GSOO METHODOLOGY

Methodology for the Gas Statement of Opportunities

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IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about the natural gas industry in eastern and south-eastern Australia, in accordance with the National Gas Law and Part 15D of the National Gas Rules.

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CONTENTS

TABLES

FIGURES

CHAPTER 1. INTRODUCTION

AEMO continues to improve the focus and clarity of its planning publications, by succinctly presenting key information in the main document, and publishing accompanying information (including methodology) separately. This document describes the methodology used to develop the 2015 Gas Statement of Opportunities (GSOO).[1]

The GSOO assesses the adequacy of gas supply and demand in eastern and south-eastern Australia over a 10-year outlook period for infrastructure, and a 20-year outlook period for reserves. The adequacy assessment is performed using a model of supply and demand (gas model) that includes representations of:

- Reserves and resources.
- Existing, committed, and some notional gas processing facilities.
- Existing, committed, and some notional gas transmission pipelines.
- Existing and committed gas storage facilities.
- Gas consumption forecasts for industrial, residential and commercial customers, gas-powered generation (GPG), and liquefied natural gas (LNG) export.

The gas model determines the least-cost supply and demand balance, subject to infrastructure and reserves limitations, on a daily basis over the 20-year outlook period. The supply–demand balance solution indicates the timing, location, and magnitude of potential shortfalls of supply.

The analysis is repeated for a range of scenarios to determine the sensitivity of outcomes to changes in modelled assumptions.

[1] AEMO. *2015 Gas Statement of Opportunities*. 12 March 2015. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

CHAPTER 2. SCENARIOS

The GSOO reports on a range of possible futures by overlaying future assumptions regarding the status of new infrastructure projects and the priority that producers place on demand for LNG export. Consistent with AEMO's suite of planning publications, the 2015 GSOO considers three scenarios to cover the range of possible futures the gas industry faces:

- High energy consumption from a centralised source.
- Medium energy consumption from a centralised source.
- Low energy consumption from a centralised source.

Table 1 lists the demand drivers underpinning the three scenarios. See the 2014 Planning and Forecasting Scenarios report[2] for further information.

Table 1 Overview of the scenario demand drivers

Driver	High scenario	Medium scenario	Low scenario
Economic activity and population growth	Higher level of economic activity than reported by the Reserve Bank of Australia (RBA), strong population growth.	Continues consistent with RBA economic activity and historical population growth reported by the Australian Bureau of Statistics.	Lower level of economic activity than reported by the RBA, slow population growth.
Domestic gas production and global LNG	Higher than current market expectations.	Continues according to current market expectations.	Lower than current market expectations.
Energy-intensive industrial sectors	Increased consumption levels.	Continues at current energy consumption levels.	Decreased consumption levels.
Research and development	Slow growth.	Slow to moderate growth.	Moderate to rapid growth in research and development.
Distributed generation	Reduced uptake of distributed generation options.	Moderate penetration of distributed generation.	Strong uptake of distributed generation.
Demand-side response	Weak demand-side response.	Continues at current levels.	Strong demand-side response.
Carbon	Meet the 5% target by 2020 and implement the Direct Action policy reverse auction component only from 2020.	Meet the 5% target by 2020 and implement the Direct Action policy safeguarding emissions from 2020.	Meet the 5% target by 2020 and implement the Direct Action policy safeguarding emissions with high strength from 2020.
GreenPower	Falling sales.	Sales continue at flat rate.	Rising sales.

These scenario parameters are used as an input into the gas demand forecasts for the 2015 GSOO. Development of gas demand forecasts is discussed in Section 4.7.

AEMO's Planning Assumptions webpage[3] provides detailed data sets used in AEMO's planning publications.

[2] AEMO. *2014 Planning & Forecasting Scenarios*. 11 February 2014. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx. Viewed: 20 February 2015.
[3] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions. Viewed: 20 February 2015.

Gas price assumptions

Modelling conducted for the 2015 GSOO does not use gas price assumptions directly; it considers gas production and transmission costs to determine least-cost solutions.

Assumed gas prices affect model outcomes indirectly. AEMO develops demand for GPG during electricity modelling performed to support the 2014 National Transmission Network Development Plan (NTNDP)[4]. The NTNDP model uses a range of gas prices (between $4.52/GJ and $12.71/GJ under the medium scenario), developing an hourly electricity dispatch solution over a 20-year outlook horizon, with gas prices determining how frequently GPG is dispatched. The hourly GPG dispatch is converted to daily GPG gas demand for use in the gas model. For further details on the methodology used to develop the GPG demand, see the 2014 National Gas Forecasting Methodology Information Paper[5], chapter 5.

For more information about representative eastern and south-eastern Australian gas prices for 2015 to 2034 see the Fuel and Technology Cost Review.[6]

Gas costs are also considered when developing the reserves projections (which are inputs into the supply–demand modelling), where gas costs, equity gas, and current contracts are used to determine the production profile.

[4] AEMO. *2014 National Transmission Network Development Plan*. 17 December 2014. http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. Viewed 20 December 2014.

[5] AEMO. *National Gas Forecasting Methodology Information Paper.* 19 December 2014. http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report/NGFR-Supplementary-Information. This paper covers the methodology for developing industrial, commercial and residential demand forecasts, as well as gas powered generation forecasts.

[6] ACIL Allen. *Fuel and Technology Cost Review*. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/2014%20Assumptions/Fuel_and_Technology_Cost_Review_Report_ACIL_Allen.ashx. Viewed: 20 February 2015.

CHAPTER 3. ASSESSING ADEQUACY

AEMO's adequacy assessment determines the capability of the gas system to supply demand over a 20-year outlook period. The gas model solves a transport problem for each day in the outlook period, assessing:

- The capability of transmission system (gas pipelines) to deliver gas to demand centres.
- The capacity of gas processing facilities to supply sufficient gas into the transmission system.
- The availability of reserves to maintain gas processing facility throughput.
- The availability of storage to help manage peak demand periods.

When any one of these elements is insufficient to meet demand, the gas model substitutes production with supply shortfalls.

Initially, the gas model considers existing transmission and production and committed projects only for supply. As demand grows throughout the outlook period, the system approaches and then exceeds its capacity to supply. No further development is assumed, and the location and timing of shortfalls are analysed.

In some cases, AEMO reviews projects that have been proposed (but not sufficiently advanced to achieve committed status) to assess whether those projects can defer or relocate observed shortfalls and enrich discussion surrounding the scale of investment required to ensure security of supply. In 2015, AEMO considered the following as sensitivities:

- An augmentation of the South West Queensland Pipeline to deliver additional gas supply to Wallumbilla.
- An additional production project in Southern Queensland or Moomba (or both), delivering an extra 100 TJ/d.
- A gas production project located in the Gloucester Basin with transmission to Newcastle, capable of delivering 80 TJ/d, similar to a proposal currently under consideration by AGL.
- A gas production project located in the Gunnedah Basin, with transmission to the Moomba–Sydney Pipeline (MSP), capable of delivering 100 TJ/d, similar to a proposal currently under consideration by Santos.
- A pipeline between Alice Springs and Moomba to deliver gas to the existing eastern and south-eastern gas system. The quantity of gas to be delivered is only limited by the existing infrastructure capacity.

Shortfalls were observed in Queensland under the medium scenario when considering existing and committed projects only.

A new pipeline between Alice Springs and Moomba was also modelled as a separate sensitivity, assessing its impact on the existing eastern and south-eastern gas system, should it become a source of new gas supply. The capacity of the new pipeline was considered effectively infinite, but the cost of gas significantly more expensive than any other supply, ensuring that this gas was selected last by the model to satisfy local demand, and the actual quantity of gas delivered to the system would be limited by the existing infrastructure constraints.

CHAPTER 4. GAS MODEL

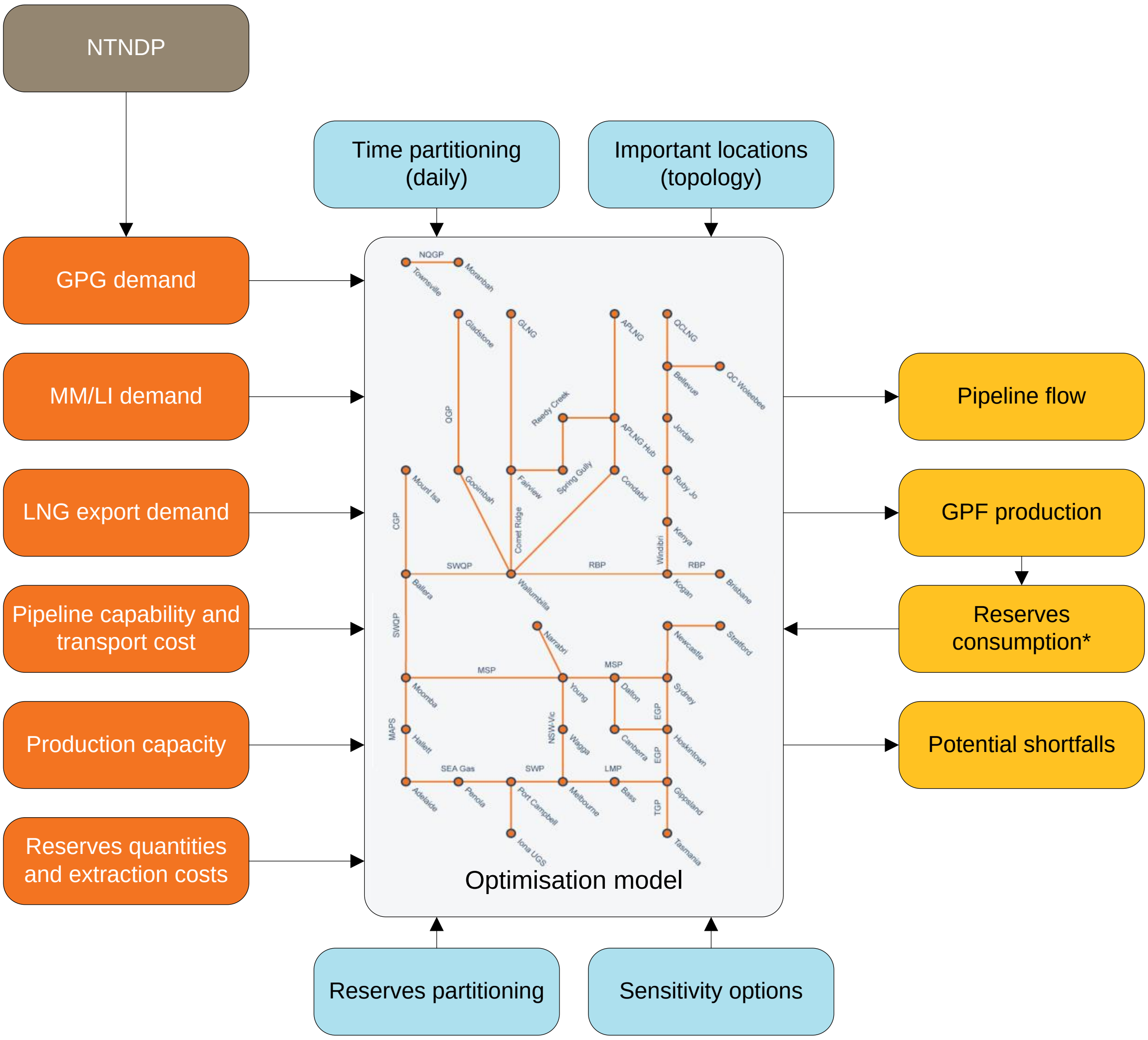
The GSOO supply and demand model (gas model) is a linear program that simulates gas market supply and demand conditions over the 20-year reserves outlook period, from 2015 to 2034. It calculates optimum production and flow by minimising the cost to supply demand. It solves a transport problem for each day in the outlook period, assessing:

- The capability of transmission system (gas pipelines) to deliver gas to demand centres.
- The capacity of gas processing facilities to supply sufficient gas into the transmission system.
- The availability of reserves to maintain gas processing facility throughput.

The gas model contains representations of pipelines, industrial, residential and commercial, gas-powered generation (GPG) and liquefied natural gas (LNG) export demand, pipeline flow capabilities and transport costs, gas processing facility processing capacities and reserves, and resources with associated partition costs. These are all defined at a resolution in time and space that is high enough to capture important details in the transportation problem. It produces a daily production profile for each reserves tranche and processing facility, a flow on each defined connection, an estimation of potential shortfalls, and a reserves consumption profile developed by feeding production information back into it. A representation of the gas model with its inputs and outputs is shown in Figure 1.

The transportation problem is solved considering a series of connected locations. At each location, gas may be injected or withdrawn from the system, or flow redirected. Connections between locations define paths over which gas can flow. Together, locations and their connections define a topology. The topology used for modelling in 2015 is shown in Figure 2, designed to capture key features of the physical system shown in Figure 3. In Figure 2, the sensitivity studying the effect of a pipeline between Alice Springs and Moomba has not been shown.

Figure 1 Model inputs and outputs



* Reserves consumption is calculated from production, which is set to zero when associated reserves are fully consumed.

Figure 2 Gas model topology for 2015 GSOO

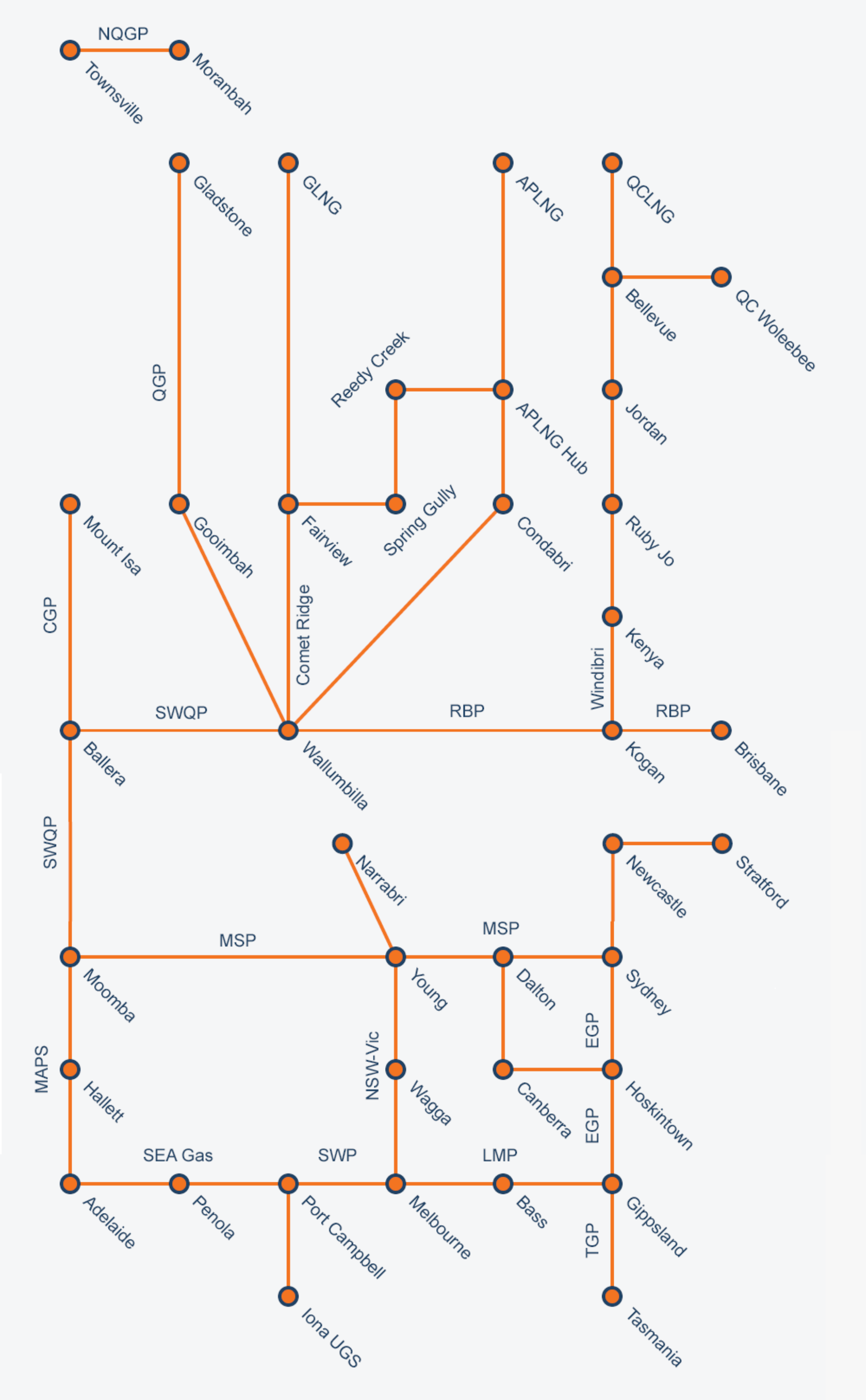
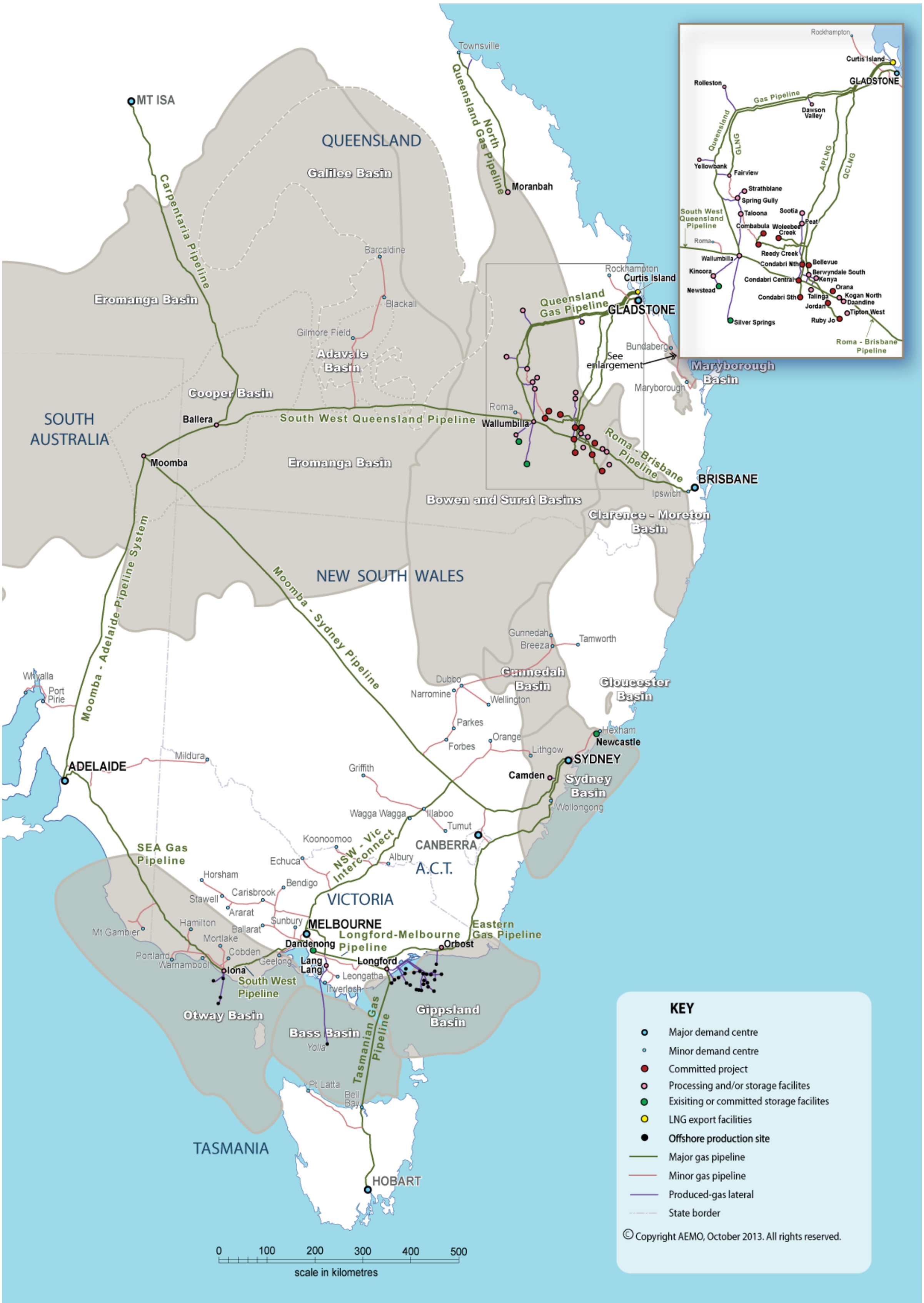


Figure 3 Eastern and south-eastern Australian gas transmission network



4.1 Pipelines

Figure 2 shows abbreviated pipeline labels associated with connections. In many cases, a connection (or series of connections) is representative of an actual pipeline. Flow on connections are limited in the model by capacity limitations on the associated pipeline.

In practice, pipeline flow capacity is variable, subject to a range of factors impacting gas pressure gradients between injection and withdrawal points. The northerly flow capacity of the New South Sales – Victoria Interconnect, for example, is higher during summer because summer demand in Melbourne is lower, allowing for higher pressures at the southern end of the pipeline. For the purposes of modelling, AEMO selects a single pipeline capacity value for use throughout the simulation. In many cases, this value is at the low end of the pipeline's real-world (variable) capacity, because times at which flow is constrained are of interest for adequacy assessments.

Table 2 provides detail of modelled pipelines and their capacity limitations. Pipeline data was acquired by direct survey of industry participants.

Flow is controlled in the model using a transport cost. AEMO engaged Core Energy Group (Core) to determine transport costs on each pipeline in the modelled system.[7] These costs were used for 2015 modelling in most cases. In some instances, the transport costs conflicted with the information provided by the pipeline operators, in which case the costs provided by the pipeline operators was used.

Table 2 Modelled pipelines

Pipeline	Abbreviation	Description
Australia Pacific LNG Pipeline	APLNGP	The pipeline between the Condabri/Talinga/Orana processing facilities and Gladstone, and its lateral extending to Reedy Creek, capable of 1,560 TJ/d.
Carpentaria Gas Pipeline	CGP	The pipeline between the Ballera processing facility and Mount Isa and its laterals, capable of 119 TJ/d.
Comet Ridge Pipeline	CRP	The pipeline between Wallumbilla and Fairview linking production at Fairview and the GLNGP to the domestic system.
Dalton–Canberra Pipeline	DCP	The lateral of the MSP between Dalton and Canberra, capable of 56 TJ/d.
Eastern Gas Pipeline	EGP	The pipeline connecting processing in the Gippsland Basin to Sydney, via Wollongong and the ACT, capable of 298 TJ/d.
Gladstone LNG Pipeline	GLNGP	The pipeline between Fairview and the GLNG facility at Gladstone, capable of 1,400 TJ/d.
Gloucester Pipeline	GP	A notional future pipeline between notional future gas processing in the Gloucester Basin and Newcastle.
Hoskintown–Canberra Pipeline	HCP	The lateral of the EGP between Hoskintown and Canberra, capable of 77 TJ/d.
Longford to Melbourne Pipeline	LMP	The pipeline connecting the Longford processing facility in Gippsland with Melbourne, capable of 1,030 TJ/d.
Moomba–Adelaide Pipeline System	MAPS	The pipeline between Moomba and Adelaide, including laterals to Port Augusta and the Riverlands, capable of 241 TJ/d. Reverse direction flows from Adelaide to Moomba have been included from June 2015.
Moomba–Sydney Pipeline	MSP	The pipeline between Moomba and Sydney, including the Central Ranges and Central West laterals, capable of 439 TJ/d. Reverse direction flows from Sydney to Moomba have been included from September 2015.
Narrabri Pipeline	NP	A notional future pipeline between notional future gas processing in the Gunnedah basin and Young.
New South Wales – Victoria Interconnect	IC	The pipeline connecting Wollert north of Melbourne with the MSP lateral extending south from Young to Wagga Wagga, capable of 120 TJ/d in a southerly direction and 118 TJ/d in a northerly direction.

[7] Core Energy Group. *Gas Production and Transmission Costs.* Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2015-GSOO-Supporting-Information.

North Queensland Gas Pipeline	NQGP	The pipeline between Moranbah and Townsville, capable of 110 TJ/d.
Queensland Curtis LNG Pipeline	QCLNGP	The pipeline between the Ruby Jo/Jordan/Bellevue processing facilities and Gladstone, and its lateral extending to Woleebee Creek, capable of 1,410 TJ/d.
Queensland Gas Pipeline	QGP	The pipeline between Wallumbilla and Gladstone, capable of 152 TJ/d.
Roma–Brisbane Pipeline	RBP	The pipeline between Wallumbilla and Brisbane, capable of 233 TJ/d. Reverse direction flows from Sydney to Moomba have been included from July 2015.
South East Australia Gas Pipeline	SEA Gas	The pipeline connecting Otway Basin processing facilities at Port Campbell with Adelaide, capable of 314 TJ/d.
South West Pipeline	SWP	The pipeline connecting Otway Basin processing facilities at Port Campbell with Melbourne, capable of 429 TJ/d in an easterly direction from July 2015 and 92 TJ/d in a westerly direction.
South West Queensland Pipeline	SWQP	The pipeline between Moomba and Wallumbilla, capable of 404 TJ/d flow in a westerly direction and 340 TJ/d in an easterly direction.
Sydney–Newcastle Pipeline	SNP	The pipeline between Sydney and Newcastle, supplying Newcastle demand. The capability of this pipeline is not modelled, with all demand at Newcastle referred to Sydney.
Tasmanian Gas Pipeline	TGP	The pipeline connecting processing in the Gippsland Basin to Tasmania, capable of 130 TJ/d.
Walloons Pipeline	WLP	The pipeline between Wallumbilla and Condabri, linking production near Talinga and the APLNG main line to the domestic system.
Windibri Pipeline	WBP	The pipeline between processing at Kenya–Argyle and the RBP at Condamine, linking the QCLNG main line to the domestic system.

4.2 Production

Gas production in the model occurs at processing facilities. At each daily step, a modelled processing facility may add gas to the supply–demand balance up to its processing capacity. Processing facilities draw their gas from fields, and might not draw more gas than the sum of the gas in their connected fields. Adding gas to the system incurs a cost. The model attempts to minimise this cost by drawing gas from the fields with the lowest cost first.

AEMO engaged Core to provide production costs for input into the GSOO.[8] Each processing facility within the gas model has a separate production cost, and is associated with the field of reserves from which the production facility draws.

Table 3 provides details of modelled processing facilities and their capacity limitations. Facility data was acquired by direct survey of industry participants.

Table 3 Modelled processing facilities

Facility	Location (see Figure 2)	Capacity (TJ/d)
Ballera	Ballera	100
Bellevue	Bellevue	220
Berwyndale South	Kenya	144
Camden	Sydney	27
Combabula	Reedy Creek	225
Condabri Central	Condabri	150
Condabri North	Condabri	150
Condabri South	Condabri	125
Daandine	Kogan	55

[8] Core Energy Group. *Gas Production and Transmission Costs.* Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2015-GSOO-Supporting-Information.

Facility	Location (see Figure 2)	Capacity (TJ/d)
Dawson Valley	Gooimbah	30
Eurombah Creek	Reedy Creek	180
Fairview123	Fairview	142
Fairview4	Fairview	250
Fairview5	Fairview	160
Gloucester	Stratford	80
Iona	Port Campbell	80
Jordan	Jordan	300
Kenya	Kenya	180
Kogan North	Kogan	12
Lang Lang	Bass	67
Longford	Gippsland	1145
Minerva	Port Campbell	81
Moomba	Moomba	390
Moranbah	Moranbah	68
Narrabri	Narrabri	100
Orana	Condabri	170
Orbost (Patricia–Baleen)	Gippsland	75
Otway Gas Project	Port Campbell	205
Peat	Kogan	15
Reedy Creek	Reedy Creek	150
Rolleston	Gooimbah	26
Roma Hub 2	Fairview	145
Ruby Jo	Ruby Jo	440
Scotia	Kogan	30
Spring Gully	Spring Gully	69
Strathblane	Spring Gully	78
Talinga	Condabri	120
Taloona	Spring Gully	60
Tipton West	Kogan	26
Woleebee Creek	QC Woleebee	300
Wungoona	Wallumbilla	30
Yellowbank	Gooimbah	26

4.3 Fields/reserves

Each modelled processing facility may be associated with one or more fields. In the gas model, a field is any defined accumulation of gas with a specific uniform extraction cost. A modelled field may correspond to a real-world field (for example, Minerva or Longtom), an aggregation of fields (for example, the Casino, Henry and Netherby fields are represented by a single field in the model), or a partition of a field or aggregate of fields (for example, all of the Cooper–Eromanga Basin 2P reserves are represented by a single field, and all the Cooper–Eromanga Basin 3P/2C reserves and resources are represented by another field).

The gas model draws gas from lowest-cost fields first, subject to processing and transmission limitations. At the beginning of each time step, the gas model removes from each field the gas produced in the previous time step. When reserves in a field reach zero, processing facilities associated with the field may no longer draw on it.

Most processing facilities are associated with more than one field. When a processing facility empties its lowest-cost field to zero, it begins to draw on the next-lowest-cost field. In this way, fuel supply moves up the supply cost curve as model time proceeds.

AEMO engaged Core to develop reserves and resource quantities available to the gas model. AEMO asked Core to categorise reserves and resources to reflect the likelihood of their commercial development, to provide a more detailed outlook of how these reserves will be developed. This provided a categorisation of reserves that enables higher resolution results, providing the points across the outlook period when 3P/2C reserves and resources need to be developed to meet supply. The categorisation provided was based on Core's knowledge of contracted reserves, and the internationally recognised Petroleum Resources Management System[9], resulting in the following reserves tranches:

- 2P reserves.
- 2C/3P reserves and resources.
- Prospective resources.

The reserve projections provided in Core's report provide a high-level assessment of reserves likely to be available to meet demand, excluding consideration of gas infrastructure capability and constraints (processing facilities, pipelines, and storage facilities). This high-level assessment included consideration of contracted (or committed) and available reserves.

Core's assessment of reserves included a cost to extract gas from each reserves tranche. In some cases these costs were modified to ensure sensible model outcomes.

The reserve production profile produced by AEMO's gas model includes consideration of gas infrastructure capability and constraints. This results in minor differences between Core's reserves projections and reserves consumption profiles developed by the GSOO modelling.

Further detail about reserves quantities used in the 2015 GSOO is available on AEMO's website.[10]

4.4 Storage

AEMO improved the 2015 GSOO by modelling the behaviour of gas storage facilities dynamically, rather than the static assumed behaviour modelled previously. Actual gas storage facility operation is particularly sensitive to assumptions about commercial behaviour, with decisions about whether to inject into or withdraw from storage on any one modelled day subject to assumed prices.

Price information in the gas model is not of a suitable resolution to allow the model to self-determine storage facility injection and withdrawal behaviour on a commercial basis. Instead, the gas model optimises gas storage operation on the assumption that there is a unit cost for both injection into and withdrawal from a storage facility. The gas model then optimises the injection and withdrawal behaviour of each storage facility in order to meet local peak demand fluctuations at the least cost.

The gas model also aims to recycle the storage capacity at each facility so that at the end of each year the storage returns to the same level it was at the start of the year. Should returning the storage capacity to initial levels prove to be excessively difficult or costly, there is a penalty cost that may be paid instead.

[9] Available: http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf. Viewed: 23 February 2015.
[10] Core Energy Group. *Gas Reserves and* Resources. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2015-GSOO-Supporting-Information.

4.5 Facilities survey

AEMO surveyed gas industry participants to obtain updated information on the gas facility details:

- Processing facility capacities and potential or committed future expansions.
- Pipeline capacities and potential or committed future expansions.
- LNG facility capacities and potential or committed future expansions.
- Reserves developments.
- Storage facility capacities and potential or committed future developments.

Where possible, the information provided was used directly by the gas model. In some cases, the gas model used modified values to account for new information received after completion of the survey.

Collated results from the facilities survey are available from AEMO's website.[11]

4.6 Contract positions

As a supply adequacy model, the gas model assesses the physical capability of the eastern Australian gas supply system to meet growing demand. In most cases, commercial arrangements are not modelled, because they do not reflect physical limitations to supply.

In 2013, reserves data detail was increased. Reserves are typically reported on the basis of the companies that own the rights to them, and the reserves data necessarily contain information about ownership as a result. The ownership of reserves can impact supply adequacy if specific demand centres are known to draw on specific reserves. This is particularly the case for LNG export, where reserves are earmarked for either QCLNG, APLNG, or GLNG. It is of lower concern for domestic demand, which is often supplied from a portfolio of contracts.

Where specific information was available for supply contracts to LNG export demand centres, these were included in the gas model:

- A supply contract from Origin reserves to GLNG at Fairview, supplying 100 TJ/d, with an additional 55 TJ/d between 2016 and 2020.[12] Although this contract is for a 10-year period from 2015, it remains in place in the gas model to the end of the outlook period because no further information is available to substitute supply for GLNG after contract expiry. The contract is for delivery at Wallumbilla, however, it was implemented as a dedicated link between processing at Spring Gully and Fairview, sequestering the arrangement from the domestic system.
- QCLNG to use up to 190 PJ of APLNG-owned reserves in the first two years of operation, and 25 PJ subsequently.[13] This was implemented in the gas model by implementing a link (nominally representing the Walloons Pipeline) that allowed Berwyndale South and Kenya facilities to supply only QCLNG or domestic demand, as these facilities are co-owned by APLNG.
- GLNG to use up to 140 TJ/d supplied from Santos' Cooper Basin production facilities. In practice, the assumption that LNG export demand is prioritised, combined with increased eastern haul capability of the SWQP, ensures that this contract is satisfied. Flows from Moomba to Wallumbilla were significantly above 140 TJ/d for most of the modelled outlook period.

[11] AEMO. *2015 Gas Processing, Transmission, and Storage Facilities*. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2015-GSOO-Supporting-Information.
[12] See http://www.santos.com/Archive/NewsDetail.aspx?id=1328 and http://www.santos.com/Archive/NewsDetail.aspx?p=121&id=1409.
[13] See http://www.bg-group.com/OurBusiness/WhereWeOperate/Pages/Australia.aspx.

4.7 Demand

The gas model defines three classes of gas demand:

- Industrial, residential and commercial demand, as forecast by the National Gas Forecasting Report (NGFR).[14]
- Demand for GPG, as forecast by modelling undertaken for the 2014 NTNDP.[15]
- Demand for LNG liquefaction facilities, as forecast by Jacobs[16], a consultancy engaged by AEMO.

Each class of gas demand is considered separately. Demand has an associated value of customer reliability (VCR), which allows the gas model operator to control which class of demand is supplied first.[17] In 2015, gas demand is supplied in the following order:

1. Demand for LNG export.
2. Industrial, residential and commercial demand.
3. Demand for GPG.

A consequence of the VCR ordering is that demand for GPG will be the first to be replaced by a potential shortfall. In some cases, gas will flow past a location with demand for GPG in order to supply mass market and large industrial demand further away, despite the higher transmission cost.

The GSOO defines two aggregations of demand:

- Total gas demand, which is the sum of all three classes of demand.
- Domestic gas demand, which is the sum of industrial, residential and commercial, and GPG demand.

4.7.1 Demand forecasts

Demand forecasts are expressed on different bases for each class of demand:

- Demand for LNG export is expressed as an annual demand in PJ for each LNG export project.
- Demand for GPG is expressed as hourly generation in GJ from NTNDP electricity modelling, for each modelled gas generator.
- Industrial, residential and commercial demand is expressed as a combination of annual energy in PJ and summer and winter peak day maximum demand in TJ for each demand zone.

In each case, AEMO converted the demand forecasts into a daily demand profile for use by the gas model.

For further information regarding the development of each class of demand and the key assumptions used, refer to the 2014 National Gas Forecasting Methodology Information Paper[18] and the Jacobs LNG report[19].

[14] AEMO. *2014 National Gas Forecasting Report*. Available: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report.
[15] Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. Viewed 23 February 2015.
[16] Jacobs. *Updated Projections of Gas and Electricity Used in LNG.* Available at: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report/NGFR-Supplementary-Information.
[17] Unlike AEMO's electricity modelling, the gas model's VCR values are not determined by consultation with stakeholders, because the VCR is not used to provide a valuation of augmentation proposals. Instead, the gas model VCR values are merely large numbers that ensure demand is supplied to the capacity of the system before a potential shortfall is reported, and ordered to allow prioritisation of some classes of demand over others.
[18] AEMO. *2014 National Gas Forecasting Methodology Information Paper*. 19 December 2014. Available: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report/~/media/Files/Gas/Planning/Reports/NGFR/2014/2014%20National%20Gas%20Forecasting%20Information%20Paper%20FINAL.ashx. Viewed 24 February 2015.
[19] Jacobs. *Updated Projections of Gas and Electricity Used in LNG*. 27th August 2014. Available: http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report/~/media/Files/Gas/Planning/Reports/NGFR/2014/Jacobs%20updated%20LNG%20forecast.ashx. Viewed 25 February 2015.

4.7.2 Daily demand profile development

AEMO developed a daily demand profile for each industrial, residential and commercial demand area, each gas-powered generator, and each LNG export project. The development process is different in each case.

For industrial, residential and commercial demand areas, AEMO developed a daily reference profile using historical data from either the Gas Bulletin Board[20], Victorian Declared Transmission System data (for Victorian demand only), or pipeline operator-provided flow data where available. The reference data is based on flows observed in 2011, selected as a typical year from analysis of historical flows over the range of available data.

AEMO combined the daily reference profile with energy and peak demand forecasts for the 20-year outlook period, producing 20 years of daily demand for each industrial, residential and commercial demand area, where the maximum demand in each year matches forecast maximum demands, and the sum of the daily demand over the year matches the annual energy forecast. Each demand area is assigned to a specific location (node) in the gas model.

For GPG, NTNDP simulations produce hourly generation data for the 20-year outlook period. This data is combined with estimates of the heat rates of GPG to develop gas consumption values for each generator in each hour of the outlook period. Hourly demand profiles are aggregated to daily demand before being applied to the model. Each generator's demand is assigned to a specific location (node) in the gas model.

The NTNDP projects the expansion of generation to meet growing electricity demand. New GPG is forecast to be installed by the NTNDP model in locations that minimise the total cost to the electricity generation and transmission network. A key NTNDP modelling assumption is that gas transmission infrastructure is less expensive compared to electricity infrastructure. Consequently, new GPG is located close to electricity demand, and gas transmission for supply is assumed to occur where this is required.

AEMO based the daily LNG demand on the monthly or six monthly data, as available. A step growth in demand between periods was assumed such that the sum of daily demand in each period matched the forecasts as developed by Jacobs.

Demand at the QCLNG export facility was assumed to begin in mid-2014. Demand at GLNG and APLNG was assumed to begin in 2015.

[20] See Glossary for information about the Gas Bulletin Board.

LINKS TO SUPPORTING INFORMATION

Table 4 provides links to additional information provided either as part of the 2015 GSOO accompanying information suite, or other related AEMO planning information.

Table 4 Links to supporting information

Supporting Information	Website address
2015 GSOO	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
2015 GSOO – Attachment A Detailed Supply Adequacy Results	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
2015 GSOO – Attachment B Victorian Gas Planning Review	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
Gas Demand Forecasts for the 2015 GSOO	http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report
Gas facility information	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2015-Supporting-Information
Gas production costs and transmission costs	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2015-Supporting-Information
Gas Reserves Update	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2015-Supporting-Information
LNG export demand projections	http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report/NGFR-Supplementary-Information
Maps and diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Planning Assumptions	http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions
Supply–demand analysis data files	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2015-GSOO-Supply-Demand-Modelling-Data-Files

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
PJ	Petajoule
TJ	Terajoule

Abbreviations

These terms are used in the 2015 GSOO, Attachment A, Attachment B and/or the GSOO Methodology document.

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
CGP	Carpentaria Gas Pipeline
EGP	Eastern Gas Pipeline
GDP	gross domestic product
GLNG	Gladstone LNG
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
LMP	Longford to Melbourne Pipeline
LNG	Liquefied Natural Gas
MAPS	Moomba to Adelaide Pipeline
MSP	Moomba to Sydney Pipeline
NQGP	North Queensland Gas Pipeline
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
QLD	Queensland
RBA	Reserve Bank of Australia
RBP	Roma to Brisbane Pipeline
SEA Gas	South East Australia Gas Pipeline
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
WTS	Western Transmission System

GLOSSARY

These terms are used in the 2015 GSOO, Attachment A, Attachment B, and/or the GSOO Methodology document.

Term	Definition
1-in-2 peak day	The 1-in-2 peak 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 peak day	The 1-in-20 peak 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.
1C contingent resources	Low estimate of contingent resources.
2C contingent resources	Best estimate of contingent resources.
3C contingent resources	High estimate of contingent resources.
1P reserves	A low-side estimate of quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as proved gas reserves.
2P reserves	The sum of proved-plus-probable estimates of gas reserves. The best estimate of commercially recoverable reserves. Often used as the basis for reports to share markets, gas contracts, and project economic justification.
3P reserves	The sum of proved, probable, and possible estimates of gas reserves.
Gas Bulletin Board (GBB)	A website **(**www.gbb.aemo.com.au**)** managed by AEMO that provides information on major interconnected gas processing facilities, gas transmission pipelines, gas storage facilities, and demand centres in eastern and south-eastern Australia. Also known as the National Gas Market Bulletin Board or simply the Bulletin Board.
gas powered generation (GPG)	Where electricity is generated from gas turbines (combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT)).
lateral	A pipeline branch.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network each day, and as a buffer for within-day balancing.
liquefied natural gas (LNG)	Disconnection of electricity customer load. Natural gas that has been converted into liquid form for ease of storage or transport.
LNG train	A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant.
peak day	Over the course of a season (winter or summer), the day when maximum gas demand occurs.
peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
possible reserves	Estimated quantities that have a chance of being discovered under favourable circumstances. ‘Possible, proved, and probable’ reserves added together make up 3P reserves.
probability of exceedance (POE)	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% probability of exceedance (POE) maximum demand will, on average, be exceeded only 1 year in every 10.
probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved-plus-probable reserves added together make up 2P reserves.
production	In the context of defining gas reserves, gas that has already been recovered and produced.
prospective resources	Gas volumes estimated to be recoverable from a prospective reservoir that has not yet been drilled. These estimates are therefore based on less direct evidence.
proved resources	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.
proved-plus-probable	See 2P reserves.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas.
reserves	Gas resources that are considered to be commercially recoverable and have been approved or justified for commercial development.
resources	See contingent resources and prospective resources.

Term	Definition
shale gas	Gas found in shale layers that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
unconventional gas	Gas found in coal seams, shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques.
within-day balancing	The balancing of supply and demand during the gas day by use of scheduled injections and depletion of system linepack. Liquefied natural gas (LNG) is used as an additional supply if linepack is predicted to fall below the minimum level required for system security.