VICTORIAN GAS OPERATIONS PLAN – WINTER 2016

GAS REAL TIME OPERATIONS

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

The purpose of *Victoria Gas Operations Plan – Winter 2016* (Winter 2016 Plan) is to provide insights and understanding of system and market operational strategies for winter 2016. The strategies are designed to support secure operation of the Victorian Declared Transmission System (DTS) and the Declared Wholesale Gas Market (DWGM).

The annual winter stakeholder information session will be held on 3 May 2016. The purpose of the information session is to present the Winter 2016 Plan to stakeholders for discussion and comment.

This paper supplements the stakeholder information session, and provides further technical information on the Winter 2016 Plan.

Disclaimer

This document is not exhaustive and cannot cover every possible situation. It contains information based on methodologies and assumptions that may not be applicable to every situation. This document represents general principles applicable to most situations, subject at all times to exceptions. This document should be considered along with the various applicable industry rules and procedures. The language and terminology is consistent with the *2016 Victorian Gas Planning Report*. Where a contingency or event is of such severity that it cannot be managed using the principles described in this document, other strategies, guidelines or procedures may be used.

Version control

Version	Release date	Changes
1	3/5/2016	

EXECUTIVE SUMMARY

Winter 2016[1] Victorian Declared Transmission System (DTS) gas demand is forecast at:

- 1,194 Tera joules (TJ) for a 1-in-2 system demand day.
- 1,304 TJ for a 1-in-20 system demand day.[1]

In winter 2015, the highest system demand was 1,168 TJ. This was higher than the 1,126 TJ forecasted winter 1-in-2 peak demand day, but lower than the forecasted 1,248 TJ for a 1-in-20 peak demand day.

The operational and communication strategies for the Winter 2016 Plan remain similar to those of last year. AEMO is confident these strategies will support effective winter operations in the Declared Wholesale Gas Market (DWGM) and the DTS.

This paper uses demand forecasts from AEMO's *2015 National Gas Forecasting Report*[1], and gas supply, production and capacity information from AEMO's *2016 Victorian Gas Planning Report Update.*[2]

Supply and demand balance

AEMO does not expect a supply demand shortfall for the 2016 winter period.

The total available daily gas supply to the Victorian DTS is estimated at 1,351 TJ. The total supply consists of Longford and VicHub (850 TJ), BassGas (55 TJ), and Port Campbell region (446 TJ). Additional supplies are available from the Dandenong liquefied natural gas (LNG) facility, and imported through the Victorian Northern Interconnect (VNI).

Forecast conditions for winter 2016 are similar to those for winter 2015. Notable changes in the interconnected gas market dynamics that may impact Victoria's gas supply include:

- Increased gas exports to New South Wales via the Eastern Gas Pipeline (EGP).[3] This is due to the commissioning of two new compressors on the EGP, increasing the pipeline's capacity by 20%.
- Tamar Valley gas-powered generation (GPG) in Tasmania is expected to operate at least until the Basslink interconnector returns to service.[4] Should Tamar Valley GPG remain in service over the 2016 winter period, AEMO does not expect a gas supply-demand shortfall in Victoria or Tasmania. On peak gas demand days for the DTS, there is sufficient gas (including the Tasmanian Gas Pipeline's linepack) to supply both demand in Victoria and Tasmania (including fuel for Tamar Valley GPG).

Augmentation work and transportation capacity

The DTS' daily system capacity[5] is 1,450 TJ. This is sufficient for a 1-in-20 peak demand day. The total system capacity is made up of the Longford to Melbourne Pipeline (1,030 TJ), South West Pipeline (446 TJ), and VNI (125 TJ).[6]

1 AEMO. *2015 National Gas Forecasting Report*. Available at: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report.
2 AEMO. 2016 *Victorian Gas Planning Report Update.* Available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-Planning.
3 AEMO. *2016 Update – Victorian Gas Planning Report.* Available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-Planning.
4 AEMO. *March 2016 Energy Adequacy Assessment Projection*. Available at: http://www.aemo.com.au/AEMO%20Home/Electricity/Resources/Reports%20and%20Documents/EAAP.
5 The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors, see glossary for more details.
6 Due to system conditions and network topology a back-off effect occurs, total system capacity reduces the total injection capacity to less than the sum of the individual pipeline capacities.

The following system augmentations are being completed to increase the VNI capacities during winter 2016:

- VNI import capacity is 125 TJ/d. The import capacity will increase to 196 TJ/d when augmentations are completed in third quarter 2016, however, actual imports will be constrained to the existing 125 TJ/d due to limits on assets outside the DTS (in New South Wales).
- VNI export capacity is 118 TJ/d. This is expected to increase to 148 TJ/d when augmentations are completed in third quarter 2016.

Transmission operation plan

The main challenges for transmission operation for winter 2016 are:

- Managing linepack and pressure requirements in the Longford to Melbourne Pipeline.
- Supporting high injections in the South West Pipeline.
- Facilitating VNI exports to New South Wales.

AEMO's strategies have effectively managed these challenges over previous winter periods.

Market operation plan

Mechanisms to facilitate an effective market operation over winter 2016 include:

- Apply constraints to reflect facility or DTS physical limitations which can impact DWGM scheduling and pricing outcomes.
- Manage demand forecasts in over and under-forecast situations through the application of demand forecast overrides.
- Consider interactions between the DWGM, the gas Short Term Trading Market and the National Electricity Market, so AEMO can anticipate outcomes from those interactions and support participants' requirements.

Peak demand management

AEMO aims to operate the DTS in a normal operating state, as defined in the *Wholesale Market System Security Procedures (Victoria).*[7] Normal operating state requires maintaining system pressures and flows within defined operating limits.

On a peak demand day:

- Injection profiling is available to maximise linepack during the evening peak.
- Should a threat to system security occur:
  - AEMO assesses and notifies the market of the threat.
  - If there is sufficient time, AEMO may request the market to respond to the threat.
  - If there is insufficient time, or the market response is inadequate to alleviate the threat, AEMO will take action in priority order according to the *Wholesale Market System Security Procedures (Victoria)*.
- AEMO regularly communicates relevant information to participants.

If an emergency occurs, AEMO has an Emergency Management Framework and Incident Management Plan to ensure the safety, security and reliability of the DTS.

[7] AEMO. *Wholesale Market System Security Procedures (Victoria).* Available at: http://www.aemo.com.au/Gas/Policies-and-Procedures/Declared-Wholesale-Gas-Market-Rules-and-Procedures.

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1. WINTER 2016 OUTLOOK

- Winter 2016 gas demand forecasts are similar to last year, with the 1-in-20 system demand day forecast at 1,304 terajoules (TJ).[8]
- The expected maximum daily supply of 1,351 TJ[9] is sufficient to meet the 1-in-20 system demand day forecast.

1.1 Gas demand

The winter 2016 gas consumption and peak demand in the Declared Transmission System (DTS) is expected to be similar to 2015.

This paper uses the annual gas system consumption forecasts in AEMO's *2015 National Gas Forecasting Report* (NGFR).[10]

Peak system demand

Peak system demand in 2015 was 1,162 TJ. Winter 2016 peak system demand forecasts for the DTS are:

- 1,194 TJ for a 1-in-2 system demand day.
- 1,304 TJ for a 1-in-20 system demand day.

Gas consumption

Table 1 shows the DTS average monthly winter consumption forecast for 2016 by DTS system withdrawal zone.

Table 1 DTS average monthly winter consumption forecast (PJ), 2016

	Jun	Jul	Aug	Sep	Total
Ballarat	1.39	1.58	1.42	1.03	5.42
Geelong	2.74	3.03	2.76	2.60	11.13
Gippsland	1.62	1.71	1.59	1.38	6.31
Melbourne	16.95	19.02	17.25	12.82	66.05
Northern	2.45	2.78	2.51	1.98	9.72
Western	0.46	0.53	0.49	0.47	1.95
System consumption	**25.62**	**28.66**	**26.02**	**20.28**	**100.58**

The forecast shows that:

- July 2016 is expected to be the highest gas consumption month.
- 66% of winter withdrawals are expected to be from Melbourne system withdrawal zone, 11% from Geelong system withdrawal zone, and 10% from Northern system withdrawal zone.
- Total winter 2016 forecast consumption is expected to be 100.58 petajoules (PJ), which is 51% of the 2016 calendar year forecast consumption of 197 PJ.

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8 A 1-in-20 forecast means the projection is expected to be exceeded, on average, one out of every 20 years (or 5% of the time).
9 AEMO. *2016 Victorian Gas Planning Report Update.* Available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-Planning.
10 AEMO. *2015 National Gas Forecasting Report*. Available at: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report.

1.2 Gas supply

The DTS' total daily maximum gas supply for 2016 is expected to be 1,351 TJ, which is sufficient to meet a 1-in-20 system demand day. Table 2 summarises supply sources, their available maximum supply to inject into the DTS on a peak demand day, and their forecast production range for 2016.

This report uses gas supply, production and capacity information from AEMO's *2016 Victorian Gas Planning Report Update* (VGPR Update).[11]

Table 2 DTS supply sources and maximum daily supply (TJ), 2016

DTS supply sources	Peak demand day	Total plant production capacity[12]
Longford and VicHub	850	1,024
BassGas	55	70
Port Campbell	446[13]	692[14]
Total	**1,351**	**-**
Other supply sources	**Maximum supply**	
LNG	87	
VNI import	125	

The total daily maximum gas supply of 1,351 TJ comprises supply from Longford and VicHub, BassGas and Port Campbell production facilities (see following sections). Neither liquefied natural gas (LNG) nor Victorian Northern Interconnect (VNI) imports are part of the total daily maximum gas supply, because:

- LNG has historically been used as a supply of last resort.
- VNI imports are not a guaranteed supply source, as availability depends on operational and market conditions in New South Wales.

Longford and VicHub

Longford and VicHub's maximum daily supply availability to the DTS is expected to be 850 TJ.

In winter 2016, increased flows are expected from Longford to New South Wales via the Eastern Gas Pipeline (EGP) and to Tasmania via the Tasmanian Gas Pipeline (TGP). The demands from New South Wales and Tasmania, supplied from Longford, are not projected to have a material impact on gas supply to the DTS in winter 2016.

Interconnected energy markets' gas demands are discussed further in Section 4.3.

BassGas

BassGas can provide a maximum daily supply of 55 TJ. Its Lang Gas Production Plant is a base load facility with a plant production capacity of 70 TJ, which is split between the DTS and the South Gippsland Natural Gas Pipeline.

Port Campbell

Port Campbell supply region provides gas up to the daily injection capacity of 446 TJ, and is made up of Iona Underground Gas Storage (UGS), Otway and Minerva gas production plants. Iona UGS is the main supplier of the region, with a maximum daily capacity of 423 TJ. The Port Campbell region's total plant production capacity is split between the DTS, Mortlake gas-powered generation (GPG), and South Australia via the SEA Gas Pipeline.

[11] AEMO. 2016 *Victorian Gas Planning Report Update.* Available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-Planning.
[12] Nameplate capacity as of April 2016 on Natural Gas Services Bulletin Board (GBB). Available at: http://www.gasbb.com.au/.
[13] The transportation capacity of the South West Pipeline is 429 terajoules a day (TJ/d), however an additional 17 TJ can be injected at Iona to support demand within the western transmission system.
[14] Made up of Iona UGS (423 TJ), Otway (205 TJ), and Minerva (64 TJ) gas production plants.

LNG

LNG can be injected in the DTS for two main purposes:

- Operational response (otherwise known as peak shaving gas), where AEMO schedules out of merit order gas in response to a threat to system security.
- Market response, where market participants can use LNG, as they would any injection facility, to manage their portfolio.

When used, LNG can be injected at either a:

- Firm rate of 5.5 TJ per hour (TJ/hr).
- Maximum non-firm rate of 9.8 TJ/hr.[15]

Normally, LNG is not scheduled from the beginning-of-day, but is included in an intraday schedule for within-day balancing purposes. LNG only effectively supports system pressures when injected before 10:00 pm, the time when DTS linepack is at its lowest point.

A total of 112.4 TJ (2,505 tonnes) of LNG was scheduled by the market into the DTS during winter 2015. Operational response LNG has not been used for peak shaving purposes since 2013.

VNI import

The VNI is connected to the Moomba to Sydney Pipeline (MSP) and can import and export gas between Victoria and New South Wales. VNI flow direction can depend heavily on market conditions in the DWGM and in New South Wales.

The VNI maximum import capacity is highly dependent on New South Wales' transmission system conditions. These conditions may include New South Wales GPG demand, MSP linepack levels, and New South Wales' regional pressures. The highest daily VNI import quantity during winter 2015 was 52 TJ.

1.3 Peak day supply and demand

On peak demand days, the DTS is expected to rely heavily on Longford and VicHub injections. Typically, 63% of the peak day supply is delivered from the Longford and VicHub injection point.

AEMO expects Port Campbell supply into the DTS to be maximised on peak demand days.

LNG injection is available to provide additional gas supply, should the DTS experience any pipeline congestion, supply outages, or severe unforecast demand.

AEMO has considered three scenarios to demonstrate a potential supply and demand balance within the DTS for a 1-in-20 system demand day:

- Scenario 1 – base scenario.
- Scenario 2 – reduced Longford injection.
- Scenario 3 – reduced Longford injection with GPG.

The scenarios do not take into account any pipeline dynamics. DTS peak demand can be satisfied in all scenarios, by scheduling gas from sources such as LNG and VNI imports under a variety of supply conditions. This assumes an accurate beginning-of-day demand forecast, no facility deviations, and perfect linepack distribution. The supply demand balance does not account for intraday DTS congestion.

[15] 5.5 TJ/hr is equivalent to 100 tonnes/hr, and 9.8 TJ/hr is equivalent to 180 tonnes/hr. LNG is typically measured in tonnes.

Scenario 1 – base scenario

Base scenario considers that all of the peak day supplies are available on a 1-in-20 system demand day, as shown in Table 3. Under this scenario, the DTS has enough supply to meet the 1-in-20 system demand day.

Table 3 Scenario 1 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford and VicHub	850	1-in-20 system demand	1,304
BassGas	55	GPG	0
Port Campbell	446	VNI export	0
Total supply	**1,351**	**Total demand**	**1,304**

Scenario 2 – reduced Longford injection

Scenario 2 considers Longford supply into the DTS being reduced by 100 TJ on a 1-in-20 system demand day, assuming Longford supplies this gas to other markets. The scenario assumes other supply sources are fully available.

As Table 4 shows, this scenario projects a DTS shortfall of 53 TJ, unless LNG or VNI imports were scheduled as alternate supply sources.

Table 4 Scenario 2 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford and VicHub	750	1-in-20 system demand	1,304
BassGas	55	GPG	0
Port Campbell	446	VNI export	0
Total supply	**1,251**	**Total demand**	**1,304**

Scenario 3 – reduced Longford injection with GPG

Scenario 3 builds on scenario 2, considering Longford injection being reduced by 100 TJ and GPG demand being 30 TJ (30 TJ/d is the average winter 2015 GPG consumption when the GPGs were on for 10TJ/d or more), on a 1-in-20 system demand day.

As Table 5 highlights, this scenario projects a DTS shortfall of 84 TJ. Again, LNG or VNI imports would be possible supply sources to prevent this shortfall.

Table 5 Scenario 3 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford and VicHub	750	1-in-20 system demand	1,304
BassGas	55	GPG	30
Port Campbell	446	VNI export	0
Total supply	**1,251**	**Total demand**	**1,334**

2. PIPELINE CAPACITY

The total system capacity for winter 2016 is 1,450 TJ, which is unchanged from last year, and is sufficient to transport the maximum expected supply of 1,351 TJ.

There are three major pipelines in the DTS, which make up the total system capacity:

- Longford to Melbourne Pipeline (LMP).
- South West Pipeline (SWP).
- Victoria Northern Interconnect (VNI).

When gas flows along a pipeline, there is a physical limit to the quantity that can flow. The pressure drop along the pipe increases as flowrate increases, and the maximum possible flowrate along any given section of a pipeline is limited by the maximum and minimum allowable pressures.

DTS maximum injection capacity

Table 6 shows the maximum injection capacities within the DTS. AEMO schedules injections and withdrawals in the DTS considering these physical capacities, taking forecast demand into account.

Table 6 DTS maximum pipeline capacities, 2016

Major pipelines	Injection point	Pipeline capacity (TJ)
LMP	Longford, VicHub, BassGas	1,030[16]
SWP	Port Campbell	446[17]
VNI	Culcairn	125[18]
Total system capacity[19]		**1,450**[20]

For injection points, the amount of gas that can be injected into the pipeline increases with system demand, as gas is consumed and withdrawn along the pipeline. The opposite is true for controllable withdrawals, since gas flowing towards the withdrawal point is consumed, reducing the quantity available for withdrawal.

2.1 Longford to Melbourne Pipeline

The LMP's daily injection capacity is 990 TJ if only Longford (including Vic Hub) is injecting.

The combined maximum injection capacity from Longford and BassGas is 1,030 TJ. Although the daily injection capacity of BassGas is 60 TJ[21], if the LMP is scheduled above the transportation capacity, then tie-breaking occurs. The Market Clearing Engine (MCE)[22] schedules to the calculated injection tie-breaking rights across both locations based upon the allocation of Authorised Maximum Daily Quantity (Authorised MDQ) and Authorised MDQ Credit Certificates.[23]

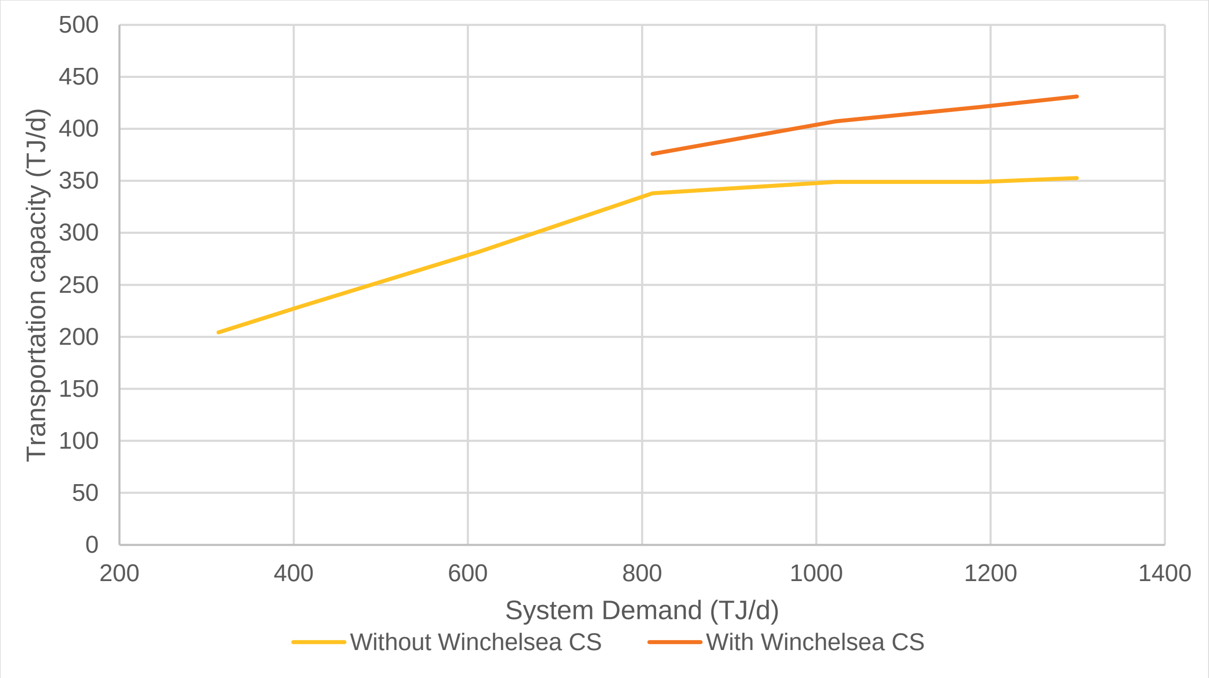
16 The Longford maximum injection capacity is 990 TJ if BassGas is not injecting, otherwise the combined maximum capacity for injection of Longford, VicHub and BassGas is 1,030 TJ (with 970 TJ from Longford / VicHub combined and 60 TJ from Bass Gas).
17 429 TJ pipeline capacity plus 17 TJ to supply Western Transmission System.
18 VNI injection capacity is 196 TJ, but assets outside the DTS, in New South Wales limit injections to 125 TJ.
19 Excludes LNG and Culcairn imports.
20 Due to system conditions and network topology a back-off effect occurs, so total system capacity reduces the total injection capacity to less than the sum of the individual pipeline capacities.
21 DTS available supply from BassGas.
22 Market Scheduling Engine (MCE) is the gas scheduling and pricing engine for the DWGM.
23 Where tie-breaking is required for scheduling purposes, participants with Authorised MDQ or Authorised MDQ Credit Certificate are scheduled preferentially ahead of participants without Authorised MDQ or Authorised MDQ Credit Certificate.

2.2 South West Pipeline

The commissioning of Winchelsea Compressor Station before winter 2015 increased the import capacity on the SWP by 20% on high demand days, offering increased system supply capacity as well as improving system security and operational flexibility. With Winchelsea compressor available, the injection capacity from Port Campbell is 446 TJ per day (TJ/d).

Figure 1 shows the import capacity for the SWP for varying system demand, with and without the Winchelsea compressor.

Figure 1 South West Pipeline import capacity, 2016



SWP net exports are not expected in winter 2016. Information about export scheduling or capacities is available in the 2016 VGPR Update and the Gas *Wholesale Consultative Forum South West Pipeline Scheduling Methodology*.[24]

2.3 Victoria Northern Interconnect

VNI expansion project

System augmentations are currently being completed to increase the VNI export and import capacities. At completion of the project, planned to be during Q3 2016, the export capacity on a 1-in-20 system demand day will increase from 118 TJ to 148 TJ. The maximum import capacity via the VNI will also increase, from 125 TJ to 196 TJ.

The planned augmentations include pipeline duplications and planned modifications to regulating equipment at Euroa and Wollert, as well as reconfiguration of the Springhurst compressor, to allow higher flowrates to support the increased pipeline capacity.

[24] Gas Wholesale Consultative Forum, Refer to August 2015 agenda. Available at: www.aemo.com.au/About-the-Industry/Working-Groups/Wholesale-Meetings/Gas-Wholesale-Consultative-Forum.

VNI capacity

Figure 2 shows the VNI export capacity over the expected system demand ranges in 2016 for a variety of compressor combinations. When all three compressors (Wollert, Euroa and Springhurst) are available, the VNI export capacity does not vary significantly with demand, and daily capacity is expected to be in the range 148–153 TJ.

When only two compressors are available, the export capacity becomes much more demand-dependent:

- If Springhurst Compressor Station is unavailable, with Wollert and Euroa Compressor Stations available, a maximum 75 TJ may be exported on a 1-in-20 system demand day.
- If Euroa Compressor Station is unavailable, with Wollert and Springhurst Compressor Stations available, the requested delivery pressure into the New South Wales transmission system is not achievable, so no exports are possible on a 1-in-20 system demand day.

Figure 2 Victorian Northern Interconnect export capacity for winter 2016

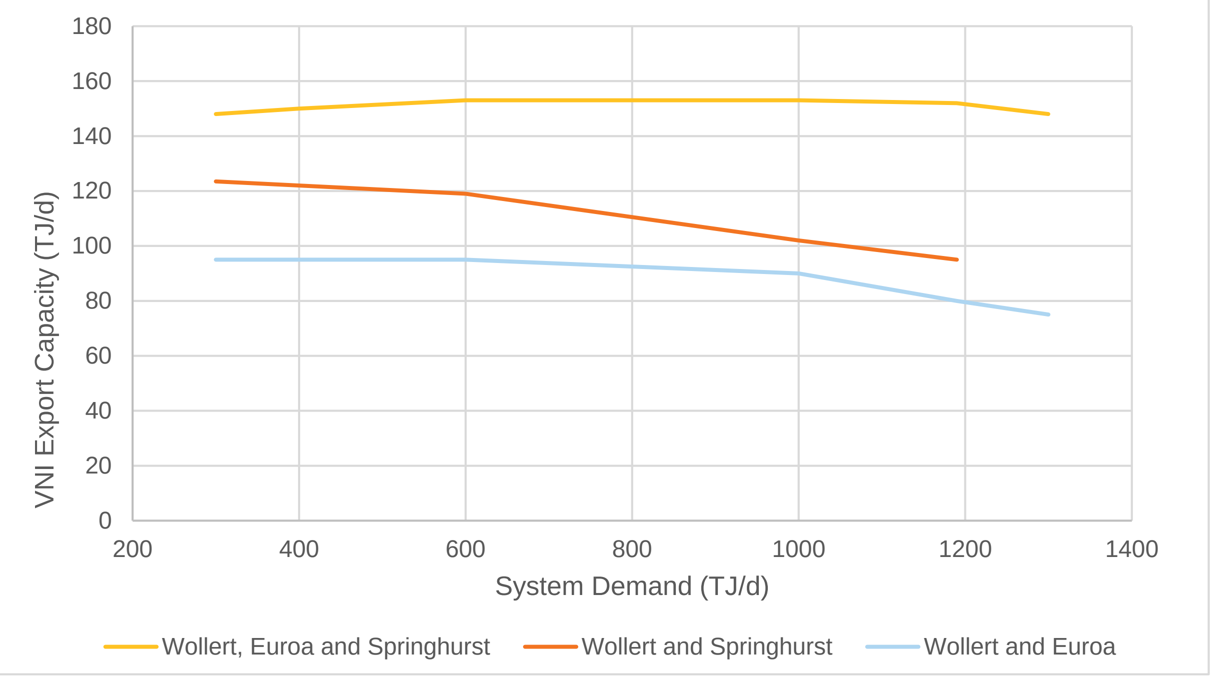
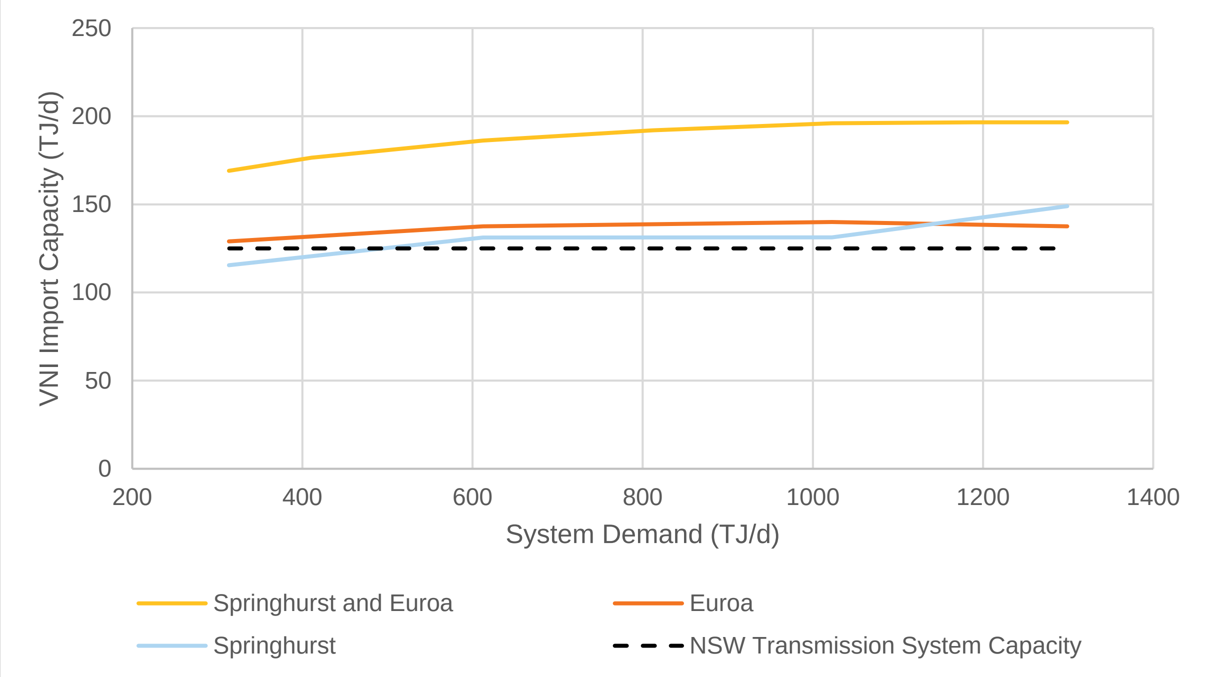


Figure 3 shows the VNI import capacity over the demand range for a variety of compressor combinations. The maximum import capacity for the VNI is 196 TJ/d. However, the capacity will be limited at 125 TJ/d, due to the New South Wales transmission system's capacity to supply gas at Culcairn.

Figure 3 Victorian Northern Interconnect import capacity for winter 2016



3. TRANSMISSION OPERATION PLAN

Key challenges for transmission operation in winter are:

- Managing linepack and pressure requirements in the LMP.
- Supporting high injections in the SWP.
- Facilitating VNI exports.

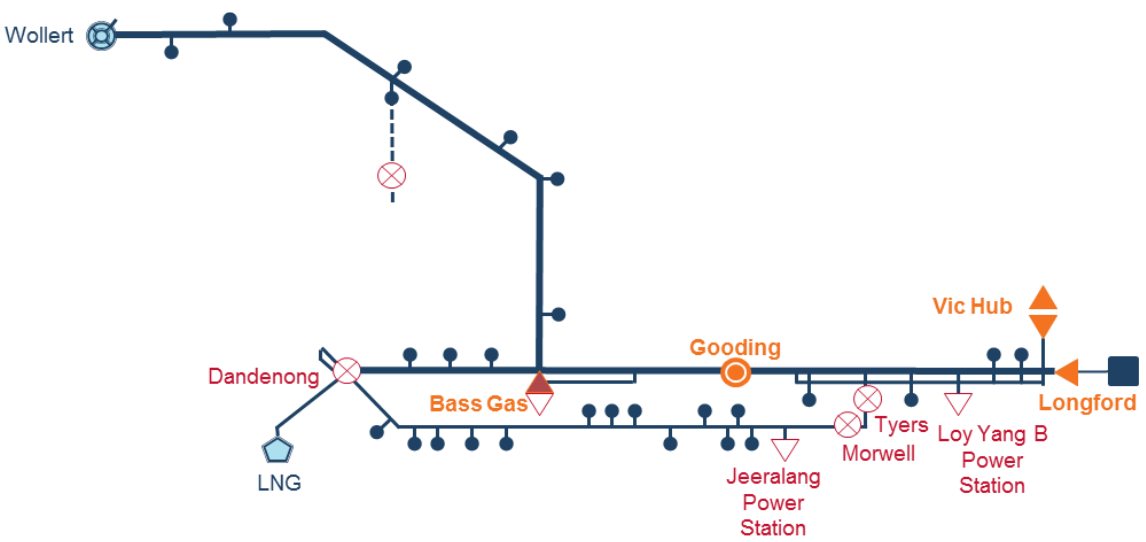
This chapter explains the proven strategies that AEMO has successfully employed over previous winter periods, and has in place for winter 2016, to manage these challenges.

3.1 Longford to Melbourne Pipeline

Figure 4 includes:

- The LMP, which runs from Longford to Dandenong City Gate (DCG).
- The Pakenham to Wollert Pipeline, which runs north of Pakenham to the Wollert City Gate and Wollert Compressor Station.
- The Lurgi Pipeline, which runs parallel to the LMP from Tyers Pressure Limiter to Dandenong Terminal Station.

Figure 4 Longford to Melbourne Pipeline



3.1.1 Pipeline pressure

Pressure along the LMP is managed by balancing linepack within the DTS. If LMP injection facilities deviate from their schedule by over-injecting, it is possible for the pipeline pressure to get too high.

Where an imminent high pressure event is identified, AEMO will notify the Longford facility operator. The notification is to allow time for the Longford Gas Plant to take appropriate action and minimise the ramp down rate required. The Gooding compressors can be used to assist in moving linepack from Longford to Melbourne if system conditions allow compressors to be run effectively.

AEMO will inform market participants of the approaching high pressure event via publication of a system wide notice (SWN), concurrent with its notification to the Longford plant.

3.1.2 Dandenong City Gate

On high system demand days, the DCG inlet pressure can approach its minimum operational target pressure of 3,300 kilopascals (kPa) as linepack is depleted along the LMP. Maintaining this minimum operational pressure target is critical for ensuring Melbourne metropolitan demand is safely met.

Operational strategies to maintain the DCG inlet pressure above 3,300 kPa include:

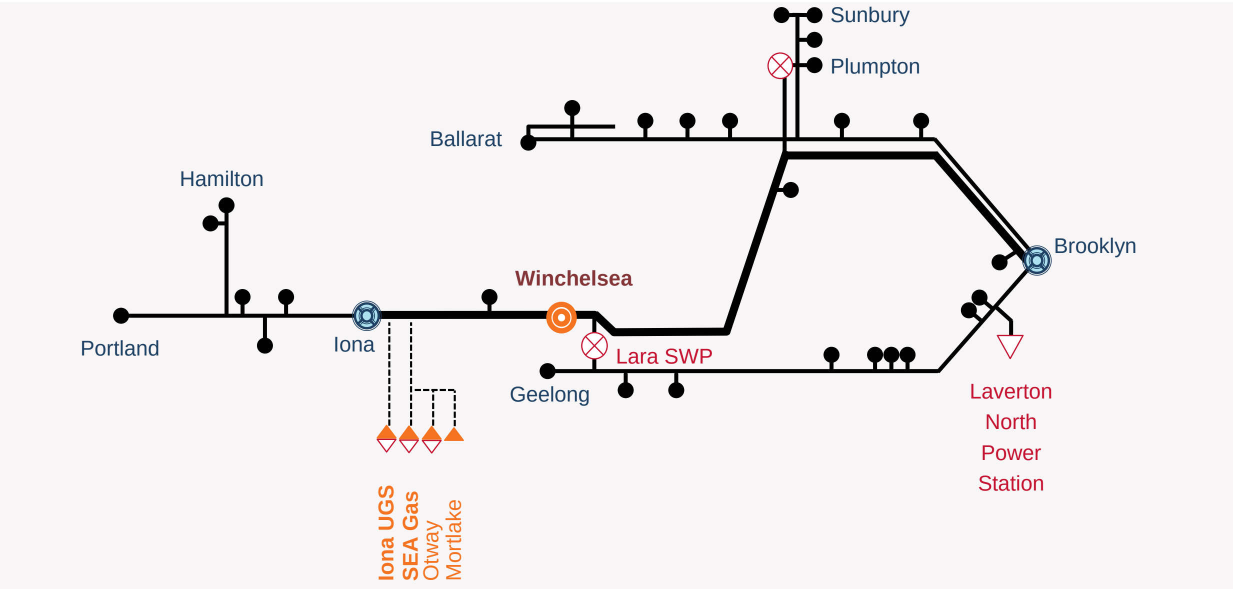
- Maximising SWP supply.
- Operating Gooding compressors
- Injecting peak shaving LNG.
- Restricting or shutting down Wollert Compressor Station (see Section 3.3.2).

3.2 South West Pipeline

Figure 5 includes:

- The SWP, which runs from Iona injection point to Lara City Gate.
- The Brooklyn to Lara Pipeline, which continues on from the SWP and extends from the Lara to Brooklyn City Gate.
- The Brooklyn to Corio Pipeline, which runs from Geelong to Brooklyn City Gate, south of the Brooklyn to Lara Pipeline.
- The Brooklyn to Ballan Pipeline, which runs from Brooklyn City Gate to Ballarat.
- The Western Transmission System (WTS), which runs from Iona to Portland.

Figure 5 South West Pipeline



For winter 2016, Port Campbell is expected to continue injecting into the DTS during the winter months.

On peak demand days, flows on the SWP are expected to approach the transportation capacity. Strategies to maximise Port Campbell supply to Melbourne are crucial to meet the overall supply demand balance.

High pressures in the SWP can affect the ability of the gas production plants to inject gas into the pipeline. If not managed, this can reduce supply, affect the system linepack balance, and potentially necessitate injections from other sources.

With the Winchelsea Compressor Station available, the maximum transportation capacity from Port Campbell to Melbourne is 429 TJ on a 1-in-20 demand day. An additional 17 TJ can be injected to supply the WTS, which makes the total injection capacity 446 TJ/d.

When Longford plant maintenance is conducted during the summer months, the DCG outlet pressure set point may be lowered to increase the SWP transportation capacity. This has been a successful plan for improving security of supply into Melbourne, but has limited capability during the winter. The DCG pressure must be higher in winter, due to the higher pressure drop that occurs when Melbourne metropolitan demand increases.

Brooklyn to Ballan Pipeline

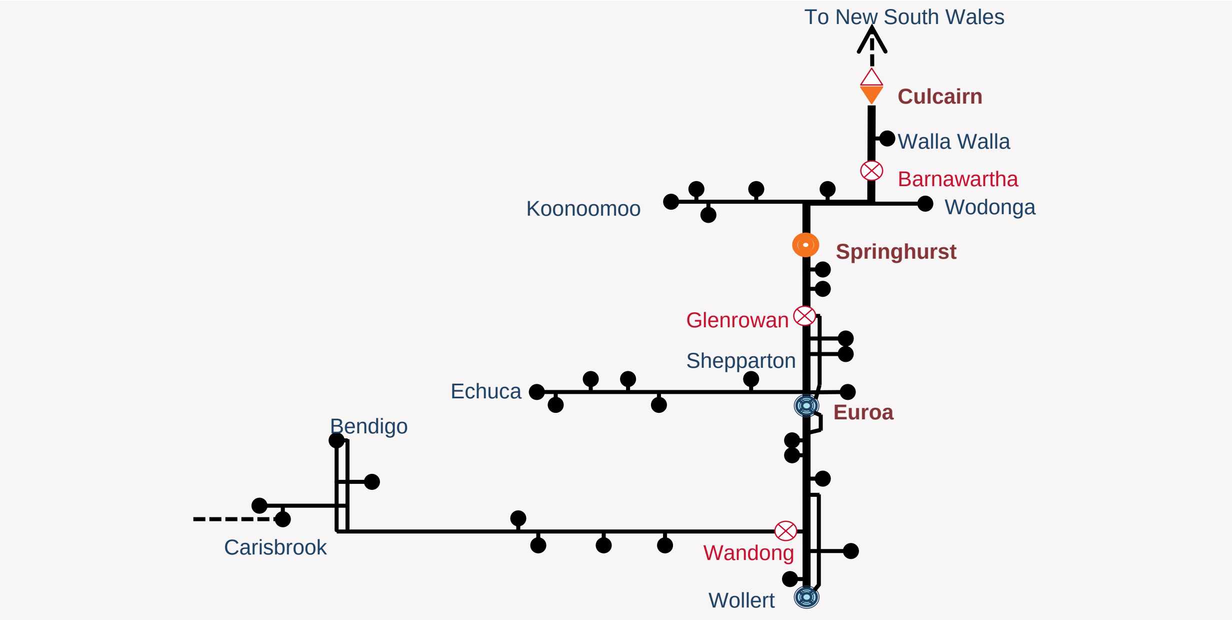
The Brooklyn to Ballan Pipeline runs from the Brooklyn City Gate to Ballarat, which is the highest demand point along the pipeline. During winter on peak demand days, a Brooklyn compressor may be required to maintain minimum operational pressures at Ballarat.

3.3 Victorian Northern Interconnect

Error! Reference source not found. includes:

- The major pipelines for transportation of gas to and from New South Wales via Culcairn.
- Wollert, Euroa and Springhurst Compressor Stations, which increase the transportation capacity along the VNI.
- Lateral pipelines to Bendigo, Echuca, Koonoomoo and Wodonga.

Figure 6 Victorian Northern Interconnect



3.3.1 VNI export

For winter 2016, VNI exports to New South Wales are expected to increase as:

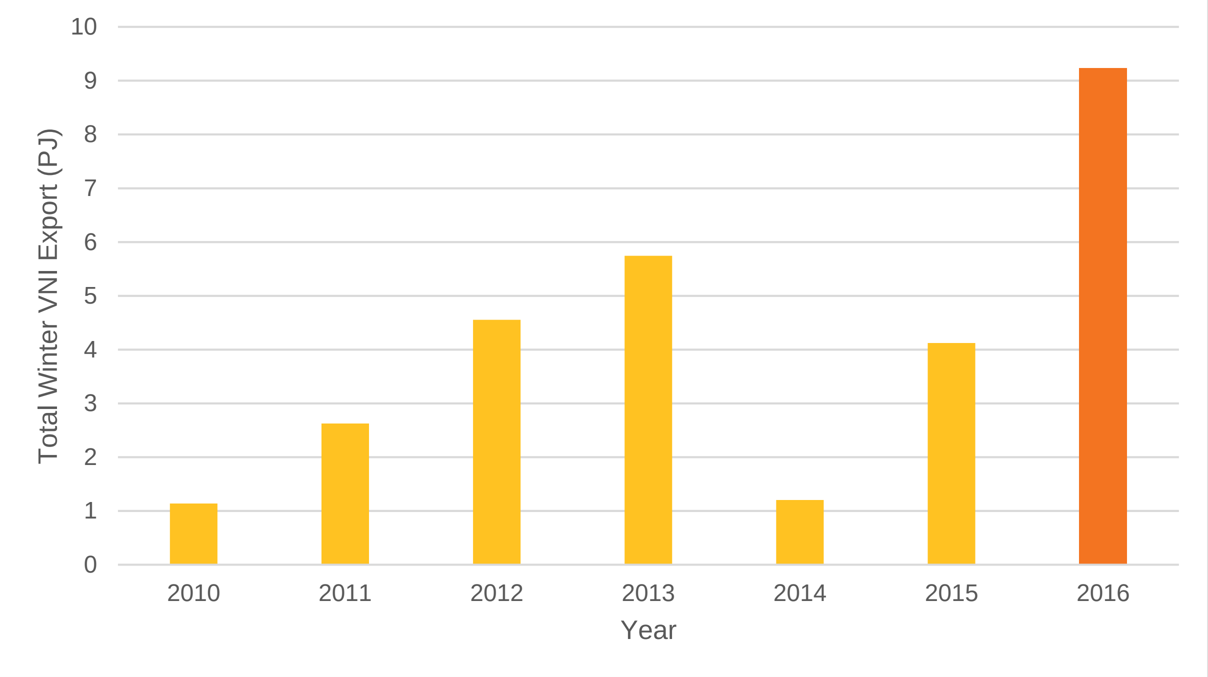
- Queensland LNG capacity continues to ramp up.[25]
- Further VNI capacity is commissioned.

[25] AEMO. *2016 Gas Statement of Opportunities.* Available at: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

 shows historical VNI exports during winter since 2010, as well as forecast winter VNI exports for 2016:

- From 2010 to 2014, VNI exports increased steadily.
- In 2014, coal seam gas (CSG) wells were brought online to supply LNG plants in Queensland. The wells were brought online ahead of the LNG plants being commissioned, which meant additional gas supplies were temporarily provided to the interconnected east coast gas markets, reducing the need for VNI exports.
- In 2015, VNI exports increased again as LNG trains commenced operation.
- In 2016, it is expected that the trend of increasing VNI exports will continue.

Figure 7 Victorian Northern Interconnect export to New South Wales (PJ), winter 2010–16



3.3.2 Prioritisation of peak shaving LNG

On peak demand days, maintaining a high VNI linepack to support high exports can decrease the linepack available for Melbourne demand. If this occurs, LNG may be required to maintain the DCG inlet pressure above 3,300 kPa, while VNI export continues.

In the event that DCG inlet pressure is forecast to fall below the minimum operating pressure, AEMO will take the following steps, in order of preference, to maintain system security:

1. Use Gooding compressors to shift linepack toward Melbourne.
2. Ensure all available system linepack from other pipelines have been exhausted to support pressures at DCG.
3. Schedule peak-shaving LNG at Dandenong up to the firm rate of 100 tonnes/hr (5.5 TJ/hr).
4. Reduce compression at Wollert Compressor Station to prioritise the supply of gas to Melbourne.
5. Schedule peak-shaving LNG at Dandenong up to the non-firm capacity of 180 tonnes/hr (9.8 TJ/hr).

If these steps are insufficient, AEMO may utilise the *Gas Load Curtailment and Rationing and Recovery Guidelines*.[26]

3.3.3 VNI flow direction changes

Although exports into New South Wales via the VNI are expected to increase in winter 2016, switching between injections and withdrawals can occur. Production of CSG wells that typically supply the Gladstone LNG plants cannot be shut in without long-term impacts on their production rates. As a result, any reduction of LNG plant capacity for planned or unplanned maintenance may result in additional supplies being diverted to other markets, including the DWGM.

Imports into Victoria via the VNI can be assisted with the bi-directional compressors at Springhurst and Euroa. When the scheduled flow direction changes, the full pipeline capacity may not be available. The time taken to respond to any schedule changes depends on the magnitude of the change and the system conditions.

3.3.4 Impact of compressor availability

When compressors are unavailable due to planned or unplanned maintenance, the VNI export capacity reduces significantly. On a 1-in-20 system demand day:

- Without availability of the Springhurst Compressor Station, the projected VNI export capacity reduces by approximately 50%, from 148 TJ to 75 TJ.
- Without availability of the Euroa Compressor Station, no exports via VNI are possible.

[26] AEMO. *Gas Load Curtailment and Rationing and Recovery Guidelines* Available at http://www.aemo.com.au/About-AEMO/Services/Emergency-Management/Gas-Emergency.

4. MARKET OPERATION PLAN

Key mechanisms that can facilitate an effective market operation in winter are to:

- Apply constraints to reflect facility or DTS physical limitations which can impact DWGM scheduling and pricing outcomes.
- Manage demand forecasts in over and under-forecast situations through the application of demand forecast overrides.
- Consider interactions between the DWGM, the gas Short Term Trading Market and the National Electricity Market, so AEMO can anticipate outcomes from those interactions and support participants' requirements.

4.1 Scheduling constraints

Constraints can be initiated by AEMO or a facility operator, and are applied to:

- An individual Operating Schedule (OS), or
- Both the Pricing Schedule (PS) and OS.

If the application of a constraint is necessary, the constraint can be applied to:

- Injections, where the highest priced injection bid is removed first, and then the second highest bid, until the injections are reduced down to the constraint quantity.
- Controllable withdrawals, where the lowest priced withdrawal bid is removed first, and then the second lowest bid, until the withdrawals are reduced down to the constrained quantity.

If multiple bids set the market price, participants with Authorised MDQ are given priority. If multiple participants have Authorised MDQ, then they are prorated.

A constraint can be a:

- Supply and Demand Point Constraint (SDPC).
- Directional Flow Point Constraint (DFPC).
- Net Flow Transportation Constraint (NFTC).
- Supply Source Constraint (SSC).

SDPC

An SDPC is applied to restrict or specify energy flows at an injection or a withdrawal point. For example, if a facility operator advises AEMO that there will be planned or unexpected maintenance at an injection or a withdrawal point, an SDPC is applied to both the PS and OS at an injection point to the facility operator's specified quantity.

DFPC

A DFPC is used to prevent net withdrawal at a bi-directional supply point. Historically DFPCs have primarily been used to prevent net withdrawals at bi-directional meters where financial flows are allowed but physical net withdrawals are not possible.

DFPCs have been applied permanently on both the VicHub and SEAGas bi-directional meters to prevent net withdrawals, as neither facility currently can physically withdraw from the DTS.

A DFPC is also used to limit a facility to a particular net rate during maintenance or other physical limitation which is occurring outside the DTS. For example, if one of the three compressors at the VNI is undergoing maintenance, a DFPC can limit exports at the Culcairn injection and withdrawal meters to achieve a specific withdrawal rate.

NFTC

An NFTC is applied to a collection of meters on a pipeline to prevent the transportation capacity being exceeded. For example, an NFTC may be applied to the SWP meters, which will limit the total net scheduled quantity on the SWP to its transportation capacity.

NFTCs have been applied to the OS only, since the changes to the *Wholesale Market Gas Scheduling Procedures (Victoria)* in May 2015.[27]

SSC

An SSC can be used to constrain one supply source out of multiple supply sources at a system injection point. For example, if a gas plant trips and can no longer supply gas into the DTS, an SSC is applied to restrict an unavailable supply while the rest of supply sources continue to provide at that injection point. An SSC can be used by participants who pre-register, however it has not been used to date in the DWGM.

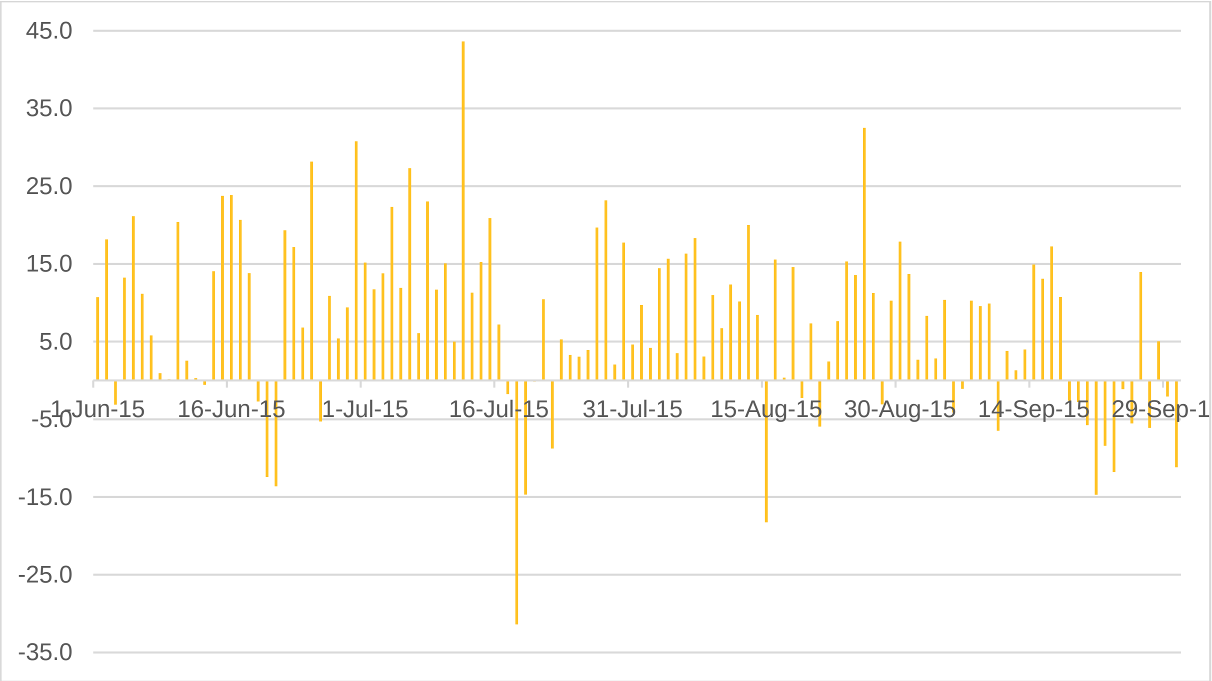
AEMO does not yet have any participant who has pre-registered. Therefore, it is not anticipated that an SSC will be applied in winter 2016.

4.2 Demand forecast management

Demand forecast accuracy is critical when scheduling gas during winter.

Figure 8 displays the difference between market participants' aggregated forecast demand and actual demand during winter 2015.

Figure 8 Difference between market participants' forecast and actual demand (TJ), winter 2015[28]



This demonstrates that during winter, market participants have tended to over-forecast total demand.

[27] See Paper 7 of the Gas Wholesale Consultative Forum paper for February 2015: http://www.aemo.com.au/About-the-Industry/Working-Groups/Wholesale-Meetings/Gas-Wholesale-Consultative-Forum.

[28] Forecast and actual compared for the 10:00 pm schedule interval.

If gas demand is over-forecast:

- Too much gas may be stored in a pipeline, which reduces scheduling flexibility later in the gas day.
- Oversupply can cause gas injections to be blacked-out, which may cause injection plants to trip, threatening supply availability.
- The market price can decrease later in the gas day.
- Facility operators may not meet their injection schedules resulting in deviations.

If gas demand is under-forecast:

- Scheduled supply can be insufficient to meet the actual demand.
- A system withdrawal point could breach its minimum operating pressure, creating a public safety risk.
- Peak shaving gas may be scheduled to support system pressures, which comes at a cost to the market.

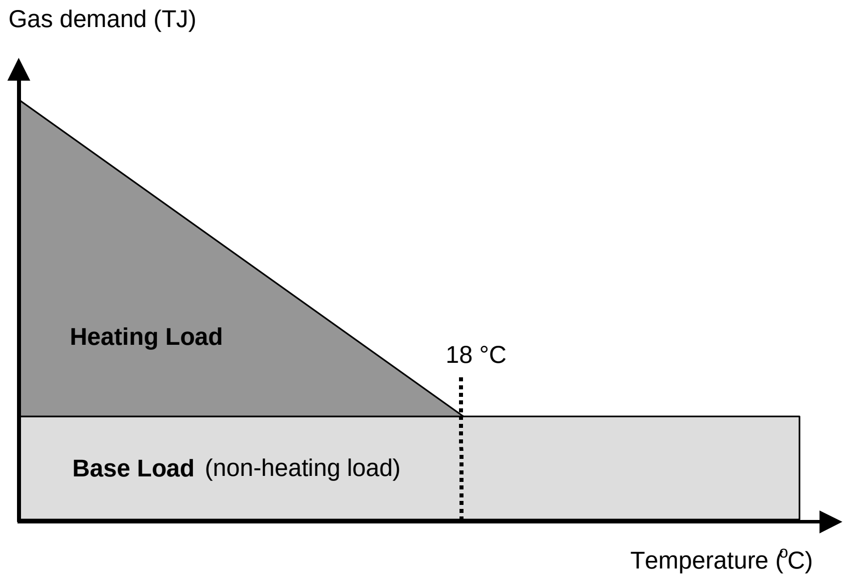
System demand

Market participants forecast both system and site-specific demands, which are aggregated to produce total demand forecast quantity.

System demand includes base load and heating load. Base load typically does not change throughout the year, but heating load is dependent on temperature. In winter, there is greater demand variance due to heating load and its relationship to temperature variance (see Figure 9).

Site-specific demand includes GPG and industrial sites.[29]

Figure 9 Gas demand and temperature relationship



Heating load can be seen as part of a system demand as soon as the average temperature drops below 18 º Celsius.

[29] Industrial sites are also referred to as tariff D withdrawal points. This is a system withdrawal point or distribution delivery point at which gas is withdrawn at a rate of more than 10 gigajoules (0.01 TJ) in any hour or more than 10 TJ in any year.

Forecast uncertainties

The accuracy of demand forecasts in winter can be impacted by variables such as weather (temperature, wind, sunshine, or previous day's temperature) and sudden GPG demands.

Despite the uncertainties, there are market mechanisms to ensure the supply and demand balance is met throughout the gas day:

- Intraday scheduling process to take into account the DTS' current pressures, as well as updated market participants' aggregated total demand forecast.
- AEMO may override market participants' aggregated total demand forecast, in accordance with the *Victorian Wholesale Gas Demand Override Methodology*.[30]

Intraday schedules

Scheduled injection and withdrawal quantities can deviate more during winter compared to summer. This may be due to sudden weather changes, resulting in inaccurate demand forecasts. Schedule deviation may exist any time of the year due to a sudden injection plant outage, DTS asset outage, or sudden changes in site-specific demands.

All these variations can result in intraday schedule deviations and cause the system to experience higher than expected linepack variation. To maintain system security, the MCE takes into account current system pressures, updated demand forecasts and facility injections at every intraday scheduling intervals. The MCE then adjusts the supply and demand balance to ensure the end-of-day linepack target can be met.

These rebalancing actions, which are required to account for under and over-forecasts, can affect the market outcome:

- When demand has been over-forecast in previous scheduling intervals, injections are reduced for the following scheduling interval, potentially decreasing the market price.
- If demand has been under-forecast in previous scheduling intervals, injections are increased for the following scheduling interval, potentially increasing the market price.

Therefore, improved accuracy of market participants' intraday demand forecasts can reduce the likelihood of system congestion and a volatile market price.

Demand forecast override

If the market participants' demand forecast is too high or too low relative to AEMO's demand forecast, an override quantity may be subtracted from (or added to) the market participants' demand forecast. This ensures an appropriate amount of gas is scheduled to maintain a safe level of linepack reserve and system security.

The override quantity is calculated based on the *Victorian Wholesale Gas Demand Override Methodology*. It considers variables such as:

- Beginning-of-day linepack level (high, on target or low).
- Profile type (light, average or heavy).[31]
- Demand override adjustment factors.

The variables are then used to calculate upper or lower threshold limits for each scheduling interval. The threshold limit is compared to the difference between AEMO's and market participants' total demand forecasts. Then, an adjustment is made to the market participants' forecast so it is within the upper or lower threshold limit.

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[30] AEMO. *Victorian Wholesale Gas Demand Forecast Methodology.* Available at: http://www.aemo.com.au/Gas/Market-Operations/Declared-Wholesale-Gas-Market/Victorian-Wholesale-Demand-Override-Methodology.

[31] Profile type is determined by obtaining a profile value. Profile value is the difference between total hourly withdrawal and injection for 16 hours.

4.3 Market interaction

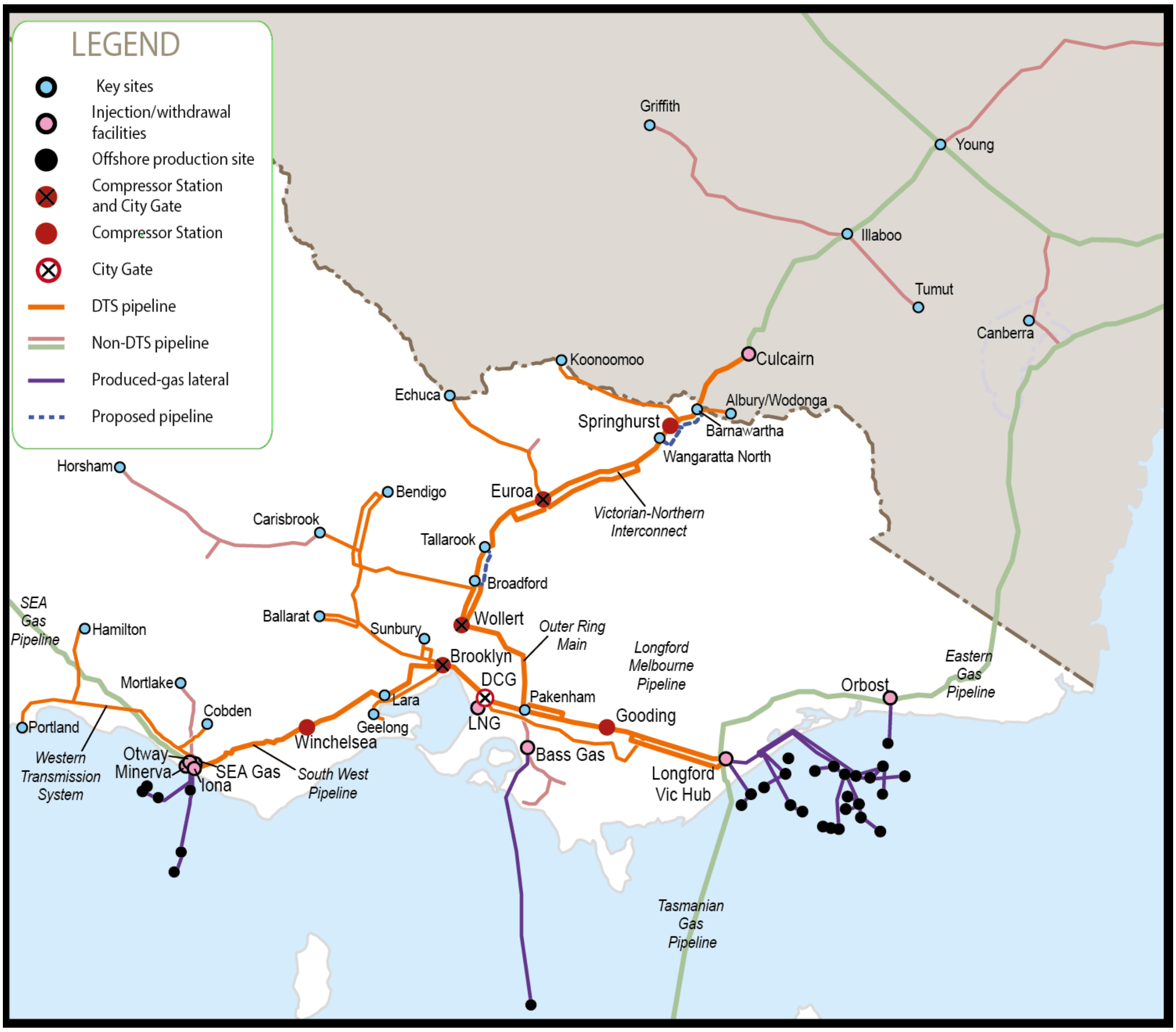
It is anticipated that Victoria will continue to supply gas to other markets during winter 2016. The market interactions are largely due to gas demands in the STTM and the NEM, and are not expected to cause any threat to system security in the DWGM.

4.3.1 Short Term Trading Market

Victoria supplies gas to the STTM:

- Adelaide hub via the SEA Gas Pipeline.
- Sydney hub via the EGP and the VNI (which joins the MSP).

Figure 10 Map of Victoria's gas transmission system



The installation of new compressors on the EGP has increased its gas transportation pipeline capacity by 20% to 358 TJ/d. The VNI export capacity will also increase in winter 2016, to transport more gas to New South Wales from Victoria.

Contingency Gas

On 22 July 2015, an upstream valve closure on the MSP triggered a Contingency Gas event at the STTM Sydney hub. The event did not require any Contingency Gas, as trading participants chose to renominate their gas to prevent a potential supply shortfall of 70 TJ:

- The EGP received renominations to transport an additional 60 TJ from Victoria.
- The VNI export scheduled quantity increased by 50 TJ.
- 4 TJ of market response LNG was scheduled and injected into the DTS.

As shown in Table 7, during the Contingency Gas event the DWGM market price was significantly higher than the DWGM winter 2015 average price of $4.34.

Table 7 DWGM market price on 23 July 2015 during STTM Contingency Gas event ($/GJ)

Scheduling interval	6:00 am	10:00 am	14:00 pm	18:00 pm
Market price	9.75	10.55	9.95	3.59

As well as facilitating STTM conferences during Contingency Gas events, AEMO participates in these conferences as the DWGM pipeline operator, providing information on DWGM scheduling outcomes and the most up-to-date DTS export capacity for VNI.

AEMO anticipated an increased likelihood of a STTM Contingency Gas event as east coast interconnected gas markets adjusted to the changing environment involving LNG exports in Queensland. AEMO and market participants identified and prepared for this increased risk through the *Energy Markets for a Changing Environment* project, which was presented to the Gas Wholesale Consultative Forum in August 2014.[32]

4.3.2 National Electricity Market

Victoria

AEMO expects the NEM interaction with GPG in Victoria in winter 2016 to be typical of previous winters. GPG demands are site-specific, considered uncontrollable, and difficult to forecast, as the GPGs are used for a fast demand and price response in the NEM.

Other NEM GPGs outside the DTS may have an effect on the total gas supply. For example, SEA Gas Pipeline supply to the DTS may be affected when Mortlake GPG responds to NEM demand.

GPG demand forecast uncertainty means AEMO must be prepared day to day to ensure enough supply reserves are available to meet minimum operating pressures throughout the DTS.

New South Wales

Gas supplies for Tallawarra GPG are transported along the EGP, and supplies for Uranquinty GPG may be transported along the VNI, to provide electricity in the NEM.

These peak stations, similar to GPGs in Victoria, are difficult to predict as demand depends on NEM conditions. Tallawarra and Uranquinty GPG demands may redirect Victorian gas supply towards New South Wales.

[32] AEMO. *Gas Wholesale Consultative Forum*. Available at: http://www.aemo.com.au/About-the-Industry/Working-Groups/Wholesale-Meetings/Gas-Wholesale-Consultative-Forum.

Tasmania

Tasmania has been importing gas from Victoria via the TGP, to fuel the Tamar Valley GPG since it returned to service in January 2016. This GPG is expected to operate at least until the Basslink interconnector returns to service.[33]

While AEMO does not expect this to have a material impact on gas supply for Victoria during winter 2016, it is worth noting that there is some flexibility in the Tamar Valley GPG. Should Tamar Valley GPG remain in service over the 2016 winter period, AEMO does not expect a gas supply-demand shortfall in Victoria or Tasmania. On peak gas demand days for the DTS, there is sufficient gas (including the Tasmanian Gas Pipeline's linepack) to supply both demand in Victoria and Tasmania (including fuel for Tamar Valley GPG).

The TGP connection (120 TJ) into the DTS was expected to be available for winter 2016, but is now not expected to be commissioned until after winter 2016.

[33] AEMO. *March 2016 Energy Adequacy Assessment Projection*. Available at: http://www.aemo.com.au/AEMO%20Home/Electricity/Resources/Reports%20and%20Documents/EAAP.

5. PEAK DAY MANAGEMENT

- When a high demand day is forecast, injection profiling can be used to maximise linepack availability during the evening peak.
- Where the system pressures are forecast to drop below defined operational limits, AEMO may indicate a threat to system security, and take action to alleviate the threat.
- AEMO will communicate relevant information to participants.

AEMO aims to operate the DTS in a normal operating state, as defined in the *Wholesale Market System Security Procedures (Victoria).*[34] A normal operating state includes maintaining system pressures and flows within defined operating limits.

5.1 Injection profiling

On peak demand days, conserving or increasing system-usable linepack before the evening peak is an effective way to minimise the likelihood of a threat to system security occurring. When a peak demand day is forecast, AEMO can ensure system security by scheduling more gas into the DTS early in the gas day, and balancing this with less gas later in the day.

The total quantity injected for the day is the same, so the market is not impacted by this process.[35] However, the gas available before and during the evening peak is increased. This plan may be utilised when the total Day +1 demand forecast exceeds 1,150 TJ. AEMO consults Longford and VicHub facility operators before scheduling profiled injections.[36]

5.2 Threat to system security

AEMO must monitor the operational conditions to identify any material schedule deviation or forecast that may cause a threat to system security. This includes:

- Rapidly increasing demand due to deteriorating weather conditions.
- Unscheduled DTS asset outage.
- A transmission pipeline incident and/or a gas supply incident.

5.2.1 Notice of threat to system security

If AEMO identifies a threat to system security, it notifies market participants as soon as possible, communicating:

- The nature and magnitude of the threat, including the likely duration of the threat and the shortfall in gas supplies likely to occur during that period.
- Whether AEMO needs to intervene in the market to avert the threat, and the time by which intervention will be required if the threat has not subsided.
- The DTS system withdrawal zones in which the threat is likely to be located.

AEMO may also issue a notice requiring participants to provide information about their capability to inject or withdraw non-firm, or off-specification, gas. This information will be used by AEMO to assist in determining options for alleviating the threat. AEMO may also request information regarding participants' ability to voluntarily reduce industrial load if required.

[34] AEMO. *Wholesale Market System Security Procedures (Victoria).* Available at: http://www.aemo.com.au/Gas/Policies-and-Procedures/Declared-Wholesale-Gas-Market-Rules-and-Procedures.
[35] Profiling injections does not impact either imbalance or deviation payments.
[36] Injection profiling is available at the Longford injection point.

5.2.2 Responses to a threat to system security

After AEMO identifies a threat to system security, a response to avert the threat is required. The following responses are available to AEMO – they are listed in order of preferred response.[37]

1. Market response

Under some circumstances, AEMO may identify a threat to system security that does not require immediate AEMO action, as the threat can be alleviated through a market response.

In this case, AEMO will:

- Provide details to participants of the threat to system security.
- Advise participants of actions they should take (or refrain from taking) for the threat to subside. These actions could include re-bidding to increase or decrease the amount of gas injected or withdrawn at particular injection or withdrawal points within the DTS.

2. Out of merit order gas injection in the next Operating Schedule

If a market response is unable to alleviate a threat to system security, AEMO can schedule out of merit order injections in the OS at the next planned schedule. Out of merit order gas can be injected at any injection point in the system, to ensure minimum contractual pressures are maintained throughout the DTS. On peak demand days, pressures at key demand centres can fall rapidly. In this case, peak shaving LNG injections are the quickest way to alleviate the threat.

3. Publishing ad hoc operating schedules

If a market response is unable to alleviate a threat to system security, and an immediate rebalancing action is required, an ad hoc OS can be published by AEMO. These ad hoc schedules allow out of merit order gas (such as LNG) to be injected into the DTS as soon as possible to alleviate the threat.

4. Directing participants to inject or withdraw gas

If a facility has gas available for injection, or has the ability to withdraw gas, AEMO may direct participants to inject or withdraw, even if bids have not been made for that gas (which would not allow it to be scheduled in an ad hoc schedule). This direction to inject can extend to non-firm supply or off-specification gas. AEMO considers critical factors such as potential public safety implications or potential damage to capital equipment.

5. Curtailment

AEMO may enact curtailment in accordance with the *Gas Load Curtailment, Gas Recovery and Rationing Guidelines*[38], where the threat to system security cannot be alleviated through other means.

6. End of a threat to system security

When AEMO believes that a threat to system security no longer exists, it will send an SWN to market participants to inform them there is no longer a threat.

[37] Note that points 3, 4 and 5 above are interventions under the National Gas Rules (NGR).
[38] AEMO *Gas Load Curtailment and Gas Rationing Recovery Guidelines.* Available at: http://www.aemo.com.au/About-AEMO/Services/Emergency-Management/Gas-Emergency.

5.3 Communication with market participants

AEMO has procedures in place to ensure consistent communications with market participants regarding any events that may affect operational and scheduling decisions.

Events that AEMO will communicate to the market include, but are not limited to, the following:

- Notification of gas quality excursions.
  - The market is notified within 25 minutes after a gas quality parameter excursion initially occurs.
- Application of constraints that reflect physical limitations of facilities or pipelines (such as for maintenance or a pipeline that is constrained).
  - The market is notified after a constraint application is received by AEMO, allowing participants to make adjustments to bids as required.
- Changes to system conditions, such as the end of day linepack target.
  - The market is notified three days prior to the change occurring unless an immediate change is required for urgent operational reasons.

On peak demand days, additional communications are sent to the market. One important notification is the intraday supply and demand shortfall likelihood chart, as shown in Figure 11.

Communication is triggered when the total demand forecast exceeds 1,150 TJ/d. AEMO will send an email notification at the 06:00, 10:00, 14:00 and 18:00 scheduling intervals.

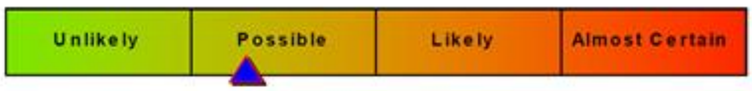
Figure 11 Weather and AEMO gas demand forecast

Weather and AEMO Gas Demand Forecast

Gas Day: Friday 01/08/2014

Weather Forecast				Total Demand Forecast (System + GPG)
Maximum	Minimum	Sunshine Hr	EDD	
10.3	5.8	1	15.2	1225.7 TJ

Intra Day Demand / Supply Linepack Shortfall Likelihood Chart



Last Update: 14:00 hrs 01/08/14

AEMO also has other market notifications available to provide relevant information, when:

- The DTS is experiencing extreme demands.
- AEMO requires action to maintain system security.

AEMO primarily uses email or SWNs to communicate operational issues to the market. SWNs are posted on AEMO's market information bulletin board (MIBB) and sent via SMS text message to the relevant distribution list.

The following notification process will continue to be used in winter 2016:

- Email.
  - Likely intraday demand/supply shortfall.
- SWN/SMS alert.
  - Threat to system security.

  - Low linepack reserve.
  - Large increase of Effective Degree Day.[39]
  - Ad hoc schedules.
  - Longford pipeline pressure.
  - Scheduled injection confirmation.
- Natural Gas Services Bulletin Board.[40]
  - Linepack capacity adequacy for each pipeline (status is indicated by green, amber or red flags).
  - Capacity information for production facilities and pipelines.

[39] Effective Degree Day (EDD) is a measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the more energy will be used for area heating purposes.

[40] For more information on information available on the Natural Gas Services Bulletin Board (http://www.gasbb.com.au/), see the Natural Gas Services Bulletin Board procedures. Available at: www.aemo.com.au/Consultations/Gas-consultations/General/~/media/Files/Other/consultations/gas_IIR/Natural%20Gas%20Services%20Bulletin%20Board%20Procedures%20v4.ashx

6. EMERGENCY MANAGEMENT

AEMO manages threats to system security and gas emergencies using a consultative and risk-based approach, to ensure:

- Relevant information and knowledge is shared during an event.
- Decisions are clear and informed.

AEMO's Emergency Management Framework (EMF) and Incident Management Plan (IMP) align AEMO's preparedness and response capabilities, minimising risk:

- The EMF outlines the management structure and responsibilities for incident coordination and managing the Incident Coordination Team (ICT). All AEMO emergency and incident management documentation, including business continuity plans, aligns with the framework.
- The IMP is an operational document that outlines how the Incident Coordinator and ICT will be notified and activated to deal with incidents so AEMO returns to normal operations as soon as possible. The IMP complements other industry and government emergency policies and procedures.

Once activated, the incident coordination team takes responsibility for:

- All the activities undertaken to manage the incident.
- Establishing AEMO's incident coordination centre.
- Managing the interface with organisations and people operating outside the incident management structure, as well as with communities and people likely to be affected by the incident.

6.1 Legislation and rules

The *National Gas (Victoria) Act 2008* is the legislation for the application of the National Gas Law (NGL) and rules in Victoria.

The NGL provides the definition of an emergency applied in Victoria. It specifies what is required to prepare for gas emergencies, the requirements for the Gas Emergency Protocol, and that registered participants must comply with the Gas Emergency Protocol.

6.2 Emergencies

Emergencies are defined under the Section 333 of the National Gas Rules (NGR) as follows:

(1) An emergency occurs when:

(a) AEMO reasonably believes there to be a situation which may threaten:

(i) reliability of gas supply; or

(ii) system security or the security of a declared distribution system; or

(iii) public safety,

and AEMO in its absolute discretion considers that the situation is an emergency and declares there to be an emergency; or

(b) AEMO declares there to be an emergency at the direction of a government authority authorised to give such directions.

AEMO will declare an emergency if it reasonably believes an operational response cannot address the issue. It will implement the declaration by issuing an Emergency Declaration Notice to the Emergency Manager, Duty Manager, or General Manager of each registered participant.

AEMO is also responsible for maintaining the Gas Emergency Protocol. This protocol consists of:

- *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*.
- *Wholesale Market System Security Procedures*.
- *Emergency Procedures (Gas)*.

The *Gas Load Curtailment and Gas Rationing and Recovery Guidelines* define classes of gas customers within prioritised curtailment tables, from which curtailment lists are derived. These guidelines are based on system security criteria and can be modified by government direction.

The *Wholesale Market System Security Procedures (Victoria)* set the thresholds for operation of the DTS, so threats to system security are averted or minimised.

The *Emergency Procedures (Gas)* guide the management, preparation, response and recovery for gas emergencies in Victoria. The procedures are underpinned by the principles of maintaining the gas reliability, maintaining DTS system security, and minimising risk to public safety.

The NGR outlines four key requirements for registered participants. Each must:

- Notify AEMO as soon as practicable of any emergency or situation that may threaten system security.
- Use best endeavours to ensure that its safety plan (if any) permits it to comply with emergency directions.
- Provide AEMO with emergency contacts (including an email address, telephone and fax number, name and title) of an appropriate representative who has the authority and responsibility to act in the event of an emergency.
- Ensure all of its relevant officers, staff, and customers are familiar with the emergency protocol and the registered participant's safety plan or procedures.

AEMO's powers during an emergency

AEMO may use s.91BC of the NGL for managing:

- The operation or use of any equipment or installation.
- The control of natural gas flow.
- Any other matter that may affect the safety, security or reliability of the declared transmission or declared distribution systems.

While AEMO's powers under s.91BC can be used without declaring an emergency or threat to system security, it is unlikely AEMO would invoke these powers without declaring one or both.

Energy Safe Victoria power to issue directions

During a gas emergency, the Director of Energy Safe Victoria (ESV) may also issue a direction that ESV believes is needed for making the situation safe. The intent is to regulate the available gas supply (having regard to community needs), and facilitate the reliability of gas supply or the security of systems for the transmission and distribution of gas.

The Governor and the Minister for Energy

The Governor may also declare a proclamation under Part 9 of the *Gas Industry Act*, if it appears that the available supply of gas is (or is likely to become) insufficient for the community's essential needs. The proclamation remains in effect until the Governor revokes it. While the proclamation is in force, the Minister for Energy may give any direction that is necessary to ensure the safe and secure supply of gas.

6.3 Threats to System Security

A threat to system security[41] can be indicated by any one of the following:

- The annual planning reviews prepared by AEMO.
- An operating schedule.
- Any other fact or circumstance which AEMO becomes aware of.

A threat to system security may impact the DTS partially or as a whole. AEMO has the power to indicate a threat to system security if it reasonably believes some level of operational response can address the issue, otherwise an “emergency” will be declared.

Market response and Intervention

AEMO may take the following measures to overcome a threat to system security (under s.91BC of the NGL):

- Directing the injection of LNG.
- Curtailment[42] (in accordance with curtailment tables).
- Increasing withdrawals.
- Using reasonable endeavours to inject gas which is available, including non-firm gas.
- Injecting off-specification gas.
- Doing anything AEMO believes necessary in the circumstances.

[41] A threat to system security is defined with rule 341 of the NGR.
[42] In the event of a threat to system security attributable to a transmission constraint AEMO will curtail customers in accordance with sections 3 and 4 of the Gas Load Curtailment and Gas Rationing and Recovery Guidelines.

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
$	Australian dollars
kPa	Kilopascals
PJ	Petajoule (1 PJ = 1,000 TJ)
TJ	Terajoule (1 TJ = 1,000 GJ)
TJ/d	Terajoules per day
TJ/hr	Terajoules per hour

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
DCG	Dandenong City Gate
DFPC	Directional Flow Point Constraint
DTS	Declared Transmission System
EDD	Effective Degree Day
EGP	Eastern Gas Pipeline
EMF	Emergency Management Framework
ESV	Energy Safe Victoria
GBB	Natural Gas Services Bulletin Board
GPG	Gas-powered generation
ICT	Incident Coordination Team
IMP	Incident Management Plan
MIBB	Market Information Bulletin Board
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
NFTC	Net Flow Transportation Constraint
OS	Operating Schedule
PS	Pricing Schedule
SDPC	Supply and Demand Point Constraint
SSC	Supply Source Constraint
STTM	Short Term Trading Market
SWN	System-wide notice
SWP	South West Pipeline
TGP	Tasmanian Gas Pipeline
UGS	Underground Gas Storage
VNI	Victorian Northern Interconnect
WTS	Western Transmission System

GLOSSARY

Term	Definition
1-in-2 system demand day	The 1-in-2 system demand day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 system demand day	The 1-in-20 system demand day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Authorised Maximum Daily Quantity	Authorised Maximum Daily Quantity (Authorised MDQ) and Authorised MDQ Credit Certificate are transportation rights in the DTS, collectively known as AMDQ. Authorised MDQ is a withdrawal right for customers and/or market participants on the DTS for transported gas injected at Longford. Subsequent capacity increases to the DTS such as South West Pipeline, the Western Transmission System and the Bass Gas project have been allocated as AMDQ Credit Certificates. AMDQ is an input to: • Determining congestion uplift charges payable by a market participant for each scheduling interval of a gas day as part of the funding of ancillary payments. • Tie-breaking rights when scheduling equal priced injections or withdrawals bids, and in determining the order of curtailment in the event of an emergency.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (gas DTS), and injected at Pakenham.
Capacity	Pipeline transportation capacity.
Culcairn	The gas transmission system interconnection point between Victoria and New South Wales.
constraint	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
Declared Transmission System	The declared gas transmission system in Victoria, in accordance with the National Gas Law. Owned by APA GasNet and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
distribution	The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.
distribution system	Pipelines for the conveyance of gas with one or other of the following characteristics: • A maximum allowable operating pressure of 515 kPa or less. • Uniquely identified as a distribution pipeline in a distributor's access arrangement, where the maximum operating pressure is greater than 515 kPa.
distributor	The service provider of the distribution pipelines that transport gas from transmission pipelines to customers.
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the more energy will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
Facility operator	Producers, Storage Providers, and interconnected transmission pipeline service providers in the DTS.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas	See natural gas.
gas market (market)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT)).
Gas Statement of Opportunities (GSOO)	The GSOO is published annually by AEMO, under the National Gas Law and Part 15D of the National Gas Rules, to report on the projected adequacy of eastern and south-eastern Australian gas markets to supply forecast maximum demand and annual consumption.

Term	Definition
Gigajoule (GJ)	An International System of Units (SI) unit, 1 gigajoule equals 1,000 J.
injection	The physical injection of gas into the transmission system.
Interconnect (The)	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
Lateral pipeline	A pipeline branch off a larger pipeline.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline system throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas (LNG)	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne liquefied natural gas (LNG) storage facility is located at Dandenong.
maintenance	Work carried out by service providers, Producers and Storage Providers that, in AEMO's opinion, may affect any of: • AEMO's ability to supply gas through the declared transmission system. • AEMO's ability to operate the declared transmission system. • DTS capacity. • System security. • The efficient operation of the DTS generally. It includes work carried out on pipeline equipment, but does not include maintenance required to avert or reduce the impact of an emergency.
market participant	A party who is eligible to participate in an energy market operated by AEMO in one or more of the following roles: • A market generator, market customer, or a market network service provider (electricity). • Storage provider. • Transmission customer. • Distribution customer. • Retailer. • Trader (gas).
maximum allowable operating pressure (MAOP)	The maximum pressure at which a pipeline is licensed to operate.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand. See also Authorised Maximum Daily Quantity.
National Gas Forecasting Report (NGFR)	The NGFR is published annually by AEMO, under clause 91D of the National Gas Law, to report on forecast maximum demand and annual consumption in eastern and south-eastern Australia.
Natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
Natural Gas Services Bulletin Board (GBB)	The GBB (http://www.gasbb.com.au/) is an online gas market and system information website covering all major gas production fields, major demand centres and natural gas transmission pipeline systems of South Australia, Victoria, Tasmania, NSW, the ACT, and Queensland. It was established in 2008 and is operated by AEMO.
peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
Petajoule (PJ)	An International System of Units (SI) unit, 1 petajoule equals 1,000 TJ (or 10^{15} joules). Also PJ/yr. or petajoules per year.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours' notice.
probability of exceedance	Refers to the probability that a forecast peak demand figure will be exceeded. For example, a forecast 1-in-20 peak demand will, on average, be exceeded only 1 year in every 20.
scheduling	The process of scheduling bids that AEMO is required to carry out in accordance with Part 19 of the National Gas Rules for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.

Term	Definition
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Port Campbell.
storage facility	A facility for storing gas, including the liquefied natural gas (LNG) storage facility and the Iona Underground Gas Storage (UGS).
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include the following: • Load distribution across the system. • Hourly load profiles throughout the day at each delivery point. • Heating values and the specific gravity of injected gas at each injection point. • Initial linepack and final linepack and its distribution throughout the system. • Ground and ambient air temperatures. • Minimum and maximum operating pressure limits at critical points throughout the system. • Compressor station power and efficiency.
system constraint	See Declared Transmission System constraint.
system demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas-powered generation (GPG) demand, exports, and gas withdrawn at Iona UGS.
system injection point	A gas transmission system connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas Declared Transmission System (gas DTS) connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
Tariff D	The gas transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
Tasmanian gas pipeline	The pipeline from VicHub (Longford) to Tasmania.
Terajoule (TJ)	An International System of Units (SI) unit, 1 terajoule equals 1,000 GJ (or 10^{12} joules). Also TJ/d or terajoule per day.
transmission pipeline	A pipeline for the conveyance of gas that is licensed under the Pipelines Act and has a maximum design pressure exceeding 1,050 kPa.
transmission system	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
Underground Gas Storage (UGS)	The Iona Underground Gas Storage (UGS) facility at Port Campbell which supplies gas to Victoria to meet winter peak demand, and in summer supports South Australian GPG demand via the SEA Gas Pipeline and, as needed, Victorian demand if capacity is reduced at other facilities.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas Declared Transmission System (DTS) at Longford, facilitating gas trading at the Longford hub.
Western Transmission System (WTS)	The transmission pipelines serving the area from Port Campbell to Portland.
winter	1 June to 30 September.