2012

GAS STATEMENT OF OPPORTUNITIES

For Eastern and South Eastern Australia

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EXECUTIVE SUMMARY

Gas is an international commodity and Eastern and South Eastern Australia's domestic gas market is being impacted by the emerging liquefied natural gas (LNG) export market.

Unlike electricity, which only services the domestic market, the Gas Statement of Opportunities (GSOO) considers international market impacts in its gas adequacy assessment.

Eastern and South Eastern Australia have sufficient gas resources to meet demand over the 20-year outlook period to 2032, based on industry developing 2P[1] reserves in a timely way to meet growing demand from both the domestic and LNG export markets.

Table 1 lists the location and expected timing of potential shortfalls under a range of demand[2], economic conditions and policy inputs captured by two scenarios.[3] These potential shortfalls present potential opportunities for investment in production, pipeline, processing or storage facilities to increase capacity to meet forecast demand. For more information about potential opportunities see Figure 4.

Table 1— Timing of potential shortfalls

Location	Planning scenario		Slow Rate of Change scenario	
	1-in-20	1-in-2	1-in-20	1-in-2
Gladstone	2013	2013	2013	2013
Brisbane	2018	2020	>2022	>2022
Townsville	2021	2021	>2022	>2022

Forecast domestic gas demand for a number of proposed large industrial projects[4] currently exceeds the capacity of the pipelines to supply gas in Gladstone, Queensland from 2013. Competition for gas supply may impact the timing or scope of these proposed projects.

Demand

Figure 1 shows the gas demand projections for the Planning scenario (medium growth). This shows that combined Mass Market (residential and small commercial) and Large Industrial demand will be relatively static with the exception of the Queensland area, where the rapid growth in the Large Industrial market segment of the past four years is expected to continue, although at a slower rate.

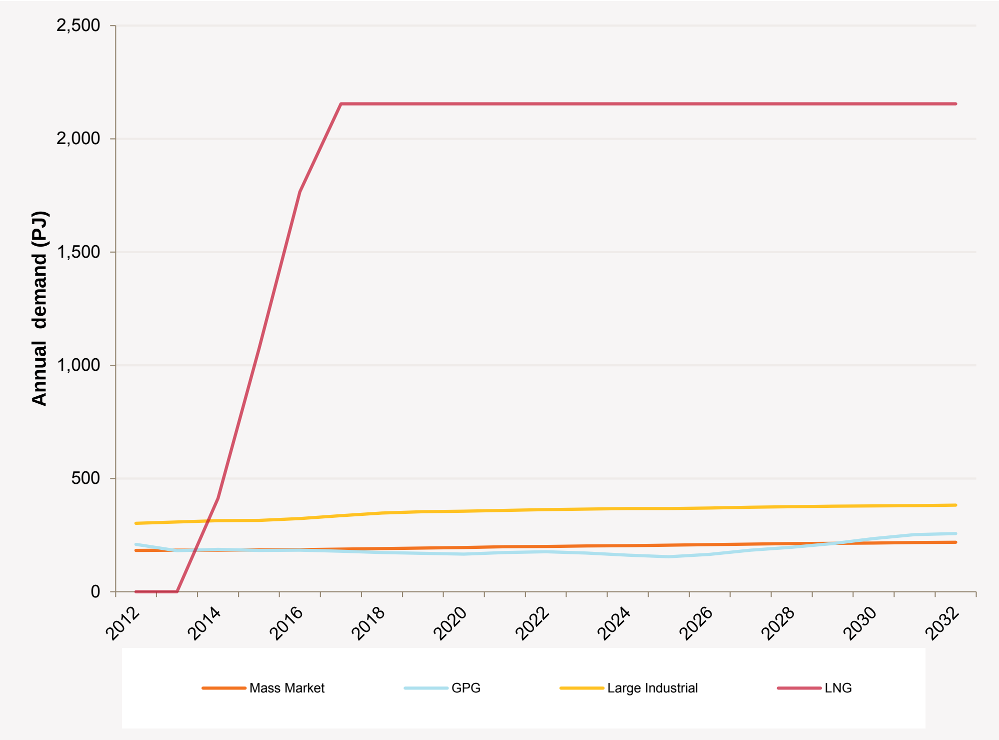
Growing potential for Queensland LNG exports is expected to result in LNG production trains being built in Eastern and South Eastern Australia to support the Asia-Pacific market, which currently accounts for nearly 60% of world LNG demand. There is a projected increase in LNG exports from Australia, requiring gas reserves of between

1 Proved-plus-probable reserves, the best estimate of commercially recoverable resources.
2 A 1-in-2 peak demand condition is expected, on average, to be exceeded once in two years, and a 1-in-20 peak demand condition is expected, on average, to be exceeded only once in 20 years.
3 The Planning scenario assumes medium economic growth, a carbon reduction target, LNG production, and stable international coal prices. The Slow Rate of Change scenario assumes low economic growth and LNG production, no carbon price (after the first three-year fixed-price period), and falling coal prices.
4 Prospective projects driving demand growth included in the Gladstone area in preparation of the 2012 GSOO gas demand projections include Rio Tinto's Yarwun refinery expansion, Queensland Magnesium reinstatement of cement operations at Rockhampton, QAL's feasibility investigation of a co-generation plant at its Yarwun site, and Orica's planned expansion of its ammonium nitrate facility at Yarwun. For more information on projects and demand growth drivers, see Appendix A.

43,000 PJ and 53,000 PJ. This growth is not expected to continue after 2021 due to competition from LNG developments in the United States, Qatar, Western Australia and the Northern Territory.

Under the Planning scenario, no new combined cycle gas turbine installations are required for at least a decade. Open cycle gas turbine investment in the longer term has led to an increase in gas powered generation (GPG) demand from 2025.

Figure 1 — Projected Eastern and South Eastern Australia annual gas demand (Planning scenario)



Gas demand for GPG is projected to decrease under the Slow Rate of Change scenario between 2014 and 2021. This is based on the assumed removal of the carbon price modelled under this scenario and the expected uptake of renewable energy generation out to 2020 under the Large Scale Renewable Energy Target. The projected GPG demand is lower overall, consistent with the lower electricity projections published in the 2012 National Electricity Forecasting Report.[5]

Reserves projections

Current estimated recoverable resources are sufficient to satisfy both the domestic and LNG markets over the 20-year outlook period. However, the gas market is entering a transition period. Gas fields currently in production are reaching end of economic life, existing domestic long-term gas supply contracts are approaching expiration, and LNG exports are expected to commence in 2014.

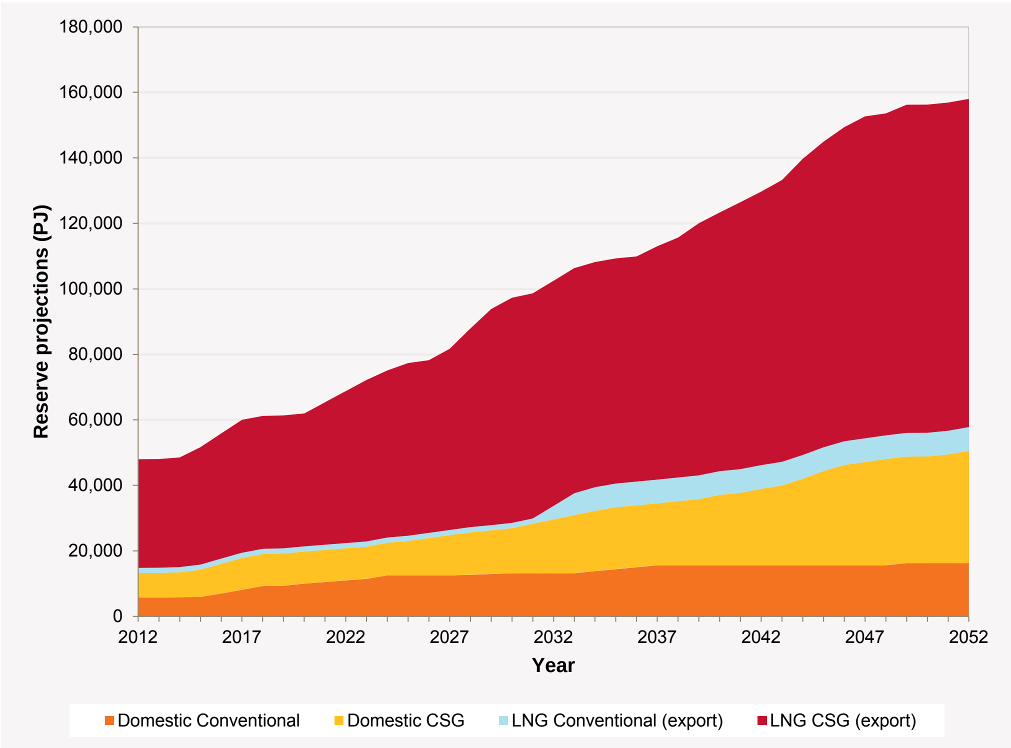
As conventional resources are depleted or committed to LNG exports, Coal Seam Gas (CSG) and other shale or tight gas reserves will be developed and used by the domestic market. The relatively small volume of uncommitted

[5] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Viewed 6 December 2012.

2P reserves, combined with a large proportion of resources committed or earmarked for LNG projects, may create challenges for domestic supply, prompting a market response when companies look to recontract in the short term.

Figure 2 contrasts the volume of domestic reserves against LNG reserves, and the domination of CSG in the projected LNG reserves to 2052 under the Planning scenario.

Figure 2 — Domestic and LNG 2P reserves projections (Planning scenario)



LNG market impacts

A secondary LNG export market is emerging, which is primarily driven by international gas prices rather than domestic production and transmission costs. The LNG export market is having a significant impact on the domestic market. As a result, AEMO looked at reduced reserve development[6] and the prioritisation of gas to supply the LNG export market.

If 2P reserves are not developed in a timely way, potential supply shortfalls to the LNG export and domestic markets may be seen towards the end of the period of increasing LNG demand in 2016.

[6] 2P reserve development of Surat-Bowen Basins' LNG earmarked reserves were reduced in the model for this study.

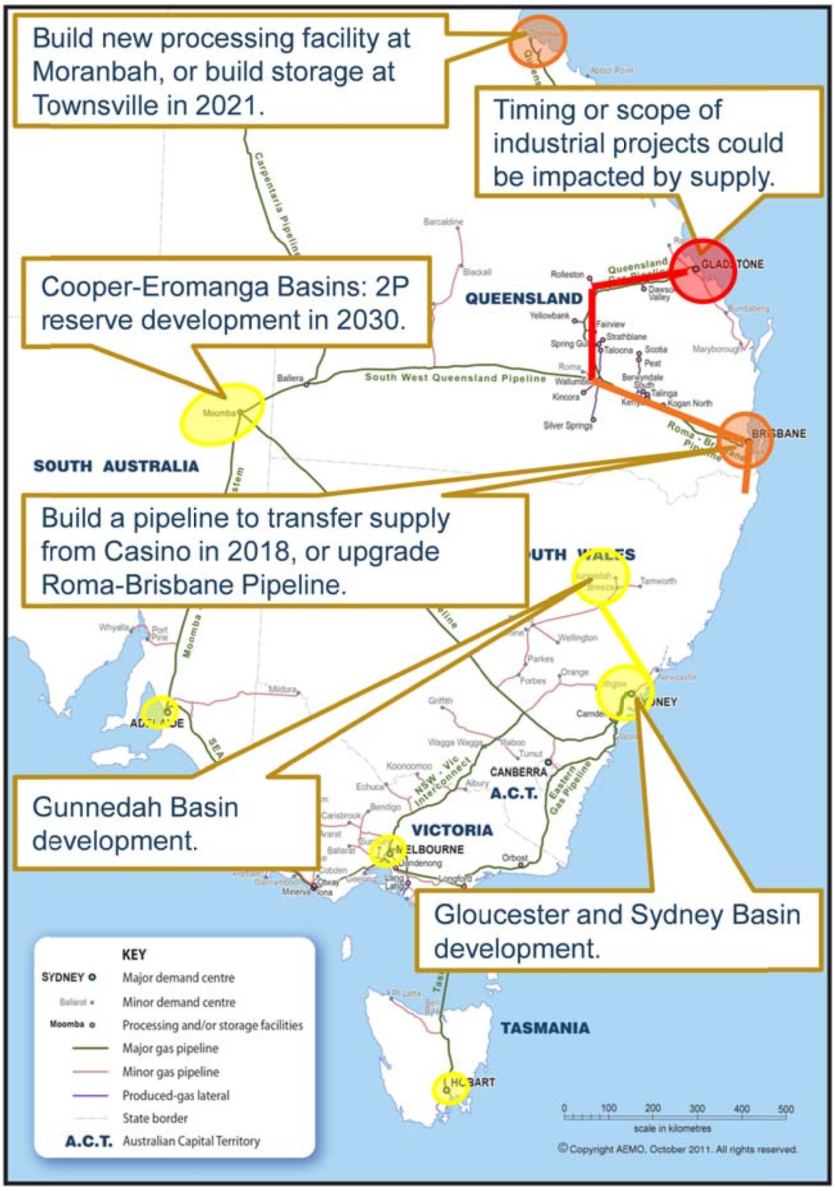
Challenges and opportunities

Projected gas demand currently exceeds the capacity of the pipelines to supply gas in several demand centres in Queensland over the outlook period, involving Gladstone in 2013, Brisbane in 2020, and Townsville in 2021.

In the medium to long term, depletion of gas in the Cooper-Eromanga Basins may lead to opportunities to further develop 2P reserves in these basins to avoid insufficient contracted supplies to New South Wales.

Figure 3 summarises potential opportunities for augmenting processing and pipeline capacity to ensure that gas can be delivered to both domestic and export markets across Eastern and South Eastern Australia. The colour-scale from red to yellow corresponds to shorter to longer term timing.

Figure 3 — Potential opportunities to ensure system adequacy[7]



[7] Results shown derive from the Planning scenario, 1-in-20 peak weather conditions.

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CHAPTER 1 - INTRODUCTION

1.1 Introduction

The Gas Statement of Opportunities (GSOO) provides information about the current state of the gas industry in Eastern and South Eastern Australia. The GSOO presents gas reserve adequacy over a 20-year outlook period, and gas supply and transmission adequacy over a 10-year outlook period. In particular, the GSOO assesses the adequacy of gas reserves, processing, storage, and transmission facilities to meet projected demand.

The GSOO compares projected long-term gas availability, annual gas demand projections, peak day demand projections, and gas processing and transmission capability. These comparisons are made under different scenarios that present a range of possibilities and viewpoints for projecting gas infrastructure constraints and investment opportunities.

Information the GSOO provides to the Australian energy industry aims to facilitate a competitive market and efficient investment, operations, and use of energy. Geographically, the GSOO includes information for Australian states and territories including New South Wales, the Australian Capital Territory, Queensland, South Australia, Tasmania, and Victoria, but not the Northern Territory or Western Australia.

The GSOO is published in accordance with Section 91DA of the National Gas Law. For more information about the gas industry regulatory structure and legal framework see the 2011 GSOO.[1]

1.2 Changes to the GSOO since 2011

The Australian Energy Market Operator (AEMO) is changing the way it presents energy market publications to provide stakeholders with more timely and focussed information. AEMO is electronically publishing a series of smaller reports that focus on specific issues, and are supported by supplementary reports and data files.

To facilitate the new approach, AEMO separately published supporting reports and data as the information became available. Information already published on the AEMO website to support the 2012 GSOO includes the following:

- Current gas reserves (to December 2011) and gas reserve projection reports.
- A report on liquefied natural gas (LNG) projections.
- A report on gas processing, transmission, and storage facilities.
- Production and transmission cost reports.
- Links to information sources providing an overview of the gas market.
- The (Victorian) Gas Declared Transmission System, Medium-Term Outlook.[2]

For a full list of this supplementary information see Section 1.7.

These changes have resulted in an abridged GSOO that aims to be more concise and focussed on key information, and the implications for industry.

[1] AEMO. Available http://www.aemo.com.au/en/Gas/Planning/2011-Gas-Statement-of-Opportunities/Main-Report#chapter1. Viewed 14 August 2012.

[2] The Victorian Gas DTS Medium Term Outlook, published as Attachment 1 to the 2011 GSOO, is a 2012 stand-alone report. Available: http://www.aemo.com.au/Gas/Planning/Victorian-Annual-Planning-Report/Victorian-Gas-DTS-Medium-Term-Outlook. Viewed 3 December 2012.

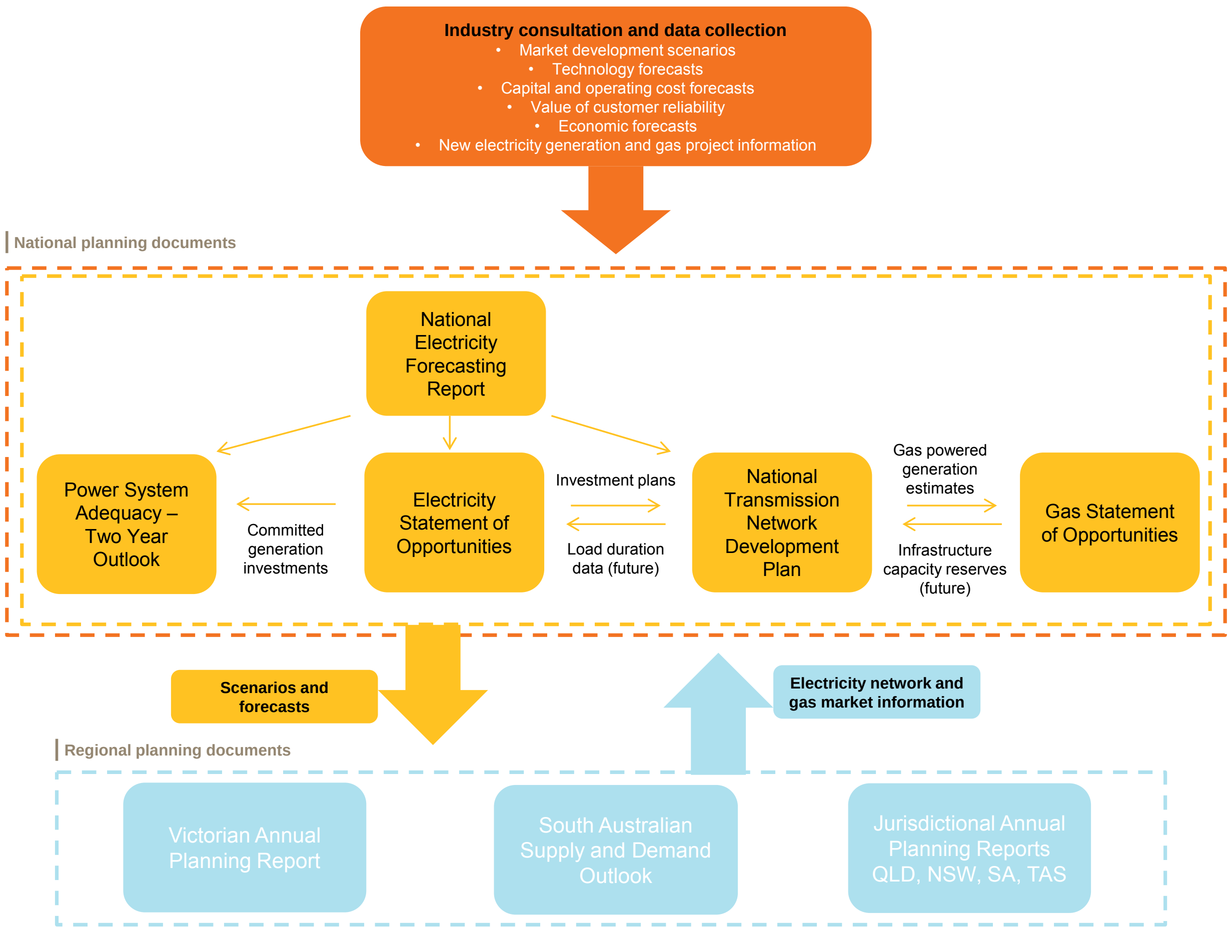
1.3 The GSOO within the energy planning context

AEMO publishes the GSOO to provide independent, up-to-date gas market information and analysis. Through its suite of national planning documents, AEMO also delivers strategic gas and electricity transmission planning advice to guide long-term investment in network infrastructure and resource management. This includes the National Transmission Network Development Plan (NTNDP), which considers how the National Electricity Market (NEM) transmission network may develop in the long term, and the Electricity Statement of Opportunities (ESOO), which analyses electricity supply and demand over a 10-year outlook period, highlighting opportunities for new generation and demand-side investments based on projected supply shortfalls.

AEMO also publishes a range of reports as part of its South Australian Advisory Functions, which address the current state and future development of South Australian electricity supplies, and complement the South Australian jurisdictional planning body's annual planning report.

Figure 1-1 shows the context of the GSOO within the AEMO energy planning reports.

Figure 1-1 — Energy planning reports and the GSOO



1.4 GSOO scope and data sources

1.4.1 Gas supply chain inclusions and exclusions

The GSOO supply-demand adequacy modelling aims to provide an assessment of what existing and committed assets can potentially achieve to ensure supply adequacy, focussing on the following aspects of the gas supply chain:

- Reserves assessment.
- Field development.
- Processing facilities and capacity.
- Transmission pipelines and capacity.
- Storage facilities and capacity.
- Customer demand.

As a result, the assessment of adequacy is based on the physical capability of existing and committed gas assets similar to the Electricity Statement of Opportunities. Differences between the least-cost modelled physical system and market conditions observed allow an assessment of market efficiency, or investigation of other factors influencing system adequacy. Subsequently, commercial positions are out of scope of the GSOO, which does not include the following:

- Detailed information about gas wells and gas collection activities.
- Discussion of gas reserves ownership.
- Gas facility operational arrangements.
- Contractual arrangements for access to pipelines and other facilities.
- Distribution facilities.
- Retailing.

The development of the LNG export industry will drive gas infrastructure development in Queensland and New South Wales. AEMO understands that this will involve dedicated transmission pipelines, resulting in assumptions that the industry is largely independent of the domestic gas transmission network, but some cases have been modelled allowing LNG export facilities to supplement domestic demand via spare capacity.

1.4.2 GSOO information sources

The 2012 GSOO draws on data from the following sources:

- Regional gas demand projections produced by AEMO from a range of inputs:
  - Information provided by gas distribution businesses and pipeline operators about historical demand and pipeline flows.[3]
  - Annual and peak day residential, commercial, and smaller industrial demand projections (referred to in the 2012 GSOO as the Mass Market) provided by the National Institute of Economic and Industry Research (NIEIR) consultants.[4]
  - Annual and peak day gas demand projections for large industrial users, including large cogeneration projects, derived from a NIEIR survey of major industrial and commercial gas users.[5]
  - Projections of gas demand for gas powered generation (GPG) that are an output of AEMO's NTNDP modelling.[6]

[3] For more information about demand projection inputs and methodology see Appendix A, Section A.5.

[4] See note 3.

[5] See note 3.

  - Projections of gas demand for LNG export provided by Core Energy Group (consultants).[7]
- Gas reserves development projections based on data provided by Core Energy Group.[8]
- AEMO Gas Bulletin Board data.[9]
- Information about future processing and transmission developments sourced from Core Energy Group and either provided or verified by gas industry participants.[10]
- Publicly available information relating to changes in gas usage.
- Other data collected by AEMO in the course of conducting its various gas and electricity roles.

1.5 Planning scenarios and key economic parameters

The 2012 GSOO projections and modelling results presented in Chapters 3, 4, and 5 are based upon two scenarios involving planning assumptions developed in consultation with industry stakeholders, each representing a possible path of future development.

Two scenarios were selected from the six scenarios AEMO developed for 2012, following stakeholder feedback that the NTNDP should address fewer scenarios than in 2010. This is also needed to achieve consistency with the NTNDP as the GPG demand for the GSOO is drawn from NTNDP analysis.

The Planning scenario is a central growth scenario, and includes currently legislated carbon policies based on the Australian Treasury's core policy scenario[11], as well as currently estimated rates of new technology development.

The Slow Rate of Change scenario reflects a lower rate of economic growth, which enables Australia to meet its international emissions targets with minimal effort. As a result, under this scenario the Australian carbon price effectively drops to zero after the three-year fixed-price period.

Both scenarios offer the highest value to stakeholders, with the Planning scenario being selected because stakeholders also requested a central scenario, and the Slow Rate of Change scenario being selected to test the impact of a carbon price that effectively drops to zero.

Table 1-1 summarises the two scenarios used in the 2012 GSOO and related reports.

Table 1-1 — 2012 GSOO scenarios and key parameters

Parameter	Scenario	
	Slow Rate of Change	Planning
Economic growth	Low.	Medium.
Carbon reduction target	Zero (no carbon price, after an initial three-year fixed-price period).	Medium (5% reduction on Treasury's core policy scenarios).
International coal prices	Falling.	Stable.
East coast gas prices[a]	4.70 $/GJ to 13.67 $/GJ.	4.71 $/GJ to 12.38 $/GJ.

6 For more information about the NTNDP modelling see Appendix A, Section A.5.2, or the NTNDP. AEMO. Available: http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan. Viewed 6 December 2012.

7 AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Liquid-Natural-Gas-Projections. Viewed 24 October 2012.

8 AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Reserves-Projections. Viewed 24 October 2012.

9 AEMO. Available: http://www.gasbb.com.au/. Viewed 24 October 2012.

10 AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Processing-Transmission-and-Storage-Facilities. Viewed 24 October 2012.

11 The Treasury and the Department of Climate Change and Energy Efficiency modelled the potential economic impacts of reducing emissions over the medium and long term, proposed in the 'Strong Growth, Low Pollution, Modelling a Carbon Price' report, released on 10 July 2011. Australian Government. The Treasury, Available http://archive.treasury.gov.au/carbonpricemodelling/content/default.asp. Viewed 28 June 2012.

Parameter	Scenario	
	Slow Rate of Change	Planning
East Coast LNG production	Low.	Medium.
Research and development	Moderate.	Weak.
Distributed generation penetration	Weak.	Strong.

a. For more information see the section about gas price assumptions.

In addition to these scenarios, a further study has been modelled to investigate reduced reserve development and the prioritisation of LNG export demand. For more information see Chapter 5, Section 5.1.1.

Gas price assumptions

The modelling conducted for the 2012 GSOO does not use gas price assumptions directly, but considers gas production and transmission costs to determine least-cost solutions.[12] For more detailed information about this modelling see Chapter 5, Section 5.3.

The gas prices summarised in Table 1-1 formed inputs into the scenario-based demand projections involving the Mass Market, Large Industrial and LNG market segments.

The NTNDP uses representative gas prices in the market modelling that provides the GPG demand. For more information about representative Eastern and South Eastern Australian gas prices for 2012 to 2032 see the Fuel Cost Projections report.[13]

Gas costs are also considered in the development of the reserves projections (and are inputs into the supply-demand modelling), where gas costs, equity gas, and current contracts are used to determine the production profile. For more information about the consideration of gas costs in the development of reserves projections see the AEMO website.[14]

For more detailed information about the 2012 scenarios and planning assumptions see the AEMO website.[15]

1.6 Content and structure of the 2012 GSOO

Chapter 2, Processing, transmission, and storage facilities, provides summary information about current and key developments for future processing, transmission, and storage facilities in Eastern and South Eastern Australia.

Chapter 3, Gas demand and data projections, provides a summary of gas demand projections for Eastern and South Eastern Australia.

Chapter 4, Reserve adequacy and field development opportunities, provides information about gas reserves projections and the adequacy of gas reserves in Eastern and South Eastern Australia.

Chapter 5, Gas infrastructure adequacy and opportunities, provides an overview of the projected constraints and opportunities resulting from the supply-demand analysis under a range of modelled scenarios.

12 AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Gas_Production_Costs_Report_Updated.ashx and http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Gas_Transmission_Costs_Report.ashx. Viewed 26 September 2012.

13 AEMO. Available http://www.aemo.com.au/en/Electricity/Planning/Related-Information/~/media/Files/Other/planning/ACIL_Tasman_Fuel_Cost_%20Projections_2012.ashx. Viewed 14 August 2012.

14 See note 8.

15 AEMO. Available http://www.aemo.com.au/en/Electricity/Planning/Related-Information/2012-Planning-Assumptions. Viewed 26 September 2012.

Appendix A, Gas demand projections for Eastern and South Eastern Australia, provides the detailed gas demand forecasts that form the basis for Chapter 3.

Appendix B, GSOO component guide, provides information about where other, separately published information relating to the GSOO can be located, as well as a list of AEMO's statutory functions.

Measures and abbreviations provides the units of measure and abbreviations used throughout the GSOO.

Glossary and list of company names provides a glossary of terms and a list of the companies referred to throughout the GSOO.

1.7 Supporting information

Information source	Website address
Eastern and Southern Australia: Projected Gas Reserves	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserves-Projections
Eastern and Southern Australia: Projections of Gas Demand for LNG Export	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/LNG-Projections
Eastern and Southern Australia: Existing Gas Reserves and Resources	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserve-Update
Economic Outlook	www.aemo.com.au/Electricity/Forecasting
Gas Bulletin Board	www.gasbb.com.au
Gas Bulletin Board analysis (updating historical data provided in the 2011 GSOO)	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
Gas DTS Medium Term Outlook	http://www.aemo.com.au/Gas/Planning/Victorian-Annual-Planning-Report/Victorian-Gas-DTS-Medium-Term-Outlook
Gas Production Costs	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Production-Costs
Gas Transmission Costs	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Transmission-Costs
Maps and Network Diagrams	www.aemo.com.au/en/Gas/Planning/Maps-and-Diagrams
National Transmission Network Development Plan	http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan
Previous years' GSOO reports	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Previous-years-GSOO-reports
Review of Gas Facilities: Existing and New	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Processing-Transmission-and-Storage-Facilities
Useful GSOO links (providing market overview information)	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Useful-GSOO-Links
2012 Scenario Descriptions	http://www.aemo.com.au/~/media/Files/Other/planning/2418-0005%20pdf.ashx
2011–12 NEM Demand Review Information Paper	www.aemo.com.au/Electricity/Forecasting

CHAPTER 2 - PROCESSING, TRANSMISSION AND STORAGE FACILITIES

Summary

This chapter presents information about gas facilities in Eastern and South Eastern Australia.

Liquefied natural gas (LNG) features prominently in the current development of gas facilities, with approximately half of the proposed processing facilities catering for LNG export. Committed processing facilities[1] (Australia Pacific LNG (APLNG) gas plants[2]) will total up to 1,800 TJ/d compared to existing processing facilities of 3,778 TJ/d.

Committed gas field developments primarily for the LNG export market are expected to supply over 3,500 TJ/d, compared to an expected supply of 300 TJ/d of committed developments primarily servicing the domestic market.

Committed transmission facilities total up to approximately 4,700 TJ/d, all of which will service the LNG export market. Existing gas transmission capacities supply over 3,500 TJ/d to the domestic market.

Committed storage facilities have a capacity of 1.5 PJ compared to the existing storage facilities, which currently exceed 150 PJ.

2.1 Gas field developments and processing, transmission, and storage facilities

This section provides information about gas field developments and processing, transmission, and storage facilities.

Facilities have been classified as either existing, committed, or proposed based on the following guidelines:

- An existing facility or development is commissioned and operating.
- A committed project is considered to be proceeding.
- A proposed project can be either an advanced proposal, representing projects at an intermediate stage of development, or a publically announced proposal, representing projects at an early stage of development.

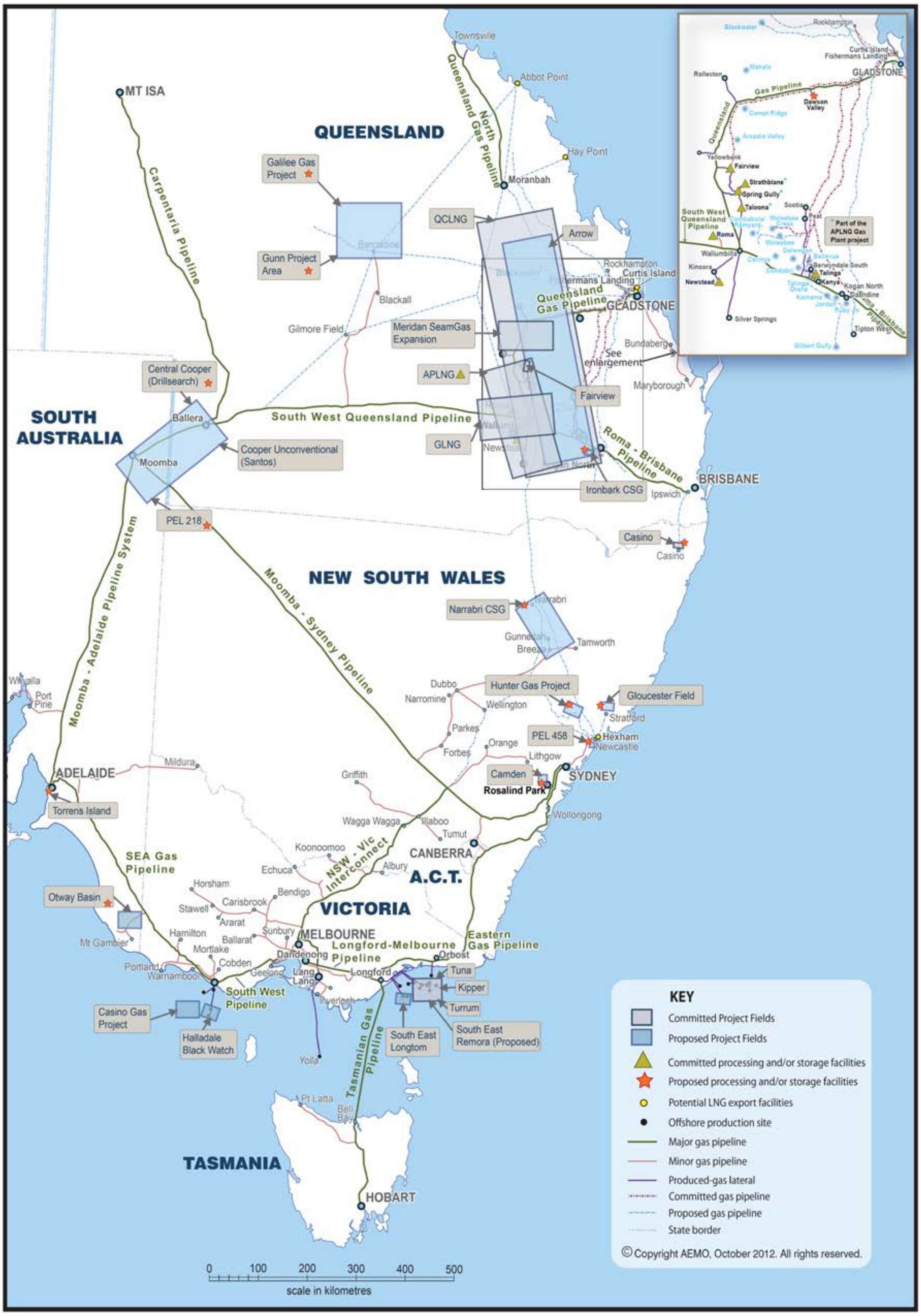
AEMO published a review of Eastern and Southern Australian gas facilities in June 2012 as an input into the 2012 GSOO, and engaged Core Energy Group to provide information (as at 31 March 2012) about major existing, committed, and proposed network-connected gas transmission pipelines, processing and storage facilities, and field developments.[3]

Developments are often able to supply either the LNG or domestic markets, but are usually expected to supply primarily to one or the other and have been grouped accordingly. The majority of the developments currently emerging are linked to the LNG export market.

Figure 2-1 shows committed and proposed facilities (including field developments) and their relationship to existing pipelines.[4] For more information about each committed and proposed project (and whether a development is likely to supply LNG export markets or domestic markets or both) see the AEMO website.[5]

[1] These do not include LNG trains.
[2] This project plans to develop up to 23 processing facilities, some of which already exist, and are included in the existing facilities' processing capacity.
[3] AEMO. Available http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Processing-Transmission-and-Storage-Facilities. Viewed 4 September 2012.
[4] No location map is available for the proposed Origin Energy Otway Basin Storage project to be built in South Australia.
[5] See note 3.

Figure 2-1 — Committed and proposed facilities in Eastern and South Eastern Australia



2.1.1 Gas field developments

The Eastern Australian gas market is entering a transition period, with fields that are currently in production being depleted, current long-term domestic gas supply contracts concluding, and demand growing in Queensland.

Gas field developments primarily catering for the LNG export market include the following:

- Australia Pacific LNG (APLNG) development of the Surat-Bowen basins.
- Gladstone LNG (GLNG) development of the Surat-Bowen basins.
- Queensland Curtis LNG (QCLNG)[6] development of the Surat-Bowen basins.
- Fairview Gas Plant development of the Bowen basin for the APLNG and GLNG export markets.

These projects are expected to supply over 3,500 TJ/d.

Committed gas field developments that will primarily cater for the domestic market include the following:

- Casino development of the Clarence Moreton basin.
- Kipper development of the Gippsland basin.
- Meridian Seam Gas development of the Bowen basin.
- Tuna development of the Gippsland basin.
- Turrum development of the Gippsland basin.

These projects are expected to supply at least an additional 300 TJ/d.

2.1.2 Processing facilities

APLNG Gas Plants (expected to process up to 1,800 TJ/d over the life of the project) is the only committed processing facility taking gas from the Walloons gas field in the Surat Basin for delivery to the APLNG export plant. APLNG Gas Plants comprises a number of existing processing facilities including Spring Gully, Strathblane, Talinga, and Taloona. Existing processing capacity totals 3,778 TJ/d. This is a slight change from information reported in the 2011 GSOO due to differences in the processing capacities of the Ballera, Fairview, Moomba, Daandine, Rosalind Park, Berwyndale South and Moranbah facilities.

The Metgasco Limited Casino (New South Wales) project is the only committed processing facility to cater to the domestic market, with a capacity of at least 6.3 TJ/d, supplying the Richmond Valley Power Station and Richmond Dairies.

2.1.3 Transmission facilities

Committed transmission facilities (primarily supplying the LNG export market) include APLNG, GLNG and QCLNG, providing up to approximately 4,700 TJ/d. Existing gas transmission facilities supply over 3,500 TJ/d to the domestic market.

2.1.4 Storage facilities

Total existing storage facility capacity exceeds 150 PJ, with Moomba Underground Gas Storage representing more than half. The committed[7] AGL Energy Newcastle LNG project, expected to begin operations in 2015, will have a storage capacity of 1.5 PJ.

[6] QCLNG is a priority project for the Queensland Gas Company (QGC).

[7] This project has received approval since the publication of the Facilities report in June. See http://www.agl.com.au/about/ASXandMedia/Pages/NewcastleGasStorageFacilityprojectreceivesapproval.aspx. Viewed 11 October 2012.

2.2 Links to supporting information

This section provides links to other information about gas facilities, some of which may previously have been included in the GSOO and are already published on the AEMO website.

Information source	Website address
Additional information provided by Origin Energy after completion of the Core Energy Report	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Processing-Transmission-and-Storage-Facilities
Gas Bulletin Board	www.gasbb.com.au
Maps and network diagrams	www.aemo.com.au/en/Gas/Planning/Maps-and-Diagrams
Review of Gas Facilities: Existing and New	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Processing-Transmission-and-Storage-Facilities

CHAPTER 3 - GAS DEMAND AND DATA PROJECTIONS

Summary

This chapter provides demand projections for total annual demand, including the Mass Market, Large Industrial, gas powered generation (GPG), and liquefied natural gas (LNG) market segment demands.

Total demand

Total annual demand growth is driven by LNG export, which is expected to account for 70% of demand under the Planning scenario and more than 80% under the Slow Rate of Change scenario, the difference being due to two additional LNG trains under the Slow Rate of Change scenario.

Under the Planning scenario, total domestic demand grows slowly until 2025. Under the Slow Rate of Change scenario, domestic demand declines between 2014 and 2016 before increasing again to 2032. The decline from 2014 reflects a decrease in GPG demand as the scenario assumes carbon prices are effectively zero after the end of the fixed-price period, making GPG less competitive with other forms of generation.

Mass Market and Large Industrial market segment demand

The combined Mass Market and Large Industrial market segment demand growth has declined in recent years, with a projected average annual growth rate between 2013 and 2032 of approximately 1.1% under the Planning scenario and 0.8% under the Slow Rate of Change scenario. The variation is driven by the Large Industrial market segment, which is projected to grow by 1.1% a year under the Planning scenario and 0.7% a year under the Slow Rate of Change scenario.

Combined Mass Market and Large Industrial market segment gas demand is projected to grow at higher rates in Queensland (due to the Large Industrial market segment and mining projects), and Tasmania (due to an increase in the Large Industrial market segment demand).

GPG demand

Under the Planning scenario, no new closed cycle gas turbine installation is required during the outlook period. Open cycle gas turbine investment in the longer term, however, leads to an increase in GPG demand from 2025.

Gas demand for GPG decreases markedly under the Slow Rate of Change scenario between 2014 and 2021, due to a zero carbon price and the uptake of renewable energy generation to 2020 to meet the Large-scale Renewable Energy Target (LRET). Overall, forecast GPG demand is lower, which is consistent with the lower electricity demand forecasts (published in AEMO's National Electricity Forecasting Report).[1]

LNG demand

Under the scenarios considered, growing potential for Queensland LNG exports is likely to see at least eight LNG production trains being built in Eastern and South Eastern Australia to support the Asia-Pacific market, which currently accounts for nearly 60% of global LNG demand.

There will be growing demand for LNG export from Australia, requiring gas reserves of between 43,000 PJ and 53,000 PJ under the Planning and Slow Rate of Change scenarios, respectively. This growth is not likely to continue after 2021 due to competition from probable LNG development in other areas of the world.

[1] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Viewed 6 December 2012.

3.1 Total demand projections for all market segments

This section provides Eastern and South Eastern Australian total annual demand projections for the market segments.

Gas demand projections were developed for the following gas market segments:

- Liquefied natural gas (LNG) export.
- Gas powered generation (GPG).
- Mass Market (MM), which includes residential demand, and business demand (of less than 10 TJ/yr).
- Large Industrial (LI) consumers with gas demand greater than 10 TJ/yr.

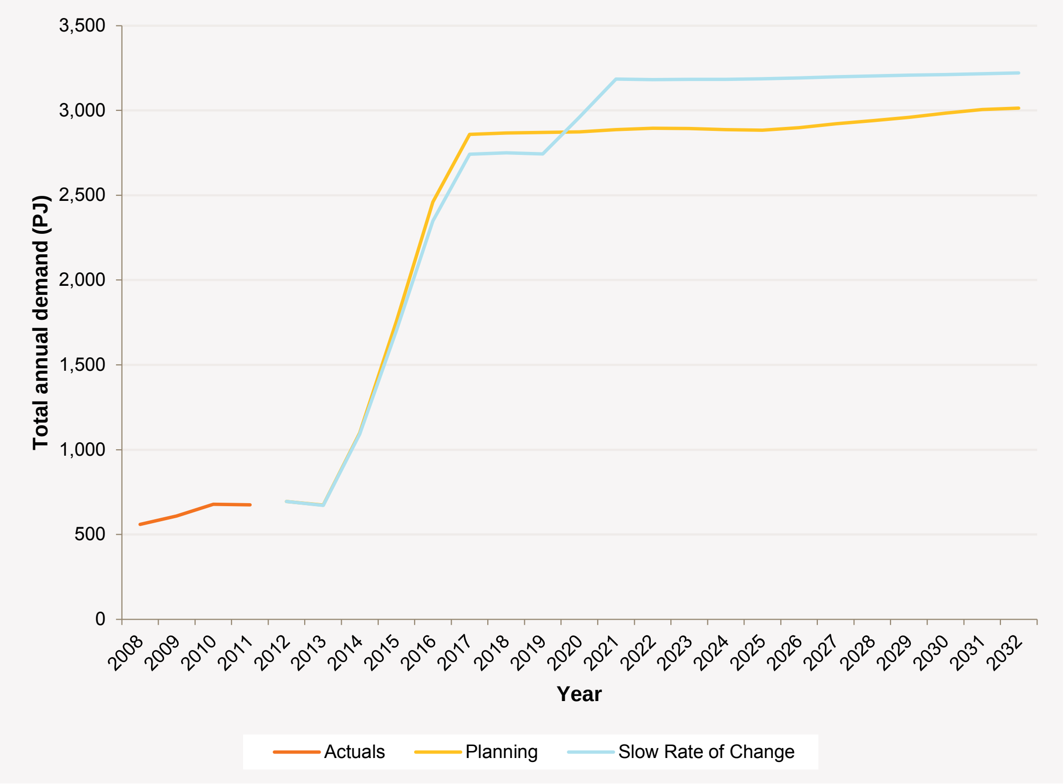
Total gas demand comprises all four market segments, referred to as the LNG, Large Industrial, Mass Market and GPG market segments. Domestic gas demand comprises the Large Industrial, Mass Market, and GPG market segments.[2]

For information about the demand projection methodology, including data sources and assumptions, see Appendix A, Section A.5.

3.1.1 Annual demand

Figure 3-1 shows the total annual demand projections for the Planning and Slow Rate of Change scenarios for all market segments.

Figure 3-1 — Annual combined market segment demand by scenario



[2] The LNG market segment demand projections assume that 15% of gas is lost after it is extracted from a field due to processing, transmission, and liquefaction losses, so this gas will be consumed domestically, but is included in the LNG market segment demand projections.

Demand growth under both scenarios is largely driven by LNG export, which is projected to exceed domestic demand by 2015. LNG export demand is expected to reach 2,150 PJ a year by 2017, accounting for more than 70% of demand under the Planning scenario and more than 80% under the Slow Rate of Change scenario.

Demand increases under both scenarios until 2017 as a result of the increase of LNG production in Queensland to eight LNG trains. Demand grows again under the Slow Rate of Change scenario from 2019–20 as additional LNG trains begin production.

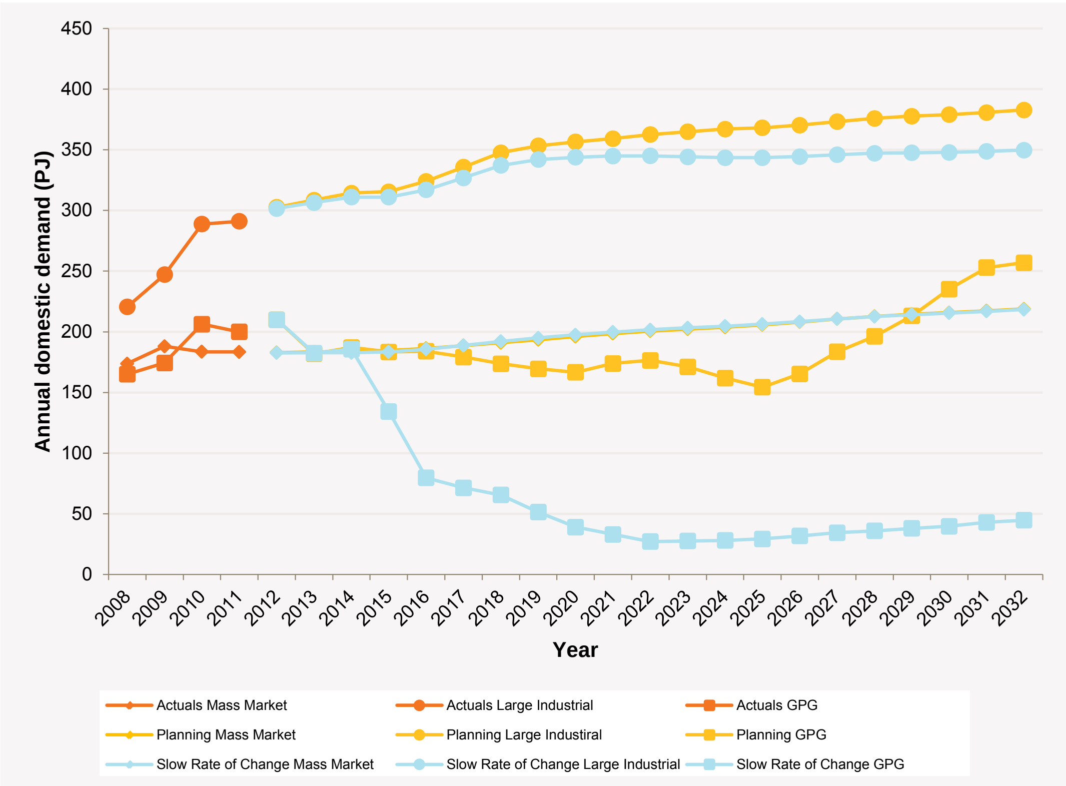
Two additional trains are assumed under the Slow Rate of Change scenario, driven by a number of factors including larger volumes of uncommitted domestic gas being available for export due to lower domestic gas demand, and reduced investment in renewable generation leading to higher LNG demand. For more information about the drivers of LNG growth under the Slow Rate of Change scenario, see Section 3.2.4. No additional trains are developed after 2021–22 due to competition from probable LNG development in other areas of the world.

Domestic gas demand is projected to increase at an average annual rate of 1.3% under the Planning scenario, primarily due to the Tariff V[3] growth driven by economic and population growth in all demand groups and Large Industrial market segment growth in Queensland. Domestic gas demand then decreases at a rate of 0.5% under the Slow Rate of Change scenario due to a general decline in GPG gas demand.

3.1.2 Annual domestic demand

Figure 3-2 shows the annual domestic demand projections for the Planning and Slow Rate of Change scenarios for the Mass Market, Large Industrial and GPG market segments.

Figure 3-2 — Annual domestic demand by market segment and scenario



[3] Tariff V demand is the gas transportation Tariff applying to non-Tariff D load sites (Tariff D loads are metered sites with an annual consumption in excess of 10,000 GJ). This includes residential and small to medium-sized commercial and industrial gas users.

The Large Industrial market segment continues to be the largest source of domestic demand, with some variation between the Planning and Slow Rate of Change scenarios.

The Mass Market market segment projections show no significant difference between the scenarios, as they are growing in line with economic and population growth.

GPG demand is expected to vary significantly between the scenarios for the outlook period, with a sustained decline driven by the zero carbon price assumption under the Slow Rate of Change scenario (for more information about GPG demand drivers see Section 3.2.3).

Under the Planning scenario, domestic demand grows at an average annual rate of approximately 0.6% until 2025 when it increases to approximately 2.4% until 2032. This reflects increased GPG demand from 2025 due to electricity demand growth.

Under the Slow Rate of Change scenario, domestic demand declines at an average annual rate of approximately 4.7% between 2014 and 2016, before growing annually at 0.3% until 2032. The decline from 2014 reflects a decrease in GPG demand as the scenario assumes carbon prices are effectively zero after the end of the fixed-price period, making GPG less competitive with other forms of generation.

Combined Mass Market and Large Industrial market segment gas demand is projected to increase from approximately 483 PJ in 2012 to between 570 PJ and 600 PJ in 2032, reflecting average annual growth rates of 1.1% under the Planning scenario and 0.8% under the Slow Rate of Change scenario.

Combined Mass Market and Large Industrial market segment gas demand is projected to grow at higher rates in Queensland and Tasmania than in New South Wales (including the Australian Capital Territory), Victoria and New South Australia for the following reasons:

- Queensland growth is driven by increasing demand from the Large Industrial market segment and mining projects in Queensland, including the installation of co-generation plants.
- Tasmanian growth is driven by increases in industrial gas demand and increasing household gas connections.
- In New South Wales, Victoria, and South Australia, combined Mass Market and Large Industrial market segment demand grows more slowly due to manufacturing and industrial site closures. These closures can be attributed to a high Australian dollar, high gas prices, and prolonged global economic uncertainty.

3.2 Demand projections for individual market segments

This section provides demand projections for the individual Mass Market, Large Industrial, GPG and LNG market segments.

3.2.1 Demand groups

Eastern and South Eastern Australia is divided into five demand groups:

- Demand Group 1 (SA) includes South Australia.
- Demand Group 2 (VIC) includes Victoria.
- Demand Group 3 (TAS) includes Tasmania.
- Demand Group 4 (NSW/ACT) includes New South Wales and the Australian Capital Territory.
- Demand Group 5 (QLD) includes Queensland.

Locally supplied and consumed gas (for example Camden CSG in New South Wales) is not included, because it does not constrain the transmission network. As a result, total gas demand does not necessarily equal total gas consumption.

For more information about the demand groups, including the major demand centres and pipeline connections, see Appendix A, Section A.1.2.[4]

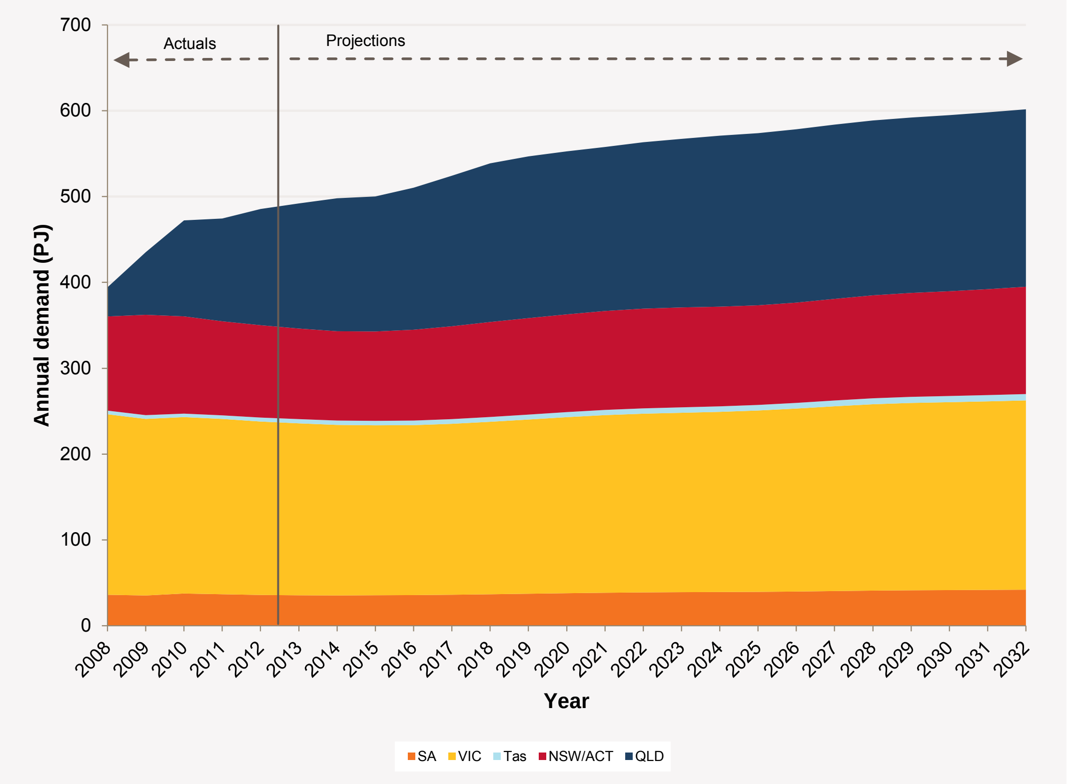
3.2.2 Mass Market and Large Industrial market segment gas demand

Annual demand

Figure 3-3 shows the combined Mass Market and Large Industrial market segment annual demand projections under the Planning scenario by demand group.

In New South Wales (including the Australian Capital Territory) and Victoria, combined Mass Market and Large Industrial market segment demand is projected to decline from 2012, before returning to 2012 levels between 2017 and 2019. In New South Wales this is due to a short-term reduction in demand from the Large Industrial market segment. In Victoria it represents a persistent decline in Large Industrial market segment demand (eventually offset by increasing Mass Market market segment demand), which is due to a high Australian dollar coupled with higher gas prices.

Figure 3-3 — Combined Mass Market and Large Industrial annual demand, Planning scenario



[4] To reduce the possibility of double counting, demand group categorisation differs from the zone and hub descriptions referred to by the Gas Bulletin Board.

The Slow Rate of Change scenario shows a similar growth pattern to the Planning scenario although growth is more subdued, particularly for the Queensland Demand Group. The combined Mass Market and Large Industrial market segment gas demand shows the following overall characteristics:

- In Queensland, the combined Mass Market and Large Industrial market segment gas demand growth of the past four years continues, but at a slower rate. Gas demand is projected to grow at average annual rates of 1.9% and 1.5% under the Planning and Slow Rate of Change scenarios respectively, driven mainly by Large Industrial market segment demand and mining projects.
- In New South Wales and the Australian Capital Territory, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 0.9% and 0.6% under the Planning and Slow Rate of Change scenarios respectively. Large Industrial market segment growth, at average annual rates of 0.8% under the Planning scenario and 0.3% under the Slow Rate of Change scenario, is lower than residential, business and commercial segment growth for the outlook period.
- In Victoria, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 0.5% and 0.4% under the Planning and Slow Rate of Change scenarios respectively. Large Industrial market segment demand is projected to decrease due to reductions in the manufacturing sector as a result of a high Australian dollar coupled with higher gas prices over the outlook period.
- In South Australia, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 0.9% and 0.4% under the Planning and Slow Rate of Change scenarios respectively. Mass Market market segment demand is projected to grow at an average annual rate of approximately 0.5% under both scenarios, and Large Industrial market segment demand is projected to grow at approximately 1.0% under the Planning scenario and 0.4% under the Slow Rate of Change scenario.
- In Tasmania, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 2.2% and 2.1% under the Planning and Slow Rate of Change scenarios respectively, driven mainly by the Mass Market market segment. Under the Planning scenario, growth in residential demand (3.8%) outpaces business and commercial demand (1.6%) for gas. Average annual growth in Large Industrial market segment gas demand is projected to be approximately 2.0% under both scenarios.

3.2.3 GPG market segment gas demand

This section presents the GPG market segment gas demand projections by demand group for each scenario, which derive from AEMO's electricity modelling for the 2012 National Transmission Network Development Plan (NTNDP). For more information about the GPG modelling methodology see Appendix A, Section A.5.2.

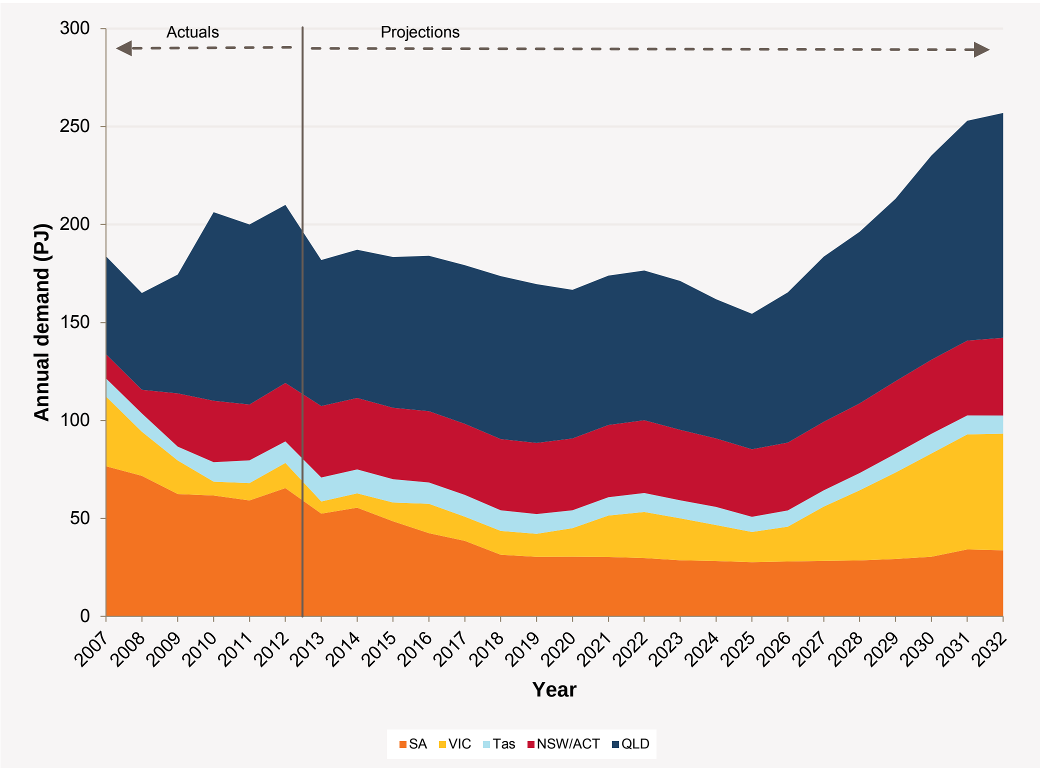
GPG annual demand projections by demand group (Planning scenario)

Figure 3-4 shows the annual GPG market segment gas demand projections for a 1-in-20 peak demand condition[5] by demand group under the Planning scenario.

Annual GPG demand under the Planning scenario has the following key features:

- A steady decline in GPG demand until 2025 before entering a period of growth to 2032 due to electricity demand growth.
- No new closed cycle gas turbines are required by the model for at least a decade. Open cycle gas turbine investment in the longer term, however, leads to an increase in GPG demand from 2025.
- In Queensland and New South Wales (including the Australia Capital Territory), GPG demand is projected to rise from current levels to support growing electricity demand and a large uptake of wind generation.
- In Victoria, there is a short-term decline in GPG market segment demand, which rises again from 2019 as carbon prices make the operation of combined cycle gas turbines more competitive with coal-fired generation, and existing GPG generation increases to meet growing electricity demand.
- In South Australia, GPG market segment demand steadily declines due to the uptake of renewable technologies displacing the need for GPG.

Figure 3-4 — GPG annual demand by demand group, Planning scenario



[5] 1-in-20 peak day demand has a 5% POE. This projected level of demand is expected, on average, to be exceeded only once in 20 years.

GPG annual demand projections by demand group (Slow Rate of Change scenario)

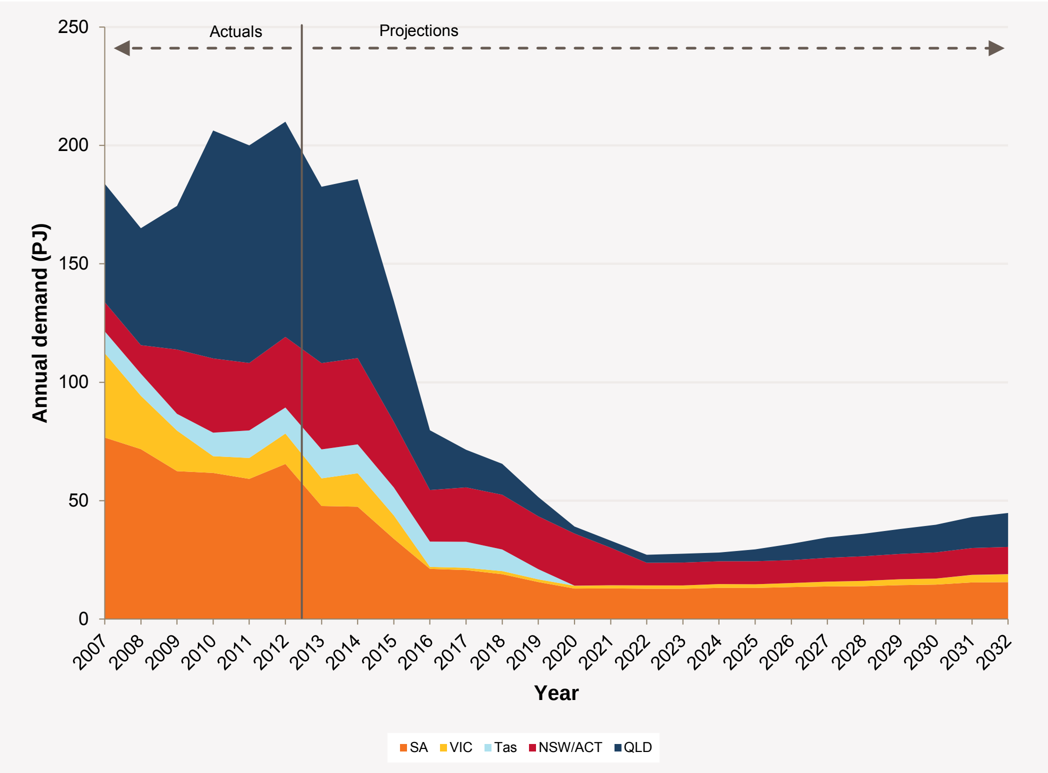
Figure 3-5 shows the annual GPG market segment gas demand projections for a 1-in-20 peak demand condition by demand group under the Slow Rate of Change Scenario.

GPG demand is projected to decrease from approximately 186 PJ in 2013 to less than 58 PJ in 2032 due to the removal of the carbon price, making gas less competitive with more carbon-intensive but less expensive black and brown coal. The LRET also results in renewable generation being installed to meet the electricity demand growth prior to 2020.

Annual GPG demand under the Slow Rate of Change scenario has the following key features:

- GPG demand decreases by 54% by 2016 and 80% by 2022 before entering a phase of steady growth.
- A sudden decrease in GPG demand from 2014 corresponds with the removal of carbon pricing.
- The LRET is another major factor contributing to the large decrease in demand. The modelling indicates LRET-driven renewable energy (mostly wind generation) dominates the new generation mix until 2020. Projected electricity demand under the Slow Rate of Change scenario is lower than under the Planning scenario and therefore the GPG demand is more greatly affected by the fixed LRET target.
- In Queensland, high gas prices driven by LNG exports will compound the impact of the removal of the carbon price and competition from renewable energy. GPG demand will drop from 75 PJ in 2013 to less than 6 PJ in 2020 before steadily increasing due to electricity demand growth.
- In New South Wales (including the Australia Capital Territory), GPG demand is projected to decline more slowly than in Queensland as black coal-fired generation is retired.
- In Victoria, South Australia and Tasmania, GPG demand is projected to decline as new renewable electricity generation investments occur, particularly wind generation.

Figure 3-5 — GPG annual demand by demand group, Slow Rate of Change scenario



3.2.4 LNG export market segment gas demand

This section provides a high-level summary of the demand outlook for liquefied natural gas (LNG) in Eastern and South Eastern Australia conducted by Core Energy Group, and the resulting LNG projections that were input to the supply-demand modelling presented in Chapters 4 and 5. For more information see the full Core Energy Group report.[6]

Export opportunities and market competition

The global LNG trade has grown annually by 8.5% over the last 10 years, with the Asia Pacific LNG market accounting for nearly 60% of total world LNG demand in 2010. Historically, the Asia Pacific region accounts for the majority of global LNG trade, and the region's demand for LNG is assumed to grow at approximately 2.8% per annum from 2012 to 2032.

Nearly all (99%) current Australian LNG exports supply the Asian region, largely because of favourable shipping costs. Total delivered LNG costs, however, have increased substantially over the last 10 years, and the competitiveness of Eastern and South Eastern Australian LNG will be increasingly linked to the cost of extracting and liquefying gas, with the shipping cost becoming less significant.

Asia is likely to remain the primary market for Eastern and South Eastern Australian LNG. Over the next 20 years, contracted supply to the Asian LNG market will trend down, while uncontracted demand[7] and unfulfilled[8] demand will trend up at rates of 10.5% per annum and 8.6% per annum respectively, which is largely due to the conclusion of existing contracts.

Unfulfilled LNG demand in the Asian market is predicted to grow annually by 8.6%, from 28 million tonnes per year in 2012 to 146 million tonnes per year in 2032. Key competitors for this unfulfilled demand include the United States of America, Iran, Russia, Canada, Qatar, Papua New Guinea, and Western Australia and the Northern Territory. Eastern and South Eastern Australian LNG projects, however, have a number of advantages over competing suppliers:

- Australia's vicinity to the Asian market and resulting lower shipping costs.
- Low sovereign risk.
- The advanced progress of several projects, particularly for the period up to 2017.

The ability for Eastern and South Eastern Australian projects to compete for Asia Pacific LNG demand is primarily a function of project economics and timing (to enable market opportunities to be realised). Key factors impacting project economics include industry hyperinflation (associated with limited skilled labour), well deliverability and productivity, compliance costs, water management and the value, if any, of associated hydrocarbon liquids.[9]

[6] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Eastern_SouthEastern_Australia_Projections_of_Gas_Demand_for_LNG_Export%20pdf.ashx. Viewed 26 September 2012.

[7] LNG demand unmet by firm contracts.

[8] LNG demand unmet by firm contracts and likely supply.

[9] Conventional gas to LNG projects can produce liquids in conjunction with gas that can improve project economics compared to a CSG-to-LNG project from which no liquids are produced.

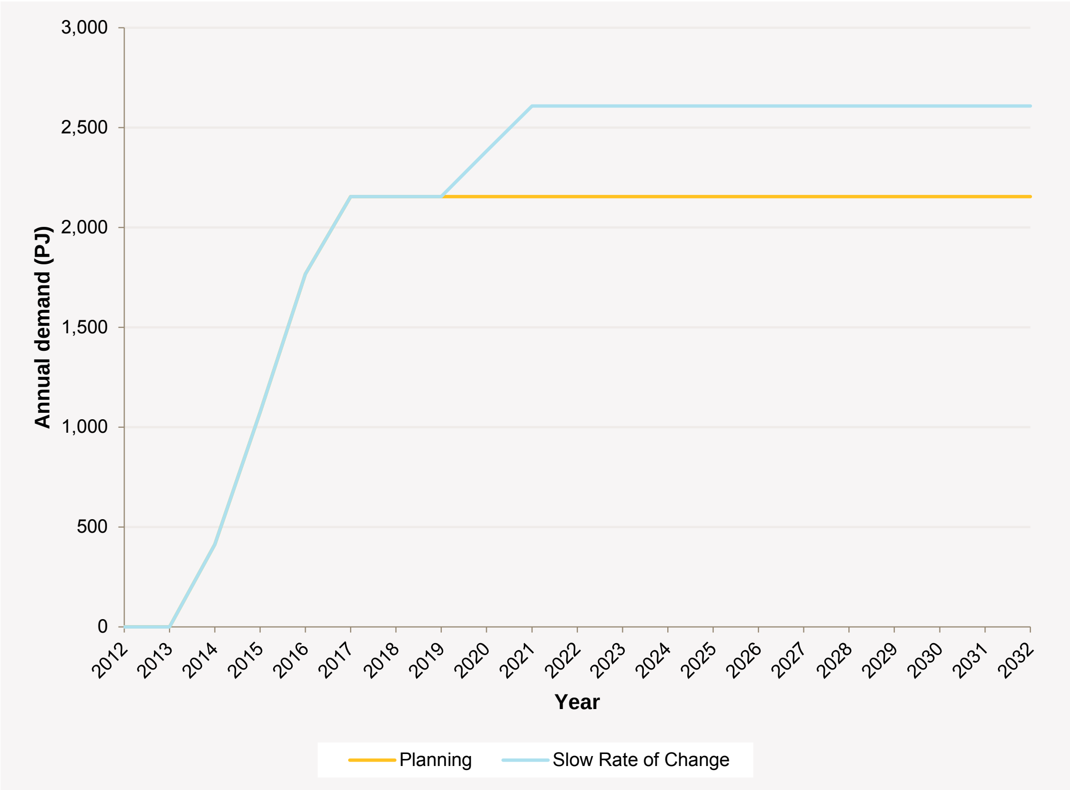
LNG demand and projected LNG development

Figure 3-6 shows projected annual LNG exports by scenario.

Growing demand for LNG exports from Eastern and South Eastern Australia will lead to 8 to 10 LNG trains being built over the next 20 years, with annual capacity from approximately 33 million tonnes to 40 million tonnes, requiring gas reserves of between 43,000 PJ and 52,000 PJ under the Planning and Slow Rate of Change scenarios, respectively.

There are currently three projects comprising five committed trains with a total annual capacity of 20.8 million tonnes. The available information shows there are potentially an additional 18 to 33 trains in Eastern and South Eastern Australia under a number of proposed projects. For information about LNG train development assumptions in relation to proposed projects see the AEMO website.[10]

Figure 3-6 — Annual LNG exports by scenario



The Slow Rate of Change scenario assumes the following factors will drive additional LNG trains:

- Lower domestic gas demand (driven by lower electricity demand, and no carbon price) and moderate research and development support lead to larger volumes of uncommitted domestic gas available for export.
- Less investment in renewable generation, which may in turn lead to a higher than expected demand for LNG.
- Constrained investment and a low level of capital liquidity provide more advanced projects with high levels of sunk-investment, which is an advantage compared to new projects.

[10] See note 6.

- A weaker economic outlook for the United States of America, allowing Australian projects to increase their market share.
- Competitive domestic production costs combined with high international LNG prices mean Eastern and South Eastern Australian projects are internationally viable.

Continuous growth is projected to be unlikely after 2021 due to possible competition from other global LNG suppliers and the economic benefits associated with liquids[11] production from Western Australia and the Northern Territory.

3.3 Links to supporting information

This section provides links to other information about gas demand forecasting. It also provides information about the gas network and sources of historical data.

Information source	Website address
Accompanying 2012 GSOO data files	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
Economic Outlook	www.aemo.com.au/Electricity/Forecasting
Gas Bulletin Board	www.gasbb.com.au
LNG projections	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Liquid-Natural-Gas-Projections
National Transmission Network Development Plan	http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan

11 See note 9.

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CHAPTER 4 - RESERVE ADEQUACY AND FIELD DEVELOPMENT OPPORTUNITIES

Summary

This chapter provides information about gas reserve adequacy.

The gas reserves projections indicate there are sufficient resources to satisfy projected gas demand for the next 40 years under all scenarios. However, this analysis assumes that proved-plus-probable (2P)[1] reserves are developed in a timely manner and are available to the market when required.

The initial 2P reserves, assessed to be over 65,000 PJ, are dominated by the Bowen, Surat and Gippsland Basins, with the majority being classified as coal seam gas (CSG).

The majority of the total remaining reserves[2], assessed to be over 48,000 PJ, are in Queensland, in particular the Bowen and Surat Basins.

As conventional resources are depleted or used in the liquefied natural gas (LNG) export market, CSG or unconventional (shale or tight) gas reserves may need to be utilised by the domestic market. The relatively small volume of uncommitted[3] 2P reserves, combined with a large proportion of resources committed or earmarked for LNG projects, may create challenges for domestic supply, prompting a market response when companies look to recontract in the short term.

Projections for the outlook period show declining Gippsland and Otway offshore conventional gas reserves, and depletion of the Cooper-Eromanga Basins reserve by 2030 to 2031 under the Planning scenario. Cooper-Eromanga Basins reserve depletion will cause potential supply shortfalls for New South Wales (including the Australian Capital Territory), and peak constraints for South Australia, Victoria, and Tasmania. Opportunities for easing the potential shortfalls and constraints include the following:

- Gunnedah Basin development.
- Gloucester Basin development.
- Cooper-Eromanga Basins development.
- Sydney Basin development.

[1] Initial reserves represent the quantity of gas, on a given assessment date, expected to be recovered from a reservoir over its entire productive life. 2P reserves are the best estimate of commercially recoverable resources.
[2] Remaining reserves are the total quantity of 2P reserves (as at 31 December 2011) expected to be recovered from a basin for its remaining productive life (for example, 1 January 2012 to 2025).
[3] LNG demand unmet by firm contracts and likely supply.

4.1 Gas reserves

This section provides a high-level summary of two reports produced for AEMO by Core Energy Group:

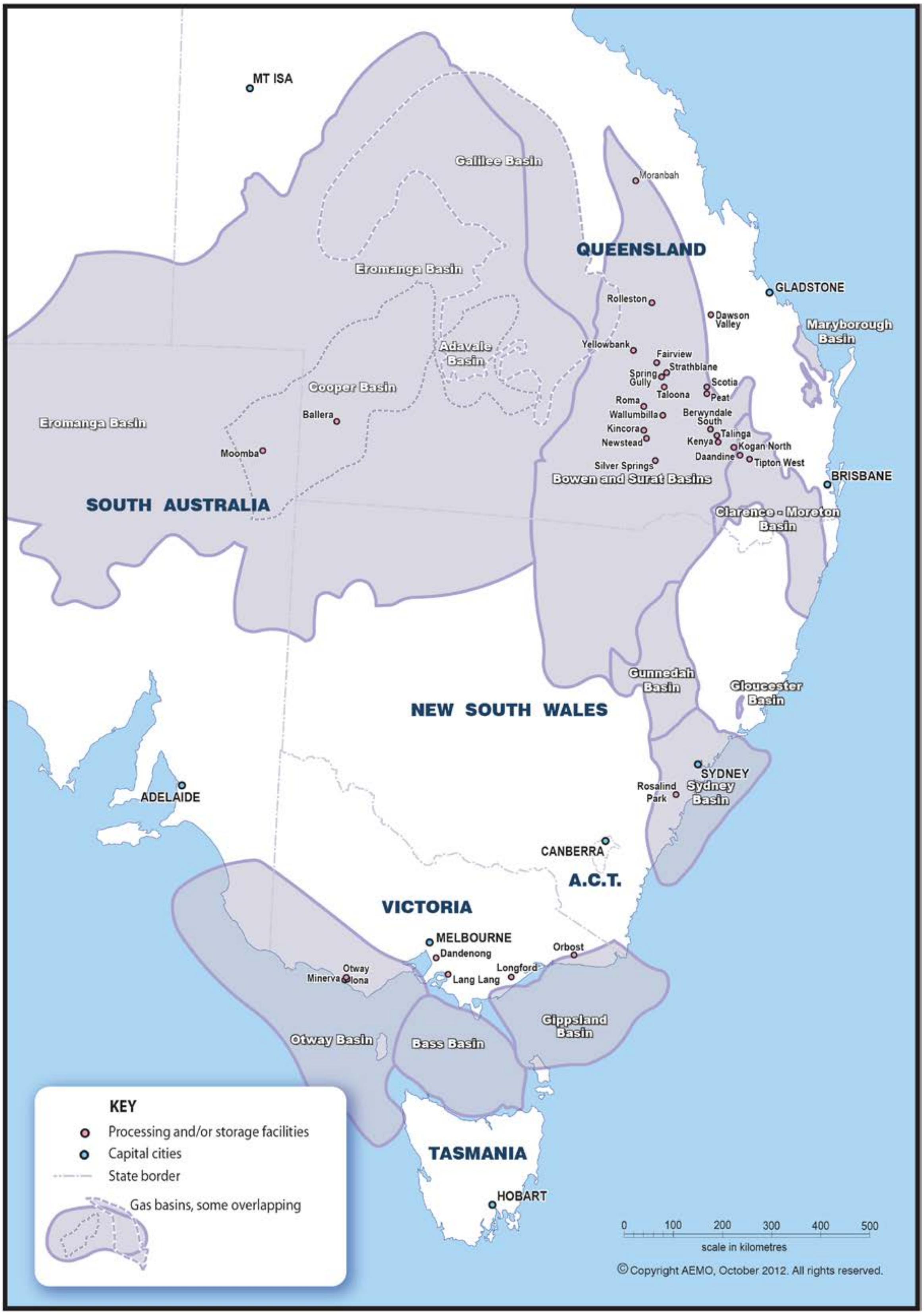
- Eastern and Southern Australia: Existing Gas Reserves and Resources reports on existing gas reserves and resources as at 31 December 2011.[4]
- Eastern and Southern Australia: Projected Gas Reserves reports on reserve projections to 2052.[5]

Both reports form 2012 GSOO inputs and are consistent with the changes to the 2012 GSOO (outlined in Chapter 1).

Figure 4-1 shows gas basins in Eastern and South Eastern Australia. For more information about each gas basin and its gas type, see the Core Energy Group report on existing gas reserves and resources.

[4] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Reserve-Update. Viewed 9 October 2012.
[5] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Reserves-Projections. Viewed 9 October 2012.

Figure 4-1 — Gas basins in Eastern and South Eastern Australia



4.1.1 Gas reserves as at 31 December 2011

This section summarises the available gas reserves as at 31 December 2011. Gas sources are categorised as one of the following:

- Conventional, which is gas produced from conventional reservoirs.
- Coal seam gas (CSG), which is gas produced from coal seams, also known as coal seam methane (CSM).
- Unconventional, which is shale or tight gas.

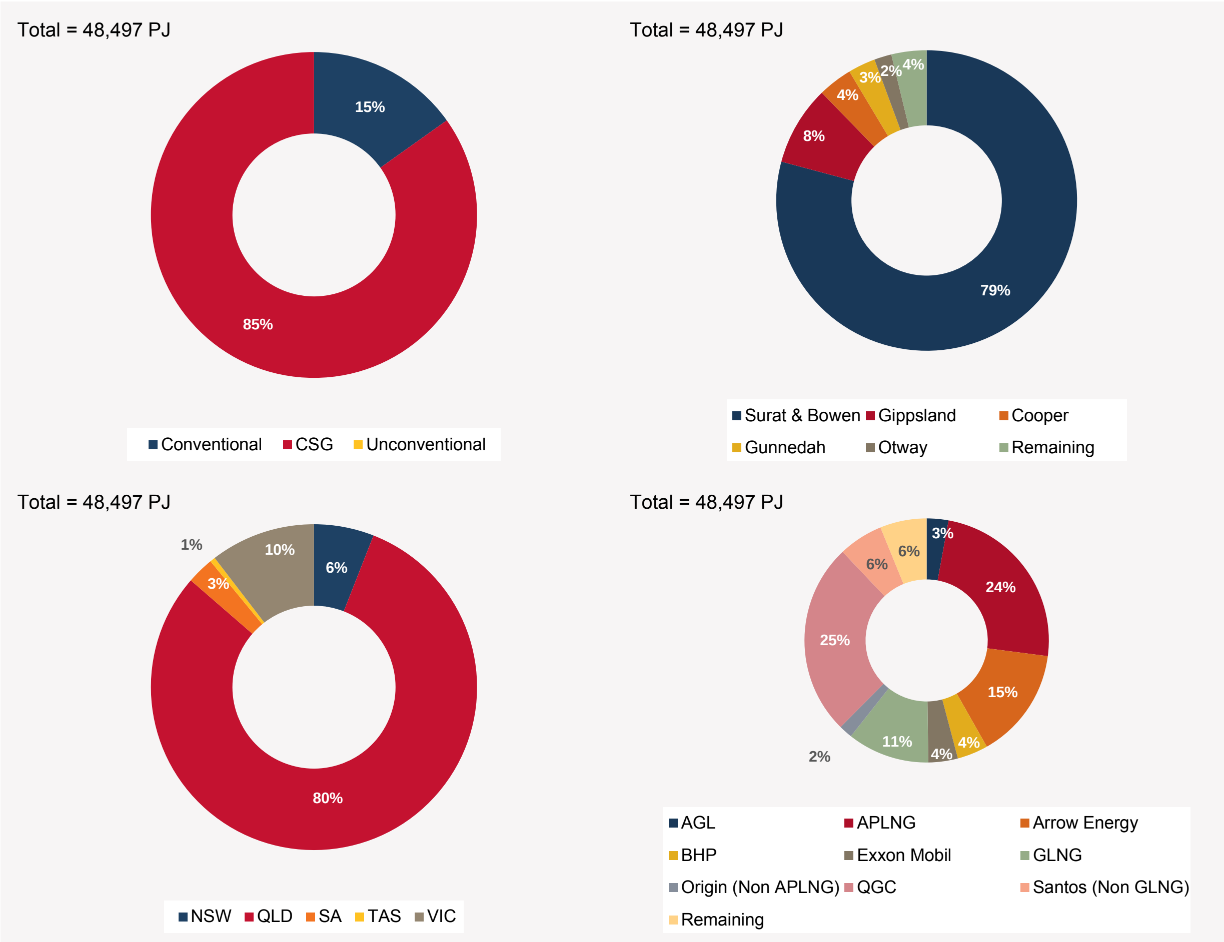
Reserves are presented as either initial or remaining reserves, and are defined as follows:

- Initial reserves are the 2P reserves as at 31 December 2011 if the field is not (and has never been) in production. If the field is in production, the 2P reserves include reserves as at 31 December 2011 and the field's historical production. This represents the quantity of gas on a given assessment date that is expected to be recovered from a reservoir over its entire productive life.
- Remaining reserves are the total quantity of 2P reserves (as at 31 December 2011) expected to be recovered from a basin for its remaining productive life (for example, 1 January 2012 to 2025).

The initial 2P reserves (over 65,000 PJ) were dominated by the Bowen, Surat and Gippsland Basins. Of all initial 2P reserves, over 23,000 PJ were conventional gas, and over 42,000 PJ were CSG. Unconventional gas has emerged as a potential large-scale supply source. However, as at 31 December 2011 there were no unconventional sources in production or classified as reserves. The 2011 GSOO reported on the increasing growth of CSG reserves, and this trend continues.

Figure 4-2 shows the proportions of the total remaining 2P reserves (over 48,000 PJ) as at 31 December 2011, broken down by gas source, basin, state and owner. The majority of reserves are in Queensland, in particular the Bowen and Surat Basins.

Figure 4-2 — Total remaining 2P reserves (31 December 2011)



From the remaining 2P reserves of 48,497 PJ, there is currently over 19,000 PJ of 2P uncontracted[6] gas in the market, most of which has been earmarked for either domestic use or LNG export. Of this 19,000 PJ of 2P uncontracted gas, it is estimated that there is approximately 4,000 PJ of 2P uncommitted gas currently available. The relatively small volume of uncommitted 2P reserves may prompt a market response when companies look to recontract in the short term.

Natural gas reserves and resources will continue to be dominated by CSG development.

For a more detailed breakdown of the reserves by basin and type, see the Core Energy Group report on existing gas reserves and resources.[7]

[6] LNG demand unmet by firm contracts.
[7] See note 4.

4.1.2 Gas reserves projections

Gas reserves projections were developed under three AEMO scenarios, Planning, Decentralised World, and Slow Rate of Change. The 2012 GSOO and National Transmission Network Development Plan (NTNDP) present results under the Planning and Slow Rate of Change scenarios. For more information about the scenarios see Chapter 1, Section 1.5. Projected gas demand for domestic and large industrial customers, gas powered generation (GPG) demand, and LNG demand for export also formed inputs to this analysis.[8]

The gas reserves projections indicate there are sufficient resources to satisfy projected gas demand for the next 40 years under all scenarios. However, this analysis assumes that 2P reserves are developed in a timely manner and are available to the market when required.

As conventional resources are depleted or used in the LNG export market, CSG or unconventional gas resources will have to be utilised by the domestic market. Combined with a large proportion of resources committed or earmarked for LNG projects, this may create challenges for domestic supply, prompting a market response.

[8] Core Energy was provided with the latest demand projections available at the time (July 2012). However, the demand projections in Chapter 3 have since been revised with new information.

Figure 4-3 shows the projected gas reserves by type and by basin for the domestic and LNG markets to 2052 under the Planning scenario. The ratios of conventional to CSG reserves are evenly weighted for the domestic market until approximately 2032, with CSG becoming more dominant in the longer term to 2052. CSG sourced predominantly from the Bowen and Surat Basins, dominates the LNG reserves. Unconventional (shale or tight) gas reserves are not developed under the Planning scenario, which only requires a combination of LNG and domestic reserves to provide total reserves ranging between approximately 47,900 PJ and 158,000 PJ over the period 2012 to 2052.

Figure 4-3 — Domestic and LNG 2P reserves projections, Planning scenario

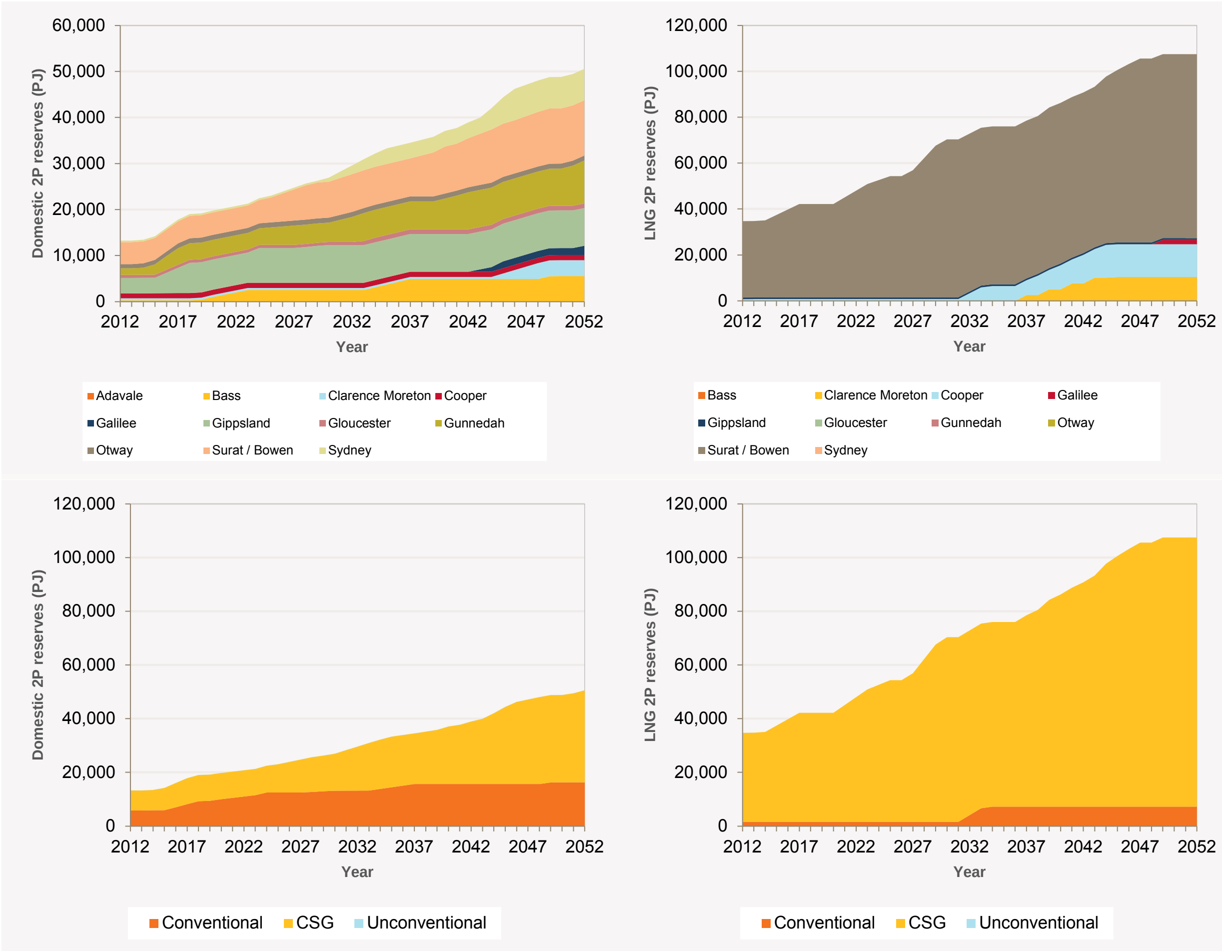
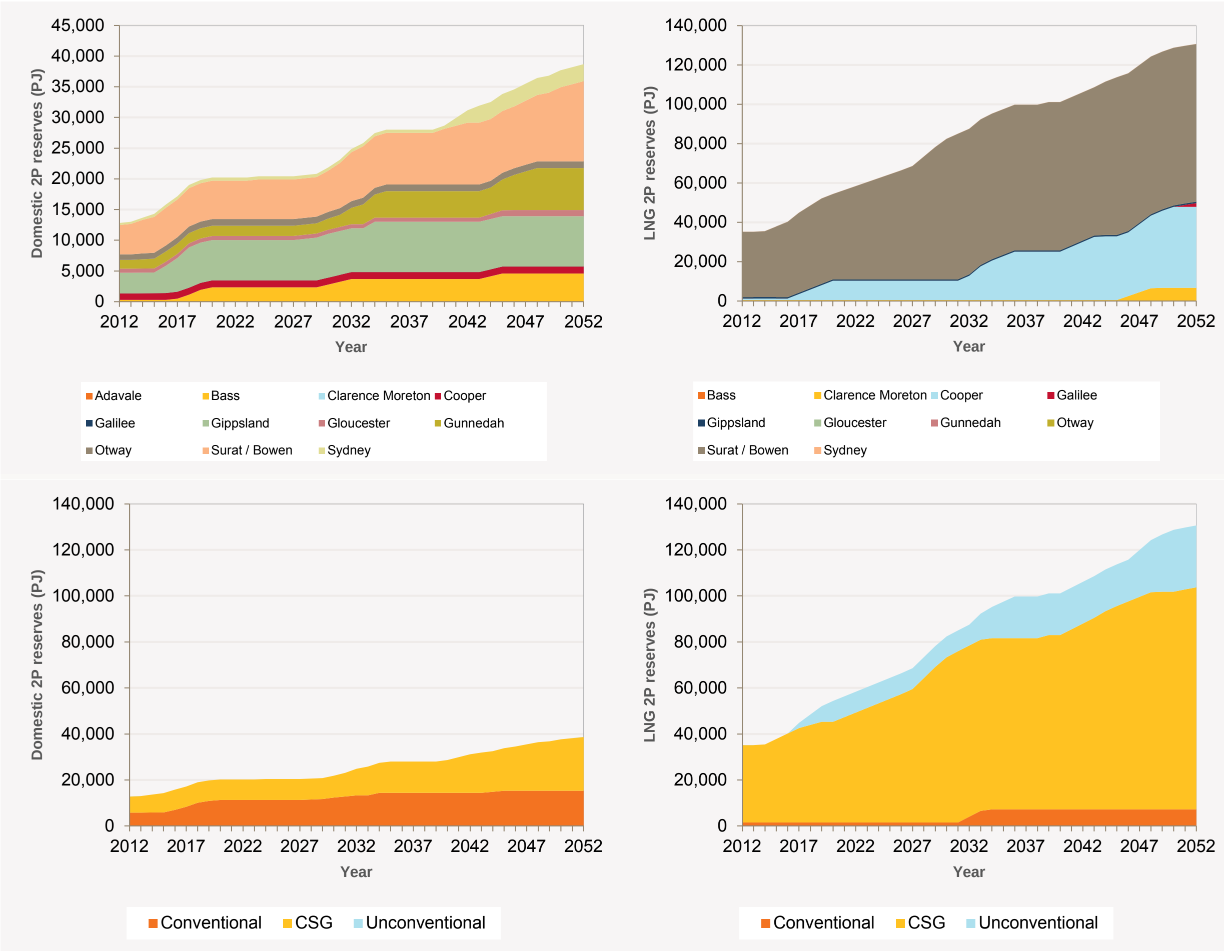


Figure 4-4 shows the projected gas reserves by basin and by type for the domestic and LNG markets to 2052 under the Slow Rate of Change scenario. In contrast with the Planning scenario, the ratios of conventional to CSG reserves show slightly higher domestic market consumption of conventional gas until approximately 2038, with CSG becoming more dominant in the longer term until 2052. CSG again dominates the LNG reserves under the Slow Rate of Change scenario, with unconventional gas reserves being used from 2017 onwards following the decline of lower-cost resources. The combination of LNG and domestic reserves provide total reserves ranging between approximately 47,900 PJ and 169,000 PJ over 2012 to 2052 under the Slow Rate of Change scenario.

Figure 4-4 — Domestic and LNG 2P reserves projections, Slow Rate of Change scenario



The current estimated recoverable resources are sufficient to satisfy the market over the outlook period, and the target 15-year 2P reserves-to-production (R/P) ratio[9] is maintained for both domestic and LNG markets over the same period of time. This ratio has decreased since the 2011 GSOO (which aimed to maintain a 20-year ratio) since the increase in development of unconventional resources is likely to lead to progressive increments in 2P reserve development, and long-term contracts are expected to decrease from 20 years in the current environment. However, this assessment also assumes that 2P reserves are developed in a timely manner and are available to both the domestic and LNG markets when required.

[9] The R/P ratio is an indicator of the remaining lifespan of a resource. A 15-year ratio was assumed in the development of the reserve projections. For more information, see AEMO. http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Eastern_and_Southern_Australia_Projected_Gas_Reserves_Updated.ashx. Pg 6. Viewed 25 October 2012.

Current market dynamics are creating uncertainty, with 2P reserves potentially not being developed in a timely manner due to competition for supply, a market response anticipated in the current transitional environment resulting from an increasing LNG export market, and companies looking for more certainty in terms of future market conditions prior to committing to investment. Environmental factors may also impact resource development. A study has been conducted to further investigate some potential outcomes if 2P reserves are not developed in a timely manner (see Chapter 5, Section 5.1.1).

4.2 Supply-demand analysis and development opportunities

The 2012 GSOO modelling indicates that the gas resources in Eastern and South Eastern Australia are sufficient to supply domestic and LNG export demand growth over the 20-year reserves outlook period for all scenarios modelled.

Projections for the outlook period show declining Gippsland and Otway offshore conventional gas reserves, and depletion of the Cooper-Eromanga Basins reserve by 2030 to 2031 under the Planning scenario. Depletion of these basins will cause supply shortfalls for New South Wales (including the Australian Capital Territory), and constraints during periods of peak demand for South Australia, Victoria, and Tasmania. Opportunities for easing the shortfall and constraints include the following:

- Gunnedah Basin development.
- Gloucester Basin development.
- Cooper-Eromanga Basins development.
- Sydney Basin development.

For more comprehensive modelling results see the accompanying data files on the AEMO website.[10]

The Bowen-Surat Basins

Several LNG developments are expected in Queensland over the next five years (for more information see Chapter 2). The modelling assumed all LNG exports are to be supplied by CSG resources located in the Bowen-Surat Basins using dedicated pipelines and processing facilities, and results show sufficient 2P reserves to supply LNG exports over the 20-year outlook period.

[10] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed 19 November 2012.

Figure 4-5 shows the projection of remaining 2P reserves in the Bowen-Surat Basins. Figure 4-6 shows the R/P ratio. The early high R/P ratios reflect current CSG development for LNG export. After full commissioning of the LNG projects, the ratio declines significantly and maintains a 15-year level.

Figure 4-5 — Bowen-Surat Basins projected remaining 2P reserves

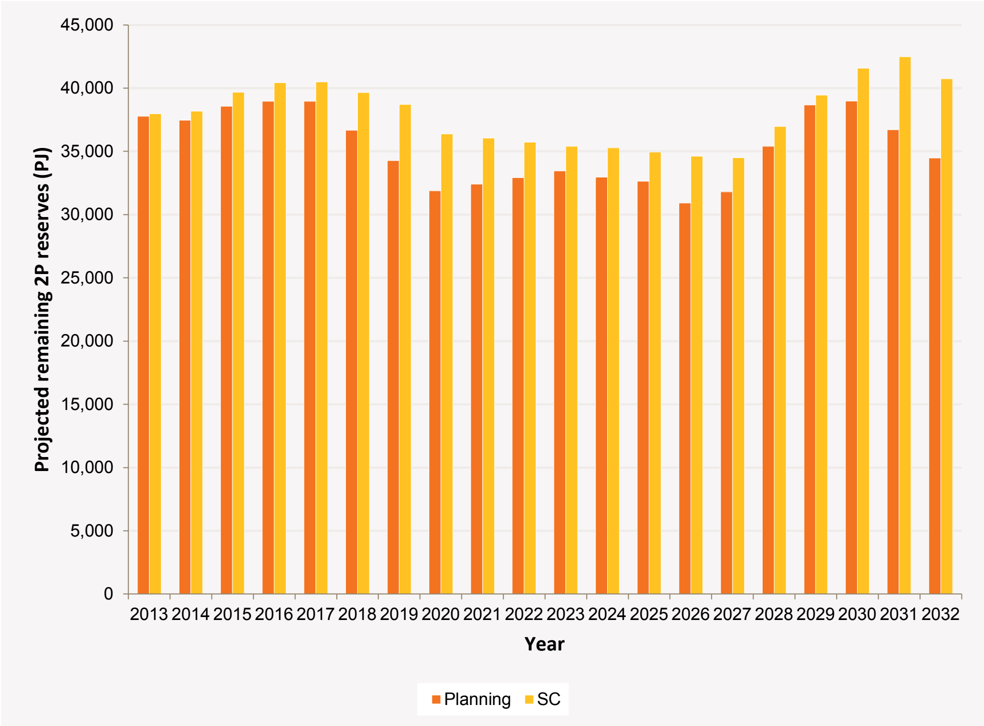
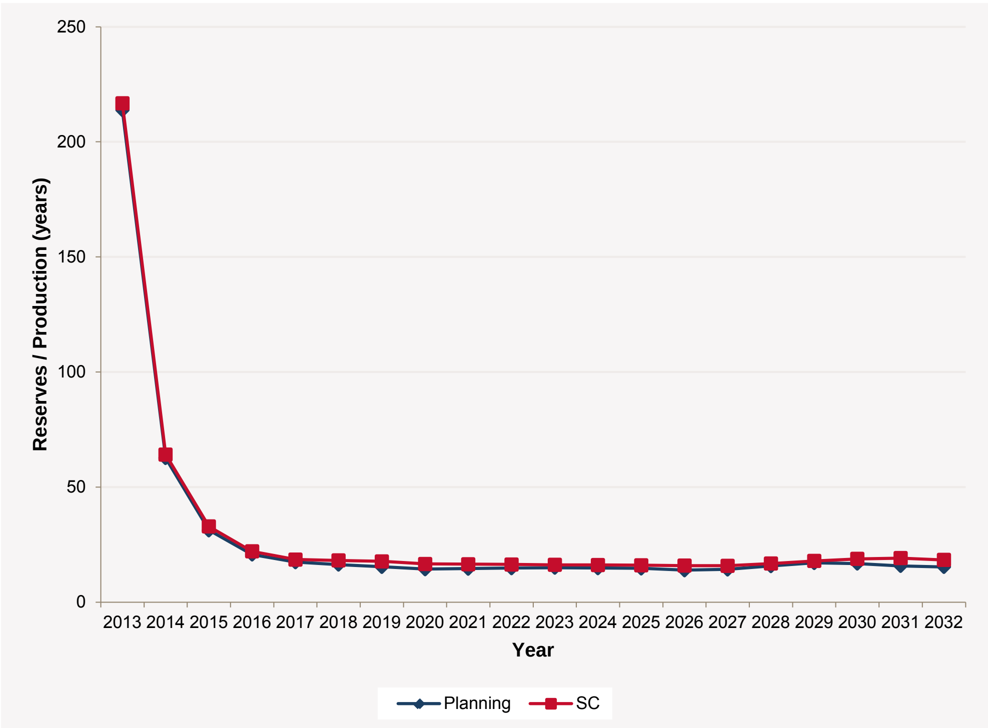


Figure 4-6 — Bowen-Surat Basins 2P R/P ratio



The Cooper-Eromanga Basins

The modelling indicates depletion of 2P reserves for the Cooper-Eromanga Basins by 2030 and 2031 under the Planning scenario. Figure 4-7 shows the basins' projected remaining 2P reserves. Depletion is expected due to the following:

- Processing facilities in Ballera and Moomba have a relatively high total capacity of 490 TJ/d. The modelling shows high utilisation rates for these facilities to supply growing domestic demand from South Australia and New South Wales.
- No significant 2P reserve development is expected until 2032.

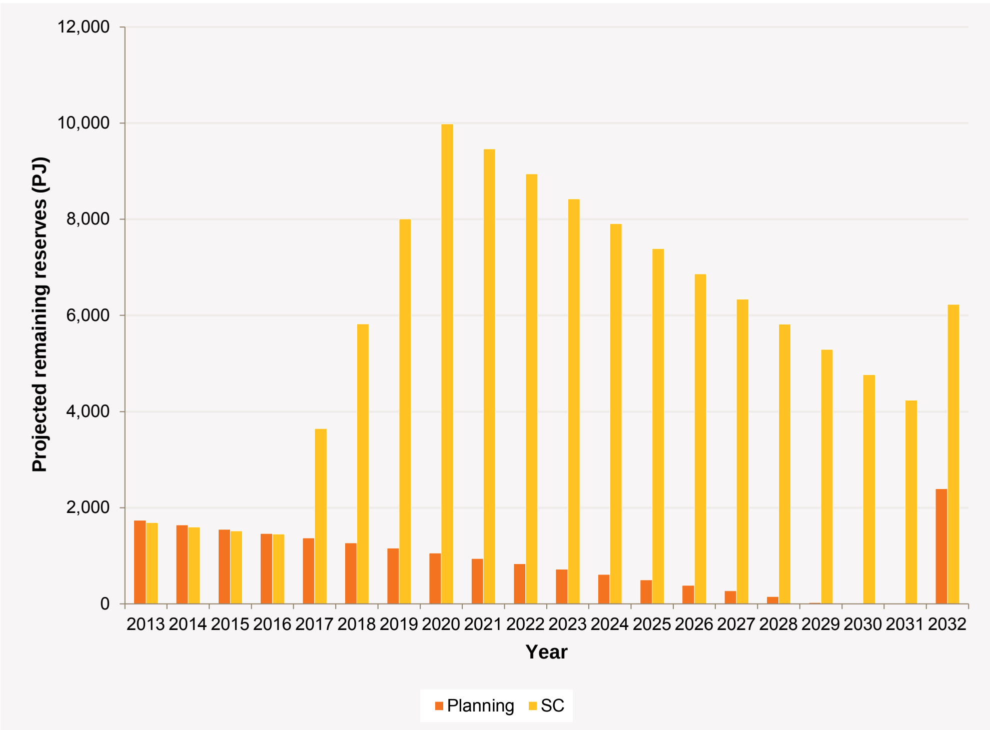
Loss of supply from the Cooper-Eromanga Basins will mean there is insufficient gas to support Sydney's domestic demand under the Planning scenario. Part of the potential shortfall will be met by increasing supplies from the Bowen-Surat, Gippsland, Bass, and Otway Basins. This is expected to significantly change gas flows within Eastern and South Eastern Australian transmission pipelines around 2030 to 2032.

Under the Slow Rate of Change scenario, significant 2P reserve developments are expected between 2017 and 2020, leading to sufficient supply for domestic demand. This development is driven by two additional LNG production trains with the Cooper-Eromanga Basins' unconventional (shale or tight) gas being the likely gas source under the Slow Rate of Change scenario.

Opportunities to accommodate loss of supply from the Cooper-Eromanga Basins include the following:

- Cooper-Eromanga Basins development.
- Gloucester Basin development to supply Sydney and Newcastle gas demand.
- Sydney Basin development to supply Sydney gas demand.

Figure 4-7 — Cooper-Eromanga Basins projected remaining 2P reserves



The Gunnedah Basin

No existing processing facility is located in the Gunnedah Basin. The 2012 NTNDP[11] study shows a significant reduction in GPG in comparison to the 2011 NTNDP.[12] New GPG is forecast around the Hunter Valley towards the end of the outlook period, and an option to meet this new demand could include development of the Gunnedah Basin.

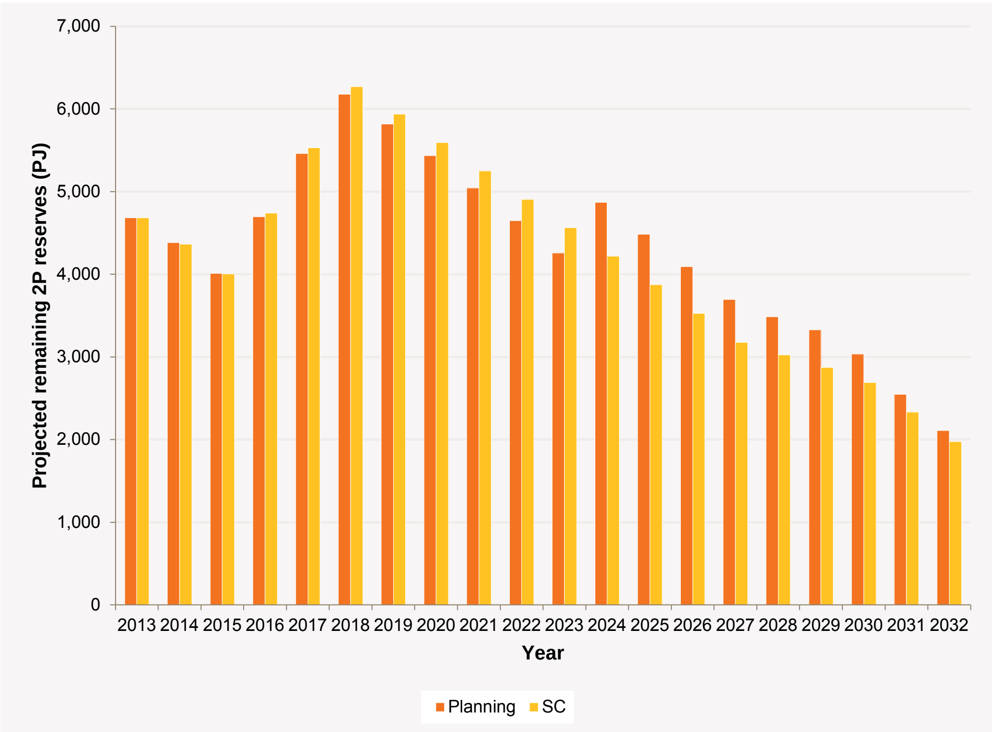
The Gunnedah Basin is an undeveloped CSG field, which also offers the opportunity to develop processing and transmission facilities. The New South Wales Government has stated that uncertainty about future availability and prices of gas in New South Wales can be alleviated by developing the local CSG sector. The New South Wales infrastructure strategy also recommends facilitating augmentation of the existing national gas transmission networks to connect new supply areas including the Gunnedah Basin.[13]

The Gippsland, Bass, and Otway Basins

Similar to the 2011 GSOO modelling, the 2012 results show a decline in 2P reserves for the Gippsland and Otway Basins over the outlook period. Production from these basins is projected to be high, particularly in 2030 and 2031 with the expected loss of supply from the Cooper-Eromanga Basins.

Figure 4-8 shows the projection of aggregated remaining 2P reserves in the Gippsland and Otway Basins. The reserves projection growth observed between 2015 and 2019 is driven by the need to meet LNG export and domestic demand while maintaining a 15-year R/P ratio, with a number of Gippsland Basin projects being either committed or proposed. The 2P reserve development is primarily in the Gippsland Basin, with the Otway basin's 2P reserves projected to deplete in 2023.

Figure 4-8 — Gippsland and Otway Basins projected remaining 2P reserves



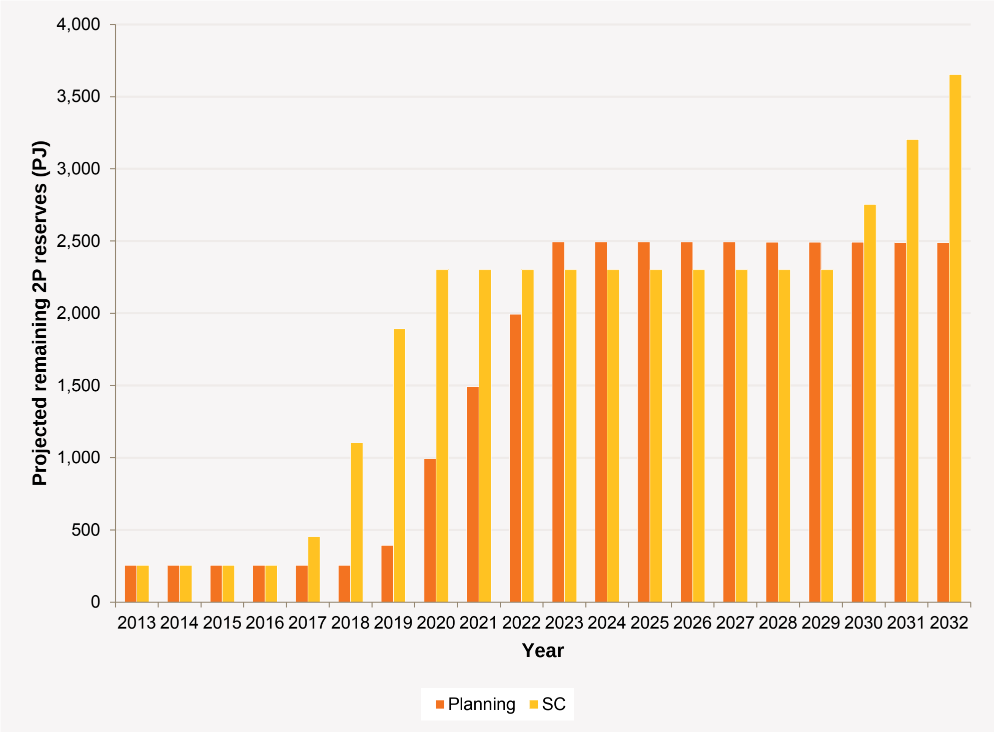
[11] AEMO. "2012 National Transmission Development Plan". December 2012. Available: http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan. Viewed 6 December 2012.

[12] AEMO. "2011 National Transmission Development Plan". December 2011. http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan/Overview. Viewed 6 December 2012.

[13] New South Wales Government. First things first: The State Infrastructure Strategy 2012-2032. Pg 155. Available: http://www.infrastructure.nsw.gov.au/state-infrastructure-strategy.aspx. Viewed 18 October 2012.

Figure 4-9 shows the projection of remaining 2P reserves in the Bass basin. While minimal production is expected from the Bass Basin because of high production costs[14], its 2P reserve remains high for the entire outlook period.

Figure 4-9 — Bass Basin projected remaining 2P reserves



4.3 Links to supporting information

This section provides links to other information about reserves and resources.

Information source	Website address
Eastern and Southern Australia: Projected Gas Reserves	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserves-Projections
Eastern and Southern Australia: Existing Gas Reserves and Resources	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserve-Update

[14] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Production-Costs. Viewed 26 September 2012.

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CHAPTER 5 - GAS INFRASTRUCTURE ADEQUACY AND OPPORTUNITIES

Summary

This chapter presents information about gas processing and transmission adequacy modelled under the Planning and Slow Rate of Change scenarios for a range of demand conditions over a 10-year outlook period (from 2013 to 2022). The chapter also presents the available opportunities (where relevant) for ensuring system adequacy.

Under the Planning scenario and 1-in-20 peak demand conditions over the outlook period, potential shortfalls have been projected for Gladstone in 2013, Townsville in 2021, and Brisbane in 2018.

Queensland is expected to experience a step change in gas demand over the next five years, largely resulting from liquefied natural gas (LNG) exports and future large industrial developments. Competition for gas supply may impact the timing or scope of the large industrial projects currently proposed in Gladstone.

The gas market is entering a transition period. Gas fields currently in production are reaching end of economic life, existing long-term gas supply contracts are approaching expiration, and LNG exports are expected to commence in 2014. This is likely to result in the following:

- Increased competition for both gas resource development and processing capacity.
- Decreased investment from large industrial customers due to the difficulty in securing long-term supply contracts.
- Increased pressure on availability of domestic supply for at least three to five years.

If 2P reserves are not developed in a timely way, potential supply shortfalls to the LNG export market and Queensland domestic market may be observed towards the end of the period of increasing LNG demand in 2016.

No potential supply shortfalls have been projected in Victoria, South Australia, Tasmania, or New South Wales (including the Australian Capital Territory, providing supply from the Moomba to Sydney pipeline is available).

5.1 Processing and transmission adequacy

This section summarises the findings of an analysis of processing and transmission adequacy under five scenarios[1]:

- The Planning scenario for 1-in-2 and 1-in-20 peak demand conditions.
- The Slow Rate of Change scenario for 1-in-2 and 1-in-20 peak demand conditions.
- A sensitivity study that examined the impact of potential 2P reserve development impediments and the LNG export market (modelled using the Planning scenario, 1-in-2 peak demand conditions).

Throughout this chapter, modelling results highlighting when supply is insufficient to meet demand are referred to as 'potential shortfalls'. This is intended to signal potential opportunities for investment in production, pipeline, processing or storage facilities. These potential shortfalls are not intended to be a prediction of future shortfalls, unless they happen before there is an opportunity for market correction. In this case, modelled supply deficits will

[1] For more information about the scenarios and their key parameters see Chapter 1, Section 1.5. For a modelling overview, including information about the peak demand conditions see Section 5.3. For more detailed information about the sensitivity study see Section 5.1.1.

probably result in a market response, which will impact the timing or scope of projects, since large industrial customers may have difficulty securing contracts at a price they are willing to pay.

Table 5-1 lists the location and expected timing of potential shortfalls. The 1-in-2 and 1-in-20 results are similar, with the timing of potential shortfalls being either the same or slightly earlier under 1-in-20 peak demand conditions.

The 2012 GSOO results are largely consistent with the results from 2011, with differences being driven by modelling methodology enhancements, input data quality improvements, and changes in gas and electricity demands.

Table 5-1 — Timing of potential shortfalls

Location	Planning scenario		Slow Rate of Change scenario	
	1-in-20	1-in-2	1-in-20	1-in-2
Gladstone	2013	2013	2013	2013
Townsville	2021	2021	>2022	>2022
Brisbane	2018	2020	>2022	>2022

For the complete set of modelling results see the accompanying data files on the AEMO website.[2]

5.1.1 Emerging developments

The GSOO aims to provide an adequacy assessment of how existing and committed assets can potentially meet supply. As a result, the modelling can be considered a best case scenario regarding how market supplies are met.

The model uses production and transmission costs to simulate supply to meet projected demand, minimising the total costs to the market. The model also assumes that available[3] 2P reserves are always developed in time to meet projected domestic demand and LNG export requirements. Gas prices are not a direct input into the model, but are considered in a number of modelling inputs like the scenarios, reserve and LNG projections. For more information about gas price considerations in the GSOO and the National Transmission Network Development Plan (NTNDP) see Chapter 1, Section 1.5.

The LNG export market

The current domestic market is strongly influenced by the LNG export market, which is linked to international gas prices and is less reliant on domestic production and transmission costs. The LNG export contract arrangements also provide strong incentives for industry to meet contracted LNG export volumes.

The transitional domestic environment

The domestic environment is in a period of transition as a result of gas fields currently in production reaching the end of their economic life, existing long-term domestic gas supply contracts expiring, and LNG exports beginning in 2014. This transitional period is likely to produce two significant effects:

- Increased competition for both gas resource development and processing capacity.
- Pressures on domestic supply for at least three to five years.

There is also significant uncertainty about long-term LNG prices. Holders of gas reserves may prefer to keep their reserves rather than sell at today's domestic prices, providing an option for future development to supply LNG trains. Withheld reserves combined with other factors such as potentially unfavourable weather and high labour costs may impact the timely development of 2P reserves.

[2] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed 19 November 2012.

[3] In accordance with the reserve projections published on the AEMO website in August. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Reserves-Projections. Viewed 12 November 2012.

The results under the two scenarios listed in Table 5-1 do not necessarily reflect the LNG export market and transitional domestic environment. As a result, the 2012 GSOO has more closely investigated some potential impacts of the current environment:

- Artificially reducing the development of LNG reserves[4] by 10%, 15%, and 20% to examine what may happen if 2P reserves are not developed in a timely manner.
- Prioritising supply of gas to the LNG export market (rather than the domestic market).

If 2P reserve development is reduced by 15%, domestic reserves are adequate to meet domestic and LNG supply until towards the end of the period of increasing LNG demand in 2016. After this, LNG export demand and Queensland domestic demand may experience potential supply shortfalls if the market does not adequately react to increased LNG exports and Queensland domestic demand. This investigation highlights the criticality of timely development of 2P reserves and creates further opportunities to ensure LNG export and Queensland domestic demand is met.

5.2 Processing and transmission adequacy and opportunities

This section presents more detailed information about findings from the analysis of processing and transmission adequacy under the Planning scenario and 1-in-20 peak demand conditions, and the sensitivity study. Potential opportunities for ensuring system adequacy are also presented.

Of the four modelling scenarios examined (excluding the sensitivity study), this section focusses on the Planning scenario and 1-in-20 peak demand conditions, which shared similar timings with modelled potential shortfalls under 1-in-2 conditions, and ensures the system can meet a worst case planning condition. The Slow Rate of Change scenario results are included only where relevant, as supplies are usually adequate under this scenario (see Table 5-1).

Previous GSOO analysis presenting historical Gas Bulletin Board information about gas production, pipeline flows and capacities are available from the accompanying data files on the AEMO website.[5]

5.2.1 Queensland

The modelling suggests several demand centres in Queensland are expected to see insufficient gas supply over the 10-year outlook period, including Gladstone, Townsville, Brisbane, and Mount Isa. The modelled potential shortfall in Mount Isa can be supplied by linepack.

Queensland is expected to experience a step change in gas demand over the next five years, largely resulting from LNG exports and future large industrial developments.

The uncertainties around the stability of the global economy and the international LNG market, together with large-scale LNG export projects, are likely to decrease investment by large industrial customers due to the difficulty in securing long-term supply contracts.

For more detailed information about demand projections see Chapter 3 or Appendix A.

[4] 2P reserve development of Surat-Bowen Basins' LNG earmarked reserves were reduced in the model for this study.

[5] AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed 19 November 2012.

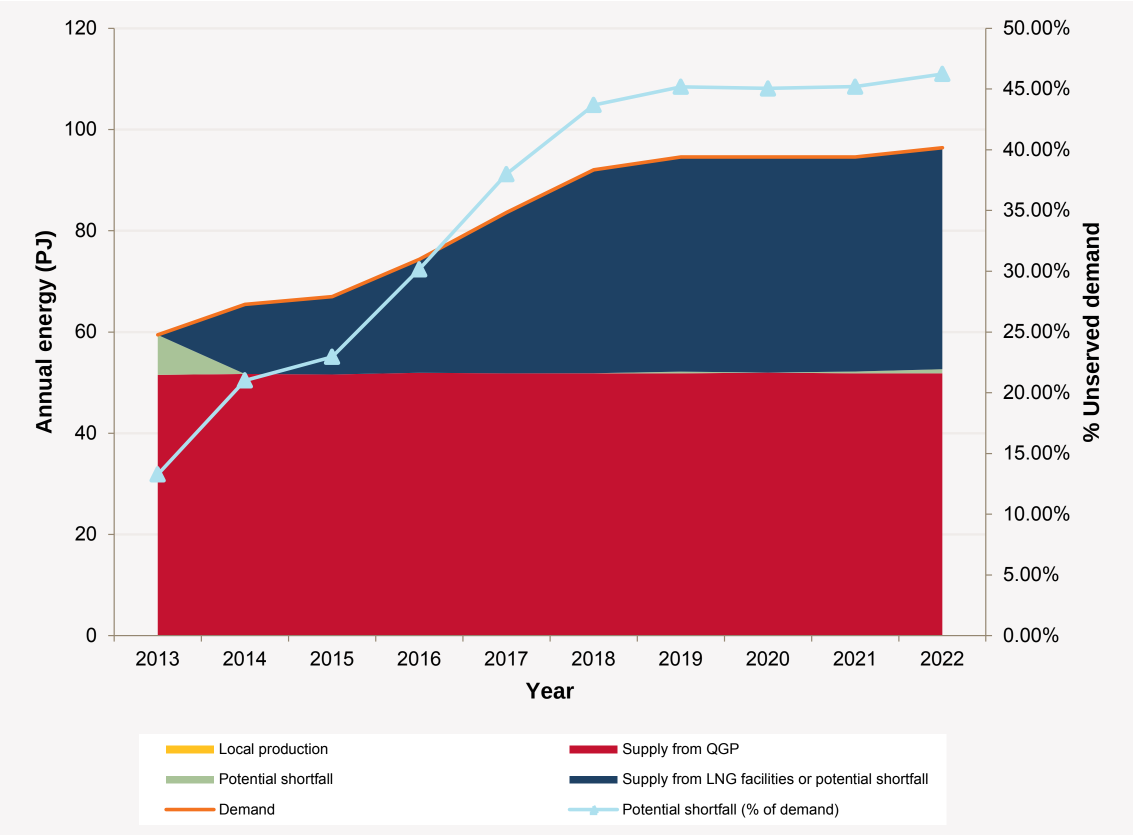
Gladstone (excluding gas for LNG export)

Figure 5-1 shows annual supply and demand for Gladstone under the Planning scenario and 1-in-20 peak demand conditions over the outlook period. The modelled Gladstone supply only meets domestic demand, and excludes LNG export demand.

Demand at Gladstone is supplied from conventional gas and CSG in the Bowen-Surat Basins via the Queensland Gas Pipeline (QGP). The modelling included an option to allow spare LNG pipeline and facility capacity to supply Gladstone's domestic demand.[6] Since this is unlikely to occur due to the incentives to meet LNG export contracts, an alternative outcome may be that the supply from these LNG facilities may not be forthcoming, leading to an additional potential shortfall, or proposed project delays.

Demand growth from the Large Industrial market segment represents the largest contribution to forecast demand. Several large industrial developments at Gladstone over the next three years are expected to increase annual Large Industrial market segment demand by an average of 8% between 2013 and 2019.[7] The domestic winter peak day demand at Gladstone (excluding LNG exports) is expected to grow from approximately 140 TJ/d to between 301 TJ/d and 319 TJ/d in 2022 under the Slow Rate of Change and the Planning scenarios, respectively.

Figure 5-1 — Gladstone annual supply-demand balance, Planning scenario, 1-in-20



Competition for gas supply may impact the timing or scope of large industrial projects currently proposed in Gladstone. The QGP is currently running at or close to its full capacity of 142 TJ/d[8], and the modelling indicates that QGP capacity is insufficient to supply the additional Large Industrial market segment demand at Gladstone.

[6] The modelled pipeline and facility capacities are based on the daily production of the committed field development.
[7] For more information, see Appendix A, Section A.4.5.
[8] A figure detailing Gas Bulletin Board (GBB) capacity and daily flow data is available in the GBB analysis included in the accompanying data files. AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed 26 November 2012.

The modelled winter peak deficit is approximately 20 TJ/d in 2013, indicating that proposed projects are likely to be deferred until gas is secured.

AEMO understands that Jemena and the broader industry are aware of the QGP pipeline constraints, and is investigating increasing its capacity.[9]

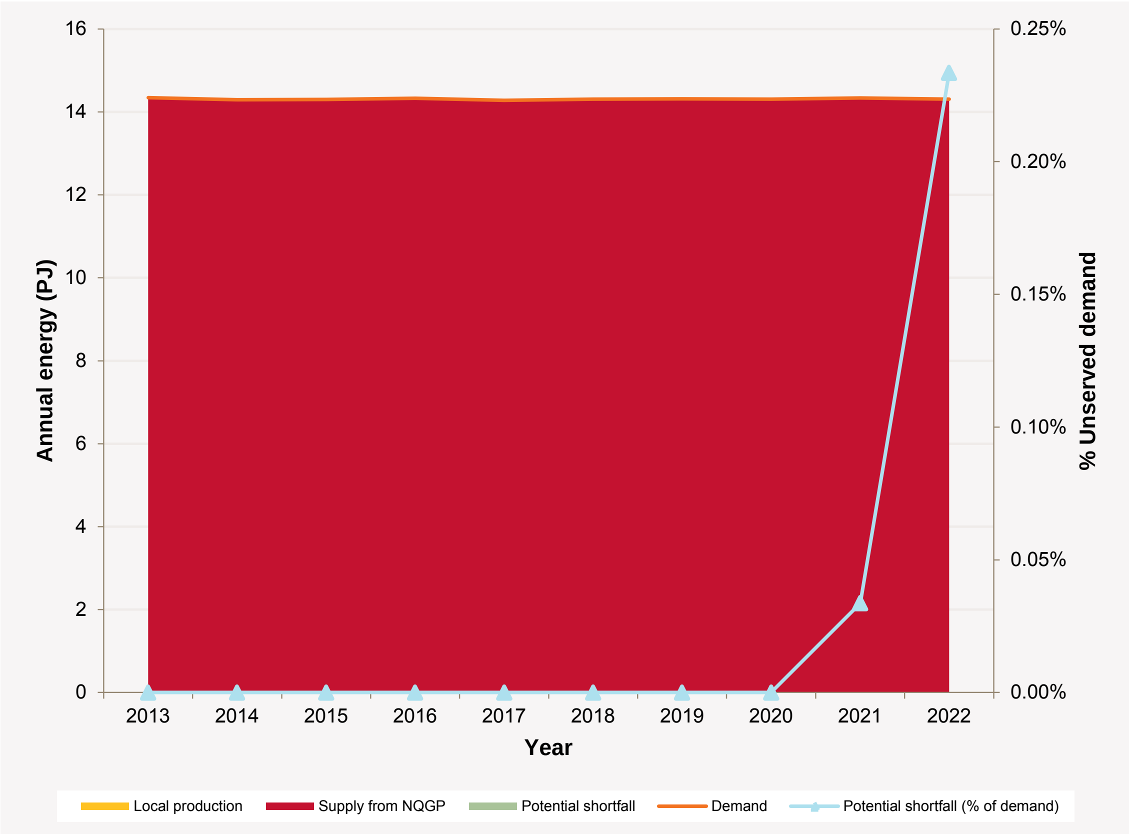
Opportunities for increasing supply include the following:

- Augmenting the QGP.
- Development at Moranbah and a new pipeline to transfer supply to the Gladstone area.

Townsville

Figure 5-2 shows annual supply and demand[10] for Townsville under the Planning scenario and 1-in-20 peak demand conditions over the outlook period. Demand at Townsville is supplied by the processing facility at Moranbah via the North Queensland Gas Pipeline (NQGP). New Large Industrial market segment gas demand is expected to be located at Moranbah from 2013.[11]

Figure 5-2 — Townsville annual supply-demand balance, Planning scenario, 1-in-20



[9] IES. Modelling and analysis for the 2012 GMR – part 3. Pg 108. Available http://www.deedi.qld.gov.au/documents/energy/gas-market-modelling-GMR-2012-part-3.pdf. Viewed 28 September 2012.

[10] The figure includes a line depicting the percentage of potential shortfall (relative to total demand), since the potential shortfall is too small to visualise.

[11] Incitec Pivot commenced operating the Moranbah ammonium nitrate plant in July 2012, with the commissioning of an ammonium plant to proceed in 2013 (NQGP). Incitec Pivot. Available http://www.asx.com.au/asxpdf/20120702/pdf/427548hz3mrv8k.pdf. Viewed 23 October 2012.

Planning scenario modelling indicates potential shortfalls in meeting peak demand in Townsville by 2021, caused by insufficient processing capacity at Moranbah. No potential shortfall is expected under the Slow Rate of Change scenario due to the low domestic demand projection. The NQGP has sufficient capacity to meet demand under both scenarios.

Opportunities to avoid the potential shortfalls include the following:

- Expansion of the existing processing facility at Moranbah.
- Development of a new processing facility at Moranbah.
- Additional compression to the existing pipeline to increase linepack.
- Development of a storage facility at Moranbah.
- Development of a storage facility at Townsville.

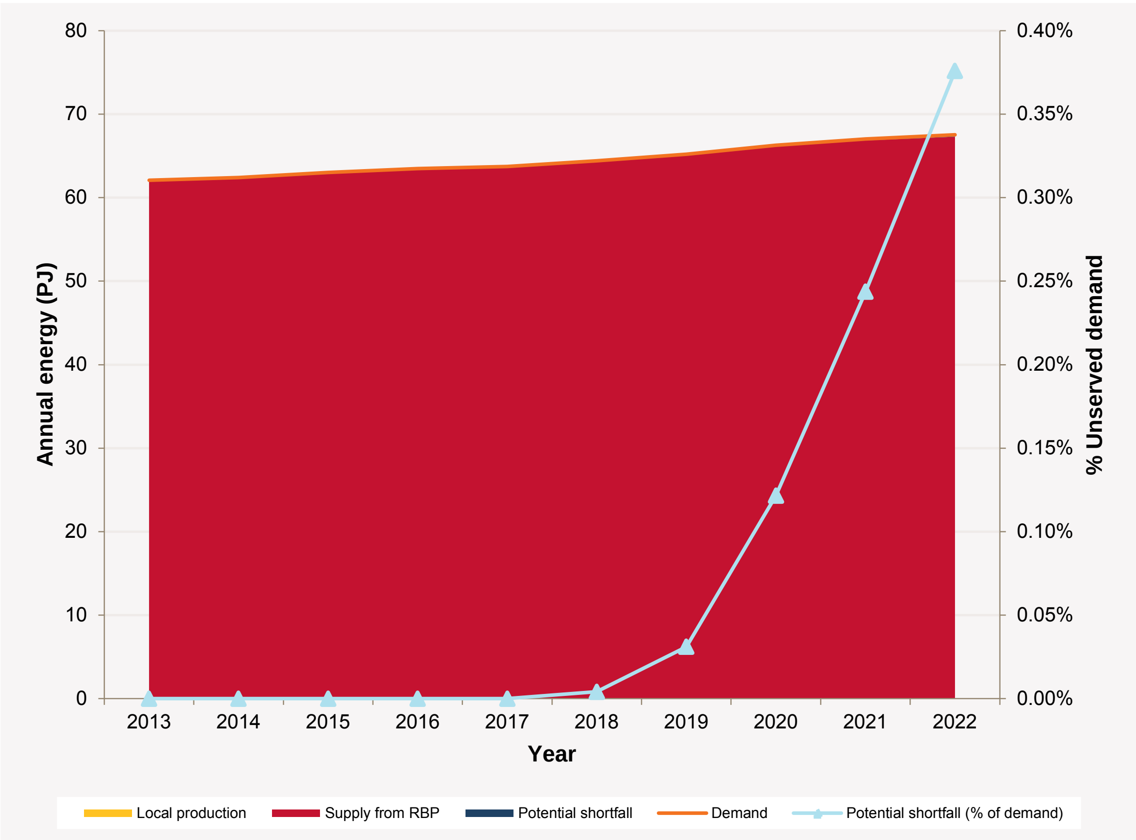
Brisbane

Figure 5-3 shows annual supply and demand for Brisbane under the Planning scenario and 1-in-20 peak demand conditions over the outlook period.

Demand at Brisbane is supplied from developments in the Bowen-Surat Basins via the Roma to Brisbane Pipeline (RBP).

Under the Planning scenario, Brisbane has potential shortfalls for a 1-in-20 winter peak demand condition in 2018, and a 1-in-2 winter peak demand condition in 2020 as a consequence of Mass Market and Large Industrial market segment gas demand growth. Brisbane experiences no potential shortfall under the Slow Rate of Change scenario.

Figure 5-3 — Brisbane annual supply-demand balance, Planning scenario, 1-in-20



Opportunities include the following:

- Development of a pipeline to transfer coal seam gas from the Clarence–Moreton Basin.[12]
- Augmentation of the Roma to Brisbane pipeline (RBP).

Mount Isa

Demand at Mount Isa is supplied by development in the Cooper-Eromanga and Bowen-Surat Basins via the Carpentaria Gas Pipeline (CGP). The modelling indicates that summer peak day demand at Mount Isa exceeds the modelled CGP capacity of 119 TJ/d between 2013 and 2015.

The CGP has capacity to store a significant amount of linepack, which exceeds the potential shortfall over the 10-year outlook period. As a result, the potential shortfall suggested by the modelling is expected to be able to be avoided through the use of existing facilities.

5.2.2 New South Wales/Australian Capital Territory

The 2012 modelling did not show any potential shortfalls in New South Wales (including the Australian Capital Territory), suggesting the existing pipeline and processing facilities are likely to be sufficient to supply demand for the 10-year outlook period.

New South Wales is a net importing state and its customers have to compete for supply with growing demand in Victoria, Queensland and South Australia. The state gets most of its supplies from South Australia via the Moomba to Sydney Pipeline (MSP), and from Victoria via the Eastern Gas Pipeline (EGP) and the New South Wales–Victoria Interconnect (IC). Changes in gas flows in other states resulting from increased LNG exports may have a direct impact on supply to New South Wales.

Sydney

Sydney is the largest demand centre in New South Wales and contributes approximately 80% to the state's demand. Sydney's demand is met by imports from the MSP, the EGP, and production from the Camden gas plant located south west of Sydney.

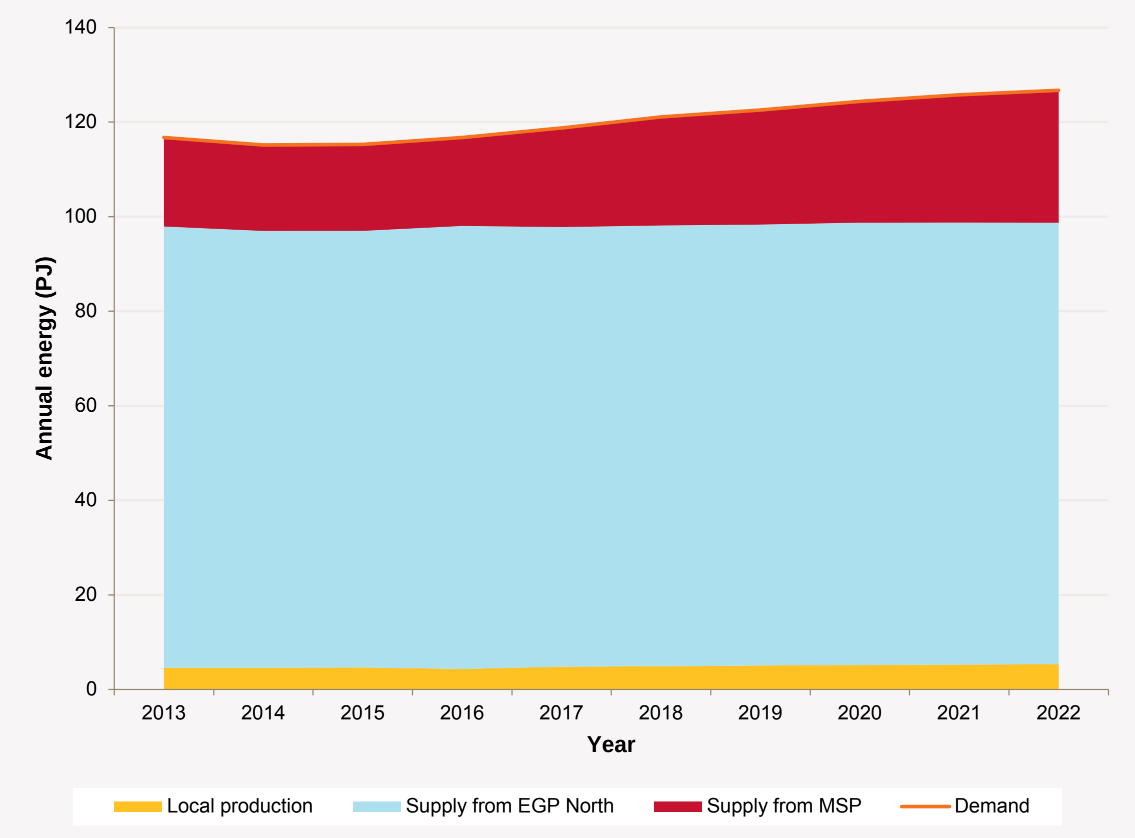
[12] The proposed Lions Way project planning application has been withdrawn from the New South Wales Government. In its current form, the project needs to be assessed under several environmental protection laws as it crosses state borders and is close to declared national parks and World Heritage areas (New South Wales Government. Available: http://majorprojects.planning.nsw.gov.au/page/project-sectors/transport--communications--energy---water/pipelines/?action=view_job&job_id=2754. Viewed 23 November 2012. Metgasco. Project Description Report. Pg 10. Available: https://majorprojects.affinitylive.com/public/87e26848a8cb47e24d39b40ca997ab7a/Preliminary%20Environmental%20Assessment.pdf. Viewed 8 October 2012).

Figure 5-4 shows annual supply and demand for Sydney under the Planning scenario and 1-in-20 peak demand conditions over the outlook period.

The modelling suggests both the EGP and the IC maintain very high utilisation with average rates of approximately 90% and 70%, respectively. The MSP has relatively low utilisation with an average rate of approximately 20%. Under the Slow Rate of Change scenario, the pipeline utilisation rates decrease from 2015, driven by a reduction in gas demand for gas powered generation (GPG). The reduction in GPG under this scenario is the result of the removal of carbon pricing, and the NTNDP electricity modelling of the Large-scale Renewable Energy Target (LRET). Electricity demand under the Slow Rate of Change scenario was forecast to be lower and the LRET fixed, driving more generation from renewables and less generation from GPG.

The local processing facility is expected to maintain high utilisation with an average rate above 90% over the outlook period. There were no modelled potential shortfalls for Sydney providing there is supply from the MSP.

Figure 5-4 — Sydney annual supply-demand balance, Planning scenario, 1-in-20



5.2.3 Victoria

Victoria is a net gas exporter. Production from its offshore conventional gas fields continues to be sufficient to supply the growing demand in Victoria, South Australia, and New South Wales (including the Australian Capital Territory), and Tasmania over the 10-year outlook period. No potential shortfalls have been identified in Victoria for the outlook period.

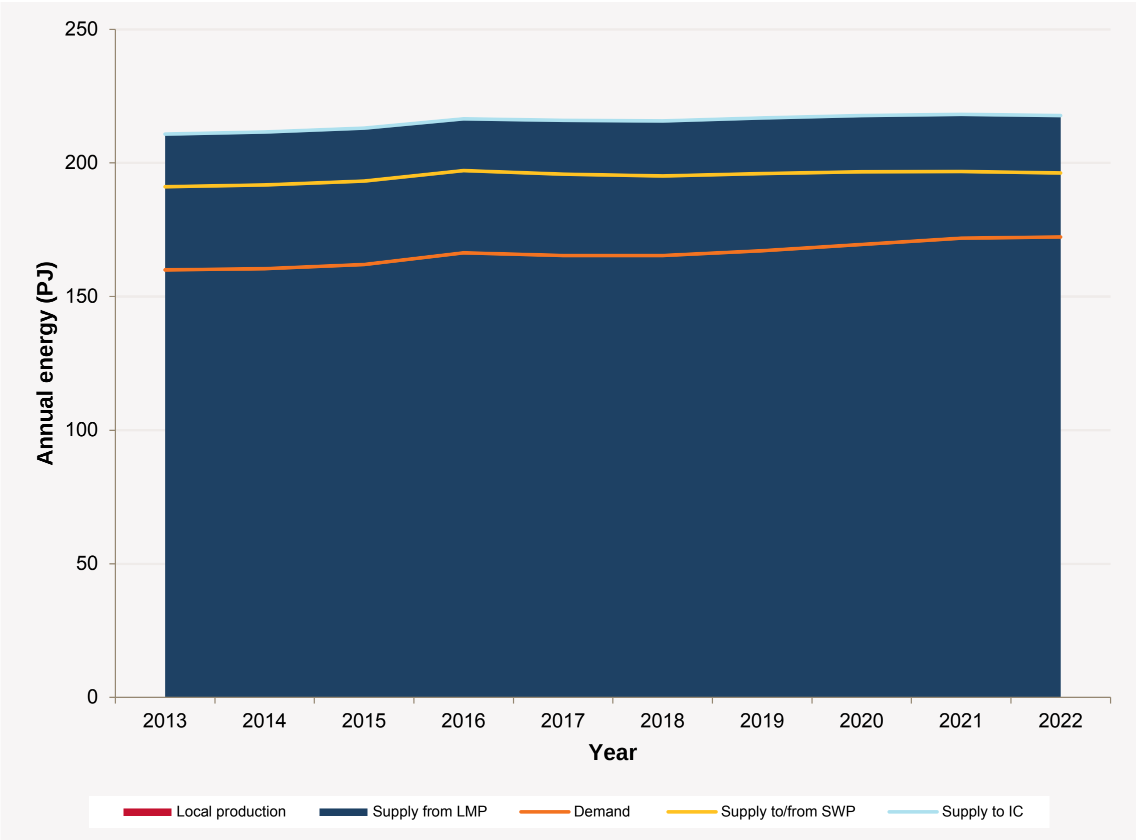
Melbourne

Figure 5-5 shows annual supply and demand for Melbourne under the Planning scenario and 1-in-20 peak demand conditions over the outlook period.

Melbourne is the largest demand centre in Victoria, representing approximately 77% of total state demand. Melbourne has no local processing capacity and demand needs to be met by developments in the Gippsland, Bass and Otway Basins.

Production from the Gippsland Basin via the Longford to Melbourne Pipeline (LMP) supplies Melbourne demand as well as interstate exports. The LMP's expected utilisation rate is well above 50%. The IC pipeline and the South West Pipeline (SWP) connect Melbourne with the MSP and the SEA Gas Pipeline (SEA), respectively. Both pipelines have the capability to reverse their flow.

Figure 5-5 — Melbourne annual supply-demand balance, Planning scenario, 1-in-20



5.2.4 South Australia

South Australia is reliant on gas supply from Moomba production facilities via the Moomba to Adelaide Pipeline System (MAPS), and imports additional supply from Victoria via the SEA.

In South Australia, the modelling indicates that the processing and gas transmission infrastructure is sufficient to meet state peak and annual demand. No potential shortfalls have been identified in South Australia for the outlook period.

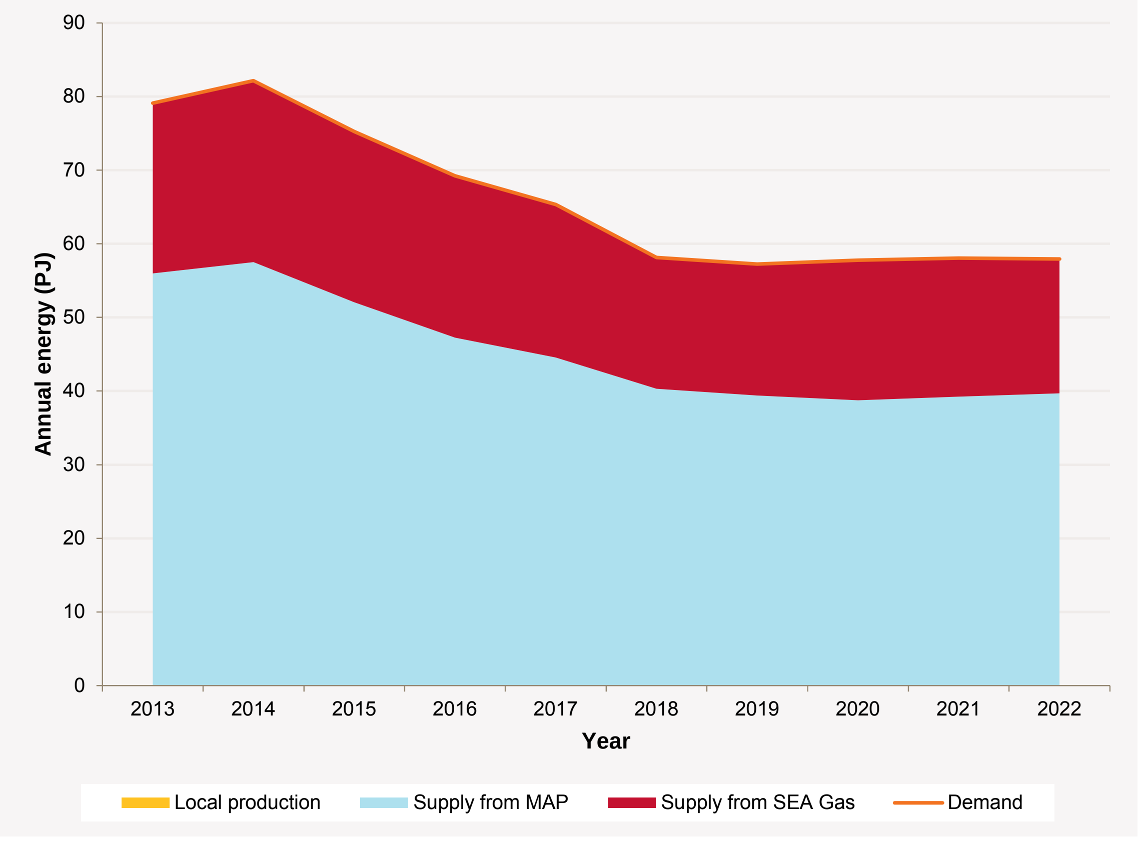
Adelaide

Figure 5-6 shows annual supply and demand for Adelaide under the Planning scenario and 1-in-20 peak demand conditions over the outlook period.

More than 80% of demand is located in or near Adelaide, with GPG being the largest consumer. Despite continuous growth in Mass Market and Large Industrial market segment demand, overall growth is projected to be negative from 2015 onward, driven by decreasing GPG demand. In the 2012 NTNDP modelling, more than 1,300 MW of wind generation is projected to be planted in South Australia in 2015 to fulfil the LRET, resulting in reduced GPG demand.

The MAPS transfers supplies from Moomba to Adelaide, and has an average utilisation rate of 59% under the Planning scenario, and 46% under the Slow Rate of Change scenario. Supplies from Otway basin are transferred via the SEA to Adelaide, which has an average utilisation rate just below 20% under both scenarios. Supplies from either of these two pipelines are sufficient to meet Adelaide demand.

Figure 5-6 — Adelaide annual supply-demand balance, Planning scenario, 1-in-20



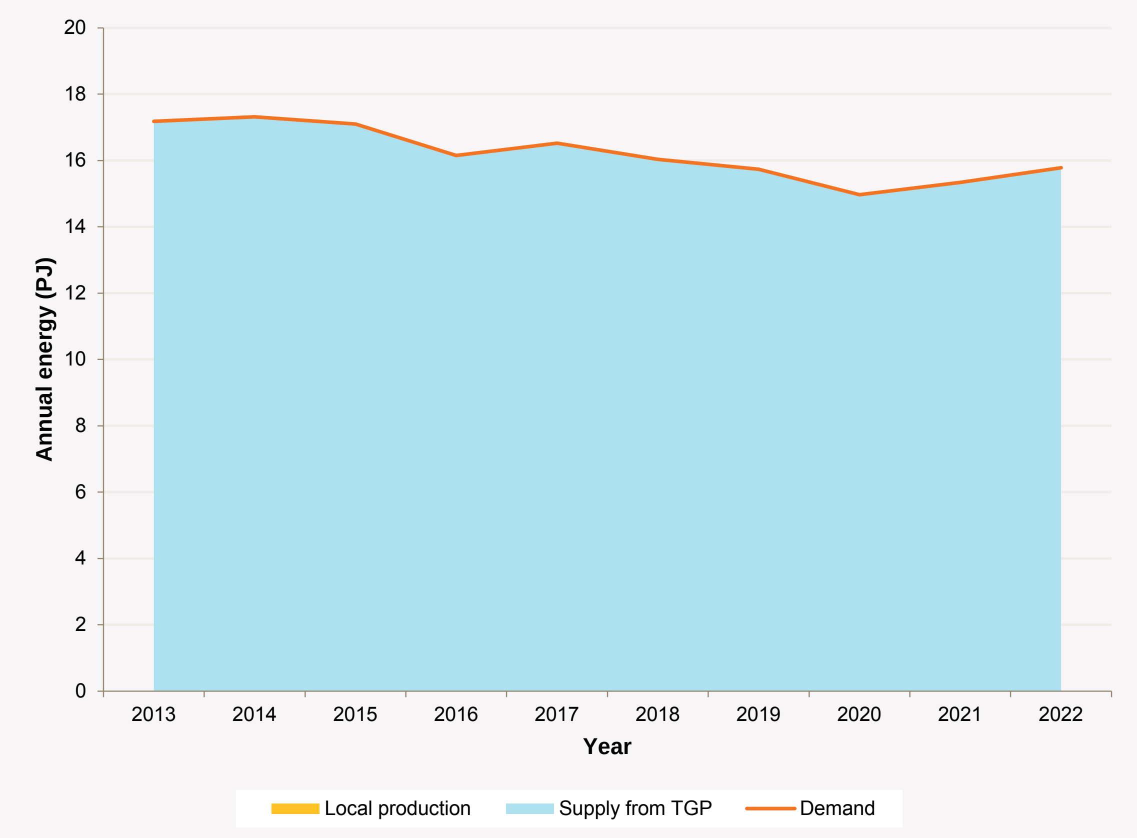
5.2.5 Tasmania

Figure 5-7 shows annual supply and demand for Tasmania under the Planning scenario and 1-in-20 peak demand conditions over the outlook period.

Demand in Tasmania is relatively small, representing 2.5% of Eastern and South Eastern Australian gas demand in 2013, and decreasing to less than 1% in 2022. No local production is located in Tasmania, and all demand is supplied from the Tasmanian Gas Pipeline (TGP).

No potential shortfalls have been identified in Tasmania. Modelling indicates that production from Gippsland is sufficient to meet Tasmania's modest demand growth. The average pipeline utilisation rate for the TGP is 34% under the Planning scenario and 26% under the Slow Rate of Change scenario.

Figure 5-7 — Tasmanian annual supply-demand balance, Planning scenario, 1-in-20



5.3 Modelling overview

The 2012 GSOO supply and demand model is a linear program model that simulates gas market supply and demand conditions from 2013 to 2032. The model's optimisation logic uses information about gas demand for the Large Industrial, Mass Market, GPG, and LNG market segments together with processing facility and pipeline constraints to balance supply with demand. The model's objective function[13] aims to minimise the total costs to the market.

[13] The model's primary optimisation algorithm.

Based on the 2011 GSOO model[14], the modelling for 2012 maintains the following assumptions:

- Mass Market and Large Industrial market segment gas demand areas.
- GPG location and supply assumptions.
- Gas processing and storage facility locations.
- Gas basin nodal representations.

Key 2012 modelling improvements include the following:

- The objective function used production and transmission costs, providing a more economical gas supply solution.
- Daily demand traces were used to capture demand diversity.[15]
- The GSOO gas modelling and NTNDP electricity modelling use a feedback loop to co-optimise electricity and gas transmission augmentations with generation expansion, improving the quality of generation expansion plans and GPG demand forecasts (for more information about the GPG projection methodology see Appendix A, Section A.5.2).
- Storage facilities were modelled using a post-processing tool.
- An updated nodal typology (available from the accompanying data files on the AEMO website[16]) consistent with the report Review of Gas Facilities: Existing and New.[17]
- Information involving processing, transmission and storage capacities for existing and proposed projects were sourced from industry participants, input reports (see Chapter 2), and publicly available information. Long-term estimates were used for modelling.[18] Actual capacities are dynamic, however, and are subject to factors like seasonality, weather, and operational conditions, which were considered in the post analysis.

Contract positions for pipelines were not modelled as this information is not necessarily disclosed to the market. As a result, modelling is based on production and transmission costs only. The results represent a long-term market equilibrium condition and may differ from short-term market supply.

The model assumes gas demand for LNG export is met by a corresponding growth in processing and pipeline capacity. In all scenarios, gas demand for LNG occurs at Curtis Island, which is separated from domestic demand at Gladstone. All LNG exports are projected to be supplied from the coal seam gas (CSG) resources located in the Bowen-Surat Basin. The model has been structured to provide flexibility for allowing spare LNG processing and pipeline capacity to supply the domestic market.

Committed projects are included in the model based on available information.

The study also investigated options to resolve any potential shortfalls. Publicly announced projects were the first ones to be studied. If there was no proposed project available, AEMO added what was believed to be the most economical option to resolve the issue.

[14] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2011-Gas-Statement-of-Opportunities. Viewed 8 October 2012.

[15] Daily demand traces were developed using 2010 Gas Bulletin Board historical flow data as the reference traces for most demand centres, except for Gladstone, where the QGP had a major upgrade in late 2010, and the 2011 flow trace was used to exclude the upgrade's impact. This also enabled the daily profiles to match the historical input profiles for the forecasts.

[16] AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed 19 November 2012.

[17] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Processing-Transmission-and-Storage-Facilities. Viewed 27 September 2012.

[18] See note 17.

The following conditions were modelled:

- A 1-in-2 peak demand condition.[19] This projected level of demand is expected, on average, to be exceeded once in two years.
- A 1-in-20 peak demand condition.[20] This projected level of demand is expected, on average, to be exceeded only once in 20 years.

5.4 Links to supporting information

This section provides links to other information about gas infrastructure adequacy and opportunities.

Information source	Website address
Accompanying data files (including full modelling results, Gas Bulletin Board analysis, figure data, tables, and figures)	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
Review of Gas Facilities: Existing and New	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Processing-Transmission-and-Storage-Facilities
2012 Scenario Descriptions	http://www.aemo.com.au/~/media/Files/Other/planning/2418-0005%20pdf.ashx

[19] Also known as a 50% probability of exceedence (POE) or the 50% peak day.
[20] Also known as a 5% probability of exceedence (POE) or the 5% peak day.

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APPENDIX A - GAS DEMAND PROJECTIONS FOR EASTERN AND SOUTH EASTERN AUSTRALIA

A.1 Introduction and overview

This appendix presents information about the 2012 gas demand projections over the 20-year outlook period from 2013–2032. The annual and peak day demand projections represent total demand, demand by market segment, and demand by region.

The appendix also includes information about two of six scenarios developed by AEMO (the Planning scenario and the Slow Rate of Change scenario), as well as the assumptions and methodology used to produce the projections, and key factors expected to affect demand during the outlook period.

A.1.1 Appendix structure

Section A.1, Introduction and overview, provides information about the demand group definitions, market segments, key demand factors, and scenarios.

Section A.2, Total demand projections for all market segments, provides the total annual and peak day demand for the combined market segments (Mass Market, Large Industrial, GPG, and LNG) by scenario.

Section A.3, Total demand projections for individual market segments, provides the annual demand projections for the individual market segments by demand group (where relevant).

Section A.4, Regional demand projections, provides the annual and peak day demand projections by demand group.

Section A.5, Demand projection methodology, provides information about the demand projection methodology including data sources, supply assumptions for each market segment, peak day demand projection methodology, and the diversity of demand between market segments.

A.1.2 Demand groups

Eastern and South Eastern Australia is divided into five demand groups:

- Demand Group 1 (SA) includes South Australia.
- Demand Group 2 (VIC) includes Victoria.
- Demand Group 3 (TAS) includes Tasmania.
- Demand Group 4 (NSW/ACT) includes New South Wales and the Australian Capital Territory.
- Demand Group 5 (QLD) includes Queensland.

For the purpose of analysing GSOO gas demand projections, specific demand areas are considered within each demand group, with each demand area being defined as either a demand centre (for example Sydney), a GPG demand zone (for example South West Queensland), or as a pipeline, including any smaller lateral pipelines that branch from the major transmission pipeline.

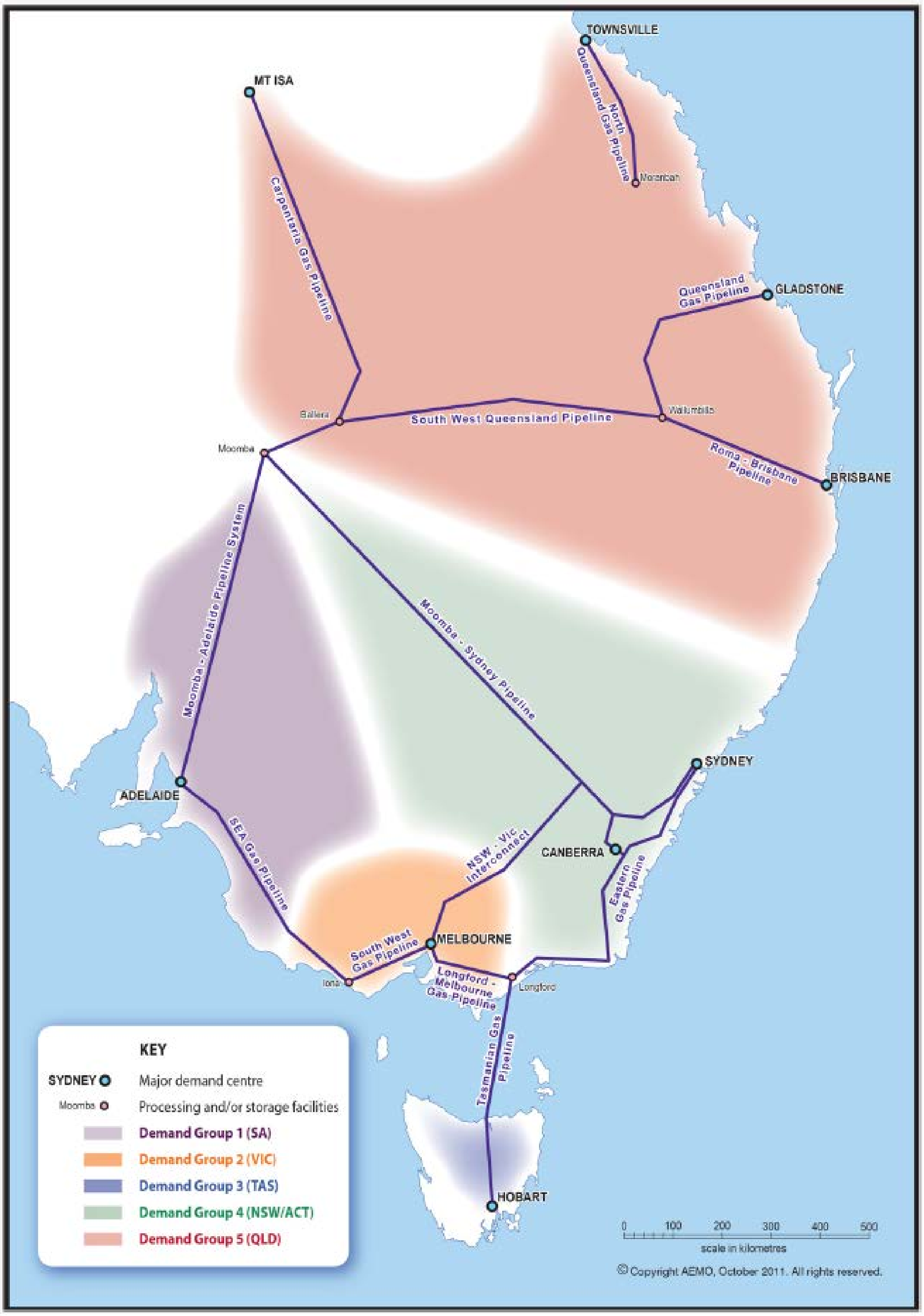
As an example, Demand Group 1 (SA) includes the following demand areas:

- The Adelaide demand centre.
- The South East Australia Gas Pipeline and its lateral pipelines.
- The Moomba to Adelaide Pipeline System and its lateral pipelines.

Locally supplied and consumed gas (for example Camden CSG in New South Wales) is not included because it does not constrain the transmission network. As a result, total gas demand does not equal total gas consumption.

Figure A-1 shows the gas transmission network and demand groups.

Figure A-1 — Gas transmission network and demand groups



A.1.3 Market segments

Gas demand projections were developed for the following gas market segments:

- Liquefied natural gas (LNG) export.
- Gas powered generation (GPG).
- Mass Market (MM), which includes residential demand and business demand (of less than 10 TJ/yr).
- Large Industrial (LI) consumers with gas demand greater than 10 TJ/yr.

Total gas demand comprises all four market segments, referred to as the LNG, Large Industrial, Mass Market and GPG market segments. Domestic gas demand comprises the Large Industrial, Mass Market and GPG market segments.

A.1.4 Key demand factors

Over the outlook period, changes to annual gas demand in Eastern and South Eastern Australia are projected to be influenced by the following factors:

- Global and national macro factors, involving the following:
  - The installation of LNG export facilities, which is influenced by international energy prices and demand.
  - Climatic and weather pattern changes, which influence the amount of gas used for space heating.
  - Population growth or decline, which drives changes in the number of residential gas connections.
  - Economic growth or decline at territory, state or national level.
- Infrastructure development and exploration, involving the following:
  - Capital and operating costs for GPG and for competing energy technologies.
  - Technological developments in the gas industry and in competing industries.
  - Gas processing and transmission capacity.
  - Gas reserves and availability.
- Policy involving the following:
  - Carbon pricing.
  - Energy efficiency policy measures.
  - Renewable energy support policies.
- Market factors involving the following:
  - Electricity demand growth or decline.
  - Prices and availability of competing energy sources.
  - Gas prices.

Demand projections are presented for two peak day probability conditions:

- 1-in-2 peak day demand has a 50% probability of exceedence (POE). This projected level of demand is expected, on average, to be exceeded once in two years.
- 1-in-20 peak day demand has a 5% POE. This projected level of demand is expected, on average, to be exceeded only once in 20 years.

A.1.5 Scenarios

The Planning scenario used the following basis for its development:

- Based on AEMO's best estimate of the future direction of the major drivers.
- Designed to include any policy or other changes that can be predicted with reasonable certainty.
- Designed as a central growth scenario.
- Includes currently legislated carbon policies based on the Australian Treasury's Core scenario.
- Currently estimated rates of development of new technologies.

The Slow Rate of Change scenario is based on the Planning scenario, with changes to some key assumptions involving lower growth, a carbon price effectively of zero after the first three years, and slower development of new technologies.

Table A-1 lists the demand drivers underpinning each scenario.

Table A-1 — Broad definition of scenario demand drivers

Scenario	Economic growth	CO2-e reduction (%)	Carbon price	Green power	Coal price	LNG production
Planning	Medium	5	Core	Flat	Medium	Medium
Slow Rate of Change	Low	0	Core then 0 $/t CO2-e	Flat	Low	Low

A.2 Total demand projections for all market segments

This section provides Eastern and South Eastern Australian total annual demand projections for all market segments, which includes Mass Market, Large Industrial, GPG and LNG export.

It also provides Eastern and South Eastern Australian 1-in-20 peak day annual, summer, and winter demand projections for domestic demand (the Mass Market, Large Industrial and GPG market segments combined).

A.2.1 Total annual energy demand

Figure A-2 shows the total annual demand projections for the Planning and Slow Rate of Change scenarios for all market segments.

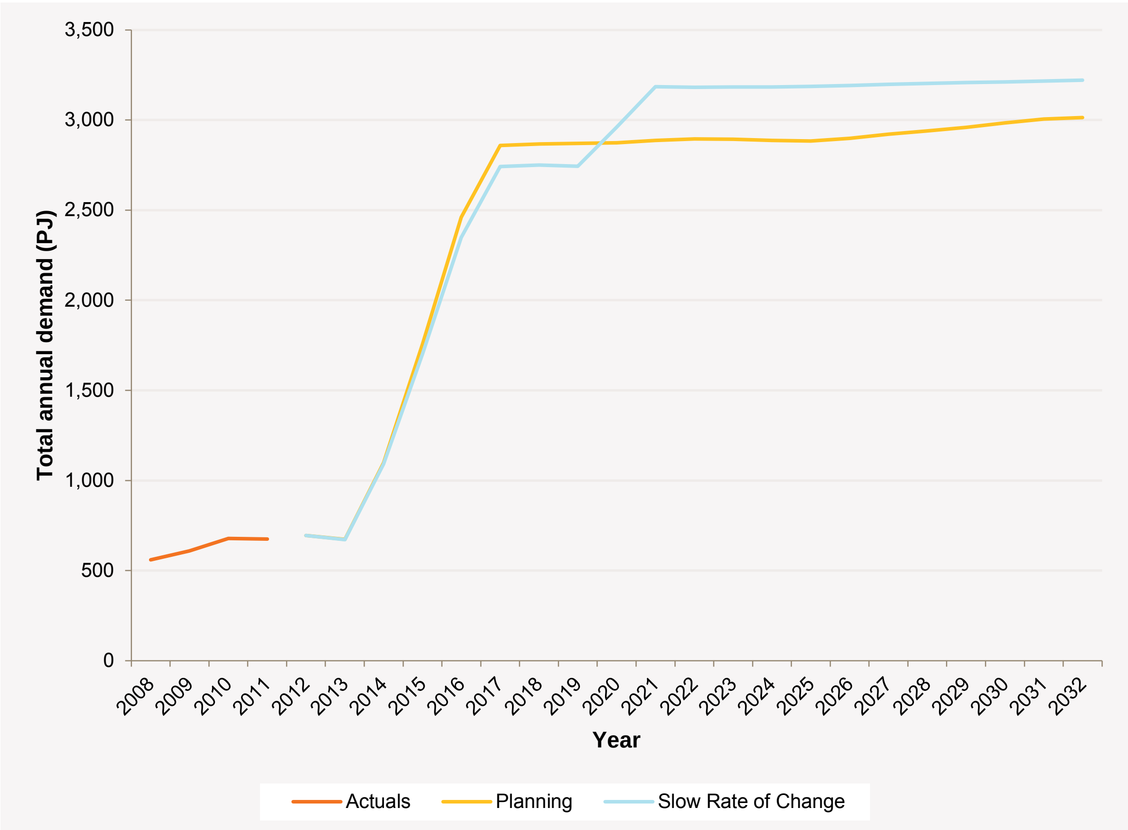
Demand growth under both scenarios is largely driven by LNG export, which is projected to exceed domestic demand by 2015. LNG export demand is expected to reach 2,150 PJ a year by 2017, accounting for more than 70% of demand under the Planning scenario and approximately 80% under the Slow Rate of Change scenario.

Demand increases under both scenarios until 2017 as a result of increased LNG production in Queensland to a total of eight LNG trains. Demand grows again under the Slow Rate of Change scenario from 2019–20 as additional LNG trains begin production.

Two additional trains are assumed under the Slow Rate of Change scenario driven by a number of factors including larger volumes of uncommitted domestic gas being available for export due to lower domestic gas demand, and reduced investment in renewable generation leading to higher LNG demand. For more information about the drivers of LNG growth under the Slow Rate of Change scenario, see Section A.3.3. No additional trains are developed after 2021–22 due to competition from probable LNG development in other areas of the world.

Domestic gas demand is projected to increase at an average annual rate of 1.3% under the Planning scenario, primarily due to Tariff V[1] growth driven by economic and population growth in all demand groups, and Large Industrial market segment growth in Queensland. Domestic gas demand then decreases at a rate of 0.5% under the Slow Rate of Change scenario due to a general decline in GPG gas demand.

Figure A-2 — Annual combined market segment demand by scenario



[1] Tariff V demand is the gas transportation Tariff applying to non-Tariff D load sites (Tariff D loads are metered sites with an annual consumption in excess of 10,000 GJ). This includes residential and small to medium-sized commercial and industrial gas users.

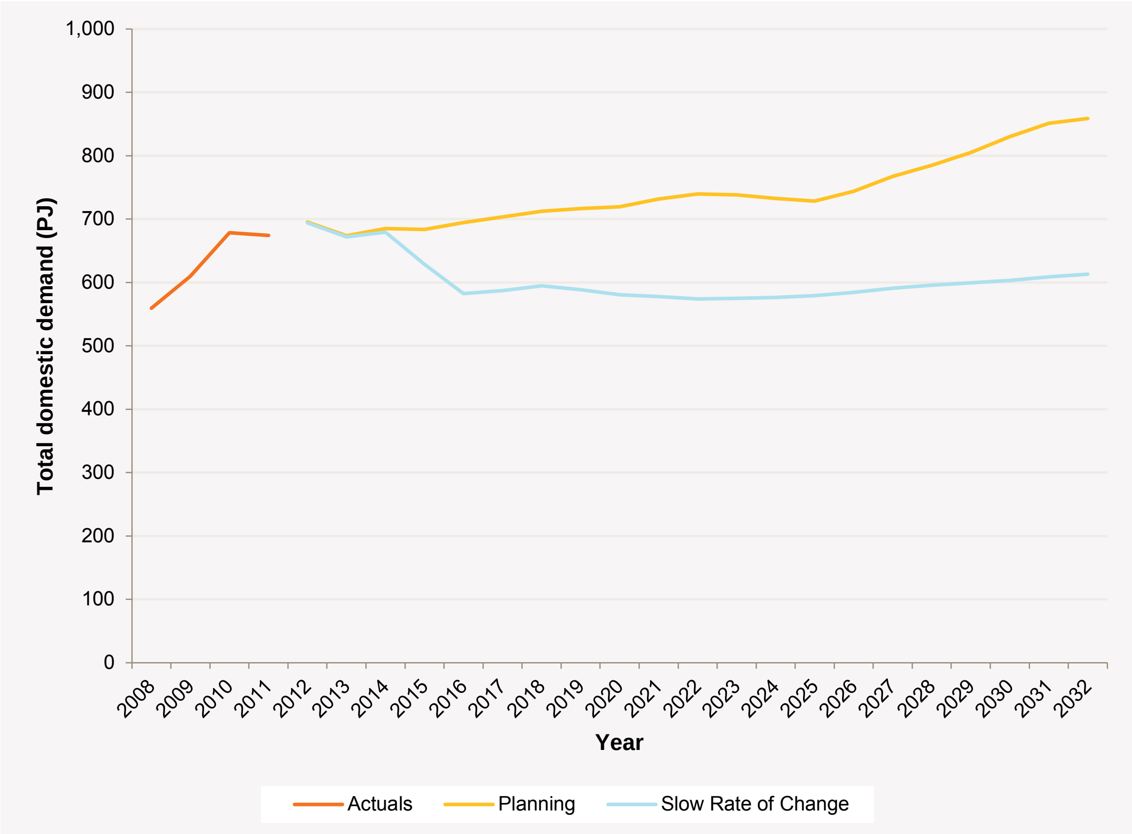
A.2.2 Annual domestic demand

Figure A-3 shows the annual demand projections for the Planning and Slow Rate of Change scenarios, for the combined Mass Market, Large Industrial and GPG market segments.

Under the Planning scenario, domestic demand grows at an average annual rate of approximately 0.6% until 2025 when it increases to approximately 2.4% until 2032. This reflects increased GPG demand from 2025 due to electricity demand growth.[2]

Under the Slow Rate of Change scenario, domestic demand declines at an average annual rate of approximately 4.7% between 2014 and 2016, before growing annually at 0.3% until 2032. The decline from 2014 reflects a decrease in GPG demand as the scenario assumes carbon prices are effectively zero after the end of the fixed price period, making GPG less competitive with other forms of generation.

Figure A-3 — Annual domestic demand by scenario



Combined Mass Market and Large Industrial market segment gas demand is projected to increase from approximately 483 PJ in 2012 to between 570 PJ and 600 PJ in 2032, reflecting average annual growth rates of 1.1% under the Planning scenario and 0.8% under the Slow Rate of Change scenario.

Combined Mass Market and Large Industrial market segment gas demand is projected to grow at higher rates in Queensland and Tasmania than in New South Wales (including the Australian Capital Territory), Victoria and South Australia for the following reasons:

- Queensland growth is driven by increasing demand from the Large Industrial market segment and mining projects in Queensland, including the installation of co-generation plants.

[2] This excludes LNG demand, which is significantly greater than domestic demand, to highlight changes driven by domestic demand.

- Tasmanian growth is driven by increases in industrial gas demand and increasing household gas connections.
- In New South Wales, Victoria, and South Australia, the combined Mass Market and Large Industrial market segment demand grows more slowly due to manufacturing and industrial site closures attributed to a high Australian dollar, high gas prices, and prolonged global economic uncertainty.

Figure A-4 shows the annual domestic demand projections for the Mass Market, Large Industrial and GPG market segments.

The Large Industrial market segment continues to be the largest source of domestic demand, with some variation between the Planning and Slow Rate of Change scenarios.

The Mass Market market segment projections show no significant difference between the scenarios, as they are growing in line with economic and population growth.

GPG demand is expected to vary significantly between the scenarios for the outlook period, with a sustained decline driven by the zero carbon price assumption under the Slow Rate of Change scenario (for more information about GPG demand drivers see Section A.3.2).

Figure A-4 — Annual domestic demand by market segment and scenario

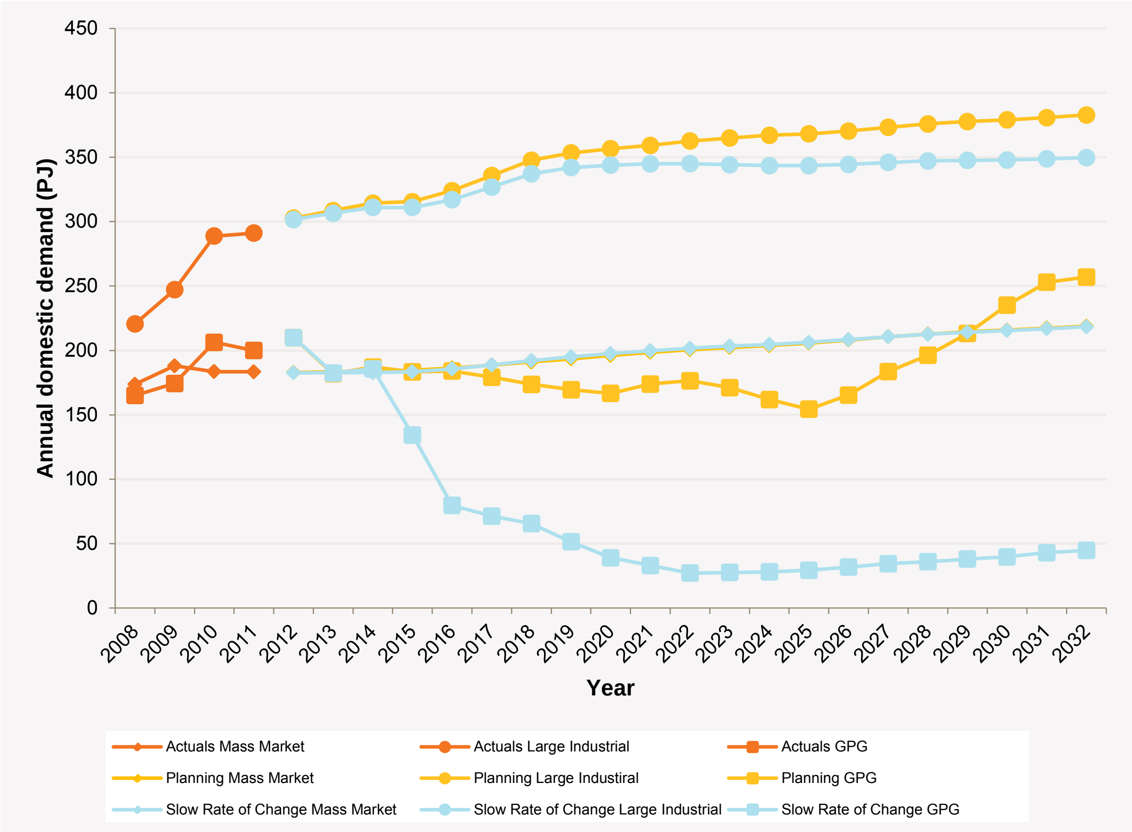


Figure A-5 shows the annual domestic demand projections under the Planning scenario by demand group.

The projections show steady growth in total demand from 2012. With the exception of South Australia, each demand group shows flat or positive demand growth until 2026. From 2026, Victorian demand is projected to significantly increase while demand in New South Wales, South Australia and Tasmania stabilises.

Figure A-5 — Annual domestic demand and projections, Planning scenario

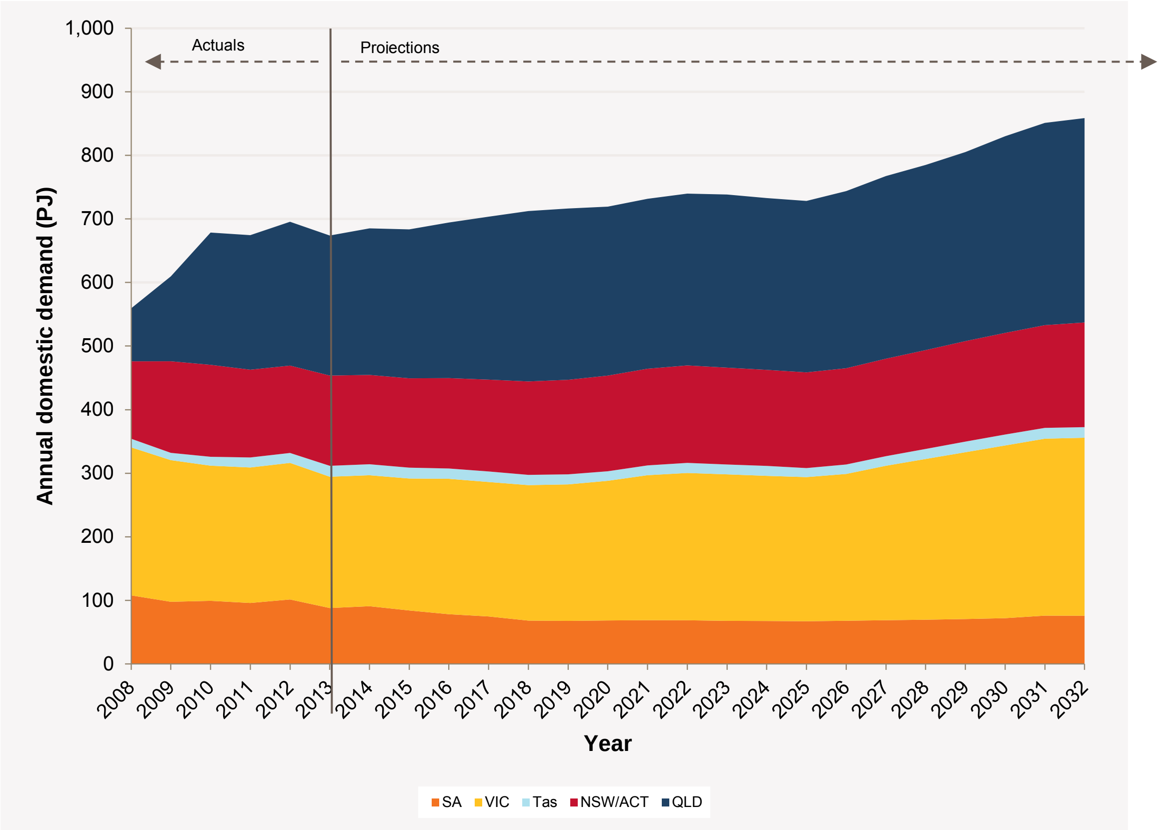
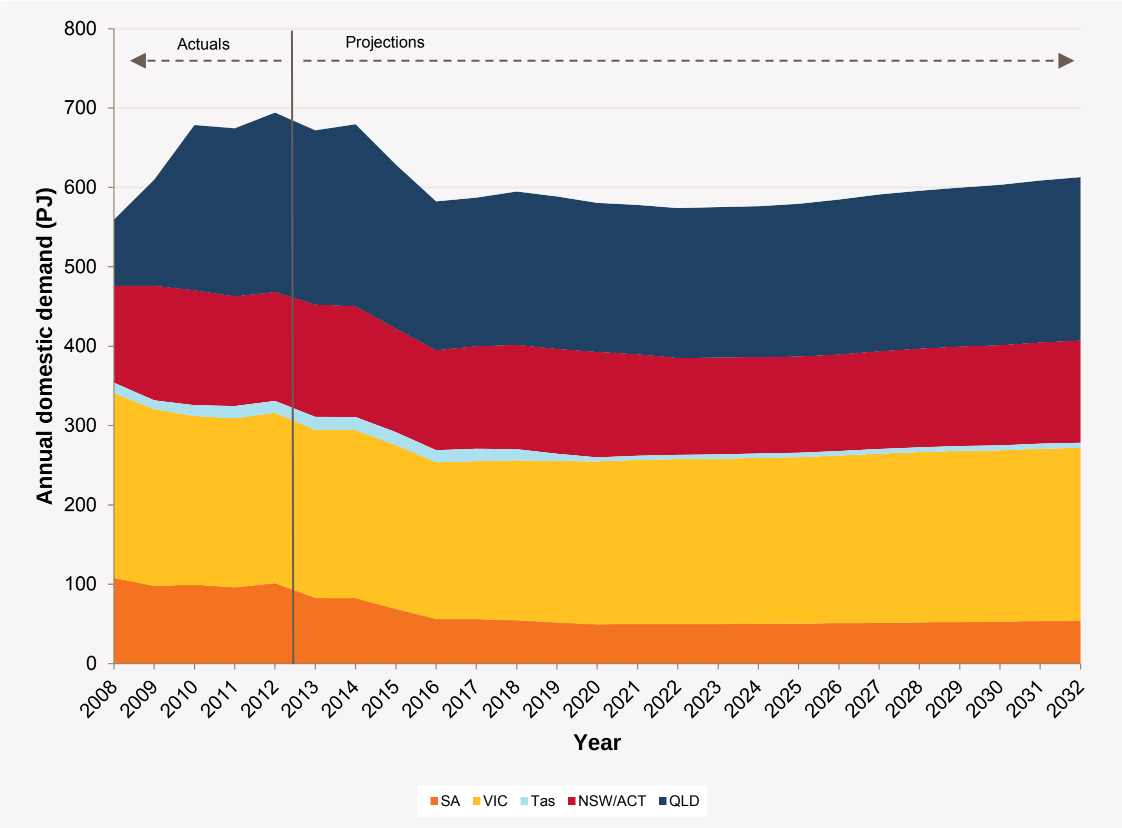


Figure A-6 shows the annual domestic demand projections under the Slow Rate of Change scenario by demand group. From 2014 there is a significant drop in GPG demand across all the demand groups, which coincides with this scenario's removal of the carbon price. After 2016, demand growth remains subdued and only returns to 2009 levels by the end of the outlook period in 2032.

Figure A-6 — Annual domestic demand and projections, Slow Rate of Change scenario



A.2.3 Peak day domestic demand

Figure A-7 shows summer and winter 1-in-20 peak day domestic demand projections.

Under the Planning scenario, winter and summer peak day demands increase at a similar rate. Under the Slow Rate of Change scenario, winter peak day demand growth is slower (resulting from negative winter peak demand growth in the GPG market segment, corresponding to the negative annual demand growth under the zero carbon price assumption), only reaching a similar level of demand as the summer peak day by 2032. Growth for summer projections is similar under both scenarios as the GPG peaking plants tend to operate in summer rather than winter.

Figure A-7 — Peak day domestic demand by scenario, summer and winter, 1-in-20

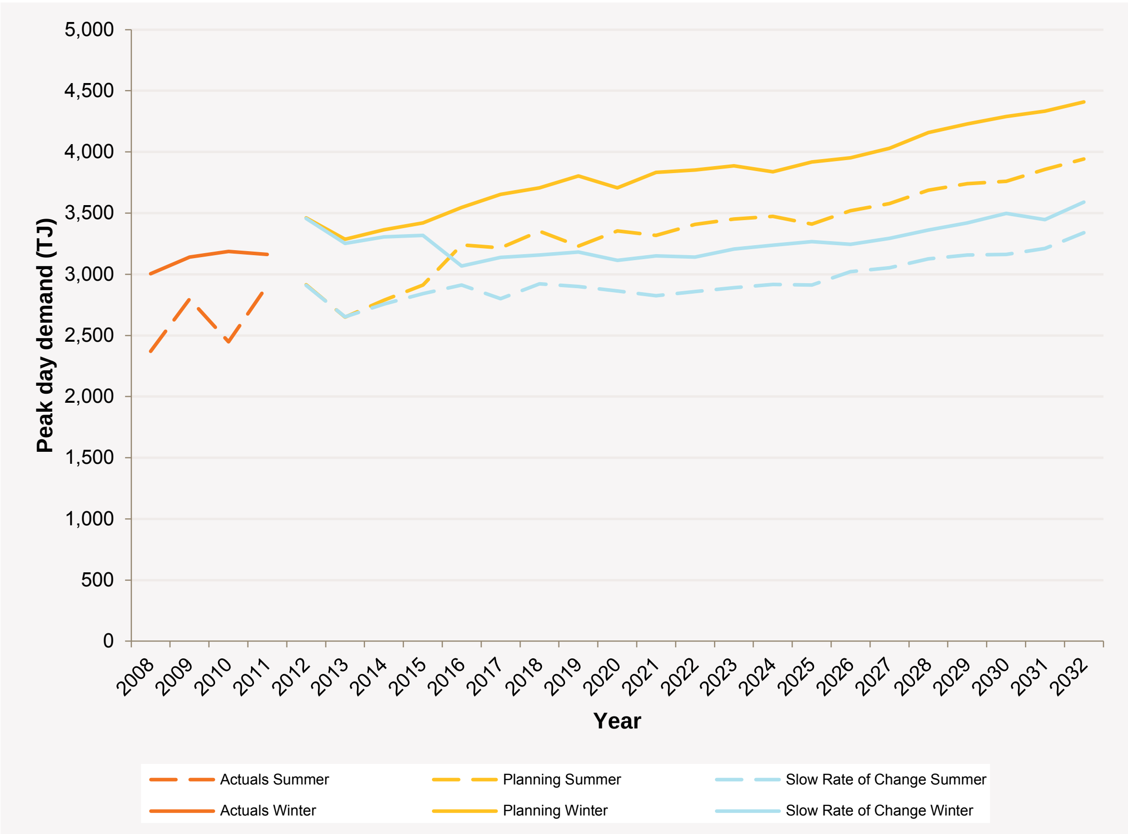


Figure A-8 shows the summer and winter 1-in-20 peak day demands for the combined Mass Market, Large Industrial and GPG market segments by scenario.

The growth in the summer and winter peak day combined Mass Market and Large Industrial market segment demand under the Slow Rate of Change scenario is expected to be approximately 0.2% lower than growth under the Planning scenario (which is consistent with the approximate 0.2% difference in annual demand growth rates between the two scenarios).

Under the Slow Rate of Change scenario, winter peak day demand decreases from 2015 onwards due to the availability of alternative generation sources at lower cost, given the scenario's zero carbon price assumption.

Figure A-8 — Peak day combined Mass Market, Large Industrial and GPG demand by scenario, summer and winter, 1-in-20

A.3 Total demand projections for individual market segments

This section provides demand projections for the GPG, LNG, and combined Mass Market and Large Industrial market segments.

A.3.1 Mass Market and Large Industrial market segment gas demand

Annual demand

Figure A-9 shows the annual demand projections for the combined Mass Market and Large Industrial market segment under the Planning scenario by demand group.

Combined Mass Market and Large Industrial market segment demand growth has declined in recent years after a period of rapid growth between 2008 and 2010. Between 2013 and 2032 an average combined Mass Market and Large Industrial annual growth rate of approximately 1.1% is projected under the Planning scenario and 0.8% under the Slow Rate of Change scenario. The variation between the two scenarios is driven by gas demand from the Large Industrial market segment.

Figure A-9 — Annual combined Mass Market and Large Industrial demand by scenario

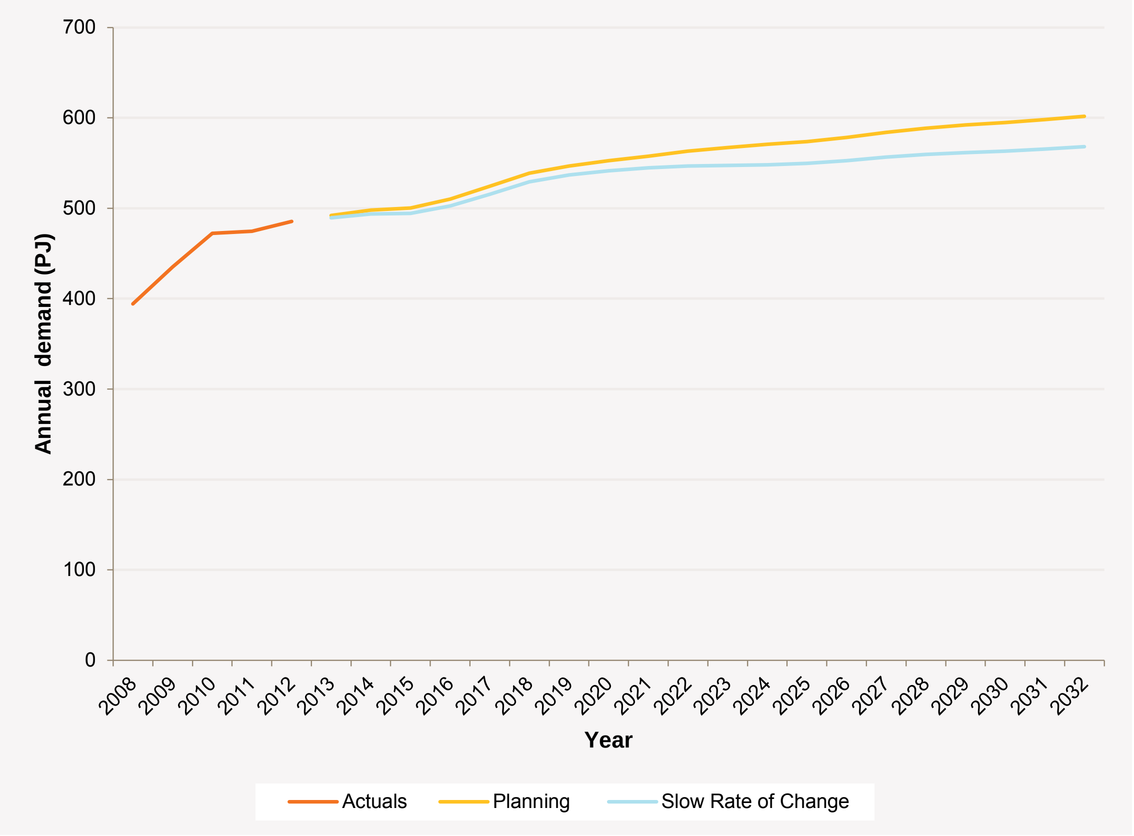


Figure A-10 shows the combined Mass Market and Large Industrial annual demand projections under the Planning scenario by demand group.

Figure A-10 — Combined Mass Market and Large Industrial annual demand, Planning scenario

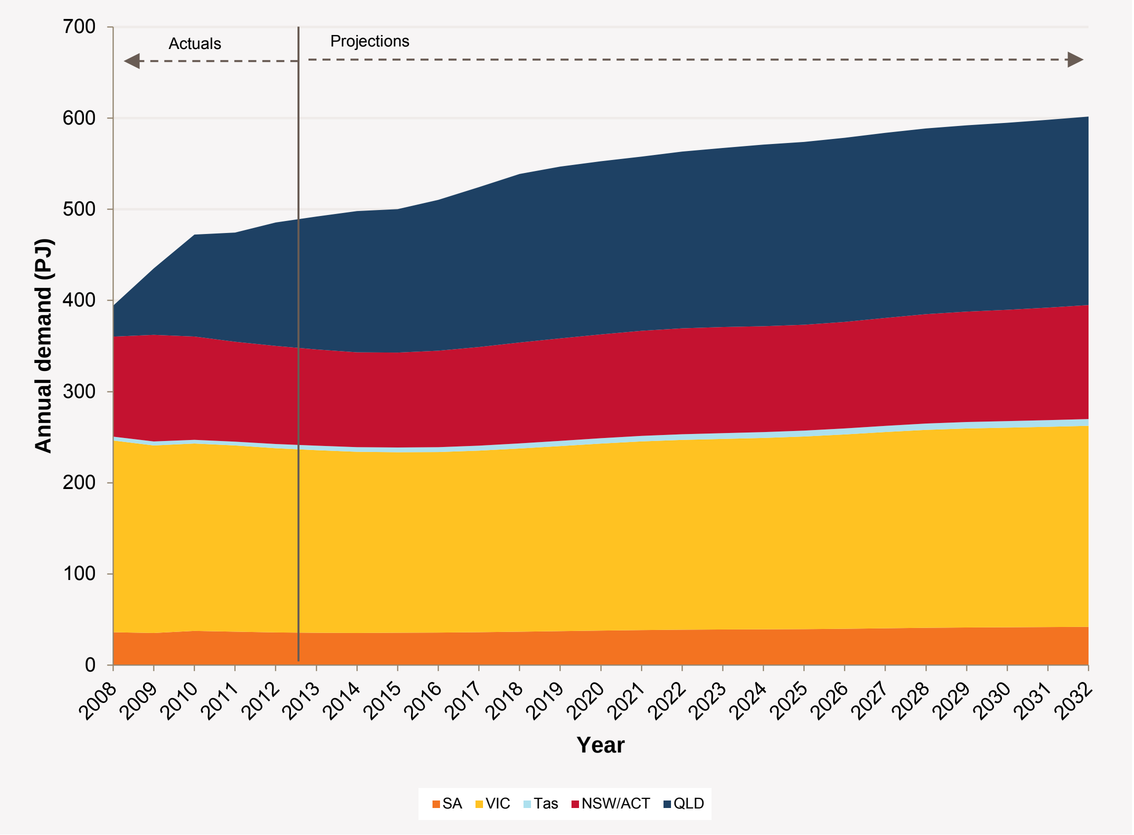
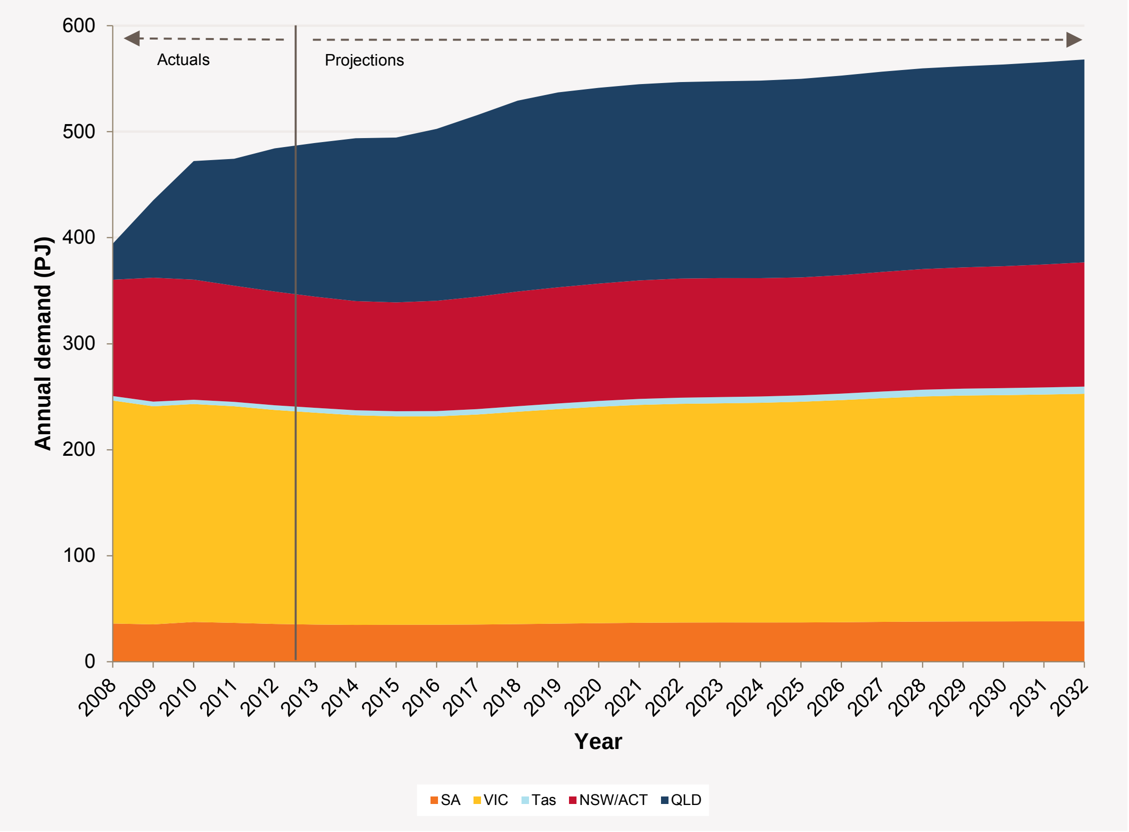


Figure A-11 shows the combined Mass Market and Large Industrial annual demand projections under the Slow Rate of Change scenario by demand group. The Slow Rate of Change scenario shows a similar growth pattern to the Planning scenario although growth is more subdued, particularly for the Queensland Demand Group.

Figure A-11 — Combined Mass Market and Large Industrial annual demand, Slow Rate of Change scenario



Combined Mass Market and Large Industrial market segment gas demand has the following overall characteristics for the outlook period:

- In Queensland, the combined Mass Market and Large Industrial market segment gas demand growth of the past four years continues, but at a slower rate. Gas demand is projected to grow at average annual rates of 1.9% and 1.5% under the Planning and Slow Rate of Change scenarios respectively, driven mainly by Large Industrial market segment demand and mining projects.
- In New South Wales and the Australian Capital Territory, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 0.9% and 0.6% under the Planning and Slow Rate of Change scenarios respectively. Large Industrial market segment growth, at average annual rates of 0.8% under the Planning scenario and 0.3% under the Slow Rate of Change scenario, is lower than residential, business and commercial segment growth for the outlook period.
- In Victoria, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 0.5% and 0.4% under the Planning and Slow Rate of Change scenarios respectively. Large Industrial market segment demand is projected to decrease due to reductions in the manufacturing sector as a result of a high Australian dollar coupled with higher gas prices over the outlook period.
- In South Australia, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 0.9% and 0.4% under the Planning and Slow Rate of Change scenarios respectively. Mass Market market segment demand is projected to grow at an average annual rate of

approximately 0.5% under both scenarios, and Large Industrial market segment demand is projected to grow at approximately 1.0% under the Planning scenario and 0.4% under the Slow Rate of Change scenario.

- In Tasmania, combined Mass Market and Large Industrial market segment gas demand is projected to grow at average annual rates of 2.2% and 2.1% under the Planning and Slow Rate of Change scenarios respectively, driven mainly by the Mass Market market segment. Under the Planning scenario, growth in residential demand (3.8%) outpaces business and commercial demand (1.6%) for gas. Average annual growth in Large Industrial market segment gas demand is projected to be approximately 2.0% under both scenarios.

In New South Wales (including the Australian Capital Territory) and Victoria, combined Mass Market and Large Industrial market segment demand is projected to decline from 2012, before returning to 2012 levels between 2017 and 2019. In New South Wales this is due to a short-term reduction in demand from the Large Industrial market segment. In Victoria it represents a persistent decline in Large Industrial market segment demand (eventually offset by increasing Mass Market market segment demand), which is due to a high Australian dollar coupled with higher gas prices. For information about the drivers for each demand group see Section A.2.2.

Summer and winter 1-in-20 peak day demands

Table A-2 shows the forecast 1-in-20 peak day 2032 demands by demand group and scenario.

Table A-2 — Combined Mass Market and Large Industrial summer and winter 1-in-20 peak day 2032 demand by demand group and scenario

	South Australia		Victoria		Tasmania		New South Wales /Australian Capital Territory		Queensland	
	Peak day demand (TJ)	Annual growth (%)	Peak day demand (TJ)	Annual growth (%)	Peak day demand (TJ)	Annual growth (%)	Peak day demand (TJ)	Annual growth (%)	Peak day demand (TJ)	Annual growth (%)
Summer peak day Mass Market and Large Industrial market segment demand										
Summer peak day – Planning scenario	158	0.8	956	0.6	27	2.3	499	1.0	677	2.3
Summer peak day – Slow Rate of Change scenario	143	0.4	935	0.5	24	2.1	470	0.7	627	1.9
Winter peak day Mass Market and Large Industrial market segment demand										
Winter peak day – Planning scenario	202	0.8	1,445	0.6	30	2.3	677	1.0	703	2.1
Winter peak day – Slow Rate of Change scenario	186	0.4	1,426	0.6	28	2.1	639	0.7	651	1.7

Projected combined Mass Market and Large Industrial summer and winter peak day demand grows in line with annual demand for each demand group. Peak demand is projected to grow at higher rates in Queensland (driven by increasing demand from the Large Industrial market segment, which includes mining projects) and Tasmania (driven by increases in Large Industrial market segment gas demand and increasing household gas connections) than in New South Wales and the Australian Capital Territory, Victoria and South Australia. There is little difference between summer and winter peak day demand annual growth rates under each scenario.

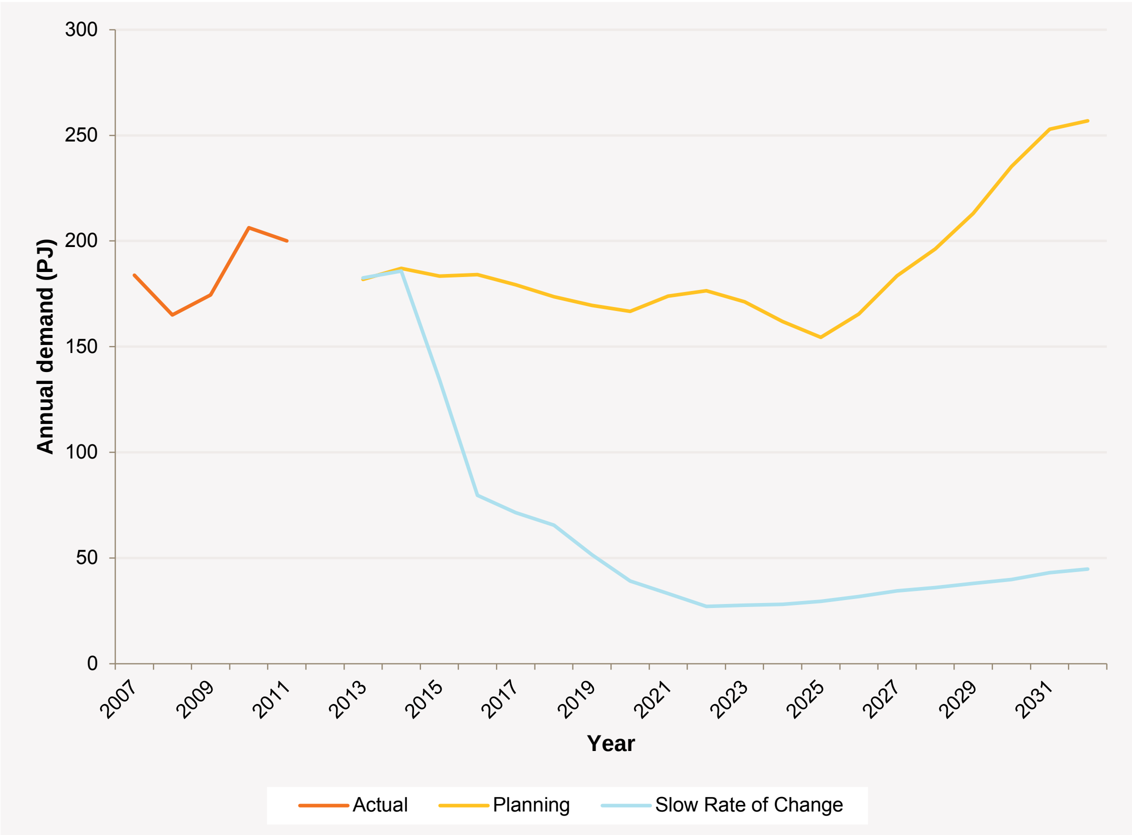
A.3.2 GPG market segment gas demand

This section presents the GPG market segment gas demand projections, which derive from AEMO's electricity modelling for the 2012 National Transmission Network Development Plan (NTNDP). For more information about the GPG modelling methodology see Section A.5.2.

GPG annual demand projections for a 1-in-20 peak demand condition (by scenario)

Figure A-12 shows the annual GPG market segment gas demand projections for a 1-in-20 peak demand condition[3] under the Planning and Slow Rate of Change scenarios.

Figure A-12 — GPG market segment annual gas demand by scenario



Annual GPG demand under the Planning scenario has the following key features:

- A steady decline in GPG demand until 2025 before entering a period of growth to 2032 due to electricity demand growth.
- No new closed cycle gas turbines are required by the model for at least a decade. Open cycle gas turbine investment in the longer term, however, leads to an increase in GPG demand from 2025.

[3] This projected level of demand is expected, on average, to be exceeded only once in 20 years.

Annual GPG demand under the Slow Rate of Change scenario has the following key features:

- GPG demand decreases by 54% by 2016 and 80% by 2022 before entering a phase of steady growth.
- A sudden decrease in GPG demand from 2014 corresponds with the removal of carbon pricing.
- The Large-scale Renewable Energy Target (LRET) is a major contributor to the large decrease in demand. The modelling indicates LRET-driven renewable energy (mostly wind generation) dominates the new generation mix until 2020. Projected electricity demand is also lower than under the Planning scenario and so is more greatly affected by the fixed LRET target.

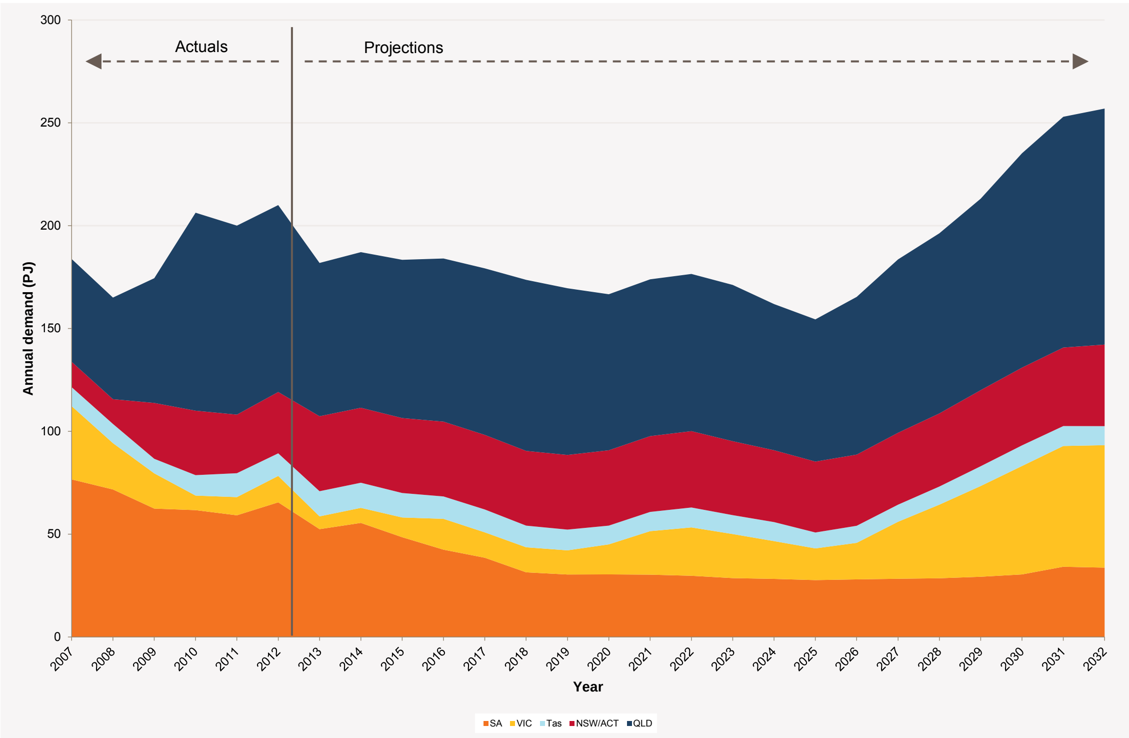
General observations include the following:

- There is significant uncertainty around the future of carbon pricing in Australia, which is highlighted by the significant variation between the two scenarios.
- The gas price increase further reduces the competitive advantage of gas relative to coal. Gas prices under the Slow Rate of Change scenario surpass the Planning scenario after 2018, highlighting an upward pressure created by additional LNG trains (for more information see Section A.3.3).
- The late increase in GPG market segment gas demand under both scenarios is driven by growth in electricity demand.
- The projections highlight that GPG market segment demand is highly sensitive to the underlying assumptions and the highly volatile nature of this market segment when it comes to gas demand.

GPG annual demand projections by demand group (Planning scenario)

Figure A-13 shows the annual GPG market segment demand projections for a 1-in-20 peak demand condition by demand group under the Planning scenario.

Figure A-13 — GPG annual demand by demand group, Planning scenario



Annual GPG demand under the Planning scenario has the following key features:

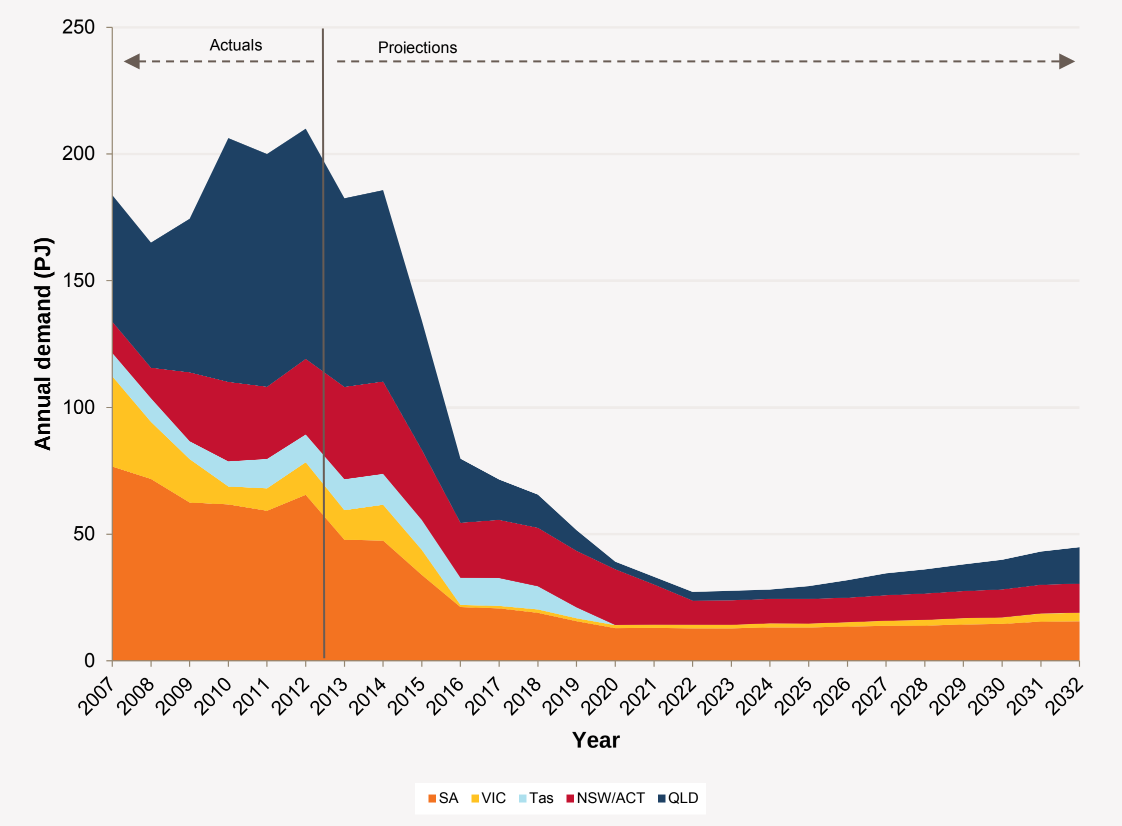
- In Queensland, New South Wales (including the Australia Capital Territory) and Tasmania, GPG demand is projected to rise from current levels to support growing electricity demand and a large uptake of wind generation.
- In Victoria, there is a short-term decline in GPG market segment demand, which rises again from 2019 as carbon prices make the operation of combined cycle gas turbines more competitive with coal-fired generation, and existing GPG generation increases to meet growing electricity demand.
- In South Australia, GPG market segment demand steadily declines due to the uptake of renewable technologies displacing the need for GPG.

GPG annual demand projections by demand group (Slow Rate of Change scenario)

Figure A-14 shows the annual GPG market segment gas demand projections for a 1-in-20 peak demand condition by demand group under the Slow Rate of Change Scenario.

GPG demand is projected to decrease from approximately 186 PJ in 2013 to less than 45 PJ in 2032 due to the removal of the carbon price, making gas less competitive with more carbon-intensive but less expensive black and brown coal. The LRET also results in renewable generation being installed to meet electricity demand growth prior to 2020.

Figure A-14 — GPG annual demand by demand group, Slow Rate of Change scenario



Annual GPG demand under the Slow Rate of Change scenario has the following key features:

- In Queensland, high gas prices driven by LNG exports will compound the impact of the removal of the carbon price and competition from renewable energy. GPG demand will drop from 75 PJ in 2013 to less than 6 PJ in 2020 before steadily increasing due to electricity demand growth.
- In New South Wales (including the Australia Capital Territory), GPG demand is projected to decline more slowly than in Queensland as black coal-fired generation is retired.
- In Victoria, South Australia and Tasmania, GPG demand is projected to decline as new renewable electricity generation investments occur, particularly in wind generation.

A.3.3 LNG export market segment annual gas demand by scenario

This section provides a high-level summary of the outlook for liquefied natural gas (LNG) in Eastern and South Eastern Australia conducted by Core Energy Group, and the resulting LNG projections that were applied to the supply-demand modelling presented in Chapters 4 and 5. For more information see the full Core Energy Group report.[4]

Export opportunities and market competition

The global LNG trade has grown annually by 8.5% over the last 10 years, with the Asia Pacific LNG market accounting for nearly 60% of total world LNG demand in 2010. Historically, the Asia Pacific region accounts for the majority of global LNG trade, and the region's demand for LNG is assumed to grow at approximately 2.8% per annum from 2012 to 2032.

Ninety-nine percent of Australian LNG exports currently supply the Asian region, largely attributed to favourable shipping costs. Total delivered LNG costs, however, have increased substantially over the last 10 years, and the competitiveness of Eastern and South Eastern Australian LNG will be increasingly linked to the cost of extracting and liquefying gas, with the shipping cost element becoming less significant.

Asia is likely to remain the primary market for Eastern and South Eastern Australian LNG. Over the next 20 years, contracted supply to the Asian LNG market will trend down, while uncontracted demand[5] and unfulfilled[6] demand will trend up at rates of 10.5% per annum and 8.6% per annum respectively, which is largely due to the conclusion of existing contracts.

Unfulfilled LNG demand in the Asian market is predicted to grow annually by 8.6%, from 28 million tonnes per year in 2012 to 146 million tonnes per year in 2032. Key competitors for this unfulfilled demand include the United States of America, Iran, Russia, Canada, Qatar, Papua New Guinea, and Western Australia and the Northern Territory. Eastern and South Eastern Australian LNG projects, however, have a number of advantages over competing suppliers:

- Australia's vicinity to the Asian market and resulting lower shipping costs.
- Low sovereign risk.
- The advanced progress of several projects, particularly for the period to 2017.

The ability for Eastern and South Eastern Australian projects to compete for Asia Pacific LNG demand is primarily a function of project economics and timing (to enable market opportunities to be realised). Key factors impacting project economics include industry hyperinflation (associated with limited skilled labour), well deliverability and productivity, compliance costs, water management and associated hydrocarbon liquids value (or lack thereof).[7]

[4] AEMO. Available http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Eastern_SouthEastern_Australia_Projections_of_Gas_Demand_for_LNG_Export%20pdf.ashx. Viewed 26 September 2012.
[5] LNG demand unmet by firm contracts.
[6] LNG demand unmet by firm contracts and likely supply.
[7] Conventional gas to LNG projects can produce liquids in conjunction with gas that can improve project economics compared to a CSG-to-LNG project from which no liquids are produced.

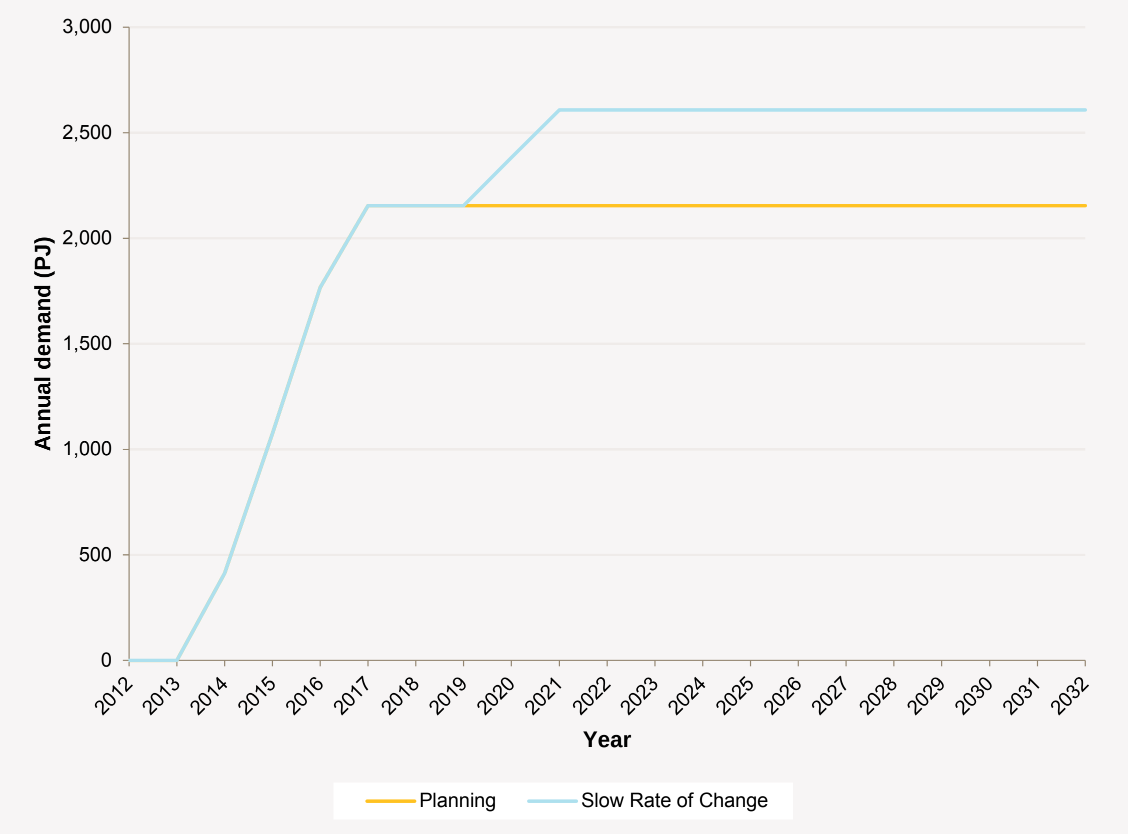
LNG demand and projected LNG development

Figure A-15 shows projected annual LNG exports by scenario.

Growing demand for LNG exports from Eastern and South Eastern Australia will lead to 8 to 10 LNG trains being built over the next 20 years, with annual capacity from approximately 33 million tonnes to 40 million tonnes, requiring gas reserves of between 43,000 PJ and 53,000 PJ under the Planning and Slow Rate of Change scenarios respectively.

There are currently three projects comprising five committed trains with a total annual capacity of 20.8 million tonnes. The available information shows there are potentially an additional 18 to 33 trains in Eastern and South Eastern Australia under a number of proposed projects. For information about LNG train development assumptions in relation to proposed projects see the AEMO website.[8]

Figure A-15 — Annual LNG exports by scenario



The Slow Rate of Change scenario assumes the following factors will drive additional LNG trains:

- Lower domestic gas demand (driven by lower electricity demand and no carbon price) and moderate research and development support lead to larger volumes of uncommitted domestic gas available for export.
- Less investment in renewable generation, which may in turn lead to a higher than expected demand for LNG.
- Constrained investment and a low level of capital liquidity provide more advanced projects with high levels of sunk-investment an advantage compared to new projects.

[8] See note 4.

- A weaker economic outlook for the United States of America, allowing Australian projects to increase their market share.
- Competitive domestic production costs combined with high international LNG prices mean Eastern and South Eastern Australian projects are internationally viable.

Continuous growth is projected to be unlikely after 2021 due to possible competition from other global LNG suppliers and the economic benefits associated with liquids[9] production from Western Australia and the Northern Territory.

A.4 Regional demand projections

A.4.1 Demand Group 1 — South Australia

This section presents the annual and peak day demand projections for Demand Group 1 – South Australia (SA), which indicate the following:

- GPG annual demand is projected to decrease (from 2012 levels) by 48% under the Planning scenario and 76% under the Slow Rate of Change scenario by 2032.
- Combined Mass Market and Large Industrial market segment demand is projected to have an average annual growth rate of 0.9% and 0.4% under the Planning and Slow Rate of Change scenarios, respectively, for the outlook period.

Demand areas

This demand group includes the following demand areas:

- The Adelaide demand centre.
- The South East Australia Gas Pipeline.
- The Moomba to Adelaide Pipeline System.

Market segmentation and demand drivers

Table A-3 shows the historical gas demand for South Australia.

Gas demand over the past five years has been dominated by demand from GPG, although GPG demand displays a downward trend over the five-year period. This corresponds with a period during which rooftop photovoltaic generation (PV) and wind generation installations increased significantly while electricity demand decreased, which is likely to be driving the reduced demand for GPG.

Table A-3 — Historical gas demand by market segment, South Australia

	2007	2008	2009	2010	2011
MMLI[a] (PJ)	37	36	35	38	37
GPG (PJ)	77	72	62	62	59
Total (PJ)	**114**	**108**	**97**	**100**	**96**

a. Combined Mass Market and Large Industrial market segment demand.

[9] See note 7.

In 2011, Mass Market and Large Industrial market segment customers made up 31% and 69% of the combined Mass Market and Large Industrial component of gas demand, respectively. As a result, the combined Mass Market and Large Industrial market segment projection is largely driven by economic factors that have a greater impact on large industrial customers than mass market consumers.

Annual demand projections

Figure A-16 shows the annual demand projections for South Australia. Both the Planning and Slow Rate of Change scenarios show a steep decline in demand between 2014 and 2018 before entering a period of almost flat demand until 2032. The short-term decline is more sudden and pronounced under the Slow Rate of Change scenario as a result of rapidly declining GPG demand over this period.

Figure A-16 — Annual demand projections by scenario, South Australia

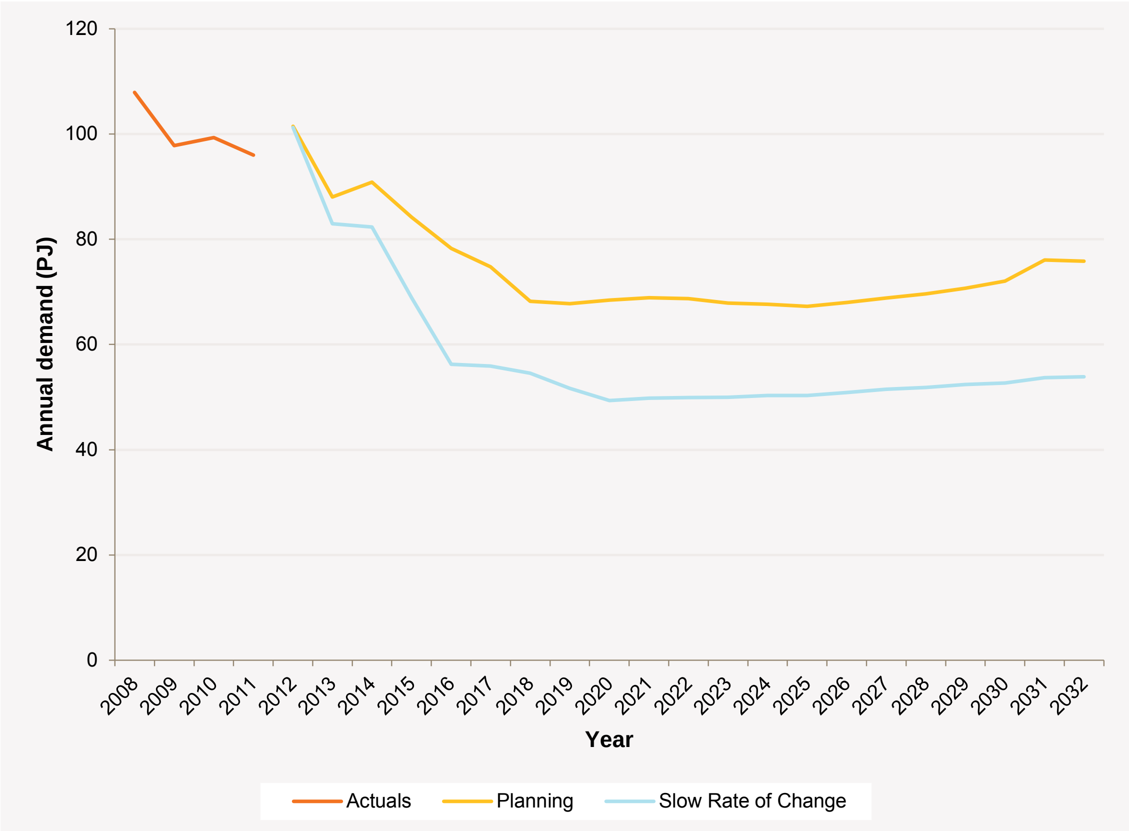
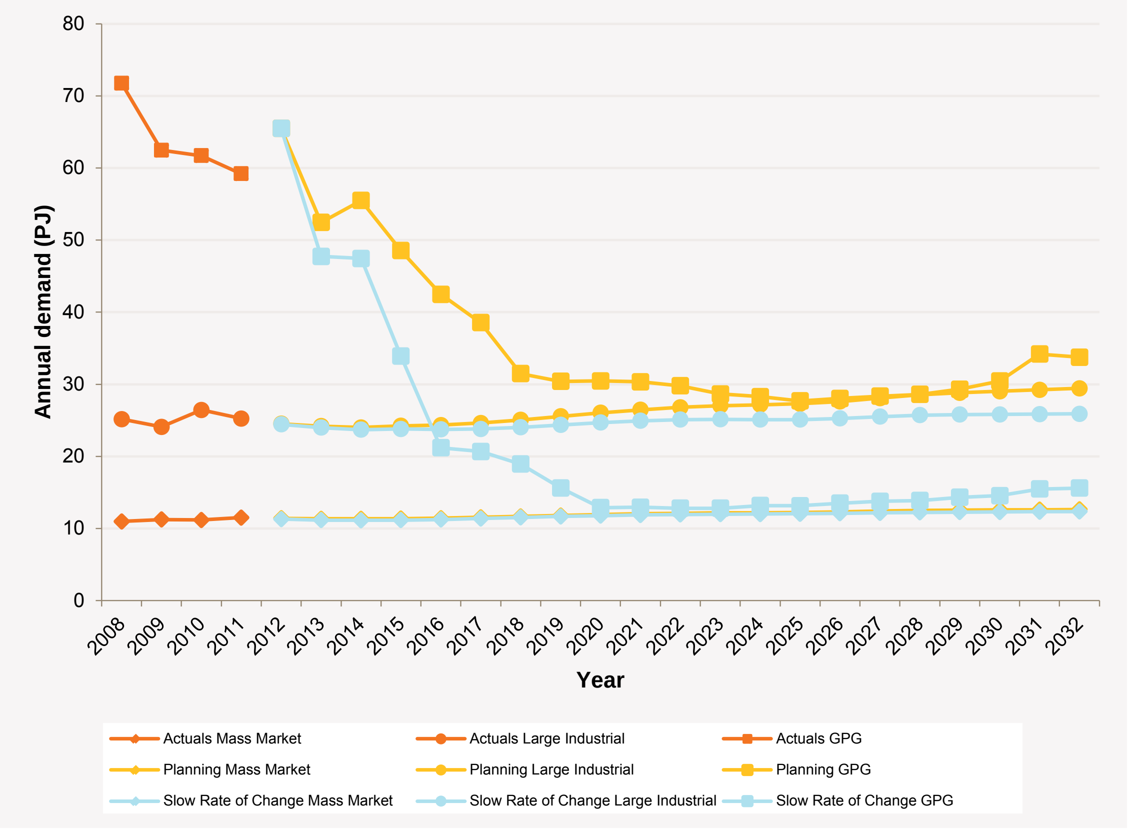


Figure A-17 shows the annual demand projection for each market segment for South Australia.

Mass Market market segment demand remains relatively static under each of the scenarios, while the GPG component decreases considerably during the outlook period. Large Industrial market segment demand is projected to grow modestly, at an annual averge of 1.0% under the Planning scenario, and with only slight growth at an annual average of 0.4% under the Slow Rate of Change scenario.

Figure A-17 — Annual demand projections by segment and scenario, South Australia

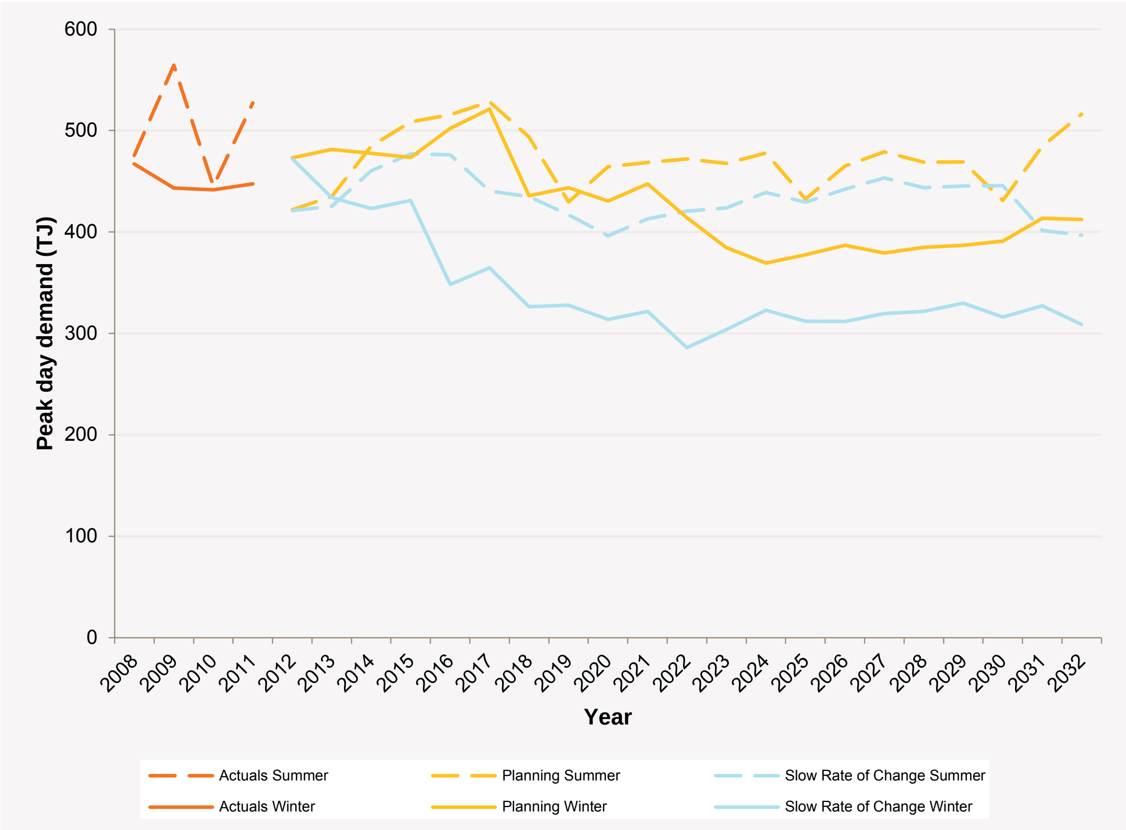


Peak day domestic demand projections

Figure A-18 shows the 1-in-20 summer and winter peak day domestic demand projections for South Australia by scenario.

Under the Planning scenario, the summer and winter peak day demands show an increase until 2017–18 and then decline over the outlook period. Summer peak day demand grows faster than winter peak day demand, which reflects the continuing need for GPG on summer peak days under that scenario despite a lower level of annual GPG demand.

Figure A-18 — Summer and winter domestic peak day demand, South Australia



A.4.2 Demand Group 2 — Victoria

This section presents the annual and 1-in-20 peak day demand projections for Demand Group 2 – Victoria (VIC), which indicate the following:

- GPG demand under the Planning scenario is projected to remain below 10% of total demand until 2026, growing to 21% of total demand by 2032. Under the Slow Rate of Change scenario GPG demand remains at approximately 5% of total demand until 2015, then falls to approximately 0.6% until 2021 and slowly increases to 1.5% of total demand for the remainder of the outlook period.
- The Mass Market market segment remains the dominant source of demand over the outlook period, although GPG demand is projected to rapidly increase from 2026 under the Planning scenario, reducing the Mass Market market segment's share of demand from 57% in 2012 to 51% in 2032.
- Mass Market market segment demand is projected to increase steadily at an average annual rate of 0.8% under both scenarios. Large Industrial market segment demand is projected to decline over the same period at annual growth rates of 0.0% and -0.5% under the Planning and Slow Rate of Change scenarios respectively.

Demand areas

This demand group includes the following demand areas:

- The Melbourne area (MEL).
- South West Victoria GPG (SW VIC GPG).[10]
- The Longford to Melbourne Pipeline (LMP).
- The South West Pipeline (SWP).

Market segmentation and demand drivers

Table A-4 shows the historical gas demand for Victoria.

Typically, over 90% of total demand has come from the combined Mass Market and Large Industrial market segments, which has grown from 90% in 2008 to 96% in 2011. The majority of this increase comes from reduced GPG demand, which is a reflection of a corresponding decline in total electrical energy demand (see the 2012 Electricity Statement of Opportunities for more information[11]). With GPG being less competitive than other forms of electricity generation, the impacts of reduced electricity demand are more pronounced for GPG than for other generation types. The combined Mass Market and Large Industrial market segment demand over this period has been steady, with a slight reduction in demand since 2008.

Table A-4 — Historical gas demand by market segment, Victoria

	2007	2008	2009	2010	2011
MMLI[a] (PJ)	207	210	206	205	204
GPG (PJ)	36	23	17	7	9
Total (PJ)	**243**	**233**	**223**	**212**	**213**

a. Combined Mass Market and Large Industrial market segment demand.

[10] The South West Victoria GPG demand area includes the Mortlake Power Station and other prospective GPG in the South West of Victoria that do not take gas from the South West Pipeline or the Victorian DTS.
[11] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Reports/Electricity-Statement-of-Opportunities. Viewed 25 October 2012.

Annual demand projections

Figure A-19 shows the annual demand projections for Victoria.

Under the Planning scenario, the average annual growth rate is approximately 1.6% compared to 0.2% under the Slow Rate of Change scenario, due to the GPG component. The Mass Market market segment demand demonstrates one of the most stable demand patterns in Eastern and South Eastern Australia as a result of the large share of Mass Market market segment demand, which is much more stable over time than demand from both the GPG and Large Industrial market segments.

Figure A-19 — Annual demand projections by scenario, Victoria

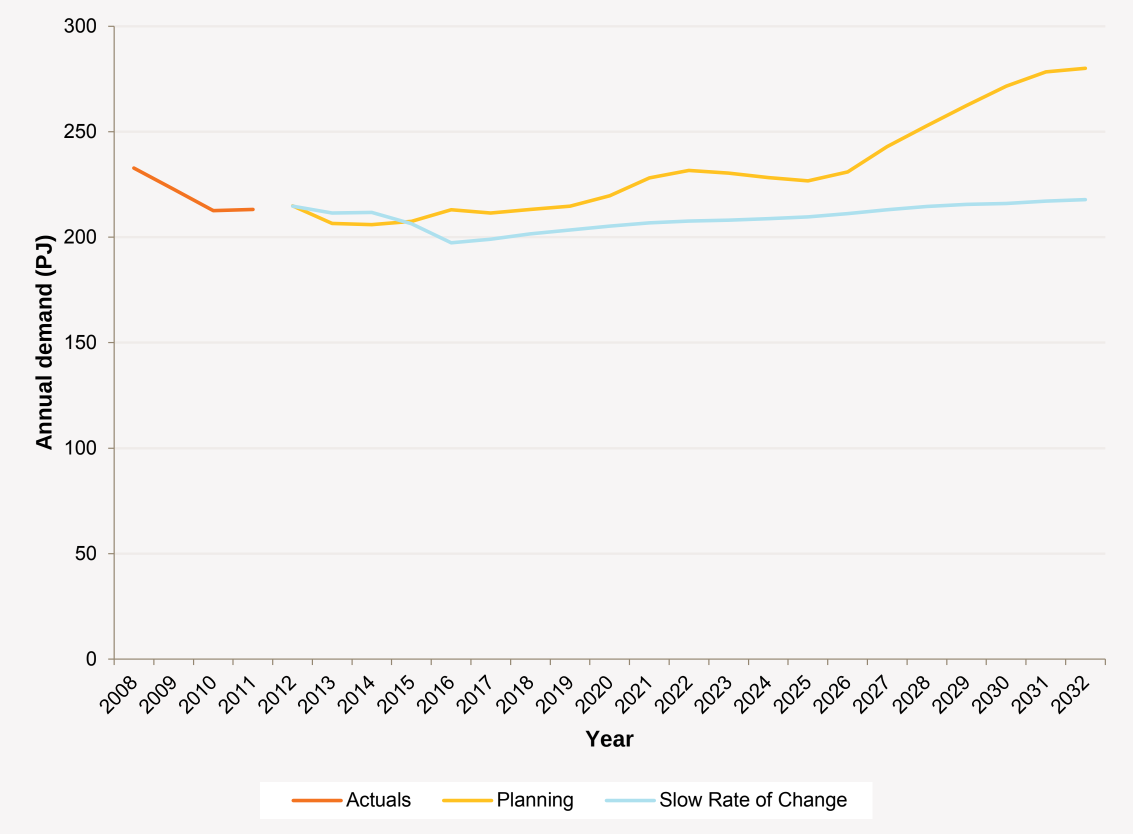
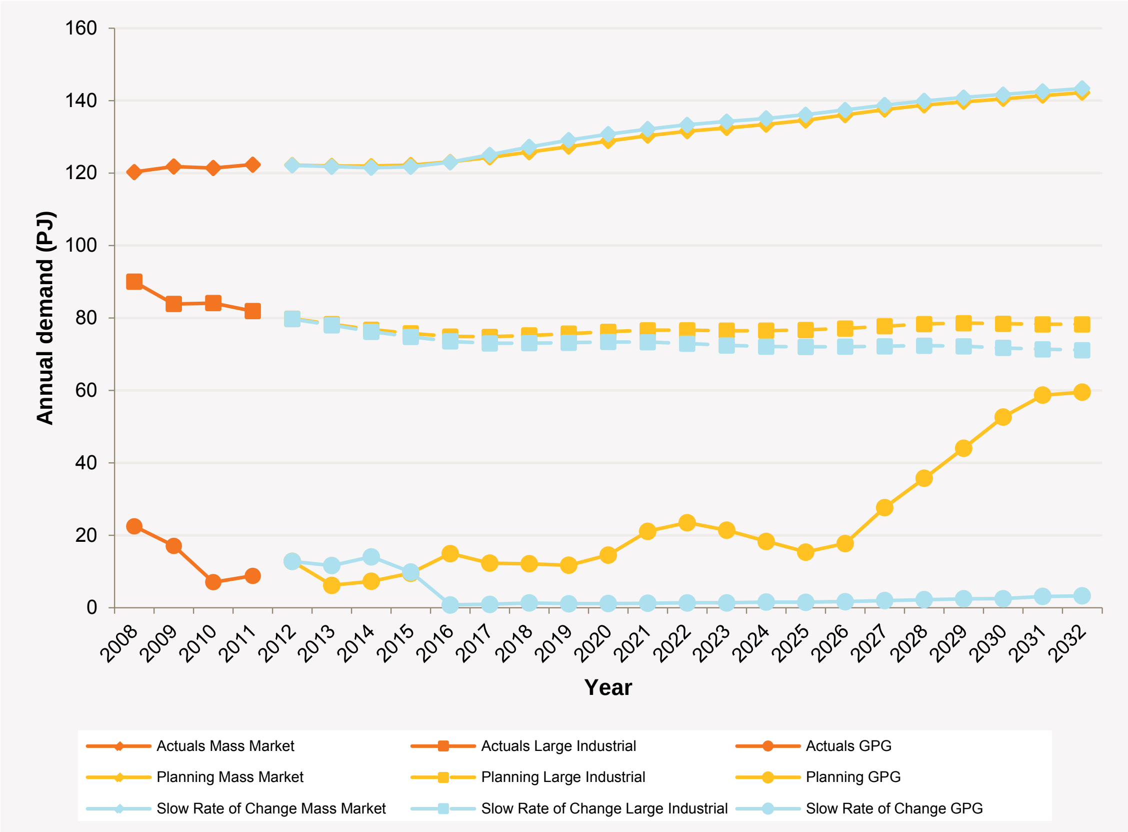


Figure A-20 shows the annual demand projection for each market segment for Victoria.

Average annual growth in the Mass Market market segment is approximately 0.8%, while Large Industrial market segment demand remains flat under the Planning scenario and declines by 0.5% each year under the Slow Rate of Change scenario. Under the Slow Rate of Change scenario, GPG demand is projected to peak at 14 PJ in 2014, before declining to between 1 PJ and 3 PJ for the remainder of the outlook period due to the removal of the carbon price after 2015. Under the Planning scenario, GPG demand grows erratically to 27 PJ in 2027 before entering a period of rapid and stable growth to 60 PJ in 2032 as carbon prices reset the generation merit order, favouring GPG over brown coal-fired generation.

The lower gross state product (GSP) forecasts impact the commercial and industrial sectors, resulting in reduced gas demand in the Large Industrial market segment and low growth in the Mass Market market segment.

Figure A-20 — Annual demand projections by segment and scenario, Victoria

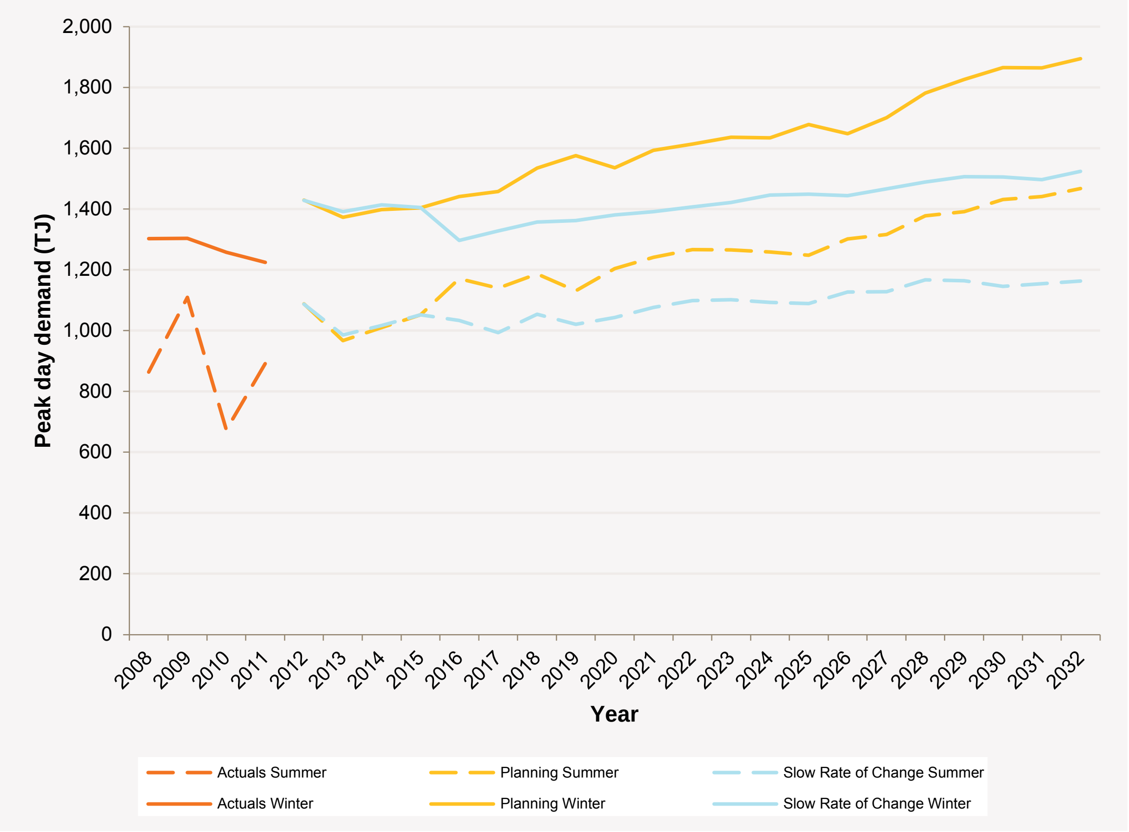


Peak day domestic demand projections

Figure A-21 shows the 1-in-20 summer and winter peak day domestic demand projections for Victoria by scenario.

Winter peak day demand is driven mainly by winter heating. Victoria has experienced mild winters over the last few years, and a weather warming trend has been identified that contributes to low future growth in winter peak day demand. Winter heating load is relatively insensitive to economic factors, especially in the short term.

Figure A-21 — Summer and winter domestic peak day demand, Victoria



A.4.3 Demand Group 3 — Tasmania

This section presents the annual and 1-in-20 peak day demand projections for Demand Group 3 — Tasmania (TAS), which indicate the following:

- GPG demand is projected to decline during the outlook period under both scenarios. Under the Slow Rate of Change scenario this leads to GPG demand decreasing to near zero by 2020 and remaining at this level for the remainder of the outlook period. The reduction in GPG demand is more gradual under the Planning scenario, reaching 76% of 2013 levels in 2032.
- Under the Planning scenario, combined Mass Market and Large Industrial market segment demand is projected to grow at a faster rate than in all other demand groups. The average annual growth in Tasmania of 2.2% is higher than in Queensland at 1.9%, albeit from a lower base (5 PJ in Tasmania compared with 146 PJ in Queensland).
- Growth in combined Mass Market and Large Industrial market segment annual demand in Tasmania is largely driven by the Large Industrial market segment, which accounts for 89% of combined Mass Market and Large Industrial demand in 2012.

Demand areas

This demand group comprises demand along the Tasmanian Gas Pipeline (TGP) and the Port Latta lateral.

Market segmentation and demand drivers

Table A-5 shows the historical gas demand for Tasmania.

Combined Mass Market and Large Industrial market segment demand increased and then decreased over the last five years, ranging between 3.5 PJ and 4.4 PJ. GPG demand shows growth over the same period with the exception of 2009 when demand was lower than in other years.

Table A-5 — Historical gas demand by market segment, Tasmania

	2007	2008	2009	2010	2011
MMLI[a] (PJ)	3.5	4.2	4.4	4.1	4.1
GPG (PJ)	9.2	9.3	7.1	9.9	11.6
Total (PJ)	**13**	**14**	**11**	**14**	**16**

a. Combined Mass Market and Large Industrial market segment demand.

Annual demand projections

Figure A-22 shows the annual demand projections for Tasmania.

Under the Planning scenario, annual demand remains relatively constant for the outlook period, while under the Slow Rate of Change scenario demand decreases by 9 PJ between 2017 and 2019 before returning to slow growth, largely due to the fall in GPG demand.

Figure A-22 — Annual demand projections by scenario, Tasmania

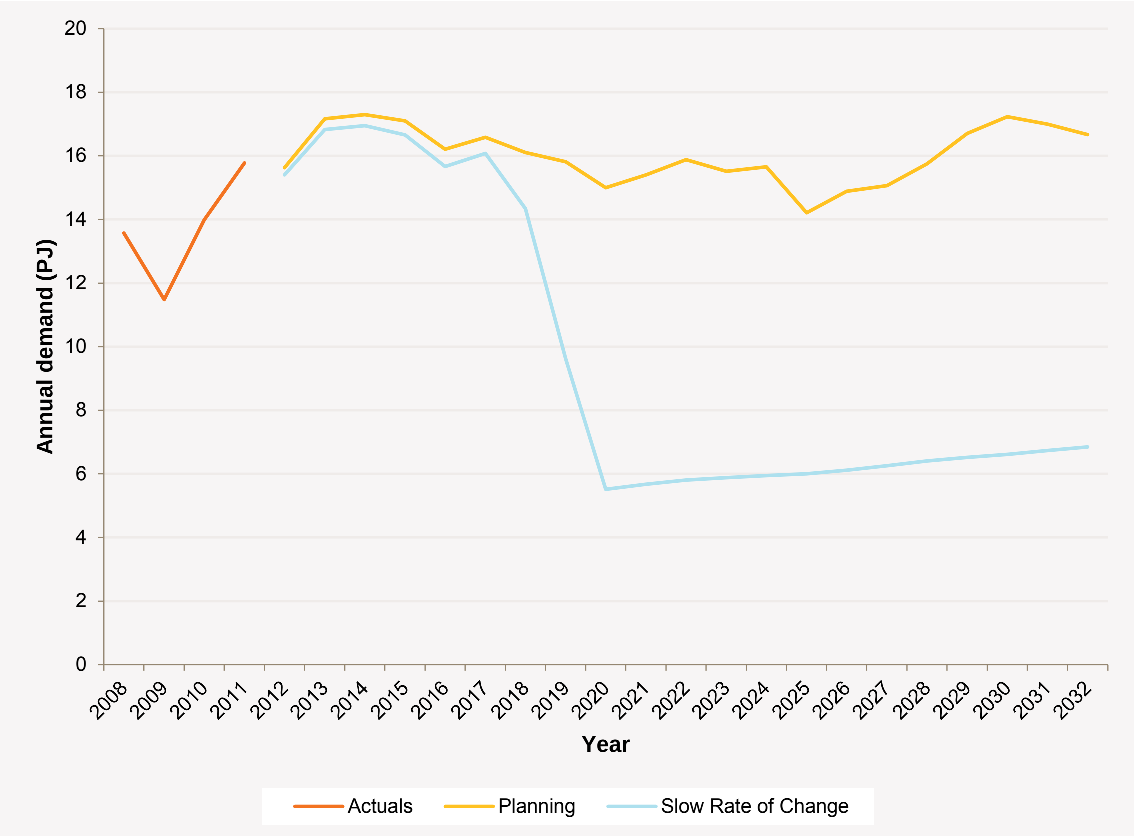
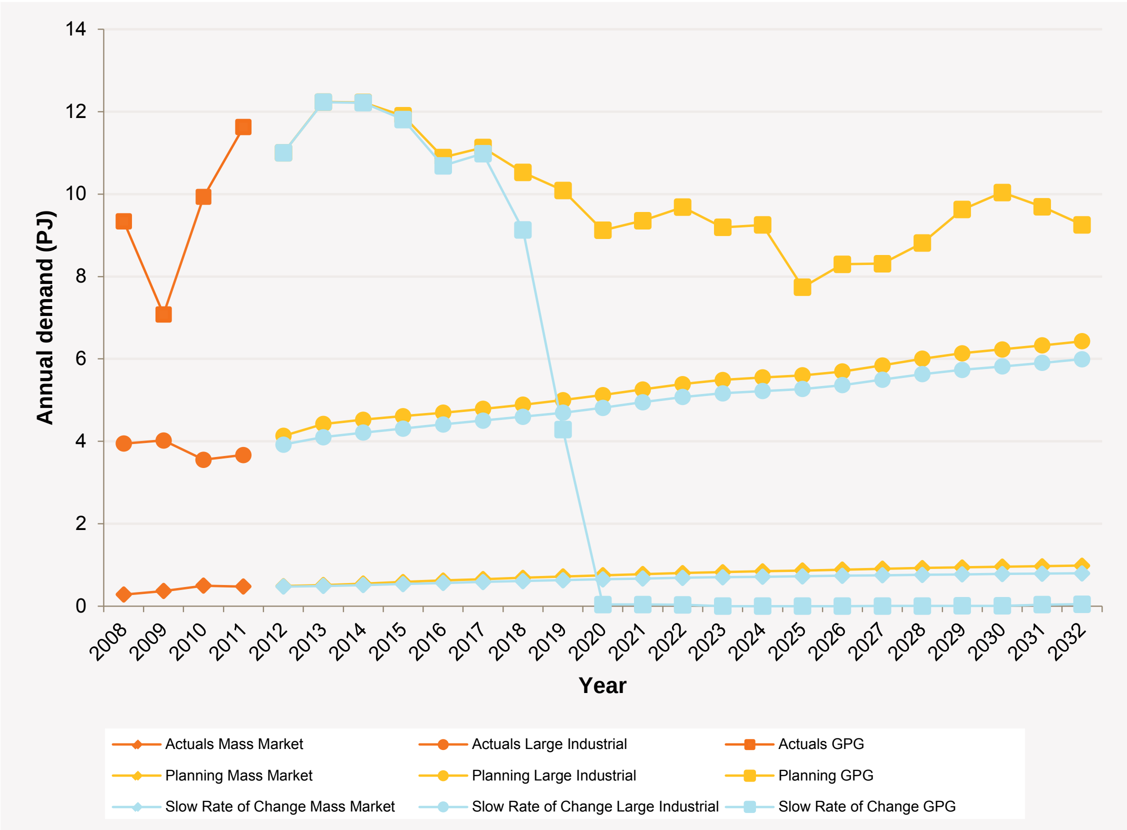


Figure A-23 shows the annual demand projections for each market segment for Tasmania.

Tasmania is projected to experience the most significant growth in Large Industrial market segment annual demand. Large Industrial demand is projected to grow by average annual rates of 2.0% under both scenarios. Similarly, Mass Market market segment demand is projected to grow under the Planning and Slow Rate of Change scenarios at average annual rates of 3.5% and 2.6% respectively.

GPG demand is projected to decline from 2014 under both scenarios. Under the Slow Rate of Change scenario this leads to GPG demand decreasing to near zero by 2020 and remaining at this level for the remainder of the outlook period. Demand under the Planning scenario is projected to decline more gradually, and by 2032 will be 24% lower than in 2013.

Figure A-23 — Annual demand projections by segment and scenario, Tasmania

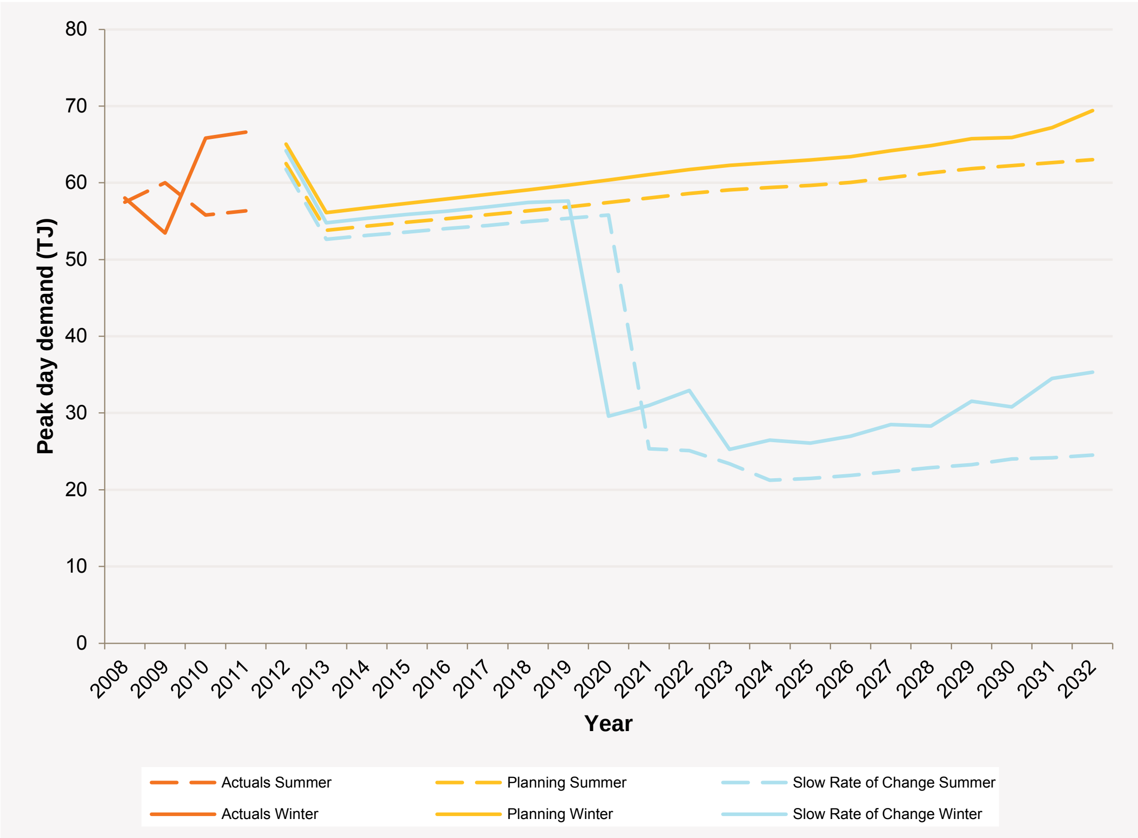


Peak day domestic demand projections

Figure A-24 shows the 1-in-20 summer and winter peak day domestic demand projections for Tasmania by scenario.

Demand in Tasmania is dominated by the GPG and Large Industrial market segments, with only low levels of Mass Market market segment demand. The GPG and Large Industrial market segments in Tasmania are not generally seasonal loads, and as a result summer and winter peak day demands are similar under both scenarios. Peak day demand differs between scenarios, reflecting the different levels of GPG and Large Industrial market segment annual demand under each scenario.

Figure A-24 — Summer and winter domestic peak day demand, Tasmania



A.4.4 Demand Group 4 — New South Wales (including the Australian Capital Territory)

This section presents the annual and 1-in-20 peak day demand projections for Demand Group 4 — New South Wales (including the Australian Capital Territory), which indicate the following:

- Large Industrial market segment demand is projected to decline until 2015 followed by a period of moderate growth due to a series of announced industrial closures.
- Over the 20-year outlook period, Mass Market market segment demand is projected to grow annually at approximately 1.1% under each scenario, in line with economic and population growth, while growth in the Large Industrial market segment depends on the scenario settings, with 0.8% and 0.3% average annual growth under the Planning and Slow Rate of Change scenarios respectively.
- GPG is projected to vary between 34.5 PJ and 39.6 PJ under the Planning scenario, or enter a phase of rapid decline under the Slow Rate of Change scenario when the carbon price drops to zero. Under the Slow Rate of Change scenario, the annual GPG demand projection reaches a minimum 9.5 PJ per annum in 2022, less than half of current levels, before growing slowly to the end of the outlook period.

Demand areas

This demand group includes the following demand areas:

- The Sydney area (SYD).
- The Australian Capital Territory area (ACT).
- The Northern New South Wales area (NNS).
- The Eastern Gas Pipeline (EGP).
- The Moomba to Sydney Pipeline (MSP).

Market segmentation and demand drivers

Table A-6 shows the historical gas demand for New South Wales (including the Australian Capital Territory).

GPG demand rose rapidly from 2008 to 2009 due to the commissioning of a number of GPG power stations. The combined Mass Market and Large Industrial market segment demand remained stable over the same period.

Table A-6 — Historical gas demand by market segment, New South Wales (including the Australian Capital Territory)

	2007	2008	2009	2010	2011
MMLI[a] (PJ)	109	110	117	113	110
GPG (PJ)	12	12	27	31	28
Total (PJ)	**121**	**122**	**144**	**145**	**138**

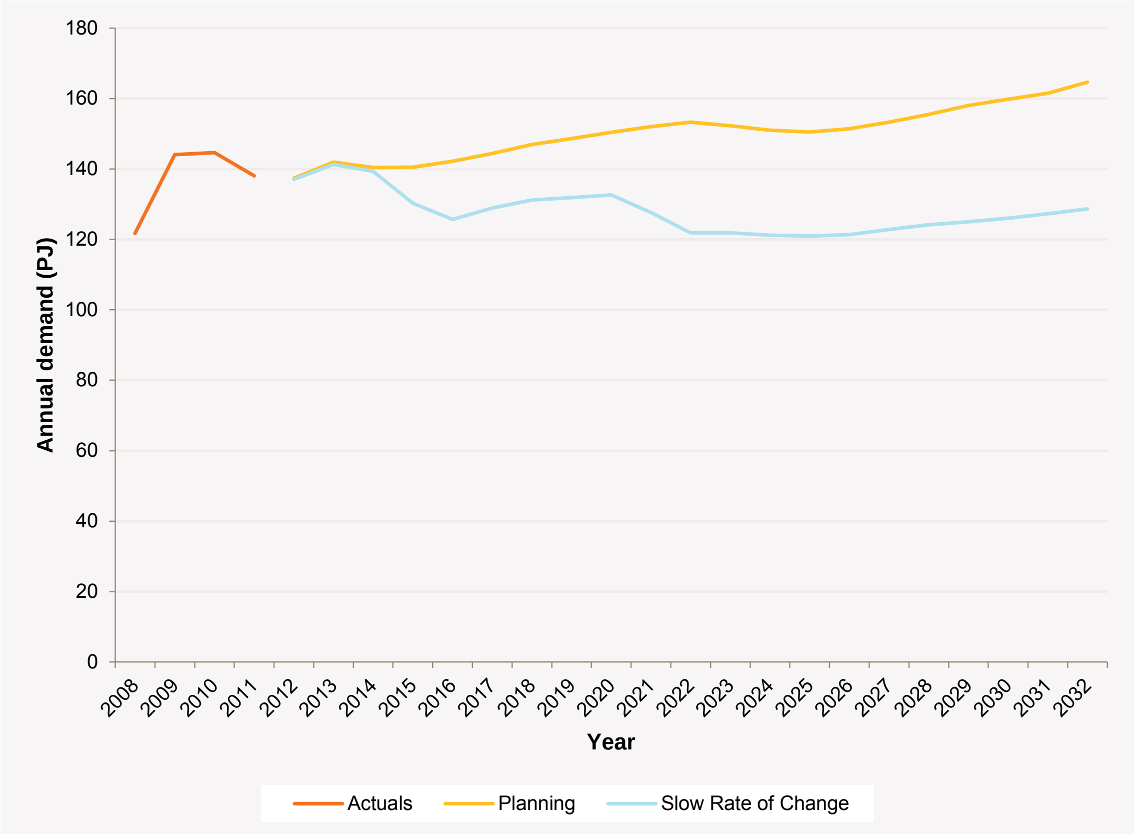
a. Combined Mass Market and Large Industrial market segment demand.

Annual demand projections

Figure A-25 shows the annual demand projections for New South Wales (including the Australian Capital Territory).

Demand grows under the Planning scenario, while the Slow Rate of Change projection shows declining demand due to a decline in GPG demand.

Figure A-25 — Annual demand projections by scenario, New South Wales (including the Australian Capital Territory)



Large Industrial market segment demand decreases between 2012 and 2015 under both the Planning and Slow Rate of Change scenarios, due to the announced closure of a number of industrial projects. Demand increases after 2015 under the Planning scenario with the expectation of economic and industrial growth in the long term. To develop these projections, the National Institute for Economic and Industrial Research (NIEIR) identified the following significant announcements:

- Shell announced the closure of its Clyde Refinery in September 2012.
- Caltex will rationalise process plants at its Kurnell Refinery by ceasing to operate a fluidised catalytic cracking unit (by February 2013) and a propane de-asphalting unit (by the end of 2012).
- Blue Scope Steel announced in August 2011 that it plans to shut down a blast furnace at its Port Kembla plant.
- Orica announced in February 2012 that it expects to see continued disruption of operation at its Kooragang Island ammonia and ammonium nitrate plants following a chemical release in August 2011.

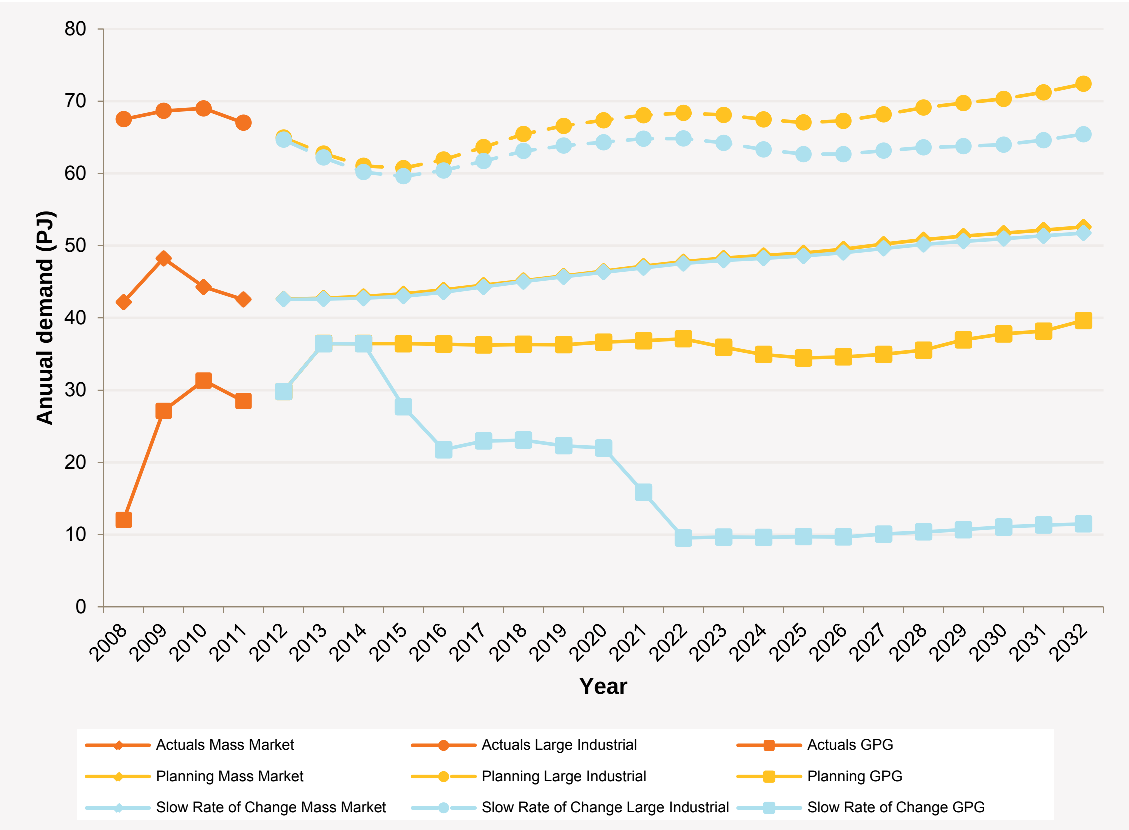
  Orica is to expand its existing ammonium nitrate manufacturing facility at Kooragang Island.
- Incitec Pivot announced a feasibility study in October 2011 into the construction of a new ammonium nitrate facility at its fertiliser facility on Kooragang Island, Newcastle.

- Amcor announced the closure of its existing plant at Botany in May 2012, and the expected commissioning of its new Botany plant in August 2012.
- Norsk Hydro announced in June 2012 the closure of its Kurri Kurri aluminium plant.
- Tomago Aluminium announced in January 2012 the restructure of its operations by reducing its workforce.

Figure A-26 shows the annual demand projections by market segment for New South Wales (including the Australian Capital Territory).

Growth in Mass Market market segment demand is relatively constant over the outlook period. The short-term reduction in demand is being driven by the Large Industrial market segment under both scenarios. Under the Slow Rate of Change scenario GPG demand largely decreases from 2014–15 and then increases again from 2022–23 until the end of the outlook period. Mass Market market segment demand is projected to grow at an average annual rate of 1.1% under both scenarios, while Large Industrial market segment demand grows at an average annual rate of 0.8% under the Planning scenario and 0.3% under the Slow Rate of Change scenario over the outlook period.

Figure A-26 — Annual demand projections by segment and scenario, New South Wales (including the Australian Capital Territory)



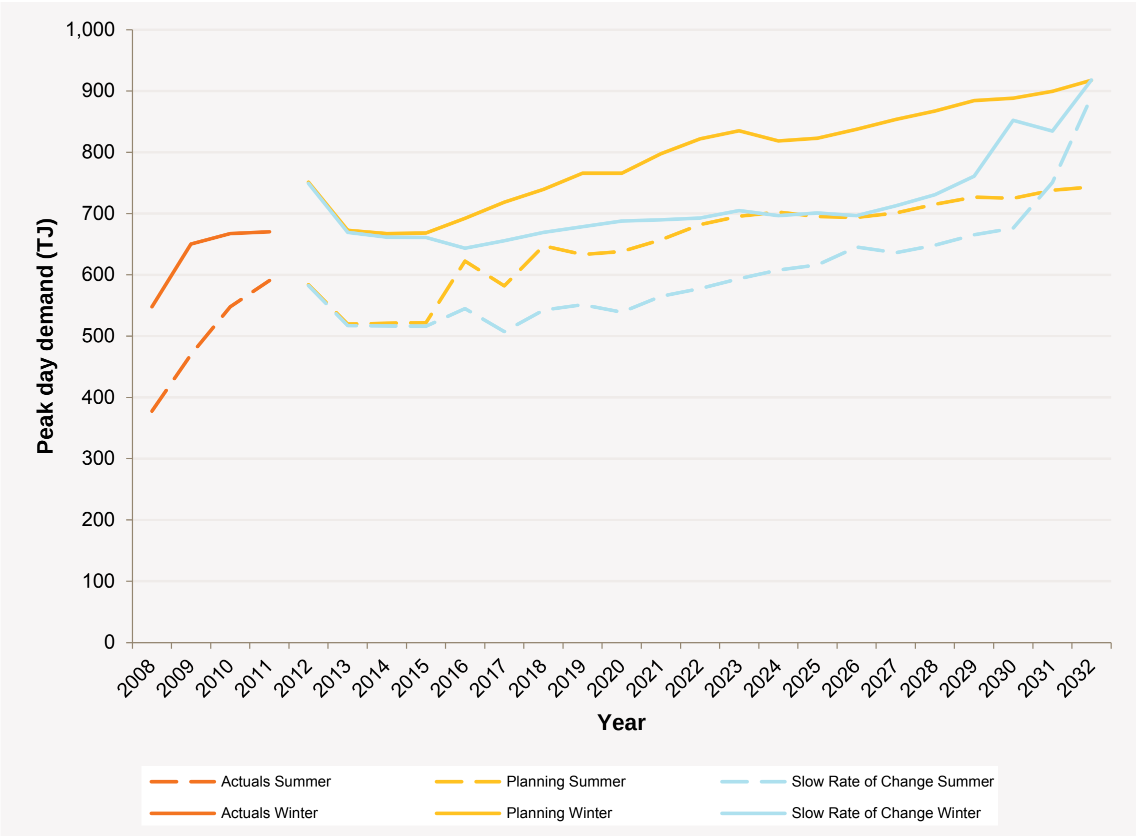
Peak day domestic demand projections

Figure A-27 shows the 1-in-20 summer and winter peak day domestic demand projections for New South Wales (including the Australian Capital Territory).

Summer and winter peak day demand grows at similar rates under both scenarios until late in the outlook period.

Under the Planning scenario, this growth continues until the end of the outlook period. From 2027 onwards, summer and winter peak day demand under the Slow Rate of Change scenario increases by approximately 55 MW per year, due to the increase in GPG peak demand.

Figure A-27 — Summer and winter domestic peak day demand, New South Wales (including the Australian Capital Territory)



A.4.5 Demand Group 5 — Queensland

This section presents the annual and 1-in-20 peak day demand projections for Demand Group 5 — Queensland (QLD), which indicate the following:

- Queensland has the fastest growing combined Mass Market and Large Industrial market segment demand of all the demand groups in terms of total volume consumed, and is driven almost entirely by the Large Industrial market segment. Combined Mass Market and Large Industrial market segment gas demand is projected to grow to 206 PJ under the Planning scenario and 191 PJ under the Slow Rate of Change scenario in 2032, compared with 145 PJ in 2012.
- Large Industrial market segment demand growth is expected to be most rapid in the next five years as a range of projects are scheduled to come on line, particularly around the Gladstone area.
- GPG demand is highly scenario dependent. Under the Planning scenario, GPG demand has a period of slight negative growth from 75 PJ in 2013 to 69 PJ in 2025 due to high gas prices reducing the competitiveness of

GPG generation, before rising to 115 PJ by 2032. Under the Slow Rate of Change scenario, demand declines steeply from 74 PJ in 2013 to 3 PJ in 2021 as the carbon price drops to zero.

Demand areas

This demand group includes the following demand areas:

- The Roma-to-Brisbane Pipeline (RBP).
- The Queensland Gas Pipeline (QGP).
- The South West Queensland Pipeline (SWQP).
- The Carpentaria Gas Pipeline (CGP).
- Gas-powered generation in South West Queensland (SW QLD GPG).
- Demand in North Queensland (Moranbah).
- The North Queensland Gas Pipeline (NQGP).

Demand Group 5 – Queensland demand excludes LNG demand.

Market segmentation and demand drivers

Table A-7 shows the historical gas demand for Queensland.

Gas demand over the last five years has increased dramatically, with GPG demand almost doubling and combined Mass Market and Large Industrial market segment demand more than tripling. Much of the increase in demand has been driven by the expansion of the mining industry and associated support industries, including the following major customers identified by NIEIR:

- Queensland Alumina.
- Rio Tinto.
- Orica.
- Boyne Smelter.
- Queensland Magnesia.

Table A-7 — Historical gas demand by market segment, Queensland

	2007	2008	2009	2010	2011
MMLI[a] (PJ)	33	34	73	112	110
GPG (PJ)	50	49	61	96	92
Total (PJ)	**83**	**83**	**134**	**208**	**212**

a. Combined Mass Market and Large Industrial market segment demand.

Annual demand projections

Figure A-28 shows the annual demand projections for Queensland.

The projections diverge significantly from 2015 onwards with the Planning scenario showing relatively constant annual growth for the outlook period of 2.0%, while the Slow Rate of Change scenario sees a decline at an average rate of 0.3%. The divergence between the two scenarios is being driven almost exculsively by GPG demand under each scenario, with combined Mass Market and Large Industrial market segment demand remaining relatively stable.

Figure A-28 — Annual demand projections by scenario, Queensland

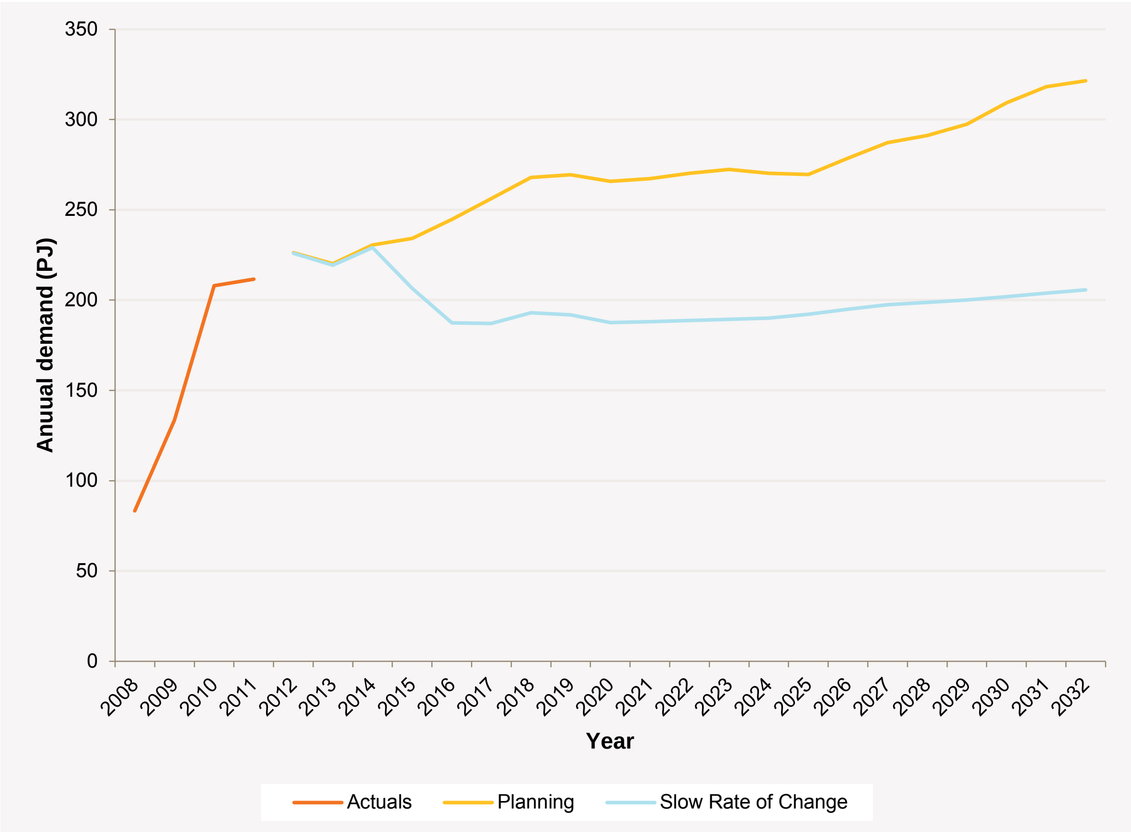
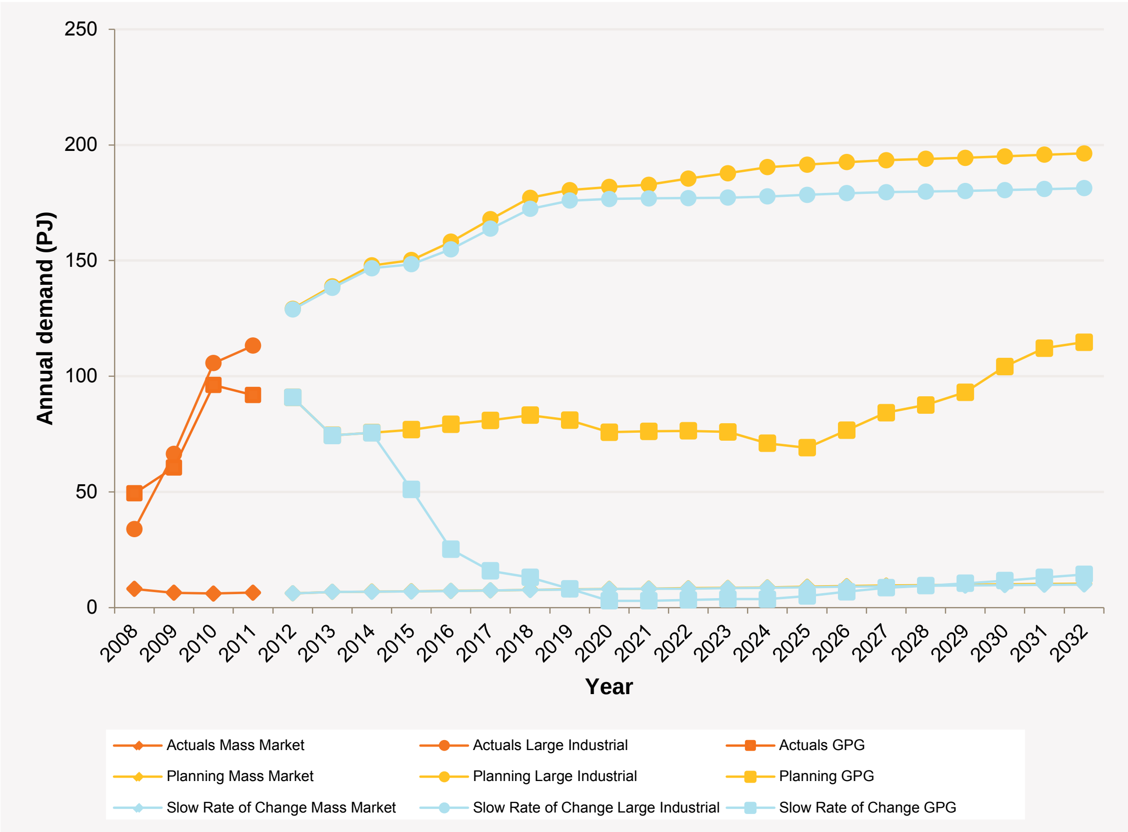


Figure A-29 shows the annual demand projections by market segment for Queensland.

Large Industrial market segment demand grows strongly between 2012 and 2018 under each scenario before entering a phase of slow growth from 2018. Much of this growth is driven by a mix of large-scale industrial projects and the installation of co-generation plants.

Figure A-29 — Annual demand projections by segment and scenario, Queensland



NIEIR has identifed a number of projects that are scheduled to be delivered over the coming years and are included in the projections. A number of these projects drive demand growth in Gladstone. Supply-demand modelling results indicate that the timing or scope of these projects may be impacted by available gas supply (for more information see Chapter 5). Unlike the other demand groups, projects in Queensland can be located in a variety of different demand areas, which each of the following projects identify:

- Xstrata Mount Isa Mines current and planned copper and zinc-lead operations, announced in October 2011 (CGP).[12]
- Incitec Pivot commenced operating the Moranbah ammonium nitrate plant in July 2012, with the commissioning of an ammonium plant to proceed in 2013 (NQGP).[13]
- The announced expansion of Rio Tinto's Yarwun refinery to Stage 2 by August 2012 (QGP).[14]

[12] Xstrata. Available http://www.xstrata.com/media/news/2011/10/06/0800CET/. Viewed 23 October 2012.
[13] Incitec Pivot. Available http://www.asx.com.au/asxpdf/20120702/pdf/427548hz3mrv8k.pdf. Viewed 23 October 2012.
[14] Rio Tinto. Available http://www.riotinto.com.au/documents/120628_FINAL_Yarwun_2_enters_home_stretch_%282%29.pdf. Viewed 23 October 2012.

- Queensland Magnesium announced the reinstatement of cement operations at Rockhampton, commencing production in 2012 and increasing over a two-year period (QGP).[15]
- QAL is investigating the feasibility of a 120 MW to 160 MW co-generation plant at its Yarwun site. A decision is scheduled for early 2013 (QGP).[16]
- Planned expansion of the Orica ammonium nitrate facility at Yarwun (QGP).[17]
- Prospective plans for a nickel cobalt refinery at the Port of Gladstone, scheduled to begin operations in 2015. An environmental impact statement is pending approval (QGP).[18]
- Prospective plans (known as the Gladstone Steel Project) to build a new greenfield steel mill in the Aldoga Precinct of the State Development Area west of Gladstone (QGP).[19]
- The Queensland Children's Hospital development in 2014, which is to include a 6 MW co-generation facility expected to output 20 GWh per year (RBP).[20]

The projections incorporate the impact of these projects, although some may not be delivered within the indicated timeframes (or at all), given uncertainties involving carbon pricing, the impact LNG export facilities will have on domestic gas prices, and the global demand for commodities.

GPG demand is highly scenario dependent. Under the Planning scenario, GPG demand has a period of slight negative growth to 2025 before rising from 74 PJ in 2013 to 115 PJ by 2032. Under the Slow Rate of Change scenario, demand declines steeply from 74 PJ in 2013 to 3 PJ in 2021.

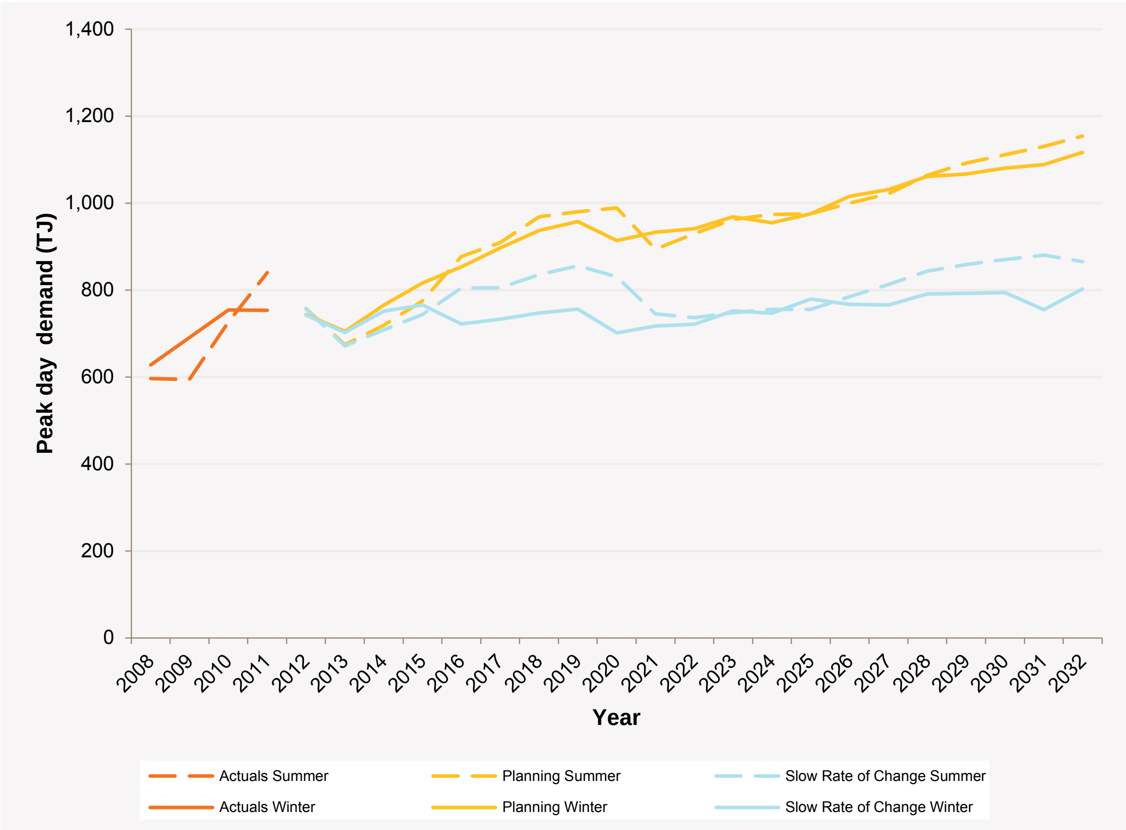
[15] Queensland Magnesia. Available http://www.qmag.com.au/pdf/QMAG%20Announces%20Acquisition%20to%20Expand%20Magnesia%20Capacity_15%20August%202011.pdf. Viewed 24 October 2012.
[16] QAL. Available http://www.qal.com.au/Community_Forum/Cogeneration%20Update%20June%202012.pdf. Viewed 24 October 2012.
[17] The Australian. Available http://www.theaustralian.com.au/business/mining-energy/orica-eyes-800m-plant-boost-at-gladstone/story-e6frg9df-1226375572884. Viewed 24 October 2012
[18] Boulder Steel Limited. Available http://www.gladstonesteelproject.com.au/timeline.html. Viewed 24 October 2012.
[19] GPN. Available http://www.gladstonepacific.com.au/. Viewed 24 October 2012.
[20] Queensland Government. Available: http://www.health.qld.gov.au/childrenshospital. Viewed 3 December 2012.

Peak day domestic demand projections

Figure A-30 shows the 1-in-20 summer and winter peak day domestic demand projections for Queensland.

Summer and winter peak day demand growth is mainly driven by Large Industrial market segment demand growth. As a result, peak day demand growth is expected to follow closely with annual demand growth for the combined Mass Market and Large Industrial market segment. Summer and winter peak demand for GPG is on a similar level, reflecting a similar need for GPG on summer and winter peak demand days under both scenarios, despite a lower level of annual demand under the Slow Rate of Change scenario due to the removal of the carbon price from 2015.

Figure A-30 — Summer and winter domestic peak day demand, Queensland



A.5 Demand projection methodology

This section provides information about the methodologies used to develop the annual demand projections for the 20-year outlook period from 2013 to 2032.

A.5.1 Data sources

The demand projections (developed using historical and projection data provided by various industry participants) include the following inputs:

- Economic projections for residential growth by NIEIR.[21]
- Historical data provided by gas pipeline owners and distributors.

[21] AEMO. Economic Outlook Information Paper. Available: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/National-Electricity-Forecasting/Information-Papers-2012. Viewed 26 October 2012.

- Weather projections, based on historical weather data from the Bureau of Meteorology.
- Gas distributor access arrangements.
- Surveys of industrial gas consumers conducted by NIEIR.
- Projections of gas demand for LNG export.[22]
- Historical and projected National Electricity Market (NEM) GPG data.
- Gas Bulletin Board historical data.

A.5.2 Demand Projection assumptions

The annual gas demand projections were calculated over the outlook period for four gas demand market segments:

- Mass Market including residential, business and small industrial consumers.
- Large Industrial, usually transmission customers.
- Gas powered generation (GPG).
- Liquefied natural gas (LNG) export.

In developing the demand projections, it was assumed that gas processing, transmission and distribution facilities have sufficient capacity to ensure they never constrain gas from reaching downstream consumers.

Mass Market and Large Industrial market segment annual demand

AEMO commissioned NIEIR to prepare annual gas demand projections for Eastern and South Eastern Australia over the outlook period for the Mass Market and Large Industrial market segments.

These projections were developed using NIEIR's state energy model, which is an industry-based model that disaggregates fuel usage by industry and fuel type. A set of models were also created for each demand area.

Economic and demographic projections for each demand area were developed using NIEIR's extensive regional data sets collated on a local government area basis across Australia. The data sets also recognise large non-reticulated gas areas in some states.

Five key elements were used to develop the annual demand projections:

- Developing a class-based and industry-based model for defined demand areas in each demand group.
- Surveys of medium and large industrial and commercial customers in each demand area.
- Assessing the impact of the Australian, state and territory government climate change and energy policy initiatives.
- Assessing and updating the prospects for co-generation and tri-generation by demand area.
- Assessing the prospects for greenfield developments by demand area.

The Mass Market market segment includes residential, business and small industrial consumers with an annual load of less than 10 TJ.

Residential demand, which dominates the Mass Market market segment, was modelled using an end-use type model that disaggregates residential usage into new and established dwellings. The residential projections have been prepared on a weather-normalised basis and incorporate the impact of real household disposable incomes and real gas prices.

The residential gas consumption projection model accounts for the following:

- The energy ratings for new homes implemented since July 2004, including 6-star ratings introduced in 2011.

[22] AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Liquid-Natural-Gas-Projections. Viewed 25 October 2012.

- The program to review and standardise the energy labelling of gas appliances followed by the development of Minimum Energy Performance Standards (MEPS) for new gas appliances.
- The ongoing negative impact of high sales of reverse-cycle air conditioning equipment.
- Additional gas load growth from extensions to the existing gas distribution network.
- Other new policies or developments in different state and territory markets.

Projections for the business and small industrial sectors were derived using a regression model that accounts for commercial output growth and movements in real gas prices.

For the Large Industrial market segment, NIEIR developed gas demand projections on an industry basis for each demand area. This segment's demand projections were aggregated and input into NIEIR's existing state gas demand projection model. The industry regression models for this segment relate its gas demand to the following:

- The change in output for that industry within the gas distribution area.
- The change in real gas prices for that industry.

These models also incorporate information about plant closures and proposed new investment projects for each industry based on information obtained from a major customer survey undertaken by NIEIR.

GPG market segment annual demand

Gas demand projections for the GPG market segment were produced using modelling and input assumptions consistent with the development of the 2012 NTNDP.

Investment in or retirement of generating systems (including GPG and other generation technologies) is modelled with the aim of minimising the power system's combined capital and operating costs. This optimisation is subject to satisfying three main criteria:

- The supply-demand balance for electricity across the NEM.
- Reserve capacity requirements at the time of a projected 10% POE maximum electricity demand.
- The LRET that mandates an annual level of generation to be sourced from renewable resources.

In general, the electricity supply-demand balance will be met by a mixture of technologies (including renewable energy, coal and combined cycle gas turbines), while the reserve requirement will be met by open cycle gas turbines that are cheaper to install and are required to run only at times of peak electricity demand.

Wind generation is currently the most competitive renewable energy technology being deployed on a large scale. Technologies such as large-scale geothermal and solar thermal generation, however, begin to become economic toward the end of the 20-year outlook period, depending on electricity demand and the impact of carbon pricing on other generation sources.

GPG projection methodology

The NTNDP least-cost modelling (using the PLEXOS model) aims to minimise the combined capital and operating cost expenses of the electricity system. PLEXOS also provides an expansion plan of generation investment and retirement patterns, which is analysed in detail through a time-sequential Monte Carlo approach that simulates hourly dispatch of the electricity market (using the Prophet model). The GPG market segment gas demand projections were extracted from this detailed modelling.

The time-sequential approach assumes constant thermal efficiency and heat-rate factors for individual generating systems. It makes assumptions about generator contracting levels and bidding strategies based on historical observed behaviour and short-run marginal costs.

A feedback loop between GSOO gas modelling and NTNDP electricity modelling was also established to co-optimise electricity and gas transmission augmentations that accommodate generation expansion. This integration improved the quality of the generation expansion plan and the GPG demand projections.

See the 2012 NTNDP reports on the AEMO website for more information.[23]

GPG modelling results

The modelling results are averaged across a range of generating unit maintenance and breakdown patterns. These assumptions are useful for projecting long-term expectations, but may differ from actual observed demand results in the early years of the outlook period.

NEM modelling zones correspond to areas assumed to have relatively similar fuel costs and containing major electricity generation or load centres. These may differ from gas demand groups and areas.

LNG export annual demand

Four key factors influence the level and timing of gas demand for LNG export:

- Asian LNG demand.
- Existing LNG supplies and contracts.
- Demand versus existing supply.
- Competing sources of supply.

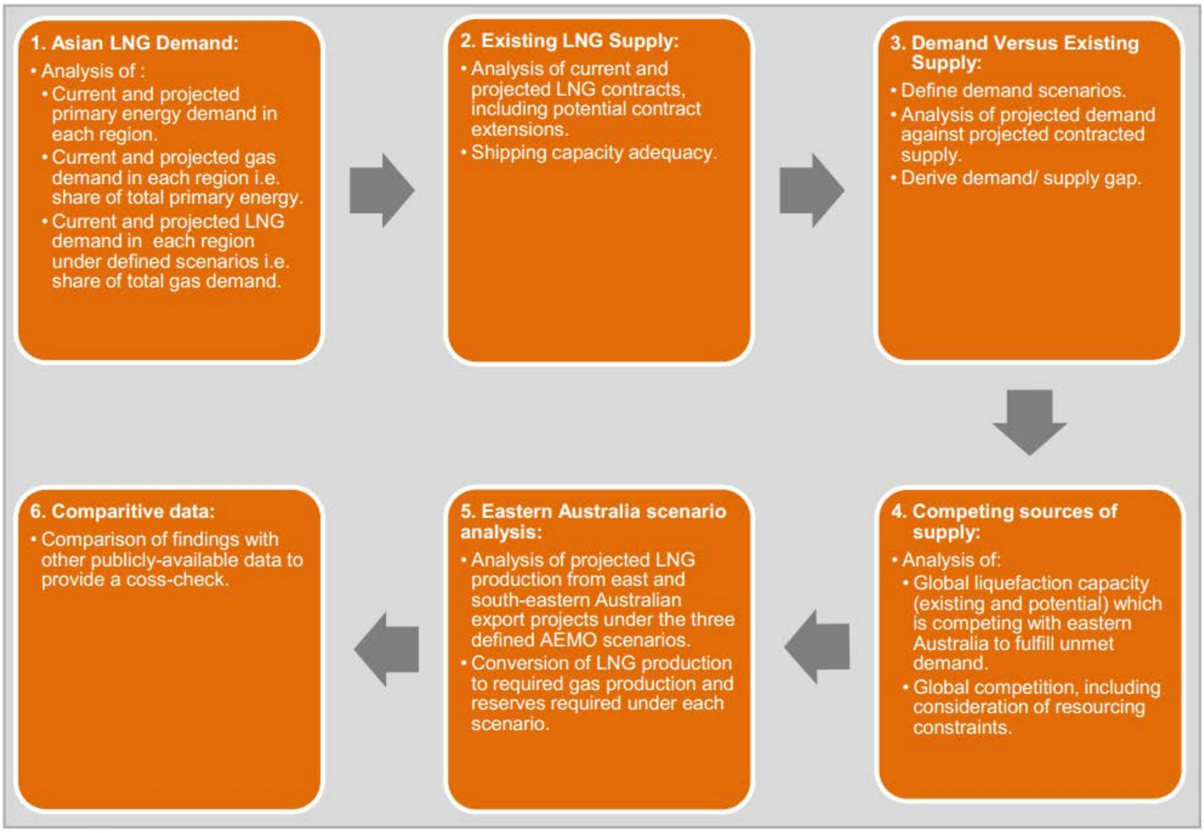
Core Energy Group analysed each of these factors to determine the level of LNG export expected under three scenarios (only two scenarios are included in this analysis to maintain consistency with demand projections for the other market segments).

The LNG market segment demand projections assume that 15% of gas is lost after it is extracted from the field due to processing, transmission and liquefaction losses.

[23] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan. Viewed 6 December 2012.

Figure A-31 summarises the methodology used by Core Energy Group.

Figure A-31 — Core Energy Group LNG export demand projection methodology



Source: Core Energy Group; June 2012.

A.5.3 Peak day demand projection methodology

Projections for peak day gas demand (calculated over a 20-year outlook period from 2012 to 2032) were determined for each of the four market segments (Mass Market, Large Industrial, GPG and LNG).

These projections represent the total amount of gas that is expected to be consumed within a 24-hour period on the highest demand days during winter and summer.[24] The POE for both winter and summer 1-in-20 peak day demand was calculated as being that level of demand expected to be exceeded 5% of the time (a 5% POE) or once in every 20 years.

Mass Market and Large Industrial market segment peak day demand

NIEIR developed winter and summer peak day gas demand projections under five scenarios for the Mass Market and Large Industrial market segments in Eastern and South Eastern Australia.

The peak day demand projections were developed using a separate daily demand model for each market segment in each demand area, and incorporated (extreme) weather conditions defined by a pre-estimated weather index and standards for 1-in-2 year and 1-in-20 year weather conditions. The weather standards allowed for any change in weather patterns due to climate change and urban warming expected over the outlook period.

[24] In calculating peak day demand projections, winter is defined as the months from April to October, and summer is defined as the months from November to March.

In winter, demand for heating on cold winter days is an important driver of peak day demand, while in summer, peak day demand is usually associated with increased usage of air conditioners on hot summer days. Given the wide definition adopted for summer (October to March), summer peak day demand can also be associated with demand for heating on a cold day during the shoulder season.

GPG segment peak day demand

In some demand groups, peak electricity demand can occur in either winter or summer. As a result, GPG demand can also peak in either winter or summer. Peak demand for GPG can also occur on mild days, if a large number of coincident power generation outages occur (for example, coal-fired generation unit outages).

AEMO's NEM five-node constrained model was used to develop 1-in-2 and 1-in-20 peak day demand conditions, which combined electricity demand projections with coal-fired generation unit outages. The 1-in-2 and 1-in-20 GPG peak day demand projections were then derived from the modelling outcomes.

LNG export segment peak day demand

LNG facilities are assumed to run continuously at an average rate. Therefore it is assumed that for gas demand for LNG there is no difference between winter and summer peak day demand.

A.5.4 Diversity of demand between market segments

Demand from each market segment responds to different drivers:

- Residential and commercial demand is strongly driven by weather, with lower temperatures driving higher gas usage.
- Industrial demand is relatively constant throughout the year.
- Gas demand for power generation is driven by prices in the wholesale electricity market because more GPG is dispatched when wholesale electricity prices are high.

These differing drivers mean that different market segments can reach peak demand at the same or at different times of the day or year. If peak demand for any sector occurs at the same time, diversity is defined as being zero and the demands are described as being coincident.

Diversity factors

Insufficient data is available for a detailed analysis of demand diversity across all gas market segments and time periods, however, it is known that peak demand for the various market segments does not generally occur on the same day. This results in peak day demand being less than the sum of the individual market segment peaks.

Diversity factors were not applied for the peak day gas demand projections, however, for two reasons:

- There is a high degree of variability in the historical diversity patterns.
- Variability in diversity is projected to continue over the 20-year peak day demand outlook period.

The Eastern and South Eastern Australian aggregate peak day demand projections assumed no diversity between the demand areas within a demand group, or any diversity between the different demand groups, potentially resulting in higher aggregate peak demand projections than will actually be observed.

Demand projections for the Mass Market, Large Industrial, GPG and LNG market segments are also shown separately to enable independent assessment of the impact of diversity.

A.5.5 Links to supporting information

Information source	Website address
Gas Statement of Opportunities 2011	http://www.aemo.com.au/en/Gas/Planning/2011-Gas-Statement-of-Opportunities/Main-Report
2012 Scenario Descriptions	http://www.aemo.com.au/en/Electricity/Planning/~/media/Files/Other/planning/2418-0005%20pdf.ashx
2012 NTNDP Projection Methodology	http://www.aemo.com.au/en/Electricity/Planning/~/media/Files/Other/planning/2418-0002%20pdf.ashx
2012 LNG Gas Projections	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/LNG-Projections

APPENDIX B - GSOO COMPONENT GUIDE

This appendix assists 2012 GSOO readers with finding information, given the GSOO now comprises multiple components published between June and December each year.

Table B-1 lists the contents of the GSOO and where information can be located, and provides a list of AEMO's statutory functions under the National Gas Law (NGL)[1] and National Gas Rules (NGR).[2]

Table B-1 — GSOO checklist of compliance clauses

Clause	Summary of requirements	Relevant GSOO component
NGL, Division 4, Section 91D(2) (a) to (e)	The Gas Statement of Opportunities must:	-
	a) Contain an assessment of medium to long-term demand (including export demand) for natural gas and for pipeline services.	Appendix A. Accompanying data files.[a] Eastern & South-Eastern Australia: Projections of Gas Demand for LNG Export (including accompanying spreadsheet).[b]
	b) Contain an assessment of supply and pipeline capacity to meet existing and foreseeable demand for natural gas and pipeline services.	Chapter 5. Accompanying data files.[a]
	c) Include forecasts of the outlook for the natural gas industry over a 20-year planning horizon.	Chapter 4. Eastern & Southern Australia: Projected Gas Reserves (including accompanying spreadsheet).[c]
	d) Point out likely long-term shortfalls in natural gas reserves, and production or transmission constraints.	Chapter 4 (reserve shortfalls). Chapter 5 (transmission constraints/supply shortfalls). Accompanying data files.[a]
	e) Contain any other information required by the Rules (NGR).	See clauses 135KB(1) to (3) of NGR (below).
NGR, Part 135KB(1) (a) to (h)	The Gas Statement of Opportunities must contain, for each participating jurisdiction, for the period of 10 years commencing on 1 January of the first calendar year to follow its publication, information about:	-
	a) Natural gas reserves (including prospective or contingent resources).	Chapter 4. Eastern & Southern Australia: Projected Gas Reserves (including accompanying spreadsheet).[c]
	b) Annual and peak day capacity of, and constraints affecting, gas production facilities.	Chapter 5. Accompanying data files. [a]

[1] South Australian Government. Available: http://www.legislation.sa.gov.au/LZ/C/A/NATIONAL%20GAS%20(SOUTH%20AUSTRALIA)%20ACT%202008/CURRENT/2008.19.UN.PDF. Viewed 21 November 2012.

[2] AEMC. Available: http://www.aemc.gov.au/Gas/National-Gas-Rules/Current-Rules.html. Viewed 22 November 2012.

Clause	Summary of requirements	Relevant GSOO component
NGR, Part 135KB(1) (a) to (h)	c) Committed and proposed new or expanded gas production facilities.	Chapter 2. Review of Gas Facilities: Existing and New (including accompanying spreadsheet).[d]
	d) Projected demand for natural gas (including annual and peak day forecasts) for each demand zone.	Chapter 3. Appendix A. Accompanying data files.[a]
	e) Annual and peak day transmission capacity and constraints (including interconnection constraints).	Chapter 5 Accompanying data files.[a]
	f) Peak day capacity of, and constraints on, storage facilities.	Chapter 5 Accompanying data files.[a]
	g) Committed and proposed new transmission pipelines and pipeline augmentations.	Chapter 2 Review of Gas Facilities: Existing and New (including accompanying spreadsheet).[d]
	h) Committed and proposed new or expanded storage facilities.	Chapter 2 Review of Gas Facilities: Existing and New (including accompanying spreadsheet).[d]
NGR, Part 135KB (2)	The Gas Statement of Opportunities must also, if practicable, include forecasts of reserves and annual demand for a further period of 10 years from the end of the period of 10 years referred to in NGR, Part 135KB(1) (a) to (h).	Chapter 3 (annual demand). Appendix A (annual demand). Accompanying data files.[a] Chapter 4 (reserves). Eastern & Southern Australia: Projected Gas Reserves (including accompanying spreadsheet).[c]
NGR, Part 135KB (3)	Forecasts made for the purposes of the Gas Statement of Opportunities must be made as far as possible on a consistent basis.	Chapter 3. Appendix A. Accompanying data files.[a,e]

a. AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed 21 November 2012.
b. AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Liquid-Natural-Gas-Projections. Viewed 21 November 2012.
c. AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Reserves-Projections. Viewed 21 November 2012.
d. AEMO. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Processing-Transmission-and-Storage-Facilities. Viewed 22 November 2012.
e. Updated demand projections are used where available to inform LNG and reserves projections. However, subsequent demand projection reviews and updates have led to minor changes.

DISCLAIMER

AEMO publishes the Gas Statement of Opportunities in accordance with section 91DA of the National Gas Law. This publication has been prepared by AEMO using information available at 31 July 2012, unless otherwise specified. Information made available after 31 July 2012 may have been included in this publication where practical.

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MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GJ	Gigajoule (an SI unit, 1 GJ equals 10^9 Joules)
GWh	Gigawatt hours
MW	Megawatts
PJ	Petajoule
t	Tonnes
TJ	Terajoule
TJ/d	Terajoules per day (see also Terajoule)
%	Percentage
$	Australian dollars

Abbreviations

Abbreviation	Expanded name
2P	Proved-plus-probable
AEMO	Australian Energy Market Operator
CCGT	Combined cycle gas turbine (a type of GPG)
CGP	Carpentaria Gas Pipeline
CSG	Coal seam gas
DTS	Declared Transmission System (gas)
EGP	Eastern Gas Pipeline
GBB	Gas Bulletin Board
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
IC	New South Wales to Victoria Interconnect
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NGL	National Gas Law
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NQGP	North Queensland Gas Pipeline
NSW/ACT	New South Wales and the Australian Capital Territory
NTNDP	National Transmission Network Development Plan
OCGT	Open cycle gas turbine (a type of GPG)
RBP	Roma to Brisbane Pipeline
POE	Probability of exceedence
QGP	Queensland Gas Pipeline
QLD	Queensland
SA	South Australia
SEA	SEA Gas Pipeline

Abbreviation	Expanded name
SWP	South West Pipeline
TAS	Tasmania
TGP	Tasmanian Gas Pipeline
VIC	Victoria

GLOSSARY AND LIST OF COMPANY NAMES

Glossary

Term	Meaning
1-in-2 peak day	The 1-in-2-peak day demand projection has a 50% probability of exceedence (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 has only a 5% probability of exceedence (POE). This projected level of demand is expected, on average, to be exceeded only 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	Estimated quantity of gas that is reasonably certain to be recoverable in future under existing economic and operating conditions. A low-side estimate also known as proved gas reserves.
2P reserves	The sum of proved-plus-probable estimates of gas resources. 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.
Annual demand	Gas demand reported for a given year.
Average annual growth rate	The average rate over a period of years at which gas demand, for example, increases or decreases. Expressed as percent per year. Negative figures indicate a decline in demand.
Basin	A geological formation that may contain coal, oil and gas.
Bulletin Board	See Gas Bulletin Board.
Coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. Also referred to in other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
Cogeneration	Using gas to simultaneously generate electricity and steam or heat. See also trigeneration.
Combined cycle gas turbine (CCGT)	A device utilising a gas turbine and heat recovery/steam generation to efficiently generate electricity. More capital intensive than open-cycle gas turbines and therefore expected to be highly utilised. See also open cycle gas turbine.
Committed	A project that is considered to be proceeding.
Contingent resources	Resources that are not yet considered commercially recoverable. Technological or business hurdles need to be cleared before these resources can be considered economically justified for development.
Conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices. See also coal seam gas (CSG) and unconventional gas.
Declared Transmission System	Owned by APA Group and operated by AEMO, the gas Declared Transmission System (DTS) refers to those aspects of the Victorian gas system that are a part of the declared network. Under the National Gas Law, the gas DTS of an adoptive jurisdiction has the meaning given by the application Act of that jurisdiction and includes any augmentation of the defined declared transmission system.
Demand area	A geographical sub-grouping within a demand group.
Demand group	A geographical grouping of gas users that is used for reporting gas demand projections and modelling gas supply and demand.

Term	Meaning
Domestic gas	Gas used within Australia for residences, businesses, and electricity generators. This comprises the Mass Market, Large Industrial, and GPG market segments, excluding gas demand for LNG export.
Existing	A project that is commissioned and operating.
Export facility	A liquefaction facility that cools gas to -160 °C (its liquefaction point), reducing its volume by 600 times for export via ship.
Gas Bulletin Board (GBB)	A website (www.gasbb.com.au) managed by AEMO that provides information about 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 source	The type of reservoir that is being targeted or that gas is being produced from (conventional, coal seam gas, or unconventional).
Gas powered generation (GPG)	The generation of electricity using gas as a fuel for turbines, boilers, or engines. A market segment of the domestic Eastern and South Eastern Australian gas market.
Initial reserves	On a given assessment date, the total quantity of gas expected to be recovered from a reservoir over its entire productive life (for example, from 1975 to 2025). Also known as total reserves, or reserves plus historic production. See also remaining reserves.
Lateral	A pipeline branch.
Linepack	The pressurised volume of gas stored in a pipeline system.
Large Industrial (market segment)	A segment of the Eastern and South Eastern Australian gas market involving businesses that consume more than 10 TJ/yr. See also Mass Market.
Large-scale Renewable Energy Target (LRET)	See 'national Renewable Energy Target scheme'.
Liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.
LNG train	An LNG plant's combined purification and liquefaction facilities. Also referred to as a unit of gas purification and liquefaction (for example, an LNG plant may have several LNG trains).
Mass Market (market segment)	A segment of the Eastern and South Eastern Australian gas market involving residential users and businesses that consume less than 10 TJ/yr. See also Large Industrial.
Market segments	To develop gas demand projections, gas consumers are grouped into domestic market segments (Mass Market, Large Industrial, and GPG) and gas demand for LNG export.
National Electricity Market (NEM)	The wholesale market for electricity supply in Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania.
National Renewable Energy Target scheme	The national Renewable Energy Target (RET) scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • The Small-scale Renewable Energy Scheme (SRES) is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC). • The Large-scale Renewable Energy Target (LRET) is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.
Open cycle gas turbine (OCGT)	A generating system that uses a gas-fired turbine to generate electricity. Less efficient and less capital intensive than a combined cycle gas turbine (CCGT), an OCGT is often used for peak electricity demand.
Peak day	Over the course of a season (winter or summer), the day on which maximum gas demand occurs.

Term	Meaning
Peak demand condition	A point in time (usually a day) where the projected level of demand is expected to reach a specified level (see also 1-in-2 peak day, and probability of exceedence).
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 exceedence (POE)	Refers to the probability that a forecast maximum demand figure will be exceeded. For example, a forecast 10% POE maximum demand figure 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 and probable reserves added together make up 2P reserves.
Production	When used in the context of defining gas reserves, gas that has already been recovered and produced.
Production facilities	Facilities in which raw gas (produced from the field) is processed to separate liquids and remove impurities.
Proposed	Either advanced proposals, representing projects at an intermediate stage of development, or publically announced proposals, representing projects at an early stage of development.
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 reserves	An estimated quantity of gas that is reasonably certain to be recoverable in the future under existing economic and operating conditions. Also known as 1P reserves.
Proved-plus-probable	See 2P reserves.
R/P ratio (years)	See reserve-to-production ratio.
Ramp-up gas	Coal seam gas produced during the early stages of an LNG export project.
Remaining reserves	On a given assessment date, the total quantity of gas expected to be recovered from a reservoir over its remaining productive life (for example, from 1 January 2012 to 2025). See also initial reserves.
Reservoir	In geology, a naturally occurring storage area that traps and holds oil or gas (or both).
Reserves	Gas resources that are considered to be commercially recoverable and have been approved or justified for commercial development.
Reserve-to-production (R/P) ratio	A quantity, expressed in years, that is the ratio of remaining reserves divided by the current rate of production. A nearly depleted gas basin may have a low R/P ratio (for example, five years) whereas a newly discovered or very large basin in the early years of its production life may have a high R/P ratio (for example, 20 years). Increasing the estimated reserves increases the R/P ratio, whereas increasing the production rate decreases the R/P ratio.
Resources	See contingent resources and prospective resources.
Shale gas	Gas found in shale layers that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
Storage facility	Facilities that store gas for use at times of high demand.
Tariff D	The gas transportation Tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or a 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.
Tariff V	The gas transportation Tariff applying to non-Tariff D load sites. This includes residential and small to medium-sized commercial and industrial gas users (see also Tariff D).
Tight gas	Gas found in tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
Transmission facilities	Facilities for transporting gas to the market (for example, pipelines and compressor infrastructure).

Term	Meaning
Trigeneration	Using gas to simultaneously generate electricity, heat, and cooling. See also cogeneration.
Uncommitted (LNG)	LNG demand unmet by firm contracts and likely supply.
Uncontracted (LNG)	LNG demand unmet by firm contracts.
Unfulfilled (LNG)	LNG demand unmet by firm contracts and likely supply.
Unconventional gas	Gas found in shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See also coal seam gas (CSG) and conventional gas.

List of company names

Company	Full Company Name	ABN/ACN
ACIL Tasman	ACIL Tasman Pty Ltd	ABN 68 102 652 148
AGL Energy	AGL Energy Limited	ABN 74 115 061 375
APA Group	APA Group Limited (a stapled trust comprising the Australian Pipeline Trust and the APT Investment Trust)	ACN 091 344 704
APLNG	Australia Pacific LNG Pty Limited	ABN 68 001 646 331
Core Energy Group	Core Energy Group Pty Ltd	ACN 110 347 085
GLNG (Gladstone LNG)	Santos GLNG Operations Pty Ltd	ABN 12 131 271 648
IES	Intelligent Energy Systems Pty Ltd	ABN 51 002 572 090
Metgasco	Metgasco Limited	ACN 088 196 383
NIEIR	National Institute of Economic and Industry Research (also known as National Economics)	ABN 72 006 234 626
QGC	Queensland Gas Company Pty Limited	ACN 089 642 553

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