Significant price variation report

East Coast Gas Markets
June 2016

26 August 2016

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1 Summary

In June this year there were twelve significant price variations **(SPVs)** across the Victorian Gas Market and the Adelaide, Brisbane and Sydney short term trading markets **(STTMs)**. This report collectively refers to these markets, along with the Wallumbilla and Moomba gas supply hubs, as the east coast gas markets.

Two SPVs occurred in Victoria when the trade weighted imbalance price reached $23.34/GJ (on 24 June 2016) and $25.74/GJ (on 27 June 2016).

Across the STTMs, SPVs were triggered by:

- Variations between the D-2 and D-1 prices (on 3 occasions)
- Variations between the D-1 and D+1 prices (on 4 occasions)
- Prices greater than the 30 day rolling average and above $15/GJ (on 3 occasions).

There were eleven more SPVs in July. While these events will be detailed in a separate report, the overall market conditions across June and July **(winter 2016)** are set out in section 2 of this report.

Prices this winter were much higher than the previous two years when the domestic market benefitted from the supply of excess 'ramp gas' during the 'build up' to Queensland's liquefied natural gas **(LNG)** export projects. In contrast in winter 2016 five (of six) LNG production trains are operating and primarily focussed on exporting gas rather than supplying the domestic market.[1]

The June high prices were largely a result of **reduced supply** and **high demand**.

Some of the supply side factors that contributed to the higher prices include:

- diversion of 'domestic' supply to export markets – including gas from South Australia's Moomba production facility, and likely from Victorian gas fields as well
- 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 Otway and Minerva gas plants in Victoria.

Some of the demand side factors that contributed to the higher prices include:

- LNG exports – in particular Santos' GLNG project. The demand from these projects is forecast to reach three to four times the level of domestic demand once fully operational
- increased output from gas fired electricity generators, particularly in South Australia
- cold weather – this led to high residential gas consumption for heating, particularly in Victoria.

[1] The sixth train is expected to come on line later this year.

On most occasions the high prices were 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.

1.1 The AER's reporting obligation

The National Gas Rules **(NGR)** require the AER to publish a report setting out any Significant Price Variations **(SPVs)**.[2]

The AER has published two guidelines which set out what constitutes an SPV in the Victorian market and the short term trading market **(STTM)** respectively.

The reporting thresholds are set out below. The different kinds of prices that feature in the STTM and the Victorian gas market are explained in further detail when necessary in section 3.

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 when:

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

2 Rule 498(3)(b) relates to SPVs in the STTM, and rule 355(1)(b) relates to SPVs in the Victorian market.

1.2 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 (who can either participate directly in the markets or have another party – usually an energy retailer – participate on their behalf)
- some gas fired electricity generators.[3]

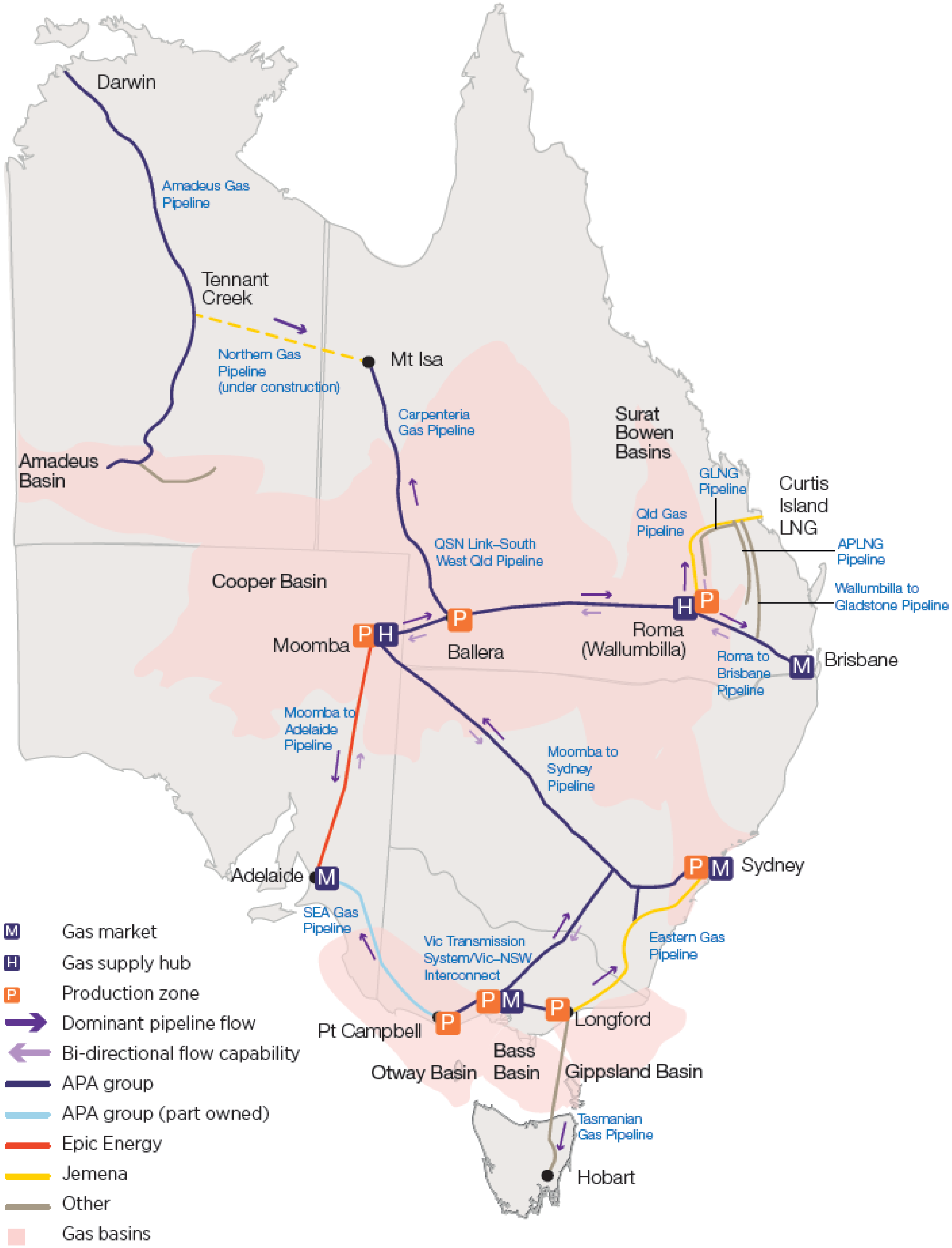
These markets are compulsory for all gas users located within the defined physical boundaries of each market.

There are also two gas supply hubs in Wallumbilla (Queensland) and Moomba (north east Adelaide). Trading in these supply hubs is voluntary and there are no SPV reporting requirements.

3 Unlike the Victorian gas market, where many gas fired electricity generators **(GFG)** sit within the physical boundaries of the market, no GFG sit 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.

Figure 1 illustrates the east coast gas markets. The markets are connected by a network of transmission pipelines which facilitate the transportation of gas across the east coast.

Figure 1: The east coast gas markets



1.2.1 Recent changes to the east coast gas markets

In 2014, the first of three liquefied natural gas **(LNG)** export projects came online in Gladstone, Queensland. These projects have effectively connected Australia's east coast gas market to the global LNG market. While outcomes across the east coast gas markets 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.[4] This has fundamentally changed all aspects of the east coast gas market.

The following investments have been made to help participants transport gas across the network to where they value it 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.[5]

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 these investments also enable gas to flow south. This may occur, for example, when an LNG export facility is undergoing maintenance.

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.

In October 2015, Energy Australia sold the Iona gas storage facility, located in Victoria, to the Queensland Investment Corporation **(QIC)** for nearly $1.8 billion.

Also, 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 below in section 2.

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4 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 1450 PJ. Source: 2015 National Gas Forecasting Report v2.0 – 2 March 2016

5 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.

1.3 The gas and electricity markets are linked

The national electricity market **(NEM)** is an energy-only mandatory market that schedules generators in order to meet 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 portfolio positions.

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.

Across winter 2016, the use of gas fired electricity generators increased following a number of outages across the NEM of coal-fired generators[6]. It particularly increased in South Australia in the wake of a coal plant closure, below average wind generation and an interconnector outage.[7] This further increased the overall demand for gas and, particularly during times of high electricity prices, may have increased the value placed on gas by some participants. These dynamics help ensure gas is allocated to its most economic use.

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: Inter-linked participation: East coast gas markets and NEM*

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

* Not showing all participants. Engie's value reflects that it 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.

6 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.

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

2 Market conditions across winter 2016

This section sets out the overall market conditions across winter 2016 with a particular focus on the supply and demand factors that collectively contributed to the high prices in June. Further analysis regarding how these factors influenced prices in July will be published in a subsequent report. Analysis of the individual June SPVs is set out in section 3.

2.1 Supply factors

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.[8]

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 2 sets out some of the key Victorian supply sources and the quantities of gas delivered across winter 2016 and 2015.

Longford is the largest supplier of gas in Victoria. Longford has been operating at nearly 100 per cent of its capacity for most of winter 2016. For the same period in 2015 Longford was operating at over 96 per cent.[9]

Participants used the Iona underground storage facility to provide supply throughout June resulting in average deliveries about 60 per cent higher than the previous year.[10]

The high use of Iona throughout June limited its ability to sustain the same levels of supply throughout July. This may have contributed to the higher prices in July. Our July report will examine this in more detail.

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 this 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.

8 South Australia, New South Wales, and Victoria.

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

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

Victorian gas transmission

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 South Australia via SEAGas and could also impact refilling Iona.[11] We are clarifying if, and to what extent, transport capacity on the SWP impacted the amount of gas available at Iona over this winter compared to individual participants' decision making.

Table 2: Key Victorian supply sources–winter 2015 vs 2016*

Source	Measure	2016		2015	
		June	July	June	July
Longford	Daily average	1,024	1,022	957	993
	Maximum	1,059	1,056	1,036	1,043
	Minimum	968	984	775	882
	Total	30,732	31,673	28,697	30,785
Iona	Daily average	221	143	134	288
	Maximum	333	329	355	370
	Minimum	36	-54.2	24	137
	Total	6,636	4,476	4,032	8,913
Otway	Daily average	99	88	110	99
	Maximum	103	106	134	130
	Minimum	72	0	5	0
	Total	2,974	2,725	3,311	3,079
Minerva	Daily average	54	55	67	72
	Maximum	55	55	74	74
	Minimum	51	52	46	61
	Total	1,624	1,695	2,020	2,242

* Also, Lang Lang production at the Bass Basin is slightly up this winter (about 43 TJ per day).
Source: Bulletin Board data, www.gasbb.com.au

South Australian gas fields

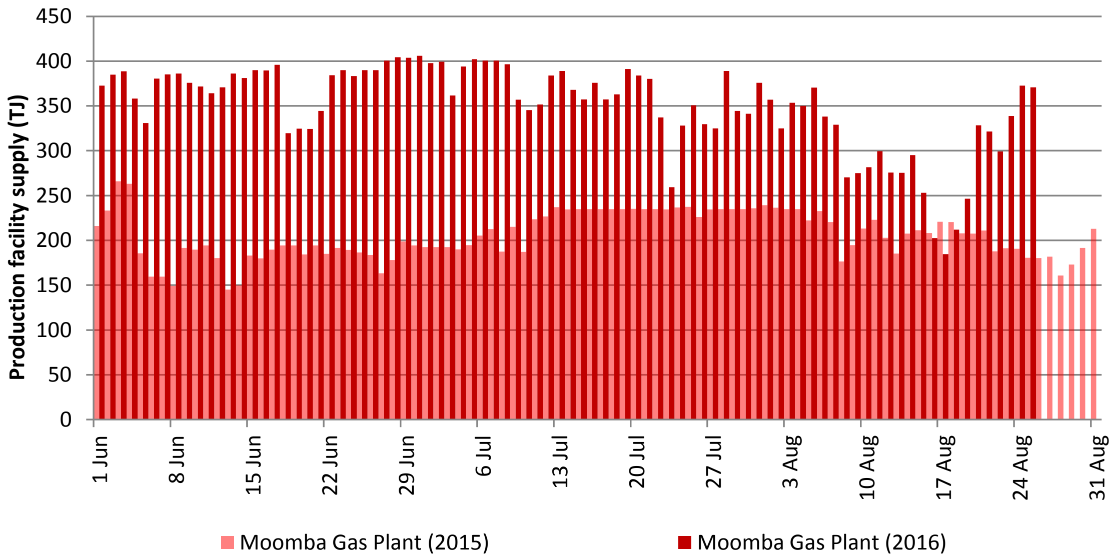
Figure 2 illustrates that in winter 2016, Moomba was operating at higher production levels than in 2015. Despite this, pipeline flow data suggests the extra gas may have been flowing into Queensland to supply demand from LNG exports, instead of domestic demand.

The diversion of supply to the LNG export market may be being coordinated by Santos, which is involved in both production at Moomba and the Gladstone LNG (GLNG) export project.

This is discussed further in section 2.2 below.

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

Figure 2: Moomba Production



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

New South Wales gas

From the second week of June to the end of July, 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.[12] 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.

AGL also supplies the Sydney STTM with gas from its Camden coal seam gas facility **(Camden)**. Camden supplied gas on every day across the same period, at over 12 TJ a day. This was similar to the quantities scheduled the year before. With the exception of Camden, New South Wales sources all its gas supplies from other states.[13]

On 7 July, AGL provided an update on its gas portfolio margins to the Australian Stock Exchange (ASX). AGL noted it had acquired a higher than anticipated proportion of wholesale gas from the spot market and other short-term sources for the first quarter of the 2017 financial year. The announcement notes this was driven by the 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. AGL anticipated a negative impact on its pre-tax wholesale gas margin in the first quarter of the 2017 financial year of approximately $35 million.[14]

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

13 On 4 February 2016 AGL announced it will cease production in Camden in 2023, twelve years earlier than previously proposed. AEMO's Gas Statement of Opportunities, published March 2016, notes New South Wales will be dependent on gas from other states once Camden ceases production.

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

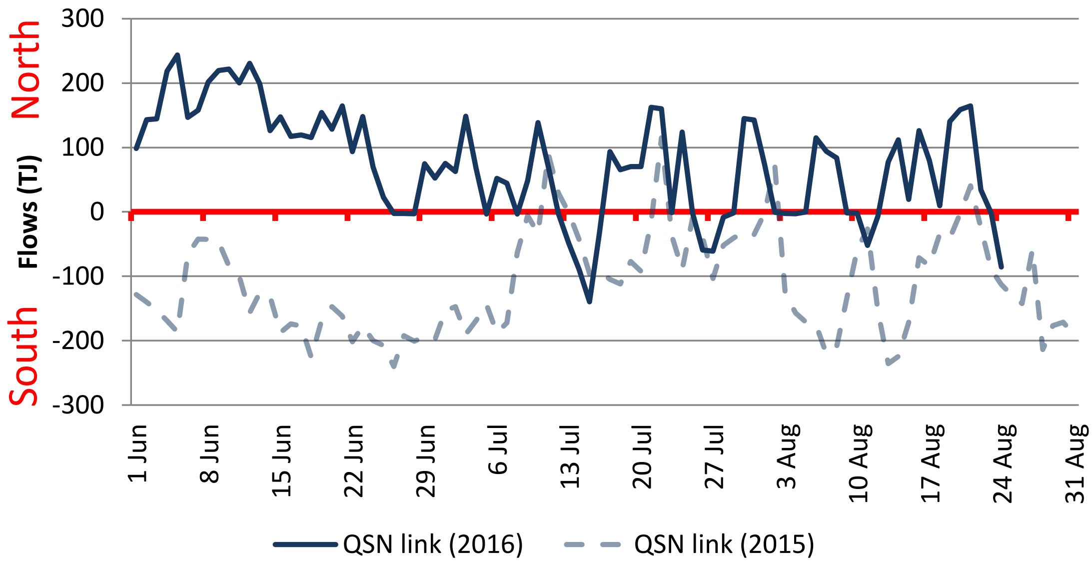
2.2 Demand factors

LNG export demand

Santos produces gas at Moomba and is a 30 per cent equity holder in and the operator of the GLNG export facility in Queensland. As noted above, Moomba has been operating at higher production levels compared to winter last year. However pipeline flow data suggests most of the additional gas may be flowing into Queensland to supply demand from LNG exports instead of domestic demand.

Gas can be transported from Moomba into Queensland using the Queensland South Australia New South Wales (QSN) link. The QSN link is bidirectional. Figure 3 below shows that, from June to August this year, flows on the QSN link were usually from Moomba towards Queensland. This contrasts with the same period in 2015, where most flows were towards Moomba.

Figure 3: QSN link flows*



Source: Bulletin Board data, www.gasbb.com.au;
* flow quantity has been adjusted to show northerly flows above the x-axis.

The ACCC Gas Inquiry Report noted that GLNG has entered into a number of agreements to purchase gas for export from third parties including from Cooper Basin or Moomba production.[15] It is very likely increased Moomba production may be for this purpose.

Overall demand from the LNG export facilities is significantly higher than winter 2015. Each of the three facilities consists of two production trains (a total of six trains). With variations, one train is capable of producing around 700 TJ of LNG a day. In winter 2015 there was only one train operating. In winter 2016 there were five trains operating.[16]

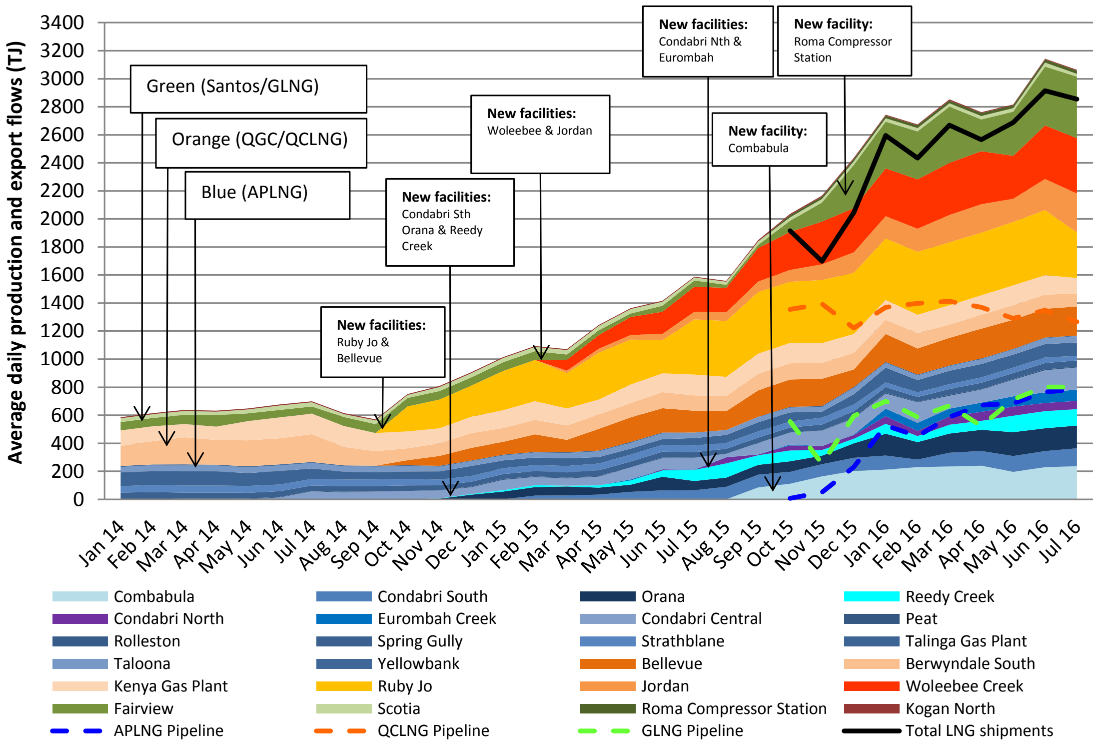
15 Table 1.2 on page 29 of the ACCC's *Inquiry into the east coast gas market – April 2016* report provides a list of gas purchases by the Gladstone LNG export facilities.

16 Based on reported Roma production and LNG export pipeline flows from the Bulletin Board, demand for LNG

Figure 4 below illustrates the level of gas production from the LNG facilities' gas fields and the flows on their respective pipelines. We understand the Queensland Curtis LNG **(QCLNG)** and Australia Pacific LNG **(APLNG)** facilities are able to supply a large proportion of their export obligations from these production facilities. However it is difficult to comment with certainty given limited transparency. On the other hand, GLNG is supplying some of its export contracts from gas sourced from the broader domestic market. Overall, we understand that the quantity of gas produced at Roma, to supply the domestic market has to date been small.

Despite this, the performance of all three facilities impact gas supply and demand across the east coast. As an example, early August 2016, flows on the QSN link trended more south at the same time QCLNG had advised maintenance on its export trains would be occurring. It is likely this resulted in extra supply becoming available for the east coast gas markets.

Figure 4: Roma Production and LNG export pipeline flows



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

exports this winter have increased rapidly from around 2.5 PJ at the start of 2016 to over 3 PJ in winter 2016.

Cold weather has driven residential demand in South Australia and Victoria

There are significant number of households, particularly in Victoria, which rely on gas for heating. Cold weather during late June and throughout July resulted in Victoria's demand regularly exceeding 1 PJ. While demand has reached these levels previously, the overall average daily demand was higher than other years.

High demand from gas fired electricity generation in South Australia & Victoria

Demand from gas fired electricity generators in Victoria and South Australia was much higher during June and July 2016 than the previous year. This was driven by a number of factors.

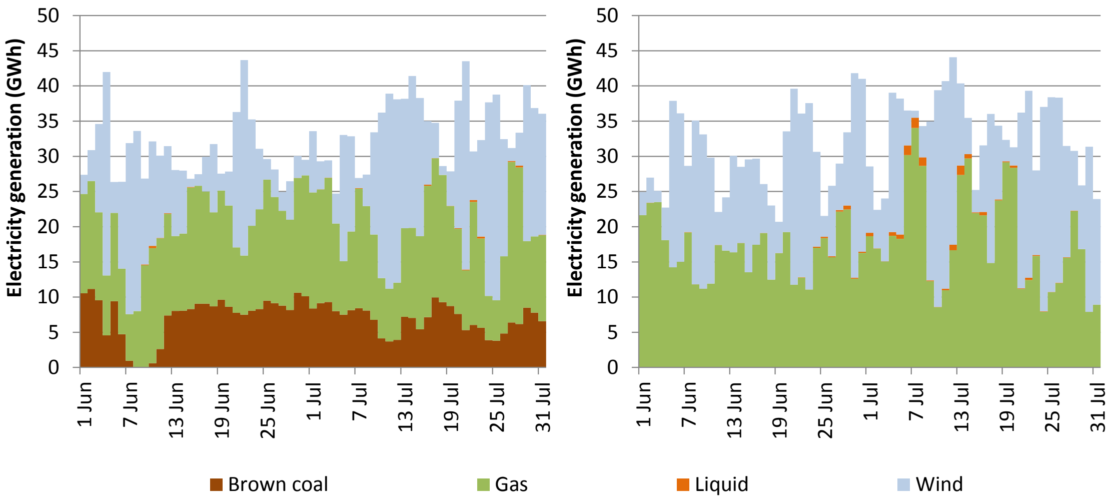
In June, there was a reduced availability of electricity generators across all regions. Total capacity from coal-fired generators was around 2,200 MW less than winter 2015. The closure of South Australia's Northern power station (in April 2016) accounted for 400 MW of this reduction, with the remainder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

Towards the end of June, the coal-fired generators that were off for maintenance began to return to service, reducing the need for gas fired generation across the NEM.

In South Australia, however, high demand from gas fired electricity generators continued into July for a number of reasons including:

- No coal fired generation following the closure of Northern Power station. The primary fuel sources in South Australia are now gas and wind (see Figure 5 below)
- 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)
- Limited capacity from interstate due to the network upgrades.

Figure 5: South Australia's generation mix – 2015 (left) and 2016 (right)[17]



17 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.

2.3 Market participant factors

Part 19 and 20 of the NGR requires the AER to monitor trading activity in the Victorian market and the STTMs for compliance with trading rules.[18] In following this requirement, the AER analyses the demand forecasting and bidding behaviour of market participants. Analysis of winter 2016 and the volatile pricing period between 23 June and 20 July has identified:

- over-forecasting of customer demand in Sydney in contrast to the Adelaide, Brisbane, Victorian markets (where demand forecasting errors appear more evenly distributed)[19]
- apparent biases within specific participants' demand forecasting for Victoria.

Our subsequent July report will investigate these issues further, as well as explore the behaviour of participants in making or changing gas supply offers.

The AER's monitoring obligations extend beyond Part 19 and 20 of the NGR to:

- part 18 of the NGR covering the Natural Gas Services Bulletin Board **(Bulletin Board)**. Transparent, accurate information through the bulletin board — such as via medium and short term capacity outlooks is important for participants to be able to trade on the east coast gas market
- part 21 of the NGR which relates to trade in the upstream gas supply hubs where the obligations focus on participants not engaging in price manipulation.

For example, to determine whether all reportable information e.g., on outages was provided to the market when required and accurately.

18 Rule 354(a) of Part 19 of the NGR and Rule 498(1)(a) of Part 20 of the NGR.

19 Over forecasting of demand in Sydney is also discussed in the AER's recent NEL Quarterly Compliance Report. Q2 2016 http://www.aer.gov.au/wholesale-markets/compliance-reporting/quarterly-compliance-report-april-june-2016

3 Analysis of June's price events

This section analyses each of the June SPVs and details the specific factors that contributed to each event.

3.1 Friday 24 June 2016

Adelaide STTM:	There was a $10.40/GJ variation between the D-2 schedule price ($8.59/GJ) and D-1 schedule price ($18.99/GJ).
Victorian market:	The imbalance price reached $23.34/GJ.

Victoria

High prices were forecast in Victoria in the lead up to the gas day.

Two days before the gas day, AEMO forecast the price could reach $42/GJ based on demand of around 1.09 PJ.[20]

While the actual prices on the day did not reach these levels, the price was still high enough to trigger the imbalance price reporting threshold.

On the day, demand exceeded 1.1 PJ. This was mainly driven by low temperatures (the minimum temperature in Melbourne was less than 7 degrees Celsius) and the resulting high demand from households using gas for heating. This triggered profiled injections at Longford, where higher hourly quantities were scheduled towards the start of the day (rather than the usual flat injection profile across the gas day) ahead of the evening peak period.[21]

The highest price on the day was $23.83/GJ at the 6 am schedule (the first schedule of the day). The price declined at each schedule for the remainder of the day with prices of $18.88/GJ at 10 am, $10.90/GJ at 2 pm, $10.04/GJ at 6 pm and $9.10/GJ at 10 pm.

The incremental reductions in price throughout the day were a result of participant rebidding and reductions to demand forecasts. Figure 6 illustrates the change in offers across schedules leading up to and during the 24 June gas day.

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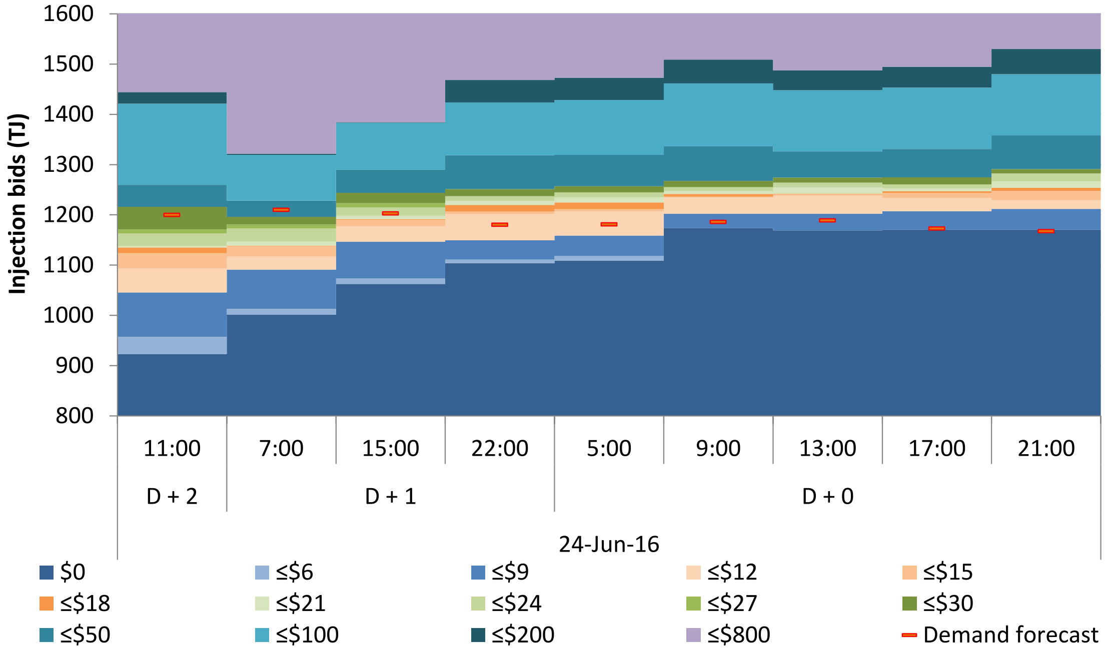
20 AEMO forecast a price of $71.80/GJ if demand was 10 per cent higher. If demand was 10 per cent lower, the forecast price was $24.99/GJ.

21 Forecast demand at 6 am was 1181 TJ, including 29 TJ of AEMO overrides.

Figure 6: Injection bids by cut-off time for 24 June[22]



For the first time this winter, the NSW-Victoria gas interconnect reversed and supplied 9 TJ into Victoria. This was driven by the increase in low priced injection bids at Culcairn from 10 am (and reductions to high priced withdrawal bid quantities from 2 pm).

Adelaide

The Adelaide market has two main supply sources; the Moomba to Adelaide pipeline **(MAP)** and the SEAGas pipeline **(SEAGas)**. The MAP brings gas from the north of South Australia into Adelaide. SEAGas brings in gas from Victoria.

The schedule used for the gas day is produced the day before the gas day **(the D-1** or **'ex ante' schedule)**. For the D-1 schedule, participants responded to the high Victorian prices by increasing lower priced supply from the MAP and decreasing low priced supply from SEAGas. Specifically, for gas offered at prices between $0–8/GJ, supply from the MAP increased by 14 TJ while supply from SEAGas decreased by 19 TJ.

At the same time participants also increased price taker bids (which reflect uninterruptable demand, such as residential gas consumption) by nearly 3 TJ.

On the day, however, the MAP was operating at reduced capacity and was unable to deliver the full quantity of gas participants wanted. This reduced the impact of participants shifting low priced gas offers from SEAGas to the MAP.

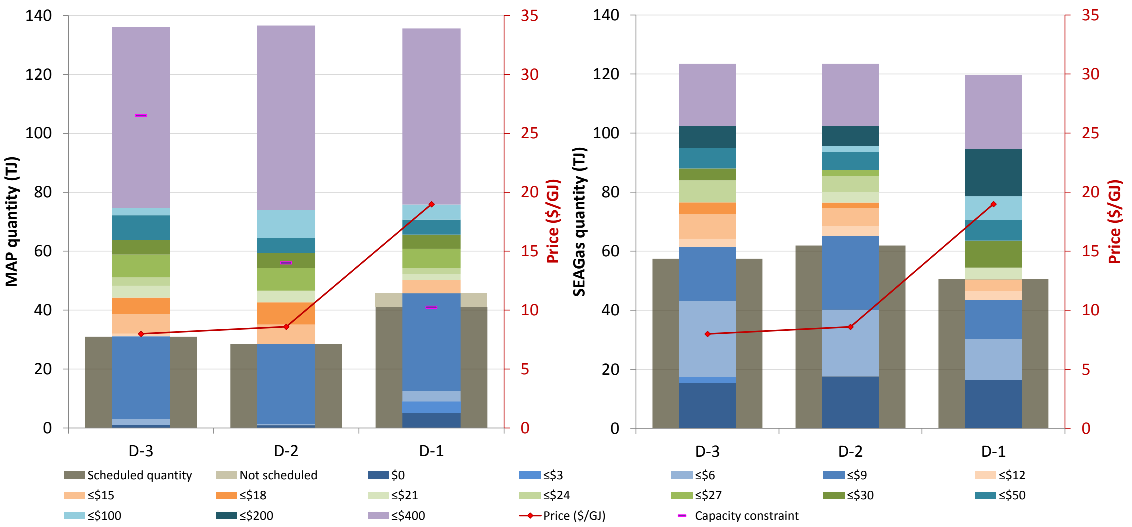
22 Supply offers across each schedule apply to requirements for the entire 24 June gas day. Gas day (D+0) cut-off times occur one hour before the start of the 5 gas schedules (6 am, 10 am, 2 pm, 6 pm and 10 pm). In addition to the level of demand, scheduled supply offers also include further gas quantities for compressor fuel usage requirements, the replenishment of linepack and unaccounted for gas (UaFG) requirements. Some offers may also be excluded from setting the ex ante price depending on locational constraints, such as pipeline capacity restrictions.

While the default capacity on the MAP is around 160 TJ, on the day its capacity was much less.[23] In the provisional schedule issued 3 days before the gas day **(D-3)**, the MAP was expected to have the capacity to deliver around 106 TJ into Adelaide. This was reduced to 56 TJ in the next provisional schedule (issued 2 days before the gas day, or "**D-2**").

The D-1 schedule could only allocate 41 TJ to be supplied into Adelaide from the MAP. This was despite participants submitting over 52 TJ of gas offers priced below the ex ante price of $18.99/GJ. We will comment further on the cause of fluctuations in capacity available to the Adelaide STTM on the MAP in our July report.

Figure 7 below illustrates the changes to offers made by participants for both the MAP and SEAGas across the provisional and ex ante schedules.

Figure 7: Adelaide STTM, 24 June 2016, supply offers for provisional and ex ante schedules for the MAP (left) and SEAGas (right)



To cover the shortfall, more gas was needed to be sourced from SEAGas. This additional gas came at a higher price following the reduction of low priced gas offers on SEAGas. This was a key contributor to the Adelaide price increasing from $8.59/GJ to $18.99/GJ between the D-2 and the D-1 schedules (a variation of $10.40/GJ).[24]

3.2 Sunday 26 June 2016

Sydney STTM:	There was a $7.78/GJ variation between the D-1 schedule price ($10.11/GJ) and the D+1 schedule price ($17.89/GJ).

A schedule is produced the day after the gas day **(the D+1** or **'ex post schedule')** to take into account actual demand and pipeline flows on the day.

23 160 TJ figure taken from INT687 AEMO website 27/07/16.

24 A -903 GJ imbalance led to the ex post price declining to $14.99/GJ.

When the price changes from the D-1 to the D+1 **(ex post)** schedules, it reflects a physical imbalance at the hub. If there was a straight line supply curve (see below), it would follow that the larger the difference in price, the larger the imbalance. However with stepped supply curves the effect of an imbalance on price depends – a small imbalance could cause a large price change or a large imbalance, only a small price change.

The $7.78/GJ increase from the D-1 to the D+1 schedules occurred because actual demand on the day was around 9.5 TJ higher than forecast in the D-1 schedule.

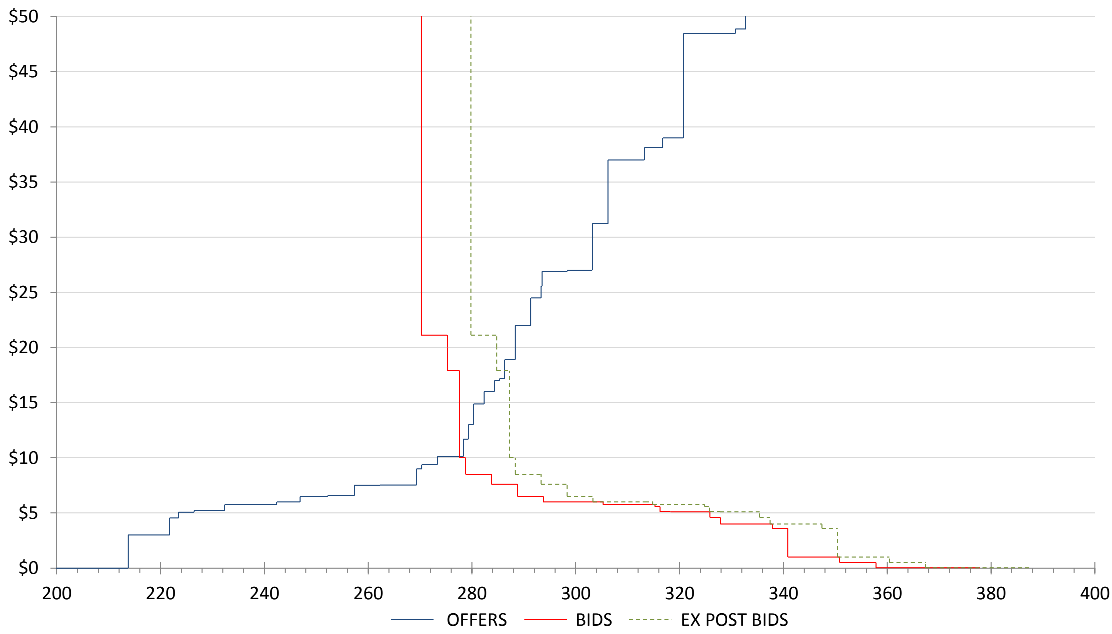
While this indicates that overall hub demand was under forecast in the D-1 schedule, analysis suggests it did not cause significant market operator service **(MOS** – or '**balancing gas')** outcomes.[25]

Figure 8 below illustrates participants' bids (the red line) and offers (the blue line) for the D-1 schedule, and the D+1 ex post bids curve (the green dotted line) which takes into account actual demand on the day.

The intersection of the red and blue lines shows the price and quantity of the D-1 schedule, being $10.11/GJ and 278 TJ respectively. To the right of this point, the blue line steepens (or becomes more inelastic), meaning that while gas offers are available beyond this point, they are at increasingly higher prices and lower quantities.[26]

While the under forecasting of demand in the D-1 schedule was relatively small (9.5 TJ, or around 3.5 per cent of forecast demand), due to the inelasticity of offers the D+1 price increased by $7.78/GJ in order to satisfy the additional demand (where the blue and green dotted lines intersect).

Figure 8: Sydney STTM, 26 June 2016, D-1 and D+1 schedules



25 MOS service payments were under $34,000.

26 The inelastic supply may have been influenced by the high prices (forecast, and actual) for gas in Victoria on the day. Colder than forecast weather led to demand exceeding 1 PJ.

3.3 Monday 27 June 2016

Sydney STTM:	There was a $12.40/GJ variation between the D-1 schedule price ($12.10/GJ) and the D+1 schedule price ($24.50).
Victorian market:	The imbalance price reached $25.74/GJ.

Sydney

The $12.40/GJ increase from the D-1 to the D+1 schedules occurred because actual demand on the day was around 13 TJ higher than forecast in the D-1 schedule.

While this indicates that overall hub demand was under forecast in the D-1 schedule, analysis suggests it did not cause significant MOS outcomes.[27]

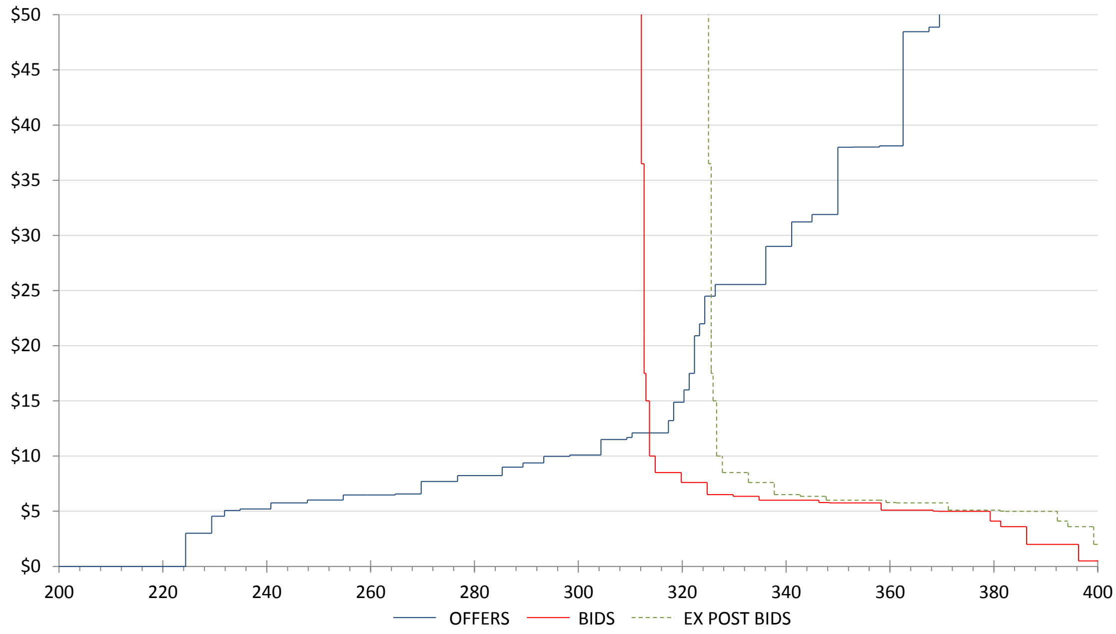
Figure 9 below illustrates participants' bids (the red line) and offers (the blue line) for the D-1 schedule and the D+1 ex post bids curve (the green dotted line).

The intersection of the red and blue lines identifies the price and quantity of the D-1 schedule, being $12.10/GJ and 314 TJ respectively.

The figure also highlights the increasingly higher prices and lower quantities of supply offers beyond around $12–13/GJ.

Due to the inelasticity of offers, the D+1 price increased by $12.40/GJ (to $24.50/GJ) in order to satisfy the additional demand (where the blue and green dotted lines intersect).

Figure 9: Sydney STTM, 27 June 2016, D-1 and D+1 schedules



27 MOS service payments were under $18,352

Victoria

High prices were forecast in Victoria in the lead up to the gas day.

One day before the gas day AEMO forecast the Victorian price could reach $37/GJ based on demand of around 1.11 PJ.[28]

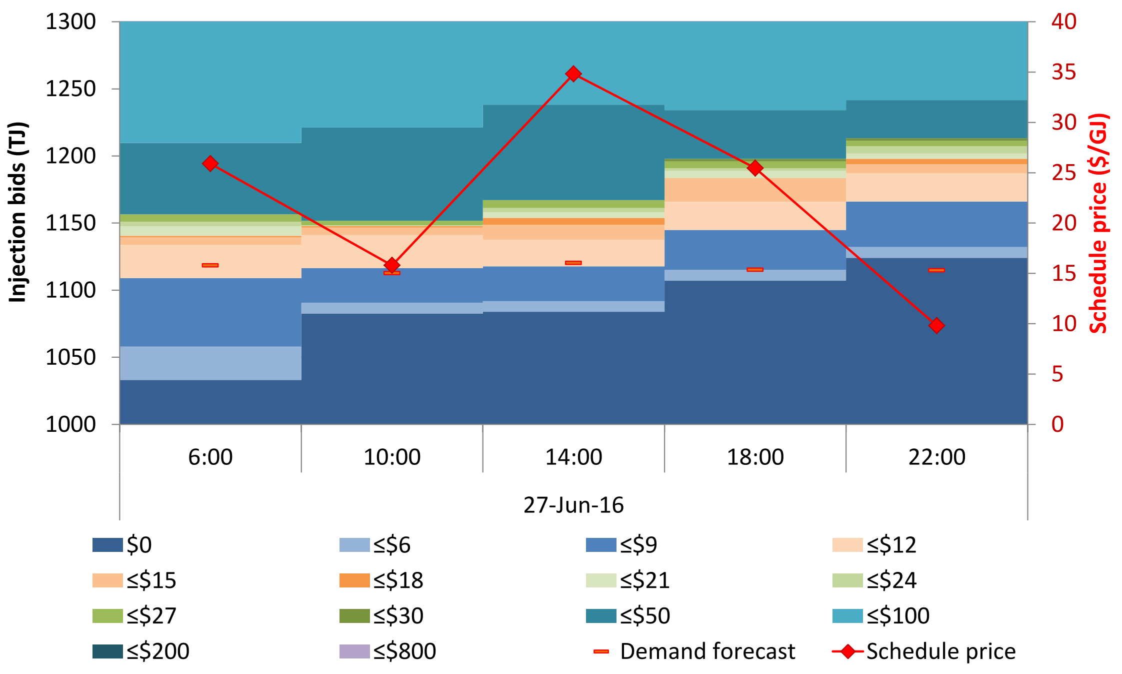
On the day, demand was 1.1 PJ. This was mainly driven by low temperatures (the minimum temperature was less than 5 degrees Celsius) and the resulting high demand from households using gas for heating.

The gas price was $25.90/GJ at 6 am schedule. The prices for the remaining schedules of the day were $15.80/GJ at 10 am, $34.81/GJ at 2 pm, $25.45/GJ at 6 pm, and $9.80/GJ at 10 pm.

The high 6 am price reduced to $15.80/GJ at 10 am following an increase in low priced offers at Iona and a reduction in demand forecasts. However Figure 10 shows the price increased sharply during the 2 pm schedule as demand forecasts increased by 7.6 TJ to 1120 TJ. At the same time, BassGas tripped and its injections reduced to 0 GJ/hour.[29] This led to the price spiking to $34.81/GJ.

For the second time this winter, the NSW-Victoria gas interconnect reversed and supplied 13.4 TJ into Victoria. Again, this was driven by the increase in low priced injection bids at Culcairn.

Figure 10: Injection bids and prices by schedule horizon for 27 June



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28 AEMO forecast a price of $60.81/GJ if demand was 10 per cent higher. If demand was 10 per cent lower, the forecast price was $8.50/GJ.

29 Offers at the facility reduced from 50 TJ to below 40 TJ from 2 pm, but were unable to be scheduled due to the constraint at the facility. The gradual increase to injection quantities was revised to 1042 GJ/hour from 6 pm.

3.4 Tuesday 28 June 2016

Sydney STTM:	There was a $7.68/GJ variation between the D-2 schedule price ($10/GJ) and the D-1 schedule price ($17.68/GJ). There was also an $11.32/GJ variation between the D-1 schedule price and the D+1 schedule price ($29/GJ).

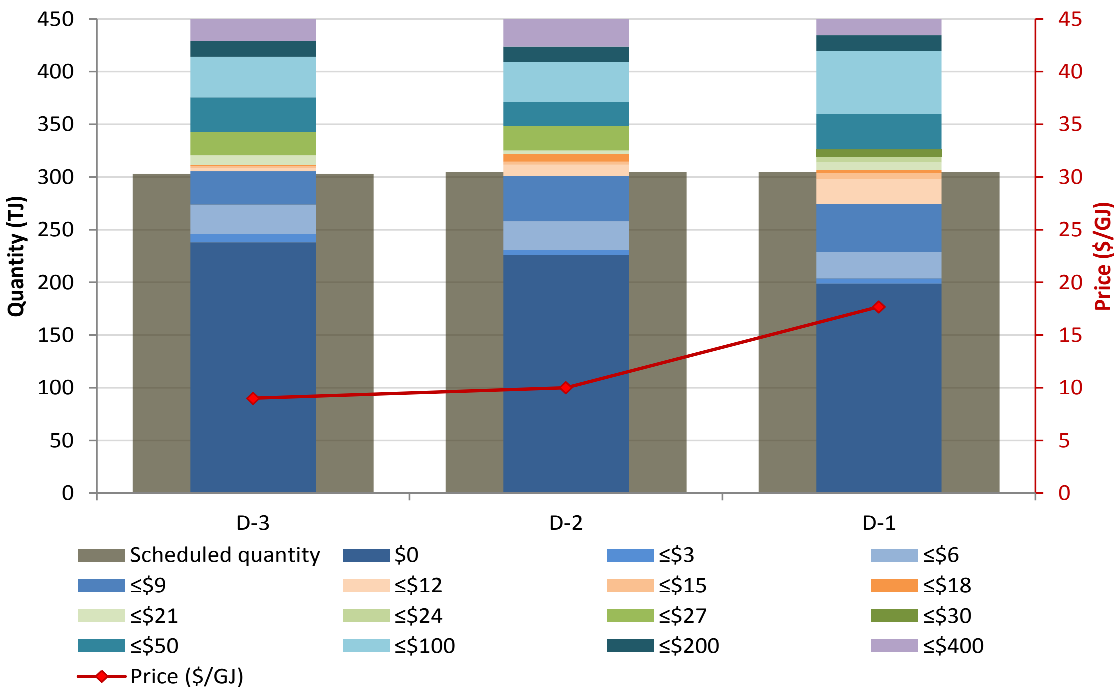
The price variation between the D-2 and D-1 schedules

Participants' bids (to buy) and offers (to sell) for the D-3 and the D-2 schedules were similar in terms of price and quantity. This was reflected in the D-3 and D-2 prices, which were $9/GJ and $10/GJ respectively.

However for the D-1 schedule, participants rebid supply offers from low prices to high prices, and left their bids relatively unchanged. These changes contributed to the D-1 price reaching $17.68/GJ, $10/GJ higher than the D-2 price.

Figure 11 below sets out the supply offers across the provisional (D-3 and D-2) and ex ante (D-1) schedules, and shows each schedules' price and quantity. For the D-1 schedule, around 27 TJ of $0/GJ priced offers were removed and 17.9 TJ of offers were added into price bands between $6–15/GJ (with the remainder added into bands above $18/GJ).[30]

Figure 11: Sydney STTM, 28 June 2016, supply offers for provisional and ex ante schedules



30 Figure 12 also illustrates the participants' bids (to buy – the red line) and offers (to sell – the blue line) for the D-1 schedule. It shows the increasingly higher prices and lower quantities of supply offers at the floor.

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

The $11.32/GJ increase from the D-1 to the D+1 schedules occurred because actual demand on the day was around 16.6 TJ higher than forecast in the D-1 schedule.

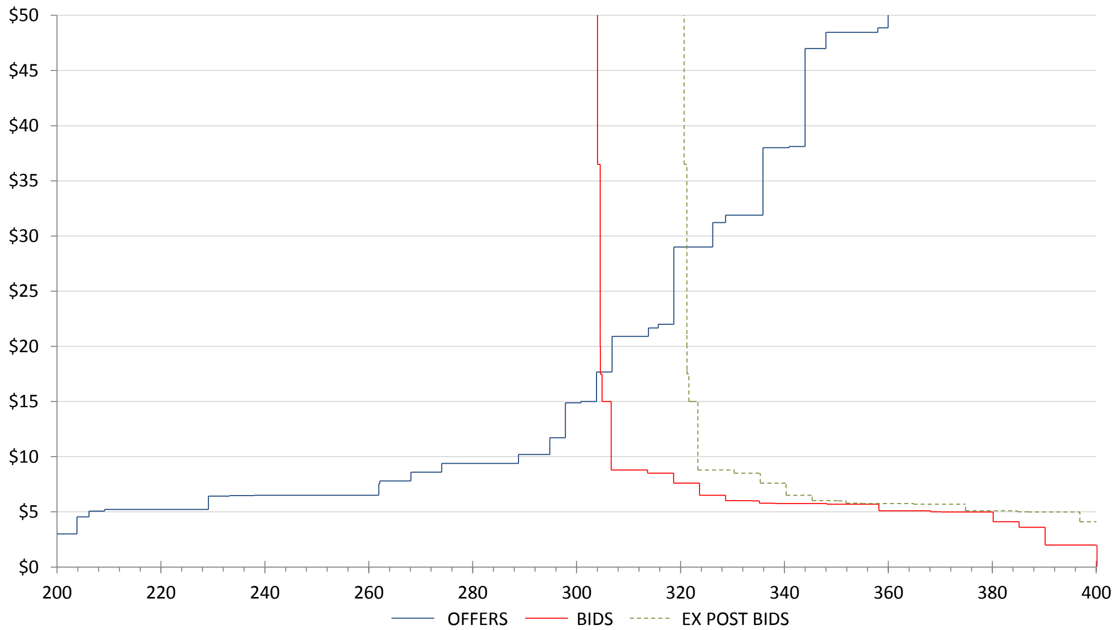
Figure 12 below illustrates participants' bids (the red line) and offers (the blue line) for the D-1 schedule and the D+1 ex post bids curve (the green dotted line).

The intersection of the red and blue lines identifies the price and quantity of the D-1 schedule, being $17.68/GJ and 305 TJ respectively.

The figure also highlights the increasingly higher prices and lower quantities of supply offers beyond $10/GJ.

Due to the inelasticity of offers, the D+1 price increased by $11.32/GJ (to $29/GJ) in order to satisfy the additional demand (where the blue and green dotted lines intersect).

Figure 12: Sydney STTM, 28 June 2016, D-1 and D+1 schedules



3.5 Thursday 30 June 2016

Sydney STTM:	There was a $16.66/GJ variation between the D-2 schedule price ($12.15/GJ) and the D-1 schedule price ($28.81/GJ).
Brisbane STTM:	There was an $8.84/GJ variation between the D-1 schedule price ($10.06/GJ) and the D+1 schedule price ($18.90/GJ).

Sydney

For the D-2 schedule, participants reduced the amount of gas offered at lower prices (at or below $6/GJ) by over 23 TJ and increased offers at higher prices (between $20–30/GJ) by nearly 8 TJ. The quantity of price taker bids also increased by around 17 TJ to 309 TJ.

These rebids, however, only had a minimal impact on the price which increased from $12.10/GJ to $12.15/GJ from the D-3 to the D-2 schedules.

For the D-1 schedule, participants further reduced the amount of low priced gas offers (at or below $4/GJ) by 16 TJ, and increased the amount of price taker bids by 4 TJ.

These rebids contributed to the price increasing by $16.66/GJ to $28.81/GJ for the D-1 schedule.

The supply offers across the schedules are set out in Figure 13 below. The bids (including pricetaker bids) to purchase gas across the schedules are set out in Figure 14.

Figure 13: Sydney STTM, 30 June 2016, supply offers for provisional and ex ante schedules

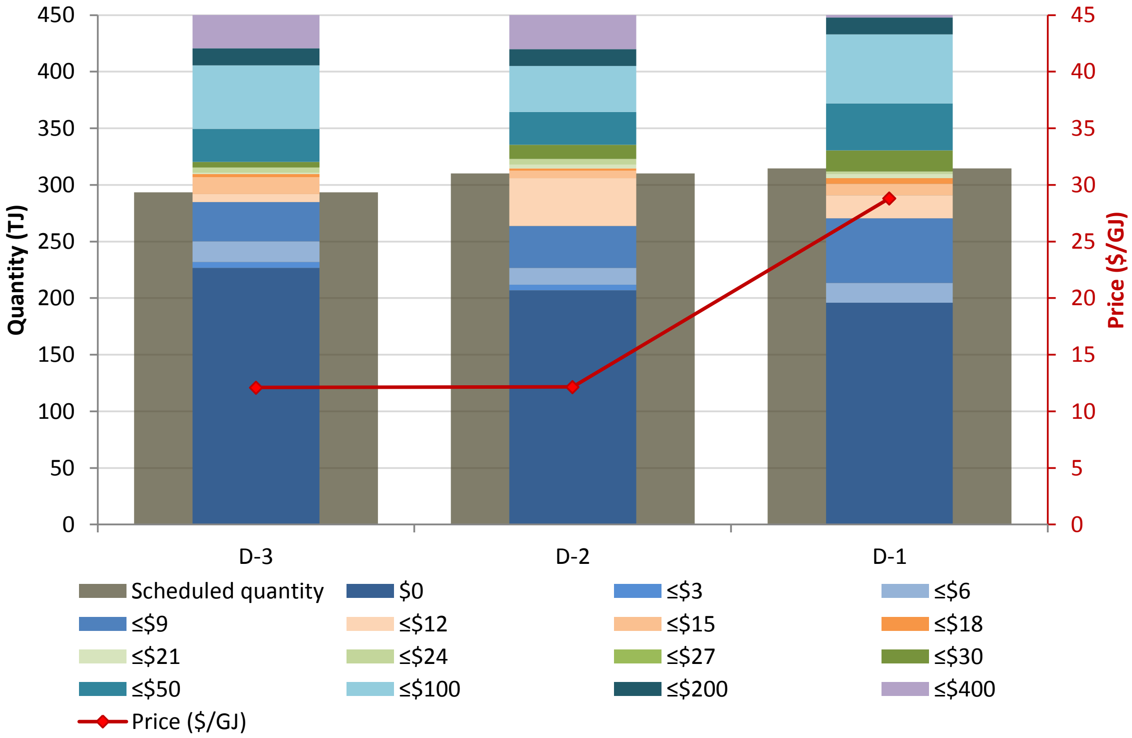
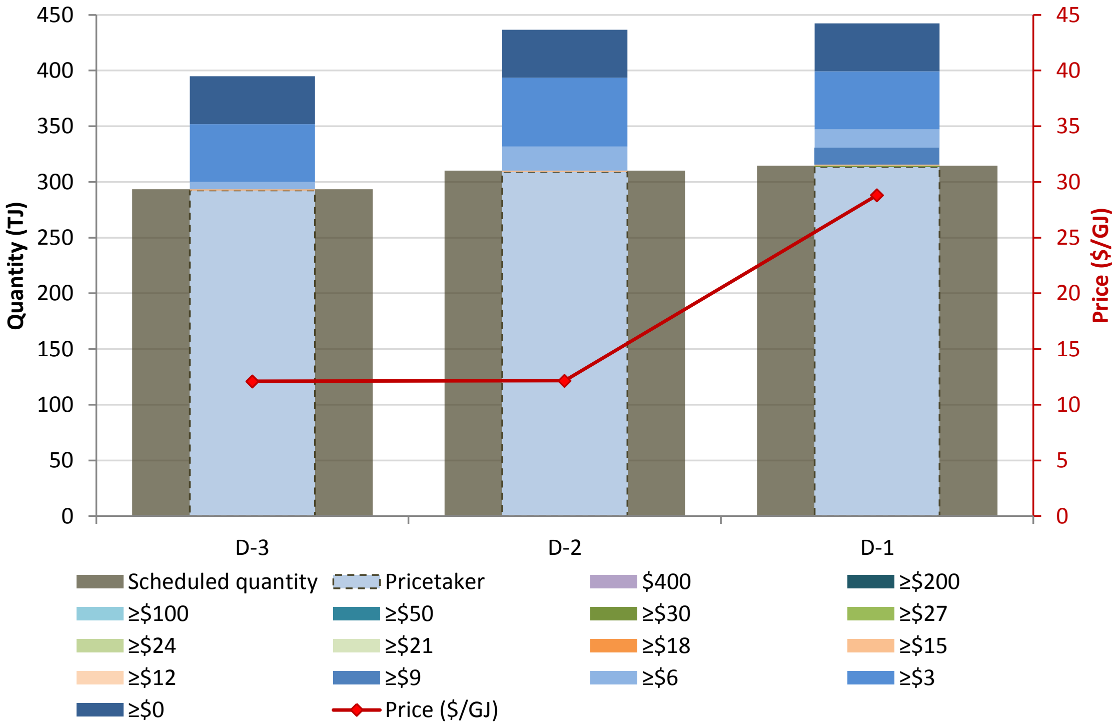


Figure 14: Sydney STTM, 30 June 2016, demand bids for provisional and ex ante schedules



Brisbane

The $8.84/GJ increase from the D-1 to the D+1 schedules occurred because actual demand on the day was around 2.2 TJ higher than forecast in the D-1 schedule.

Figure 15 below illustrates participants' bids (the red line) and offers (the blue line) for the D-1 schedule and the D+1 ex post bids curve (the green dotted line).

The intersection of the red and blue lines identifies the price and quantity of the D-1 schedule, being $10.06/GJ and 101 TJ respectively.

To the right of this point, the figure also highlights the increasingly higher prices and lower quantities of supply offers.

While the under forecasting of demand in the D-1 schedule was relatively small (2.2 TJ, or around 2 per cent of forecast demand), due to the inelasticity of offers the D+1 price increased by $8.84/GJ in order to satisfy the additional demand (where the blue and green dotted lines intersect).

Figure 15: Brisbane STTM, 30 June 2016, D-1 and D+1 schedules