[20]

Figure 7: Gas day (delivery) trades at Wallumbilla during higher prices*



* Pipeline trades: non-netted product locations traded on each pipeline have been included, only trades which occurred in June and July are shown. In July the first 'monthly' products for the delivery of gas in August (and September) was entered into with the purchase of over 20 TJ/d of Queensland gas for delivery on to the SWQP.

In late July there was also a planned outage one of QCLNG trains (on Curtis Island) which would have increased gas supply available to be sold into the domestic market.

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18 Date range: 13 June 2016 to 31 July 2016. Data source: ex ante scheduled quantity (INT652).

19 http://www.afr.com/business/energy/gas/shell-australia-juggles-gas-sales-amid-pricing-swings-20160829-gr45uk The Chairman was quoted as saying Shell had sold twice as much gas into the domestic market than it had purchased from third parties from its operation

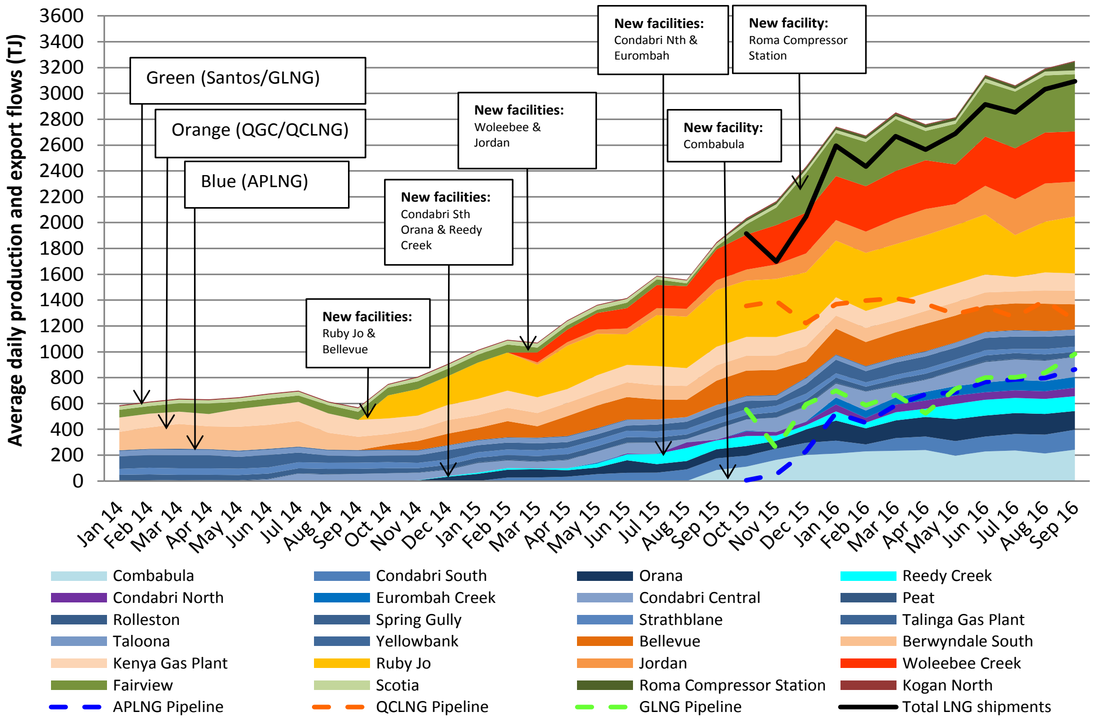
20 Visibility of gas traded at Wallumbilla is limited to trades on the Exchange, with market intelligence indicating that a smaller portion of Queensland gas is traded through the Exchange, than gas traded off-market, bilaterally.

2.3 Demand conditions

LNG supply and demand

Figure 8 highlights the amount of gas produced in Roma by the LNG export projects, including export pipeline gas flows to Gladstone. The export pipeline flows reflect LNG export demand which typically exceeds the gas reported to be produced in Roma.

Figure 8: Roma Production and LNG export pipeline flows*



* Bulletin Board reporting obligations for the three LNG pipelines commenced on 26 October 2015.

There is a larger quantity of gas being reported as export pipeline flows compared to Roma based production. This suggests a portion of the gas being used for export is supplied from outside Roma. This coincided with a greater net north physical gas flow from Moomba into Queensland on the QSN link during early winter 2016.

However, through July and August 2016, flows on the QSN link trended south (or less north) at times. During this period QCLNG advised of maintenance on its export trains and this is likely to be one factor in extra gas supply becoming available for the east coast gas markets.

The AER sought further information to understand the impact on domestic market gas flows resulting from the LNG export projects. We found that:

- During winter LNG export demand from time to time was met from a variety of different southern production sources including Moomba and Victorian fields.
- From July however on occasion, Roma LNG gas assisted to service Southern demand

On 23 July, the highest price day this winter, less gas was sent to export, meaning more gas was available for domestic markets.

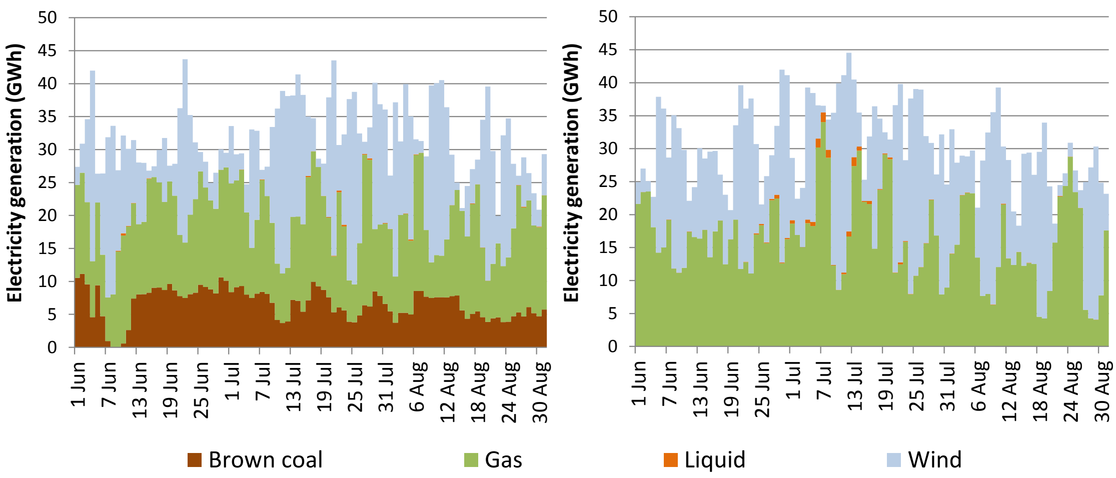
High demand from gas-fired electricity generation in South Australia

Demand from gas-fired electricity generators (GFG) in South Australia was much higher through winter 2016 than the previous year. Overall across winter 2016 demand from GFG in SA was up by around 36.4 TJ/d.[21] This was reflected In higher Moomba to Adelaide Pipeline (MAP) and SEA Gas Pipeline flows with MAP flows this winter totalling 15 PJ (up 3.1 PJ on winter 2015) and 15.9 PJ on SEA Gas (up 2 TJ on winter 2015). Increased SA GFG was driven by a number of factors.

- In June, there was a reduced availability of electricity generators across all regions. Total capacity from coal-fired generators was around 2,200 MW less than winter 2015.
- Limited capacity from interstate due to the network upgrades.
- The closure of South Australia's Northern power station (in May0 2016) accounted for 400 MW of this reduction, with the remainder due to planned maintenance.

In South Australia, since the closure of Northern Power station the primary fuel sources in South Australia are now gas and wind (see Figure 9 below). At times, low wind generation output at peak demand times (average wind output was 270 MW for July – 57 per cent below the average for July over recent years) meant more of SA's power requirements were met by gas.

Figure 9: South Australia's generation mix – 2015 (left) and 2016 (right)[22]



Weather influence on demand

During the winter months demand rises significantly as households increase their gas usage for heating, particularly in Victoria. Across winter this year there were a number of particularly cold days despite Bureau of Meteorology Data indicating it was overall a

21 This is based on estimates of gas consumption by South Australian generators for winter 2015 (137.7 TJ/d) and winter 2016 (174.1 TJ/d). The total change in GFG requirements illustrated in Figure 9 is around 3.2 gigawatt hours per day, comparing 2015 (13.1 GWh/d) and 2016 (16.3 GWh/d).

22 Liquid = diesel. There are some small peaking plants in South Australia that are powered by diesel. These units make up a small proportion of South Australia's overall generation capacity, and only run in response to high prices.

relatively warm winter. Had winter been cooler, it is likely prices would have been higher.

2.4 Outages

On 7 July 2016, AGL Energy announced it had acquired a higher than anticipated proportion of wholesale gas for the first quarter of the 2016–17 financial year from the spot market and other short-term sources. This was driven by a recent curtailment of Queensland gas supply arising from safety issues at a key supplier's project, other supply constraints in the gas market, and increased demand at its Torrens Island power station.[23]

There were other constraints and outages which impacted market prices over the winter 2016 period such as:

- a planned LNG train outage in late July influencing supply available to the domestic market
- some participants may have been constrained from putting gas into storage on the South West Pipeline (see Part 4 of the report)

The outage affecting AGL along with its general position of being short in the market probably had the most sustained impact on prices. Over this period where AGL was buying gas off short term spot markets, other participants were selling gas and some of the pricing including high prices discussed in the following section of the report are very likely to have been influenced by parties seeking opportunities to sell gas at a profit.

23 https://www.agl.com.au/about-agl/media-centre/article-list/2016/july/agl-update-on-fy17-gas-portfolio-margins

3 Analysis of the July and August price event days

This section details the 12 individual SPVs that occurred in July and August across the Victorian Gas Market and the Adelaide, Sydney and Brisbane and STTMs.

In Victoria, one SPV occurred when the trade weighted imbalance price reached $43.33/GJ (on 13 July 2016).

Across the STTMs, six SPVs occurred in Adelaide, three occurred in Sydney and two occurred in Brisbane. They were triggered by:

- Variations between the D-2 and D-1 prices (on 7 occasions)
- Variations between the D-1 and D+1 prices (on 2 occasions)
- The MOS service payment exceeding $250 000 (on 2 occasions)

This report follows our June report which details a further 12 SPVs.

Appendix A provides an explanation of how we have conducted the analysis for the different kinds of price variation. In preparing this report, the AER made inquiries of AGL, Energy Australia, Origin, Adelaide Brighton Cement, Stanwell, Qenos, Santos and Engie to understand why participants changed offers or bids which influenced price outcomes on these days. In general terms responses related to:

- Changes to supply offers reflected varied production at commercial or industrial users' sites.
- Demand forecasting inaccuracies owing to unexpected weather conditions.
- Allocating gas supplies to alternative uses at a time when gas was scarce and highly priced, such as GFG

Changes to bids and offer schedules in the STTMs can impose a cost on all market participants in the form of increased MOS payments and limiting the reliability of the price discovery process. Re-bidding must only occur in instances where participants' circumstances have materially changed since first submitting bid and offer schedules.

3.1 Friday 1 July 2016

Sydney STTM:	There was a $257 440 MOS service payment.

The Sydney hub is illustrated in Figure 28. It shows how the Sydney hub is comprised of two distribution zones (the Sydney zone and the Wollongong sub network) connected by a distribution trunk line.

The MSP provides the majority of the MOS requirements in the northern Sydney zone. This is because it is connected to the network at the only pressure controlled point along the trunk line.

The EGP provides the majority of the MOS requirements in the Wollongong sub network. This is because both of its connection points are also pressure controlled.

On the day, a total of 33.2 TJ of MOS was required on the MSP and the EGP. The service payment was made up of:

- 28.8 TJ of decrease MOS on the MSP (at a cost of $235 705)
- 4.4 TJ of increase MOS on the EGP (at a cost of $21 735)

The overall MOS requirement on the day was driven by:

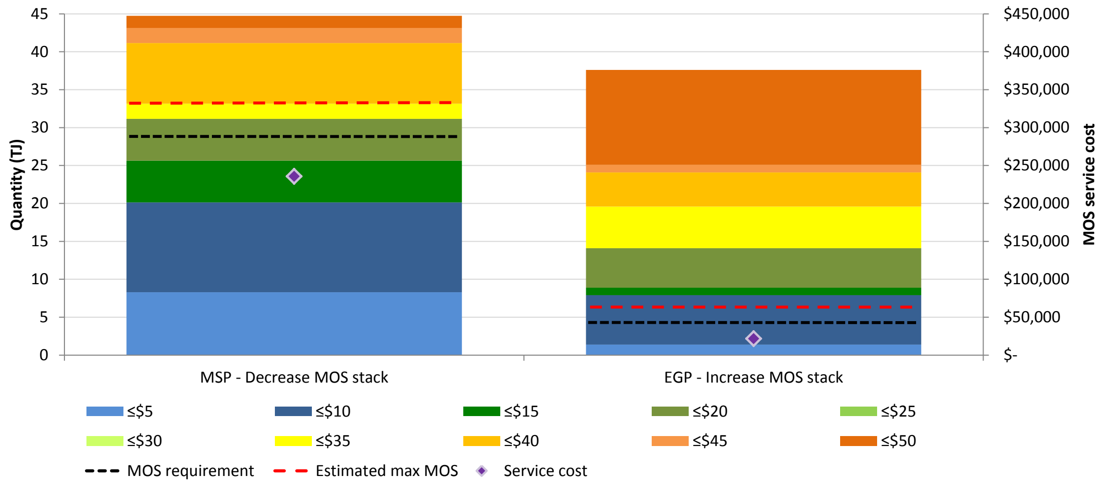
- participants over forecasting demand (in aggregate across both distribution zones) by around 22.2 TJ
- actual deliveries from the EGP and Rosalind Park injection points exceeding scheduled deliveries by 2.3 TJ.[24]

In addition to this net decrease requirement absorbed on the MSP, increase allocations providing an additional 4.4 TJ of gas to the hub on the EGP drove further decrease allocations on the MSP.[25]

The additional cost accrued due to counteracting MOS allocations (increase MOS on the EGP providing additional supply to the hub and decrease MOS allocations on the MSP parking gas nominated for delivery to the hub) is described in more detail in section 2.1.

Figure 10 shows the available balancing gas quantities offered on MOS enabled pipelines supplying the Sydney hub for the month of July 2016. The figure also illustrates the quantity of services allocated on each pipeline and the associated cost.

Figure 10: MOS stacks and allocation requirements for 1 July



24 The majority of this quantity (2 TJ) was delivered on the EGP.

25 This contributed around $41 297 of additional cost for the balancing gas services (compared to the cost for net decrease requirements being allocated entirely on the MSP). The 24.48 TJ net decrease requirement (22.15 TJ over forecast plus 2.34 TJ over supply) was also impacted by MOS deliveries on the EGP balancing under forecasting in the Wollongong sub-network (4.35 TJ). Collectively, these quantities account for the total MOS requirement (24.5 TJ supply/demand error, 4.35 TJ of increase EGP MOS and counteracting 4.35 TJ of additional MOS decrease allocations on the MSP: 33.2 TJ of MOS allocations in total).

3.2 Saturday 2 July 2016

Adelaide STTM:	There was a $14.39/GJ variation between the D-2 schedule price ($9.61/GJ) and the D-1 schedule price ($24/GJ).

Table 4 sets out the price and quantity for each of the gas schedules for the 2 July gas day in Adelaide.

Table 4: Adelaide prices and quantities, all schedules, 2 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$8.40	$9.61	$24	$24
Quantity (TJ)	71.21	70.84	76.91	+3.176

The main drivers behind the $14.39/GJ variation between the D-2 schedule price ($9.61/GJ) and the D-1 schedule price ($24/GJ) were an increase in controllable demand and a reduction in lower priced supply offers. Uninterruptable demand only increased slightly, and therefore had a less significant impact.[26]

The D-1 price on 2 July was the highest to date for the Adelaide STTM.[27] Adelaide's D-1 price exceeded this level again on 6 and 13 July gas days. These gas days are examined in further detail later in this report.

For the D-1 schedule, total demand was over 6 TJ higher than in the D-2 schedule. This was mainly due to an increase in controllable demand.

The main contributor to the increase in controllable demand was EnergyAustralia. For the D-1 schedule, EnergyAustralia increased its backhaul bid on the Moomba to Adelaide pipeline **(MAP)** priced at $80/GJ by 5 TJ. Analysis indicates this would likely have been to supply gas to Hallett; its gas-fired electricity generator located around 210 km north of Adelaide.

The main contributor to the increase in uninterruptable demand was AGL, which increased its price taker bid for the D-1 schedule by 1.1 TJ. Overall, uninterruptable demand increased by 1.2 TJ.

Some participants offered less gas priced at or under the D-1 price for the D-1 schedule than they offered in the D-2 schedule, including:

26 For the D-2 schedule, price taker bids (which reflect uninterruptable demand) were around 70.5 TJ. For the D-1 schedule, they were 71.7 TJ (1.2 TJ higher).

27 The previous record D-1 price was $18.99/GJ for the 24 June 2016 gas day which is assessed in our June report. Before this, the previous record D-1 price was $14.89/GJ for the 4 July 2012 gas day.

- Simply Energy reduced its quantity of offers on the SEAGas pipeline **(SEAGas)** by 5 TJ
- Adelaide Brighton Cement **(ABC)** reduced its quantity of offers on the MAP by 1 TJ
- AGL reduced its quantity of offers across the MAP and SEAGas by 2.2 TJ

The changes to bids and offers are illustrated below. Figure 11 sets out the offer stacks (on the left) and the bid stacks (on the right) for the D-3, D-2, and D-1 schedules. The overall changes in bids and offers can be seen by comparing one schedule with another. For example, for the D-1 schedule, there is a clear reduction in the quantity of offers priced at or above $9/GJ compared to the D-2 schedule. This is shown by a significant decrease in the amount of blue offers, and a similar sized increase in orange offers.

Figure 12 illustrates the increase in higher priced bids and the reduction in lower priced supply offers from the D-2 to the D-1 schedules and in turn how these changes resulted in the $14.39/GJ variation between the two schedules' prices. Figure 12 shows the intersection of the offer and bid curves setting the D-2 and D-1 prices.

Figure 11: Adelaide STTM, 2 July 2016, changes to offer and bid quantities

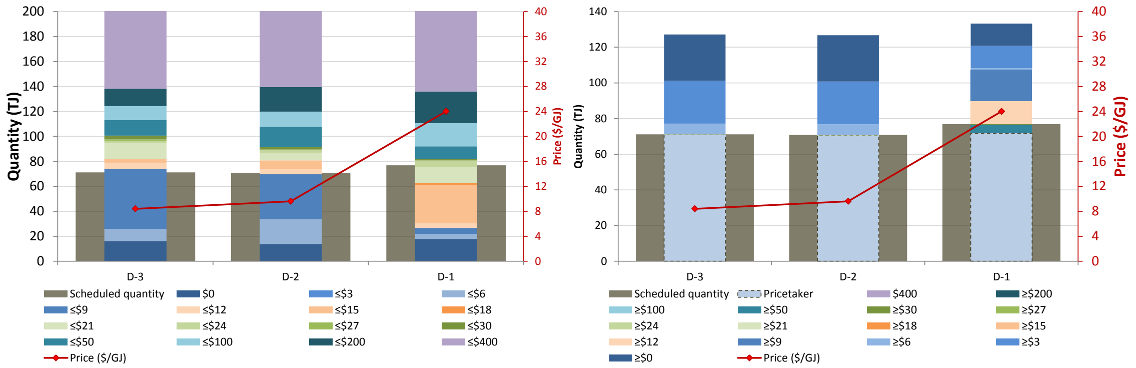
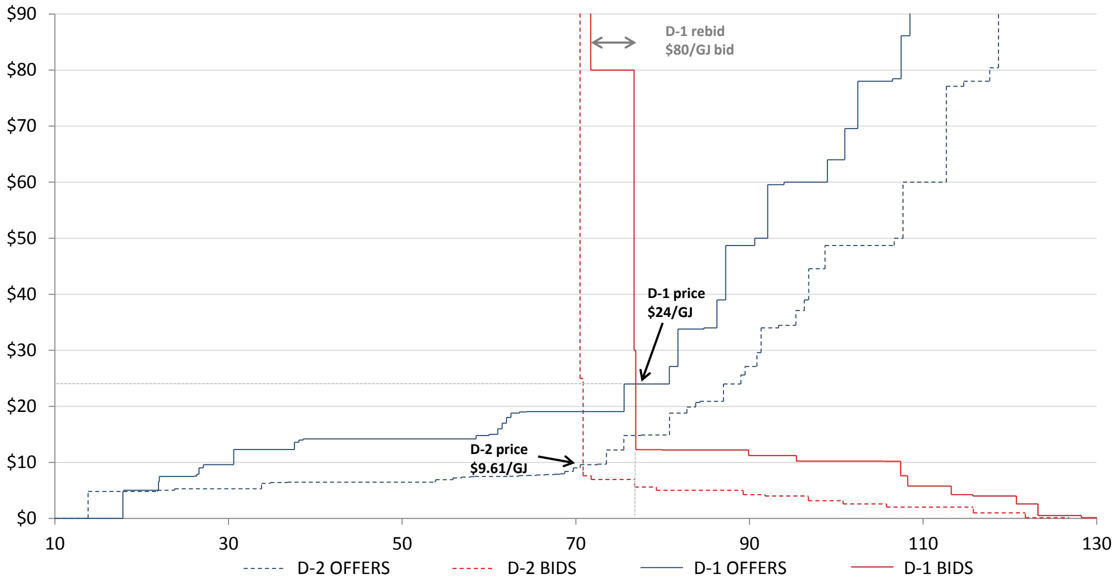


Figure 12: Adelaide STTM, 2 July 2016, D-2 and D-1 schedules (TJ)



3.3 Sunday 3 July 2016

Brisbane STTM:	There was an $8.03/GJ variation between the D-2 schedule price ($18.70/GJ) and the D-1 schedule price ($10.67/GJ).

Table 5 sets out the price and quantity for each of the gas schedules for the 3 July gas day in Brisbane.

Table 5: Brisbane prices and quantities, all schedules, 3 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$10.26	$18.70	$10.67	$10.67
Quantity (TJ)	84.81	85.79	85.39	-1.378

The main driver behind the $8.03/GJ variation between the D-2 schedule price ($18.70/GJ) and the D-1 schedule price ($10.67/GJ) was an increase in low priced supply offers. Both uninterruptable and controllable demand remained at similar levels.[28]

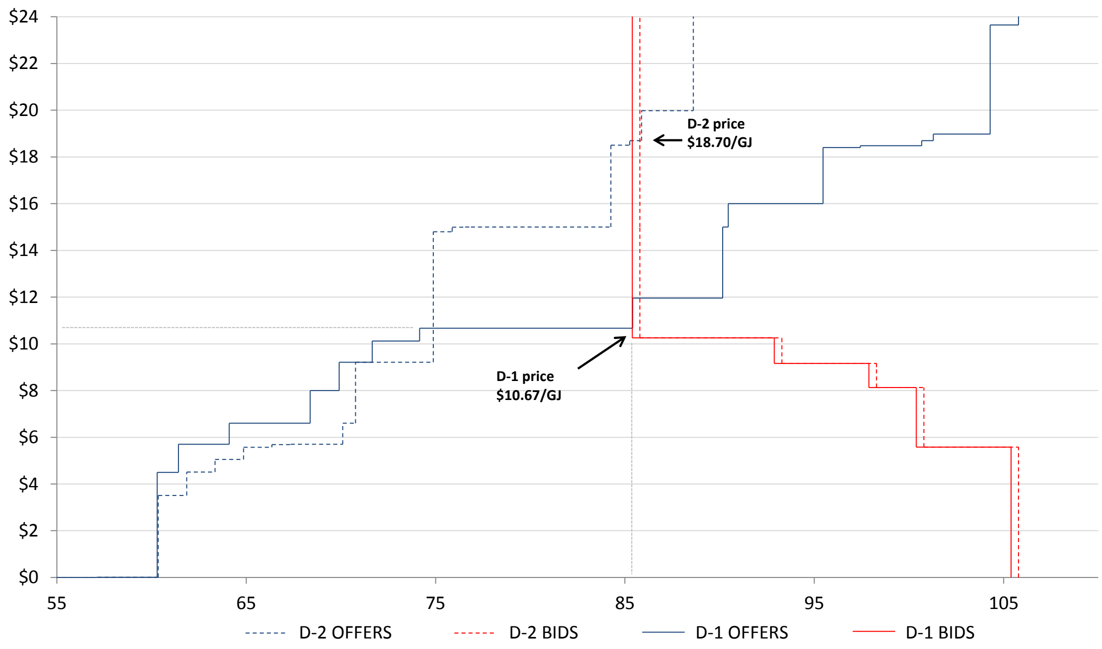
Some participants offered more gas priced at or under the D-1 price for the D-1 schedule than they offered in the D-2 schedule, including:

- Origin increased its quantity of offers on the Roma to Brisbane pipeline **(RBP)** by 12.3 TJ
- AGL increased its quantity of offers on the RBP by 3.6 TJ

Figure 13 illustrates the increase in lower priced supply offers from the D-2 to the D-1 schedules and in turn how these changes resulted in the $8.03/GJ variation between the two schedules' prices.

28 The similar levels of demand can be seen in Figure 13, where the solid red line and the dotted red line are closely correlated.

Figure 13: Brisbane STTM, 3 July 2016, D-2 and D-1 schedules (TJ)



3.4 Monday 4 July 2016

Sydney STTM:	There was a $7.77/GJ variation between the D-2 schedule price ($19.97/GJ) and the D-1 schedule price ($12.20/GJ).

Table 6 sets out the price and quantity for each of the gas schedules for the 4 July gas day in Sydney.

Table 6: Sydney prices and quantities, all schedules, 4 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$13.20	$19.97	$12.20	$12.20
Quantity (TJ)	316	321.85	319.09	-4.665

The main drivers behind the $7.77/GJ variation between the D-2 schedule price ($19.97/GJ) and the D-1 schedule price ($12.20/GJ) were a reduction in both uninterruptable and controllable demand and an increase in low priced supply offers.

The main contributor to the reduction in uninterruptable demand was EnergyAustralia, which reduced its price taker bid for the D-1 schedule by nearly 4 TJ. Qenos also reduced its price taker bid by over 1 TJ. Overall, uninterruptable demand decreased by 3.7 TJ.[29]

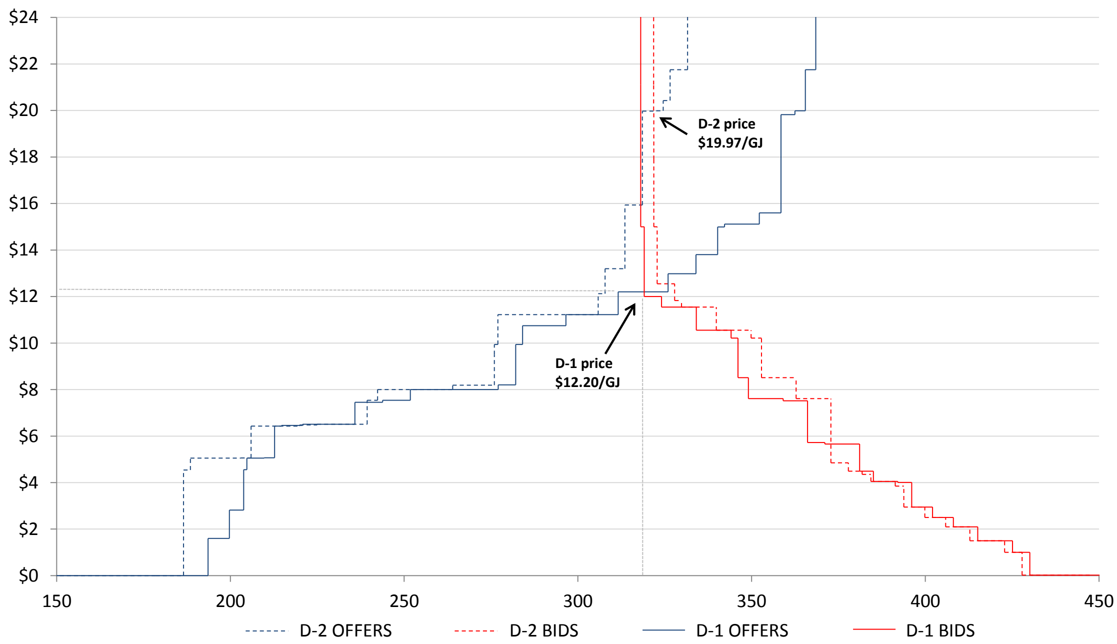
The main contributor to the reduction in controllable demand was Origin. For the D-1 schedule, Origin reduced its backhaul bid on the Moomba to Sydney pipeline **(MSP)** priced at or above $12.20/GJ by 5 TJ.

Some participants offered more gas priced at or under the D-1 price for the D-1 schedule than they offered in the D-2 schedule, including:

- Santos increased its quantity of offers on the MSP by 12.5 TJ[30]
- AGL increased its quantity of offers on the Eastern Gas Pipeline **(EGP)** and the MSP by 3.2 TJ
- EnergyAustralia increased its quantity of offers on the MSP by 2 TJ

Figure 14 illustrates the reduction in higher priced bids and the increase in lower priced supply offers from the D-2 to the D-1 schedules and in turn how these changes resulted in the $7.77/GJ variation between the two schedules' prices.

Figure 14: Sydney STTM, 4 July 2016, D-2 and D-1 schedules (TJ)



29 For the D-2 schedule, price taker bids totalled 321 TJ. For the D-1 schedule, price taker bids totalled 317 TJ.

30 Santos Direct offered a total of 25 TJ for the D-1 schedule. 12.5 TJ of this was priced at $10.75/GJ, 6.25 TJ was priced at $13.80/GJ, and the remaining 6.25 TJ was priced at $15.60/GJ. Santos had no offers for the D-2 schedule.

3.5 Wednesday 6 July 2016

Adelaide STTM:	There was a $10.62/GJ variation between the D-2 schedule price ($14.83/GJ) and the D-1 schedule price ($25.45/GJ). There was also a $7.64/GJ variation between the D-1 schedule price and the D+1 schedule price ($17.81/GJ).

Table 7 sets out the price and quantity for each of the gas schedules for the 6 July gas day in Adelaide.

Table 7: Adelaide prices and quantities, all schedules, 6 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$14.20	$14.83	$25.45	$17.81
Quantity (TJ)	93.37	93.46	95.52	-3.063

The D-1 price was the highest ever for the Adelaide STTM, exceeding the high set days earlier for the 2 July gas day. A new high occurred again on the 13 July gas day, examined later in this report.

The main drivers behind the $10.62/GJ variation between the D-2 schedule price ($14.83/GJ) and the D-1 schedule price ($25.45/GJ) were an increase in uninterruptable demand and a reduction in low priced supply offers. Controllable demand was unchanged.

There was a negative imbalance on the day of just over 3 TJ. This means the actual demand on the day was lower than the total demand forecast in the D-1 schedule. This led to the $7.64/GJ variation between the D-1 schedule price and the D+1 schedule price ($17.81/GJ).

The price variation between the D-2 and D-1 schedules

The main contributor to the increase in uninterruptable demand was AGL, which increased its price taker bid for the D-1 schedule by 1.9 TJ.[31]

Some participants offered less gas priced at or under the D-1 price for the D-1 schedule than they offered in the D-2 schedule, including:

- AGL reduced its quantity of offers on the MAP and SEAGas by 13.2 TJ[32]
- ABC reduced its quantity of offers on the MAP by 1 TJ

31 For the D-2 schedule, price taker bids totalled 93.2 TJ. For the D-1 schedule, price taker bids totalled 95.31 TJ.

32 This is a net amount. AGL increased offers on the MAP by 6 TJ, and reduced offers on SEAGas by 19.2 TJ.

The price variation between the D-1 and D+1 schedules

The ex post price then reduced significantly due to a -3 TJ imbalance (which was largely a result of over forecast demand).

Figure 15 illustrates the increase in higher priced bids and the reduction in lower priced supply offers from the D-2 to the D-1 schedules and in turn how these changes resulted in the $10.62/GJ variation between the two schedules' prices.

The figure also highlights the impact of inelastic supply from around $15/GJ and higher. Inelastic supply results in larger changes in price relative to a change in demand. This was particularly evident for the D+1 schedule, where the price fell by $7.64/GJ in response to demand reducing by around 3 TJ.

Figure 15: Adelaide STTM, 6 July 2016, D-2, D-1 and D+1 schedules (TJ)

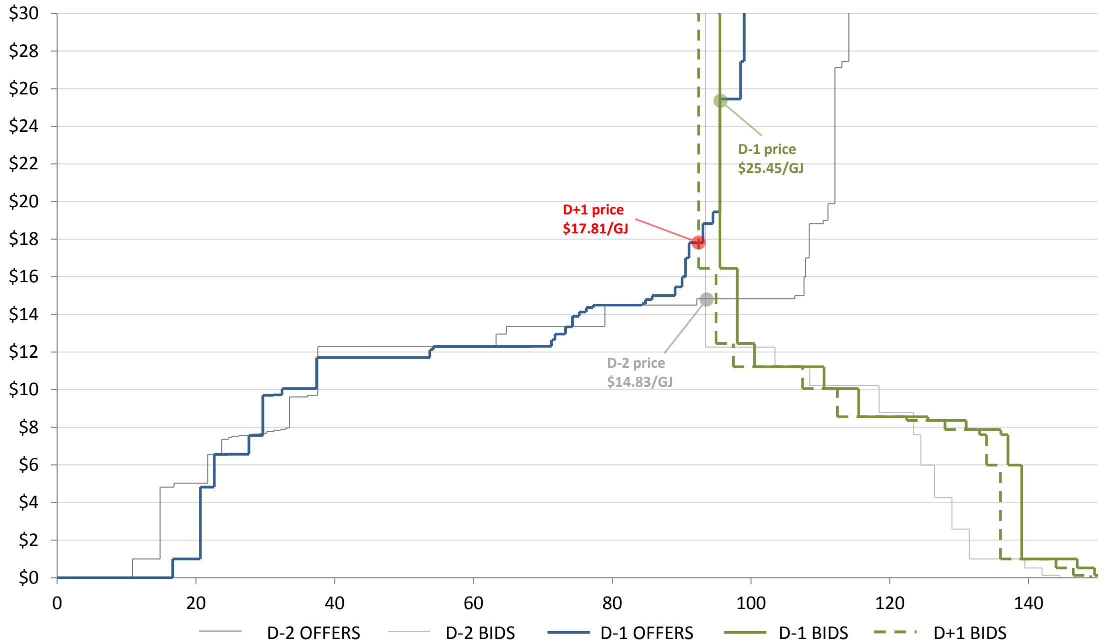
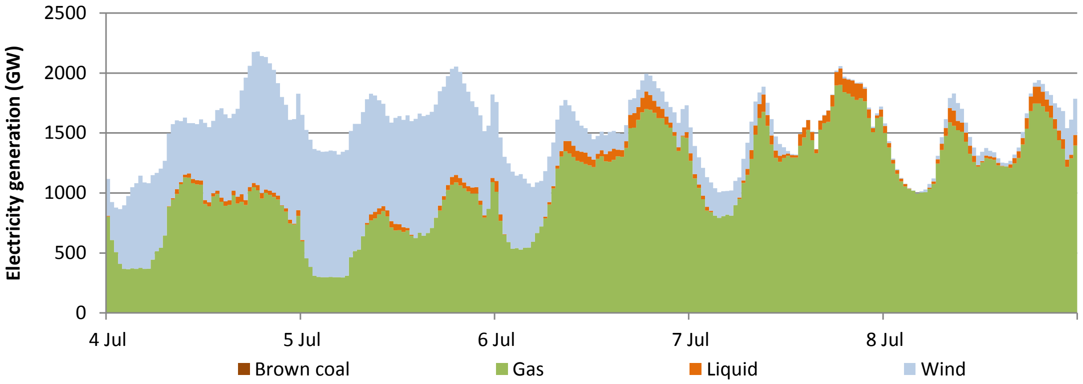


Figure 16 shows the high level of gas generation required upstream of the Adelaide hub which may have influenced the sharp increase in participants' valuation of gas quantities above the perceived level of demand in the Adelaide STTM hub.

Figure 16: South Australia's generation mix around 6 July



3.6 Tuesday 12 July 2016

Adelaide STTM:	There was a $12/GJ variation between the D-1 schedule price ($17.99/GJ) and the D+1 schedule price ($29.99/GJ).

Table 8 sets out the price and quantity for each of the gas schedules for the 12 July gas day in Adelaide.

Table 8: Adelaide prices and quantities, all schedules, 12 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$14.20	$14.99	$17.99	$29.99
Quantity (TJ)	98.12	101.24	102.7	+7.071

There was a positive imbalance on the day of just over 7 TJ. This means the actual demand on the day was higher than the total demand forecast in the D-1 schedule. This led to the $12/GJ variation between the D-1 schedule price ($17.99/GJ) and the D+1 schedule price ($29.99/GJ).

Figure 17 illustrates how the increase in demand for the D+1 schedule (after taking into account the 7 TJ imbalance) resulted in the $12/GJ increase in price. While the imbalance is the main contributor to the price rise (i.e. had demand been forecast accurately, the D+1 price would have been similar to the D-1 price), another influential factor is the inelasticity of supply offers from around $12/GJ and higher.

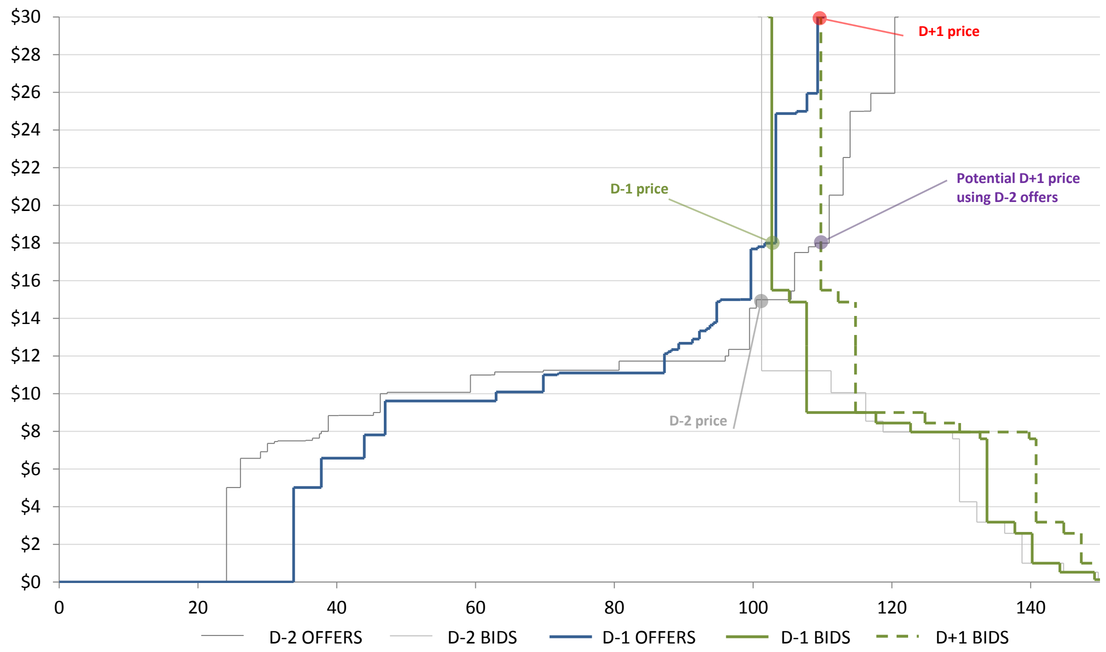
There was only 1.1 TJ of supply remaining at the D-1 price of $17.99/GJ. The next price step was for $24.88/GJ.

As the positive imbalance quantity shifted the demand (bid) curve to the right by 7.1 TJ, the ex post price increase to $29.99/GJ.

The main factor influencing the higher requirement for gas on the day was an unscheduled back haul bid (EnergyAustralia) for 5.3 TJ of gas delivered on the Moomba to Adelaide Pipeline (MAP).

Figure 17 illustrates the impact of actual demand being 7.1 TJ higher than forecast in the D-1 schedule. It also shows that supply became more inelastic in the D-1 schedule from around $14/GJ and higher. While this didn’t impact the D-1 price significantly, it was in part responsible for the high D+1 price. The D+1 price would have been around $18/GJ (instead of $29.99/GJ) had supply offers remained unchanged from the D-2 to D-1 schedules.

Figure 17: Adelaide STTM, 12 July 2016, D-1 and D+1 schedules (TJ)



3.7 Wednesday 13 July 2016

Adelaide STTM:	There was an $8.08/GJ variation between the D-2 schedule price ($17.80/GJ) and D-1 schedule price ($25.88/GJ).
Victorian market:	The imbalance price reached $43.33/GJ.

High forecast demand in Victoria and high gas fired generation requirements in South Australia upstream of the Adelaide hub drove increased demand for gas in both states. Around the same time, prices for gas traded in the Gas Supply Hub at Wallumbilla aligned with prices set in southern markets, reaching $14.25/GJ for gas traded on 12 July (for delivery on 13 July).

Victoria

On 13 July, the 6 am (beginning of day) price in the Victorian gas market reached $43.55/GJ[33] as temperatures dropped to some of the coldest levels seen this winter (4.5˚C in Melbourne), leading to forecast demand exceeding 1.15 PJ.[34]

Under forecast demand during the previous gas day led to higher than predicted afternoon consumption. This led to a depletion of the line pack in the system and resulted in actual line pack levels at the beginning of the 13 July gas day being 36.39 TJ below expected levels (demand was forecast at 1266 TJ at 6 am).

33 This is the highest Victorian price since 2007-2008 (the price previously reached $54.88/GJ on 22 November 2008).

34 While this wasn't the lowest temperature this winter, the wind chill had a more significant effect which led to overnight temperatures plummeting and snow in a number of areas across the state. Actual demand exceeded 1200 TJ, the highest level this winter.

High forecast demand and lower line pack levels resulted in injections at Longford being profiled towards the start of the gas day.[35]

Figure 18 shows the under forecasting across the afternoon of 12 July into the morning of 13 July which contributed to depleted line pack levels in the Victorian gas network.

Figure 18: Forecast demand at each scheduling horizon leading up to and during the 13 July gas day in Victoria

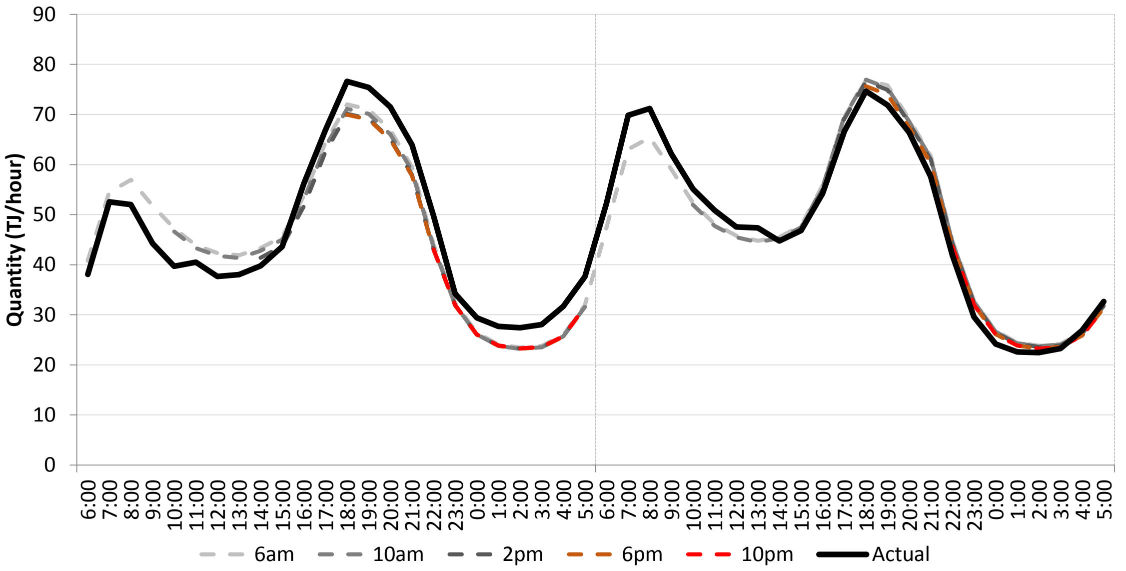
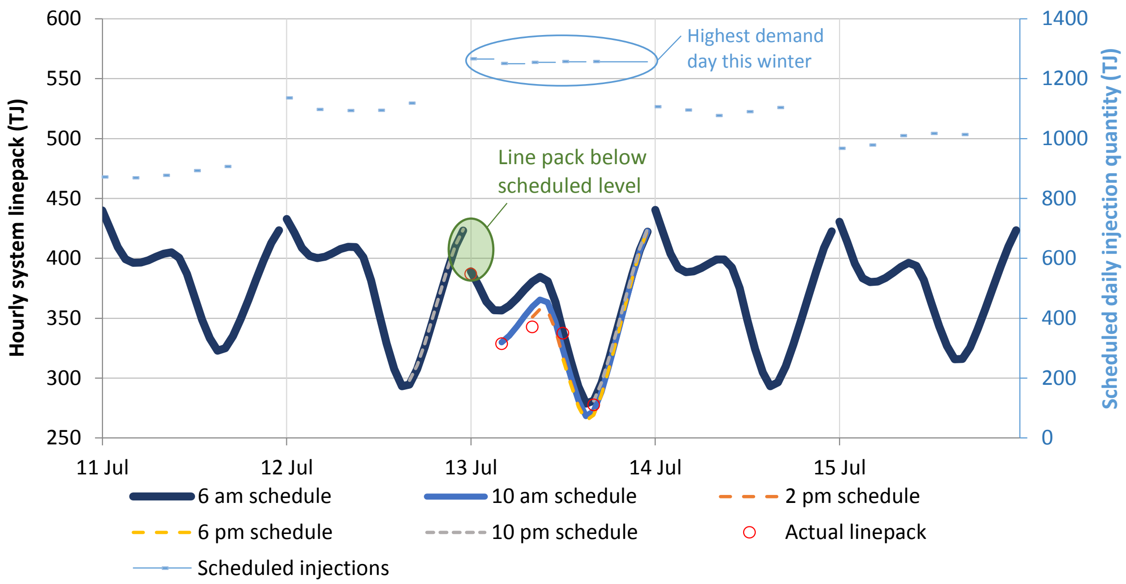


Figure 19 shows the scheduled (6 am and 10 am schedules) line pack quantities and actual line pack levels (at each of the five scheduling horizons) on 13 July and surrounding days. The figure illustrates the 36.4 TJ line pack shortfall at the beginning of the 13 July gas day and the relatively high level of supply required on the gas day.

Figure 19: Scheduled hourly line pack levels in Victoria*



* Operational schedule line pack data is shown for each gas day (beginning at 6 am). For 13 July, actual and scheduled

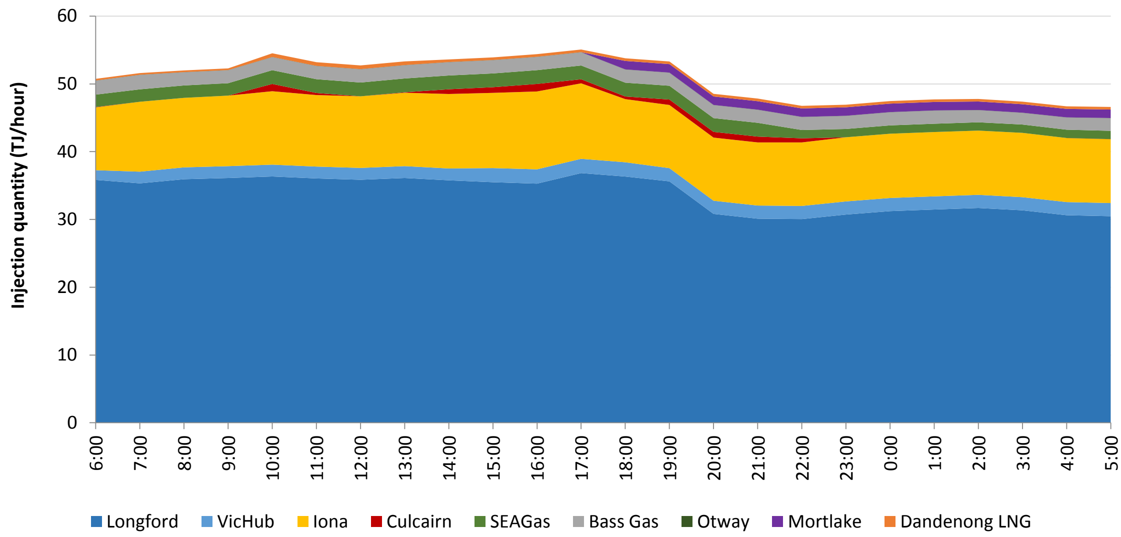
35 This hourly profiling had no impact on prices, as prices are set on the daily injection quantity.

line pack information is displayed for the five scheduling horizons at 6 am, 10 am, 2 pm, 6 pm and 10 pm. Scheduled injections for each scheduling horizon, representing the total amount of gas to be delivered across for the entire gas day, are measured on the secondary vertical axis.

The available offers to supply gas in Victoria for 13 January were similar to the surrounding days. Given the high demand and low line pack levels, the high beginning of day price was not unexpected under such circumstances.

Figure 20 shows the hourly injection quantities for 13 July, illustrating the higher injection quantities profiled during the beginning of the gas day at Longford to assist in replenishing line pack levels and catering for the high demand expected on the gas day.

Figure 20: Hourly injection quantities in Victoria on the 13 July gas day



Adelaide

Table 9 sets out the price and quantity for each of the gas schedules for the 13 July gas day in Adelaide.

Table 9: Adelaide prices and quantities, all schedules, 13 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$12.30	$17.80	$25.88	$23.50
Quantity (TJ)	94.3	95.31	101.8	-1.632

The D-1 price was the highest ever for the Adelaide STTM, beating the previous record set days earlier for the 6 July gas day.

The main drivers behind the $8.08/GJ variation between the D-2 schedule price ($17.80/GJ) and D-1 schedule price ($25.88/GJ) were an increase in both uninterruptable and controllable demand and a reduction in low priced supply offers.

The main contributor to the increase in uninterruptable demand was EnergyAustralia, which increased its price taker bid for the D-1 schedule by over 1.4 TJ. Origin also increased its price taker bid by 700 GJ.

EnergyAustralia was also the main contributor to the increase in controllable demand, however its market impact was minimised somewhat by an increase in lower priced offers of a similar quantity.

For the D-1 schedule, EnergyAustralia increased its backhaul bid on the MAP priced at or above $25.88/GJ by 4 TJ.[36] EnergyAustralia also increased its offers on SEAGas priced at or below $25.88/GJ by 3.5 TJ. The net impact still applied upwards pressure on prices; however the quantity of gas was only 500 GJ.[37]

The main contributor to the reduction in low priced offers was AGL. For the D-1 schedule, AGL reduced its offers on SEAGas priced at or below $25.88/GJ by 3.4 TJ.

Figure 21 illustrates the increase in higher priced bids and the reduction in lower priced supply offers from the D-2 to the D-1 schedules and in turn how these changes resulted in the $8.08/GJ variation between the two schedules' prices.

Figure 21: Adelaide STTM, 13 July 2016, D-2 and D-1 schedules (TJ)

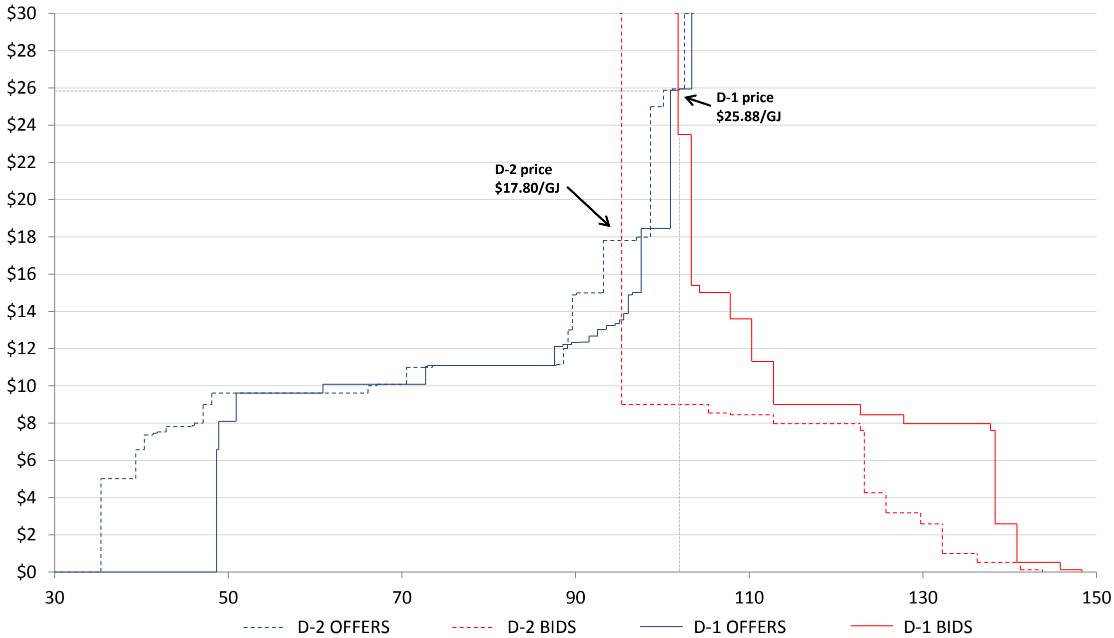


Figure 22 shows the increase in bids (reflecting both uninterruptable and controllable demand) which resulted in the higher scheduled quantity in the D-1 schedule.

36 It is likely this was to supply gas to Hallett; its gas-fired electricity generator located around 210 km north of Adelaide.

37 4 TJ – 3.5 TJ = 500 GJ

Figure 22: Adelaide STTM, 13 July, demand bids for provisional and ex ante schedules

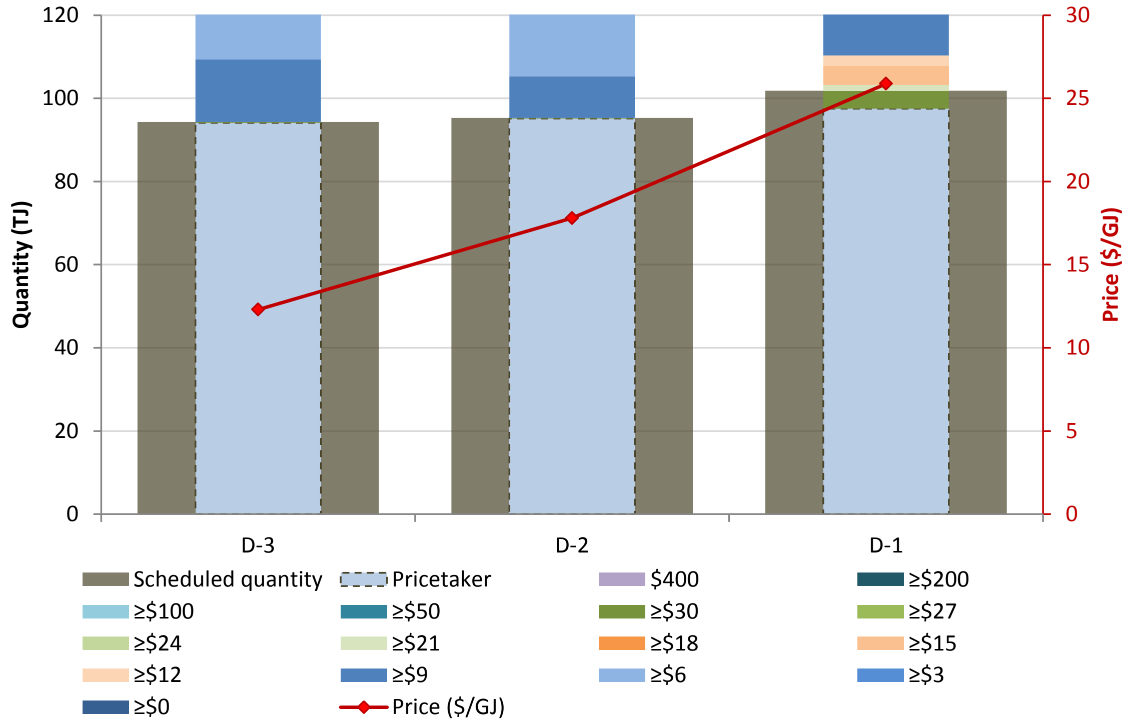
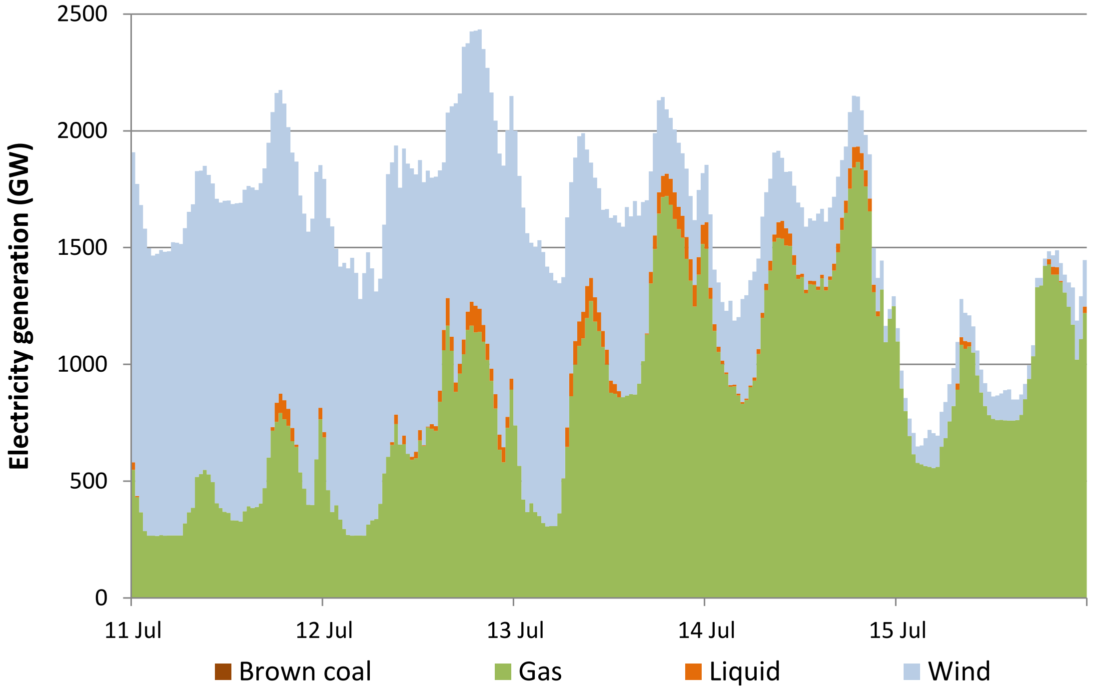


Figure 23 shows the high level of gas generation required upstream of the Adelaide hub which may have influenced the sharp increase in participants' valuation of gas quantities above the perceived level of demand in the Adelaide STTM hub.

Figure 23: South Australia's generation mix around 13 July



3.8 Friday 15 July 2016

Adelaide STTM:	There was a $9.12/GJ variation between the D-2 schedule price ($11.10/GJ) and the D-1 schedule price ($20.22/GJ).

Table 10 sets out the price and quantity for each of the gas schedules for the 15 July gas day in Adelaide.

Table 10: Adelaide prices and quantities, all schedules, 15 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$14.54	$11.10	$20.22	$20.22
Quantity (TJ)	101.63	101.7	94.10	+0.156

The main driver behind the $9.12/GJ variation between the D-2 schedule price ($11.10/GJ) and the D-1 schedule price ($20.22/GJ) was a reduction in low priced supply offers. The price increase occurred despite an overall reduction in demand.[38]

Some participants offered less gas priced at or under the D-1 price for the D-1 schedule than they offered in the D-2 schedule, including:

- AGL reduced its quantity of offers on the MAP and SEAGas by over 9 TJ[39]
- Simply Energy reduced its quantity of offers on the MAP and SEAGas by 5.5 TJ[40]
- EnergyAustralia reduced its quantity of offers on the MAP and SEAGas by 8 TJ[41]

Figure 24 illustrates the reduction in higher priced bids and the reduction in lower priced supply offers from the D-2 to the D-1 schedules and in turn how these changes resulted in the $11.10/GJ variation between the two schedules' prices. It shows the reduction in demand was small relative to the reduction in lower priced offers.

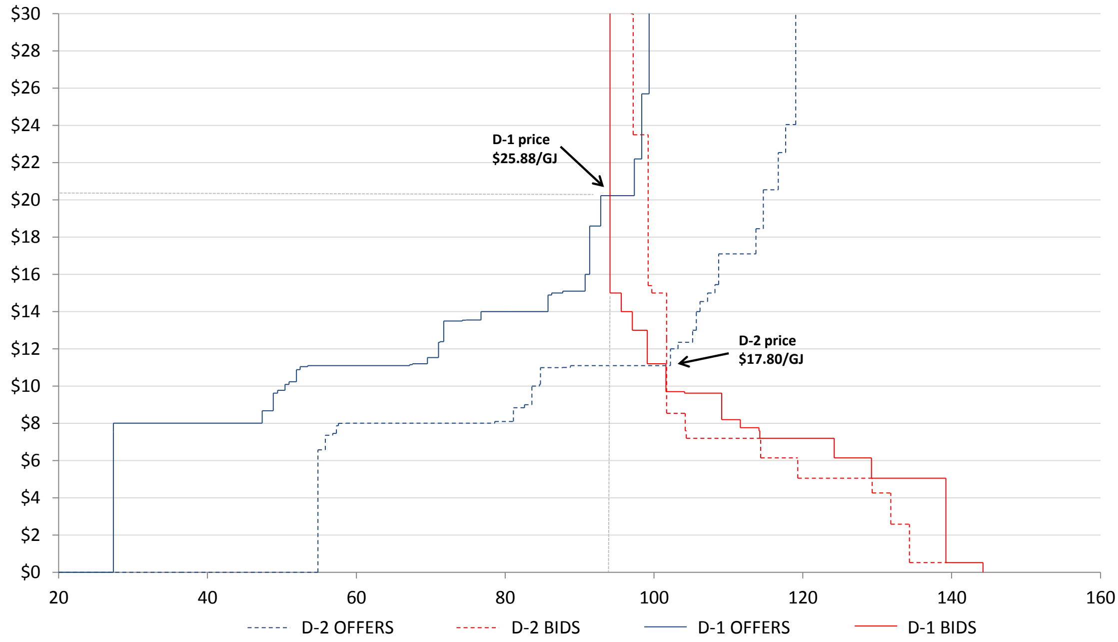
38 The reduced demand was a result controllable demand, namely EnergyAustralia reducing its backhaul bids on the MAP priced at or above $20.22/GJ by 7.5 TJ. By itself, this rebid resulted in less demand at the Adelaide hub, and therefore did not apply upwards pressure on the D-1 price.

39 AGL reduced offers on the MAP by 4.3 TJ, and reduced offers on SEAGas by 4.7 TJ.

40 This is a net amount. Simply Energy increased offers on the MAP by 3.5 TJ, and reduced offers on SEAGas by 9 TJ.

41 This is a net amount. EnergyAustralia increased offers on the MAP by 10.5 TJ, and reduced offers on SEAGas by 18.5 TJ. When considered alongside its 7.5 TJ reduction in bids, the broader net impact still applied upwards pressure on prices; however the net quantity of gas was only 500 GJ.

Figure 24: Adelaide STTM, 15 July 2016, D-2 and D-1 schedules (TJ)



3.9 Tuesday 26 July 2016

Brisbane STTM:	There was a $7.78/GJ variation between the D-2 schedule price ($14.88/GJ) and the D-1 schedule price ($7.10/GJ).

Table 11 sets out the price and quantity for each of the gas schedules for the 26 July gas day in Brisbane.

Table 11: Brisbane prices and quantities, all schedules, 26 July

Schedule	D-3	D-2	D-1	D+1
Price ($/GJ)	$14.88	$14.88	$7.10	$7.10
Quantity (TJ)	103.5	102.9	102.8	-1.143

The main driver behind the $7.78/GJ variation between the D-2 schedule price ($14.88/GJ) and the D-1 schedule price ($7.10/GJ) was an increase in low priced supply offers. Uninterruptable and controllable demand remained at similar levels across all schedules.

The main contributor to the increase in low priced offers was Stanwell. For the D-1 schedule, Stanwell increased its offers on the RBP priced at or below $7.10/GJ by

10 TJ.[42] Alinta also increased its offers on the RBP in the same price range by nearly 1.4 TJ.[43]

This also coincided with a number of trades in the Wallumbilla Gas Supply Hub (GSH) for delivery on the Roma to Brisbane Pipeline (RBP) on 26 July.[44] The reduction in offer prices prior to the 26 July gas day may have been associated with an expected increase in the availability of gas at lower prices following the QCLNG maintenance period commencing from 25 July.

Figure 25 illustrates the increase in low priced supply offers from the D-2 to the D-1 schedules and in turn how this change resulted in the $7.78/GJ variation between the two schedules' prices.

Figure 25: Brisbane STTM, 26 July 2016, D-2 and D-1 schedules (TJ)

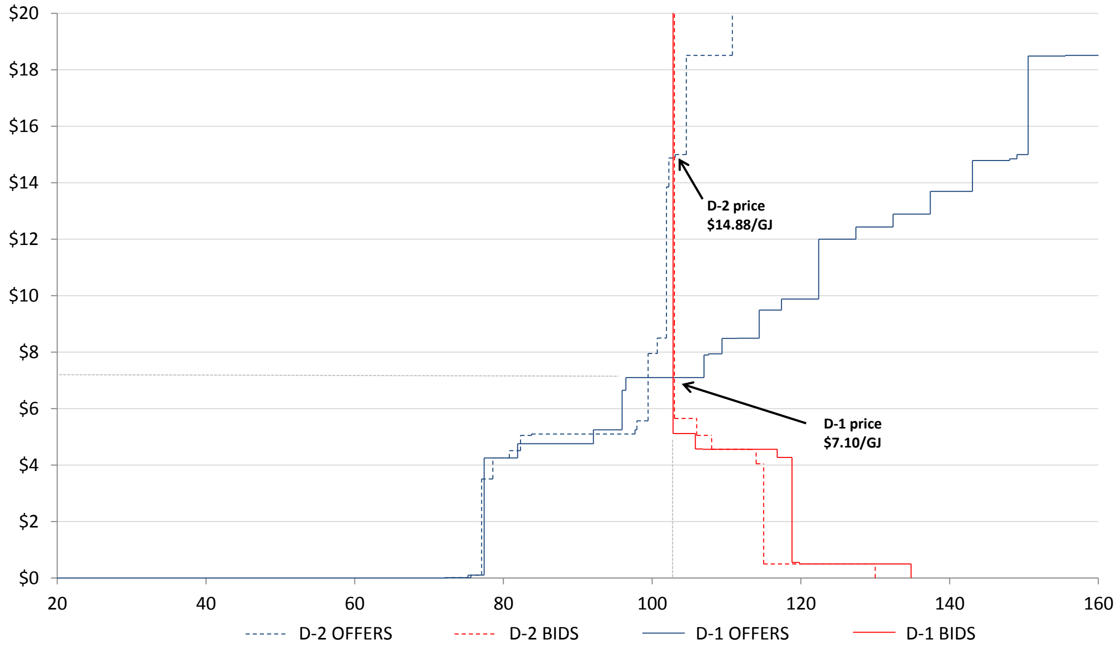


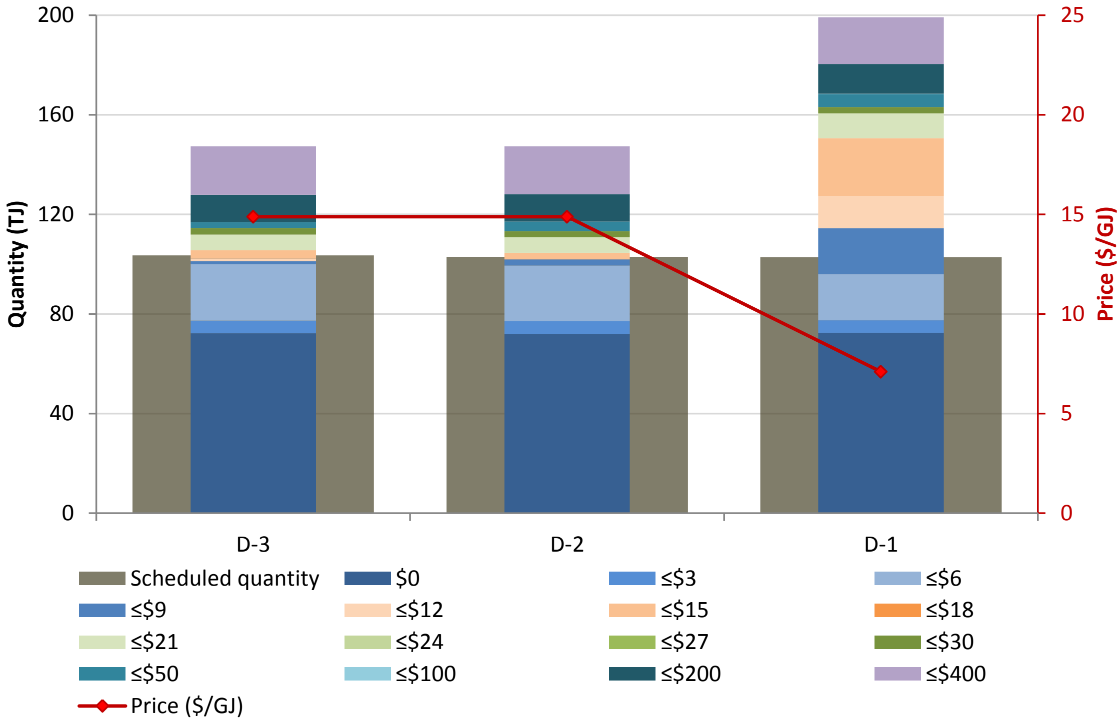
Figure 26 shows the additional quantity of gas offers made for the D-1 schedule compared to the D-2 and D-3 schedules.

42 For the D-2 schedule, Stanwell had no offers at any price. For the D-1 schedule, it made a 10 TJ offer priced at $7.10/GJ, and a 5 TJ offer priced at $12/GJ.

43 Alinta also increased its offers priced above $7.10/GJ for the D-1 schedule by 15.4 TJ.

44 17.225 TJ of gas was purchased by a number of participants at prices between $5.55/GJ - $6.20/GJ in balance-of-day product trades.

Figure 26: Brisbane STTM, 26 July 2016, supply offers across the D-3, D-2, and D-1 schedules



3.10 Thursday 25 August 2016

Sydney STTM:	There was a $256 937 MOS service payment.

On 25 August, a total of 33.2 TJ of MOS was required on the MSP and EGP. The service payment was made up of:

- 21.6 TJ of decrease MOS on the MSP (at a cost of $168 480)
- 10.6 TJ of increase MOS on the EGP (at a cost of $88 457)

The overall MOS requirement on the day was driven by:

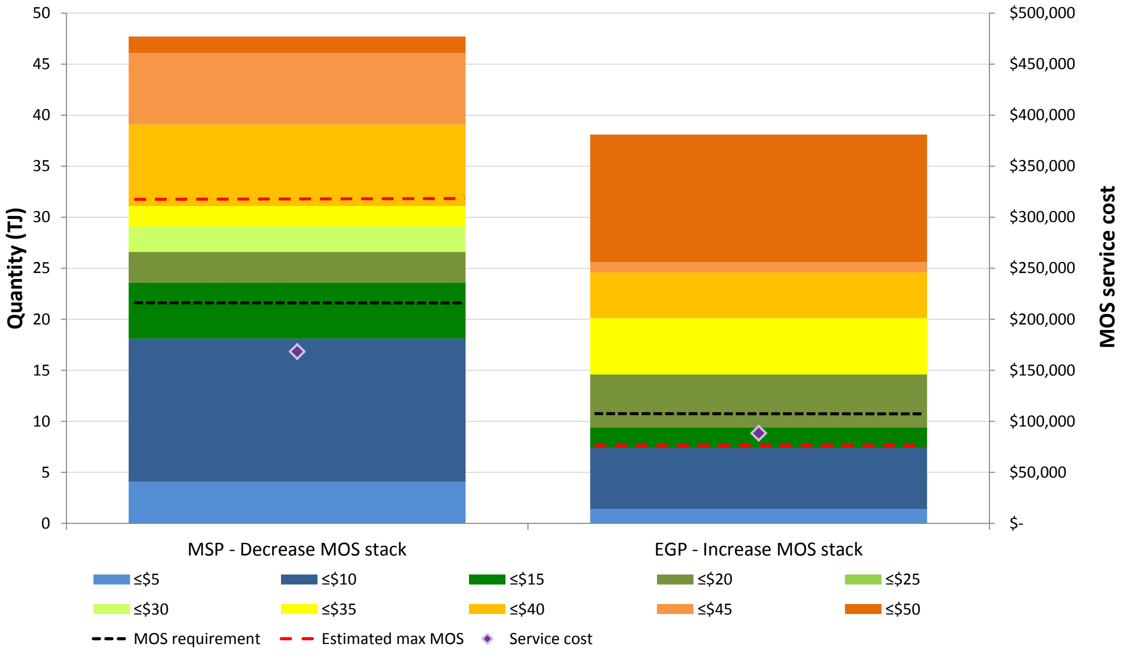
- participants over forecasting demand (in aggregate across both distribution zones) by around 15.6 TJ
- actual deliveries from the EGP injection points being reduced by 4.7 TJ (compared to the deliveries scheduled on the pipeline).[45]

[45] Analysis indicates the renomination of flows reduced the scheduled delivery quantity into flow controlled delivery points on the EGP and did not contribute to additional counteracting MOS requirements on the day.

The supply/demand deviation from schedule accounted for 10.9 TJ of the MOS allocation requirement, while the remainder of MOS allocations were related to the counteracting nature of the MOS deliveries.

Figure 27 shows the available balancing gas quantities offered on MOS enabled pipelines supplying the Sydney hub for the month of August 2016. The figure also illustrates the quantity of services allocated on each pipeline and the associated cost.

Figure 27: MOS stacks and allocation requirements for 25 August



4 Other market and compliance Issues

In addition to the information described in Part 2 and Part 3 of the report, in investigating SPV days the AER identified a number of other issues which are worth highlighting with this final report on winter SPV days. Particularly MOS Service payments can represent a significant additional ancillary cost of business to participate in the STTMs in addition to the primary market prices.

The MOS balancing gas market — MOS Service Payments in Sydney

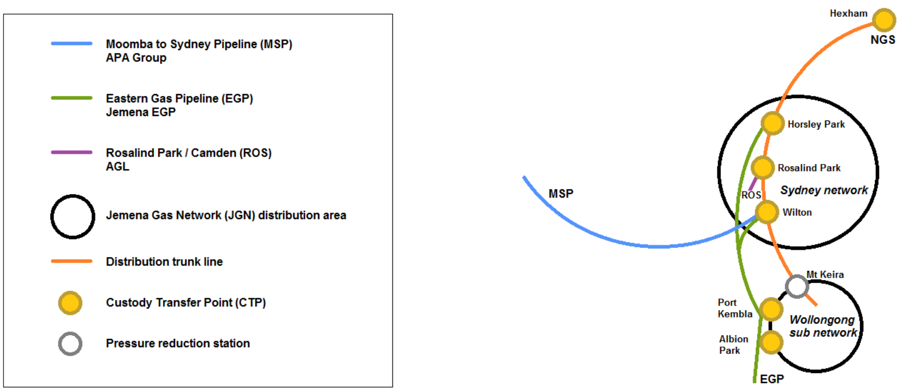
MOS, also referred to as balancing gas, is required to manage everyday pipeline deviations.[46] A pipeline deviation occurs when there is a difference between the total quantity of gas nominated by the pipeline's shippers (typically gas retailers) and the quantity of gas physically delivered. There are two kinds of pipeline deviations; positive (when more gas is delivered) and negative (when less gas is delivered).

When actual gas flows are higher than final nominations, the difference is allocated as **increase MOS**. When actual gas flows are lower than final nominations, the difference is allocated as **decrease MOS**.

MOS is provided by participants who submit offers to AEMO on a monthly basis. When MOS is required, the offers are allocated in merit order (i.e. from lowest price to highest price) until the required quantity is met.[47]

The Sydney hub is illustrated in Figure 28. Simply put, the Sydney hub is comprised of two distribution networks, or zones (the Sydney zone and the Wollongong sub network) connected by a distribution trunk line.

Figure 28: The Sydney hub



* **Custody Transfer Point (CTP) dynamics:** MSP Wilton CTP – pressure controlled; EGP Horsley Park a Wilton CTPs – flow controlled; EGP Port Kembla & Albion Park CTPs – pressure controlled; NGS & Rosalind Park CTPs – flow controlled. *Distribution trunk line: Mt Keira – pressure controlled.*

46 A pipelines ability to offer decrease MOS is limited by the amount of gas it is providing to the hub. For example, if a pipeline was providing 50 TJ to a hub, it could provide up to 50 TJ in decrease MOS. There is no such limitation for the provision of increase MOS.

47 For further details about MOS, please refer to the significant price variation report for January 2016 (https://www.aer.gov.au/wholesale-markets/market-performance/significant-price-variation-report-13-and-23-january-2016-sydney-sttm).

MOS service payments in Sydney over winter 2016 driven by high July and August payments were $5,851,262 which was 93% higher than for winter 2015:

- for the July MOS period, a total of 416.67 TJ of decrease MOS services on the MSP were required (averaging about 13.4 TJ a day) resulting in $2,017,413.56 of payments. This is the highest monthly volume of decrease MSP MOS required in the Sydney STTM since market start.
- for the August MOS period, 286.66 TJ of decrease MOS services parked on the MSP was the highest quantity since June 2012 (leaving aside July 2016 requirements).
- the average price of the first 10 TJ of decrease MOS offers for July and August 2016 increased from $1.67/GJ in 2015 to $4.31/GJ in 2016.

Accordingly, both the increased magnitude of MOS volumes required and the price of MOS impacted on the much higher MOS service payments in Sydney this winter.

Over forecasting by participants at a hub level and higher MOS offer costs

For July, an over forecasting demand trend in the hub led to 81 per cent of gas days at a hub level being over forecast at around 11.5 TJ above actual requirements. This over forecasting impacted on the high level of decrease MOS required on the MSP across July, i.e. as a general rule for each TJ of demand over forecast an extra TJ of decrease MOS was required on the MSP for gas to be 'parked' short of the Sydney hub

There are only three main suppliers of MOS in the Sydney STTM including decrease MOS on the MSP. Any single supplier can move the market price of MOS offer by changing the price of its offers. The large increase in year-on-year MOS offer costs on the MSP for July was due in part to a participant effectively withdrawing by only offering to supply MOS at prices above $8.11 per GJ. Whether this change in offer behaviour reflects an increase in the cost of contracting with the pipeline operator or some other operational factor is uncertain.

Imprecision in nominations at a sub zone level

However, participant's demand forecast for the whole of the Sydney hub were not the only cause of higher MOS, they were also appear to have been impacted by a phenomenon which reappeared this winter of counteracting MOS (CMOS)[48] which can occur because of the splitting of the Sydney hub into different zones:

- The Moomba to Sydney pipeline (**MSP**) provides the majority of the MOS requirements in the northern Sydney zone. This is because it is connected to the network at the only pressure controlled point along the trunk line.[49]

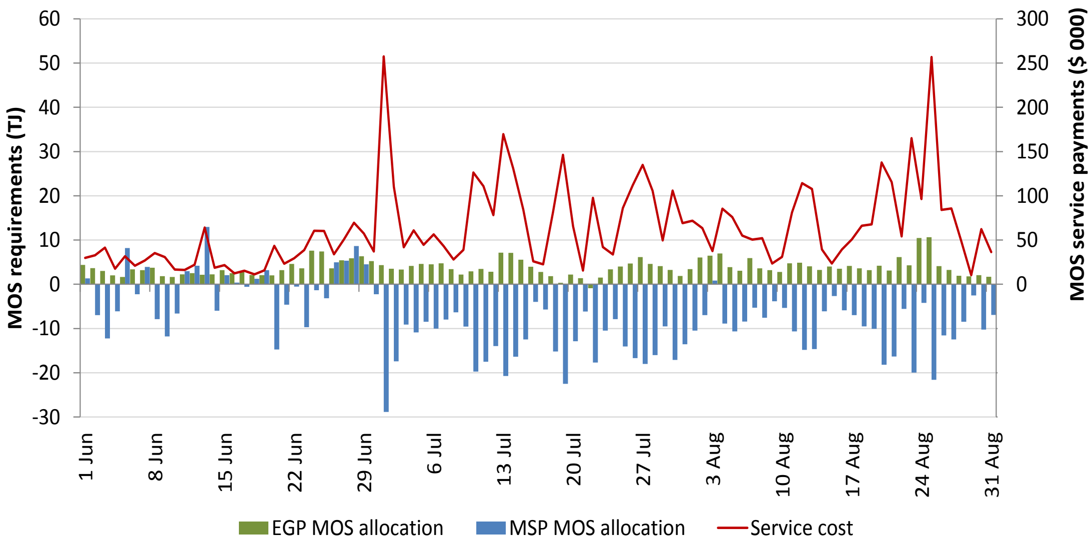
[48] CMOS is defined for this report's purposes as the need for simultaneously increase MOS (increased flows) to be provided by one pipeline at the same time as decrease MOS (parked gas) by the other pipeline on the same day in the magnitude of more than 2 TJs on both pipelines.

[49] While the EGP is also connected at Wilton, it is connected by a flow controlled point.

- The Eastern Gas pipeline (**EGP**) provides the majority of the MOS requirements in the Wollongong sub network. This is because both of its connection points are also pressure controlled.[50]

Over the months of July and August 2016[51] there was a significantly higher level of CMOS in the Sydney hub compared to the previous year. There were 58 days across June and July 2016 where CMOS allocations were greater than 3 TJ[52], compared to 42 days in 2015. The CMOS allocations over these months are illustrated in Figure 29.

Figure 29: Counteracting MOS in Sydney across July and August 2016



Despite the aggregate demand for the whole of the Sydney hub being over forecast, i.e. in July, under-forecast demand within the Wollongong sub-section of the network resulted in insufficient nominations to deliver gas to the region. The difference between these nominations and actual deliveries off the EGP (which could not be supplied through Mount Keira) were allocated as increase MOS on the EGP.[53] As the additional deliveries to Wollongong also offset the trunk line delivery requirement to meet demand in the hub, the increase MOS provided on the EGP added to the decrease MOS requirements allocated on the MSP for July. In summary, we consider this contributed to the already high decrease MOS quantities and payments on the MSP and added further to the high cost of MOS services over the period. This is shown in Figure 30.

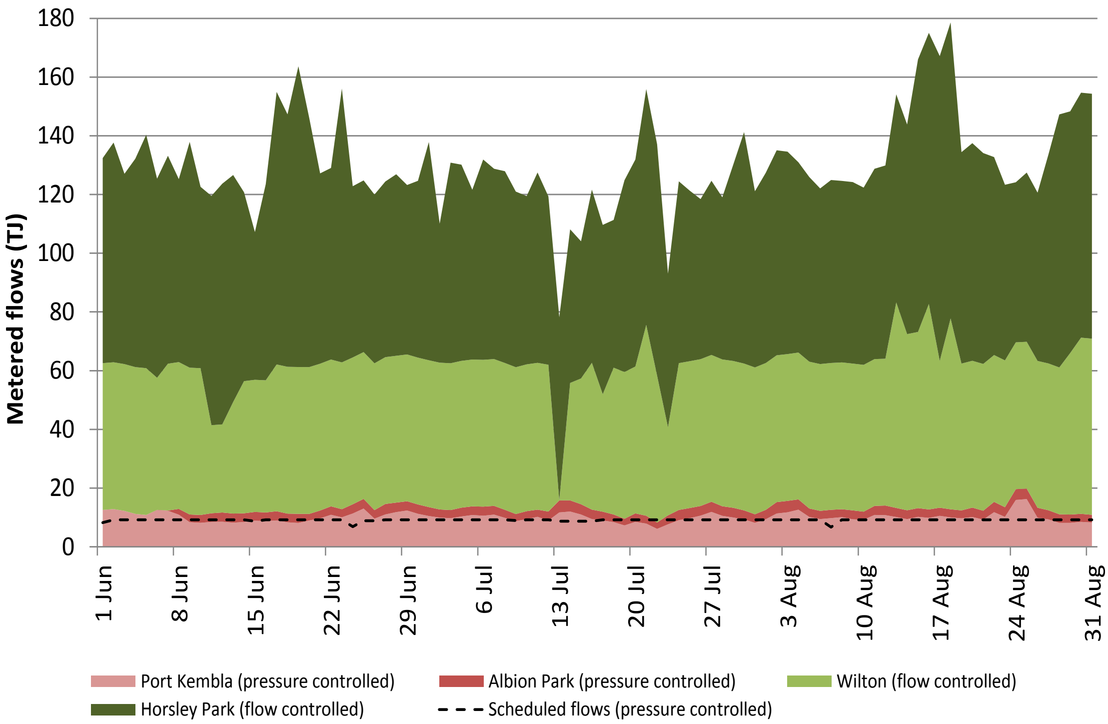
50 Gas can flow into the Wollongong sub network through the Mount Keira pressure reduction station. However gas can only flow in this direction and cannot flow back towards the northern Sydney network.

51 The numbers of counteracting MOS days in June were the same in 2015 and 2016, with a lower quantity of counteracting MOS allocated across June 2016.

52 Absolute MOS allocations of 1.5 TJ of increase MOS on the EGP, offset by an equivalent 1.5 TJ of decrease MOS on the MSP.

53 The difference between the nominated EGP deliveries through the flow controlled CTPs into Wollongong (the dotted black line in Figure 30) and the actual metered flows at those points (the delivered quantities shaded red) is the quantity of MOS allocated on the pipeline over the period.

Figure 30: EGP system point deliveries and resulting MOS requirements



The driver of higher costs over the period was due to a combination of factors including higher service costs resulting from changes to the monthly MOS offers. The combination of these higher priced offers and the large quantities of CMOS led to the significantly higher costs for MOS compared to the previous year.[54]

Impact of pipeline capacity constraints on market prices

Adelaide STTM: Constraints on the Moomba Adelaide Pipeline

On 24 June 2016, the capacity submitted for the MAP by Epic for the Adelaide STTM was 41 TJ which is significantly lower than the MAP's STTM capacity subsequently submitted from July this year. In response to our questions about the capacity on the 24 June, Epic noted that on 5 July 2016, it had changed the way it calculated available daily capacity for deliveries in the Adelaide STTM which has resulted in much higher capacities being submitted. This change in capacity appears to have understated the capacity available to shippers and potentially given the false impression of a constraint which led to a high ex ante price of $18.99/GJ as noted in the AER's June SPV report. This appears to have been an enduring issue which was only addressed in July; the AER is continuing to investigate.

South West Pipeline

Through its planning and reporting role, AEMO noted that a limitation in the South West Pipeline's (SWP) capacity from Melbourne to Port Campbell may limit flows to

54 Total MOS service costs were $94 431 higher in 2016: $156 958 in 2016 ($83 107 in June and $74 851 in July) compared to $62 527 in 2015 ($34 172 in June and $28 355 in July).

South Australia via SEAGas and could also impact refilling Iona.[55] Of participants using the Iona storage facility, one participant did comment that constraints on the SWP pre-winter for withdrawing gas into the Iona storage did impact its ability to refill the storage to the levels it required. Other participants acknowledged the presence of a constraint but that it did not impact them materially in terms of their gas trading over winter.

Impact of poor Victorian demand forecasting

The AER identified one smaller volume Victorian market participant whose demand forecasts did not meet the required standard of a best estimate forecast of demand for the Victorian Gas Market (Part 19 of the Gas Rules) consistently submitting a forecast demand which was over 20 per cent above its actual demand. The participant's forecast demand was relatively small (between 0 to 10 TJ/day), however on occasion is may have contributed to impacts on market price given the inelasticity of the supply curve around the clearing price, i.e. a small change in forecast demand — even 1 or 2 TJ — can result in a $2 - $10/GJ increase in the market price. The participant has subsequently improved its forecasting performance.

Adequacy of Bulletin Board Reporting

The AER looked into of the quality of reporting on the Gas Bulletin Board (Part 18 of the Gas Rules) over winter in general but also in response to comments raised by participants on specific issues such as AGL's reported supply outage in Queensland. The AER is satisfied that information provided was in accordance with the Gas Rules.

55 https://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report

Appendix A – AER SPV reporting thresholds

The Significant Price Variation Reporting thresholds are set out below.

The two reporting thresholds set out in the Victorian SPV guideline are when:

- the trade weighted market price published by AEMO on a gas day is more than three times the average price for the previous 30 days and the trade weighted market price is equal to or greater than $15/GJ
- the ancillary payment amount published by AEMO on a gas day is an amount payable or receivable which exceeds $250 000.

The five reporting thresholds set out in the STTM SPV guideline are:

- variations greater than $7/GJ between the D-2 price and ex ante price
- variations greater than $7/GJ between the ex ante and the ex post price
- the ex ante price being greater than three times the 30 day rolling average price and greater than $15/GJ
- the ex post price being greater than three times the 30 day rolling average price and greater than $15/GJ
- MOS service payments exceeds $250 000.

Appendix B – Price impact analysis methodology for SPV days

Short term trading market

Throughout this report, we have focussed our analysis on participant driven supply and demand factors that contributed to the significant price variation **(SPV)**.

Supply is represented by **offers** submitted to AEMO. If a participant intends to supply gas to a hub on a particular gas day, they must submit an offer to AEMO which sets out their identity, the hub (for example, the Adelaide hub), the facility (for example, a particular pipeline or storage facility), the prices and quantities offered in each price step.

The National Gas Rules **(NGR)** state offers are confidential information until the end of the gas day to which they relate.[56]

On any given gas day, total demand is made up of:

- uninterruptable (or uncontrollable) demand
- controllable (or price sensitive/interruptible) demand

An example of uninterruptable demand is residential consumption.[57] Each participant submits a **price taker bid** which represents its forecast of uninterruptable demand.

An example of price sensitive demand could be an industrial user that is prepared to purchase gas but only at (or below) a particular price. This type of consumption is reflected in price specific bids (this report refers to them as simply '**bids**').[58]

The NGR states that price taker bids are confidential information.[59]

To avoid the disclosure of confidential information, this report does not state any individual price taker bids. At times, the *change* in a particular participant's price taker bid will be noted. At times it is necessary to report on a participant's change in price taker bid so we can consider this alongside any other changes made to bids and offers in order to understand the participant's overall impact on the market. Excluding the change in price taker bids could result in an inaccurate representation of the drivers behind a particular price outcome.

Our approach is the same regardless of whether the SPV represents a rise, or fall, in price.

In general, a participant could contribute to a price rise by:

- increasing their demand (either uninterruptable or controllable)

56 Rule 407(4)
57 This is because household gas consumption is unlikely to be influenced by the market price on any given gas day.
58 These are sometimes referred to as 'ex ante bids' or 'price sensitive bids'.
59 Rule 409(4)

- reducing their quantity of lower priced offers

Conversely, a participant could contribute to a price fall by:

- decreasing their demand (either uninterruptable or controllable)
- increasing their quantity of lower priced offers

When analysing an SPV between the D-2 and the D-1 schedules, we have considered changes made by participants to price taker bids, bids priced at or above the D-1 price, and offers priced at or below the D-1 price.

This allows us to measure the overall market impact arising from a particular participant's change in bids and/or offers from the D-2 to the D-1 schedules.

If a participant's change results in their net position in the hub changing significantly in a way that could have contributed to the SPV, then it is likely to feature in this report.