INDEPENDENT MARKET OPERATOR

Gas Statement of Opportunities

July 2013

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The Independent Market Operator (IMO) has prepared this Gas Statement of Opportunities (GSOO) report under Part 6 and Schedule 3 of the Gas Services Information Rules. In preparing this publication the IMO has used all reasonable endeavours to include the best information available to it at the time. Demand and supply forecasts are prepared using publicly available input data as at 31 March 2013.

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[1] Gas referred to throughout this document refers to natural gas. All other forms of gas are specified.

Preface

We are pleased to present the first Gas Statement of Opportunities (GSOO) prepared by the Independent Market Operator (IMO), one of two key deliverables from the new information services for the Western Australian (WA) natural gas sector established under the *Gas Services Information Act 2012*.

The GSOO is an annual document that provides an independent overview of the WA natural gas market, including technical and market data and information regarding the status of and opportunities within the market. We expect the GSOO to benefit market participants and policy makers by improving transparency of market information and highlighting opportunities that will assist with the further development of the WA gas market.

This GSOO provides forecasts of gas demand and supply for the WA domestic gas market for the period 2013 to 2022. While it focuses on the domestic natural gas sector, this GSOO also considers the outlook for the WA Liquefied Natural Gas (LNG) export sector, due to the strong linkages between the domestic gas and LNG export sectors.

As the IMO's formal information gathering powers for the GSOO only commenced on 29 June 2013 and the WA Gas Bulletin Board (GBB) is not yet operational, the IMO was unable to utilise these sources of information in the preparation of this GSOO. Hence, this first GSOO is limited by the availability of information that could be used in the modelling of gas supply and demand and compilation of other data, relying heavily on publicly available information.

This first GSOO has benefited from valuable contributions from existing gas market participants. We gratefully acknowledge the gas market participants and members of the IMO's Gas Advisory Board, who have enthusiastically participated in the design and development process of the GBB and the GSOO and have shared information to assist in shaping the GSOO.

Consultation and feedback are very important to the development of the GBB and the GSOO and we would like to thank all those who took the time to respond during the development and consultation process conducted by the IMO. The IMO welcomes further constructive comments and feedback from all stakeholders in the WA gas industry in the development of future GSOO reports.

The IMO looks forward to providing future GSOO reports that will continue to inform an ongoing lively debate about the future of the WA natural gas industry. The IMO will publish its second GSOO in December 2013, for the 10-year period 2014 to 2023.

John Kelly
Chair
Independent Market Operator

Allan Dawson
Chief Executive Officer
Independent Market Operator

Executive Summary and Key Findings

The establishment of a GBB and an annual GSOO were key recommendations of the Gas Supply and Emergency Management Committee (GSEMC), which was formed following two major gas supply disruptions in 2008, with the aim of improving the security, reliability and competiveness of the WA domestic gas market.[2]

As one of the key information services established under the *Gas Services Information Act 2012*, the GSOO provides an independent insight into the WA domestic gas market that outlines supply and demand with the aim of highlighting potential shortfalls, constraints and opportunities in the WA gas market for existing and potential market participants.

The WA gas market is currently going through an exciting period of development with new domestic gas and LNG export processing facilities, as well as an expansion in gas storage.

In the next few years, the market is expected to see:

- the further expansion of domestic gas processing capacity through the completion of the Red Gully and Macedon processing facilities, adding to the recently commissioned Devil Creek facility;
- the expansion of gas storage capacity at the Mondarra Gas Storage Facility;
- the expected completion of two new LNG export facilities (Gorgon and Wheatstone); and
- the expected completion of two new domestic gas processing facilities associated with these LNG facilities.

These developments will significantly alter both the domestic gas and LNG export markets in WA, broadening the sources of supply to the domestic market, which should improve the security of supply and competitiveness of the market.

In this period of change, the commencement of the GBB and the publication of this GSOO are timely. Improved information about the gas market will assist stakeholders in identifying potential opportunities, improve risk mitigation and inform Government in relation to energy policy development.

To assist with this GSOO, the IMO engaged the National Institute of Economic and Industry Research (NIEIR). NIEIR is a forecasting consultancy that has spent more than 25 years modelling various gas and electricity markets across Australia, including WA. For this GSOO, NIEIR developed a WA gas model and provided demand and supply forecasts.

For the 2013 to 2022 period, this GSOO provides:

- a brief history of the WA gas market and description of WA gas market infrastructure (chapter 3);
- an outlook for the WA economy (chapter 4);
- projections of WA gas demand (chapter 5);
- a view of the international LNG market (chapter 6);
- projections of WA gas supply (chapter 7);
- estimates of WA gas reserves (chapter 8);
- a supply and demand assessment (chapter 9); and
- a discussion of other topics of interest, such as relevant government policy matters (chapter 10).

[2] See GSEMC's recommendations highlighted in its report to the WA Government; http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Energy_Initiatives/gsem-committee-report-government-sep-2009.pdf, accessed 5 March 2013.

Key Findings of the GSOO

This GSOO finds for the 2013 to 2022 period:

- there is expected to be adequate gas supply to meet forecast demand in the domestic market;
- the forecast average annual growth for WA domestic gas supply is expected to be 3.7% per annum, compared to a forecast average annual growth for domestic gas demand of 1.1% per annum;
- the gas processing capacity in the domestic market is anticipated to be double the forecast level of domestic gas demand by the end of 2022;
- existing gas reserves are forecast to be sufficient to continue to meet 2022 domestic and LNG demand levels for a very considerable period beyond 2022;
- gas demand forecasts suggest demand growth will be higher for areas located outside the South West Interconnected System (SWIS);
- total gas demand in WA, including both LNG production (feedstock and processing) and domestic demand, is forecast to grow 8% per annum until 2022; and
- there are several medium to long-term growth challenges confronting the WA LNG market, although these are not expected to impact on the domestic natural gas sector in the forecast period, but may have an impact into the future.

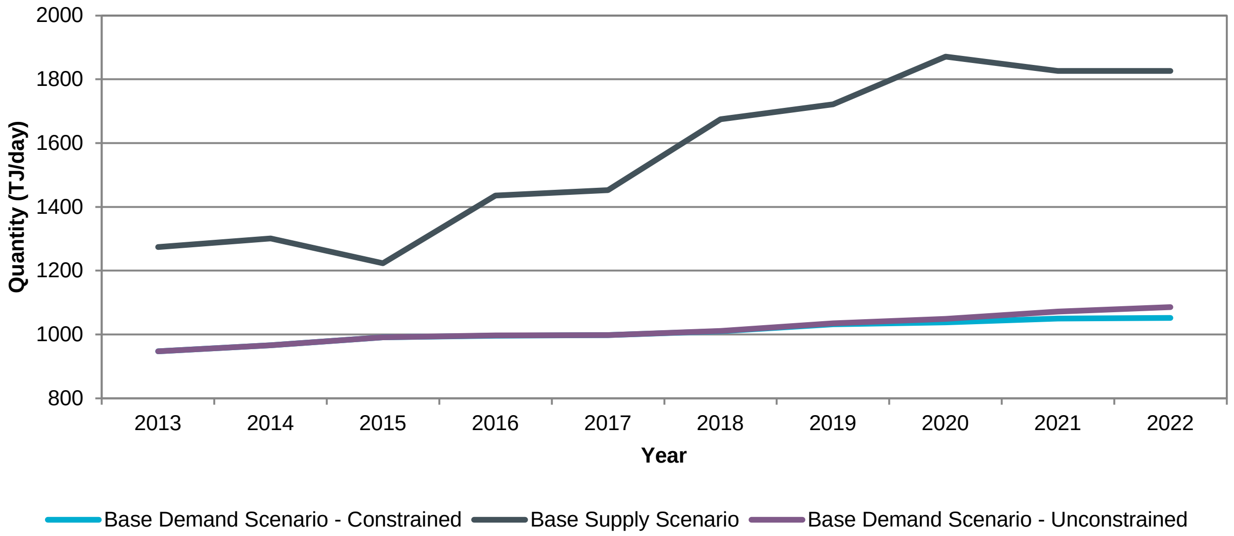
Each of these findings is explained in more detail below.

Supply-Demand Balance

The WA domestic gas market at the wholesale level is dominated by several large gas consumers (see section 5.1 – Characteristics of Gas Demand). These consumers are supplied mostly by a small number of large gas producers (see section 7 – Gas Supply, Capacity and Projections) through various gas transmission pipelines, which transport gas from gas production facilities predominantly located in the North West of the State, to consumers around the State. WA domestic gas consumption is dominated by the mining, manufacturing and electricity generation sectors was 346 PJ (excluding petroleum processing) of gas in 2012.

Figure A presents the supply-demand balance for the 2013 to 2022 period. Forecasts of potential gas supply generated for the 2013 to 2022 period suggest the domestic gas market will be well supplied in this period.

Figure A – Supply and Demand Balance, 2013 – 2022



Source: NIEIR Forecasts 2013-2022

The supply-demand balance assessment is based on gas supply forecasts that take into account assumed market conditions including price. Two forecasts of gas demand have also been prepared:

- including price assumptions (constrained demand); and
- excluding the price assumptions (unconstrained demand)

outlined in section 4.4 of this GSOO.

Domestic gas supply is forecast to grow at approximately 3.7% per annum from 1,274 TJ/day (465 PJ/annum) to 1,826 TJ/day (667 PJ/annum), while constrained domestic gas demand is forecast to only grow by 1.1% per annum from 947 TJ/day (346 PJ/annum) to 1,052 TJ/day (384 PJ/annum) in 2022. By the end of 2022, potential domestic gas supply is expected to be almost 74% higher than forecast demand for the WA domestic market (see section 9.1 – Base Case Demand and Supply).

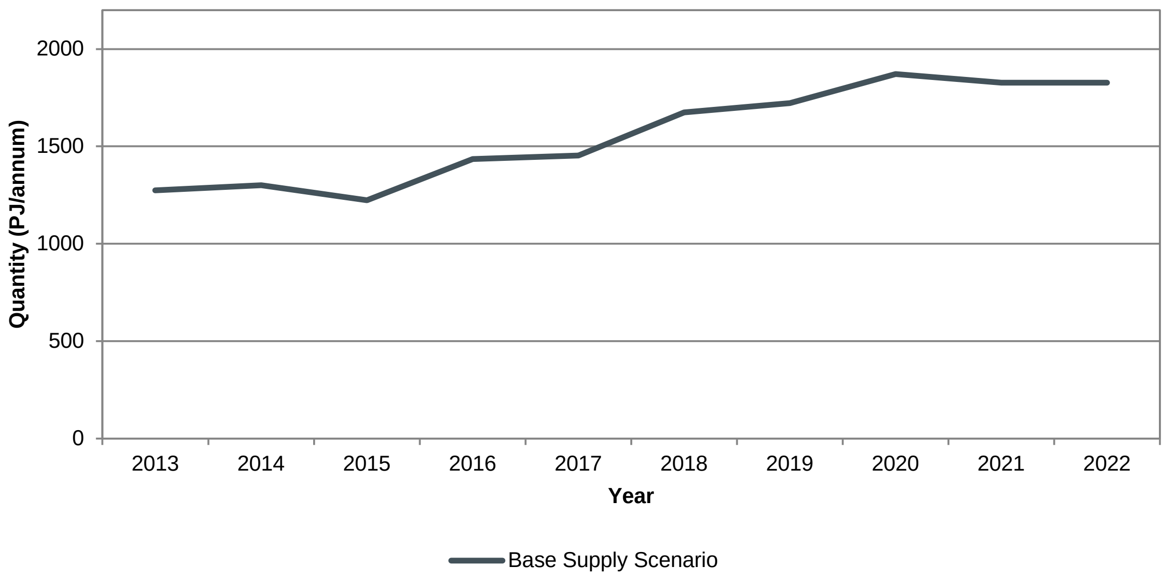
The supply-demand gap (the difference between potential domestic supply and domestic demand) will increase from approximately 327 TJ/day in 2013 to about 827 TJ/day in 2022.

Forecast supply and demand are further considered below.

Domestic Gas Supply

Gas supply forecasts for this GSOO (Figure B) are a measure of the quantity of gas that suppliers are willing to supply to the domestic market at predicted gas prices, an estimate of potential gas supply.

Figure B: Domestic Gas Supply, 2013-2022

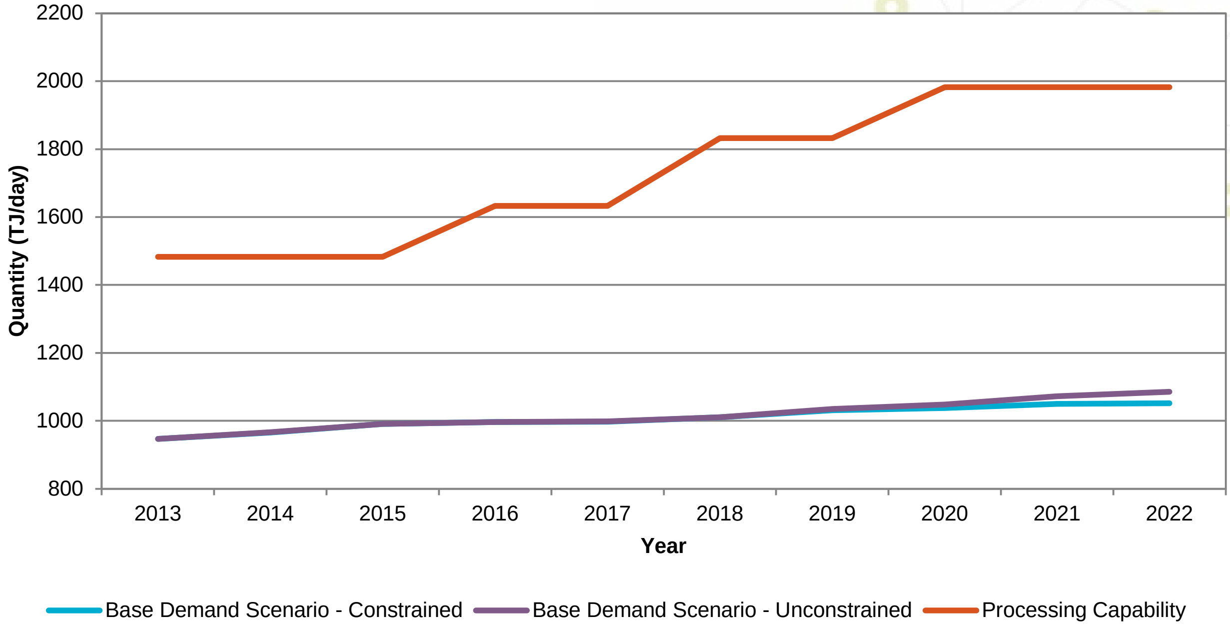


Source: NIEIR Forecasts 2013-2022

As noted previously, domestic gas supply is expected to increase by 3.7% per annum over the forecast period to reach 1,052 TJ/day by 2022. In addition to generating a forecast of potential gas supply, this GSOO considers two other perspectives, namely the availability of gas processing capacity and the adequacy of gas reserves.

In the 2013 to 2022 period, a total of 736 TJ/day of domestic gas processing capacity is anticipated to be added to existing gas processing capacity servicing the domestic gas market, bringing the total gas processing capacity to 1,983 TJ/day in 2022 (see section 8.2 – Gas Processing Capacity).

Figure C: Gas Processing Capacity, 2013-2022



Source: NIEIR Forecasts 2013-2022

Figure C compares the forecasts of total gas processing capacity with the unconstrained and constrained domestic gas demand forecasts for the 2013 to 2022 period. It shows the amount of gas processing capacity available to the domestic market in 2022 is predicted to approach almost twice the level of gas demand for that year.

In terms of gas reserves, WA is the most gas-endowed State in Australia. The Australian Bureau of Resources and Energy Economics and Geoscience Australia estimate WA onshore and offshore basins hold a total of 159,000 PJ of economic and sub-economic reserves in conventional gas, while other studies by the Energy Information Administration in the United States (US) report an estimated 305,412 PJ of unconventional gas in WA's basins at the end of 2012. Based on these estimates and projections of total gas demand (domestic market and the LNG industry) for 2022, and assuming no additional gas reserves are discovered by 2022, gas reserves in WA have the potential to last for another 131 years beyond 2022 (see section 8.4 – Remaining Reserves).[3]

Domestic Gas Demand

Domestic gas demand represents NIEIR's projections of gas required by the domestic market within WA (comprising industrial, commercial and residential demand, but excluding LNG processing consumption) for the 2013 to 2022 period.

Figure D presents the Base forecasts of domestic gas demand for the 2013 to 2022 period prepared by NIEIR. The forecasts predict that domestic gas demand will grow at approximately 1.1% per annum from approximately 947 TJ/day (346 PJ/annum) in 2013 to about 1,052 TJ/day (384 PJ/annum) in 2022 for the constrained scenario, which takes into account NIEIR's forecasted gas prices offered to the domestic market.[4] The forecast constrained rate of growth is similar to the average growth rate of the domestic market experienced between 2003 and 2012 (see section 5.2 – Projected Domestic Demand).[5]

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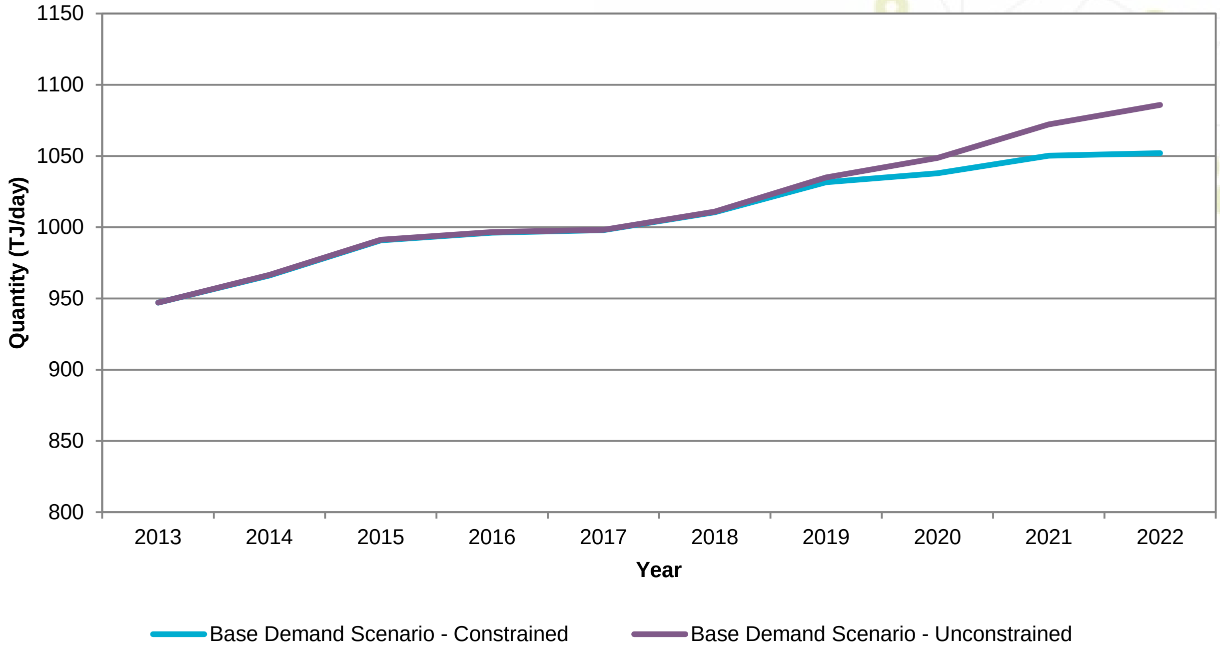
[3] The estimate assumes that total gas demand in WA remains constant at approximately 3,172 PJ/annum beyond 2022.
[4] Constrained domestic demand forecasts are forecasts of gas demand that consider the impacts of forecasted gas prices.
[5] The forecast unconstrained growth rate is 1.4% per annum.

Figure D: Domestic Demand (Constrained and Unconstrained) 2013-2022



Source: NIEIR Forecasts 2013-2022

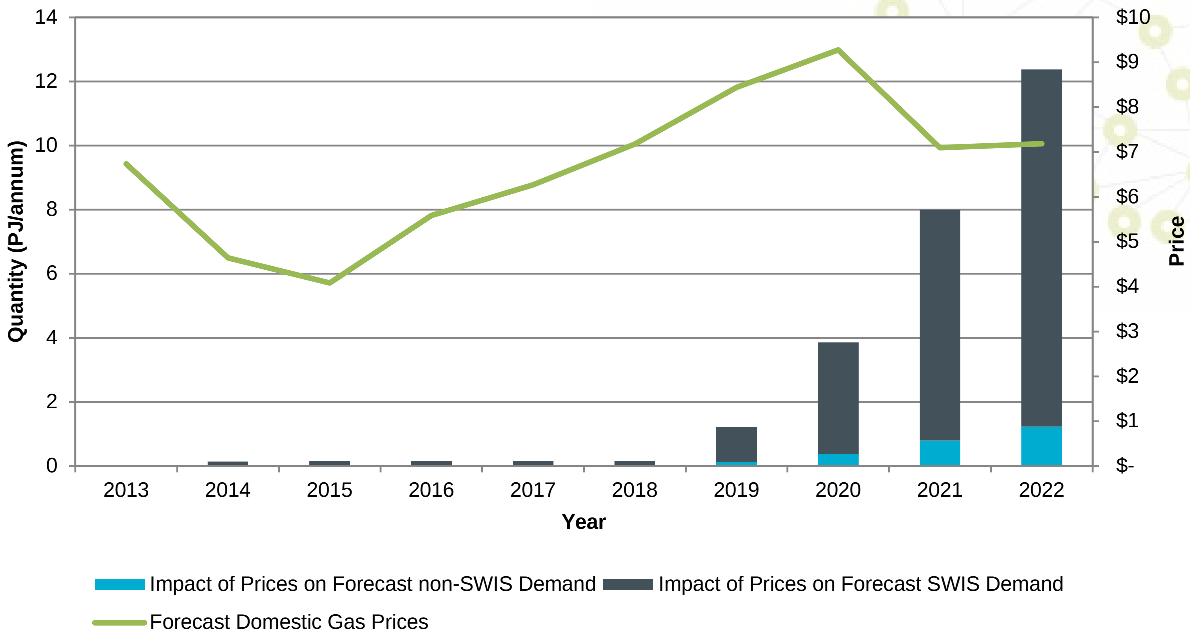
Figure D shows domestic gas demand is forecast to be only mildly impacted by the forecast gas price rises for the 2013 to 2022 period. This reflects NIEIR modelling assumptions, in particular that domestic gas demand is fairly inelastic and will not immediately respond to price changes while the gas price remains below the cost of competing fuels.

The assumed inelastic nature of domestic gas demand reflects the fact that gas consumption is dominated by the capital-intensive mining and industrial sectors. These customers have already committed capital for existing infrastructure and are likely to have long-term gas contracts. This means they are unlikely to immediately change their consumption. This inelasticity is also evident in historical gas consumption data (see section 5.1 – Existing Gas Demand).

Figure E presents the reduction in demand between the constrained and unconstrained forecasts of gas demand. Put another way, this represents potential additional gas demand that may be realisable if future gas prices are lower than NIEIR's forecast gas prices. With lower gas prices, it is forecast that gas consumption in WA in 2022 could be about 12 PJ/annum higher, of which 11 PJ/annum (or 3% of total gas demand) is in areas that comprise the SWIS and about 1 PJ/annum (or 0.3% of total gas demand) is in areas located outside the SWIS (see section 5.2 – Projected Domestic Demand).

Figure E also reflects an expectation that the impact from changes in gas prices will be lagged and the fall in gas demand is not immediate. Figure E shows as forecast gas prices rise from 2015 to 2020, forecast gas demand does not start reducing until 2019. A key factor supporting this assumption is the existence of long-term gas contracts in the domestic market.

Figure E: Demand Suppression due to Forecast Prices (SWIS and non-SWIS Demand), 2013-2022



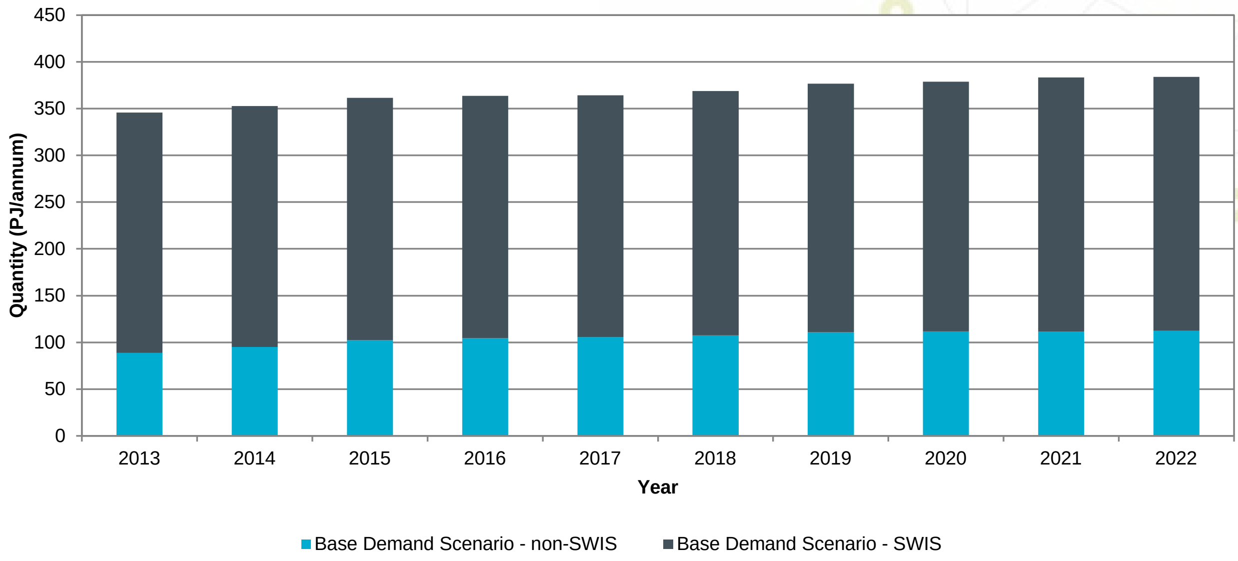
Source: NIEIR Forecasts 2013-2022. **Note:** Gas prices are nominal prices.

Gas Demand by Areas

In assessing domestic gas demand, the IMO has considered demand in both the SWIS and the area representing the remainder of the State. These areas were investigated separately, recognising the drivers of gas demand may differ. For example demand for gas in the SWIS is heavily impacted by its use for electricity generation, while demand outside the SWIS is largely driven by resources projects.

Figure F presents the gas demand forecasts for the SWIS and areas outside the SWIS. As can be seen, demand is projected to grow from about 257 PJ/annum to 272 PJ/annum (0.5% per annum growth) for the SWIS, while for areas outside the SWIS, gas demand is forecasted to grow from approximately 89 PJ/annum to 113 PJ/annum (a more rapid 2.4% per annum growth) by the end of 2022 (See section 5.2 – Projected Domestic Demand).

Figure F: Gas Demand by Regions, 2013-2022

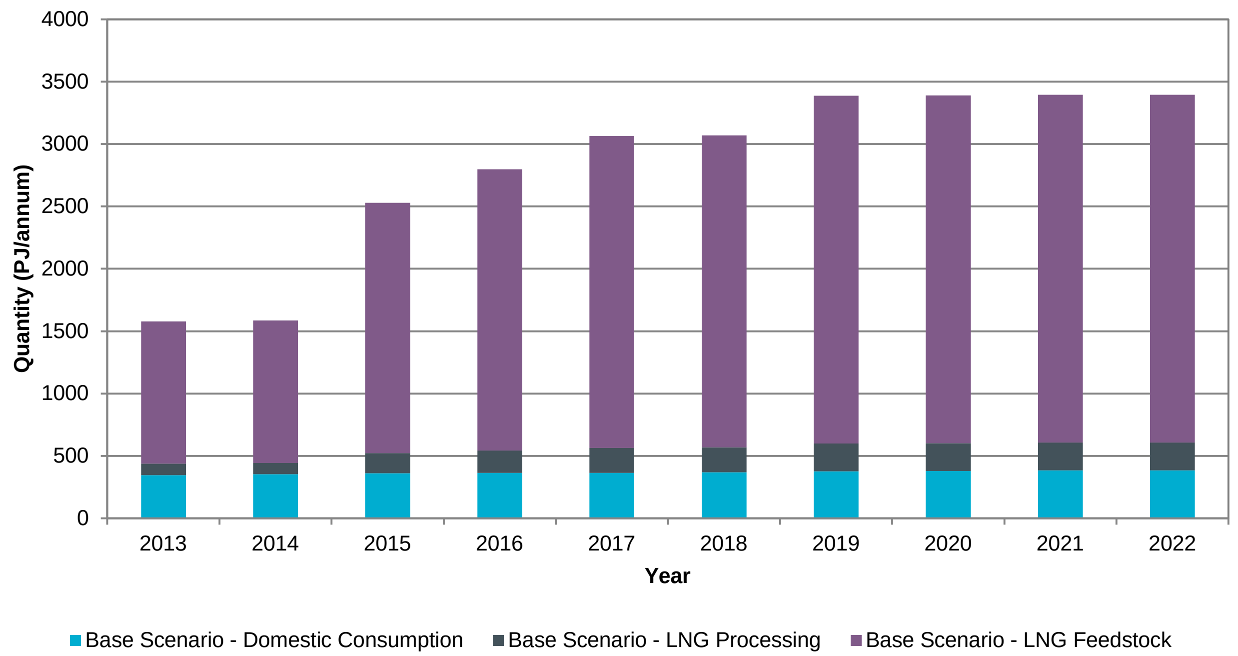


Source: NIEIR Forecasts 2013-2022

Total Gas Demand

Although forecasts suggest growth in domestic gas demand is expected to be slow, forecasts for total gas demand (domestic gas demand plus LNG, including feedstock and gas consumed in LNG production) is expected to rapidly increase. This growth is driven by the gas feedstock and processing requirements of the Gorgon and Wheatstone LNG facilities that are anticipated to be completed in the 2013 to 2022 period.

Figure G: Total Gas Demand, 2013-2022



Source: NIEIR Forecasts 2013-2022

This GSOO forecasts total gas demand will increase at approximately 8% per annum between 2013 and 2022 from approximately 1,579 PJ/annum in 2013 to 3,395 PJ/annum in 2022. Total gas demand for the forecast period is presented in Figure G (see section 5.2 – Total Gas Demand).

Growth Challenges to WA's LNG Exports

Similar to the domestic gas market, WA's LNG export market is also going through an exciting phase of expansion and development. In the 2013 to 2022 period, international LNG demand is expected to grow rapidly, with WA's LNG export capacity anticipated to increase from 21 million tonnes per annum (Mtpa) to about 50 Mtpa, more than doubling WA's LNG exports over this period.

Notwithstanding the positive outlook, there are several medium to long-term challenges confronting the WA LNG industry (see section 6.6 – Supply Risks in the International LNG Market). These include:

- potential changes to international LNG supply;
- the potential end of premium LNG pricing in the Asia Pacific region;
- the high cost of LNG production in WA; and
- the emergence of unconventional gas as a source of supply.

WA predominantly exports its LNG to customers located in the Asia Pacific. Due to the large price differentials between the Asia Pacific LNG market and other LNG markets, several countries such as Russia, the US and Canada have announced their intentions to increase supply to the Asia Pacific LNG market. If these planned LNG export projects go ahead, they are well positioned to compete against WA LNG exports.

Increasing competition in the Asia Pacific market means premium prices previously paid by Asia Pacific customers may not persist. The downward pressure on Asia Pacific LNG prices may also impact on LNG prices agreed under previous contracts that are predominantly linked to oil indexes.

The high cost of LNG production in Australia remains an issue for the LNG export market. McKinsey[6] reports the cost of developing of LNG export facilities in Australia is now 20% to 30% higher than that in North America and East Africa. If the cost of developing LNG projects becomes prohibitive in Australia, potential LNG developments currently planned for WA may be abandoned.

The emergence of unconventional gas as a new source of gas supply is also a potential game changer. In the last decade, unconventional gas has transformed the US from a net importer into a net exporter of gas. Unconventional gas is also transforming gas markets in eastern Australia and there are indications that WA is well endowed with unconventional gas resources. While its production is still in its early stages in WA and around the world, unconventional gas has the potential to transform gas markets internationally. The impact of unconventional gas on LNG exports is still not clear and will need to be monitored closely by WA LNG exporters, market regulators and governments.

These challenges facing the LNG export sector are not expected to impact on the domestic supply of natural gas in the forecast period, however they may have an impact over the longer term.

[6] See McKinsey (2013), Extending the LNG boom: Improving Australian LNG productivity and competitiveness http://www.mckinsey.com/locations/australia/knowledge/pdf/Extending_LNG_boom.pdf, accessed 13 July 2013.

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1. Objectives and the Purpose of the GSOO

In April 2012, the *Gas Services Information Act 2012* (GSI Act) was enacted by the Western Australian (WA) Government, underpinning the establishment of the GBB and the GSOO for the WA gas industry. Subsequently in June 2012, the initial provisions of the *Gas Services Information Regulations 2012* (GSI Regulations) were made, formally appointing the IMO as the operator of the GBB and GSOO. The remaining GSI Regulations and the Gas Services Information Rules (GSI Rules) made under the GSI Regulations, commenced on 29 June 2013.

The GSOO is to be published annually by the IMO. The GSOO provides information on the existing processing capacity and projected future gas demand to current and potential participants in the WA gas market.

The objectives and primary purpose of the GSOO are set out in sections 5(1) and 6 of the GSI Act:

The gas statement of opportunities is a periodic statement the primary purpose of which is to include information and assessments relating to medium and long term natural gas supply and demand and natural gas transmission and storage capacity in the State.

and

The objectives of the GBB and GSOO are to promote the long term interests of consumers of natural gas in relation to —

- *a) the security, reliability and availability of the supply of natural gas in the State;*
- *b) the efficient operation and use of natural gas services in the State;*
- *c) the efficient investment in natural gas services in the State;*
- *d) the facilitation of competition in the use of natural gas services in the State.*

The contents of the GSOO are set out in Part 6 the GSI Rules:

A GSOO must contain information about:

- *a) natural gas reserves (including prospective or contingent resources);*
- *b) committed and proposed new or expanded:*
    - *i. gas production facilities;*
    - *ii. gas transmission pipelines and pipeline augmentations;*
    - *iii. gas storage facilities; and*
    - *iv. large facilities using gas.*

A GSOO must contain, for the period of at least 10 years, projected information about:

- *a) capacity of gas production facilities, gas transmission pipelines and gas storage facilities including constraints affecting those facilities; and*
- *b) demand for natural gas.*

A GSOO may also, if practicable, include forecasts of natural gas reserves and annual demand for natural gas for the further 10 year period after the end of the 10 year period to which that GSOO applies.

This first GSOO is made in accordance to Division 7, Schedule 3 of the GSI Rules and contains forecasts for the 10 year period commencing 1 January 2013.

1.1. Approach to Forecasting Demand and Supply

This GSOO provides forecasts of gas demand and supply for the WA domestic gas market for the period 2013 to 2022, to make an assessment of the adequacy of supply to meet forecast demand over this period. While it focuses the domestic natural gas sector, this GSOO also considers the outlook for the WA LNG export sector, due to the strong linkages between these sectors.

This GSOO considers the supply of natural gas to the domestic market from three perspectives. Firstly, potential gas supply is forecast, based on assumptions about market conditions including forecast prices. In assessing supply, the IMO has considered three scenarios (Base, Low and High) based on different assumptions about likely gas prices.

For completeness, this GSOO also consider the:

- availability of gas processing capacity; and
- adequacy of gas reserves.

In forecasting gas demand, the IMO has also considered three scenarios (Base, Low and High) based on corresponding assessments of economic conditions in WA. Further, a "constrained" demand assessment has been developed, incorporating the forecast gas prices that have been used to develop the forecasts of gas supply.

In assessing domestic gas demand, the IMO has also separately considered demand in the area of WA that comprises the South West Interconnected System (SWIS) and the remainder of the State. These areas were identified by stakeholders, recognising the drivers of gas demand are likely to be different in these areas and also reflecting the substantial use of natural gas for electricity generation in the Wholesale Electricity Market (WEM) which operates in the SWIS.

It is important for readers to note that the scenarios outlined in this GSOO are indicative only. The scenarios have been independently determined in a bid to capture potential outcomes within the high and low range for the forecast period for the purpose of assessing the adequacy of future gas demand and supply. Any specific scenario outlined in this GSOO does not represent any advice or information provided by any current or potential gas market participant in the domestic gas market for the outlined timeframe. All outlined scenarios may not reflect existing or future market reality.

1.2. Development of this GSOO

This GSOO draws on recommendations made by Market Reform in its Gas Information Services Design Report: Gas Bulletin Board and GSOO Final Report, as well as submissions to the IMO on the Draft and Final Gas Information Services Design, GSI Regulations and GSI Rules.[7]

The WA GBB will not be fully operational until 1 August 2013 and the IMO's powers to collect information for the GSOO did not commence until the GSI Rules commenced on 29 June 2013, meaning information could not be formally requested from participants for inclusion in this GSOO. Recognising these limitations, this initial GSOO relies on historical information, public announcements and data voluntarily provided by market participants. The IMO only sought information from market participants when an in-depth understanding the domestic market was required in developing the gas demand and supply models for this GSOO.

This GSOO has maximised the use of publicly available data, including Commonwealth and State Government publications, and data from reports by various consultants on the WA gas industry. It is inevitable that on occasion the various sources of data don't precisely reconcile.

[7] Market Reform's Final Report and submissions received on the Draft Report are available at http://www.imowa.com.au/n6276,237.html. For ease of reference, these are identified as "MR Rec" in sections 3, 4, 6 and 7 of this document. Other submissions pertaining to the GSOO are also available on the same webpage, under submissions to the First and Second Consultation for the Draft GIS Design.

Improved information availability in the future will allow the IMO to further analyse and estimate the impact of future developments and changes. This will assist the IMO with identifying issues that may constrain the efficient operation of the WA gas market, promoting greater reliability, security, transparency and competition in the WA gas industry.

In developing this first GSOO:

- two stakeholder forums were held on the design of the GBB and the GSOO;
- modelling and analysis work was conducted by an independent consultant, NIEIR; and
- the IMO engaged in more than 25 one-on-one meetings with stakeholders, including Commonwealth and State Government agencies, peak bodies and gas market participants.

This consultation provided a broad understanding of issues faced by market participants and of current gas market conditions. The IMO has not reproduced information provided in confidence during consultation in this report unless independently sourced from public reports.

To assist with this GSOO, the IMO engaged the National Institute of Economic and Industry Research (NIEIR). NIEIR is a forecasting consultancy that has spent more than 25 years modelling various gas and electricity markets across Australia, including WA. For this GSOO, NIEIR developed a WA gas model and provided demand and supply forecasts.

1.3. Future GSOOs

The IMO will publish the next GSOO by 31 December 2013. In subsequent years, the GSOO will only be published once per annum. The GSOO is expected to evolve over time with improved information from the GBB and feedback from stakeholders.

2. Acknowledgements

The IMO acknowledges the assistance of gas industry participants; exploration firms, infrastructure providers, peak organisations, producers, retailers and shipping organisations that have provided research, data, information and guidance to assist with the preparation of this GSOO document and IMO staff who have worked tirelessly to ensure the accuracy of this report.

The IMO would particularly like to acknowledge the following industry stakeholders:

- Alcoa
- Alinta Energy
- APA Group
- Apache Energy
- Association of Petroleum Production and Exploration Association (APPEA)
- AWE Limited
- BHP Billiton
- BP Australia
- Buru Energy
- Chamber of Commerce and Industry WA (CCIWA)
- Chamber of Minerals and Energy WA (CMEWA)
- Chevron
- DBP Limited
- Department of Finance, Public Utilities Office (PUO)
- Department of Mines and Petroleum (DMP)
- Department of State Development (DSD)
- DomGas Alliance
- Economic Regulation Authority (ERA)
- EnergyQuest
- EVOL LNG
- Gas Trading Pty Ltd
- Horizon Power
- Kleenheat Gas
- NewGen Power Kwinana Pty Ltd
- North West Shelf Joint Venture Partners
- Origin Energy
- Perth Energy
- Pricewaterhouse Coopers (PWC)
- Retail Energy Market Company (REMCo)
- Synergy
- Transerv Energy
- Verve Energy
- Woodside Petroleum
- Other market participants that have kindly provided feedback during the development of the GSOO.

3. WA Gas Industry, Market Overview and Infrastructure

This chapter provides a description of the WA gas market, its history, size, structure and associated infrastructure (such as pipelines and storage). This is accompanied by a brief description of the legal and regulatory framework in the WA natural gas sector.

The WA gas industry features several highly integrated segments which operate together in a supply chain. These are:

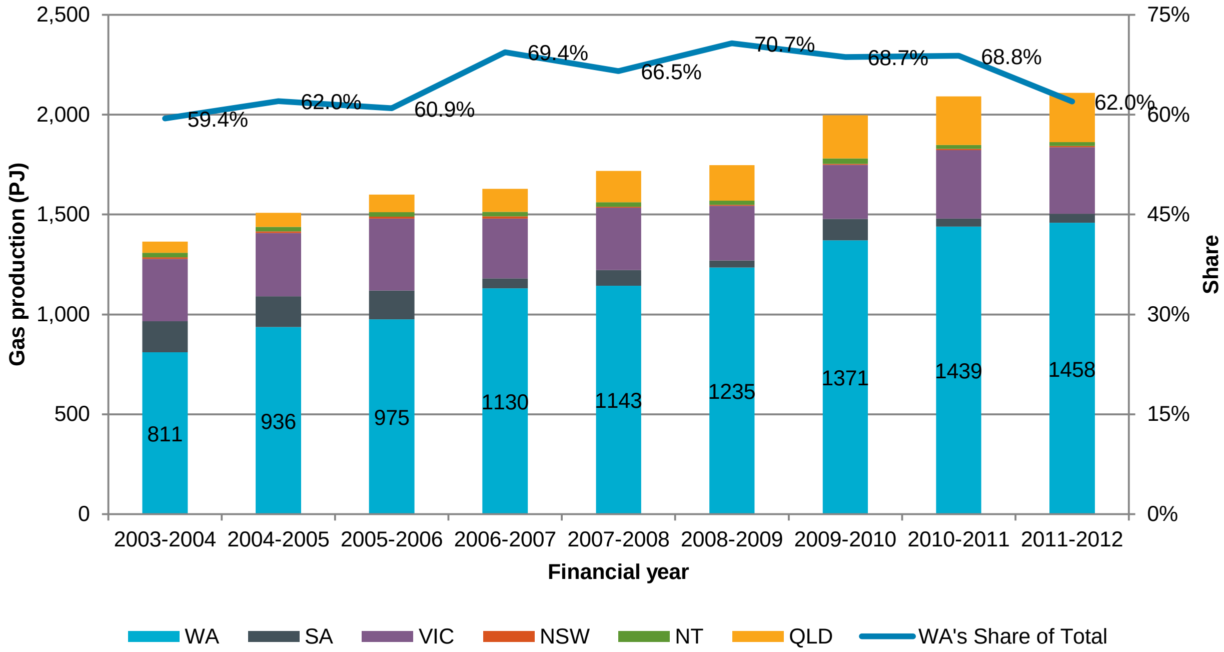
- exploration;
- production and processing;
- transmission;
- storage;
- wholesale trading;
- distribution;
- large consumer demand; and
- retail markets.

This GSOO focuses on the gas production and processing, transmission, storage and demand (in particular large customer) segments of the market.

3.1. An Overview of the Western Australian Gas Market

WA is Australia's largest State gas market and produced approximately 1,458 PJ of gas for export and domestic usage in 2012, representing 62% of Australian gas production.[8]

Figure 1 – Australia's Gas Market Production (Domestic Gas, LNG and Processing), 2003-2004 to 2011-2012



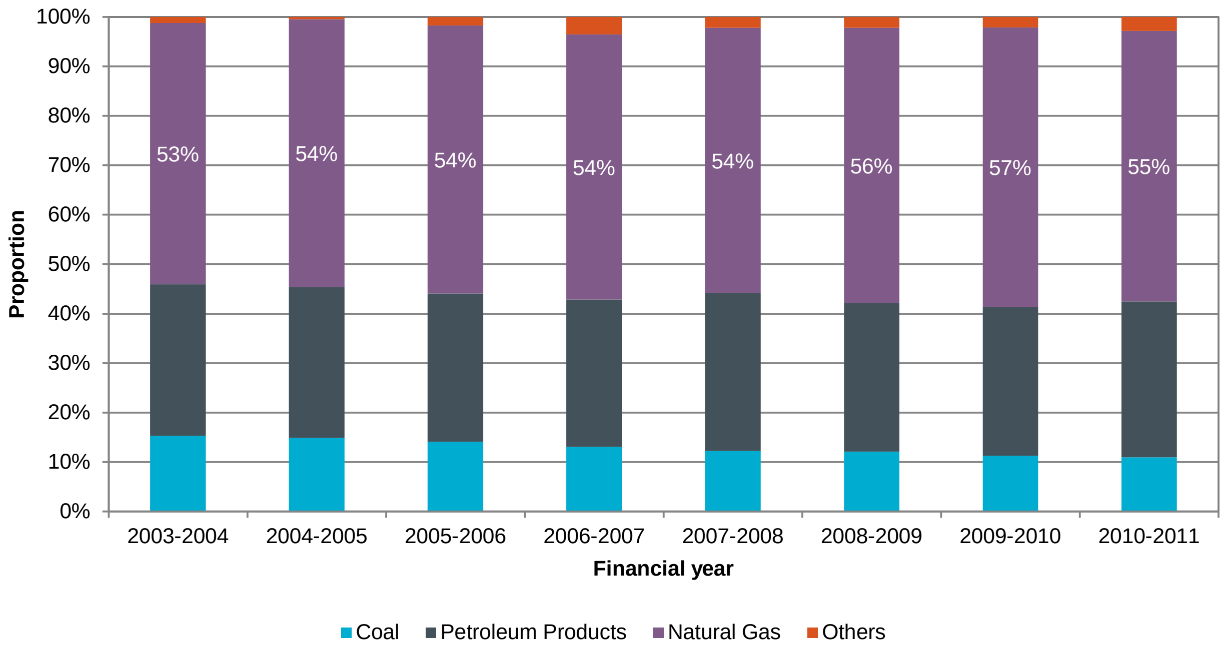
Source: BREE (2012-2013), Energy in Australia, Table 21, Australia's gas production, by State and Territory. **Note:** South Australia – SA, Victoria – VIC, New South Wales – NSW, Northern Territory – NT, Queensland – QLD.

[8] See BREE (2013b) for more information.

The majority of WA's gas production is exported as LNG, linking WA to international market prices and the exchange rate. While WA accounts for the bulk of gas production in Australia, its percentage share of total Australian gas production is expected to fall significantly over the 2013 to 2022 period, as LNG projects from Queensland (Australia Pacific LNG, Gladstone LNG and Queensland Curtis LNG projects) commence production.

Gas is the primary fuel source for WA with more than half of WA's energy consumption derived from gas.[9] The Australian Bureau of Resources and Energy Economics (BREE) expects WA gas consumption will continue to grow at approximately 2.2% per annum from 1,777 PJ in 2012-2013 to 4,036 PJ in 2049-2050.[10] Accordingly, the supply of gas is vital to the operation of the State economy, which has ensured that the WA Government has maintained a focus on the availability of gas supply within WA.[11]

Figure 2 – Western Australia's Consumption of Energy by Fuel Source, 2003-2004 to 2010-2011



Source: BREE (2012), Australian Energy Statistics Update 2012, Table C.

In essence, gas produced in WA is delivered to two main segments; the domestic market and the LNG export market.

Analysing BREE's gas production data for 2010-2011, it is estimated that the domestic gas market consumed about a quarter (23%) of the total gas produced, while about two-thirds of total gas production in WA (66%) was exported as LNG. The remaining gas production is estimated to be consumed in petroleum (oil, gas and associated products) processing totalling approximately 450 TJ/day (or approximately 164 PJ/a).[12]

This means for 2010-2011, it is estimated that approximately 70 to 75% of gas produced in WA is exported or consumed (LNG processing) by WA's LNG industry.

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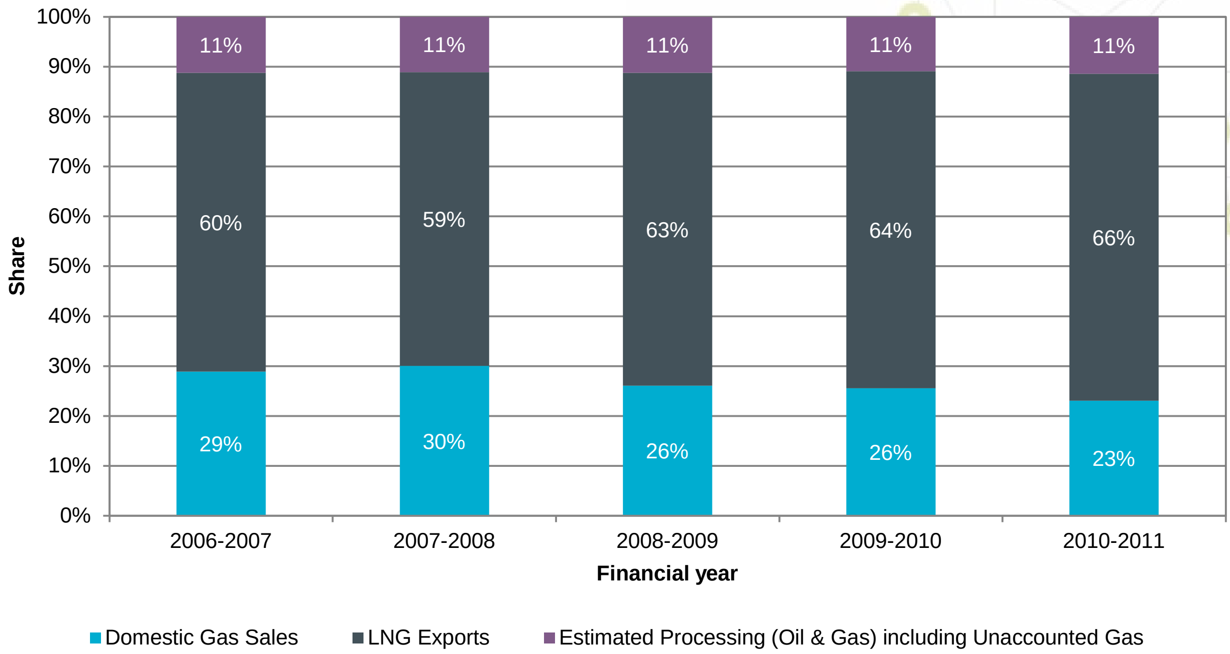
[9] Ibid

[10] BREE (2012c) forecasts suggests WA's future gas consumption will increase at a rate that is slower than the projections for the Eastern and Northern Australian markets over the same period.

[11] The West Australian (2013d).

[12] The Commonwealth Government does not report on gas consumed for processing gas in WA LNG facilities. This figure is estimated by deducting BREE's (2012) estimate of 1,439 PJ for 2010-2011.

Figure 3 – Estimated Proportions of Domestic Gas Consumption, 2006-2007 to 2010-2011

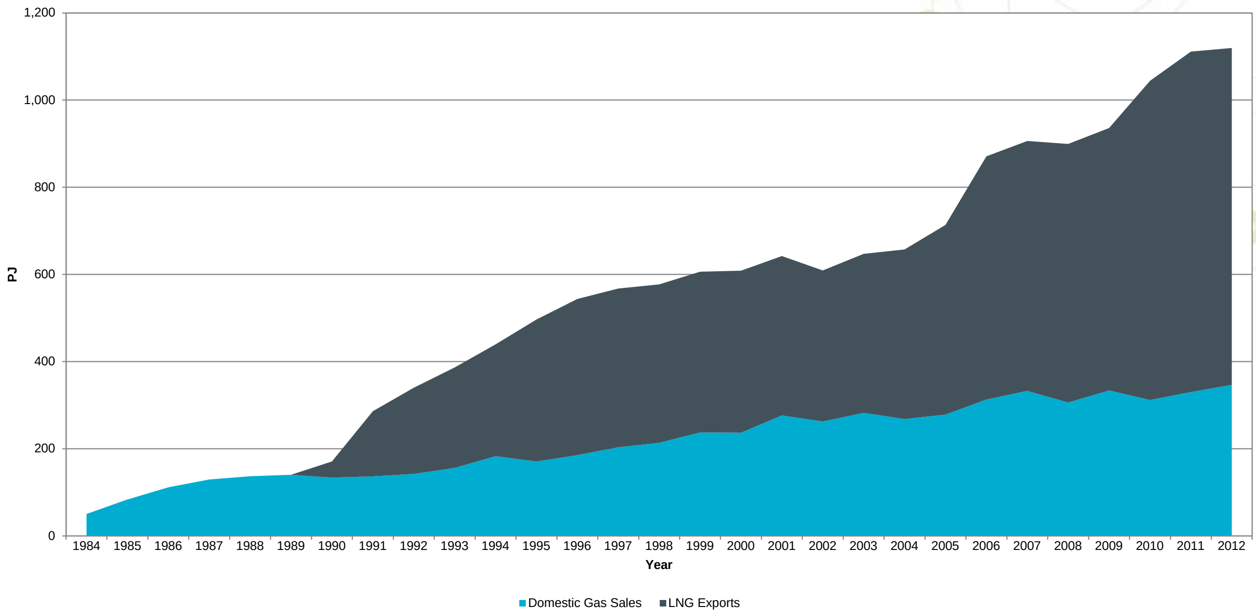


Source: IMO estimates, using BREE's (2012-2013) *Australian Energy Statistics* and *Energy in Australia* data, APPEA 2007-2012 quarterly production data and DMP 2007-2012 LNG exports data. Estimates are calculated using BREE's domestic gas consumption data, APPEA and DMP gas sales, LNG.

Australia's and WA's LNG export market began in August 1989 when the first LNG cargo left the North West Shelf (NWS) for delivery to Japan. Since this time, LNG has been a critical export commodity for Australia and WA. By the end of 1990, the quantum of natural gas supplied to the WA LNG export market exceeded the amount supplied to the WA domestic market. By 2012, gas supplied to the LNG market had grown to approximately two and a half times the quantum of gas supplied to the domestic market. It is anticipated the size of the WA LNG market will be approximately seven times the WA domestic market by the end of 2022 (chapter 6).[13]

[13] This significant increase is due to increased WA LNG exports resulting from the upcoming Gorgon & Wheatstone LNG facilities.

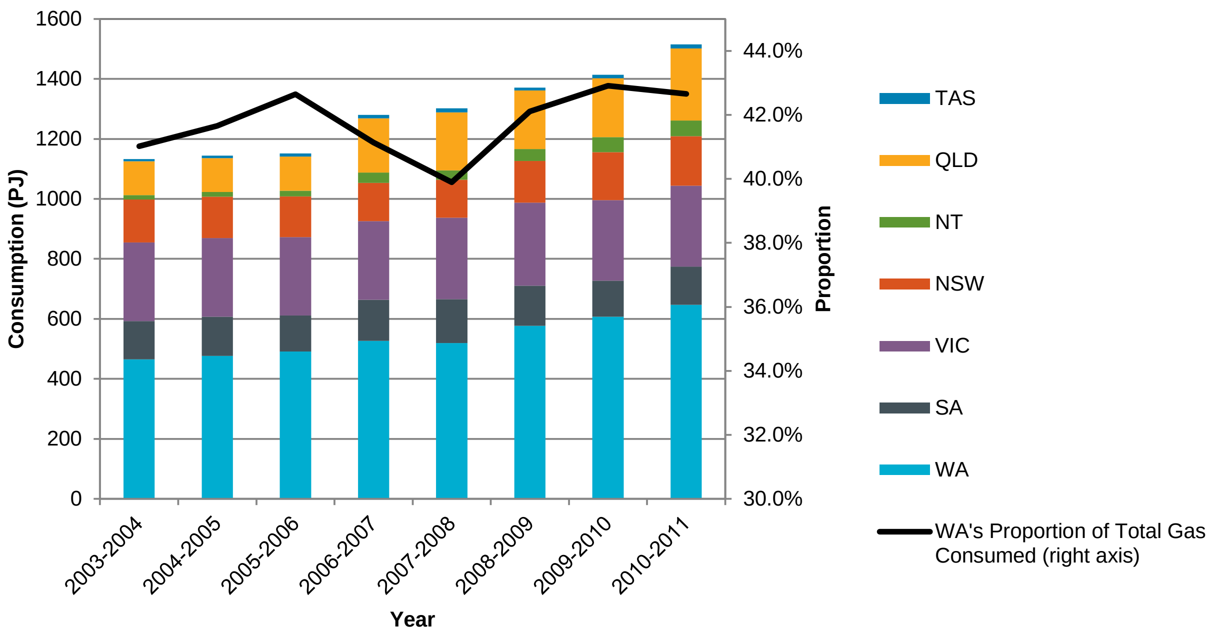
Figure 4 – Total Gas Production, 1984 – 2012



Source: DMP Gas Sales and LNG Exports Data, 1984-2012. **Note:** This figure does not include gas consumed in petroleum processing.

In addition to providing the majority of Australia's gas production, BREE reports that WA is also the largest consumer of domestic gas in Australia. WA accounted for approximately 42.7% of total Australian domestic gas consumption in 2010-2011, consuming approximately 646 PJ of gas.[14]

Figure 5 – Australia's Gas Consumption, 2003-2004 to 2010-2011



Source: BREE (2012), Australian Energy Statistics Update 2012, Table C.

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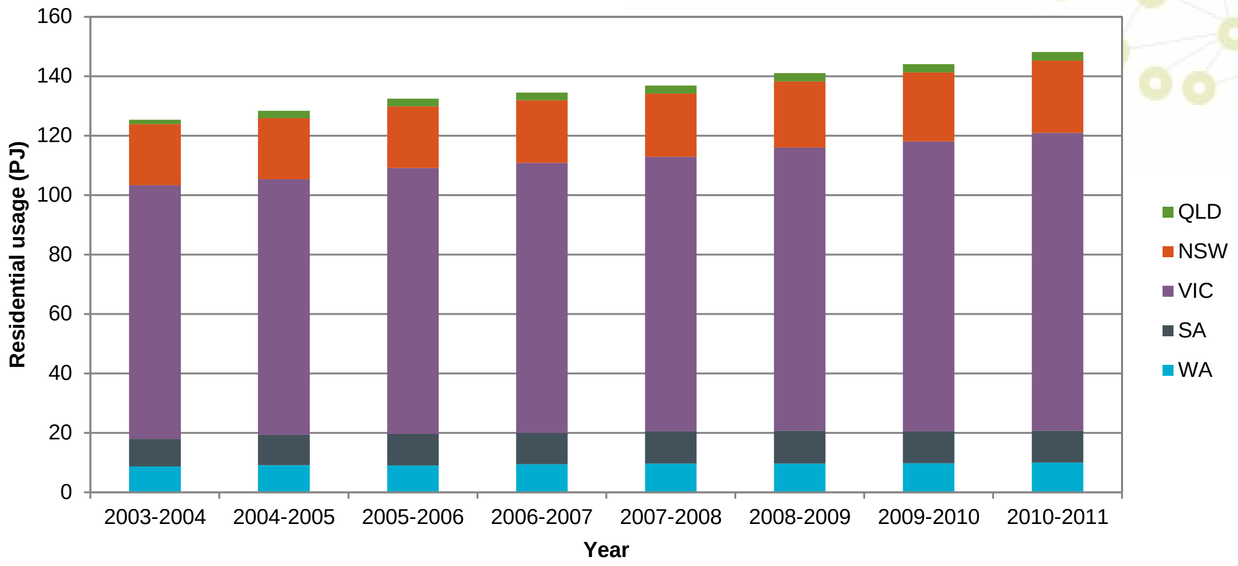
[14] Total gas consumption outlined in BREE (2012) includes oil and gas processing.

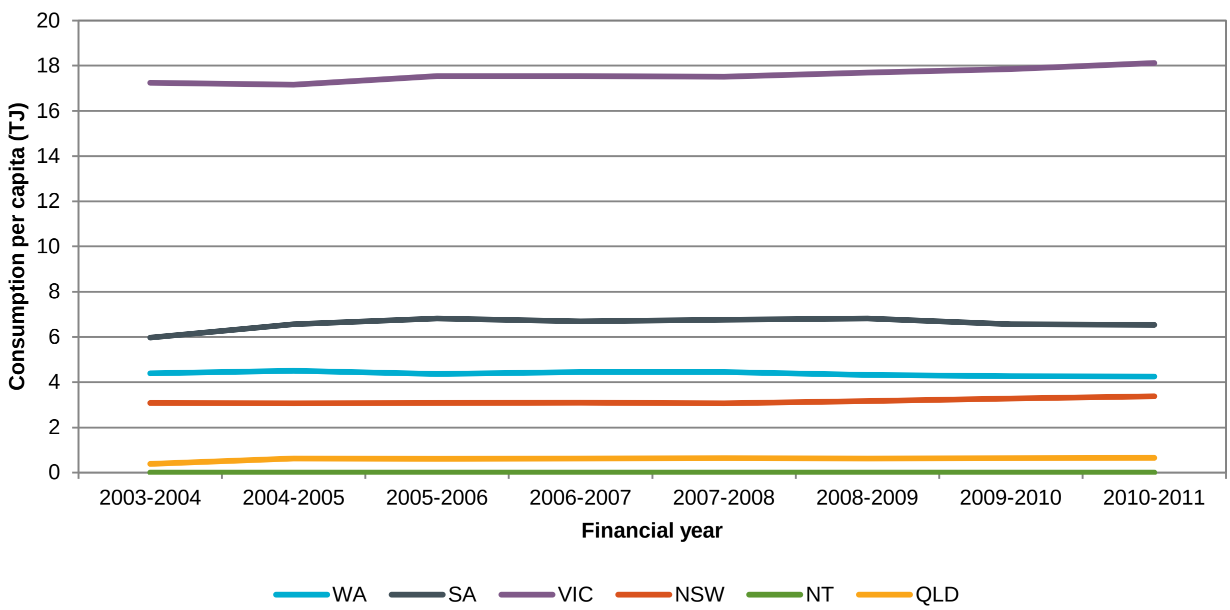
Even though WA is the largest consumer of gas by State (Figure 5), residential gas consumption in WA is low when compared to the other States (Figure 6). Gas use per capita in 2010-2011 for the WA residential market is less than a quarter of Victoria's consumption and approximately two-thirds of South Australia's consumption. This suggests that WA households are less reliant on gas for household heating compared to most other states, and that WA households are using more energy for cooling than heating.[15]

Figure 6 – Australia's Residential Gas Consumption, 2003-2004 to 2010-2011



Source: BREE (2012), Australian Energy Statistics Update 2012, Table F

Figure 7 – Residential Gas Consumption per capita per annum (TJ/a), 2003-2004 to 2010-2011



Source: IMO estimates, per capita consumption is calculated using BREE's (2012) residential gas consumption and population from ABS (2012), Australia Social Trends Catalogue 4102.0.

[15] This is also outlined in the EISC's (2011) report by WA Gas Networks, the owner of the gas distribution network in 2010. Other factors such as the penetration of gas distribution infrastructure and weather may be important.

While residential gas consumption represents only 1.5% of total WA gas use, gas demand in WA is dominated and driven by industrial gas consumption; as a fuel or feedstock for electricity generation, minerals processing and other manufacturing.

3.2. Historical Markers

A Brief History of Domestic Gas Consumption

Consumption of gas in WA has existed since 1883 and, during this early period, was mainly gas manufactured from coal.[16] Consumption was predominately in the residential, commercial and industrial sectors located around Perth. In the 1883 to 1971 period, it is understood gas demand had always attracted the availability of gas supply in the domestic market.

Several gas discoveries in the Perth Basin by West Australia Petroleum Pty Ltd (WAPET)[17] between 1964 and 1971 preceded a significant increase in WA gas consumption. These discoveries resulted in the construction of the first WA gas pipeline from Dongara to Pinjarra (now the Parmelia Pipeline) in 1971 by the West Australia Natural Gas (WANG) company, a WAPET subsidiary,[18] to supply industrial and residential customers located around Perth, Kwinana and Pinjarra. This essentially started the domestic supply market with the delivery of gas via transmission pipelines.

Of particular significance to the development of the domestic gas market was the signing of the NWS State Agreement in 1979 between the WA State Government and the NWS Joint Venture (JV) partners. Gas to the WA market was mainly supplied by gas fields in the Perth Basin until the construction of the Karratha Gas Plant under the agreement in 1984.

This agreement underwrote the establishment of the LNG export market and the domestic gas market in WA and was instrumental in increasing the availability of gas to the domestic market.[19] Under the agreement, the NWS JV partners were required to build a gas processing facility on the Burrup Peninsula in the Pilbara to service the WA gas market, while the State Energy Commission of WA (SECWA) was responsible for building a gas transmission pipeline (now the Dampier to Bunbury Natural Gas Pipeline [DBNGP]) to allow gas to be shipped from the gas processing plant to customers located mostly in the south west of WA.[20]

SECWA, Alcoa and three other entities served as foundation customers for the NWS JV and purchased large quantities of gas under long-term contracts at fixed prices for various power stations and refineries located at Kwinana, Pinjarra and Wagerup.[21] In 1984, gas started to flow from the Burrup Peninsula to domestic gas consumers and gas produced in WA was solely for domestic use until the commencement of LNG exports in 1989.

The availability of capacity through the DBNGP, coupled with the influence of low-priced contracts (between the NWS JV and its foundation customers), served as a pricing reference for gas to the domestic gas market and encouraged the rapid growth of domestic gas consumption between 1984 and 1990. This led to the construction of WA's second gas processing facility, the Harriet JV's processing facilities on Varanus Island in 1986, and the development of the Goldfields Gas Pipeline (GGP) in 1993 to supply gas to other parts of the Pilbara, Mid-West and the Goldfields. Subsequently, several other supply pipelines (Griffin and Tubridgi) in the Carnarvon Basin were also established by other gas producers to supply gas to the domestic market

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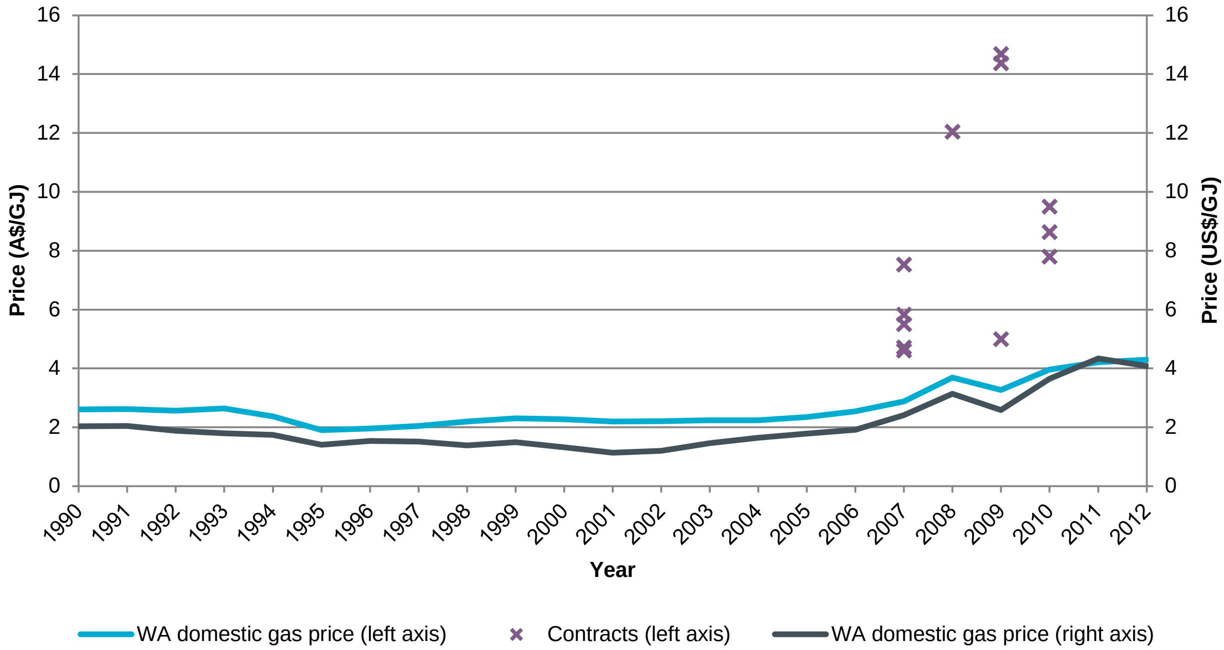
[16] See Synergies (2007) and SKM MMA (2011) for more details.
[17] A JV between Caltex, Ampol (Australian Motorists Petrol Company) and Shell that no longer exists.
[18] The foundation customers of WANG were the Midland Brick Company, Swan Cement, Western Mining, Alcoa, Fremantle Gas and Coke Company and SECWA.
[19] According to the EISC (2011), The NWS JV committed to delivering a significant volume of gas to the local market over a period covering at least 20 years (the commitment reached 5,064 PJ) while SECWA, entered into a contract with the JV in September 1980 to purchase approximately 414 TJ/day of gas for 20 years (3,020 PJ in total) commencing in 1985.
[20] SECWA disaggregated in 1995 into Western Power and AlintaGas, and Western Power further disaggregated in 2006 into four separate corporate entities; Horizon Power, Synergy, Verve Energy and Western Power.
[21] Some of these original contracts were restructured in 1995 and in 2006. These contracts started to expire in 2012. See DomGas Alliance (2013) for more details.

via the DBNGP. By 1995, gas supply to the domestic market was supplied from nine separate sources (six in the Carnarvon Basin and three in the Perth Basin).[22]

While gas consumption grew in the 1990s, a lack of access to transmission capacity along the DBNGP, which operated at or near capacity by this time, slowed the growth of gas consumption in WA coastal areas before the pipeline was expanded in 2005.[23]

Continued low domestic gas prices from 1999 to 2004 (see Figure 8) encouraged an increase in gas consumption in the Pilbara, Mid-West and Goldfields regions, attracting investment in gas transmission infrastructure through the completion of the Pilbara Pipeline System (PPS), Mid-West Pipeline (MWP) and the Kalgoorlie to Kambalda Pipeline (KKP).[24] Incremental domestic demand was easily met as domestic gas supply was abundant and prices were relatively low by interstate and international standards.

Figure 8 – Western Australian Average Natural Gas Prices, 1990 – 2012



Source: DMP (2011) and DMP (2013d). 2012 US$ price is calculated using exchange rate of $A1 = US$0.95. **Note:** The data represents an average price of all existing gas sales contacts. The most recent price increases are not very pronounced as the average is dominated by large volume long-term contracts agreed to at low prices.

Despite an increase in WA pipeline investment, by 1999, gas transmission capacity was quickly filled and allocated, limiting further gas consumption. The Economics and Industry Standing Committee (EISC) of the WA Parliament suggests a lack of spare capacity on the regulated pipelines (DBNGP and GGP) may have stifled domestic gas consumption growth in the 1999 to 2010 period.[25]

In a bid to improve revenue to offset the capital cost of infrastructure investments, entities that have the ability to supply both the international LNG market and the domestic gas market, such as the NWS JV,

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[22] These were Dongara, Thevenard Island, Griffin, Harriet, East Spar, Tubridgi, Mondarra, North West Shelf and Xyris.

[23] According to Allen Consulting Group (2009), while DBNGP's throughput increased from 550TJ/day to approximately 785 TJ/day in 2005, followed by a subsequent expansion (Stage 5B) that was completed in April 2010 that increased pipeline capacity to approximately 845TJ/day it was still unable to fulfil gas demand in WA.

[24] The DBNGP did not expand due to concerns on the proposed access arrangement. A member of the financing syndicate of the DBNGP wrote to the ERA in 2003, outlining the proposed access arrangement would not be able to sustain the financial obligations of the pipeline owner, Epic Energy. See Deutsche Bank (2003), Submission in relation to the proposed access arrangement for the DBNGP, http://www.erawa.com.au/cproot/3781/2/DB%20submission%20Apr%2003.pdf, accessed 20 March 2013.

[25] This is a conclusion outlined in EISC (2011).

increased revenue by expanding LNG production and export capacity and only pursued potential large domestic supply contracts within WA that were priced closer to LNG export prices (netback prices).[26]

Other gas producers that did not have LNG export facilities and could only focus on the domestic market concentrated on improving cash flow by focusing on sales to large domestic gas consuming customers and preferred to implement long-term contracts at commercially acceptable prices, a practice that endures to some extent today.

The growth in gas consumption from 2003 to 2011 and a lack of new gas processing investment into the domestic gas market and increasing LNG prices triggered higher domestic prices from 2003 to 2011 as shown in Figure 8, aligning domestic gas prices towards LNG netback prices.[27] This has attracted investment into new domestic gas processing capacity, such as the completion of Devil Creek processing facility in 2012.[28]

To allow for a greater appreciation of the historical developments of the WA domestic gas market, a timeline of significant events from 1965 to 2013 is shown below.

Table 1 – Key Historical Markers of the Western Australia Gas Markets 1965 – 2013

1965-1968	First gas fields (Mondarra, Dongara) discovered in the Perth Basin
1971-1975	Completion of the Parmelia Pipeline Discovery of NWS gas fields SECWA established
1977-1981	NWS agreements and contracts initiated and signed
1984-1989	Completion of the DBNGP NWS domestic gas facility commences production First Shipment of LNG departs WA Varanus Island domestic gas facility (Harriet) commences production
1992-1996	Establishment of Mondarra Gas Storage Facility Second Varanus Island domestic gas facility (East Spar) commences production SECWA splits into AlintaGas and Western Power Third party access framework introduced to separate gas purchase and gas shipping GGP completed
1997-1999	Australian Heads of Government sign National Gas Pipelines Access Agreement, a national framework for access to natural gas pipelines Establishment of the Independent Gas Pipelines Access Regulator (WA) *Gas Pipelines Access (Western Australia) Act 1998* enacted AlintaGas privatised
2003-2005	Establishment of REMCo

[26] The ERA (2007) recognises that commercial pressures will see domestic prices reflect LNG netback prices. Innovative Consulting Services (2012) and the Prime Minister's Manufacturing Taskforce (2012) also suggests most gas producers have a preference for gas reserves to be priced close to LNG parity. This can be supported by failed negotiations between Methanex Australia, Syntroleum and Plenty River Corporation and the NWS JVs for potential domestic supply contracts between the periods 2001 to 2005. Gas market producers (especially those with LNG export capacity) tend to be driven by LNG demand and LNG supply considerations (volume, margin etc.) – NWS JVs claim that this is untrue. The DomGas Alliance also suggested a lack of a national gas reservation policy increased the link to netback pricing.
[27] EISC (2011) and DomGas Alliance (2012b) find WA gas prices approached or exceeded LNG netback prices (price of gas delivered minus LNG processing and shipping costs, an estimate of the wellhead price).
[28] Although Devil Creek processing facility was only sanctioned when it was underwritten by several long-term gas supply agreements, Apache Energy was marketing the gas linked to Devil Creek prior to the commencement of construction.

	Establishment of the ERA Establishment of the Gas Industry Ombudsman Scheme (currently known as Energy Ombudsman) Deregulation of Retail Gas Market
2006-2009	WA Government releases policy on Securing Domestic Gas Supplies Two gas supply disruptions 175 tonne/day LNG facility commissioned to serve domestic LNG market Key recommendations of the Office of Energy's Gas Supply and Emergency Management Committee are released to the public *Gas Supply (Gas Quality Specifications) Act 2009* enacted
2010-2011	WA Parliamentary inquiry into domestic gas prices IMO is announced as the operator of a new GBB and GSOO Devil Creek domestic gas facility commences production
2012	Pluto LNG facility commences production *Gas Services Information Act 2012* enacted Prelude FLNG Project approved for WA, world's first floating LNG project Proposed pipeline corridor for the planned Bunbury to Albany Pipeline released Buru Energy and Mitsubishi Corporation sign Canning Basin State Agreement with WA Government *Gas Services Information Regulations 2012* made
2013	Gas Services Information Rules approved WA's first GSOO released Commencement of the WA's GBB (scheduled for 1 August 2013)

Source: Compiled from information collated from APPEA, DMP, DSD and DomGas Alliance publications, Australian Stock Exchange (ASX), public and minster announcements, corporate websites, oil and gas periodicals (such as Gas Today), gas participants and other research.

3.3. Market Regulation

Regulation of the gas market in WA is distinct to the eastern states of Australia. Even though WA is a signatory to the national gas framework under the intergovernmental Australian Energy Market Agreement, the Australian Energy Market Commission, the Australian Energy Market Operator and the Australian Energy Regulator do not oversee the gas market in WA.

Instead, gas regulation in WA adopts modified versions of the National Gas Law and National Gas Rules with the economic licensing and access regulation of the gas markets resting with the ERA. REMCo is responsible for administering gas retail market operations and settlements.[29]

The ownership and regulation of offshore gas resources rests with both the Commonwealth Government and the WA State Government (on a limited basis),[30] while the ownership and regulation of onshore gas resources is managed by the WA Government through DMP.

[29] The text of the National Gas Law that applies to WA is contained in a note to the *National Gas Access Act 2009*. The *National Gas Access Act 2009* also provides for the following subsidiary legislation; the *National Gas Access (Part 3) Regulations 2009*, the *National Gas Access (Local Provisions) Regulations 2009* and the National Gas Rules. Refer to the ERA see http://www.erawa.com.au/access/gas-access/current-legislation/ for more information.

[30] In short, the WA Government holds jurisdictional rights to all hydrocarbon resources located onshore and offshore within its coastal waters (up to the belt of water three nautical miles offshore from the WA coastline, except for the area encompassing the North West Shelf JVs). The Commonwealth Government owns the rights to all hydrocarbon resources from the State boundary to the Contiguous Zone (24 nautical miles), Exclusive Economic Zone (up to 200 nautical miles in certain territorial waters) and its continental shelf, seabed and submerged lands as defined in Article 76 of the United Nations Convention on the Law of the Sea

3.4. Market Structure and Participants

The WA wholesale gas market currently operates mainly under a contract carriage model via pipelines.[31] This means the bulk of the domestic gas delivered into the pipelines (transmission system) is traded under bi-lateral contracts (that are typically medium to long-term) for both supply and shipping. As a consequence of this, there are low quantities of uninterruptible[32] secondary gas available for short-term trading.[33]

On the wholesale consumption side, it is estimated there are over 60 industrial, manufacturing, electricity generation and transport related facilities currently consuming gas in the domestic wholesale market.[34] For the 2013 to 2022 period, the quantum of gas consumed in the North West of WA could reasonably be expected to increase with the construction of new gas-fired electricity generators at Cape Lambert, West Angeles, Newman, Onslow and South Hedland and the completion of the Gorgon and Wheatstone gas processing facilities.

There are 35 distinct shippers operating on eight transmission pipelines across the WA gas market. The bulk of gas shippers represent their own parent companies, shipping gas for their own operations, with a small number of shippers representing other customers and the remainder shipping gas for retail sales.

Table 2 – Estimated Number of Shippers operating in Western Australia, 2013

Pipeline	Number of Shippers
Dampier to Bunbury Natural Gas Pipeline	26
Goldfields Gas Pipeline	17
Pilbara Energy Pipeline	7
Telfer Gas Pipeline	2
Mid-West Pipeline	3
Parmelia Pipeline	3
Kalgoorlie to Kambalda Pipeline	2
Kambalda to Esperance Pipeline	1

Source: IMO**. Note:** Shippers from the same parent company are not considered. The number of shippers on the Kalgoorlie to Kambalda and Kambalda to Esperance Pipelines are estimated.

At the time of this report, on the supply side there are seven operating gas processing facilities that are managed by several JVs[35] supplying the domestic gas market (see section 3.5 for details). By the end of 2022, the number of domestic gas suppliers is anticipated to increase from seven to 10 with the completion of the Macedon, Gorgon and Wheatstone domestic processing facilities.

In WA, there is currently no legislated exchange framework for trading short-term gas. Hence, gas market participants balance their short-term gas requirements via an over the counter market.[36]

It is estimated that approximately 98% of the total domestic gas sales are traded bi-laterally through long-term contracts, with there being at least 60 separate gas supply agreements active between gas suppliers and consumers within WA.[37] Despite being the largest domestic market in Australia, there is a lack

under the *Seas and Submerged Lands Act 1973* (Cwth). The Commonwealth also owns a 10% share of the Joint Petroleum Development Area with East Timor under the *Timor Sea Treaty 2003* (Cwth) zone.

[31] Other market structures include common carriage, market carriage, network carriage or a hybrid.

[32] Uninterruptible capacity, also sometimes known as firm capacity is gas transmission capacity that is available at all times during a period covered by an agreement between the pipeline operator and the shipper. The service receives the same priority as any other firm service.

[33] According to DBP Limited, when secondary gas is available it is traded bi-laterally amongst the gas shippers.

[34] For the purposes of this report, industrial use includes the processing of minerals (including gas), manufacturing is defined as entities that use gas as a feedstock and transportation includes domestic LNG refuelling facilities. It does not include gas used for compression along transmission pipelines.

[35] The JVs are the North West Shelf JVs; the DomGas, Incremental Pipeline and the Extended Interest JVs and the Apache managed JVs; Harriet, East Spar, John Brookes and Devil Creek JVs and the Red Gully JV.

[36] It is understood that short-term gas demand and supply requirements are typically traded amongst existing gas market participants either directly with each other or via a broker such as Gas Trading Pty Ltd. These short-term trades are estimated to be between 10 and 25 TJ/day.

[37] The proportion of bi-lateral contracts is estimated by calculating the difference between the average annual consumption and short-term trades divided by the total gas sales reported by APPEA for 2012.

of information on existing gas supply agreements and gas trades. Details of these agreements or trades are only revealed when it is required by legislation, stock market regulations, legal disputes or energy market rules.

3.5. Infrastructure in the Western Australian Gas Market

This section provides a brief overview of the gas infrastructure servicing the WA domestic gas market. It focuses on the characteristics of existing and future gas processing facilities, transmission pipelines and gas storage facilities in WA.

Gas Processing Facilities

As at the time of this report, WA hosts 13 operational and non-operational gas processing facilities (excluding the upcoming Gorgon and Wheatstone processing plants), of which seven are currently operational and capable of servicing the domestic market. Out of the six non-operational facilities, five facilities are no longer operational due to their end-of-life gas field production, while the remaining non-operational facility is anticipated to be completed and commissioned (Macedon) by the end of 2013. Some of these non-operational facilities may be reused if appropriate opportunities arise.[38]

From the seven operational processing facilities, four are processing gas from the Carnarvon Basin and the remaining three are processing gas from the Perth Basin.

It is anticipated that at the end of the forecast period in 2022, the total number of operational domestic gas processing facilities in WA will increase to 10 (including Gorgon, Wheatstone and Macedon).[39]

Carnarvon Basin

WA's four largest domestic gas processing facilities are situated in the Carnarvon Basin, the location of significant gas reserves in the Pilbara. These four facilities are the Karratha Gas Plant (KGP, operated by the NWS JV), Varanus Island (East Spar and Harriet JVs) and the Devil Creek processing facilities providing a total of approximately 1,240 TJ/day gas processing capacity out of a total capacity of 1,282.6 TJ/day representing 97% of domestic gas processing capacity. By the end of 2013, gas processing capacity is anticipated to increase to approximately 1,482.6 TJ/day with the completion of the 200 TJ/day Macedon domestic facility.

By the end of 2022, gas processing capacity is expected to increase further with two additional domestic gas processing facilities; Gorgon and Wheatstone, currently under construction that are expected to add an additional 500 TJ/day of gas processing capacity.

Table 3 – Processing Facilities (operational, non-operational, planned and under construction) within the Carnarvon Basin, 2013

Facility	Operator	Estimated Capacity (TJ/day)	Location	Status	Pipeline Connection	Comments
Karratha Gas Plant (NWS)	Woodside	630*	Burrup Peninsula, Pilbara	Operational	DBNGP, Burrup Extension Pipeline and GGP (via others)	The gas processing capacity of this facility can be increased in the short-term, but it may run at a

[38] It is understood that some processing facilities are "mothballed", but it is unclear to the IMO if any of these non-operational facilities can be reused.
[39] Other gas processing facilities may come online after the publication of this report.

						suboptimal level.*
Varanus Island (East Spar JV)	Apache Corp	270	Varanus Island, Pilbara	Operational	DBNGP and GGP	
Varanus Island (Harriet JV)	Apache Corp	120	Varanus Island, Pilbara	Operational	DBNGP and GGP	
Devil Creek	Apache Corp	220^	Devil Creek, Pilbara	Operational	DBNGP	Currently operating at 110 TJ/day.
Griffin	Unknown, previously owned by Griffin JV and operated by BHP Billiton	90	Onslow, Pilbara	Not Operational	DBNGP	
Thevenard Island	Chevron	45	Thevenard Island, Pilbara	Not Operational	DBNGP	
Macedon	BHP Billiton	200**	Onslow, Pilbara	Not Operational	DBNGP	Construction is planned to be completed in 2013
Gorgon Domestic	Chevron	150	Barrow Island, Pilbara	Under construction, anticipated to be available by the 2016	DBNGP	Facility is anticipated to be expanded to 300 TJ/day by 2020%
Wheatstone Domestic	Chevron	200	Ashburton, Pilbara	Under construction, anticipated to start in 2018	DBNGP	Facility is anticipated to commence in 2018
Pluto Domestic	Anticipated to be Woodside	Information unavailable	Burrup Peninsula	Under Consideration	DBNGP	Subject to commercial viability conditions^^
Buru Energy Domestic	Anticipated to be Buru Energy	Information unavailable	Unknown	Under Consideration	DBNGP	Unknown
	Total Operational Capacity to date (Excluding Planned)	1,240 TJ/day	**Total Operational Capacity (including Planned)**	1,740 TJ/day		

Source: Publicly available announcements, reports and APPEA. *According to Evans and Peck (2009), the KGP comprises of two processing trains and can expand its domestic gas processing capacity up to 750 TJ/day (this was achieved after the Varanus explosion) under sub-optimal conditions (due to a lack of gas reinjection into the well). **Note:** KGP's output is shared amongst the Domgas JV and the Incremental Pipeline JV partners. **APPEA and BREE's (2013) reports Macedon will be capable of 75 PJ/a. ^Devil Creek is reported to currently operate at approximately 110 TJ/day. ^^Woodside has entered into an arrangement with the WA Government that commits it to supply domestic gas within five years after LNG is first exported, providing it is commercially viable. % Deutsche Bank (2012) expects Phase 2 of the Gorgon domestic facility to commence in 2020.

Perth Basin

Since the completion of the Parmelia Pipeline in 1972, a total of five gas processing facilities have been constructed and connected to this pipeline, each having been developed to process oil and gas from specific small gas fields. The proximity to Perth is a major advantage for gas producers in the Perth Basin, allowing these entities to respond quickly to fluctuating gas demand from gas consumers that are mostly located around Perth.

At the time of this report, there are three processing facilities operating within the Perth Basin, capable of processing a total of approximately 42.6 TJ/day of gas for the domestic market, or about 3% of gas processing capacity. However, due to falling production levels at connected gas fields and a lack of contractual agreements, gas supply facilities in the Perth Basin are only supplying approximately between 20 and 25 TJ/day.[40]

There are significant prospects for the development of unconventional gas in the Perth Basin as a source of domestic gas supply (see section 8).

Table 4 – Processing Facilities (operational, non-operational, planned and under construction) within the Perth Basin, 2013

Facility	Operator	Estimated Capacity (TJ/day)	Location	Status	Pipeline Connection	Comments
Dongara	AWE Limited	7^^	Dongara, Mid-West	Operational	Parmelia	AWE is evaluating the potential development of the Senecio and Corybas fields around Dongara facility.
Beharra Springs	Origin Energy	25	Mid-West	Operational	Parmelia	
Woodada	AWE Limited	25	Mid-West	Not Operational	Parmelia	
Xyris	AWE Limited	10^^	Mid-West	Not Operational	Parmelia	
Mondarra	APA Group	10	Mid-West	Not Operational	Parmelia and DBNGP	Decommissioned, Mondarra gas field is currently used as a gas storage facility
Red Gully	Empire Oil and Gas	10.6	Mid-West	Operational^	DBNGP	Facility may be expanded to 21.2 TJ/day before the end of 2022.
Warro	Latent Petroleum (Transerv Energy)	150*	Mid-West	Under Consideration	Parmelia* / DBNGP	Facility may be operational before the end of 2022.**
	Total Operational Capacity to date (Excluding Planned)	42.6 TJ/day	**Total Operational Capacity (including Planned)**	192.6 TJ/day		

Source: Publicly available announcements and reports, Evans and Peck (2009) and SKM-MMA (2011) or from registration information provided by GBB participants. *Information from EISC (2011). **This is an estimate of the potential start-up and does not constitute information provided from the respective company. ^See Empire Oil and Gas 18 June 2013, ASX Release http://empireoil.com.au/sites/empireoil.com.au/files/EGO_2013_06_18_Red-Gully-Gas-Facility-Update.pdf, accessed 25 June 2013.

Major Gas Transmission Pipelines

Major gas resources in WA are distant from the majority of gas users.[41] In order to allow consumers in the Goldfields, Great Southern, Mid-West, Peel and South West region of WA to access natural gas, significant

[40] 2012 quarterly production reports from AWE Limited and Origin Energy indicate gas production levels are lower than the processing facility's capacity. This is confirmed by data provided by APA Group.

[41] Gas resources are typically located within the Canning, Carnarvon or Perth Basins, while the majority of gas consuming customers (except for Yara Pilbara,

investments in transmission pipelines were made to transport gas from areas of supply in the north.[42] Historically, growth in gas transmission pipelines has been linked to the development of major oil and gas fields in WA, to either facilitate the export of LNG or to meet domestic energy demands.

The first gas transmission pipeline in WA, the Parmelia Pipeline, was completed in 1971 and shipped processed gas from the Dongara field in the Perth Basin to industrial and residential customers in Perth and Kwinana. Subsequently, other major transmission pipelines such as the DBNGP, the PPS, GGP, the MWP and the Telfer Gas Pipeline (TGP) were completed in 1984, 1995, 1996, 1999 and 2004 respectively to connect major gas producing fields and hubs to various end consumers throughout WA.

The DBNGP and the GGP are estimated to ship approximately 90% of total domestic gas produced in WA to end users. The following map and table outline all the pipelines in WA.

Table 5 – Summary of Operational and Planned Transmission Pipelines, 2013

Pipeline	Operator	Completed /Planned Completion	Nameplate Capacity (TJ/day)	Length (kms)	Compression	Covered by Legislation	Expansion/ Comments
Parmelia Pipeline	APA Group	1971	81.8^	417	Yes, two compressors unused	No	Existing compression has limited capability to expand.
Dampier to Bunbury Natural Gas Pipeline	DBP Limited	1984	845*	1,828 (1,489 km mainline and 339 km laterals)	Yes, 27 compressors at 10 locations	Yes	Approximately 84% (1,252 km) of the DBNGP pipeline is looped.
Pilbara Pipeline System	APA Group (under Epic Energy)	1995	166^	219	No	No	
Goldfields Gas Pipeline	APA Group	1996	155**	1,380	Yes, six compressors, expanding to 7 (Turee Creek) compressors in 2013	Yes, main transmission line and Newman lateral	Expanding capacity of pipeline by 47.4 TJ/day in 2013 (APA Group 2011, 2012) for Rio Tinto's Paraburdoo and West Angeles mines (20 TJ/day), BHP's Newman mine (24 TJ/day) and other customers
Mid-West Pipeline	APA Group	1999	10.6^	365	No	No	
Telfer Gas Pipeline	APA Group	2004	28.6^	443	Yes, one compressor Station	No	Extended in 2005 to service Nifty Gold and Copper Mine
Kalgoorlie to Kambalda	APA Group	1999	29.3^	44	No	Yes, light regulation	
Kambalda to	Worley Parson Asset	2004	6^^	336	No	No	

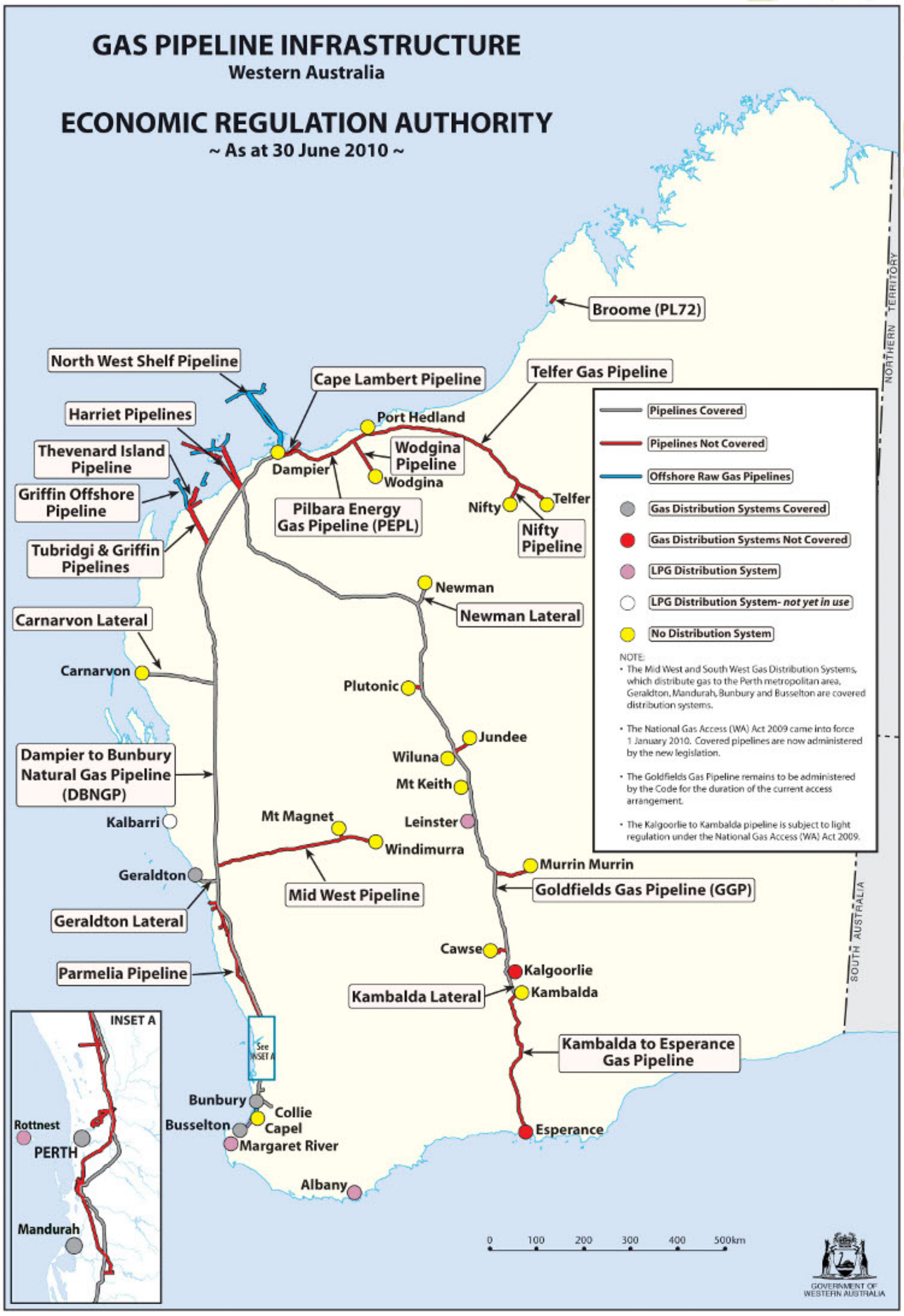
mines in the Pilbara region and remote mine sites) are mostly located to the south west of WA.

[42] For the purposes of this GSOO, major transmission pipelines are defined as transmission pipelines that serve more than one customer (>1).

Esperance Pipeline	Management Pty Ltd						
Bunbury to Albany Pipeline	Anticipated to be consortium (including Verve Energy)***	2016*** (Construction announced to begin in 2014)***	~12***	350***	No	Not applicable at this stage	Planned Pipeline
North West Pipeline	Anticipated to be either Buru Energy or a consortium (including Buru Energy)	Unknown[%]	~200[%]	~550-630	Unknown	Not applicable at this stage	Planned Pipeline
Total			**Approx 1,533.7 TJ/day**	**Approx 5,932 kms**			

Source: APA Group, Duet Group (2012b), Epic Energy, Evans and Peck (2009), the ERA website and other public announcements. **Note:** Pipeline capacities outlined in this table are nameplate capacity based on normal operating conditions. Actual operating conditions may vary. *Information provided by DBP Limited. Duet Group (2012) reports an average contracted full-haul capacity of 848 TJ/day, while SKM-MMA (2011) reports 895 TJ/day. ^Information provided by APA Group. **Information from APA Group, AER (2011) reports 150 TJ/day, GGP's capacity is currently being expanded to approximately 202.4 TJ/day. ***Information is based on the Premier's announcement, 29 October 2012. ^^Information sourced from CCIWA (2007) and AER (2011) *State of Energy 2011* report. [%]Information sourced from Buru Energy (2013); consistent with Geoscience Australia (2012). [%]Although Buru Energy's (2013) March 2013 investor presentation outlines a completion date, it is unclear when this project is likely to commence.

Figure 9 – Infrastructure Map of Major Existing Pipelines, 2010



Source: Economic Regulatory Authority (2010)

Despite a rapid expansion of gas transmission pipelines servicing WA customers between 1983 and 2004, there has been no known significant investment (except for capacity expansions and construction of laterals) in major gas transmission pipelines since 2004 until the WA Government's announcement of its intention to contribute towards the construction cost of the proposed Bunbury to Albany pipeline (BAP) in October 2012.[43]

[43] Several factors may have contributed to a lack of recent investment in gas transmission, including losses incurred on the DBNGP by Epic Energy, cancellation of large potential gas contracts, low contracted gas prices or uncertainty in the regulatory environment for gas pipelines.

Dampier to Bunbury Natural Gas Pipeline

The DBNGP is the largest gas transmission pipeline in WA, shipping natural gas from the NWS to customers located in the Pilbara, the Mid-West and South West of WA. The pipeline was completed in 1984 and is owned by the Duet Group (via its infrastructure funds, 81.5%) and Alcoa Australia (18.5%),[44] but operated by DBP Holdings Private Limited (DBP Limited). As a major WA gas transmission pipeline, this pipeline is covered under the *National Gas Access Act 2009* and the amended National Gas Law.[45]

According to DBP Limited, the DBNGP is able to ship approximately 845 TJ/day of compressed gas full-haul (along the entire pipeline) and moves gas along the pipeline to customers using 27 separate gas compressors located at 10 stations.[46] Approximately 84% of the original DBNGP is duplicated. DBP Limited has indicated that firm capacity for the pipeline is currently fully contracted and it does not have any available uninterruptible capacity to ship gas for new gas consumers.[47]

The DBNGP has the largest number of interconnections with other pipelines. In 2013, the DBNGP is connected to eight gas processing facilities (of which two are no longer operational) via seven gas inlet points[48] and also interconnected with the Pilbara Energy Pipeline (and onto the TGP), the GGP, the MWP and the Parmelia Pipeline (via the Mondarra Gas Storage Facility).[49] By 2022, the number of gas processing facilities connected to the DBNGP is anticipated to increase to 10, injecting via nine gas inlet points.[50]

According to BREE, DBP Limited is considering the expansion of the DBNGP's capacity under a project known as Stage 5C Expansion Project. It is understood that this proposed project would potentially complete the duplication of the DBNGP, increasing DBNGP's shipping capacity.[51] If the proposed expansion project proceeds, it is estimated the DBNGP's firm capacity for shipping gas will increase from 895 TJ/day to approximately 980 TJ/day or 1169 TJ/day.[52]

Although DBP Limited is constantly in discussions with various parties over the potential Stage 5C Expansion Project, DBP Limited indicated to the IMO that there are currently insufficient financial commitments to fund this proposed expansion. Typically, DBP Limited requires a minimum of 50 TJ/day (sometimes up to 80 TJ/day) of firm capacity and financial commitments from customers prior to considering an expansion of the pipeline's capacity.

Goldfields Gas Pipeline

The GGP is the second longest gas transmission pipeline in WA. Historically, the GGP was developed through an expression of interest process held by the WA State Government in 1993. This led to the Goldfields Gas Pipeline State Agreement 1994 with the initial owners of the GGP.[53]

The APA Group owns 88.2% of the main pipeline, the Newman lateral and 100% of the remaining laterals, while the remainder of the pipeline is owned by Alinta Energy. This GGP system is operated by APA Limited and is covered under the *National Gas Access Act 2009* and the amended National Gas Law.

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[44] According to Duet Group (2013), Duet Group's share of DBNGP will fall progressively as Alcoa meets its future equity calls.

[45] A covered pipeline under the Act is required to lodge access arrangements for third parties with a relevant regulator within prescribed time limits referred to in the National Third Party Access Code of the Act. In WA, the ERAis responsible for the review of the access arrangement submissions and the regulation of access to both gas transmission and distribution pipelines in WA.

[46] For a detailed description of the DBNGP gas transmission, please refer to http://www.dbp.net.au/Libraries/Customer_Access_and_Information/1_09_11_-_DBNGP_Pipeline_Description_1_September_2011.pdf

[47] See DBP Limited (2012), Capacity Register, http://www.dbp.net.au/access.aspx, for more details.

[48] Harriet and East Spar gas processing facilities share a single connection point to the DBNGP.

[49] Griffin and Tubridgi inlet points are understood to be inactive. Gas processed by East Spar and Harriet JV facilities located on Varanus Island is understood to enter the DBNGP through the Harriet inlet points.

[50] Gorgon, Macedon, Red Gully and Wheatstone domestic gas facilities servicing the domestic market are expected to be connected to the DBNGP before 2022. Decommissioned Tubridgi and Griffin facilities are expected to remain connected over this period.

[51] See BREE (2012).

[52] According to BREE (2012), DBP Limited's proposed Expansion phase 5C, the full duplication of the pipeline, is expected to increase pipeline capacity by 100 PJ/a that is approximately 274 TJ/day while Evans and Peck (2009) estimates the full duplication will increase the DBNGP by 85 TJ/day.

[53] According to ERA (2010) Goldfield Gas Access Submission by CMS, the initial owners of the GGP were Western Mining Corporation, Normandy Mining and BHP.

Interconnected with the DBNGP and Harriet JV pipeline, the GGP starts at Yarraloola, near Compressor Station One of the DBNGP, and heads south east towards Newman before heading south from Newman, passing through the Northern and Eastern Goldfields areas, terminating at Kalgoorlie. The GGP is accessible by three gas processing facilities (the KGP and the Varanus Island processing facilities) via two gas inlet points servicing gas consuming customers located east of the DBNGP. The GGP also interconnects with the KKP (and onto the Kambalda to Esperance Pipeline [KEP]).

According to APA Group, the GGP has a current compressed capacity of approximately 155 TJ/day and is fully contracted.[54]

Due to forecast increases in iron ore export capacity in the Pilbara region by 2022 and related demand increases for electricity generation, the GGP is currently in the process of adding an additional compressor at Turee Creek. This is expected to increase the firm capacity of the GGP from 155 TJ/day to approximately 202.4 TJ/day by the end of 2013 to support long-term transmission contracts for additional supplies of gas to Rio Tinto and BHP's Billiton mine upgrades; a 20 year contract for Rio Tinto's Paraburdoo and West Angeles mines and another 15 year contract for BHP Billiton's new Yarnima power station at Newman and other customers.[55]

Parmelia Pipeline

The Parmelia Pipeline, 100% owned and operated by the APA Group, was the first gas transmission pipeline constructed to service domestic demand in WA. This pipeline is not covered under the *National Gas Access (WA) Act 2009* and the amended National Gas Law.

The Parmelia Pipeline is connected to four gas processing facilities (namely the Dongara, Beharra Springs, Xyris [not-operational] and Woodada [not-operational] processing facilities) via four inlet points. It also allows gas to be shipped to the Mondarra Gas Storage Facility and to industrial and commercial customers located just north of the Perth Metropolitan area, residential gas customers connected to ATCO's Metropolitan Gas Network and customers located in the Kwinana and Pinjarra industrial areas.

The Parmelia Pipeline currently has a single interconnection with the DBNGP, though this is anticipated to change with the completion of the Mondarra facility upgrade.[56] Despite having only a single interconnection, the Parmelia Pipeline runs approximately parallel to the DBNGP and may be used to "part-haul" gas from the Carnarvon Basin via the Mondarra interconnection or through other future interconnections to the DBNGP to customers connected to the Parmelia Pipeline.

This pipeline is currently not fully utilised as gas fields supplying processing facilities connected to the pipeline are experiencing diminishing gas production. According to data provided by APA Group, it is estimated the pipeline has approximately 45% of its total capacity available for shipping additional gas.

Pilbara Pipeline System

Originally, part of this pipeline system was constructed to ship gas from Karratha to Port Hedland to supply gas to power BHP Billiton's iron ore production facility and other planned downstream processing facilities for minerals. However, since the first segment was constructed, the pipeline system has expanded into three different segments, these are 114 kilometres of main pipeline, the Pilbara Energy Pipeline, from Karratha to Port Hedland that links to the TGP (completed in 1995), 24-kilometre Burrup Extension Pipeline that connects the KGP to the first segment and the DBNGP (completed in 1999) and approximately 84.9

[54] This is according to APA Group's GGP Capacity Register as at October 2011 available at http://www.apa.com.au/media/191459/2011%20ggp%20public%20register%20october%202011.pdf, accessed 26 March 2013.
[55] APA Group announcement dated 23 January 2012, http://www.apa.com.au/investor-centre/news/asxmedia-releases/2012/apa-goldfields-gas-pipeline-further-capacity-expansions-supporting-customer-growth.aspx
[56] The former Office of Energy's Gas Supply and Emergency Management Committee (2009) recommends for additional interconnections between the Parmelia Pipeline and the DBNGP to be constructed to mitigate a gas supply outage.

kilometres of lateral pipelines connecting the Wodgina tantalum mine and Horizon Power's Karratha power station.[57]

The PPS is 100% owned by APA Group through Epic Energy.[58] According to APA Group, this uncovered pipeline is currently fully contracted.[59]

Secondary Pipelines

For the purposes of the GSOO, secondary transmission pipelines are pipelines that are not directly connected to a gas processing facility and are solely for the transmission of gas to final consumers.

Mid-West Pipeline

The MWP interconnects with the DBNGP south of DBNGP's Compression Station Seven near Geraldton. The MWP is capable of shipping gas to customers east of Geraldton to Windimurra. The MWP is currently owned by an unlisted JV consisting of the APA Group through the Australian Pipeline Limited (50%) and Horizon Power (50%), and operated by the APA Group.[60]

The MWP is not covered by third party access regulations. The MWP currently terminates approximately 400 to 500 kilometres west of the GGP and is understood to be used by only two gas consumers; approximately 55% of its total capacity is contracted to supply gas to fuel the power stations of Atlantic Limited's vanadium project located at Windimurra and the Mount Magnet gold mine.[61]

There may be opportunities to increase the usage of this pipeline by extending it to connect with either surrounding remote communities (Yalgoo and possibly Sandstone) or establishing an interconnection between the MWP and the GGP. These remote communities are currently serviced by high cost diesel generators through a power purchase agreement with Horizon Power. However, the extension cost of the MWP may be prohibitive.

Telfer Gas Pipeline

The TGP connects to the end of the PPS and ships gas to mine sites located in the Great Sandy Desert of WA. As a secondary pipeline, customers on the TGP are reliant on the availability of capacity on the PPS. This pipeline is also not covered by third party access regulations and is owned by an unlisted investment vehicle known as Energy Infrastructure Investments and operated by the APA Group.[62]

Currently, TGP's pipeline capacity is known to be fully contracted and ships gas for two customers; Aditya Birla's Nifty copper mine, approximately 300 kilometres east of Port Headland and Newcrest Mining's Telfer gold mine, approximately 400 kilometres east south east of Port Hedland.

Kalgoorlie to Kambalda Pipeline

The KKP is the shortest transmission pipeline in WA, connecting with the end of the GGP at Kalgoorlie South. The KKP ships gas to customers located in Kambalda and connects to the KEP. It is currently wholly owned and operated by the APA Group.[63]

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[57] The lateral to Horizon Power's Karratha power station was built in 2009.

[58] APA Group took over Hastings Diversified Utilities Fund, that owns and operates Epic Energy (under APA Sub Trust 2), and made it a subsidiary of Australian Pipeline Limited, a wholly owned subsidiary of APA Group in December 2012, http://www.apa.com.au/investor-centre/news/asxmedia-releases/2012/hdf--change-of-name--corp-info.aspx, accessed 19 April 2013.

[59] It is understood that the PPS's transmission capacity may be increased through compression.

[60] Information provided by Horizon Power. Although the MWP ownership is 50/50, according to Horizon Power (2012), output interests and pipeline costs are not shared equally. This is outlined in Horizon Power's (2012) 2011-12 Annual report tabled in the WA Parliament. Australian Pipeline Limited is a wholly owned subsidiary of Australian Pipeline Trust, a wholly owned subsidiary of the APA Group.

[61] Capacity utilisation is estimated from gas flow data provided by APA Group.

[62] The owners of Energy Infrastructure Investments include Marubeni Group (49.9%), Osaka Gas (30.2%) and the APA Group (19.9%).

[63] Southern Cross Pipelines Australia Pty Ltd, the company that owns the KKP is a wholly owned subsidiary of the APA Group.

The KKP is a covered pipeline (with light regulation)[64] under the *National Gas Access (WA) Act 2009* and the amended National Gas Law. It is currently fully contracted with 90% of total pipeline capacity contracted to supply gas to Mincor Resources' Nickel Mine and BHP Billiton's Nickel West operations located at Kambalda.

Kambalda to Esperance Pipeline

The sole purpose of the KEP is to ship gas from the end of the KKP located at Kambalda to gas consumers located in Esperance. The KEP is estimated to have a free flow capacity of approximately 6 TJ/day and ships gas to Esperance Power Station that supplies power for Horizon Power, the Esperance Port, and the Esperance retail gas system.

The KEP is not covered by third party access regulation and has been operational since 2004. It is currently 100% owned by Energy Infrastructure Trust.[65] The operators of the pipeline are currently Worley Parsons Asset Management Pty Ltd, a wholly owned subsidiary of Worley Parsons, a resources and energy services contract manager.

Proposed Gas Transmission Pipelines

Bunbury to Albany Pipeline

Originally proposed in 2008, the BAP is anticipated to be connected to the end of the DBNGP and this pipeline is likely to be governed under the *Dampier to Bunbury Natural Gas Pipeline Act 1997*.[66]

The WA Government has publicly indicated it will contribute $135 million towards the construction of the pipeline and it is currently attempting to form a consortium to partner with Verve Energy and two other potential parties, ATCO Australia and Alinta Energy.[67] At the time of this report, a preferred owner/operator for the proposed BAP has not been selected and it is anticipated this issue will be decided by the end of 2013.

The WA Government has also publicly indicated it expects this pipeline will be completed and operational by 2015.[68] The proposed BAP is anticipated to utilise the Bunbury to Albany gas pipeline corridor outlined by the Department of Regional Development and Lands that passes through the towns of Donnybrook, Bridgetown, Manjimup and Mt Barker in the south west of WA.[69]

Great Northern Pipeline

The Great Northern Pipeline (GNP) was originally proposed by ARC Energy (now a subsidiary of AWE Limited) in 2007 after it signed a conditional gas sales agreement with Alcoa Australia.[70] However, subsequent to a merger between ARC Energy and AWE Limited, the GNP proposal was assigned to Buru Energy.[71]

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[64] Light regulation means the pipeline operator does not require regulatory approval of terms, conditions and transmission reference tariffs prior to implementation. It only obliges the pipeline operator to publish specific information determined by the regulator that includes price, terms and conditions for access and transmission. Capacity availability of the KKP is outlined in KKP's Capacity Register in 2010 available at http://www.apa.com.au/media/174030/2010%20kkp%20public%20register.pdf, accessed 26 March 2013.

[65] This trust is managed by the Infrastructure Capital Group.

[66] The Department of Finance, Public Utilities Office has suggested that access to the pipeline may be overseen by the ERA, annual corridor charges would be determined by the Department of Finance, Public Utilities Office and the usage of the BAP corridor and the collection of the corridor charges would be managed by the Department of Regional Development and Lands.

[67] Due to WA Government's contribution to the BAP, it is understood that Verve Energy, a Government owned entity, will own a share of the proposed pipeline.

[68] See ABC News (2012).

[69] For the proposed Bunbury to Albany Gas Pipeline corridor, refer to Department of Regional Development and Lands, http://www.rdl.wa.gov.au/programsandprojects/infrastructure/InfrastructureCorridors/Pages/Bunbury-to-Albany-Gas-Pipeline-corridor.aspx.

[70] See Petroleum Exploration Society of Australia (PESA) (2007), Issue 90, Alcoa Pays ARC A$40M For Future Canning Basin Discoveries, http://www.pesa.com.au/publications/pesa_news/oct_nov_07/pesanews_9012.html, accessed 11 February 2013. According to Buru Energy's corporate announcement to the ASX on 29 December 2012, this conditional gas sales agreement remains in place with Alcoa Australia.

[71] The current proponent Buru Energy was incorporated for the purpose of acquiring and developing the exploration and production assets of ARC Energy in the Canning Basin.

Although Buru Energy has discovered potential gas resources in the Canning Basin and has signed a State Agreement with the WA Government, it is unclear at this juncture when the construction of the proposed GNP will commence.[72]

The proposed GNP is currently anticipated to originate from Buru Energy's Yulleroo field and connect to the DBNGP (and potentially with the GGP via Main Line Valve 7) around Port Hedland in the Pilbara.[73,74] This would allow it to fulfil its existing gas supply agreement with Alcoa Australia and also access other potential gas customers located in the south of WA connected to the DBNGP, GGP and other secondary pipelines.

Multi-User Gas Storage Facilities

Gas storage is still in the early stages of development in WA. A study by the Allen Consulting Group suggests the lack of gas storage services currently hinders the further evolution of the domestic gas market, via the development of gas balancing services.[75] This study estimates gas storage requirements of approximately 100 TJ/day for a minimum of 90 to 180 days, or 9 to 18 PJ are required for gas balancing services to be offered.

In addition to evolving the domestic gas market, further investments in multi-user gas storage facilities will improve gas security and contingency planning for existing domestic gas consumers, reducing the requirement for disparate and individual gas storage facilities for existing consumers. Although the current focus for gas storage in WA is to utilise depleted gas fields, several other types of gas storage, such as above or underground Compressed Natural Gas and LNG storage facilities may be considered for future WA gas storage facilities.

There is currently only one multi-user gas storage facility operational in WA, the Mondarra Gas Storage Facility with one other facility known to be under consideration.[76] The Mondarra facility, operational since 1994, was previously a depleted gas reservoir that supplied natural gas to the Parmelia Pipeline. The Mondarra facility is owned and operated by APA Group and is located approximately 350 km north of Perth, in the vicinity of the interconnection between the Parmelia Pipeline and the DBNGP.

The Mondarra facility is currently being expanded to increase its storage capacity to supplement long haul pipeline contract capacity and to provide for gas peaking requirements and backup emergency gas supplies for Verve Energy.[77] Stage one expansion of the Mondarra Gas Storage Facility is anticipated to be completed in July 2013.[78]

Table 6 – Existing and Planned (Under Consideration) Gas Storage Facilities, 2013

Facility	Operator	Total Capacity	Input Capacity (TJ/day)	Output Capacity (TJ/day)	Location	Status	Pipeline Connected ?
Mondarra (current)	APA	3 PJ	5	10^	Mid-West	Operational	DBNGP (inlet only) and Parmelia (outlet only)
Mondarra (After stage one expansion)*	APA	15 PJ	70	150**	Mid-West	Planned, anticipated to be operational by the end of July 2013[%]	DBNGP and Parmelia^^

[72] According to Buru Energy's (2013) March Investor Presentation, the GNP estimated to be completed in 2015.
[73] The GNP distance was outlined briefly in PESA (2012) News Resources, December/January 2011/2012, WA Supplement and also outlined in Geoscience Australia (2012) and in an interview with Buru Energy, Company Insight (2012).
[74] The specifications of the Great Northern Pipeline were previously outlined in the Australian Pipeliner article in 2007, http://pipeliner.com.au/news/diversity_of_development_key_to_australasias_pipeline_success/012290/.
[75] Allen Consulting Group's (2009) study also suggests the lack of gas balancing services is one of the factors for the continued joint marketing of gas.
[76] Some major gas users and producers (such as Barrow Island) have private storage facilities within their operations to allow them to adjust and ensure a smooth flow of gas.
[77] Verve Energy has contracted approximately 60% of Mondarra's total storage capacity for 20 years.
[78] Expected Completion dates are outlined in the Australian Pipeliner (2013) and The West Australian (2013b).

Tubridgi	DBP Services Co (Duet Group)	Unknown	Unknown	Unknown	Pilbara	Under Consideration	DBNGP

Source: APA Group and Duet Group (2013). *According to the Energy Minister's Announcement (2011), there is a long-term agreement between APA Group and Verve Energy to provide gas storage with withdrawal capacity of up to 90 TJ/day. **See Energy Minister's Announcement (2012). ***The depleted Tubridgi gas field (since 1994) was previously used as a gas storage facility by the Griffin JV. ^^After the expansion, the Mondarra facility will be able to output gas to the DBNGP and the Parmelia Pipeline. %Outlined in the West Australian (2013b).

Duet Group, part owner of the DBNGP through its wholly owned subsidiary DBP Services Co, is investigating the prospect of developing the depleted Tubridgi gas field into a gas storage facility.[79,80] Other potential sites for gas storage facilities include the depleted gas fields of Beharra Springs, Dongara and Woodada located in the Perth Basin.

Although the expansion of the Mondarra facility, anticipated to be completed by the end of July 2013, somewhat meets the gas storage requirements described by the Allen Consulting Group report, approximately a third of Mondarra's total gas storage capacity has been contracted by Verve Energy for its consumption and sales.[81]

Reticulated Retail Infrastructure

Reticulated gas in WA commenced about 100 years ago when gas manufactured from coal was distributed to Fremantle, Perth and Albany. In 1973, after the completion of the Parmelia Pipeline, the Perth and Fremantle gas distribution systems were converted to supply natural gas from the WANG transmission system.[82] Over the years, WA's gas supply areas have increased and there are currently eight defined gas supply areas in WA (Figure 10) that are defined in the *Energy Coordination Act 1994*.

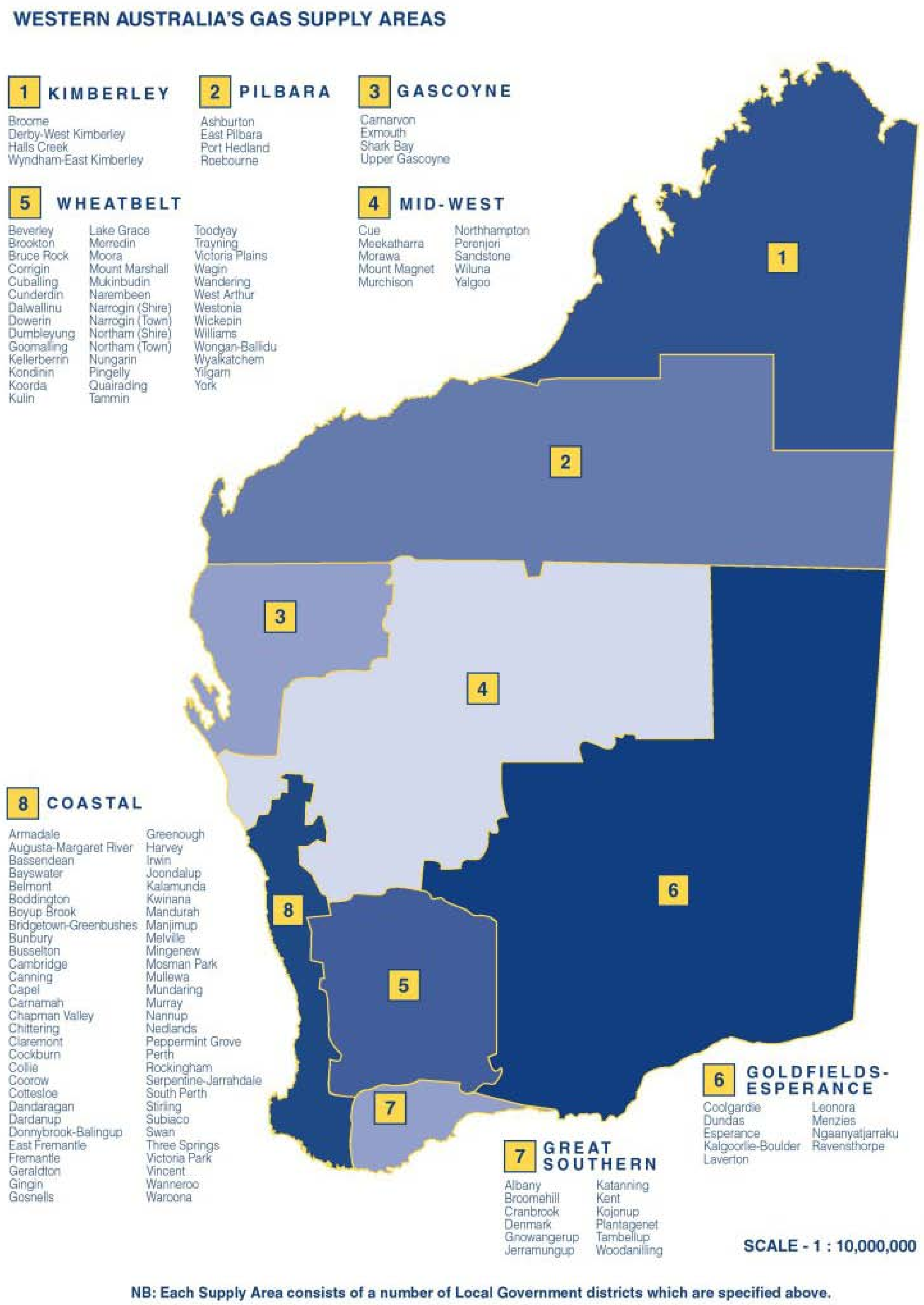
[79] For more information see Duet Group's (2013) presentation. Similar information was also articulated at DBP Limited's Shipper's Forum Breakfast at the Melbourne Hotel on 25 March 2013.

[80] It is unclear whether the depleted Tubridgi gas field may be suitable for use as a gas storage facility. BHP Billiton previously indicated to the National Competition Council that Tubridgi's geology is highly stratified. This creates uncertainties to the recoverability of gas injected into the depleted reservoir, see http://www.ncc.gov.au/images/uploads/REGaTGAp-001.pdf. Duet Group's (2013) annual report suggests otherwise.

[81] According to the Energy Minister's announcement (2011, 2012), Mondarra has been contracted by Verve Energy to provide up to 90 TJ/day for up to 60 days should WA face a gas supply disruption. This reduces the availability of firm storage capacity for other gas market participants to adequately balance their gas usage when there is a gas supply disruption. APA Group's Mondarra expansion is consistent with the recommendations of the Gas Supply and Emergency Management Committee (2009); minimum gas storage with withdrawal rates of between 35 TJ/day and 100 TJ/day coupled with additional interconnections between the Parmelia Pipeline and the DBNGP to mitigate gas supply emergencies.

[82] See ERA (2007) for a history of WA's gas distribution system.

Figure 10 – Gas Supply Areas, 2013



Source: ERA (2013)

There are also eight parties with gas trading licenses to operate in these gas supply areas. These trading licenses, granted under the *Energy Coordination Act 1994*, confer the licence holder the right to sell and supply gas to small use customers (that consume less than 1 TJ/annum).[83] As part of the licensee obligations, they must adhere to certain conditions, including the obligation to offer to supply small use customers in certain circumstances, a requirement to maintain gas supply to existing customers, an obligation to market gas, the ability to offer standard customer contracts, back-up trader arrangements, maintain a certain level of customer service and commitment to performance bonds.

Table 7 provides a list of gas trading licensees and their supply areas shown in Figure 10.

Table 7 – Current Gas Trading Licensees, 2013

Gas Trading Licensee	Gas Supply Areas
Alinta Sales Pty Ltd	Goldfields-Esperance, Great Southern and Coastal
Esperance Power Station Pty Ltd	Goldfields-Esperance
Perth Energy Pty Ltd	Kimberley, Pilbara, Gascoyne, Mid-West, Wheatbelt, Goldfields-Esperance, Great Southern and Coastal
Rottnest Island Authority	Unknown
Synergy (Electricity Retail Corporation)	Goldfields-Esperance, Great Southern and Coastal
ATCO Gas Australia	Goldfields-Esperance, Great Southern and Coastal
Wesfarmers Kleenheat Gas Pty Ltd	Wheatbelt, Goldfields-Esperance, Great Southern and Coastal
WorleyParsons Asset Management Pty Ltd	Goldfields-Esperance

Source: ERA's website, accessed 5 November 2012.

The retail gas networks total approximately 13,268 kilometres of gas mains and service lines, connecting to natural gas and liquefied petroleum gas (LPG).[84] These networks serve the areas of Geraldton, Kalgoorlie, Albany (LPG), Bunbury, Busselton, Esperance, Harvey, Pinjarra, Brunswick Junction, Capel, Leinster (LPG), Margaret River (LPG), Oyster Bay (LPG) and the Perth greater metropolitan area.

Table 8 – Retail Gas (Natural Gas and LPG) Infrastructure, 2012

Distributor	Number of Gas Connections – 2011-2012	Length of Gas Network (km)	Residential Consumption (TJ) – 2011-2012	Non-Residential (TJ) – 2011-2012
ATCO	652,808	13,181	9,528.37	16,633
Wesfarmers (Kleenheat Gas)	903	35.2	3.54	4.67
Esperance Power Station	313	50.8	5.51	0.24
Total	**654,024**	**13,268**	**9,537.42**	**16,638**

Source: ERA (2013). **Note:** Totals are rounded up.

ATCO Gas Australia currently owns operates and maintains most of the reticulated gas infrastructure in WA, except for gas networks in Esperance, Leinster, Margaret River and Oyster Bay.

3.6. Strategic Industrial Areas for Gas Processing

In 2009, the WA Government announced the establishment of the Ashburton North Strategic Industrial Area located in the Pilbara and the Browse LNG Precinct near James Price Point in the north west of WA to assist with the development of gas related projects (domestic and LNG).[85]

[83] All licensees can supply to all small use customers except Synergy. This is due to the Gas Market Moratorium that prevents Synergy from supplying gas to small customers who consume less than 0.18 TJ/annum.
[84] See ERA (2013), 2011/12 Annual Performance Report – Energy Distributors, http://www.erawa.com.au/cproot/11131/2/20130206%20-%202011-12%20Annual%20Performance%20Report%20-%20Energy%20Retailers%20(amended%20final%20for%20publication).pdf, accessed 12 June 2013.
[85] For more information, please refer to the DSD, for the Ashburton North Strategic Area, see http://www.dsd.wa.gov.au/8383.aspx and for the Browse LNG Precinct, see http://www.dsd.wa.gov.au/8581.aspx, both accessed 22 February 2013.

Both the Macedon gas facilities and the Wheatstone LNG facility, currently under construction, are located within the Ashburton North Strategic Industrial Area. The upcoming Browse LNG Precinct has also been granted state environmental approval and the land for this precinct.[86] The Browse precinct is in the process of being acquired by the WA Government, but there are no proposed facilities planned for this site at this stage.[87]

[86] DSD (2013), Minister Grants Environmental Approval, http://www.dsd.wa.gov.au/8790.aspx, accessed 22 February 2013.
[87] Premier's Media Statement (2013b), Browse gas precinct acquisition to go ahead, http://www.mediastatements.wa.gov.au/Pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7500, accessed 20 June 2013.

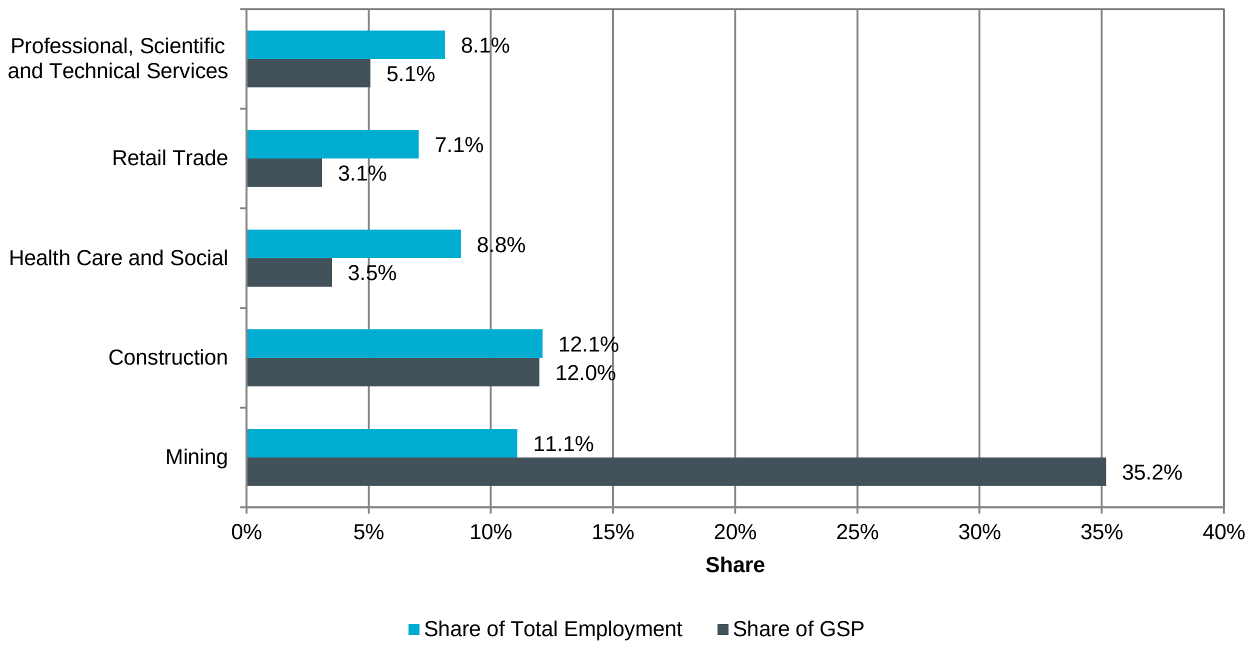
4. Western Australia and the External Economic Environment

This chapter outlines the key drivers of the WA economy and provides an economic outlook for the 2013 to 2022 period. As this economic outlook is then used in forecasting domestic demand for natural gas as part of the demand-supply assessment, this chapter outlines the assumptions underpinning difference forecast scenarios of gas demand and supply.

Brief Overview of the Western Australian Economy

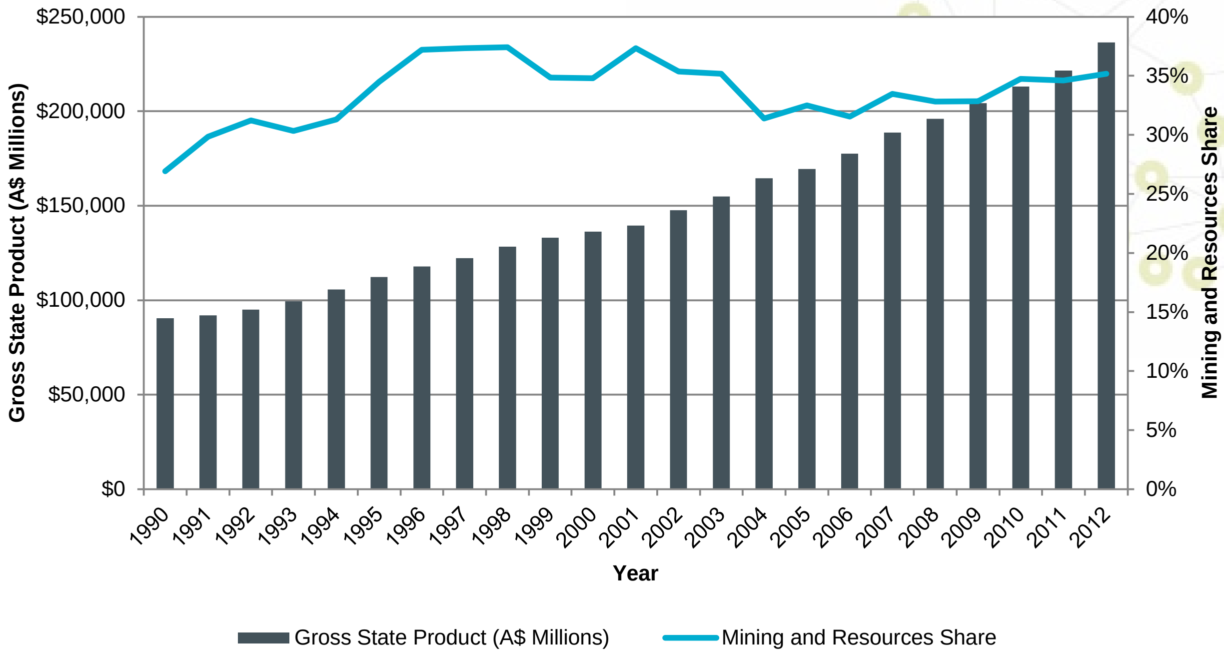
WA's economy is highly dependent on the mining and resources sector (including oil and gas). According to the Australian Bureau of Statistics (ABS, 2013), this sector alone accounts for approximately 35.2% of WA's Gross State Product (GSP) in 2011-12.

Figure 11 – Sample of WA Major Industries, 2012



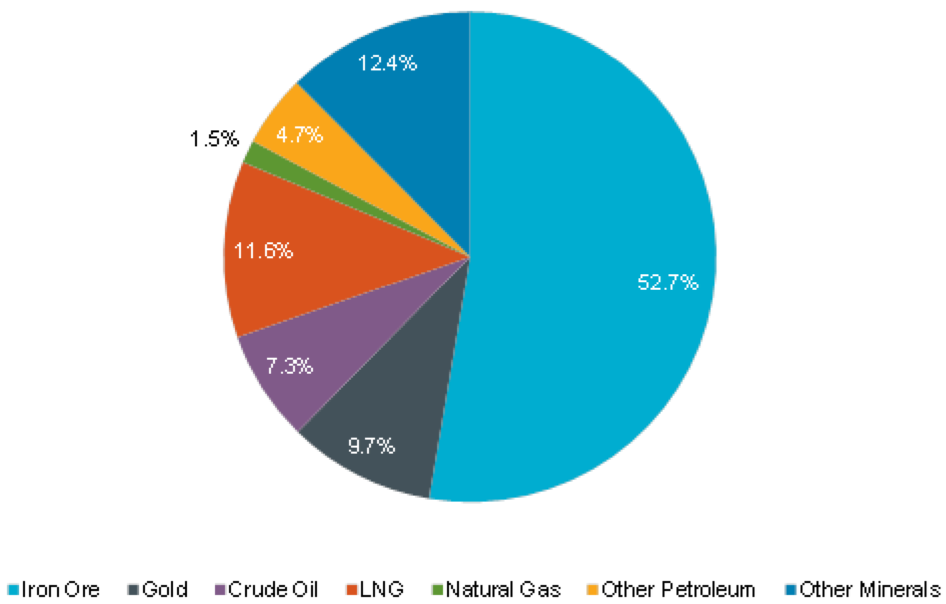
Source: ABS, Cat 5220.0 State Accounts, Chain Measures (Dec 2012) and Cat 6291.0.55.003, Labour Force, (Nov 2012).

Figure 12 – Western Australia Gross State Product (GSP) and Mining Share of GSP, 1989 – 2012



Source: ABS (1990-2012), Cat 5220.0, Australian National Accounts: State Accounts, GSP – Chain Volume Measures – Original ($ millions), Proportion of Mining to GSP is calculated using Mining – Chain Volume Measures – Original ($ millions).

Figure 13 – Share of Minerals and Petroleum Products ($ Value), Western Australia, 2012



Source: DMP (2013d), Latest Statistics Release, http://www.dmp.wa.gov.au/1525.aspx, accessed 20 May 2013.

Among all the resources mined in WA, iron ore generates the most sales revenue. In 2012, iron ore accounted for approximately 52.7% of WA's total mineral sales generating approximately $96.9 billion in 2012. WA also produces approximately a quarter (26.4%) of the world's iron ore (by volume).

The next largest sales revenue is from the petroleum and LNG sectors. These sectors account for approximately 18.9% of total mineral sales.[88] During the same period, the total value of WA petroleum and LNG exports increased in value to $11.3 billion, up 21% from 2011.

At the end of 2012, WA also supplied all of Australia's diamonds, garnets and nickel, 98.6% and 84.3% of Australia's salt and LNG, respectively.[89]

4.1. Western Australia's Economic Outlook

Economic forecasts are an important input for developing gas demand projections. The level of economic activity has both a general and specific impact on the demand for, and consumption of, energy. Economic conditions will also affect the level of discretionary spending by consumers and industry.

Resource extraction, processing and export are important to the Australian and WA economies and are key drivers of gas consumption growth. DMP reported that resource projects worth an estimated $177 billion were under construction or committed as at 31 March 2013, dominated by LNG and iron ore developments. Capital expenditure in the mining industry represented 82% of all new capital expenditure in WA during 2012.[90]

Given the high dependence of the WA economy on the resources industry outlined in the previous section, it could reasonably be anticipated that growth rates in WA will be more volatile than in other more diversified economies. WA has experienced enormous growth in resource-related investment over the last decade, but this is anticipated to peak in 2012-2013 before steadily declining over the next four years.

Beyond current commitments, further activity in the resources sector is highly dependent on economic activity in Asia. Countries such as China are in turn dependent on sales of exports to the major economies of North America and Europe, where economic recovery following the Global Financial Crisis (GFC) has been slower than anticipated. At present, it is anticipated that growth in developed economies will remain fragile as many countries struggle with high debt and other structural issues. Despite continued strong growth in developing economies, world economic growth is anticipated to be constrained to the 3 to 4% annual growth range in the short-term due to fiscal consolidation (the withdrawal of fiscal stimulus).

In the aftermath of the global economic slowdown some marginal resource development projects have experienced significant delays or cancellation. This reflects a continuing aversion to invest capital and debt in speculative projects, as well as the reduced availability of finance since the GFC.

The majority of the resources projects under development are located in the north west of WA with some projects located close to the SWIS. Of particular relevance at present are iron ore and LNG related projects in the Pilbara and Mid-West regions, either proposed or under construction, which have substantial energy needs.

Major developments in regional areas that are anticipated to have a significant impact on gas demand in WA for the 2013 to 2022 period (see Appendix 3 for more details) include:

- power upgrades to support Rio Tinto's mine expansion projects (mostly located around Tom Price);
- port expansion at Cape Lambert and Dampier (including Cape Lambert replacement facility);
- BHP Billiton's Yarnima Power Plant at Newman;
- BHP Billiton's Port Expansion Plan at Port Hedland;
- new domestic gas facilities (Devil Creek and Macedon);
- new LNG processing facilities (Gorgon and Wheatstone LNG facilities) in the Pilbara;
- Horizon Power's expansion projects (Karratha, South Hedland and Mungullah Power Stations); and

[88] See DMP (2013d) for more details
[89] Global shares are estimated via production volume. According to DMP (2013e), WA supplies approximately one-eighth of the world's alumina, garnet, nickel and zirconium.
[90] See http://www.dmp.wa.gov.au/12410.aspx.

- other mining projects (such as Hancock Prospecting's Roy Hill).

It is anticipated that investment in the resources industry should remain a key driver for gas consumption in WA in the medium term.

The economic growth forecasts in this chapter have been prepared for the IMO by NIEIR. These forecasts are consistent with those published in the IMO's Electricity Statement of Opportunities (ESOO), published in June 2013.

NIEIR's forecasts are prepared using available economic data up to the December 2012 release of the Australian National Accounts by the ABS, which occurred on 6 March 2013.

This chapter also includes a comparison between NIEIR's forecasts and a number of other publicly available forecasts.

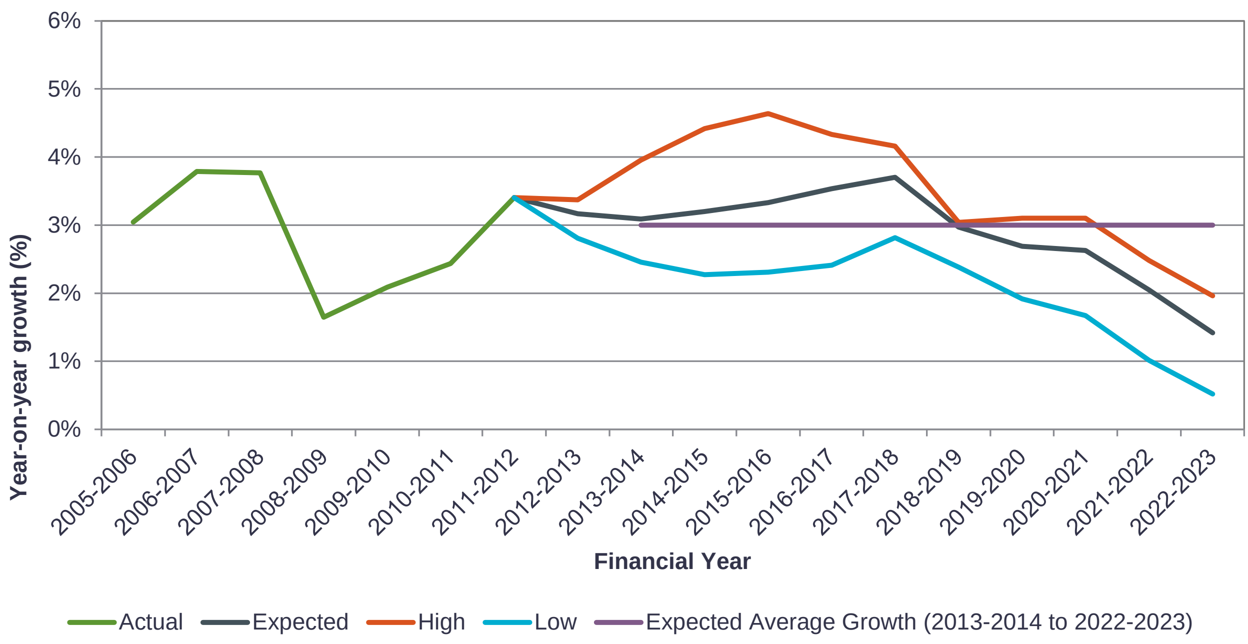
4.2. Economic Projections

Figure 14 shows the forecasts of growth in Australian Gross Domestic Product (GDP) and Table 9 shows forecasts of the key demand and supply drivers of GDP formation for the Base growth scenario.

In addition to the Base scenario, High and Low economic growth scenarios have been prepared by NIEIR. These scenarios are explained in section 4.4 below and growth forecasts for the all three growth scenarios are shown in Appendix 2.

NIEIR forecasts that Australia's annual average economic growth over the period from 2013-2014 to 2022-2023 will be at 3.0% per annum.

Figure 14 – Projected Australian Economic Growth 2011-2012 to 2022-2023



Source: NIEIR Forecasts 2012-2023.

Recent growth in GDP since 2010-2011 has been strongly supported by the acceleration of mining investment. NIEIR considers that the mining expansion explains the near majority of growth in GDP over this period when flow-on multiplier effects of this investment through the economy are considered. However, the benefits of the mining boom have been offset by the high import content of construction and equipment, and the "Dutch disease".[91] NIEIR advises that GDP growth in 2011-2012 would have been 5.4% (rather than 3.4%) if imports had been neutral.

Table 9 – Australian Growth Projections for Key Economic Parameters, Base Growth Scenario (percentage growth)

	Financial Year							
Parameter	**2010-2011**	**2011-2012**	**2012-2013**	**2013-2014**	**2014-2015**	**2015-2016**	**2016-2017**	**2017-2018**
Private consumption	3.6	3.3	2.4	3.1	3.0	3.0	3.5	3.5
Dwelling investment	2.3	-3.7	-0.1	4.0	-0.8	0.6	4.0	5.9
Business investment	8.6	22.0	5.9	-2.3	-3.0	-4.2	-1.0	5.7
Government consumption	3.1	3.4	1.4	2.3	3.4	3.7	3.3	3.1
Government investment	-2.5	-2.2	3.5	4.7	2.5	2.6	0.8	1.4
Domestic final demand	3.6	5.3	2.8	2.1	1.8	1.8	2.6	3.7
Overseas exports	-0.4	3.8	6.6	4.9	3.6	7.6	8.4	6.9
Overseas imports	6.9	9.3	2.0	0.2	-1.1	2.6	5.8	7.0
Gross Domestic Product	**2.4**	**3.4**	**3.2**	**3.1**	**3.2**	**3.3**	**3.5**	**3.7**
Population	1.2	1.4	1.5	1.5	1.6	1.6	1.5	1.5
Employment	2.9	0.6	1.0	1.4	1.1	1.3	1.7	2.1
Exchange rate (A$/US$)	1.0	1.0	1.0	0.9	0.8	0.8	0.8	0.8

Source: NIEIR Forecasts 2012-2018**.**

The decline in mining investment over the coming years will contribute negatively to growth. However, NIEIR forecasts that a range of factors will contribute to maintaining GDP growth of over 3% through to 2017-18, such as:

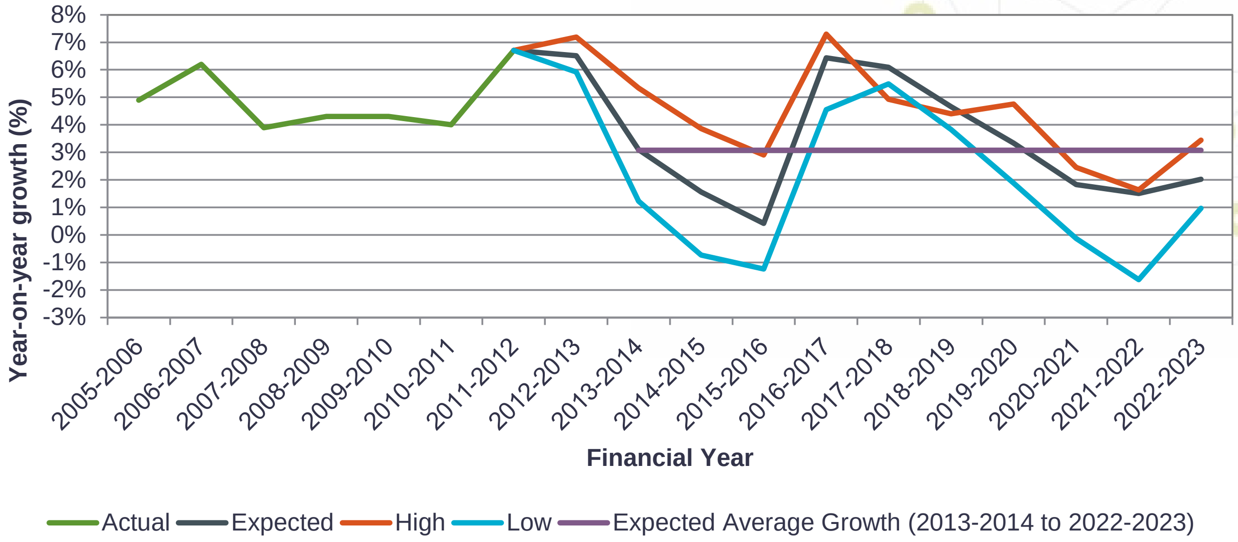
- a decline in imports;
- steady stimulus from mining production (following the high level of investment);
- a return to more typical levels of public demand growth after a period of fiscal withdrawal;
- recovery in the world economy; and
- a weakening in the Australian dollar from 2014, boosting the competitiveness of the manufacturing sector and other export industries.

NIEIR projects growth will moderate after 2018, due mostly to slower growth in the world economy. NIEIR predicts that the loss of capacity since the GFC, caused by lost investment and increased long-term unemployment, will lead to developed nations reaching capacity constraints.

Figure 15 shows the forecasts of growth in WA GSP and Table 10 shows forecasts of the key drivers of GSP formation for the Base growth scenario. Average growth forecast for the WA economy over the next 10 years is 3.1% per annum.

[91] The term "Dutch disease" is typically used to describe the apparent relationship between the increase in exploitation of natural resources, boosting a country's revenues and its exchange rate at the expense of competitiveness in the manufacturing sector and other export industries.

Figure 15 – Projected Western Australian Economic Growth, 2011-2012 to 2022-2023



Source: NIEIR Forecasts 2012-2023.

Table 10 – Western Australian Growth Projections for Key Economic Parameters, Base Growth Scenario (percentage growth)

	Financial Year							
Parameter	**2010-2011**	**2011-2012**	**2012-2013**	**2013-2014**	**2014-2015**	**2015-2016**	**2016-2017**	**2017-2018**
Private consumption	5.3	5.9	4.7	4.0	3.7	0.7	0.7	5.5
Dwelling investment	5.5	-15.1	0.2	9.9	2.0	3.3	5.0	4.0
Business investment	9.7	37.7	16.7	-4.5	-8.3	-15.5	1.9	17.4
Government consumption	2.9	4.8	2.2	3.1	4.3	4.5	3.9	3.6
Government investment	1.3	7.7	18.8	9.1	0.4	3.2	3.2	3.2
State final demand	5.3	13.5	9.1	1.2	-0.7	-3.8	1.9	8.4
Gross State Product	**4.0**	**6.7**	**6.5**	**3.1**	**1.6**	**0.4**	**6.4**	**6.1**
Population	2.3	3.0	2.6	2.4	2.6	2.5	2.2	2.2
Employment	3.2	2.4	0.8	0.9	1.7	1.4	1.4	2.4

Source: NIEIR Forecasts 2012-2018.

Growth in the WA economy is more heavily dependent on business investment than other Australian States. NIEIR reports that business investment now accounts for 34% of all expenditure in the State, compared with 20% in Queensland and 13% in New South Wales and Victoria.

While growth in WA has exceeded 6% in 2011-2012 and 2012-2013, NIEIR forecasts that growth in WA will moderate considerably over the next three years, reflecting the contraction in mining investment as well as a slowing of household expenditure. However, the housing construction market is expected to recover during this period.

NIEIR has noted that the risks to its forecast GSP growth rates are weighted slightly to the downside. The average annual GSP growth in the Low scenario is forecast to be 1.7% per annum below the Base growth, whereas the average growth in the High scenario is forecast to be 1.0% above the Base growth profile.

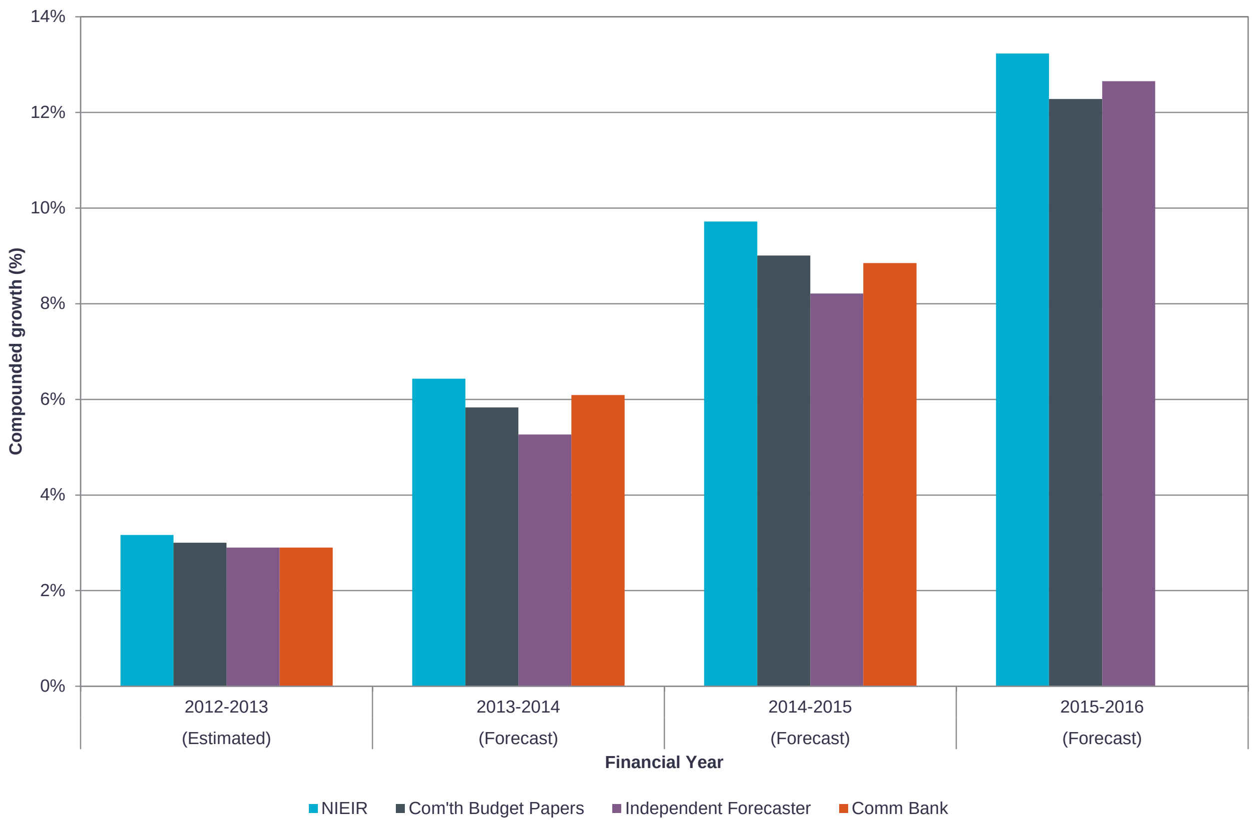
4.3. Comparisons with Other Forecasters

Figure 16 compares NIEIR's Australian economic growth forecasts with those of three other organisations:

- the Commonwealth Government Budget Papers (published May 2013);
- a major independent forecaster[92] (published April 2013); and
- the Commonwealth Bank Economic Forecast[93] (published May 2013).

This comparison of Australian growth rate forecasts is presented on a compounded basis to smooth out the variations that occur from year to year. The comparison shows general agreement between the forecasters, with NIEIR's forecasts being the highest displayed.

Figure 16 – Comparison of Compound Australian Economic Growth Forecasts

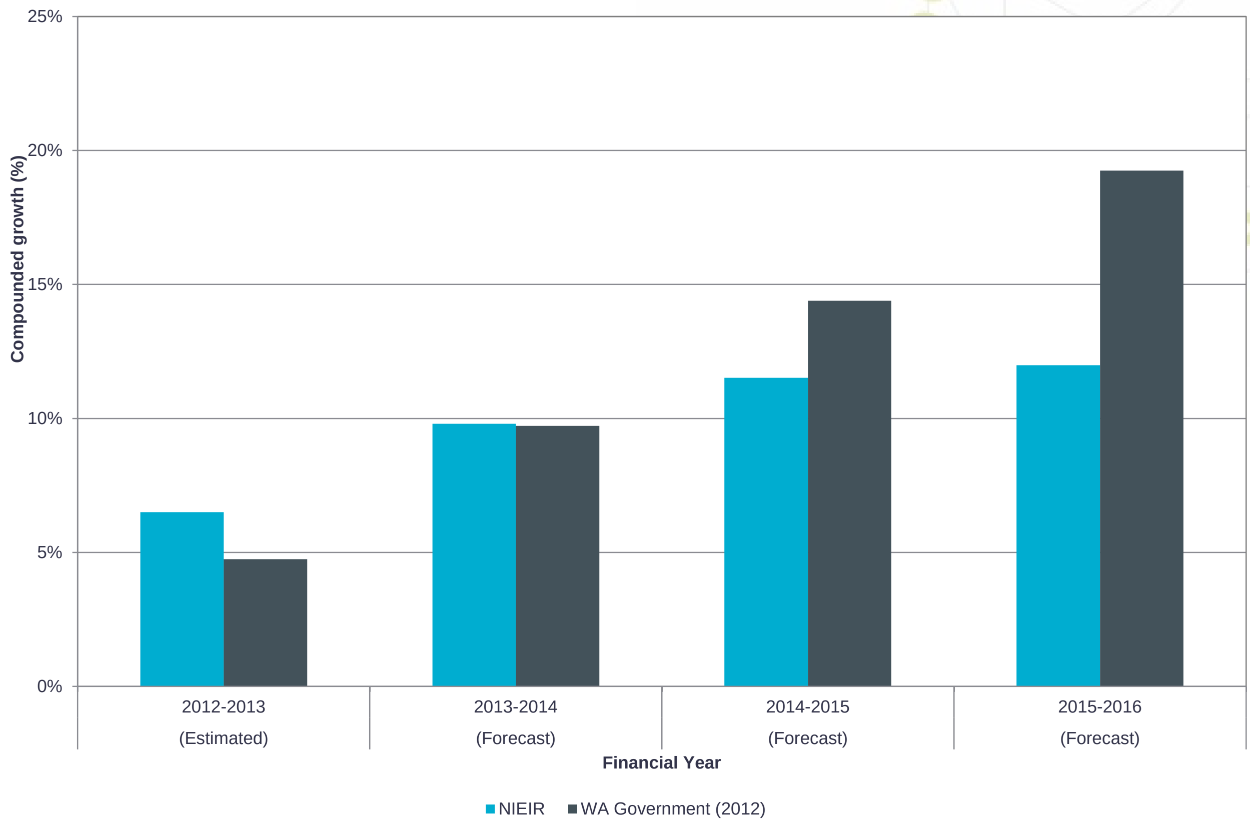


Source: NIEIR Forecasts 2012-2023, Commonwealth Government Budget Papers, Commonwealth Bank Economic Forecast and independent forecaster.

The 2013 WA State Budget is yet to be published, but Figure 17 compares the NIEIR forecasts of WA GSP growth with those published by the WA Department of Treasury in the May 2012 budget papers for the period from 2012-2013 through to 2015-2016. This comparison is also presented on a compounded basis. While NIEIR predicts higher growth for 2012-2013, Figure 17 demonstrates that NIEIR's forecasts are lower than the WA Treasury forecasts over the medium term. As highlighted in the ESOO, this is a result of revisions to NIEIR's forecasts since 2012.

[92] The "Independent Forecaster" included in the graph has requested that it not be named.
[93] Note that the Commonwealth Bank forecast extends only to 2013/13, so it is excluded from the 2013/14 comparison.

Figure 17 – Compound WA Economic Growth Forecasts



Source: NIEIR Forecasts 2012-2023.

4.4. Projection Scenarios

To ensure future gas demand and supply projections for the 2013 to 2022 period are good representatives of future domestic gas demand and supply, six possible scenarios have been developed (three for the demand of gas and three for the supply of gas). These scenarios have then been applied to the projections of future gas demand and supply for WA to capture potential future outcomes.

The scenarios applied in projecting future domestic gas consumption and gas supply for the 2013 to 2022 period are articulated below.

Issues Critical to Future Gas Demand

The WA economy is heavily dependent on the fortunes of the mining and energy related sectors, with these sectors heavily influencing the outlook for the WA economy. For the 2013 to 2022 period, the majority of domestic gas consumption is largely dependent on:

- the projected economic growth of WA;
- the Australian dollar exchange rate;
- the health of the international economy; and
- the international prices of key WA export commodities (iron, gold and LNG).

These factors influence business investment decisions in prospective mining and energy projects that will contribute towards future gas demand.[94]

[94] This GSOO acknowledges that the elasticity of gas demand is also a key factor and the gas demand projections accounts for this.

To generate an appropriate representation of future gas demand, this GSOO establishes a Base level of domestic gas demand. The Base projections of gas demand do not specifically consider gas consuming projects that have not attained Final Investment Decision (FID) by the end of March 2013. Only projects that have attained FID are encapsulated in the projections of gas demand for the 2013 to 2022 period.[95] These projects are reported in Appendix 3.

To portray potential deviations from this projected base level of gas demand, a set of potential gas demand scenarios for the period are developed and summarised in Table 11.

Table 11 – Projected Gas Demand Scenario Parameters

		Scenarios		
Parameter	**Unit**	**High**	**Base**	**Low**
Economic growth	%	As per economic growth rates outlined in Appendix 2	As per economic growth rates outlined in Appendix 2	As per economic growth rates outlined in Appendix 2
International LNG prices	USD/GJ	19.5 – 22.80	17.5 – 19.50	15.90 – 17.50
Commodities prices	Index	99	88	58
Exchange rates	A$/US$	$0.74 – $0.83	$0.64 – $0.73	$0.56 – $0.63

Note: Carbon pricing impacts have been considered in the modeling. Projected gas demand is assumed to be readily transported by existing and future pipelines.

Issues Critical to Future Gas Supply

Domestic gas supply is driven by influences including:

- costs involved in bringing gas to the domestic market;
- future gas demand;
- the opportunity cost of selling the gas as LNG exports;
- minimum operational requirements of gas processing plants;
- projected exchange rates;
- government regulation;
- transmission capacity of pipelines; and
- competition in the domestic gas market.

In the absence of information pertaining to gas prices that gas consumers will be willing to pay in WA, this GSOO forecasts prices at which producers are likely to offer gas during the 2013 to 2022 period and the quantities of gas that producers are likely to offer at those prices to the domestic market – the potential gas supply.

The following variables are used in the probability analysis carried out by NIEIR to develop annual domestic gas prices from the gas producers' perspective:[96]

- future oil prices;
- future LNG prices;
- estimated average cost of gas production;
- estimated utilisation rates of processing plants;
- projected exchange rates; and
- recoverable WA gas reserves.

These variables have been extensively researched and are deemed as important variables influencing domestic gas prices that producers are likely to offer. **It is important to note that forecast gas prices are**

[95] Future GSOOs may consider projected gas consumption from a proportion of speculative projects. The IMO welcomes feedback from market participants and other stakeholders on this possible approach.
[96] The forecasted prices are annual averages and do not represent equilibrium prices.

indicative price projections from the producers' perspective that are likely to occur using the abovementioned variables, and do not represent equilibrium prices for the domestic market.[97]

Each variable is estimated by setting initial values and assigning a probability density function and ascending cumulative probability function based on its historical statistical behaviour.[98] A probability analysis is then applied to forecast the future value of each variable.[99] A set of representative gas supply scenarios were also developed in parallel to represent High and Low gas supply scenarios (see Table 12).

Once each variable is modelled, future domestic gas prices are then estimated by applying a weighted average formula of the LNG netback price[100] and the marginal cost of gas extraction.[101] The LNG netback price is estimated from projected LNG prices that are influenced by future anticipated oil prices,[102] exchange rates and general world inflation. The marginal cost of gas extraction is estimated from projections of remaining reserves. Based on the forecast gas prices, domestic gas supply is then estimated.

The following table summarises the variables applied to the gas supply scenarios reported in section 7.3:

Table 12 – Projected Gas Supply Scenario Parameters

		Scenarios		
Parameter	**Unit**	**High Supply**	**Base**	**Low Supply**
International oil prices	USD/barrel	132.01 – 153.66	118.44 – 132.01	107.95 – 118.44
International LNG prices	USD/GJ	19.5 – 22.80	17.5 – 19.50	15.90 – 17.50
Exchange rates	AUD/USD	$0.74 – $0.83	$0.64 – $0.73	$0.56 – $0.63
Recoverable reserves	Bcm	3,621.80 – 3,938.65	3,938.65 – 4,232.98	4,232.98 – 4,390.08
Forecasted gas prices	AUD/GJ	Reported in Appendix 6	Reported in Appendix 6	Reported in Appendix 6

***Note:** Carbon tax impacts have been considered in the modeling. Scenarios outlined in this table are developed with NIEIR and do not represent any information provided by any existing market participants.

97 Equilibrium prices cannot be directly calculated by NIEIR as the IMO was not provided all existing contracted prices and the average prices reported by DMP are a poor representative of contracted prices as it is dominated by long-term contracts. Hence, NIEIR is unable to estimate equilibrium domestic prices with any accuracy for the 2013 to 2022 period.

98 All are modeled except utilisation rate of processing plants and the marginal cost of gas extraction.

99 The minimum and maximum limits applied in the probability analysis are also thoroughly researched from other studies.

100 EISC (2011) and SKM-MMA (2011) find domestic gas prices track LNG net back prices. Net back prices exclude the costs of LNG processing and transport.

101 The weights are determined by the ratio of current production to production rate of 20 years. This means that as LNG exports increase the domestic price draws closer to the LNG netback prices. This is consistent with price changes described in the DRET's (2012), Energy White Paper 2012: "*demand competition from LNG expansion is also expected to become a more significant driver of prices, which are widely forecast to increase towards netback levels by the second half of the decade.*"

102 NIEIR estimates also show a 1% rise in the price of internationally oil prices leads to an approximate 0.6% increase in international LNG prices.

5. Current and Projected Gas Consumption

This chapter provides a snapshot of demand in the WA domestic gas market, an outline of major domestic gas consumers by sector and annual gas projections for the WA gas market for the 2013 to 2022 period.

5.1. Existing Gas Demand

WA gas consumption is typically "lumpy", with growth largely driven by the electricity requirements and fuel mix of new or expanding resource projects. These projects are usually large in scale and are characteristically tied up in long-term bi-lateral contracts with a gas supplier. Hence, the entry or exit of a large gas consumer can materially alter the consumption profile of domestic gas demand. Smaller mining or industrial gas consumers tend to be overlooked by large gas suppliers and are typically serviced by gas retailers such as Alinta Energy and Synergy.

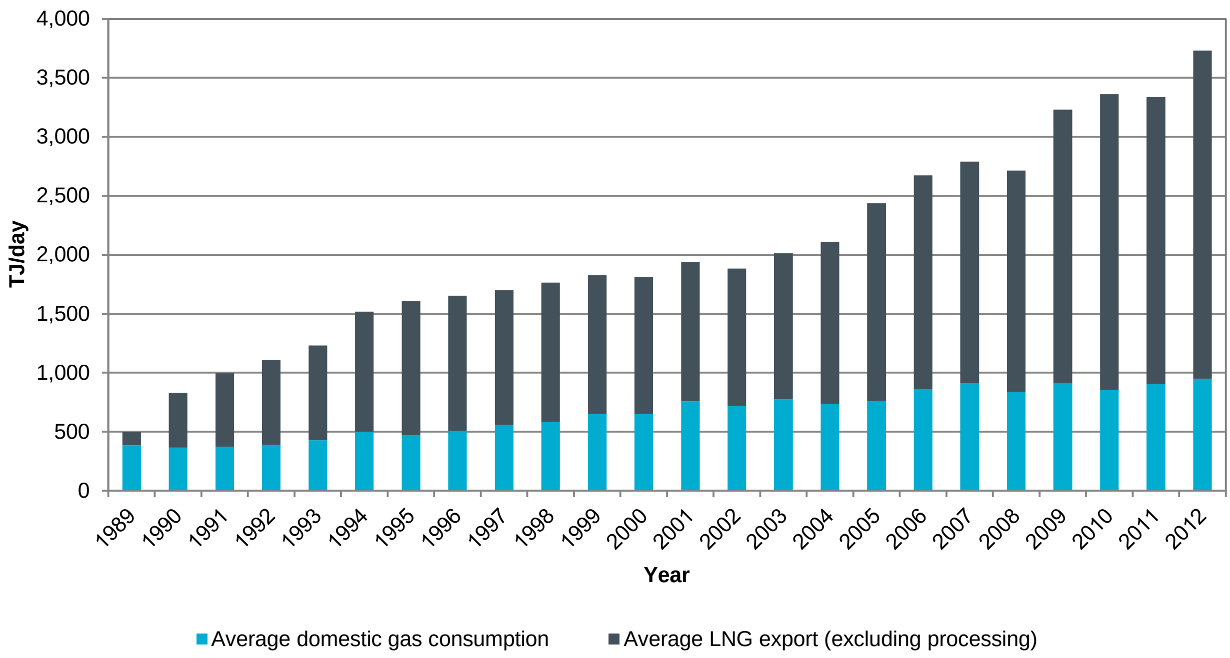
Table 13 – Annual Domestic Gas Consumption Growth, 1984-2011

	1984-1990	1991-2000	2001-2010	2007-2012
Annual compounded growth	15.71%	5.84%	1.24%	0.69%

Source: DMP (1983-2012), calculated using domestic gas sales, 1983-2011.

As shown in Table 13, according to data from DMP, between 1984 and 1990, domestic gas consumption grew rapidly before it decelerated to a growth rate of only about 0.7% per annum between 2007 and 2012. In the 1983 to 2012 period, gas consumption grew from 39 PJ in 1983 to approximately 346 PJ annually (approximately 948 TJ/day) in 2012.[103] The LNG export market however grew significantly faster than the domestic gas market from 37 PJ in 1989 to 891 PJ in 2012.

Figure 18 – Domestic Gas Demand (TJ/day, excluding petroleum processing), 1989 – 2012



Source: APPEA and DMP Petroleum Statistics (1989-2012), Gas sales and LNG. **Note:** this excludes oil and gas processing.

[103] EnergyQuest (2013) reports a similar figure of approximately 346.2 PJ/a in 2012 that translates into approximately 948 TJ/day.

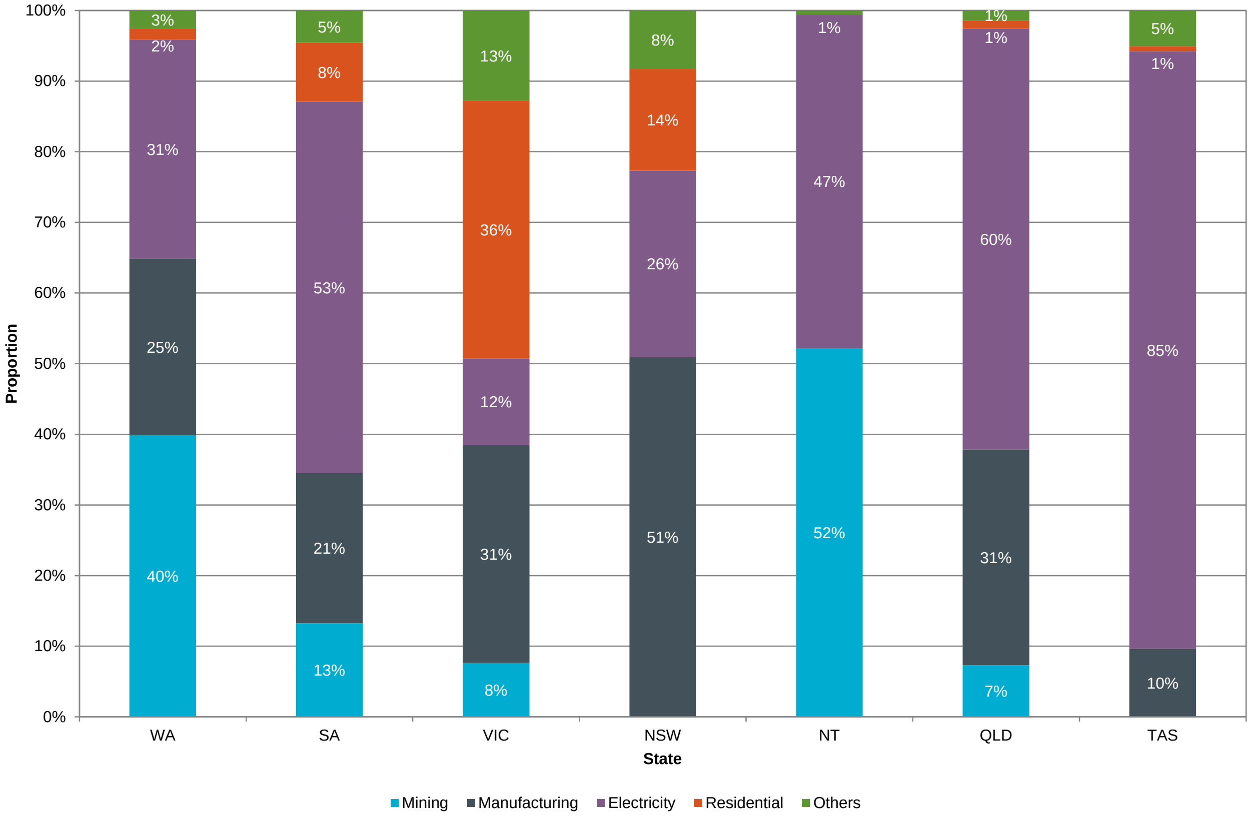
According to APPEA and DMP (Figure 18), the domestic market (in domestic sales and LNG exports, excluding oil and gas processing) in 2012 is estimated to consume approximately 3,722 TJ/day (or approximately 1,359 PJ/a).

It is anticipated by the end of 2022, changes to the domestic gas market will be significant as new sources of supply emerge, coinciding with the expiry of some legacy supply contracts and the NWS JVs' domestic supply obligation reaching fulfilment.[104]

Characteristics of Domestic Consumption

According to BREE, WA gas consumption is dominated by three sectors; electricity generation, mining (mostly electricity generation) and manufacturing (includes minerals and petroleum processing) (Figure 19). This implies that more than 65% of WA's gas consumption is related to electricity generation.

Figure 19 – Gas Demand, Australian States 2010-11



Source: Proportions derived from BREE (2012), Australian Energy Statistics Update 2012, Table F. **Note:** According to BREE, the manufacturing segment includes ferrous and non-ferrous minerals processing, iron and steel processing, petroleum (oil and gas) processing, chemicals, ceramics, glass, lime, concrete and plaster production, but does not include gas as feedstock.

At present, eight large gas customers represent approximately 90% of total gas demand in WA either through direct consumption or through resale to other end users within the domestic market.[105] Table 14 lists WA's top gas consumers:[106]

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[104] According to DSD, the obligations to supply domestic gas have been fulfilled; current gas supply from the NWS is via the exercise of contractual extension options. See chapter 10 for details.
[105] According to EISC (2011), WA's gas consumption is dominated by five large users; Alcoa Australia, Alinta Energy, BHP Billiton, Yara Pilbara and Verve Energy.
[106] At the time of this report, BHP Billiton and Apache Energy are shareholders in Pilbara mining JVs and Yara Pilbara, respectively. According to The West Australian (2013), Apache Energy is currently examining options to reduce its debt and is considering its stake in Yara Pilbara.

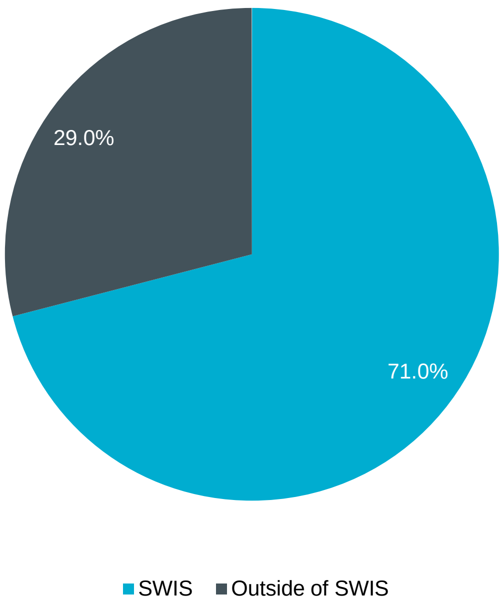
Table 14 – Estimated Market Share of Major Domestic Demand (excluding LNG industry)

Gas Purchaser/Consumer	Estimated Market Share
Alcoa	~25%
BHP Billiton and its JVs	~15%
Verve Energy	~20%
Yara Pilbara (formerly Burrup Fertilisers)	~10%
Alinta Energy	~13%
Newcrest Mining	~1 to 5%
Rio Tinto and its JVs	Unreported
Wesfarmers (including subsidiaries)	~1 to 5%
Total	**~90%**

Source: Allen Consulting (2009) and EISC (2010). ~ denotes approximate values. **Note:** Rio Tinto and Wesfarmers are also large gas consumers in WA but their share of the total gas market is not reported and is estimated. According to the EISC (2010), approximately two-thirds of the total gas use of Alcoa Australia in WA is for power generation; the remaining one-third is feedstock.

According to SKM-MMA, approximately 71% of total domestic gas consumption is in the area covered by the SWIS and approximately 29% is consumed in the area located outside the SWIS (Figure 20).[107]

Figure 20 – Estimated Proportions of Gas Demand in WA (PJ), 2011

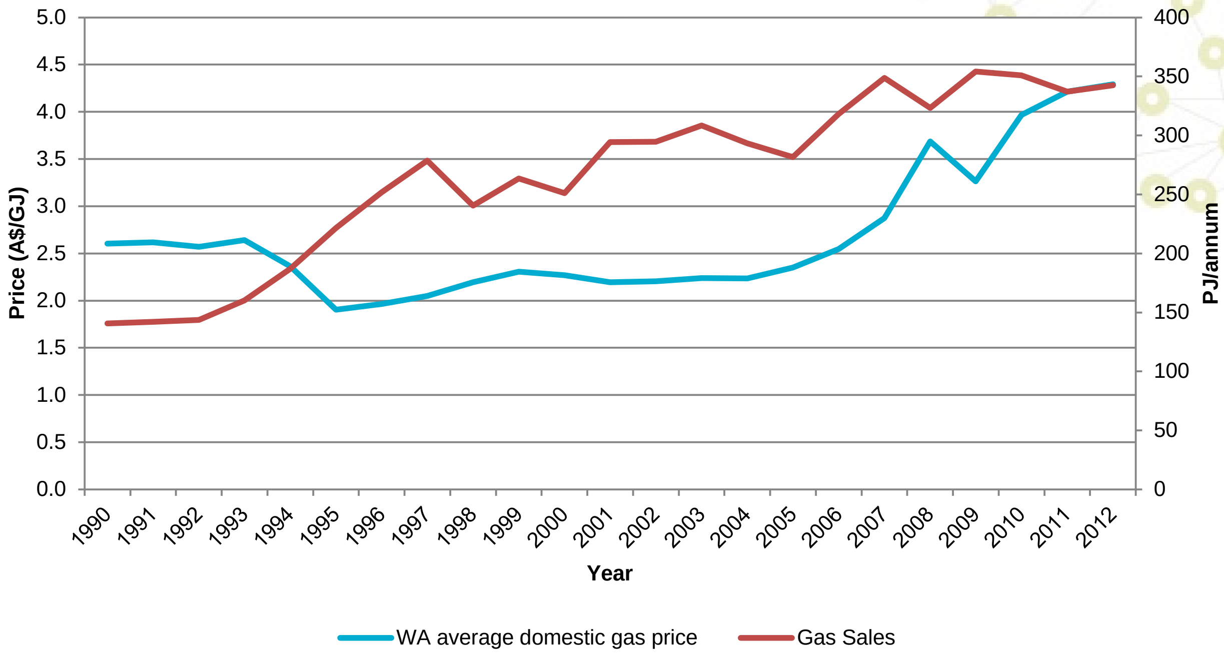


Source: SKM-MMA (2011). **Note:** Gas market proportions represented here are indicative and reliant on SKM-MMA (2011) data.

[107] Data is acquired from SKM-MMA (2011). The non-connected segment of gas consumption may grow with an increased adoption of remote LNG power generating facilities.

Elasticity of Domestic Consumption

Figure 21 – Comparison of Domestic Gas Demand against Average Domestic Gas Prices, 1990 – 2012



Source: DMP (2012), Average domestic gas prices and domestic gas sales (by volume).

Figure 21 shows domestic gas consumption is likely to be fairly inelastic. Despite a rise in the average price of gas between 1995 and 2012, domestic gas consumption continued to increase (though at a slower rate of growth). The somewhat inelastic nature of domestic gas demand may be the result of large mining and industrial customers dominating domestic gas consumption and the existence of long-term gas contracts (see Table 14 and Table 31 in section 9.1).

These gas consumers have committed and "sunk" significant financial resources into capital-intensive operations and infrastructure, are typically locked into long-term gas contracts with gas suppliers and are unlikely to react to gas price increases until the gas supply contracts start to expire. Due to the existence of these long-term gas contracts, gas price increases (see Figure 8, section 3.2) are mostly endured by new entrants to the gas consuming market and existing gas consumers renewing their gas supply contracts.

It is anticipated that as these long-term gas contracts start to approach expiry,[108] large gas consuming companies, both existing and potential, may attempt to hedge against future price rises by investing in JVs with gas exploration or gas supply companies.[109]

Electricity Generation and Domestic Gas Consumption

The Energy Supply Association of Australia (ESAA) and BREE report there is approximately 4,867 MW of gas-fired electricity generation in WA capable of consuming gas, of which approximately 2,839 MW of gas-fired generation is connected to the SWIS and 2,028 MW of gas-fired generation is located out of the SWIS area.

[108] There are at least five large contracts (>20 TJ/day) that are due for renewal before the end of 2022, of which two contracts are major gas contracts (>80 TJ/day).

[109] This has already commenced in the WA gas market with Apache Energy and BHP Billiton forming a JV to construct Macedon gas processing facility to supply gas to BHP Billiton's iron ore operations. Alcoa has also farmed into and provided capital for Empire Oil and Gas' gas fields and Red Gully processing facility and farmed into Latent Petroleum's Warro project and also signed conditional gas contracts with Buru Energy. Fortescue Metals Group also considered purchasing a stake in Oil Basins Limited in 2012.

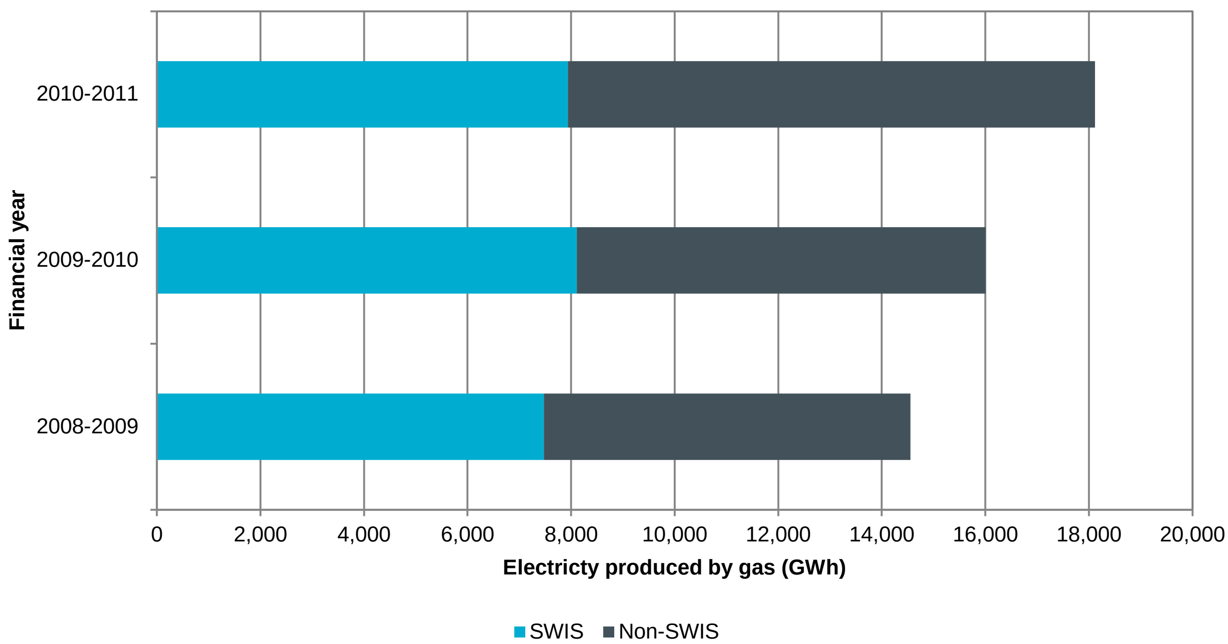
Table 15 – Gas Fired Electricity Generation, 2010-2011

Electricity Generation Capacity	(SWIS) MW	(outside the SWIS) MW
Steam	268	Not Stated
Open Cycle Gas Turbine	1,891	Not Stated
Combined Cycle Gas Turbine	680	Not Stated
Total	**2,839**	**2,028**

Source: ESAA (2013), *Electricity Gas Australia 2013*. These SWIS figures differ slightly from those reported in ESAA (2013) as Perth Energy's Kwinana's Swift Power Station was wrongly classified as a combined cycle gas turbine in the report. See http://www.perthenergy.com.au/index.php/about-perth-energy/western-energy. **Note:** Figures include LNG powered electricity generation.

BREE reports for the 2010-2011 financial year, natural gas was used to generate a total of 18,115.7 GWh of electricity for the whole of WA. Applying the IMO's data on electricity fuel type for sent out energy for the SWIS in the 2010-2011 period, it is estimated approximately 44%[110] of total gas-fired electricity generated in WA was generated within in the SWIS (approximately 7,936 GWh), with the remainder generated outside the SWIS area.

Figure 22 - Gas Demand for Electricity Generation in WA (GWh), 2008-2009 to 2010-2011



Source: IMO Estimates. The breakdown between SWIS and non-SWIS is estimated by taking the difference between BREE's (2012) Australian Energy Statistics, Table O Figures and IMO sent out generation data. **Note:** SWIS gas generation figures may not correspond to figures outlined in IMO's ESOO published in June 2013 as sent out generation has been adjusted to financial year end.

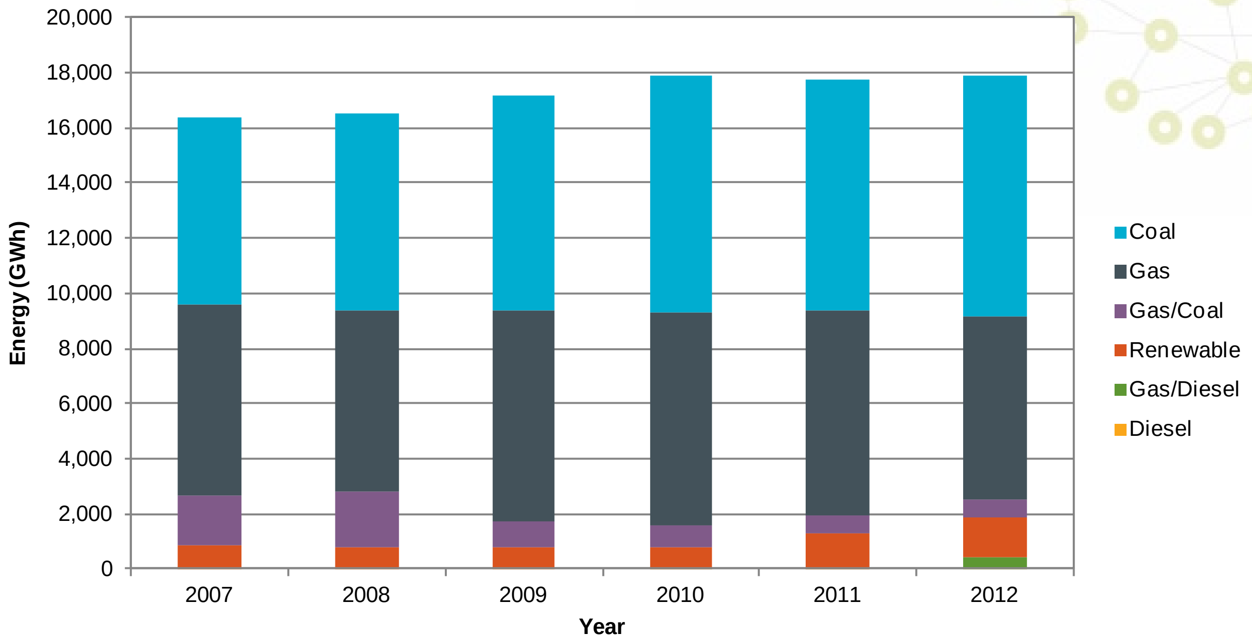
Figure 22 shows that gas consumption by gas-fired electricity generation for areas outside the SWIS is growing more rapidly than areas that comprise the SWIS in the 2008 to 2011 period. Areas outside the SWIS are more reliant on gas-fired generation (where it is available) as the available fuel substitutes for electricity generation, generally oil or diesel, have significantly higher costs per gigajoule than gas.

The SWIS has a more diverse fuel mix, shown in Figure 23, with gas-fired generation declining since 2009. Figure 23 shows the total sent out electricity for each fuel type for each calendar year since the commencement of the WEM. The rate of growth in SWIS electricity demand has slowed considerably in

[110] Note this is only an estimate. It is assumed that electricity generated from Gas/Coal and Gas/Diesel plants within the SWIS generates 50% and 90% of their electricity, respectively by gas.

recent years, dampened by the sharp increases in electricity tariffs, the effects of the GFC, the growth in small-scale photovoltaic systems and the increasing impact of energy efficient appliances, energy efficiency programmes and public awareness campaigns that are changing consumer behaviour.

Figure 23 – Energy Generation by Fuel Type (SWIS), 2007 – 2012



Source: IMO. **Note:** Figures are calculated from October to September of each year. **Note:** Diesel is a very small component of SWIS generation due to the higher cost of diesel relative to other fuels.

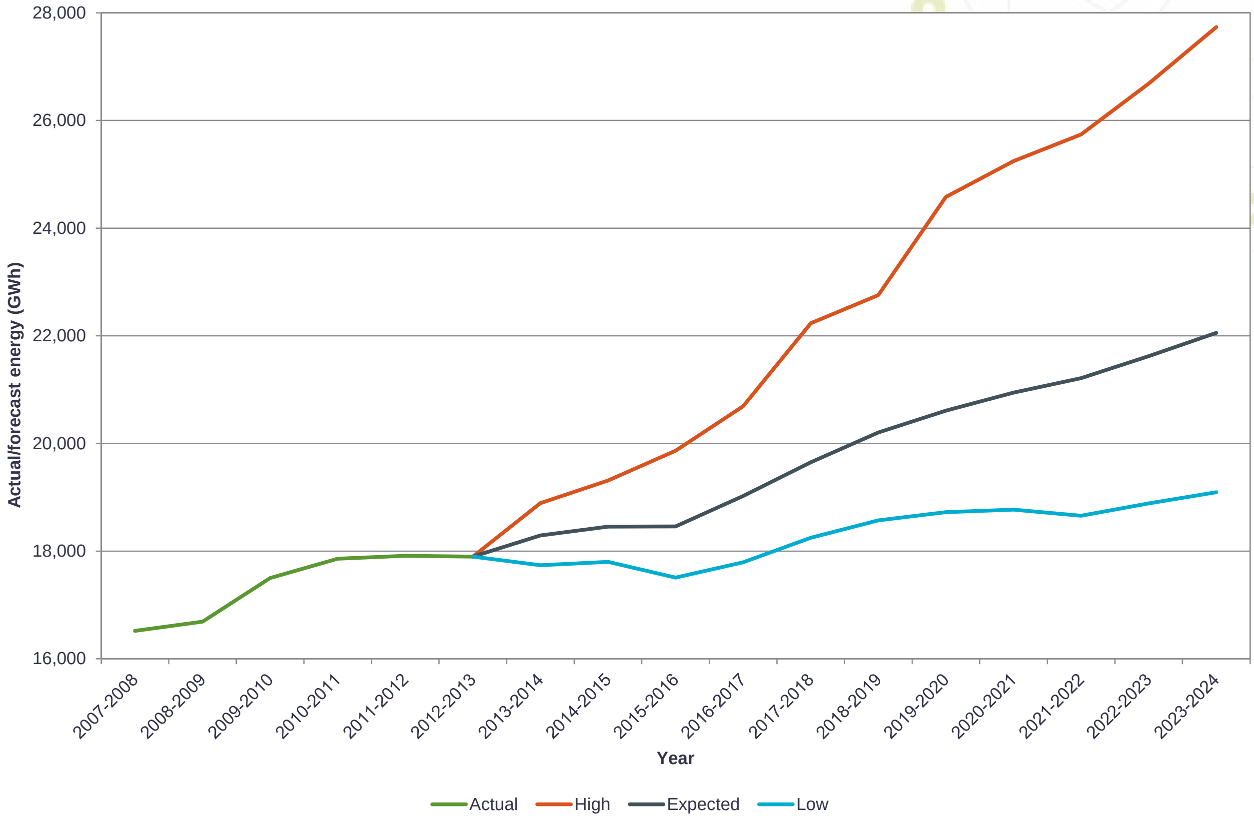
In addition, gas has been displaced in recent years by other generation fuels in the SWIS:

- Coal-fired generation has increased by 28% since 2007, predominantly due to the completion of the Bluewaters Power Station in 2009. Coal-fired generation would be expected to increase in the near term with the refurbishment of the Muja AB facilities (two of the four units, 55 MW each, are operational as at July 2013), but may decrease from 2016 following the planned decommissioning of the Kwinana C power station (361.5 MW).[111]
- Renewable generation, aided by incentives such as the Commonwealth Government's Renewable Energy Target scheme, has increased by 75% since 2007 to represent more than 8% of total sent out electricity at the wholesale level in 2012. As reported in the 2013 ESOO, significant new investment is expected in renewable generation in Australia to meet a projected shortfall in large-scale generation certificates from 2016 onwards.[112]

The IMO's forecasts of SWIS electricity demand, published in the ESOO, are shown in Figure 24 below. Total sent out electricity is forecast to grow at an average rate of 1.9% per annum over the next 10years, although growth is anticipated to be slow in the near term due to declining growth in the WA economy and the continued impact of electricity tariff increases. Under the High economic growth scenario, sent out electricity is forecast to grow at 3.9% per annum, while in the Low economic growth scenario it is forecast to increase at 0.7% per annum on average.

[111] The facility capacities represent the Capacity Credits allocated to those facilities.
[112] Available at http://www.imowa.com.au/soo. See Section 8.9.1 of the ESOO.

Figure 24 – SWIS Electricity Demand Forecasts 2007-2008 to 2023-2024



Source: IMO. **Note:** Figures are calculated from October to September of each year.

While gas-fired generation may continue to be displaced by coal-fired and renewable generation in the SWIS in the near term, the flexibility and fast response time of gas-fired generators suggests that they will continue to play an important role in the SWIS over the coming decade.

5.2. Projected Gas Demand

A plethora of studies have attempted to project WA's future gas consumption.[113] Most of these studies conclude that domestic gas consumption is rising steadily, with this trend anticipated to continue in an unconstrained fashion.

Notwithstanding some displacement of gas by an increased interest in renewable energy, past trends and the continued interest in the development of new resource projects located outside the SWIS suggests gas consumption in WA will continue to rise as a fuel for electricity generation.

Projected Demand

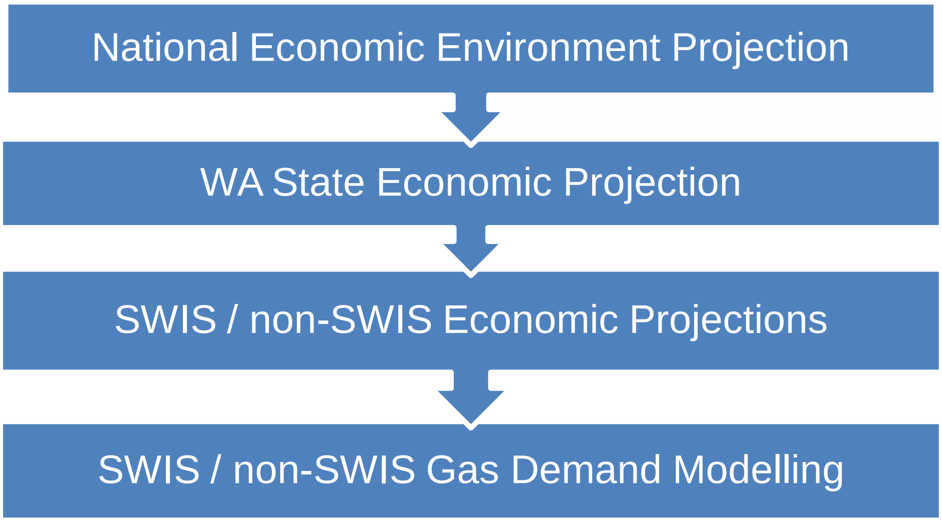
A review of domestic gas consumption and the WA economy suggests that changes in domestic gas demand for the 2013 to 2022 period are expected to be driven by the future prospects (and energy needs) of the mining and LNG sectors, which are led by the future prices of these commodities. Nevertheless, future gas demand for will remain "lumpy" and will be heavily dependent on the size and completion timeframes of

[113] Studies that have projected future gas scenarios include Chamber of Commerce and Industry WA (2007), Synergies Economic Consulting (2007), ECS (2007, 2008, 2010), CMEWA (2008, 2011, 2012), Department of Mines and Petroleum (DMP) (2010, 2011), Wood Mackenzie (2010), EnergyQuest (2010, 2011), EISC (2011), SKM MMA (2011) and ACIL Tasman (2011).

individual projects in these sectors. Future gas demand for the SWIS is vastly different to areas outside the SWIS, which has been also taken into account.

To develop a good representation of future gas demand in WA, NIEIR developed a top-down approach to estimating WA's future gas demand that complements NIEIR's energy forecast model for the SWIS.

Figure 25 – NIEIR's Gas Forecasting Methodology



Source: NIEIR

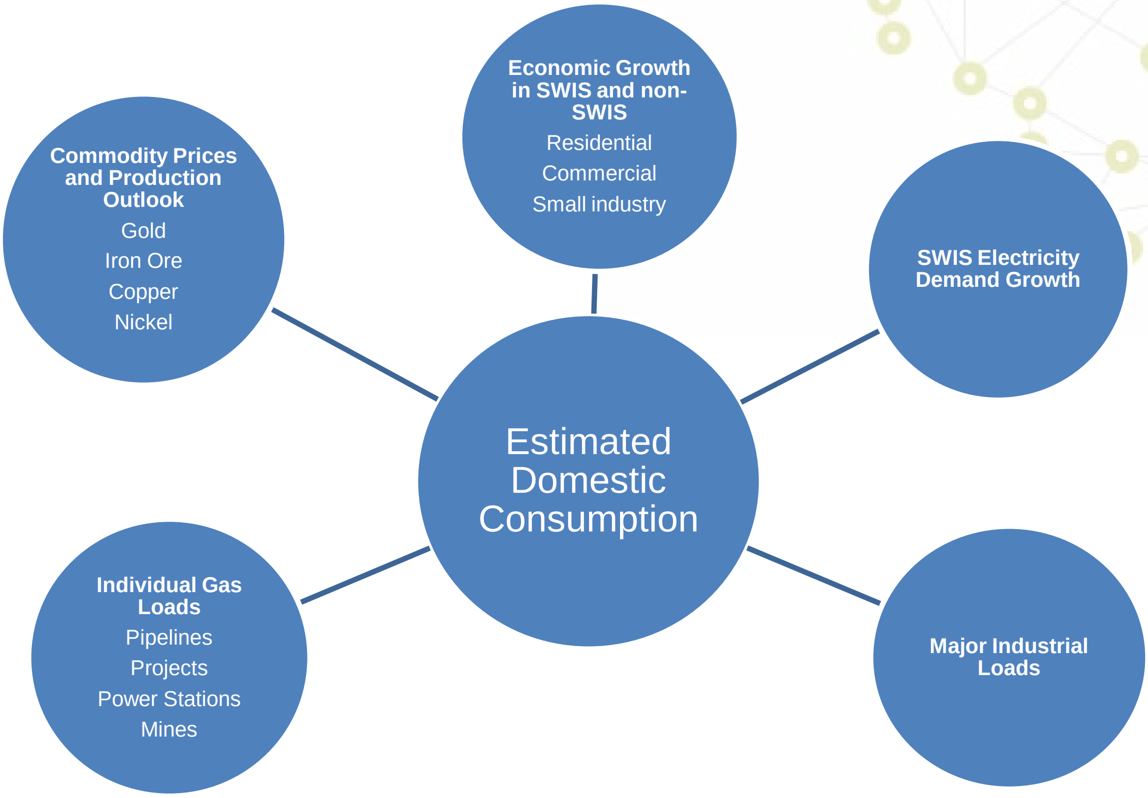
Figure 25 shows the relationships between the major components of NIEIR's integrated modelling systems applied to the domestic gas market. NIEIR's method essentially bases its gas demand forecasts on the projected macroeconomic environment and market structure of WA.

The core tool applied by NIEIR is its national econometric model of the Australian economy. This model provides projections of national economic growth using inputs from various statistical sources including the ABS and the Australian Taxation Office.

These national economic projections are then used as inputs into a State economic projection model which provides an estimate of GSP and other indicators. The State model is then further disaggregated into the statistical subdivisions that make up gas demand areas served by the SWIS and outside the SWIS.

Once energy consumption forecasts for each industry sector are developed, projected gas demand is then estimated from these forecasts for the SWIS and areas located outside the SWIS using several econometric forecasting modules. Figure 26 provides a summary of the components that constitute the domestic gas consumption forecasts for the 2013 to 2022 period (excluding gas consumption for petroleum processing).

Figure 26 – Gas Demand Projection Methodology



Source: NIEIR

The advantage of NIEIR's approach is that it links gas demand forecasts directly to WA's industry structure, expected industry sector outputs, capital stocks, dwellings formation numbers and population for WA that are driven by projections of population growth, dwelling stock composition and industry growth by sector. NIEIR's forecasting system also links WA's regional economic forecast with gas use based on assumptions about gas use efficiency and major industrial gas usage.

As the GBB only commences in August 2013, there is currently limited WA gas consumption data available to further develop the gas demand forecast model. Hence, development of the model has relied on historical gas transmission data provided by pipeline operators to the IMO. NIEIR was unable to provide a more detailed pipeline by pipeline forecast due to the limited availability of gas transmission data.

Projects that Contribute to Future Gas Demand

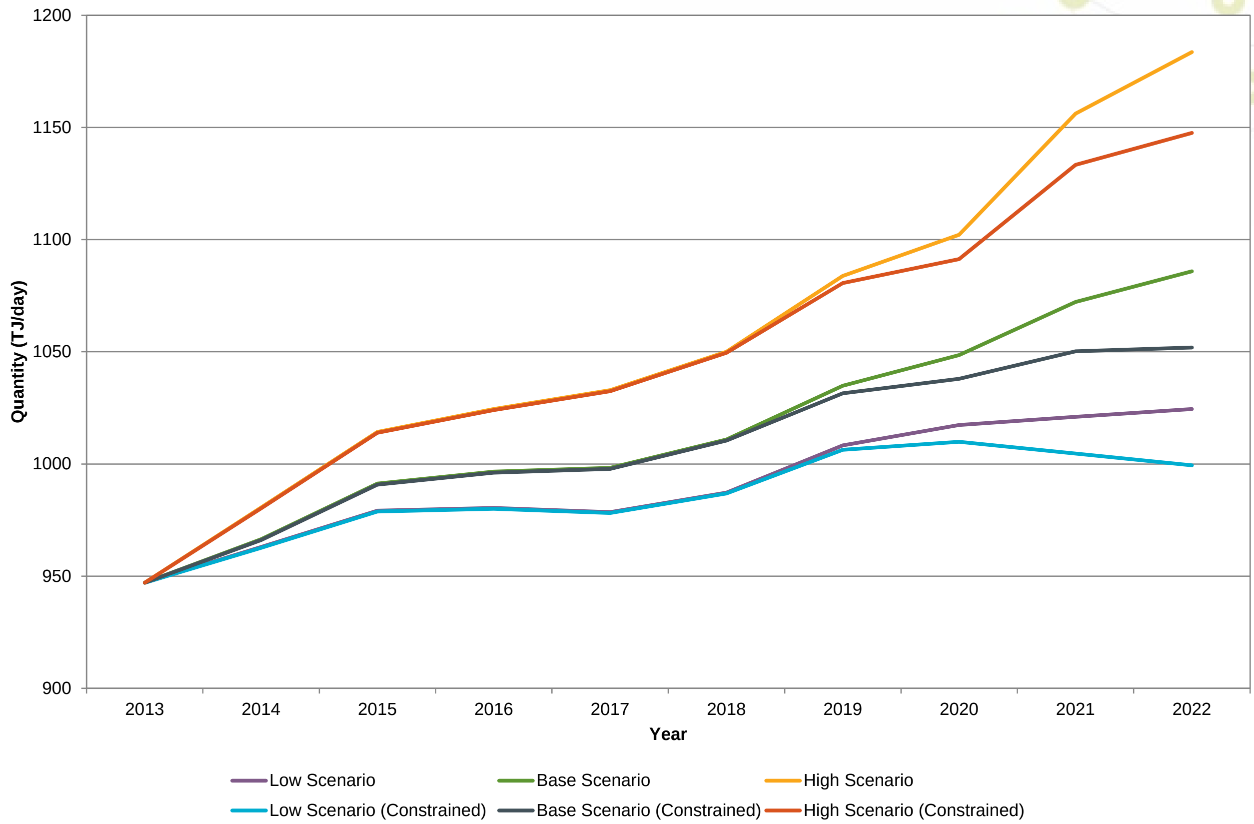
A significant proportion of projected demand growth comes from new and existing industrial and mining projects. Appendix 3 lists those projects that are included in WA's gas demand forecast in the 2013 to 2022 period. As noted in the previous chapter, for this GSOO, only projects that have acquired FID are considered in the gas demand projections for 2013 to 2022.

Projected Domestic Gas Demand

As outlined in section 4.4, the underlying economic assumptions are the key drivers to gas consumption forecasts. Forecasts associated with High or Low economic growth conditions are provided as a guide to the variability in outcomes that could be anticipated.

Figure 27 presents NIEIR's gas demand forecasts for the 2013 to 2022 period. NIEIR's demand forecasts are characterised by unconstrained and constrained demand. Unconstrained gas demand represents gas demand forecasts that are not price sensitive, while constrained demand takes into account the impact of projected gas prices (reported in Appendix 6) on future gas demand.[114] These gas demand forecasts are provided in Appendix 4.

Figure 27 – Actual and Projected (Constrained and Unconstrained) Gas Demand for WA, 2013 – 2022



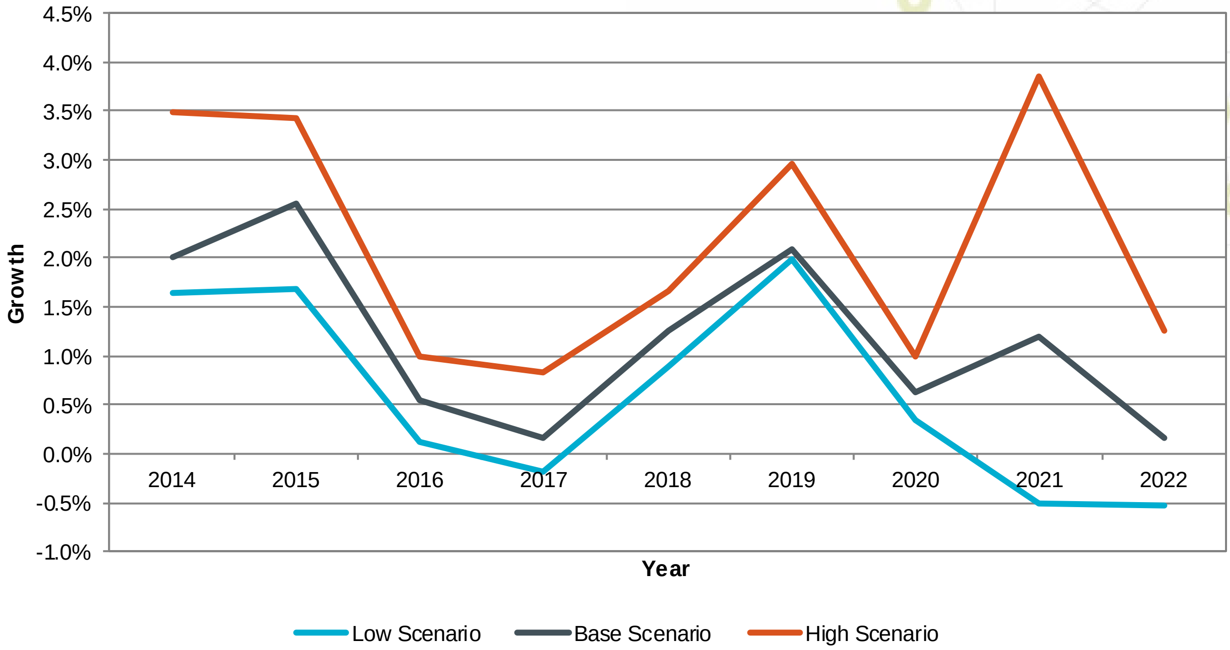
Source: NIEIR Forecasts 2013-2022. **Note:** Demand forecasts include projected gas demand along the proposed BAP from 2015.

Over the 2013 to 2022 period, constrained domestic gas consumption is forecast to grow on average by 1.1% per annum from approximately 947 TJ/day (346 PJ/annum) to about 1,052 TJ/day (384 PJ/annum) by the end of 2022. Under the High gas demand scenario, the growth in unconstrained gas consumption is forecast to be approximately 1.9% (to 1,147 TJ/day or 419 PJ/annum), while in the Low gas demand scenario, gas consumption is forecast to increase at an annual compound rate of 0.5% (to 999 TJ/day or 365 PJ/annum).

Scenario analysis of the assumptions on gas demand shows that if conditions similar to the High gas demand case are experienced up to 2022, constrained gas demand growth is forecast to be approximately 35 PJ (9.1%) higher than for the Base case. If gas demand growth is more aligned with the Low scenario, the gas demand is forecast to be approximately 19 PJ lower than the Base case.

[114] While pipeline capacity may be a potential constraint on future gas demand, pipeline capacity was not found to be a an obstacle to the development of these forecasts.

Figure 28 – Projected Gas Demand Growth Rates (Constrained), 2014 – 2022



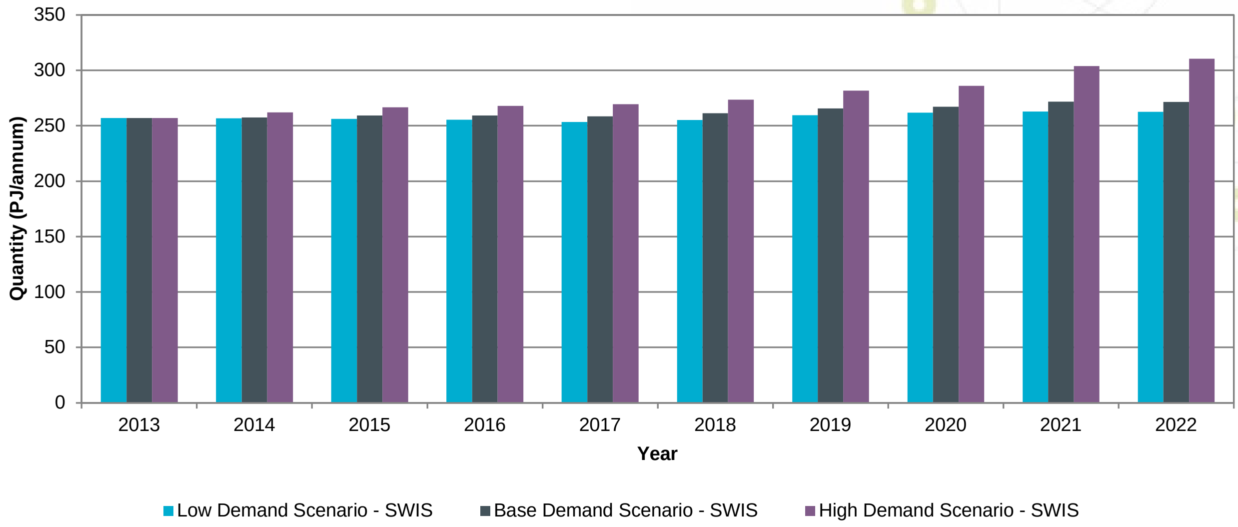
Source: NIEIR Forecasts 2013-2022.

Figure 28 presents the year-on-year growth rates of the constrained gas demand forecasts for the 2013 to 2022 period for all three scenarios. For all scenarios, the forecasts predict gas demand growth will remain strong in 2014 and 2015 before slowing down in 2016 and 2017 and then recovering towards the end of the forecast period. The variation is mainly driven by the economic projections for WA that predict business (in particular mining) investment will decline in the 2015-16 financial year prior to moderately recovering in 2018. The only exception is the Low scenario, where gas demand is projected to fall between 2021 and 2022.

Figures 29 and 30 present the breakdown of gas demand forecasts by SWIS and non-SWIS areas. The forecasts show future gas consumption is expected to grow more rapidly in the non-SWIS areas of WA especially within in the Pilbara, Mid-West and Goldfields regions that will be driven by mining expansions.

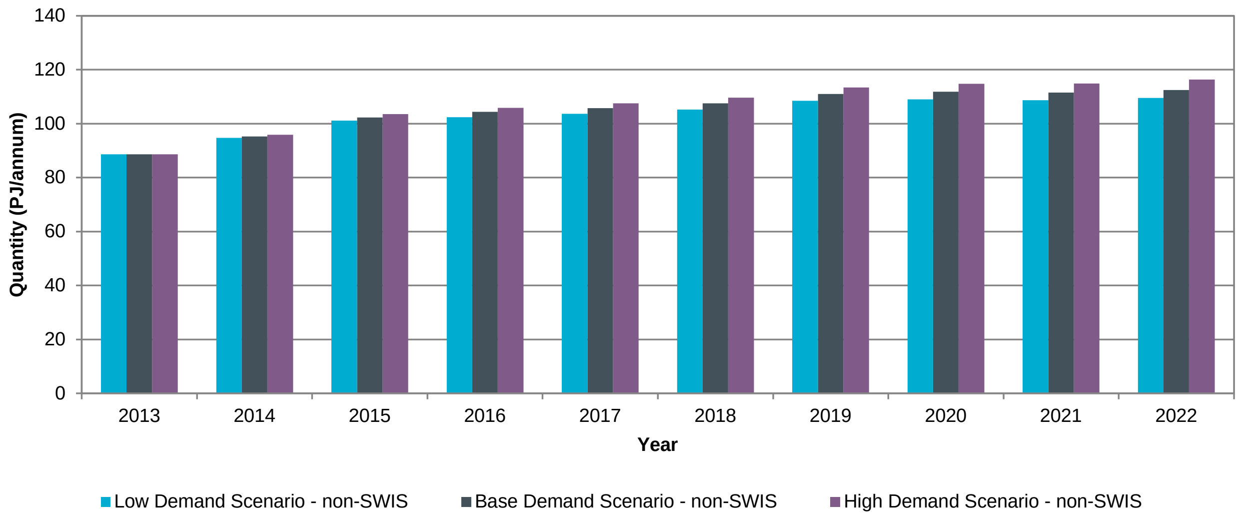
Figures 29 and 30 shows gas demand for the SWIS is forecast to grow from approximately 257 PJ/annum to 273 PJ/annum (0.5% per annum) for the Base demand scenario. Under the High gas demand scenario, the growth in constrained gas consumption is forecast to be approximately 1.9% (to about 311 PJ/annum), while in the Low gas demand scenario, gas consumption growth is forecast to be almost flat (to about 263 PJ/annum) in 2022.

Figure 29 – Comparison of Forecasted Constrained SWIS Demand across Different Scenarios, 2013 – 2022



Source: NIEIR Forecasts 2013-2022.

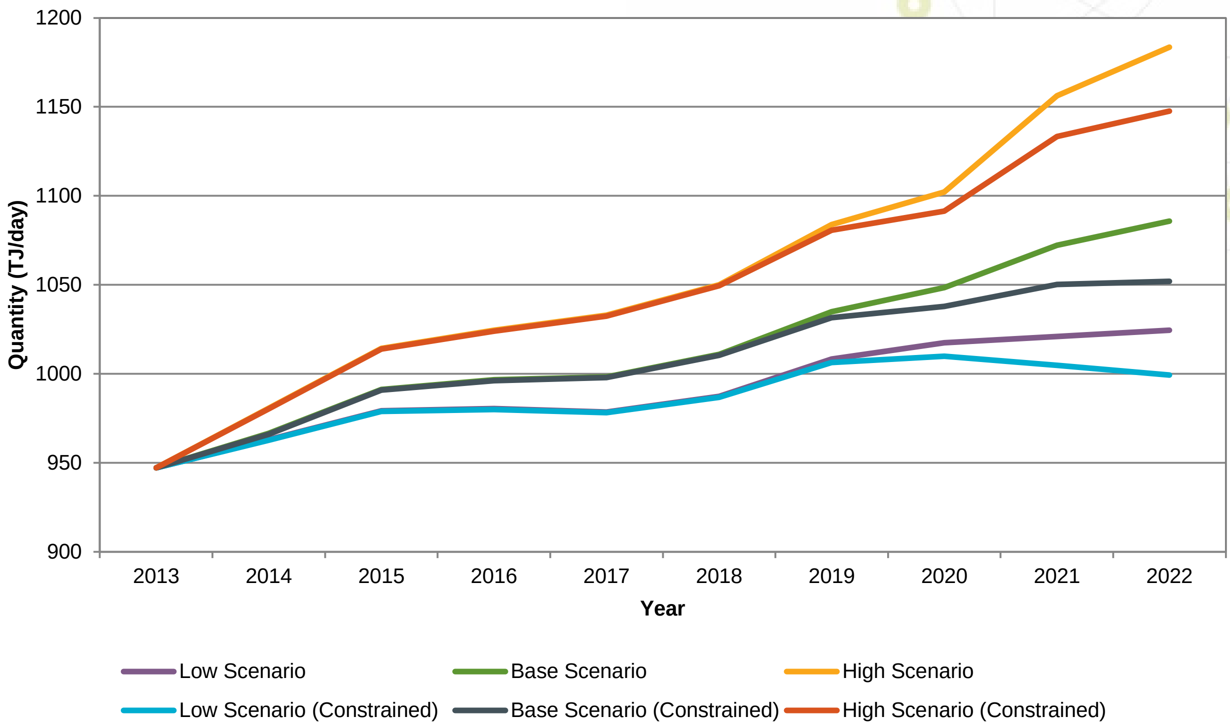
Figure 30 – Comparison of Forecasted Constrained Non-SWIS Demand across Different Scenarios, 2013 – 2022



Source: NIEIR Forecasts 2013-2022.

For areas outside the SWIS, Figure 30 shows gas demand is forecast to grow from approximately 89 PJ/annum to 113 PJ/annum (at 2.4% per annum) by the end of 2022 in the Base scenario. Under the High gas demand scenario, the growth in constrained gas consumption is forecast to be approximately 2.8% (to about 116 PJ/annum), while in the Low gas demand scenario, gas consumption is forecast to grow at an annually compounded rate of 2.1% (to about 110 PJ/annum). Gas demand forecasts by region are provided in Appendix 4.

Figure 31 – Comparison of Forecasts of Constrained Gas Demand against other Demand Forecasts, 2013 – 2022

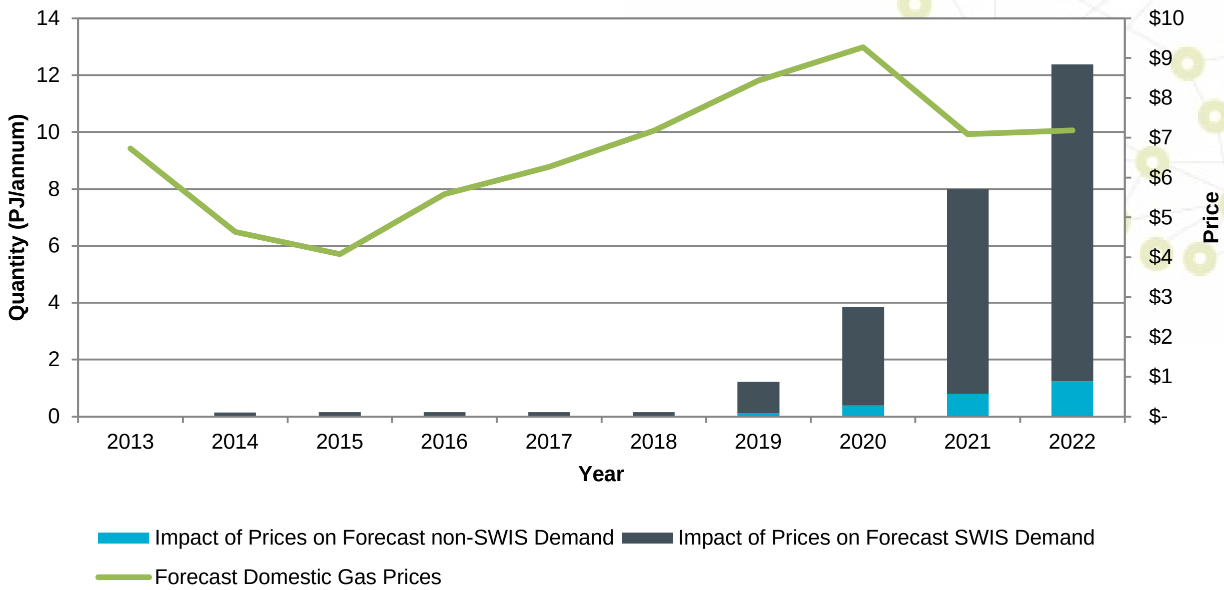


Source: NIEIR Forecasts 2013-2022. **Note:** Demand forecasts include projected gas demand along the proposed BAP from 2015.

Figure 31 reveals that NIEIR's constrained demand forecasts for the High demand scenario are almost identical to BREE's projected annual compounded growth rate of approximately 2.2% per annum.[115] In addition, NIEIR's constrained Low demand forecasts are consistent with the compounded growth rate in the 2003 to 2012 period of approximately 1.1% per annum, except for the 2020 to 2022 period, indicating NIEIR's gas demand forecast for the Low scenario is slightly more conservative than the historical 10-year growth rate. As the constrained Base demand scenario is closer to the Low demand scenario, this comparison suggests NIEIR's Base demand forecasts may also be conservative.

[115] BREE's growth rate was reported in BREE (2012c).

Figure 32: Demand suppression due to Forecast Prices on SWIS and non-SWIS Demand 20132022



Source: NIEIR Forecasts 2013-2022

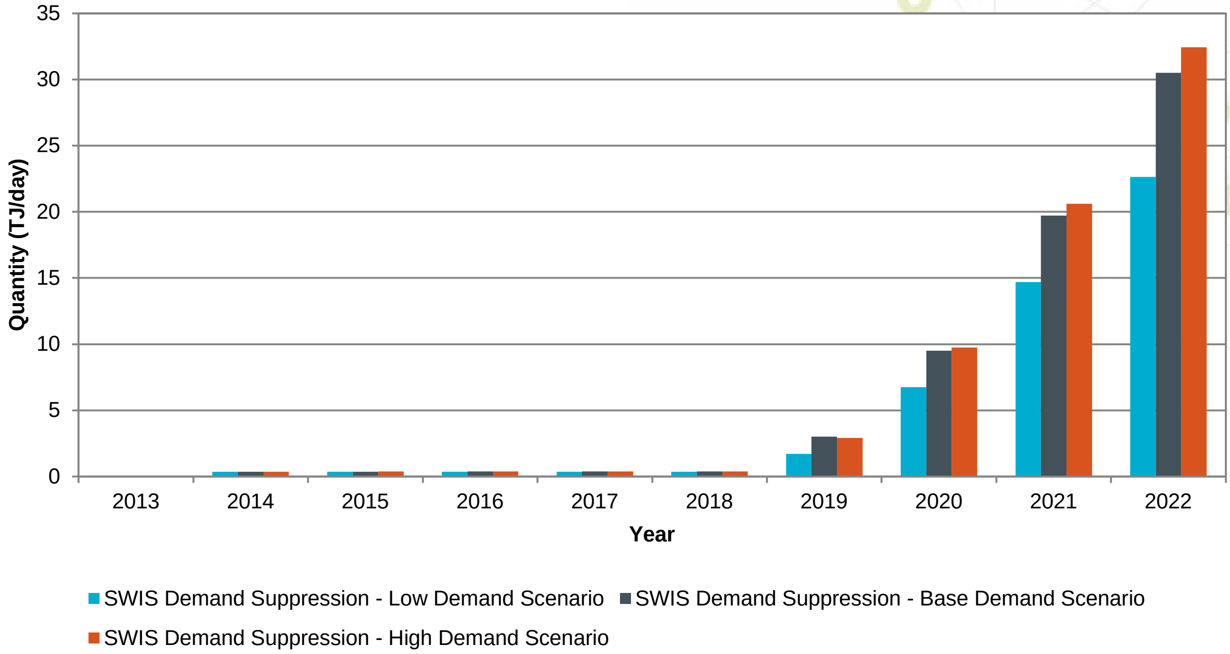
Figure 32 also reflects an expectation that the impact from changes in gas prices will be lagged, showing the drop in gas demand (relative to the unconstrained case) is not immediate. Figure 32 shows as forecast gas prices rise from 2015 to 2020, forecast gas demand does not start reducing until 2019. A key factor supporting this assumption is the existence of long-term gas contracts in the domestic market.

The majority of demand suppression is predicted to come from areas that comprise the SWIS. This is as gas consumers within the SWIS have greater access to competing fuel sources and energy supply options, meaning gas consumers within the SWIS are more likely to consider other options for their energy needs.

Gas demand suppression from higher gas prices for areas located outside the SWIS is expected to be minimal as there are frequently no cheaper alternatives to gas consumption. The reduction is likely to be the result of more efficient use of gas through minor upgrades or lowered production.

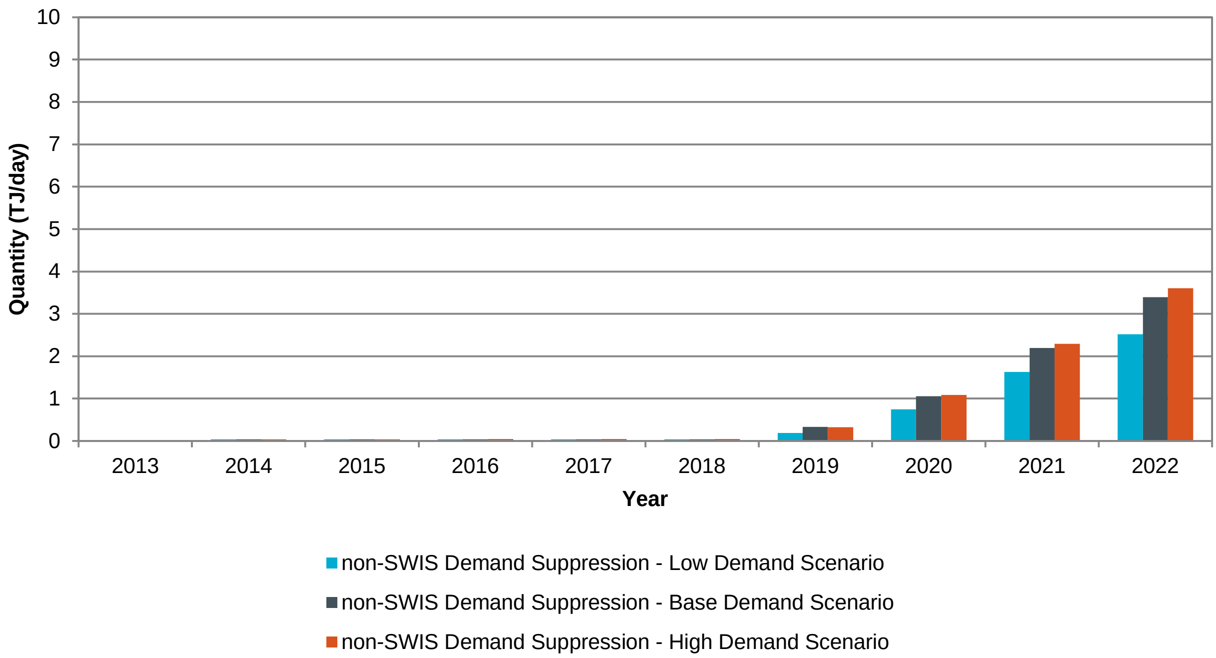
On the corollary, the demand suppression results may also be viewed as an opportunity for gas suppliers to increase gas sales in WA. Figures 33 and 34 represent potential additional gas demand that may be realisable if future gas prices are lower than NIEIR's gas price forecasts.

Figure 33 – Demand Suppression due to Forecast Domestic Gas Prices (SWIS), 2013 – 2022



Source: NIEIR Forecasts 2013-2022.

Figure 34 – Demand Suppression due to Forecasted Domestic Gas Prices (Non-SWIS), 2013 – 2022



Source: NIEIR Forecasts 2013-2022.

Figures 33 and 34 show the demand suppression impacts of gas prices reported in Appendix 6 for areas that comprise the SWIS and areas outside the SWIS under each of the Base, High and Low scenarios. The results show that as domestic gas prices increases between 2015 and 2020, gas demand falls towards the end of the 2013 to 2022 period.

Projected Total Gas Demand (Domestic and LNG)

In addition to projecting gas demand for the domestic market, NIEIR in conjunction with the IMO also developed gas demand scenarios for WA's LNG sector to develop forecasts of total WA gas demand.[116] The applied assumptions for each scenario for LNG are outlined in Table 16.

Table 16 – Scenarios applied to LNG Facilities in WA, 2013-2022

	Scenarios		
Parameters	**Low**	**Base**	**High**
LNG feedstock requirements	Only LNG facilities that have been approved. Gorgon LNG commences (15.2 Mtpa) in 2015, Wheatstone LNG commences (4.45 Mtpa) in 2016, and completes (4.45 Mtpa) train 2 in 2017.	Encapsulates assumptions in Low scenario and Gorgon LNG expands (5.2 Mtpa) in 2019.*	Includes assumptions in Low scenario and Gorgon LNG expands (5.2 Mtpa) in 2018*, Wheatstone LNG expands (4.5 Mtpa) in 2020 and Pluto LNG expands (2.2 Mtpa) in 2021.
LNG processing requirements	8% of total LNG feedstock	8% of total LNG feedstock	8% of total LNG feedstock

Source: IMO and NIEIR's assumptions. Due to escalating costs of constructing LNG facilities in Australia, the scenarios only consider expansion of existing brownfields facilities. **Note:** The scenarios only represent the best estimate of the future LNG market in WA and do not represent any confidential information provided by existing or potential LNG market participants. The scenarios only consider onshore LNG and do not consider floating LNG requirements. Processing estimates are simply assumed by taking the low range of processing estimates outlined in the book, *LNG: A non-technical guide*. *According to Reuters, http://finance.yahoo.com/news/chevron-targets-australia-lng-expansion-040156450.html, Chevron is considering expanding the Gorgon LNG plant despite cost pressures.

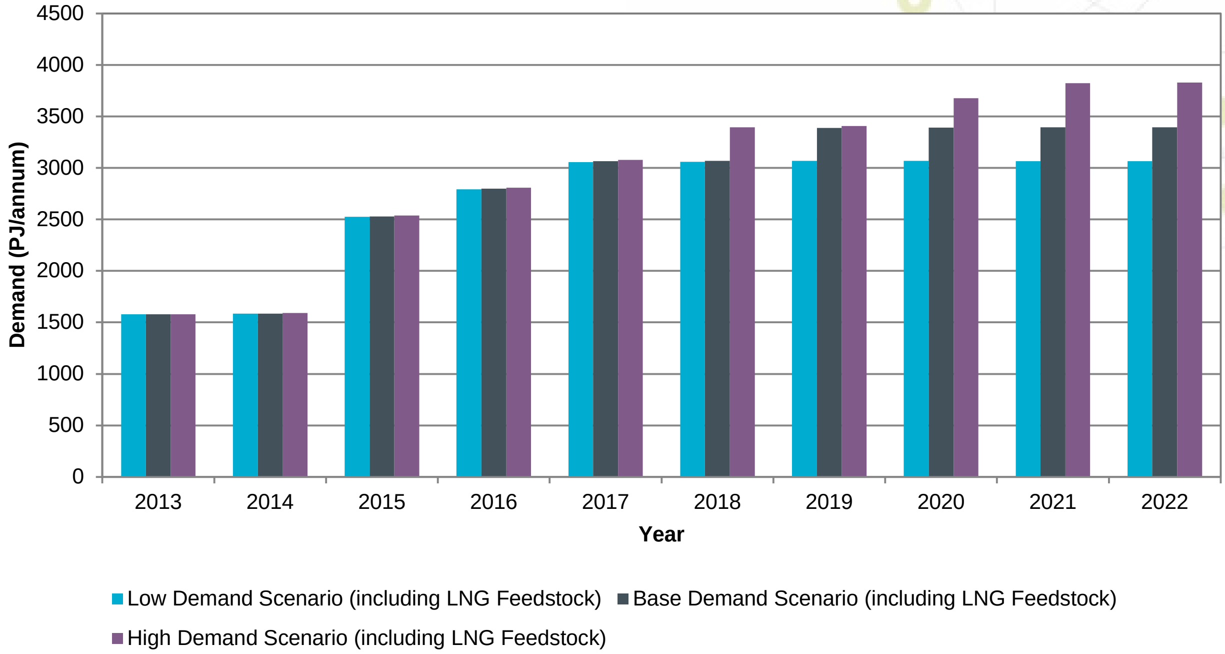
Figure 35 presents the forecasts of total gas demand for the Low, Base and High gas demand scenarios for the WA LNG market. Total gas demand is the sum of forecast domestic gas demand reported in Appendix 4 and forecast LNG requirements provided in Appendix 8.

Due to the fairly optimistic projections of the international gas market outlined in chapter 7.3, both the Base and High demand projections include expansions to existing LNG plants, while only in the Low demand scenario, is it anticipated that existing LNG plants will not expand LNG output.

Under the Base gas demand scenario, NIEIR forecasts total gas demand in WA (constrained domestic demand and the LNG industry) is anticipated to grow at an annual compounded rate of approximately 8% from an estimate of 1,579 PJ/annum in 2013 to about 3,395 PJ/annum in 2022 (Figure 35), while the Low demand scenario projects that total gas demand will grow at an annual compounded rate of approximately 6.9% per annum to about 3,065 PJ/annum in 2022. The High gas demand scenario (including LNG feedstock) projects that demand will grow at an annual rate of 9.3% per annum to about 3,828 PJ/ annum.

[116] The projections do not include gas consumed in processing petroleum or gas feedstock required for FLNG projects.

Figure 35 – Forecasted Total Gas Demand (Domestic and LNG), 2013 – 2022



Source: NIEIR Forecasts 2013-2022.

6. Liquefied Natural Gas Market

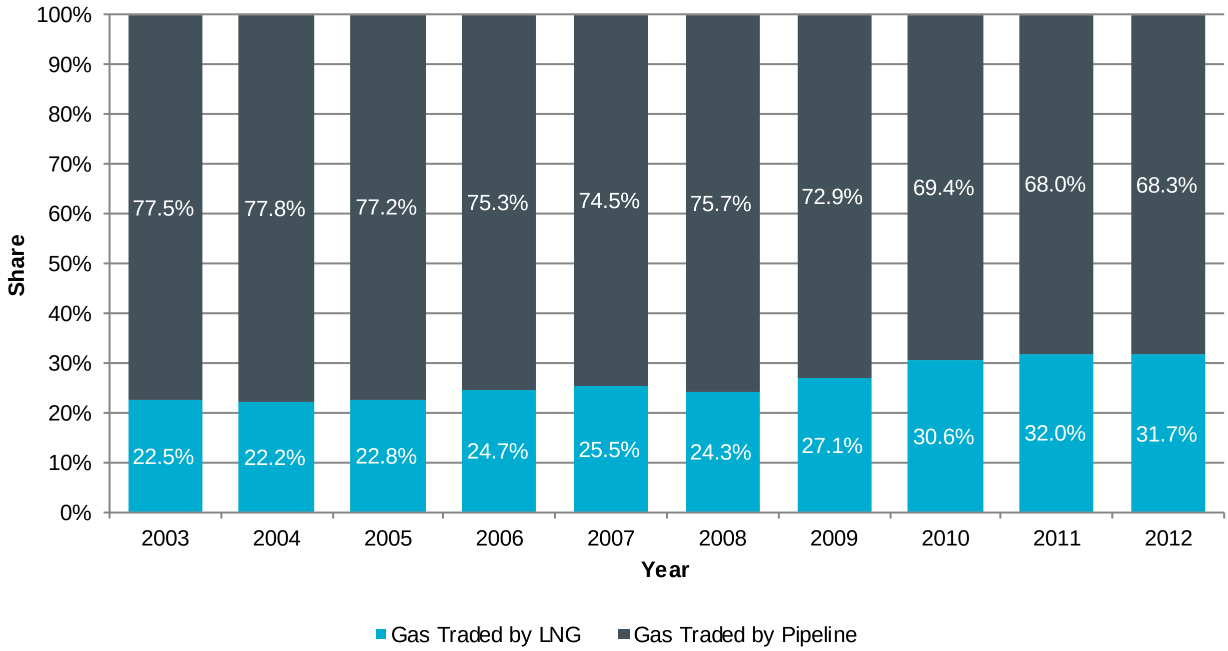
The influence of the LNG market on WA's domestic market is unquestionable.[117] Events in the international gas market (especially the LNG market) have implications for the domestic gas market. This chapter reviews the existing and potential buyers of WA's LNG and also presents some commentary on various competitors and risks to the WA LNG export market for the 2013 to 2022 period.

6.1. The International LNG Market

The international gas market is currently anticipated to experience an extended growth phase, due to the rapid industrialisation of China and India coinciding with policies in various countries attempting to curb environmental pollution and greenhouse emissions.[118] According to the International Energy Agency (IEA), international gas demand for electricity generation is expected grow at an average rate of 2% per annum from a share of 21% of the global energy mix to 25% by 2035, overtaking coal in 2030.[119] This promising outlook for international gas demand was referred to by the IEA as the "Golden Age of Gas".[120]

International gas trade currently occurs via international gas pipelines or seaborne LNG ships. According to BP's Statistical Review of World Energy 2013, pipeline gas trade accounts for approximately 68.3% of international gas trade, while LNG accounts for 31.7% in 2012 (Figure 36).

Figure 36 – Segments of the International Gas Market, 2003 – 2012



Source: ENI (2012), World Oil and Gas Review 2012 and BP (2012-2013), Statistical Review of World Energy.

As shown in Figure 36, international shipments of LNG are gaining preference over pipeline gas which may be due to their flexibility; with LNG exporters able to redirect LNG cargoes to address varying international preferences and seasonal demand.

[117] The EISC (2011) reports domestic gas prices have persistently reached or exceeded LNG net back prices.
[118] The United Nations treaty to limit the production of greenhouse gases, the Kyoto Protocol, applies to nearly 200 international countries and was extended to 2020 in December 2012, the European Union (EU) introduced its emissions trading scheme in 2005 and Australia introduced the carbon price on 1 July 2012.
[119] This figure was updated in IEA (2012) to 1.6% growth per annum to 2035.
[120] A special report by the IEA (2011), it suggests the world has entered a Golden Age of Gas and forecasts continued growth of international gas demand for the period 2011 to 2035.

The international LNG market effectively commenced when Algeria began exporting LNG to the United Kingdom in 1965 and expanded subsequently with US LNG exports to Japan in 1969.[121] This created three distinct regions that are commonly used to describe the international LNG market, the American, European (typically including Eurasia and the Middle East) and Asia Pacific regions.[122]

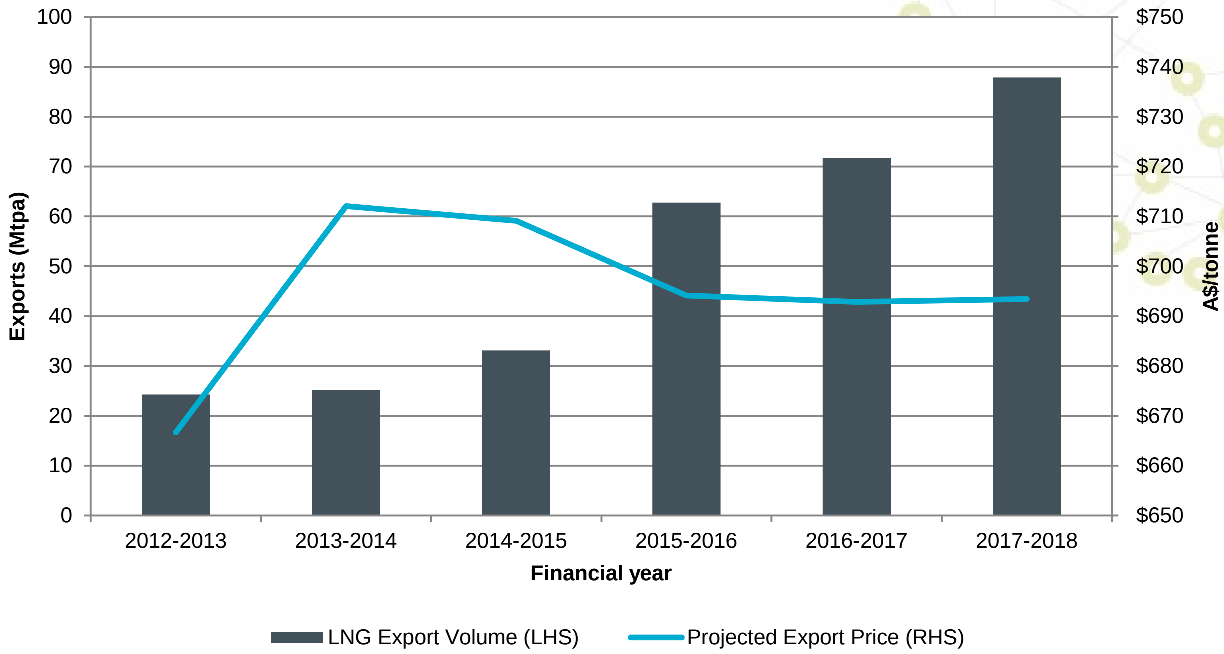
There are currently 18 countries with LNG export capabilities and 27 countries with LNG import capabilities.[123] International LNG trade is dominated by large suppliers and buyers. In 2012, eight of the 18 exporting countries supplied 83% of international LNG exports while seven of the 27 importing countries imported 81% of total LNG volumes.[124]

LNG demand consists of two segments; the premium and remaining customers. The premium segment consists of mainstay LNG customers, Japan, South Korea and Taiwan, which account for approximately 51.4% of the total LNG import market.[125] The premium segment encounters the highest wholesale gas prices, as these customers are entirely dependent on LNG to meet their gas consumption requirements. The remaining LNG customers, which in many cases have greater access to competing gas pipelines and/or energy options and include rapidly developing countries such as China and India, are expected to drive growth the international gas market in the 2013 to 2022 period.

Australia is currently the third largest LNG exporter in the world, after Qatar and Indonesia.[126] Australia is capable of supplying 24 Mtpa, commanding approximately 8% of the total LNG export market. With the upcoming completion of LNG projects in WA, Queensland and the Northern Territory, it is estimated that Australia's total export capacity will grow to 87.2 Mtpa by 2017, making it the largest international LNG exporter (23.9% of international LNG export capacity).[127] BREE projects that Australian LNG exports will grow at a rate of 31.3% per annum from 19 to 88 Mtpa for the period 2011-2012 to 2017-2018 (see Figure 34), with a nominal export value of about $61 billion in 2017-2018.[128]

[121] Core Energy Group (2012) provides a good historical overview of the international LNG market.
[122] The American region is driven by hub (spot) pricing, while the European (except for hub trades through the National Balancing Point in the United Kingdom, virtual Title Transfer Facility (TFF) in the Netherlands, Zeebrugge in Belgium and NetConnect in Germany) and Asia Pacific regions are more driven by long-term contracts and the JKM Marker Prices.
[123] See GIIGNL (2012), IGU (2012) or BP (2013) for a list of LNG exporting and importing countries.
[124] See GIIGNL (2013) for more details.
[125] Market shares for Japan, South Korea and Taiwan's LNG imports are from BP (2013), Statistical Review of World Energy 2013.
[126] According to BREE (2012, 2013), the two largest are Qatar and Indonesia, accounting for approximately 27% and 13% of total international LNG export capacity.
[127] Timeline is estimated by Innovative Energy Consulting (2012) assuming all existing LNG export capacity that has approvals remains unchanged. This sentiment is also outlined in Gas Today (2013). According to IGU (2012), by 2022, Malaysia and Indonesia are more likely to import gas and consume their gas reserves internally.
[128] See BREE (2013) for more information on LNG projections for the 2011 to 2018 period.

Figure 37 – Projected LNG Exports, (Australia) 2012-2013 to 2017-2018



Source: BREE (2013), Resources and Energy Quarterly, March Quarter 2013, Gas Outlook 2012-2018. **Note:** These are solely BREE's projections and not used in IMO's projections of LNG feedstock requirements. BREE's Resources and Energy Quarterly, June Quarter 2013, http://www.bree.gov.au/documents/publications/req/REQ-2013-06.pdf, already reports an upward revision estimate of gas production for 2013-2014.

6.2. The Australian LNG Market

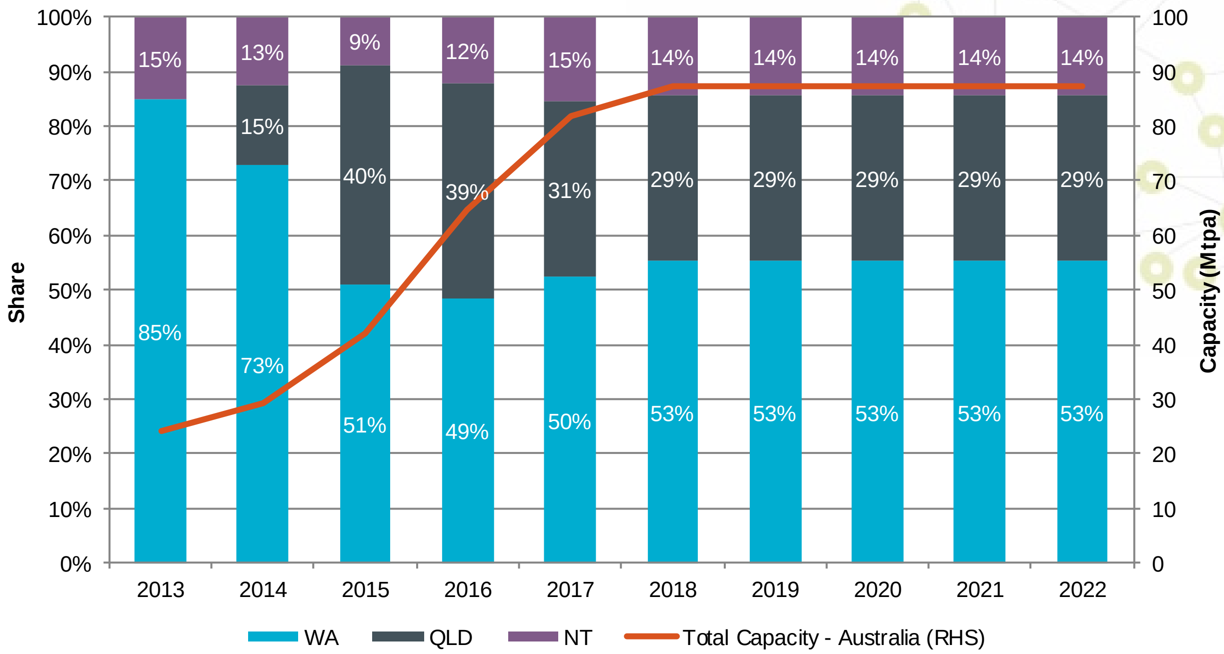
Australia entered the LNG export market when the NWS JV LNG export facility on the Burrup Peninsula was commissioned in 1989 and began exports to Japan. Two other LNG export facilities have subsequently commenced exports: Darwin LNG in 2006 and Pluto LNG in 2012.

Despite the expansion of Australia's LNG export capacity, NWS JVs' LNG facility in WA remains the largest operational LNG export facility in Australia, with almost four times the export capacity of the next largest facility (Pluto).[129]

Currently, WA hosts approximately 85% of Australia's total LNG export capacity but this share is anticipated to fall from 2014 due to the expected commissioning of LNG facilities in Queensland and the Northern Territory, as shown in Figure 38.

[129] By the end of 2022, Gorgon JV's LNG facility is expected to become Australia's second largest LNG export facility.

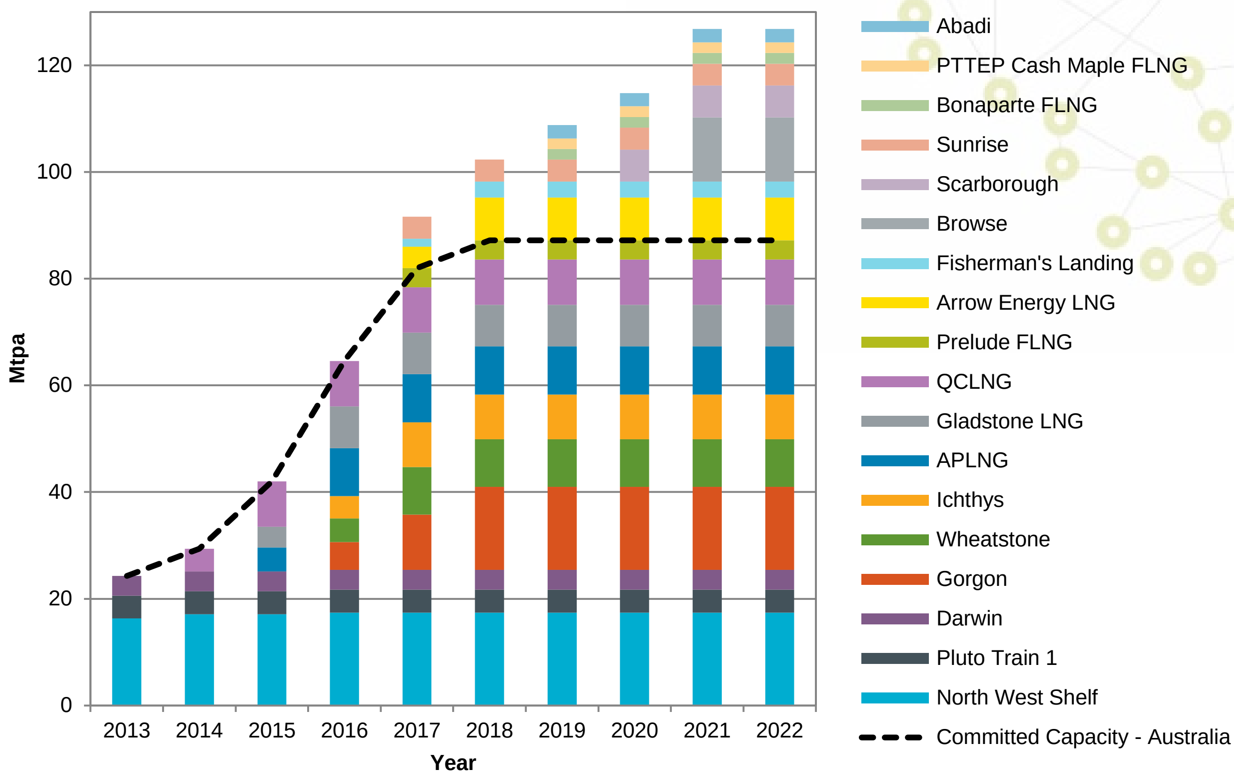
Figure 38 – Percentage Share of LNG Export Capacity by Australian States and Territories 2013 – 2022



Note: Shares of total LNG export capacity for each Australian state are estimated from public reports and includes FLNG projects such as Prelude. Proposed LNG projects that have not attained FID are excluded. **Note:** This figure assumes the NWS LNG facility will increase to its interim capacity target of 17.1 Mtpa, outlined in Woodside (2011b), in 2015 and its long-term target of 17.4 Mtpa in 2018 outlined in Woodside (2011b) and BREE (2013).

It is estimated that Australia will host 10 LNG facilities in 2022; three in Queensland (Australia Pacific, Gladstone and Queensland Curtis LNG facilities), two in the Northern Territory (Darwin and Ichthys LNG facilities) and five (four onshore, one offshore) in WA (Gorgon, NWS JVs, Pluto, Prelude and Wheatstone LNG facilities). Figure 39 shows current and proposed LNG export facilities in Australia over the 2013 to 2022 period.

Figure 39 – Total Estimated LNG Export Capacity (Mtpa) in Australia 2013 – 2022



Source: Respective corporate websites. **Note:** Projects above the committed capacity line are speculative in nature (before FID) and may not be realised in the 2013-2022 period. **Note:** This figure assumes that NWS LNG will increase to its interim capacity target of 17.1 Mtpa in 2015 outlined in (Woodside, 2011b) and its long-term target of 17.4 Mtpa in 2018 outlined in Woodside (2011b) and BREE (2013). Potential LNG projects such as Caldita-Barossa, Crux, Equus, Poseidon, Thebe, Crown and others are not reflected in this figure as there are no known indicative dates and/or export capacities.

6.3. Western Australia LNG Market

WA's LNG production serves two distinct market segments; LNG exports and domestic LNG consumption. LNG exports are dominant with the NWS JVs and Pluto LNG facilities consisting of six trains (see Table 17) capable of exporting a total of 20.6 Mtpa of LNG, estimated to be worth $2.5 to $3 billion to the WA economy annually.

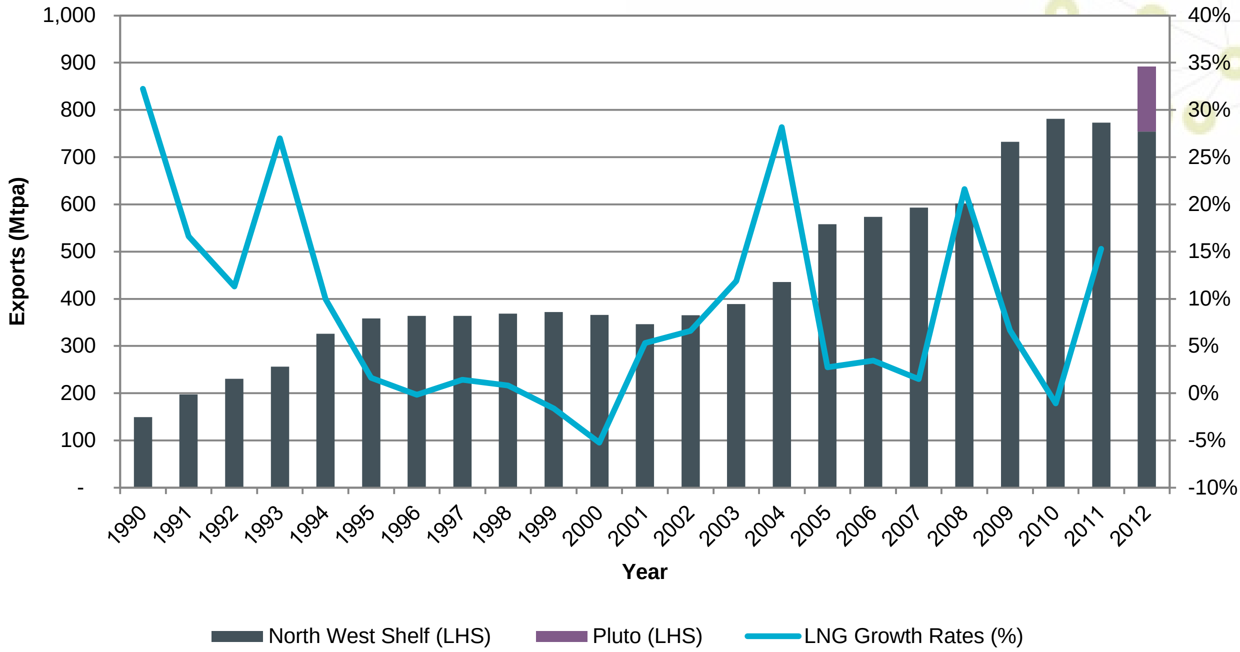
Table 17 – Existing LNG Export Facilities in Western Australia, 2013

LNG Facility	Capacity (Mtpa)	Status
North West Shelf Train 1	2.5	Operational
North West Shelf Train 2	2.5	Operational
North West Shelf Train 3	2.5	Operational
North West Shelf Train 4	4.4	Operational
North West Shelf Train 5	4.4	Operational
Pluto Train 1	4.3	Operational
Total LNG Export Capacity	**20.6**	

Source: NWS Gas, http://www.nwsg.com.au, accessed 13 November 2012 and Woodside Australia's website. **Note:** LNG train capacities for the NWS LNG facility may increase, as some facilities are being upgraded. This was outlined in Woodside (2011b).

Since 1989, more than 50 million tonnes of LNG in total have been delivered to customers in China, India, Japan, Korea, Malaysia, Spain, Taiwan and the US under long-term take or pay contracts, short-term contracts or spot cargoes. Figure 40 shows LNG exports from WA LNG facilities over the period from 1990 to 2012.

Figure 40 – WA LNG Exports (Mtpa), 1990-2012



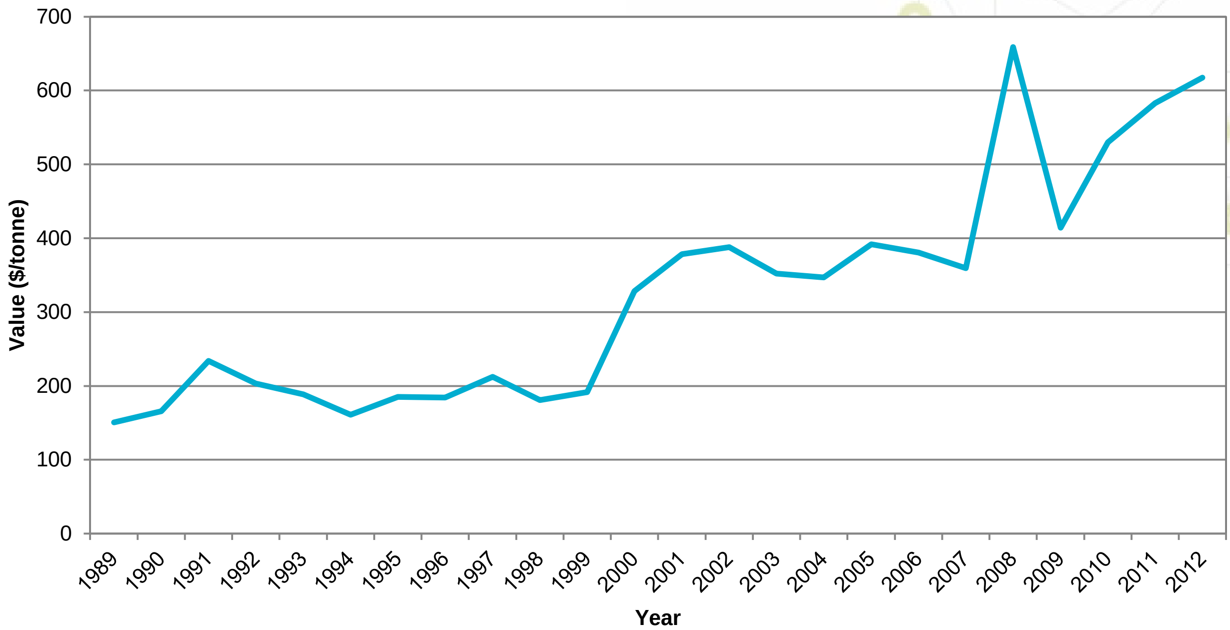
Source: APPEA (1991-2011) LNG Data, Woodside (2012-2013) Quarterly Production Reports.

DMP reports that WA exported approximately 891 PJ (16.1 Mt) in 2012 as LNG, a 13% increase from 2011. This increase is primarily due to increasing gas demand from Japan, after the Japanese Government temporarily decommissioned all its nuclear facilities for safety inspections after the Fukushima nuclear incident in 2011, and the commencement of exports from Pluto.[130]

Reviewing the LNG prices from 1989 to 2012, Figure 41 shows nominal LNG export prices remained relatively stable from 1989 to 1999 before prices started to rise significantly from 2000 until 2012. In 2009, world LNG prices fell due to the impact of the global economic downturn on major gas consuming countries.[131]

[130] See DMP (2012) for more information about LNG exports from WA.
[131] BREE (2013d) reports there were price declines in 2009 for Japan (24%), US (54%) and the EU (32%).

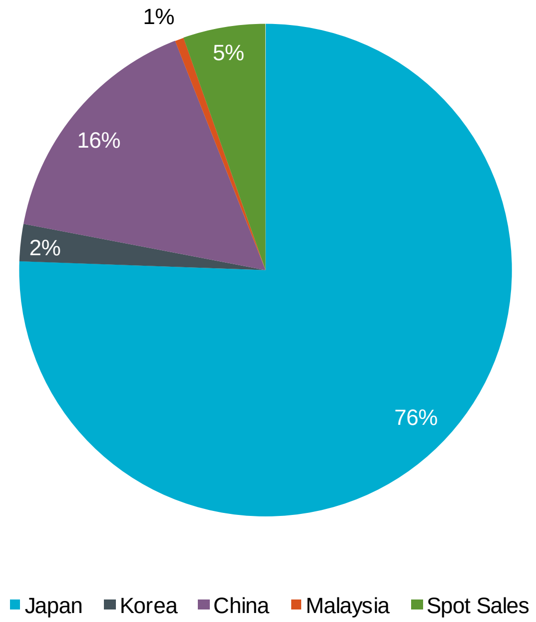
Figure 41 – WA LNG Export Prices (nominal, $/tonne), 1989 – 2012



Source: DMP (1990-2013), Petroleum Statistics, LNG Exports.

Despite rising LNG prices since 2000, WA succeeded in maintaining a long and close relationship with Japan as a source of stable supply of LNG. As a result, most long-term LNG contracts with Japan were renewed in the 2003 to 2008 period.[132] In 2012, it is estimated approximately 76% of WA's LNG exports are supplied to Japan (see Figure 42).

Figure 42 – Estimates of WA LNG Exports by Country, 2012



[132] During the same period, the quantity of LNG exported increased to Japan, new customer such as China was also supplied by the North West Shelf JV.

Source: IMO estimates. **Note:** These estimates are based on maximum quantities outlined in publicly announced long-term contractual agreements and existing capacity and not actual LNG exports outlined in LNG export data. Spot sales are estimated from corporate announcements from Woodside (2011).

The close relationship with Japan has led to Japanese companies and Japanese-linked JVs owning equity stakes in existing LNG facilities and upcoming LNG projects in WA (16.67% of NWS JVs, 10% of Pluto LNG, 2.67% of Gorgon JV and 1.46% of Wheatstone JV).[133]

At the time of this report, two additional onshore LNG facilities (Gorgon and Wheatstone) and one floating LNG (FLNG) facility (Prelude) are under construction, and these facilities are expected to add approximately 28.1 Mtpa of LNG export capacity in WA by 2022 (Table 18).[134]

Table 18 – Committed LNG Facilities under Construction in WA, 2013

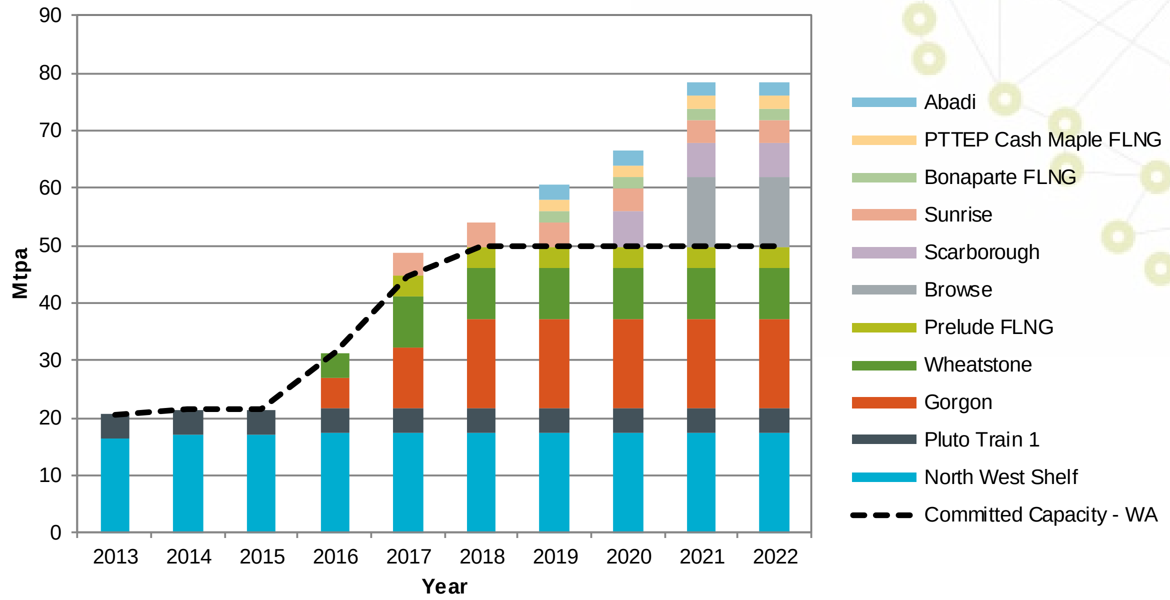
Planned Export Facilities	Expected Capacity (Mtpa)	Status
Gorgon Train 1	5.2	Anticipated to be operational in 2015 (LNG facility only)
Gorgon Train 2	5.2	
Gorgon Train 3	5.2	
Wheatstone Train 1	8.9	Anticipated to be operational in 2016
Wheatstone Train 2		
Prelude FLNG*	3.6	Anticipated to be operational in 2017
Total Committed Capacity	28.1	

Source: Chevron Australia and APPEA website, http://www.chevronaustralia.com/ourbusiness and http://www.appea.com.au/oil-a-gas-in-australia/lng.html, accessed 13 November 2012. *See The Australian (2011).

DSD expects LNG production capacity in WA will continue grow from 15 Mt in 2011-12 to almost 50 Mt in 2016-17 (Figure 43).[135] This will increase WA's share of international LNG export capacity from 6.3% in 2012 to approximately 13.7% by the end of 2017 (Australia will provide 23.6% of the world's LNG supply).[136]

133 Shares of LNG projects are reported in North West Shelf Venture (2010), Woodside (2013), Chevron (2013), Chevron (2013b).
134 While the nominal LNG capacities are often reported, these capacities are almost never reached. Typical utilisation rates for the LNG facilities located in WA for the period 2008 to 2012 have ranged from 90%+ to 97.6% of its maximum capacity, See Woodside (2012).
135 DSD (2013b) reports that Gorgon, Wheatstone and other WA projects commencing LNG production will increase LNG production capacity to 50 Mtpa.
136 According to DMP (2013e) and Grattan Institute (2013), in 2012, WA's share of international LNG export capacity is 6.3%.

Figure 43 – Committed and Speculative Capacity in WA, 2013 – 2022



Source: From DSD, BREE (2013) and public announcements. **Note:** Projects above the committed capacity line are speculative in nature (before FID) and may not be realised in the 2013-2022 time period. **Note:** This figure assumes the NWS JVs' LNG facility will increase to its interim capacity target of 17.1 Mtpa in 2014 outlined in (Woodside, 2011b) and its long-term target of 17.4 Mtpa in 2016 outlined in Woodside (2011b) and BREE (2013).

Other LNG export facilities for WA are being considered.[137] However, cost concerns relating to constructing LNG facilities in WA after a blowout in costs and project delays in Chevron's Gorgon LNG facility may affect some of these potential LNG projects.[138]

Table 19 - LNG Export Facilities under Consideration (before FID) in WA

LNG Export Facility	Expected Capacity (Mtpa)	Type	Expected FID
Pluto Train 2	4.3	Onshore	Unknown
Gorgon Train 4	5.2	Onshore	Anticipated to be 2013 or later
Wheatstone Expansion	8.6	Onshore	Anticipated to be 2013 or later
Browse	8 or 12*	Anticipated to be Offshore	Anticipated to be mid to late 2013
Timor Sea	3	Offshore	Unknown
PTTEP	3	Offshore	Unknown
Bonaparte	2	Offshore	Unknown
Scarborough	6-7**	Unconfirmed**	Anticipated to be 2014 or later**
WA LNG export capacity under consideration	**~40.1**		

Source: Respective corporate websites, DSD (2012), Daily Review (2013) and Reuters (2013b). *See the West Australian (2013). **Although project proponents have indicated a FLNG development is highly likely, this is still being evaluated. **Note:** Caldita-Barossa is not considered as Santos has announced it will to be used to backfill Darwin's LNG, see AFR (2011). At the time of this report, entities that own the most prospective gas fields; Poseidon, Equus, Thebe and Crux located offshore have not publicly stated their intentions.

[137] DSD (2012) and the Daily Review (2013) list potential LNG projects that are being considered.

[138] The Australian (2012), Chevron ups cost estimate on Gorgon LNG project to $52bn, http://www.theaustralian.com.au/business/mining-energy/chevron-ups-cost-estimate-on-gorgon-lng-project-to-52bn/story-e6frg9df-1226530997643, accessed 22 February 2013.

The domestic LNG market in WA officially commenced in 2001, when Wesfarmers Limited commissioned a 3.5 tonne/day portable LNG facility at Kwinana to trial the use of LNG in transportation vehicles.[139] This subsequently led to the expansion of WA's domestic LNG market with the commissioning of the 175 tonne/day EVOL LNG Kwinana facility and the first delivery of domestic LNG in Australia to Sands Fridge Line, a foundation customer in September 2008.[140]

At the time of this report, domestic LNG consumption in WA remains limited to transportation, remote power generation and food preservation.[141] There are currently six domestic LNG refuelling stations (including Kwinana) located around WA with two more stations planned for Bunbury and Carnarvon owned by EVOL LNG. There are also two LNG processing facilities servicing the domestic WA market, shown in Table 20.

Table 20 – LNG Processing Facilities Servicing Domestic LNG Demand, 2013

LNG Facilities	Commenced	Operator	Domestic LNG Capacity (tonnes/day)
Kwinana	2008	EVOL LNG (Wesfarmers)	175
Maitland	2007	Energy Developments Limited	200
Total			**375**

Source: EVOL LNG (2013) and Energy Developments (2013) corporate websites.

In addition, there are more than 200 duel-fuelled trucks capable of operating on LNG in WA, two remote mines and four remote communities using LNG as fuel to generate power.[142] By the end of 2013, an additional remote mine, Silver Lake's Murchison gold mine in the Mid-West (Table 21 below) is also anticipated to commence using LNG to generate power for its operations.

Table 21 – LNG Powered Electricity Generators, 2013

LNG Electricity Generators	Estimated Capacity (MW)	Operator
Darlot	12	Energy Developments Limited
Sunrise Dam	21	Energy Developments Limited
Broome	39	Energy Developments Limited
Derby	12	Energy Developments Limited
Fitzroy Crossing	4	Energy Developments Limited
Halls Creek	4	Energy Developments Limited
Tuckabianna*	Unknown	Unknown
Total	**>92**	

Source: Information provide by Energy Developments Limited. *See Gas Today (2013b) and EVOL LNG press release, http://www.evollng.com.au/docs/media-releases/8-january-2013-evol-lng-wins-silver-lakes-resources-contract.pdf?sfvrsn=0 and http://www.evollng.com.au/our-product/our-distribution-network. *Tuckabianna LNG power station is for Silver Lake's Gold Operations.

The domestic use of LNG is anticipated to expand in the 2013 to 2022 period, as more operators of vehicles in the transportation sector and remote mines located within the vicinity of existing refuelling stations in WA seek to reduce their reliance on diesel, improving fuel efficiency and reducing their carbon footprint.

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139 According to Gas Today (2013d and 2013e), domestic LNG use in Australia is expected to expand as it is currently being trialled and adopted by other Australian states; NSW, QLD, VIC and TAS via APA Group's Dandenong LNG facility, Kleenheat Gas' LNG refuelling stations in Victoria, BOC's Westbury micro-LNG facility, BOC's proposed Miles LNG facility (next to Condamine Power Station), Shell's Planned LNG Stations along the Hume highway between Melbourne and Sydney, the proposed GLP Chinchilla LNG facility and according to The Australian (2013e), Wesfarmer's EVOL LNG is building a refuelling station near Goulburn, NSW and Wogdonga, VIC.

140 According to EVOL LNG's (2009) newsletter, four additional refuelling stations at Forrestfield, Kewdale, Geraldton and Kalgoorlie were commissioned soon after the Kwinana LNG Facility. LNG storage of 1,600 tonnes is also available at the Kwinana facility.

141 According to Gas Today (2013b), remote power generation consumes more than 90 tonnes of LNG per day.

142 Data on trucks are acquired from EVOL LNG's website, EVOL LNG (2009), http://www.evollng.com.au/FACTSHEET.pdf, accessed 17 January 2013. Energy Developments Limited generates power for the Sunrise Dam and Darlot mines using LNG. This was reiterated in The Australian (2013c).

6.4. International LNG Demand Outlook

Consistent with the IEA's view of a Golden Age for Gas, a review of several international publications suggests the international gas market for the 2013 to 2022 period will continue to grow. Although LNG only makes up about one third of the total international gas market, international LNG demand has grown faster than pipeline gas for the 1995 to 2012 period.[143]

A number of international studies (see Table 22) suggest that international gas consumption will increase by 1.6% to 2.0% per year in the 2013 to 2022 period. According to BP (2013), the bulk of the expected increases in international gas consumption will be in the LNG market at approximately 4.3% per year from 2013 to 2022.

Table 22 – Projected International Gas Growth, a selection of various reports

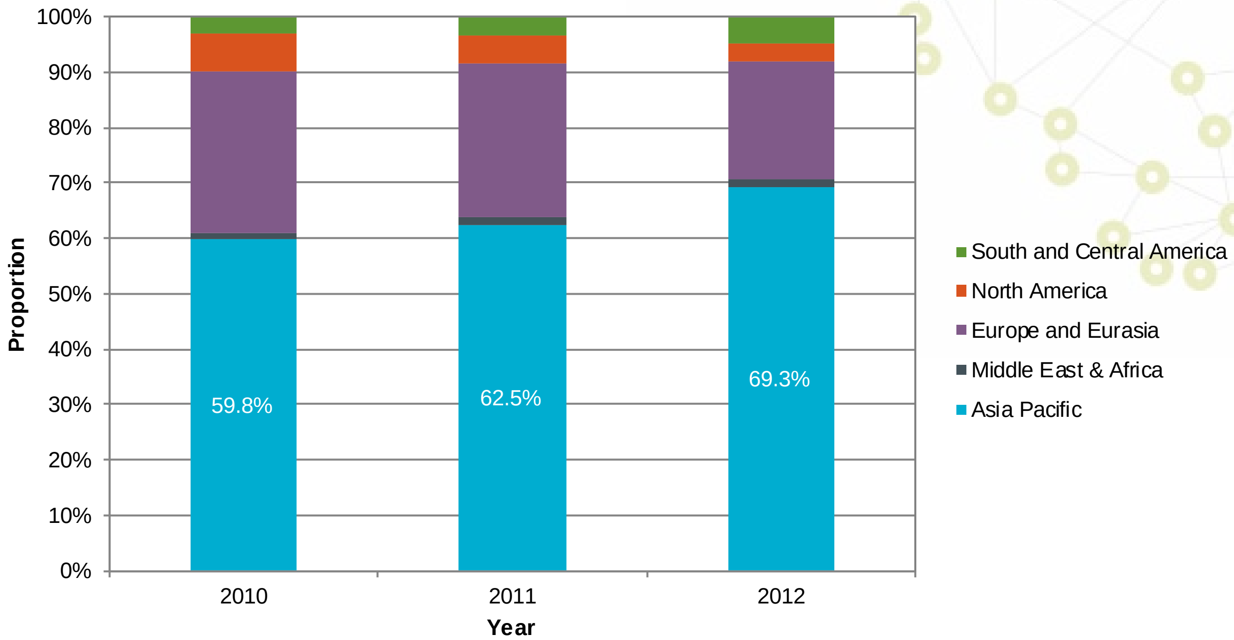
Report	Time Period	Projected Annual International Gas Consumption (pipeline and LNG) Growth (%)	Projected Annual LNG Growth (%)
BP's Energy Outlook 2030 (2013)	2011 – 2030	2.0	4.3
BREE (2013), Resources and Energy Quarterly, March 2013	2010 – 2018	1.8	Not provided
Energy Information Administration's (2011) International Energy Outlook	2008 – 2035	1.6*	Not provided
ExxonMobil's (2013) The Outlook for Energy: A View to 2040	2010 – 2040	1.7	Not provided
International Energy Agency's (2012b) World Energy Outlook	2011 – 2035	1.6^	Not provided
IEEJ (2012c) Asia/World Energy Outlook 2012	2010 – 2035	2.0**	1.9**
OPEC's (2010) World Oil Outlook	2008 – 2030	2.0	Not provided
Royal Dutch Shell's (2011) Energy Scenarios to 2050	2010 – 2030	1.3	Not provided
StatOil's (2012) Energy Perspective	2012 – 2040	1.6	Not provided

Source: International gas growth projections are extracted or estimated from outlined reports. *Estimated from data tables. ^Data acquired from Ernst and Young (2013). According to Ernst and Young (2013), a wide range of analysts see average growth of the LNG market of around 5-6% per annum until 2020 and after 2020, LNG demand grows at a slower pace of around 2-3% per annum. **This refers only to the reference scenario outlined in the IEEJ (2012c) report. Gas powered electricity is anticipated to be 26%. For Asia, growth is anticipated to be 4.1% per annum with China and India anticipated to grow at 7.2% and 4.6% per annum over the 2010 to 2035 period, respectively.

The Asia Pacific market makes up more than two-thirds of the international LNG import market (see Figure 44) and demand in this region is expected to continue to grow more rapidly than the North American and Atlantic regions. BREE expects Asia Pacific gas demand will drive the international LNG market, projecting Asia Pacific demand to exceed 200 Mt by the end of 2013. BREE also expects that Asia Pacific LNG demand will reach 272 Mt by the end of 2017-2018.[144]

[143] See ENI (2012), World Oil and Gas Review 2012, http://www.eni.com/world-oil-gas-review-2012/wogr.shtml, and BP's (2013) Statistical Review of World Energy 2013 for more information.
[144] BREE (2013) reports the Asia Pacific LNG Market is expected to grow by 9% in 2013, and 7% per annum for the period 2014 to 2018.

Figure 44 – International LNG Imports by Region, 2010 – 2012



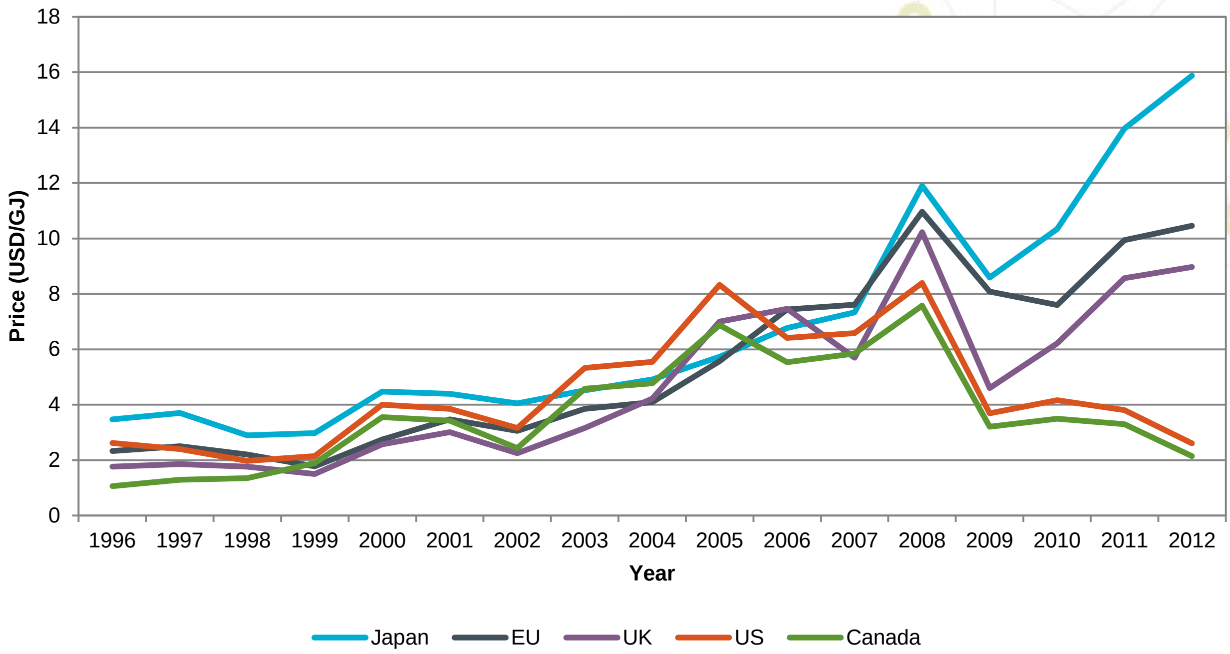
Source: BP (2012-2013), Statistical Review of Energy, Gas Trade.

The projected growth prospects for Asia Pacific LNG demand are grounded on the view that major LNG consumers, such as Japan, South Korea, China and India will continue to increase their usage of gas in power generation, industrial and residential consumption due to the rapid urbanisation, motorisation, economic development, government reforms and energy policies of these countries. In addition, potential European Union (EU) regulations and new emission standards from the International Maritime Organisation that are anticipated to be in place by 2020 will also increase the demand for LNG exports.[145]

Price differentials between Japanese LNG prices and gas prices with other LNG importing regions will also continue to drive the expansion of LNG supply to the Asia Pacific region.[146] Figure 45 shows international gas prices over the period from 1996 to 2012.

[145] See Bloomberg (2013d), EU Seeks Monitoring of Ship Emissions to Spur Global Curbs, http://www.bloomberg.com/news/2013-06-28/eu-monitoring-of-ship-emissions-proposed-to-spur-global-curbs.html, accessed 4 July 2013.
[146] As the largest international importer of LNG, Japanese LNG prices are a good benchmark for Asia Pacific LNG prices.

Figure 45 – International Gas Prices by Region, 1996 – 2012



Source: BP (2013), Statistical Review of Energy 2013, Gas Prices. **Note:** Prices are converted to USD/GJ. Japanese Prices displayed are LNG prices while the remainder prices are for natural gas, EU prices are estimated by Heren Energy Ltd, UK, US and Canada's prices are based on National Balancing Point, Henry Hub and Alberta, respectively.

The following sections provide an overview of countries that are likely to propel international LNG demand in the 2013 to 2022 period.

Japan

Japan lacks reserves of fossil fuels and is highly reliant on imported fuels (oil, gas, uranium) to generate electricity.[147] It is currently the largest importer of LNG and imports approximately 87.9 Mt of LNG, accounting for 36.2% of the international LNG market in 2012.[148]

Since the Fukushima Daiichi nuclear accident in 2011, Japan has temporarily shut down most of its 50 nuclear power facilities in a bid to ensure the safety of all remaining facilities. Prior to the accident, nuclear energy in Japan provided approximately 30% of its power generation.[149] Following the accident, in September 2012, the Japanese Government pledged to increase nuclear safety by establishing the Nuclear Regulation Authority, promising to phase out all nuclear powered electricity generation by 2040.[150] Although the Japanese government subsequently decided to reverse its decision in January 2013, the fate of nuclear power in Japan remains unclear.[151]

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[147] Although Japan has significant reserves of coal, due to its commitment to the Kyoto Protocol, it is highly reliant on other fuels for its energy needs.
[148] BP's (2013) Statistical Review of World Energy 2013 reports Japan imported approximately 118.8 Bcm of LNG (87.9 Mt) in 2012. BREE (2013) expects Japan to import 87 Mt in 2013, with imports projected to grow at 8% per annum to 2018.
[149] See World Nuclear Association (2013) for a breakdown of Japan's nuclear sector.
[150] See ABC News (2012), Japan to phase out nuclear power by 2040, http://www.abc.net.au/news/2012-09-14/japan-to-phase-out-nuclear-power/4262744, accessed 20 February 2013. This also outlined in a White Paper following the announcement released in October 2012.
[151] The Guardian (2013), Japan seeks to reverse its commitment to phase out nuclear power, http://www.guardian.co.uk/environment/2013/jan/11/japan-reverse-nuclear-phase-out, accessed 20 February 2013. The IEEJ (2013) and the Economist (2013) suggests otherwise.

These events and the absence of any international gas pipeline connections have led Japan to be more reliant on gas imports for electricity generation. Any de-nuclearisation of Japan is likely to increase LNG demand from LNG exporting countries, such as Australia that is in close proximity to Japan.[152]

China and India

The rapid industrialisation and expansion of the middle-class in China and India, the two most populous countries, is anticipated to drive increases in energy consumption per capita, supporting the growth of LNG.

The outlook of Chinese gas demand is promising,[153] as China's State Council on 24 October 2012 agreed to adopt the 12th Five-Year Energy Development Plan for the period 2011 to 2015. This plan establishes new ambitious targets for the country's energy mix for 2015 that are biased towards increasing gas consumption.[154] In addition, China's growing concerns about the air quality in major cities have coincided with the intention to introduce a new environmental taxation system (carbon tax) before the end of 2015.[155] Such initiatives would support demand for gas at the expense of other fuels.

In addition to altering the energy mix, China has also embarked on its 12th Five Year Plan for the Nationwide Development of City Gas in June 2012. This plan outlines the country's intention to expand gas usage in its metropolitan cities.[156] With China's West-East Gas Transmission Pipeline III anticipated to be completed sometime in 2014, transporting gas from gas-producing fields located to the west of China to the coastal cities in the east, the consumption of gas across all sectors of the Chinese economy is expected to increase considerably.

India is also anticipated to increase its gas consumption in the 2013 to 2022 period.[157] India is highly reliant on foreign imports for approximately 80% of its total energy requirements. This is as gas demand in India could not be met by existing gas fields that were declining and operated by India's state-owned gas monopoly Oil and Natural Gas Company.

In a bid to improve gas allocation and encourage investment in meeting gas demand, the Indian Government reduced subsidies on gas, embarked on gas market reform, started gas exploration initiatives to open oil and gas exploration areas to private investment, approved LNG regasification facilities and permitted foreign investment and ownership of LNG facilities.[158] The Indian Government also permitted gas retail competition to industrial customers on a limited basis.

In September 2012, the Indian Government announced the immediate reduction of subsidies for diesel and LPG for residential use, while signalling the intention to further reduce government subsidies on other fuels such as kerosene and petrol that are competing with gas.[159] This continued reduction of fuel subsidies for substitute fuels and the recent commissioning of the Dabhol LNG regasification facility in Ratnagiri in December 2012 will drive an increase in gas demand in India.

South Korea

South Korea is the second largest importer of international LNG accounting for approximately 14.8% of the international LNG market in 2011.[160] As the third largest importer of Australian LNG, South Korea relies

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[152] According to Ripple (2013), within Australia, Darwin's LNG export facility is the closest to the Japanese market and LNG facilities located at Burrup Peninsula and Gladstone are approximately equidistant.
[153] According to BREE (2013), China's gas demand is expected to grow at 2.8% annually to 2014.
[154] British Chamber of Commerce (2011), China's Twelfth Five Year Plan (2011- 2015) - the Full English Version http://www.britishchamber.cn/content/chinas-twelfth-five-year-plan-2011-2015-full-english-version, accessed 5 March 2013.
[155] See the Australian (2013b). Air pollution is a significant problem in China, according to Fortune (2013), where air pollution in the Beijing and Shanghai have reached several hundred times above the safe level.
[156] According to the IEEJ (2012), in 2010, China's city gas grid covered only 355,000 km, the plan is to extend this network by 600,000 kilometres by the end of 2015.
[157] BREE (2013) expects India's LNG demand to grow at 39% in 2013, then at an average of 4% per annum for the period 2014 to 2018.
[158] These are called the New Exploration Licensing Policy 1998
[159] See Financial Times (2010). http://www.ft.com/intl/cms/s/0/44586cac-8930-11df-8ecd-00144feab49a.html#axzz2K6A3pXfy, accessed 20 February 2013.
[160] IGU (2011) reports South Korea is the second largest importer of international LNG. According to BREE (2013), South Korea is expected to grow at 6% for 2013 and 5% per annum for the period 2014 to 2018.

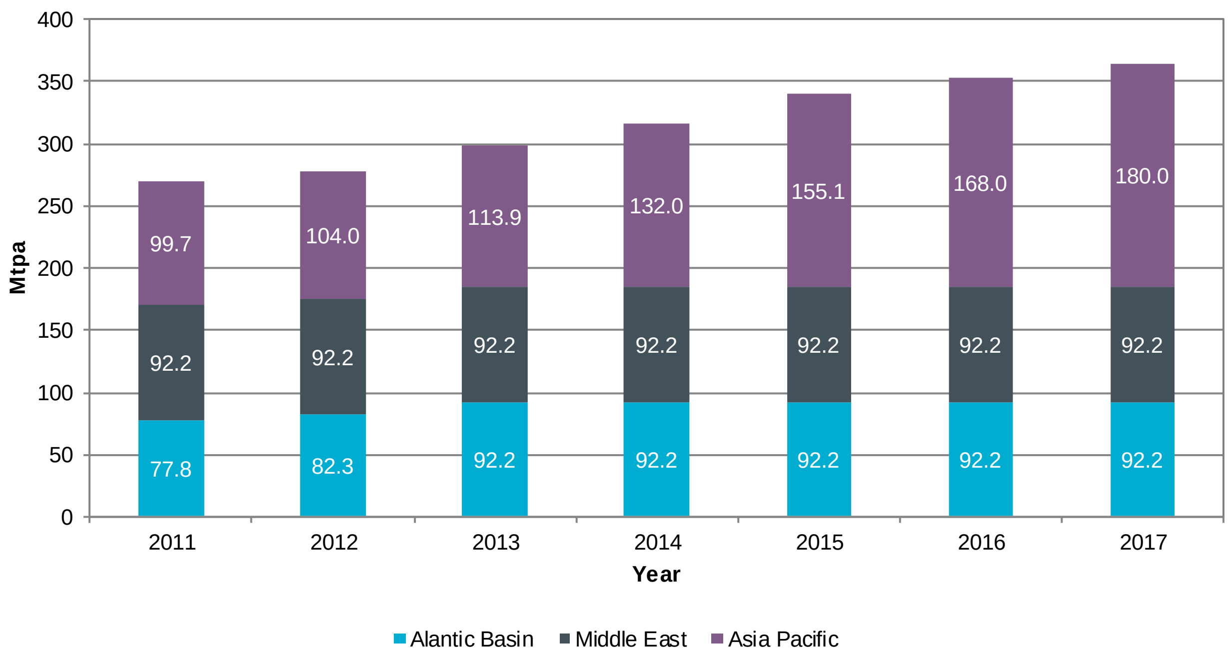
almost entirely on LNG imports, which satisfy approximately 98.7% its total natural gas consumption.[161] Similar to Japan, South Korea is not connected to any international gas pipelines (due to a demilitarized zone with North Korea), and relies almost exclusively on seaborne shipments of LNG for its domestic consumption.

According to statistics from the Korea Energy Economics Institute, gas usage in South Korea is rapidly expanding due to the increasing demand in the residential and commercial sectors (growing from 3.5 Mtpa in 1992 to 35.6 Mtpa in 2011).[162] As a result, South Korea increased its LNG imports from 3.4 Mtpa in 1992 to approximately 36.7 Mtpa in 2011. BREE expects gas consumption in South Korea will continue to grow from 38 Mtpa in 2013 up to 49 Mtpa in 2018.[163]

6.5. International LNG Supply Outlook

International LNG supply also is undergoing an expansion phase (see Figure 46), with approximately 76 Mtpa of LNG export capacity approved or currently under construction internationally.[164] At the time of this report, approximately 66.1 Mtpa of liquefaction capacity is being constructed in the Asia Pacific market, with the majority of capacity (57.5 Mtpa) being constructed in Australia.[165] Of this, approximately half (28.2 Mtpa) of new Australian LNG export capacity is in WA.[166]

Figure 46 – Estimated and Projected International LNG Liquefaction Capacity by Region, 2011 – 2017



Source: GIIGNL (2010), IGU (2012). **Note:** Data reflected in this figure only takes into account projects that are approved. Data is also updated to account for increases in Gorgon JV's capacity.

The following sections provide a brief on the largest international gas suppliers (by country) and highlight their ability to export LNG into the future.

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[161] The only known gas producing field in South Korea is the Donghae gas field located in the Ulleung Basin.
[162] KEEI (2013) statistics are available at http://www.keei.re.kr/main.nsf/index_en.html.
[163] Although South Korea gas demand is forecasted to increase by BREE (2013), gas demand in South Korea is typically seasonal, with gas is often used for heating in winter.
[164] LNG facilities are mostly being constructed in Algeria, Australia, Indonesia and Papua New Guinea.
[165] Figures are acquired from IGU (2012). Ernst and Young (2013) expect regasification facilities globally will rise by 200 Mtpa by 2020.
[166] This figure includes Prelude's FLNG facility that is currently being constructed in South Korea. There are only two known FLNG projects (Kanowit and Prelude FLNG) internationally confirmed, both are under construction in South Korea.

Qatar

Currently, Qatar is the largest exporter of LNG. It hosts approximately 78 Mtpa of LNG export capacity. According to BP's Statistical Review of World Energy 2013, Qatar shipped approximately 78 Mt of LNG internationally in 2012, with more than half of its supply going to Japan, South Korea, Taiwan and India. Qatar plays a pivotal role in influencing energy security in the Asia Pacific region as it also holds the third largest conventional gas reserves internationally.[167,168]

Although Qatar's LNG facilities are situated in the historically volatile region of the Middle East, its gas exports are secure and stable, partially due to its close relationship with the US.[169] Wood Mackenzie reports approximately 44 Mtpa of Qatar's LNG export capacity is contracted through long-term contracts, while the remaining capacity is available to flexible (spot/short-term) markets.[170]

United States

The US is unique in the international gas market. The US is both the largest consumer and largest producer of gas internationally. Previously, the US was expected to become a major importer of gas from neighbouring Canada and other countries, but this has significantly changed with the discovery of shale gas.[171] Due to a rapid increases in US shale gas production, in 2011, the US surpassed Russia to become the largest producer of gas (pipeline and LNG) in the world, accounting for a fifth (20%) of international gas production.[172]

The rapid increase in gas production caused domestic gas prices in the US to collapse from US$9.48/GJ in 2008 to US$2.84/GJ in 2012, creating a more profitable opportunity to liquefy shale gas into LNG for export to the higher priced Asia Pacific region.[173] At the time of this report, the US has started re-exporting LNG from other countries and has one LNG export facility in Alaska capable of exporting approximately 1.3 Mtpa of LNG to the Asia Pacific.[174] While gas exports are currently small, as at 17 May 2013, there are 21 LNG projects with a capacity totalling 224.66 Mtpa seeking approval from the US Department of Energy (DOE), driving expectations that the US will become a key exporter of the gas (in particular LNG) in the 2013 to 2022 period.

Russia

Previously the largest gas producer internationally, Russia remains a dominant player in the international gas market and remains the largest exporter of gas internationally, accounting for approximately 19.4% of international gas exports.[175] Russia exports most of its gas production through long distance cross country natural gas pipelines (mostly to Europe and the former Soviet Republics).

Russia is one of the largest LNG suppliers to the Asia Pacific region and is ideally situated to supply gas to China, Japan, South Korea and Taiwan.[176] In addition, Russia has the financial capability to ramp up gas production reasonably quickly to exploit its substantial gas reserves. Russia is currently considering the

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[167] IEA (2012b) outlines the importance of Qatar in the international LNG supply. GIIGNL (2012) reports Qatar's LNG export for 2012 is 76.4 Mt.
[168] According to MIT (2010), Qatar is estimated to hold approximately 875,167 PJ of reserves which represents approximately 14% of total international gas reserves.
[169] ExxonMobil is a partner in the LNG export facility with QatarGas and RasGas, while ConocoPhilips is in partnership with RasGas. The US also situated its troops in Qatar during the Gulf War.
[170] See Wood Mackenzie (2012) for details.
[171] According to the Economist (2012), the US invested approximately US$100 billion in LNG import infrastructure that is now redundant. Some of the infrastructure is being converted for LNG exports.
[172] See BP (2013), Statistical Review of World Energy 2013
[173] According to Deloitte (2013), estimated LNG shipping costs are approximately US$5.7/GJ and prices in the Asia Pacific region are US$15-16/GJ, creating a huge profitable opportunity for LNG exports from the US.
[174] According to the EIA (2013), LNG re-exports from the US come from Freeport facility in Texas, Sabine Pass and Cameron facilities in Louisiana. http://www.eia.gov/todayinenergy/detail.cfm?id=5970, accessed 25 February 2013. According to Bloomberg (2012), ConocoPhilips has restarted LNG exports from the Kenai LNG facility in Alaska in July 2012, the facility is capable of exporting 1.5 Mtpa.
[175] See BP (2013), Statistical Review of World Energy 2013.
[176] Russia's major gas field, Sakhalin is also connected to Vladivostok through a 180 kilometre gas pipeline in close proximity to the major gas demand centres of China, South Korea and Japan.

expansion of international gas exports and in December 2012, the President of Russia re-iterated the importance of gas rich Eastern Siberia and the Russian Far East by announcing tax incentives in the regions to encourage economic development.[177]

6.6. Demand Risks in the International LNG Market

While China and India are anticipated to drive growth in international gas demand in the 2013 to 2022 period, this projection is not without risks. This section outlines potential risks to this view.

China

Although Chinese domestic gas demand is anticipated to be the primary driver for growth in international gas demand, China intends to supply some of this future demand indigenously. In 2012, China set itself ambitious targets of producing 6.5 billion cubic meters (Bcm) of shale gas annually by 2015 and between 60 and 100 Bcm by 2020. This was outlined in China's Shale Gas Development Plan for 2011 to 2015.[178] Although China currently does not produce commercial quantities of gas to meet existing demand, meeting a proportion of this target remains a distinct possibility.[179]

In addition, China's proximity to Russia and other emerging gas producers such as Myanmar, Tajikistan and Kazakhstan, suggest some of China's growing demand may be met by its neighbours, as there are already agreements and infrastructure in place to ship gas from some of these countries.[180] Additional cross country pipelines connecting Russian gas-producing fields located in East Siberia and the Russian Far East to China's gas transmission network located just across the border may also be a possibility.

China's future gas consumption for the 2013 to 2022 period may also be constrained by its ability to receive seaborne LNG shipments. At the time of this report, China has four new regasification facilities under construction; Hainan, Qingdao, Tangshan and Zhuhai LNG facilities. One facility (Zhuhai) is anticipated to be completed in 2013, two (Qingdao and Tangshan) in 2014 and another (Hainan) in 2015.[181] If these regasification facilities are not completed on schedule, this may potentially constrain China's LNG imports.

India

Similarly, there are risks associated with India's gas consumption for the 2013 to 2022 period. The Oxford Institute for Energy Studies suggests India may face significant challenges in securing sufficient gas supply to meet future demand, despite expanding its LNG import infrastructure from 15 Mtpa to 25 Mtpa by the end of 2013.[182] There is currently a lack of gas pipelines supplying gas to India so it relies almost exclusively on seaborne LNG to address its growing gas demand.[183] Given the delays experienced in constructing LNG import infrastructure in India, future gas demand may be constrained if similar delays to planned LNG import infrastructure are experienced.

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[177] This announcement was outlined in IEEJ (2012b). Russia's East Siberia Pacific Ocean pipeline is a good example of oil and gas infrastructure built to service energy hungry economies of Japan, China and Korea.

[178] According to CSIS (2012), China plans to scale up shale gas exploration during the 13th Five Year Plan (2016-2020). Fortune (2013) reports the 12th Five Year Plan originally had a goal of 230 bcm by 2015 and at least 2.2 Tcf by 2020.

[179] According to Bloomberg (2013), China's Shale Gas No Revolution as Price Imperils Output: Energy, 19th February 2013 http://www.bloomberg.com/news/2013-02-19/china-s-shale-gas-no-revolution-as-price-imperils-output-energy.html , accessed 20 February 2013. According to EIA (2011), China also holds approximately 1,275 Tcf of shale resources approximately 3.2 times the amount of shale resources estimated to be in Australia.

[180] Wall Street Journal (2013), CNPC, Partners Sign Tajikistan Oil and Gas Deal, June 18 2013, http://online.wsj.com/article/SB10001424127887324520904578552454252003518.html, accessed 24 June 2013 and Straits Times (2013), CNPC completes construction of China-Myanmar gas pipeline, http://www.straitstimes.com/breaking-news/se-asia/story/cnpc-completes-construction-china-myanmar-gas-pipeline-20130601, accessed 24 June 2013.

[181] According to Hydrocarbon Asia (2012), outlines the upcoming regasification facilities. The Zhejiang facility outlined in the article is already operational in 2012.

[182] See the Oxford Institute for Energy Studies (2012) for more information.

[183] At the time of this report, Dahej LNG (12.5 Mtpa), Hariza LNG (2.5 Mtpa) and Dabhol LNG (5.0 Mtpa) facilities are online and Kochi LNG facility (1.5 Mtpa) is expected to be operational by the end of 2013, several other import facilities such as Kakinada FLNG facility (3.5 Mtpa, under consideration) and Gangavaram LNG facility (5.0 Mtpa, planned) and Ennore LNG facility (5.0 Mtpa, FEED) and expansions to the Dahej, Hariza and Dabhol LNG facilities are expected to be operational in the 2013 to 2022 period.

In addition to potential infrastructure delays, planned moves by the Indian Government to reduce fuel subsidies for competing fuels may impact on India's future gas demand.

6.7. Supply Risks in the International LNG Market

While section 6.4 outlines a rapidly growing international gas demand for the 2013 to 2022 period, there are risks to this positive outlook. The time required to construct gas supply infrastructure to service the international LNG market remains long.[184] As such, most of the risks outlined in this section are perceived as longer term LNG supply risks, with the exception of Singapore.

LNG export volumes from existing WA LNG facilities and those under construction are locked in long-term LNG contracts. Most of these contracts are understood to contain "take or pay" minimum and maximum quantity clauses, with some containing restrictive destination clauses that shifts volume risks to the LNG importer. Although these contractual clauses significantly reduce the risks for existing facilities under construction in WA, these facilities are not totally immune to potential market shifts in the 2013 to 2022 period, especially towards the end of the period. The shifts include potential increases in short-term LNG contracts, a potential international gas glut from North American LNG facilities supplying the international gas market if LNG export applications are granted, the increasing cost of constructing LNG terminals in Australia, potential changes to Asia Pacific LNG pricing and the emergence of unconventional gas.

These risks may compel existing LNG importers with WA LNG contracts to take only minimum contracted quantities, enforce price reopener clauses (if LNG prices vary significantly) or seek dispensation on existing contracts. Some of these risks may also impact the financial viability of planned Australian projects that have not obtained approvals. Australian projects are considered to be more expensive when compared to similar projects in other international regions.[185,186]

The following sections review the risks posed by other LNG exporting countries, issues concerning the LNG industry and changes to the Asia Pacific LNG market, the predominant export market for WA's LNG.

Qatar

Qatar is increasingly diversifying its customer base, which was previously weighted towards the European market.[187] Since the GFC, European gas consumption and LNG prices in the Atlantic region have weakened, which has led Qatar to sell LNG in the higher priced Asia Pacific region, focusing on Japan, India, South Korea, Thailand and Singapore.[188] This change in focus towards customers in the Asia Pacific region may affect WA LNG exports to the Asia Pacific.

Qatar currently has a moratorium until 2014 on increasing LNG supply to the international market while it studies the optimisation of existing production. Any unexpected changes to this moratorium will change international LNG supply dynamics in the 2013 to 2022 period.[189]

North America

The domestic North American gas market is currently oversupplied due to a significant increase in supply stemming from shale gas discoveries in the US. This has led to a sharp reduction in gas prices at the Henry

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[184] A presenter at the 2013 IHS Energy Insight Symposium on 13 May 2013 in Perth suggested the minimum timeframe required to build an onshore LNG liquefaction processing plant has increased from 5 years to approximately 5.5 years.
[185] At the time of this report, potential LNG export projects in Australia in advanced stages that have not achieved FID status include; LNG Limited's Fisherman's Landing LNG, Browse LNG, Bonaparte FLNG, PTTEP FLNG, Timor Sea LNG and planned expansions to Pluto, Gorgon, Wheatstone projects.
[186] For a comparison of international LNG capital expenditure costs, see Credit Suisse Global Equity Research (2012), Deutsche Bank (2012) and McKinsey (2013).
[187] Qatar LNG Spot Sales to Fall 40% by 2014, QNB Says, http://www.bloomberg.com/news/2012-12-08/qatar-lng-spot-sales-to-fall-40-by-2014-qnb-says.html.
[188] See AMEInfo, http://www.ameinfo.com/qatar-export-lng-asiaqnb--321984, accessed 17 July 2013.
[189] See EIA (2013) for more details.

Hub in 2012 and 2013.[190] In a bid to improve profitability, American and Canadian gas companies are seeking to export excess gas as LNG to Asia Pacific customers to access higher gas prices.

While the potential to export LNG is significant, Canada and the US have government policies that require export licences for gas sales to countries that do not have a Free Trade Agreement (FTA) with these countries. This prevents direct exports of North American LNG to many gas consuming countries.[191] US Government legislation, however, does not prevent the re-exports of LNG, imported from other countries.[192]

This situation may quickly change as the US DOE is currently assessing LNG export applications. In December 2012, the DOE released the two studies commissioned to analyse the impact of LNG exports on the US economy.[193] NERA Consulting's report finds that, in each of the market scenarios tested, net economic benefits increased with the level of LNG exports, with a slight increase in US domestic gas prices being projected.[194,195]

Analysis by the Energy Information Administration's (EIA) report also finds LNG exports from the US will lead to higher prices for the domestic US market.[196] At the time of this report, the studies are out for public consultation and the responsible departments are considering the issue of allowing international LNG exports.[197]

Table 23 – Applications to Export LNG in the United States, May 2013

US Company	Total Quantity (Bcf/d)	Annual Capacity (Mtpa)	FTA Applications	Non-FTA Applications
Sabine Pass Liquefaction	2.2	17.32	Approved	Approved (May 2011)
Freeport LNG Expansion and FLNG Liquefaction	1.4	11.02	Approved	Approved (May 2013)
Freeport LNG Expansion and FLNG Liquefaction (second application)	1.4	11.02	Approved	Under Review
Lake Charles Exports	2.0	15.74	Approved	Under Review
Carib Energy	0.04	0.31	Approved	Under Review
Dominion Cove Point	1	7.87	Approved	Under Review
Jordon Cove Energy Project	2	15.74	Approved	Under Review
Cameron LNG	1.7	13.38	Approved	Under Review
Gulf Coast LNG Export	2.8	22.04	Approval	Under Review
Gulf LNG Liquefaction	1.5	11.81	Approved	Under Review
LNG Development Company LLC	1.25	9.84	Approved	Under Review
SB Power Solutions	0.07	0.55	Approved	Not Applicable
Southern LNG	0.5	3.94	Approved	Under Review
Excelerate Liquefaction	1.38	10.86	Approved	Not Applicable

[190] Henry Hub is the main price point for the US. The average Henry Hub price for gas ranged between US$1.95/MMBtu to US$5.83/MMBtu or approximately US$1.83/GJ to US$5.47/GJ between January 2010 to March 2013.
[191] According to Ratner et al. (2013), gas exports from the US require federal approval under section 3 of the *Natural Gas Act* (15 U.S.C 717b) with the US Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC). There are no known gas export restrictions to FTA countries. Three LNG export facilities in the US (Sabine Pass LNG, Kenai LNG and Freeport LNG) have been approved to export LNG to non-FTA countries.
[192] According to Ratner et al. (2013), there are currently seven companies that have permission (four are pending) to re-export LNG cargoes from foreign countries. According to the Department of Energy's Quarterly Gas Imports and Exports reports and GIIGNL (2013), in 2012, US companies have already re-exported approximately 0.41 million tonnes of LNG (or 18.8 Bcf) to other countries.
[193] The US DOE studies on LNG exports, namely the EIA's analysis (2012c) and NERA Consulting (2012) report, are available at http://energy.gov/fe/services/natural-gas-regulation/lng-export-study, accessed 13 June 2013.
[194] NERA's (2012) study also indicated large US consumers of gas may be hurt by LNG exports due to price rises. However, a report by the Bipartisan Policy Centre (2013) finds otherwise, stating that LNG exports are unlikely lead to US domestic gas price rises.
[195] A report by the Bipartisan Policy Centre (2013) find contrary results to NERA's (2012) study, that LNG exports are unlikely lead to US domestic gas price rises.
[196] The high export scenario examined in the EIA's (2012c) analysis assumes exports are limited to 12 bcf/day (approximately 80 Mtpa), which is significantly lower than all the projects under consideration.
[197] The LNG export debate is active in the US capital. According to Ratner et al. (2013), several Bills have been introduced to the US House of Congress to consider expediting international LNG exports, S.192 and H.R. 580 – Expedited LNG for American Allies and H.R. 1189 and H.R. 1191 – American Natural Gas Security and Consumer Protection.

Solutions				
Golden Pass Products	2.6	20.47	Approved	Not Applicable
Cheniere Marketing	2.1	16.53	Approved	Under Review
Main Pass Energy Hub	3.22	25.35	Approved	Not Applicable
CE FLNG	1.07	8.42	Approved	Under Review
Waller LNG Services	0.16	1.26	Approved	Not Applicable
Pangea LNG	1.09	8.58	Approved	Under Review
Magnolia LNG	0.54	4.25	Approved	Not Applicable
Trunkline LNG Export	2.0	15.74	Approved	Under Review
Gasfin Development USA	0.2	1.57	Approved	Not Applicable
Freeport-McMoRan Energy	3.22	25.35	Approved	Under Review
Sabine Pass Liquefaction	0.28	2.20	Under Review	Under Review
Sabine Pass Liquefaction	0.24	1.89	Under Review	Under Review
Venture Global LNG	0.67	5.27	Under Review	Under Review
Total Applications Received	**36.63 Bcf/d**	**288.32 Mtpa**	**278.97 Mtpa**	**224.66 Mtpa under review**

Source: DOE US, Applications received by the DOE/Fossil Energy to Export Domestically Produced LNG, http://energy.gov/sites/prod/files/2013/05/f0/summary_lng_applications_0.pdf, 17 May 2013, accessed 7 June 2013. LNG facilities that have applied for non-FTA exports are assumed to seek "blanket" approvals from the DOE, US. Table is updated to account for Freeport LNG obtaining approval from US DOE in May 2013, See Oil and Gas Journal (2013) or http://energy.gov/sites/prod/files/2013/05/f0/ord3282.pdf. **Note:** approximately 2.2 bcf/d of the liquefaction capacity of Sabine Pass Liquefaction facility has been committed to 20 year contracts for supply to BG Group, gasNatural fenosa, GAIL Limited and Kogas. See http://www.cheniereenergypartners.com/liquefaction_project/liquefaction_project.shtml, accessed 8 November 2012.

Table 23 shows that a large quantity of LNG from the US could become available post 2015 if some of all of the requested non-FTA export licenses are approved.[198] While only two LNG export facilities have been approved to date (Sabine Pass and Freeport LNG, totalling 28.34 Mtpa), it is anticipated that LNG exports could commence in the near term to the countries that already have FTAs with the US until non-FTA export approvals are granted.[199]

Canada is also considering several LNG projects that would facilitate the export of gas. In February 2013, Canada's National Energy Board granted a LNG export licence to LNG Canada to export up to 24 Mtpa. This brings to three (for 36 Mtpa) approvals granted for projects located on the West Coast of Canada.[200]

If changes in US regulations facilitate the export of gas, up to a total of 224.66 Mtpa may be supplied to the international LNG market in the 2013 to 2022 period, potentially creating an excess of LNG supply internationally towards the end of the period.[201] This may potentially influence the pricing of existing LNG contracts with WA suppliers.

Russia

As a major exporter of gas, Russia has the potential to significantly influence LNG projects supplying the Asia Pacific region due to its proximity to the three largest LNG consumers in the Asia Pacific.

[198] Despite the prospect of the US significantly contributing to international LNG supply, Credit Suisse Global Equity Research (2012) indicates US dry gas converted to LNG requires more processing as US gas is "leaner" (lower heating or calorific value) than gas sourced from WA. Gas that is purchased from WA meets Japanese city gas mandated calorific value. In addition, Moody's Investor Service (2013) suggests only four additional projects (in addition to Sabine Pass) are expected to be approved in the US. The projects that are likely to obtain approval are brownfield projects that already have infrastructure in place and do not require stringent environmental approvals and are backed by companies with at least investment grade balance sheets and experience in the international LNG business.

[199] The US currently has FTAs with 19 countries, including South Korea, a large Asia Pacific consumer of LNG, Mexico and Chile as other potential customers (Deutsche Bank, 2012), see http://www.ustr.gov/trade-agreements/free-trade-agreements for a list of FTA countries.

[200] According to IEEJ (2013) and Reuters (2013), the three projects that have been granted approval are LNG Canada (February 2013 – Project Partners - Shell, Kogas, Mitsubishi and PetroChina), Kitimat LNG (October 2011 - Chevron and Apache Corporation) and privately owned BC LNG Export Co-operative's project.

[201] Note the total figure LNG export figures does not include speculative LNG projects in Canada.

China is actively negotiating multiple gas purchases with Russia, with some agreements already signed for LNG shipments from Russia to China anticipated to commence in 2015.[202]

Although Russia has only issued a single export license to date to its government-owned entity, Gazprom, and only exports approximately 14.8 Mtpa of LNG internationally, this situation is likely to change.[203] Russia is planning to produce 40 to 50 Mtpa of LNG by 2020 by further opening up the gas export market by licensing other privately owned gas producers.[204,205]

Singapore

Singapore is well positioned as a gas trading hub in the Asia Pacific region. As a major transhipment hub for the Asia Pacific and Europe, Singapore is at the centre of major LNG shipping routes between existing and potential gas producing regions such as Africa, Australia, Europe and the Middle East and Asia Pacific gas consumers.

In 2013, Singapore completed Phases 1 and 2 (two storage tanks) of its multi-user LNG storage facility and commenced commercial operations in May 2013, after receiving its first cargo from Qatar.[206,207] Although the facility only recently commenced operations, Singapore is already expanding this facility (phase 3, to 6 Mtpa) by the end of 2014.[208]

This facility has the ability to import and export LNG as well as accommodate multiple types of LNG carriers, located just off the main island of Singapore.[209] Coupled with an active oil trading community, fuel bunkering specialists and an international trader scheme in Singapore, this multi-user LNG storage facility will significantly increase the availability of short-term LNG to the Asia Pacific region, allowing Singapore to initiate and price short-term LNG for the Asia Pacific.[210] This may impact on export dependent LNG projects, LNG contract prices and domestic gas prices currently being negotiated in Australia.[211]

Singapore currently has FTAs with potential key LNG producers and suppliers such as Australia, China, the EU, India, Japan, South Korea, the Association of South East Asian countries and the US. It is also anticipated to complete FTAs with Taiwan by June 2013 and Canada by the end of 2020.[212,213] These FTAs may provide Singapore with a comparative advantage allowing it to access and acquire LNG gas supplies that are currently abundant in EU and US for redirection and re-export to Asia Pacific LNG customers.[214] Despite the inherent possibility of Singapore becoming a key player in Asia Pacific's LNG market, this ability

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[202] See Bloomberg (2013b), Russia Hastens China Energy Pivot with Oil, LNG Supply Deals, http://www.bloomberg.com/news/2013-06-21/russia-hastens-china-energy-pivot-with-crude-lng-supply-deals.html, accessed 24 June 2013.

[203] LNG deals between Russia and China were signed between OAO Novatek and China National Petroleum Company for gas to be processed at the proposed Yamal LNG facility for China. OAO Novatek would require licenses to export gas. Gazprom has also eased its stance against Russia issuing other LNG licenses, see Bloomberg (2013c), http://www.bloomberg.com/news/2013-06-28/gazprom-eases-stance-on-lng-monopoly-as-putin-urges-competition.html, accessed 4 July 2013.

[204] According to the IEEJ (2013b), Russia has only issued a single LNG export licence to Gazprom.

[205] See Bloomberg (2013), Russia's LNG Rush Gives Japan Strongest Bargaining Chip, 13 June, 2013, http://www.bloomberg.com/news/2013-06-12/russia-s-lng-rush-gives-japan-strongest-bargaining-chip.html, accessed 17 June 2013.

[206] See Bloomberg (2013) Singapore Gets First LNG Cargo from Qatar at Jurong Island, http://www.bloomberg.com/news/2013-03-28/singapore-receives-first-lng-cargo-from-qatar-at-jurong-island.html, accessed 28 March 2013.

[207] See Energy Market Authority of Singapore's (2013b) new release.

[208] Wall Street Journal (2012), Singapore Plans to Expand Unfinished LNG Terminal, http://online.wsj.com/article/SB10001424052970203897404578076112199131482.html, accessed 28 March 2013.

[209] According to public statements from the Energy Market Authority of Singapore (2013), the Singapore LNG facility is expected to be operationally active by the second half of 2013. At the initial stage, it can store around 6 Mt of LNG. According to speech by Mr Iswaran, Second Minister for Trade and Industry for Singapore, http://www.ema.gov.sg/news/view/590, Singapore is constructing additional storage to expand capacity to 9 Mt with the potential for further expansion to 12 Mpta within the next 10 years. See http://www.slng.com.sg for more details.

[210] Singapore's International Trader scheme http://www.guidemesingapore.com/industry-guides/trade/singapore-global-trader-scheme, accessed 8 April 2013.

[211] Currently, a number of LNG contracts are priced using traditional oil-related indexes (the Japanese Customs Cleared or some other combination of oil indexes) or using the Japan/Korea marker for spot LNG. Japanese customers have publicly indicated they are unhappy with the situation (Reuters, 2012). Some new LNG gas sales agreements from the US for 2017 are already linked to Henry Hub price (Reuters, 2012b).

[212] See IE Singapore (2013), http://www.fta.gov.sg/sg_fta.asp, United States Trade Representative (2013), http://www.ustr.gov/trade-agreements/free-trade-agreements and Europa (2012), press release, 16 December 2012, http://europa.eu/rapid/press-release_IP-12-1380_en.htm, accessed 5 March 2013.

[213] International Times (2013), http://www.globaltimes.cn/content/759308.shtml, accessed 5 March 2013.

[214] Note that many existing LNG supply contracts may include destination/resale restriction clauses within the sale and purchase agreements though the enforceability of these clauses is being disputed by international competition authorities (such as the EU Commission).

may be curtailed as the operator of the LNG storage facility, Singapore LNG Corporation, has publicly stated that the LNG storage will be prioritised to meet Singapore's domestic gas needs.

End of Premium LNG Pricing in the Asia Pacific Region

Between 2010 and 2012, the average imported price of LNG in the Asia Pacific region ranged between A$10.90 and A$15.87 per GJ, significantly higher than gas prices quoted at the Henry Hub (approximately A$1.83 to $5.47 per GJ between January 2010 and March 2013) in the US.[215] The persistent high price of LNG in the Asia Pacific region results from the reliance of Japan, South Korea and Taiwan on the LNG market. These major LNG consumers lack indigenous gas production and access to infrastructure connecting these countries to major sources of gas supply, relying almost exclusively on LNG as the source of gas.[216] Asia Pacific LNG demand is also more than double the size of Asia Pacific LNG export capacity, supporting comparatively higher prices in the region.

The persistence of high Asia Pacific LNG prices has led Japan, the largest LNG consumer, to release a strategy document aimed at lowering gas prices domestically. In September 2012, Japan's Energy and Environment Council's Innovative Strategy for Energy and the Environment outlined how Japan intends to increase its LNG imports from North America to stabilise the cost of its LNG supply.[217] Japan has also publicly stated it does not favour oil-linked pricing in its LNG import contracts.[218] This stance may jeopardise potential LNG projects in WA that have yet to secure long-term LNG sale agreements.

The misalignment in LNG pricing across LNG regions has also encouraged the unabated interest in developing LNG liquefaction projects (especially in North America and Russia) to serve Asia Pacific demand.[219] Although it is unlikely at this point, the potential future abundance of supply servicing the Asia Pacific region may cause Asia Pacific LNG prices to be delinked from oil-indexed pricing.[220] At the time of this report, some long-term LNG contracts signed between US LNG exporters and other countries are already delinked from oil indexes; Cheniere Energy's Sabine Pass with BG Group, Total, Korea Gas, India's GAIL, Spain's Fenosa and the United Kingdom's Centrica.[221] In addition to the potential for price delinking, other models of LNG contracting are emerging, such as tolling agreements between Freeport LNG and Japanese customers, Chubu Electric and Osaka Gas and BP Energy.[222]

As one of the highest cost producers of LNG internationally, WA is at risk of displacement in the LNG supply chain when long-term LNG contracts for WA LNG begin to expire from 2016.[223,224] This displacement may accelerate if the US approves a significant number of pending LNG export applications.[225]

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[215] Data used is from BP (2013) Statistical Review of World Energy 2013, converted using A$1 = $USD1.01 and converting 1 million BTU (mmBTU) = 1.055 PJ.

[216] The exception is China that has access to international supply of gas from cross country pipelines.

[217] This is outlined in the Innovative Strategy for Energy and Environment policy document, available at http://www.npu.go.jp/en/policy/policy06/pdf/20121004/121004_en2.pdf.

[218] This was outlined by Mr Yukio Edano, the Japanese Trade Minister, Mr Ken Koyama, Managing Director, IEEJ and the President of Tokyo Gas, at the inaugural LNG Producer-Consumer Conference in Japan (Reuters, 2012). Currently, Asia Pacific pricing of LNG in the Asia Pacific is usually linked to the Japanese Customs Cleared (sometimes also known as Japanese Crude Cocktail, oil-linked) price.

[219] According to IEEJ (2013), Japanese LNG import volumes registered a new high in 2012.

[220] It is likely new gas contracts will partially move towards other forms of pricing in the interim, with the flexible portion of contracts likely to be hub or regional priced (using price markets such as Henry Hub, Japan Korea Marker or East Asia LNG Index). Due to the high costs of LNG liquefaction investment, much of the contracted volumes may continue to remain oil-linked.

[221] All Sabine Pass contracts are linked to the Henry Hub price. In addition to the Sabine Pass LNG contracts, Tokyo Electric (TEPCO) also signed a conditional agreement with Cameron LNG that links its LNG to Henry Hub prices (see Wall Street Journal, 2013). Although Henry Hub pricing seems advantageous today, EnergyQuest (2013b) reports that several speakers at the recent LNG 17 Conference in April 2013 suggest the Henry Hub is currently below the replacement cost of gas and when gas is priced at replacement cost, US LNG linked to Henry Hub is no different to oil index pricing.

[222] Tolling agreements are agreements that essentially separate liquefaction from the acquisition of gas. The LNG liquefaction operator and customers only agree to the rights of liquefaction and loading of gas onto LNG ships ("toll"). The LNG customer is responsible for acquiring its own gas and shipping to the liquefaction facility for processing. See FreePort LNG Press Release (2012) for information on Chubu Electric and Osaka Gas and FreePort Press Release (2013) for more information.

[223] See Macquarie Equity Research (2012), Credit Suisse Global Equity Research (2012), Deutsche Bank (2012) and Deloitte (2013b) for international comparisons of LNG production costs, McKinsey and Company (2013) also provides a breakdown of cost estimates for LNG projects in Australia. Some NWSJVs' long-term contracts are anticipated to expire starting 2016.

[224] AFR (2013) reports that some LNG contracts in Australia are already at significant risk of being discontinued.

[225] Deloitte (2013) suggests this may be a likely outcome.

High Cost of LNG Production

The high cost of LNG production in Australia remains a key issue for the LNG export market. The development of FLNG projects is a demonstration of this trend, as international LNG suppliers benchmark their projects internationally. A study by McKinsey reports the cost of development of LNG export facilities in Australia is now 20% to 30% higher than that in North America and East Africa.[226] The report highlights the following factors that form the cost differential that may be reduced are:

- tax, including royalties, duties and tariffs, depreciation, capital allowances and carbon tax;
- length of regulatory approvals;
- lower labour productivity, due to working hours, the remoteness of LNG developments, logistics errors and a less experienced workforce;
- cost of construction due to labour costs; and
- project design and engineering due to choice of design, regulation and economies of scale.

If the cost of developing LNG projects becomes prohibitive in Australia, potential LNG developments currently planned for WA may be abandoned.

Availability of Unconventional Gas to International Gas Supply

The timing and availability of unconventional gas, in the form of shale gas, tight gas and coal bed methane (coal seam gas [CSG]) has the potential to significantly modify the international gas supply landscape. The best example of this potential impact is the change to the US domestic gas market experienced between 2000 and 2012. During this period, the US has moved from a major importer of international gas to a potential supplier of international gas due to unconventional gas supplies entering the US domestic market, causing US domestic prices to fall rapidly.

International resources of gas have increased primarily due to the rapid exploration for and extraction of unconventional gas. Previously, it was estimated there was approximately 50 to 60 years of gas remaining for the entire international gas market, however unconventional gas resources have significantly improved this estimate to more than 200 years.[227]

According to the EIA's assessment of shale gas resources in 32 countries, China holds a large reserve of shale gas followed by the US, Argentina and Mexico.[228] With China exploring for unconventional resources intensively and the US ready to export LNG, the timing and the quantum of unconventional gas contributing to international gas supply may alter the international gas market considerably.[229]

While its production is still in its early stages in WA and around the world, unconventional gas has the potential to transform gas markets internationally that are centred on conventional gas supply. The impact of unconventional gas on LNG exports is still not clear and this needs to be monitored closely by WA LNG exporters, market regulators and governments.

[226] See McKinsey (2013), Extending the LNG boom: Improving Australian LNG productivity and competitiveness http://www.mckinsey.com/locations/australia/knowledge/pdf/Extending_LNG_boom.pdf, accessed 13 July 2013.
[227] This is outlined in Ernst and Young (2013).
[228] EIA (2011) reports China, US, Argentina and Mexico hold 1,275 Tcf, 862 Tcf, 774 Tcf and 681 Tcf of shale resources, respectively.
[229] While the timing of gas supply is important, the composition of unconventional gas (typically less dense than conventional gas) is also a consideration for gas exports.

7. Gas Supply, Capacity and Projections

This section provides a snapshot of gas supply in the WA domestic gas market, an outline of major domestic gas suppliers and annual gas supply projections for the 2013 to 2022 period.

7.1. WA Domestic Gas Supply

Currently, gas supply to the domestic market is mostly extracted from associated “wet” gas or condensate rich hydrocarbon fields.[230] Following field appraisal and development, gas is then processed and sold as a commodity either domestically or internationally, or consumed to meet the energy requirements of the processing facilities.

Due to the varying characteristics of hydrocarbon fields, the cost of gas processing is largely driven by plant design and commercial considerations that are typically matched to field characteristics to maximise the recovery of the resource. Scale is often an important consideration to ensure the viability of gas production, especially with projects located offshore.[231]

Gas supply to the domestic market is largely contingent on the commercial viability of LNG export projects or the production of associated hydrocarbons.[232] The small size of the domestic gas market relative to these markets implies the development of large offshore gas fields (>2,000 PJ) solely for the domestic market is not considered as they may not be commercially viable.[233]

Gas producers (with LNG export capacity) value their resources primarily on the market opportunity of selling it internationally or domestically.[234] Hence, the price of domestic gas in WA is guided by domestic demand and supply conditions and international LNG prices.[235] High domestic gas prices draw investment into expanding domestic gas processing capacity.[236]

Since the completion of the WANG pipeline (now known as Parmelia Pipeline) and the DBNGP, the rapid growth of domestic gas consumption drove the expansion of domestic gas supply between 1986 and 1995 to various parts of WA; such as the Pilbara, Mid-West and the Goldfields. By 1995, gas supply to the domestic market was supplied from two basins through nine gas suppliers (six in the Carnarvon and three in the Perth Basins).

Despite an increase in domestic supply from various sources, the Carnarvon Basin remains the dominant source of supply (as discussed in chapter 3). Low domestic gas prices locked into long-term gas supply contracts and low international oil prices between 1997 and 2003 provided little encouragement for further resource exploration in WA. This resulted in no new suppliers entering the domestic gas market in this period and led to the exit of some domestic gas producers (via the depletion of gas fields) until gas prices started to climb around 2004.[237]

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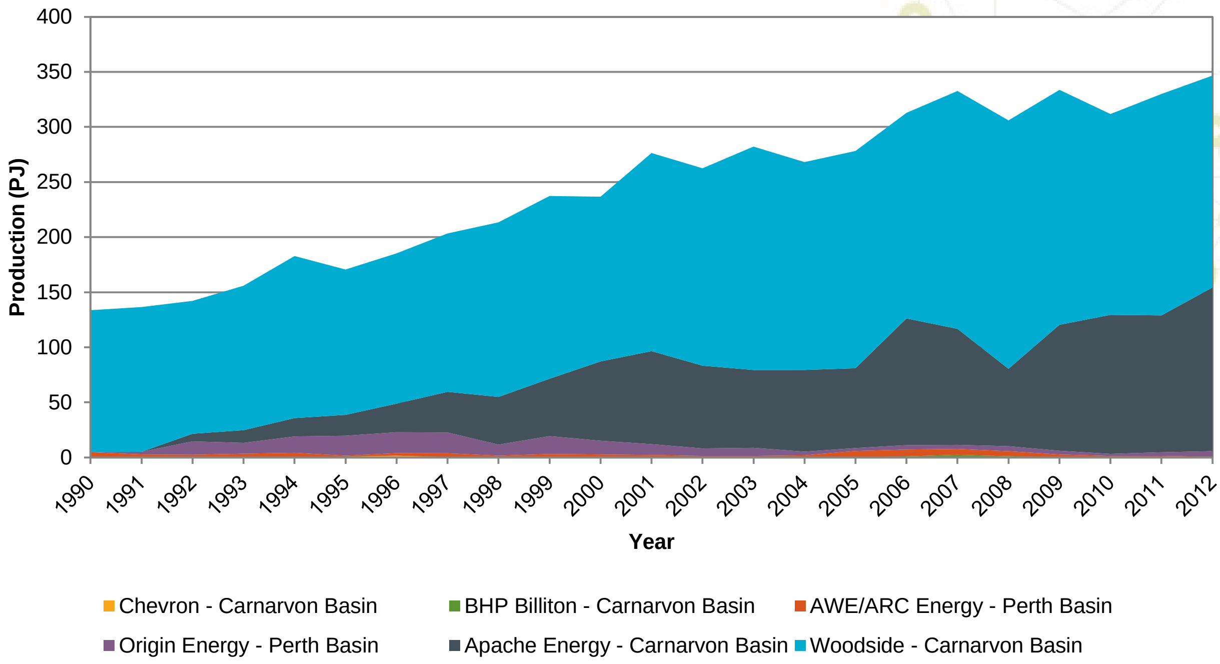
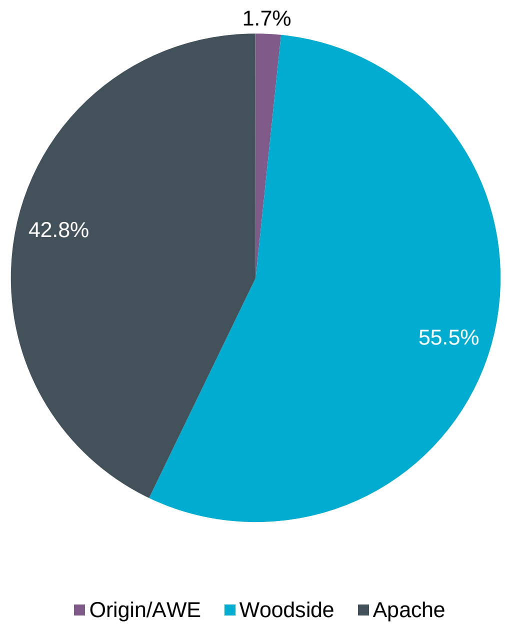
[230] Oil and gas companies typically prefer to exploit “wet” gas fields as these field are higher in profitability with approximately 3%-6% of associated gas. Gas may also be termed “non-associated” when it comes from dry wells, where there are low quantities of crude oil or condensate.
[231] The volume of associated “liquid” hydrocarbons and/or forward gas sales (either by volume or price) for a field may also influence project viability.
[232] Sometimes domestic gas projects may also be tied to oil export projects. This situation is expected to persist for the 2013 to 2022 period as the bulk of domestic gas supply continues to be “LNG linked” via the NWS JVs, Gorgon and Wheatstone LNG projects.
[233] The field size thresholds were outlined in the Wood McKenzie (2010) report and used to define large gas fields.
[234] This was outlined in reports by Marchment Hill Consulting (2009) and Frontier Economics (2010). This sentiment was also reiterated by a large market participant to the IMO verbally.
[235] There are other factors such as government regulation and prices of alternative fuels.
[236] This is evidenced by the development of Apache Energy’s Devil Creek facility that is backed by high gas contract prices. This sentiment is also outlined in CRA International (2007) and ACIL Allen (2013).
[237] When SECWA disaggregated in 1995, the subsequent gas and electricity providers (AlintaGas and Western Power respectively) assumed independent legacy contracts with greater flexibility in the terms and conditions but it is understood prices did not vary significantly. Verve Energy then assumed responsibility for Western Power’s legacy contract when the latter was disaggregated in 2006.

Figure 47 – Western Australia Domestic Gas Sales by Operator, 1990 – 2012



Source: APPEA Quarterly Production Data (1990 to 2012).

Figure 48 – Proportion of Domestic Gas Sales (by Operator), 2012



Source: APPEA 2012 Quarterly Production data, http://appea.com.au/oil-a-gas-in-australia/statistics.html, accessed 1 May 2013. **Note:** Actual production statistics are only representative of sales as actual sales may deviate from these values due to gas storage.

As shown by Figure 47, by 2009, the smaller gas fields located in the Perth Basin had largely depleted and gas supply competition in the domestic market had largely disappeared, becoming concentrated to two producers, the Apache operated Varanus Island (Harriet and East Spar JVs) and the NWS JVs.[238]

Between 2009 and 2011, high domestic gas prices and the signing of several new gas supply contracts led to the commencement of the Devil Creek gas processing facility in 2012. According to 2012 production statistics from APPEA, the NWS, Varanus Island and Devil Creek facilities supplied approximately 98.3% of the total domestic market (see Figure 48).

In the 2013 to 2022 period, additional gas supply and capacity is anticipated to come from Empire Oil and Gas' Red Gully and BHP Billiton's Macedon facilities in 2013 and two additional domestic processing facilities (Gorgon and Wheatstone) before 2022 (see Table 24). Other proposed facilities such as Buru Energy's Yulleroo, Transerv Energy's Warro and Woodside's Pluto are planned, but these projects have yet to reach investment decisions and it is unclear when these facilities may commence.

Table 24 – Domestic Gas Processing Facilities that may be Operational by 2022

Processing Facility	Operator	Basin	Pipeline Connection	Anticipated Completion
Red Gully	Empire Oil and Gas	Perth	DBNGP	2013**
Macedon	BHP Billiton	Carnarvon	DBNGP	2013
Gorgon Domestic	Chevron	Carnarvon	DBNGP	2016 and 2020
Wheatstone Domestic	Chevron	Carnarvon	DBNGP	2019
Warro	Latent Petroleum	Perth	Parmelia** /DBNGP	Currently under evaluation; subject to commercial viability
Pluto Domestic*	Woodside	Carnarvon	DBNGP	Currently under evaluation; subject to commercial viability*
Yulleroo / Valhalla	Buru Energy	Canning	Proposed Great Northern Pipeline	Currently under evaluation; subject to commercial viability

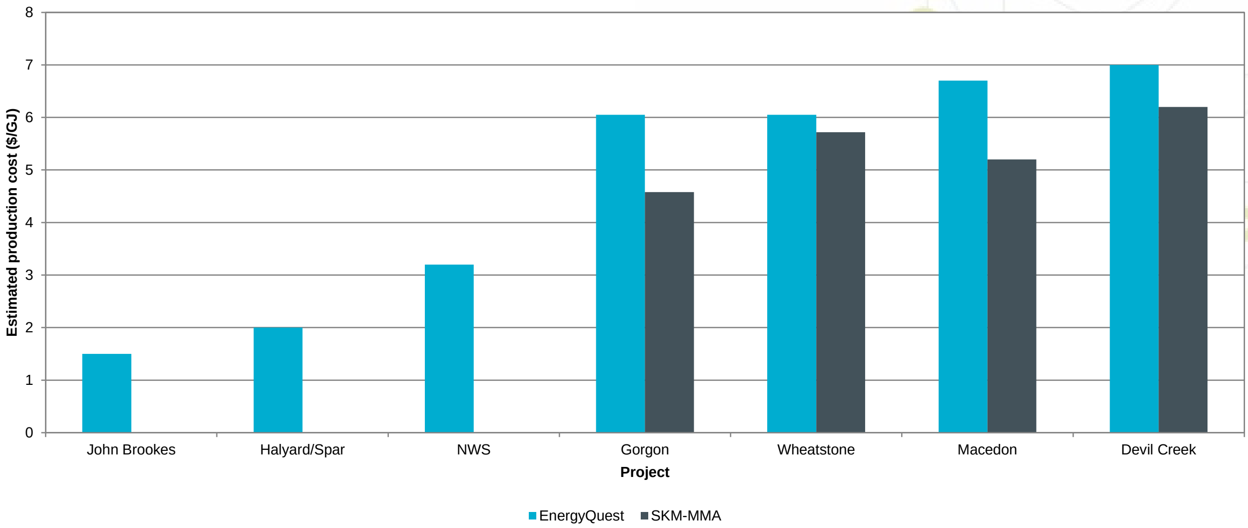
Source: Respective corporate websites. **Note:** *The status of Pluto domestic is unclear, according to Energy-pedia (2013b), Woodside recommenced exploration in 2014 in an attempt to expand Pluto's LNG plant, but this decision may have been reversed in July 2013, see the West Australian (2013e) article. Pluto's domestic gas facility may be dependent on the results of this exploration. Woodside has entered into an arrangement with the WA Government that commits to the supply of domestic gas, which is anticipated to begin 5 years after the first LNG is exported, providing it is commercially viable to do so. ** At the time of this report, Empire Oil and Gas' Red Gully facility is already operational.

7.2. Gas Production Costs

According to EnergyQuest, the production cost of domestic gas from conventional sources has significantly increased with recent projects such as Gorgon, Wheatstone, Macedon and Devil Creek processing facilities having a production cost in the range of $6/GJ to $7/GJ (see Figure 49).[239] A recent report by the Australian Council of Learned Academies (ACOLA) estimates the required gas price for shale gas to be approximately $5.30/GJ to $8.65/GJ.[240]

[238] There were smaller gas producers such as ARC Energy and Origin Energy in the Perth Basin.
[239] SKM-MMA (2011) also finds gas production costs to be between $4.50/GJ to $6.50/GJ in 2010 for various gas projections.
[240] See ACOLA (2013) for the cost of shale gas production. According to Business News (2013), this is similar to Santos' estimate of $6/GJ to $9/GJ.

Figure 49 – Estimated Production Costs (nominal), 2010



Source: Energy Quest (2011) and SKM-MMA (2011). **Note:** The estimates for John Brookes, Halyard/Spar and NWS may not truly represent the full cost of production, as the fields are tied back to existing processing facilities and the cost estimates do not take into account any additional capital costs that may have been incurred to modify and upgrade existing facilities to support varying field specifications.

The increasing cost of processing gas sets a floor for the price of WA domestic gas.[241] Short-term gas demand from conventional resources (for May 2013) is priced between $4.75/GJ and $7.20/GJ, while medium to longer term gas contracts (greater than one year) are believed to be priced above $6.50/GJ (see Figure 8 in section 3.2).[242]

7.3. Gas Supply Projections

For the 2013 to 2022 period, domestic gas availability will be influenced by domestic gas prices, prices of alternative fuels, regulation and international LNG demand and supply, with these factors driven by an increasing focus on:

- the introduction of emissions trading in various countries[243] and the drive to reduce carbon emissions;
- the need to balance the variability of electricity produced by intermittent generation in the electricity system due to the growth of these generators (such as solar and wind);
- the expected de-nuclearisation of Western Europe[244] and perhaps Japan (by 2040) in a post-2011 Fukushima disaster world;
- increasing energy intensity in China and India to power these fast growing economies; and
- competing gas supply from other countries (US, Canada etc.).

This GSOO considers the supply of natural gas to the domestic market from three perspectives.

- gas supply;

[241]In the Productivity Commission's (2013) report, APPEA highlights new gas discoveries are often distant from customers and shipping infrastructure and are increasingly more expensive to commercialise.

[242] Short term gas prices are acquired from Gas Trading Pty Ltd for May 2013, http://www.gastrading.com.au/spot-market/historical-prices-and-volume.html, accessed 7 June 2013. For information on long term gas contracts completed for the period 2001 to 2011, see Prime Minister's Manufacturing Taskforce (2012), Appendix 2, Domgas Alliance (2013) and EnergyQuest (2013) for more information.

[243] Australia and 31 European countries have emissions trading scheme in place http://ec.europa.eu/clima/policies/ets/index_en.htm and China is expected to introduce a carbon trading scheme in 2015, see http://www.smh.com.au/federal-politics/political-news/china-seeks-australias-help-building-emissions-trading-scheme-20130711-2prjh.html.

[244] According to the World Nuclear Association (2013), European countries such as Austria, Belgium, Denmark, Germany, Greece, Ireland, Italy, Latvia, Luxembourg, Malta, Norway, Portugal, Slovenia, Spain, Sweden and Switzerland have indicated that they are either phasing out nuclear reactors or remain opposed to nuclear energy.

- availability of gas processing capacity; and
- the adequacy of gas reserves (see chapter 8).

The measure of gas supply is essentially the quantity of gas that suppliers are willing to supply to the domestic market at various gas prices,[245] being an estimate of potential gas supply. Gas producers are willing to supply gas to the domestic market if a commercially acceptable price is agreed with existing or potential consumers. The price would be greater than the marginal costs (gas extraction costs, operating costs) and at least equivalent to the opportunity cost of future sales.[246] Domestic gas prices and related factors are described in section 4.4. Equilibrium prices are not estimated as historical data on these prices are unavailable to NIEIR and the IMO.

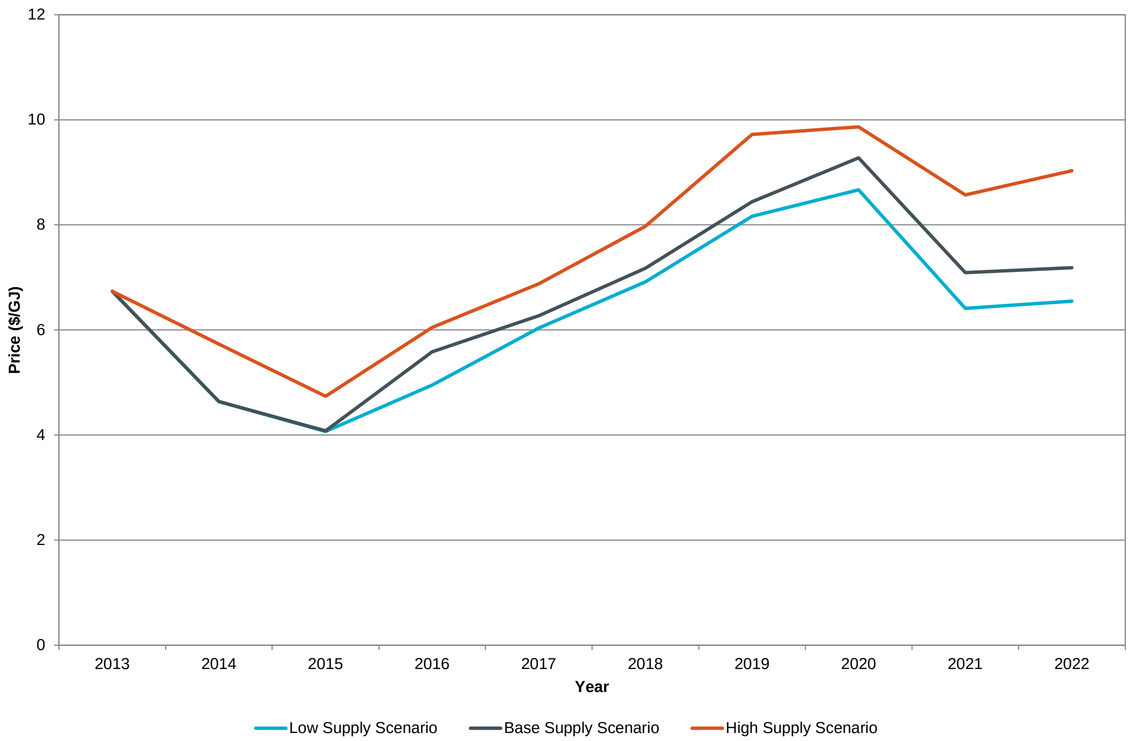
In this GSOO, gas supply refers to this potential gas supply.

This GSOO considers three scenarios (Base, Low and High) for gas supply on the basis of different assumptions for domestic prices for the 2013 to 2022 period outlined in section 4.4 (see also Figure 50).

While pipeline capacity is discussed in chapter 9, this GSOO does not project pipeline capacity for the gas transmission system.[247] As pipeline operators have indicated they do not increase the transmission capacity of existing pipelines unless incremental increases in gas transmission are secured by financial commitments via long-term agreements with gas shippers. Consequently, transmission capacity for the 2013 to 2022 period is assumed to be available to ship gas to domestic consumption. This means gas supply forecasts reported in this GSOO are estimated on the assumption that there are no constraints to pipeline capacity.

Domestic Gas Supply

Figure 50 – Forecast Gas Prices for Domestic Market, 2013 – 2022

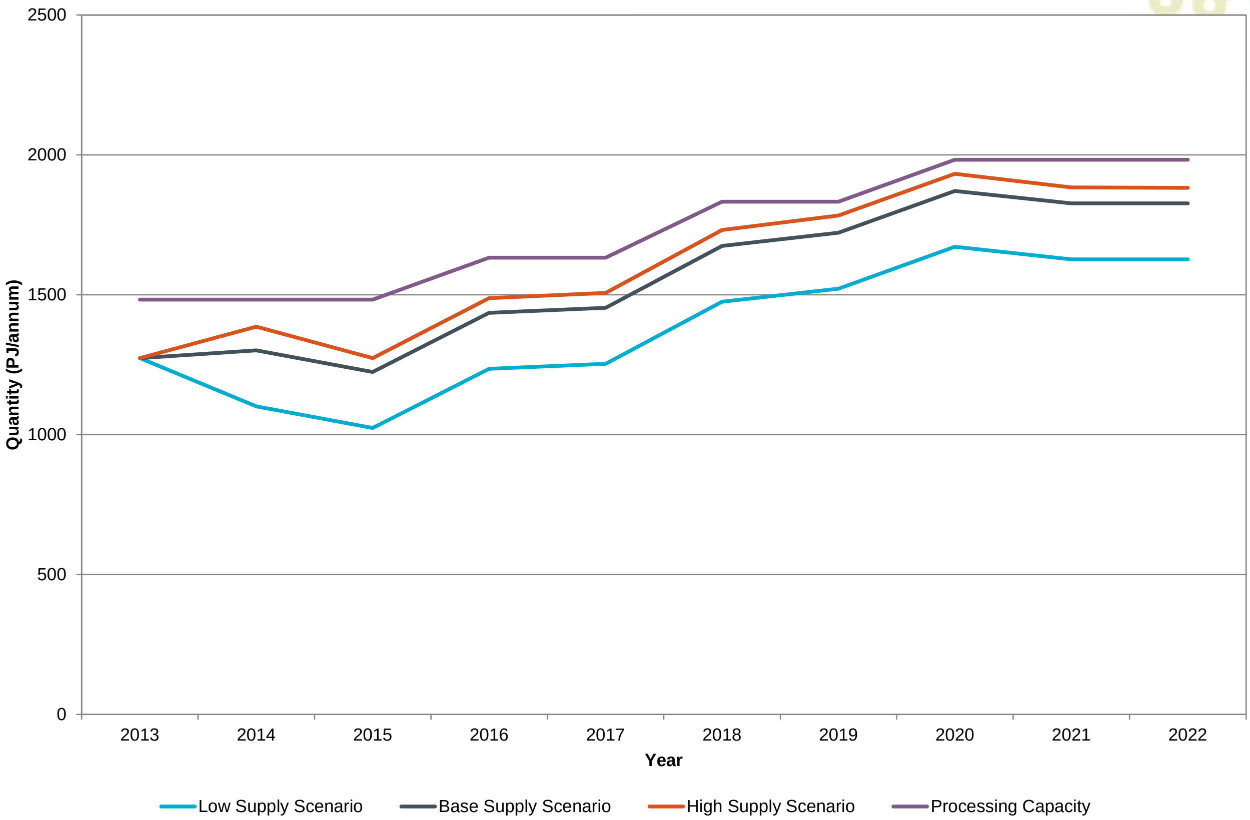


[245] The IMO recognises that while domestic gas prices are a major determinant of gas sales agreements, the terms of the contract may also be a very important aspect of gas supply.
[246] This was outlined by a major gas producer to the IMO.
[247] Only announced expansions to pipeline capacity have been considered in the domestic supply model.

Source: NIEIR's Forecasts 2013-2022. **Note:** Gas prices are nominal prices. Supply availability forecasts must be used with caution they depend on the projected prices for the 2013 to 2022 period.

Figure 50 presents the forecast gas prices for the domestic market for the 2013 to 2022 period. NIEIR forecasts gas prices will fall between 2013 and 2015 but start to increase beyond 2015, tracking fluctuations in forecast LNG netback prices. According to NIEIR's forecasts, the linkage between domestic gas prices and LNG netback prices increases with the commencement of Gorgon and Wheatstone LNG export facilities, which are expected to be operational in 2015 and 2016.

Figure 51 – Potential Domestic Supply Forecasts, 2013 – 2022



Source: NIEIR's Forecasts 2013-2022. **Note:** Supply availability forecasts must be used with caution as they depend on the projected prices for the 2013 to 2022 period.

Figure 51 shows NIEIR's domestic supply forecasts through to 2022. These gas supply curves are highly dependent on the forecast gas prices for the same period, as shown in Figure 50 and reported in Appendix 6. The gaps between the supply side scenarios are attributed to the difference in forecasted gas prices, while the gap between the High supply scenario and gas processing capacity (discussed further below) may be explained by operational requirements, contract-capacity mismatches, prices, field depletion and capacity utilisation.

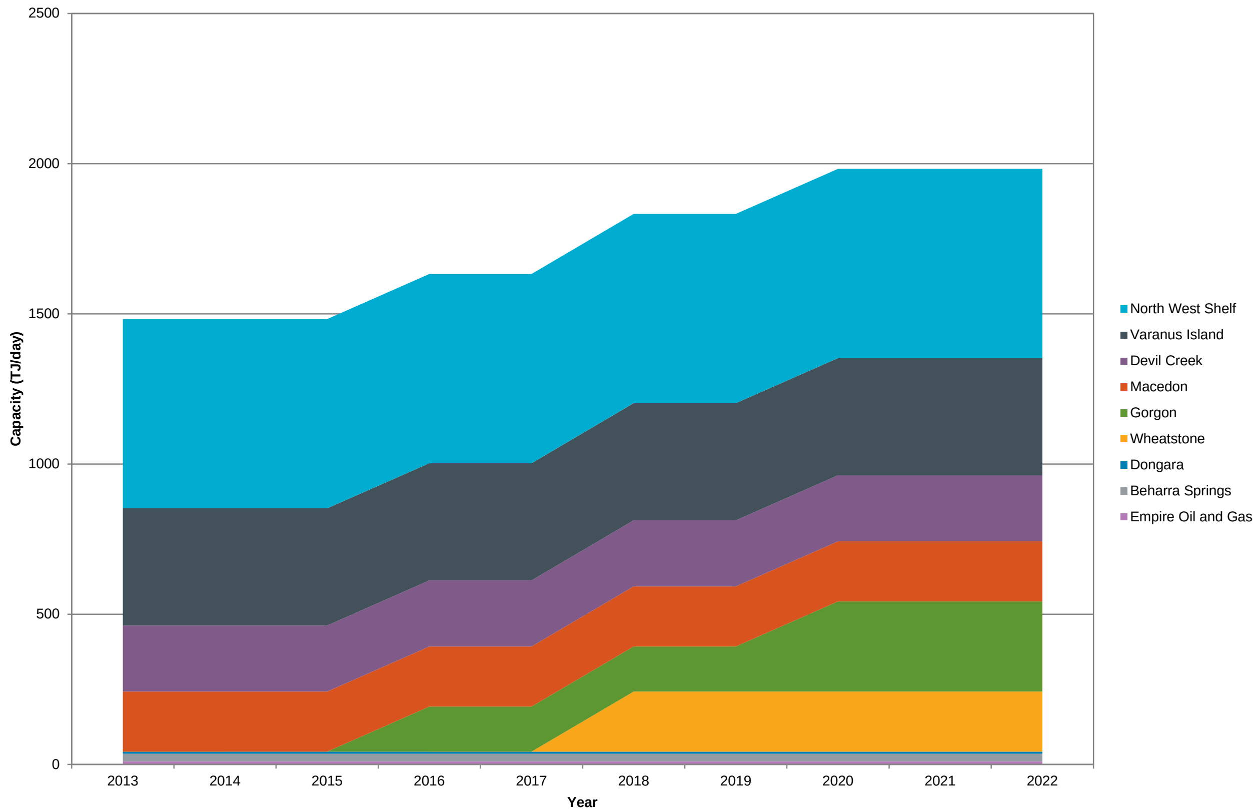
Over this period, gas supply is forecast to grow on average by 3.7% per annum from approximately 1,274 TJ/day (465 PJ/annum) to 1,826 TJ/day (667 PJ/annum) by the end of 2022. Under the High gas supply scenario, domestic supply growth is forecast to be 4.0% per annum to 1,882 TJ/day (687 PJ/annum), while in the Low gas supply scenario domestic supply is forecast to increase at 2.5% per annum on average to 1,626 TJ/day (594 PJ/annum).

Gas Processing Capacity

This section reviews the gas processing capacity for the 2013 to 2022 period. Past reports[248] have often presented gas processing capacity as gas supply. Gas processing capacity is simply the maximum amount gas producers can supply to the domestic market. This is estimated by aggregating the output capacities of all gas processing facilities in WA that are existing and operational, under construction or committed for the 2013 to 2022 period.[249]

Figure 52 presents a view of domestic gas processing capacity based on expected availability and commencement times of all existing and upcoming gas processing facilities. Domestic gas processing capacity will increase from approximately 1482.6 TJ/day to 1982.6 TJ/day by the end of 2022.

Figure 52 – Estimated Gas Processing Capacity of the WA Domestic Gas Market, 2013 – 2022



Source: IMO and various corporate websites. Gas processing capacity for facilities is outlined in section 3.5. Start-up dates represented in this figure are Red Gully and Macedon (2013), Gorgon Phase 1 and 2 (2016 and 2020), Wheatstone (2018) and Dongara expansion (2014). **Note:** Proposed gas processing facilities such as Woodside's Pluto, Buru Energy's Yulleroo and Latent Energy's Warro are not included as these facilities are still being evaluated and there are no known publicly availably commencement dates associated with these proposed facilities.

While gas processing capacity is paramount to gas supply, it is not in and of itself an appropriate representation of gas supply to the domestic market. This view assumes each processing plant intends to operate close to or near maximum capacity, which is inconsistent with production reports from existing gas suppliers operating in the domestic gas market.[250]

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[248] Such as DMP (2010, 2011) and Santos (2013).

[249] Potential domestic supply facilities such as Woodside's Pluto, Buru Energy's Yulleroo and Latent Petroleum's Warro field are not considered in any future supply estimates for this GSOO, due to a lack of certainty regarding completion timeframes associated with their potential contribution to domestic gas supply.

[250] According to Woodside's quarterly production reports, the NWS facility currently operates at approximately 80% capacity, while Apache Energy's Devil Creek plant is reported to only operate at approximately 50% capacity.

8. Gas Reserves

A study into WA's gas supply is incomplete without reviewing the quantity of reserves. WA is the most gas endowed state in Australia. Despite the relative abundance of gas resources in WA, relative to eastern Australia, domestic gas prices in the WA market remain relatively high.

Increasing oil and gas prices have led to an increased interest in WA's gas reserves by international companies over the last decade.

In the last three years, there have been notable investments from international companies such as Apache Energy, BHP Petroleum, Chevron, Eni, Hess, JX Nippon, Mitsubishi Corporation, OMV, PetroChina, Royal Dutch Shell, Santos and Woodside. In addition, investment-backed entities such as Hydra Energy, have also started to take an interest.[251]

There is also increasing interest in the onshore Canning Basin. At the time of this report, it is estimated there are in excess of 90 exploration entities owning interests in various partnerships, JVs, tenements and special prospecting permits in WA.[252]

This chapter provides an overview of key hydrocarbon basins in WA and outlines the reported volume of gas resources that are estimated to lie within these prospective basins.

8.1. Key Basins in Western Australia

There are currently five basins in WA that are known to contain hydrocarbon resources. These are the Canning, Carnarvon, Bonaparte, Browse and Perth Basins (see Table 25).[253]

Table 25 – Conventional gas basins, WA, 2012

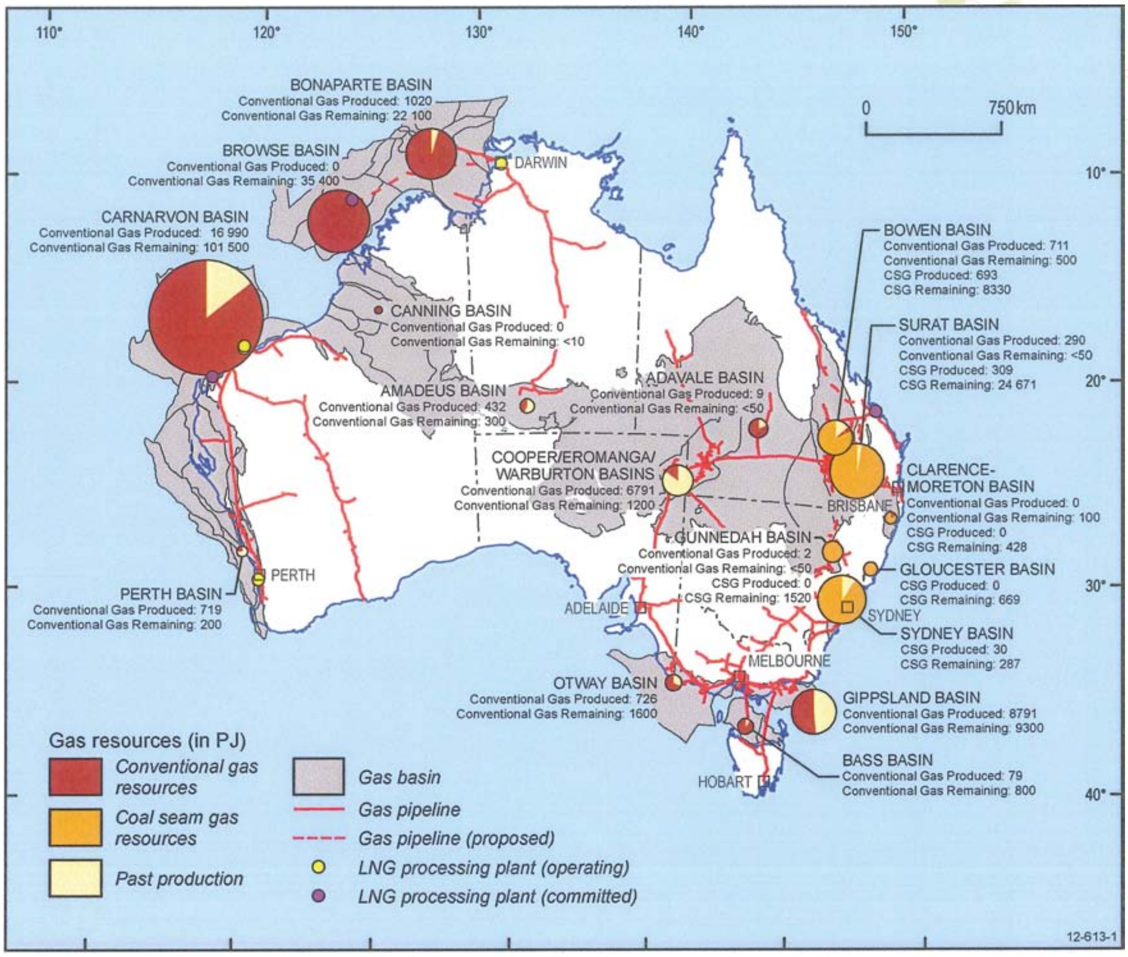
Basin	Total Area offshore, km2 (approximate)	Total Area, onshore, km2 (approximate)	Gas Reserves, by Company (2P, PJ)	Estimated Remaining Reserves (McKelvey's EDR + SDR) (PJ)	Gas Produced (PJ)
Bonaparte	250,000*	20,000*	1,054**	22,000	1,020
Browse	140,000*	0	17,384**	35,300	0
Canning	76,000	430,000	Not available**	<10	0
Carnarvon	535,000	115,000	71,885**	101,500	16,990
Perth	122,500	50,000*	40**	200	719
Total	**1,123,500**	**615,000**	**90,363**	**159,000**	**18,729**

Source: Geoscience Australia (2012), Australian Gas Resources Assessment, 2012, https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=74032, accessed 31 January 2013, and Australian Energy Regulator (2012), State of the Energy Market 2012, http://transition.accc.gov.au/content/item.phtml?itemId=1094439&nodeId=70d6880c1df03a09bca07093f1b5c274&fn=State%20of%20the%20Energy%20Market%20Report%20-%20Complete%20publication.pdf, accessed 13 March 2013. **Note:** The table only highlights conventional gas resources and does not include any estimates of unconventional resources such as CSG, shale gas or tight gas. While the onshore Canning Basin is not well investigated, geologists expect it to be a good prospect for gas resources. *Area figures are from DMP (2013) and Geoscience Australia (2012). Reserves figures are also similar to those reported in Santos (2012). **Gas reserve figures from EnergyQuest (2013b).

[251] Hydra Energy is a privately owned WA company backed by Barclays Natural Resource Investments, an investment arm of Barclays PLC (UK) that has stated it is purchasing shares in several tenements.
[252] Reports from The West Australian (2012) and the AFR (2013) suggest an increasing interest in WA oil and gas resources.
[253] Note that the Amadeus, Bremer, Officer, Ord and Eucla Basins are not outlined in this GSOO as there are currently no official or known estimates of gas reserves in these basins within WA. Some geological information about these basins is outlined in brief in the Government of South Australia's Roadmap for Unconventional Gas Projects in South Australia Report, December 2012, http://www.petroleum.dmitre.sa.gov.au/__data/assets/pdf_file/0008/179621/Roadmap_Unconventional_Gas_Projects_SA_12-12-12_web.pdf, accessed 4 July 2013. At the time of this report, only Rodinia Oil Corp (Canadian company) and Ahava Energy (Australia) are known to be exploring the Officer Basin. DMP has also released new areas in the Officer Basin in June 2013, for petroleum exploration, http://www.dmp.wa.gov.au/7105_17803.aspx.

According to Geoscience Australia, approximately 92% of Australia's entire conventional gas resources are located in WA, most of which are in the Carnarvon, Bonaparte and Browse Basins, while unconventional gas resources (specifically tight and shale) have been discovered in the Canning and Perth Basins.[254]

Figure 53 – Key Australian Gas Basins



Source: Geoscience Australia (2012), gas basins in Australia (offshore and onshore).

8.2. Conventional Gas Reserves

In 2012, Geoscience Australia estimates there are approximately 159,000 PJ of conventional gas reserves located in the five WA basins, of which 90,363 PJ of conventional gas has been booked as 2P[255] reserves by existing entities.

Currently, only the Bonaparte, Carnarvon and Perth Basins are producing gas in WA. Of these, the Carnarvon and Perth Basins produce gas for the WA domestic market and LNG exports and the Bonaparte Basin produces gas for both the Northern Territory domestic market and LNG exports.[256]

Domestic WA gas is expected to continue to be supplied from the Carnarvon and Perth Basins until gas transmission infrastructure is constructed to connect with the other basins.[257] Despite the size and scale of

[254] See Geoscience Australia (2012), Australian Gas Resource Assessment, http://www.ga.gov.au/webtemp/image_cache/GA21116.pdf, for more details
[255] 2P reserves refer to proven and probable reserves that are commonly reported to the ASX.
[256] Eni's Blacktip gas field is producing gas from the Bonaparte Basin which is processed at Wadeye for NT's Power Water Corporation, see Eni's Press Release (2009) for more information. LNG exports from the Bonaparte Basin are produced from the Bayu-Undan gas field.

WA's gas reserves, the distance from most gas basins (except the Perth Basin) to the majority of domestic gas consumers in the South West and Goldfields represents a significant challenge.

Carnarvon Basin

The Carnarvon Basin contains the largest gas reserves and is the most extensively explored gas basin in WA. In 2012, approximately 98.3% of the domestic gas supply and 100% of all LNG exports from WA originated from this basin.

The elongated Carnarvon Basin covers approximately 650,000 square kilometres, of which approximately 535,000 square kilometres are offshore and mostly situated to the north of the basin and approximately 115,000 square kilometres of the basin is located onshore towards the south of this basin.[258]

The Carnarvon Basin is expected to continue its dominance as WA's leading gas basin in the 2013 to 2022 period, supplying gas to the domestic and LNG export markets.[259] Before the end of 2022, the number of domestic gas facilities that are expected to extract gas from the Carnarvon Basin will increase from four[260] to seven; including the Macedon, Gorgon and Wheatstone domestic gas facilities.[261] Also the number of LNG facilities processing and liquefying gas into LNG will increase from two to four; including the Gorgon and Wheatstone LNG facilities (see section 6.3 for details).

Perth Basin

The Perth Basin is also a geographically elongated basin that extends about 1300 kilometres in a north to northwest direction along the WA coast to the north of Perth. The Perth Basin covers approximately 50,000 square kilometres onshore and 122,500 square kilometres offshore.[262]

Due to the quantum of estimated reserves located in this basin and its proximity to existing and potential gas consumers, almost all gas projects in the Perth Basin are onshore projects and supply gas solely to the domestic market.[263]

The Perth Basin is located in close proximity to two gas transmission pipelines, the DBNGP and the Parmelia Pipeline. Despite these advantages, the Perth Basin's less than ideal geological characteristics and relatively small estimated resources mean it is substantially less significant to WA's gas production when compared to the Carnarvon Basin.[264] In 2012, it is estimated the Perth Basin supplied only approximately 1.7% of the total domestic market (see section 7.1 for details).

Browse Basin

The Browse Basin is an offshore gas basin that covers an area of approximately 140,000 square kilometres. The WA Government is actively encouraging the development of this basin and is in the process of developing the Browse LNG Precinct in the Kimberley region.[265]

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257 Gas extracted from the Browse and Canning Basins may be made "available" to the domestic market through swap deals with existing operators operating within the vicinity of gas transmission infrastructure.
258 The Carnarvon Basin is typically split into North and South using Rough Range as a centre reference. See DMP (2013) and Geoscience Australia (2013) for details.
259 According to Energy-pedia (2013), since mid-2009 Chevron alone has made 21 hydrocarbon discoveries adding a total of 10 Tcf of gas to reserves in the Carnarvon Basin.
260 Varanus Island is considered as two facilities.
261 There are other planned facilities but only those that are confirmed (FID) are reported.
262 See DMP (2013) and Geoscience Australia (2013) for more details.
263 The only offshore project in the Perth Basin is AWE Limited and Roc Oil's Cliff Head project. While this project mainly focuses on crude oil production, gas is known to be produced from this field and part of this gas consumed by the power station located at the processing facility with the remainder understood to be sold directly to a single consumer.
264 The largest gas field discovered in the Perth Basin is Dongara and it only contained approximately 0.5 Tcf of gas. According to Bell Porter Securities (2011), Perth Basin fields typically have a resource size of between 0.5 to 1.5 Tcf – significantly smaller than gas fields in the Carnarvon Basin.
265 See Premier's Media Statement (2012). The WA Government through the DSD is encouraging project proponents to consider land based LNG processing facilities to provide long-term growth options for industry, to encourage local industry participation and regional development, and to support the WA policy on

At the time of this report, only INPEX's Ichthys (to Darwin) and Shell's FLNG Prelude projects are confirmed projects for the Browse Basin.[266] Other potential gas projects under consideration include Woodside's Browse, ConocoPhilips' Poseidon and Santos' Crown projects. Although there have been significant gas discoveries at the Browse Basin by various entities, it is very unlikely that any gas supply from this basin will be available to the domestic market before 2022.[267]

Bonaparte Basin

The Bonaparte Basin is the northern-most WA basin. It covers approximately 270,000 square kilometres with 250,000 square kilometres located offshore and approximately 20,000 square kilometres onshore, straddling the border between WA and the Northern Territory.

At the time of this report, there are two gas projects known to operate within the Bonaparte Basin; Eni's Blacktip and ConocoPhilips' Bayu-Undan Darwin LNG. Although these projects are extracting gas from the basin, these projects process gas in the Northern Territory for LNG export and consumption in the Northern Territory domestic gas market. The GDF Suez/Santos' Bonaparte FLNG project is also planned for this basin.

Despite the existence of these projects and large gas reserves located in the Bonaparte Basin, there is no gas processing and transmission infrastructure located onshore in the Kimberley region to commercially extract, process and ship gas to the domestic WA market.[268] The lack of appropriate gas related infrastructure and facilities suggests it is highly unlikely that any gas reserves from the Bonaparte Basin will be extracted and processed for supply to the domestic gas market in the foreseeable future.

Canning Basin

The Canning Basin is an onshore/offshore hydrocarbon rich basin that is approximately 506,000 square kilometres, of which 430,000 square kilometres are located onshore.

There is currently no permanent gas-related infrastructure known to be located in the Canning Basin.[269] As such, any Canning Basin gas development project would be reliant on the construction of new infrastructure.

At the time of this report, several exploration and production companies, including Buru Energy, ConocoPhillips, Hess, Key Petroleum, Mitsubishi, New Standard Energy, Oilex Limited and Oil Basins Limited are exploring the Canning Basin for hydrocarbons with an intention to supply gas to the domestic gas market.

8.3. Unconventional Gas Reserves

The quantum of WA unconventional gas, specifically tight and shale gas, is largely unverified and imprecise. As such, only reported approximations are provided in this GSOO.[270] Currently, all shale and tight gas exploration activities have been confined to onshore exploration due to the depth of the potential resource.[271]

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securing domestic gas supply.

[266] FLNG projects utilise large ships that allow the field operator to process and liquefy extracted gas offshore and offload the LNG directly to LNG tankers for export.

[267] Although gas has been discovered in this basin and will be extracted under the Ichthys (NT) and Prelude (FLNG) projects, these projects are not supplying the WA market. Other potential projects such as Woodside's Browse and ConocoPhilips' Poseidon projects may not be constructed by 2022. Although Santos' Press Release (2013 and 2013b) also reports gas discovered at Crown-1 and Basset West gas fields, the commercial value of these fields are yet to be determined and are unlikely to be available by 2022.

[268] At the time of the report, the Browse LNG Precinct is the only location approved for gas processing in the Kimberley region.

[269] There are, however, temporary storage facilities (owned by Oil Basins and Buru Energy) for crude oil awaiting transfer to the BP refinery located in Kwinana.

[270] At the time of this report, Geoscience Australia has indicated it is considering a joint study with the US EIA to study the 5 unconventional basins in Australia outlined in EIA (2011).

[271] All unconventional wells drilled to date in WA have been vertical, as confirmed by a DMP official at CEDA's Energy Future Series Part 3: WA's Unconventional Future at the Pan Pacific Hotel on 6 March 2013. According to Ripple (2013), there is also no known onshore horizontal drilling equipment available in WA.

The size and relatively lower risk of conventional reserves in WA may indirectly impede the extensive exploration of unconventional gas. Due to the higher risks associated with unconventional gas exploration, such exploration is primarily focused on considerably well explored areas for conventional hydrocarbons within WA; namely within the onshore Perth, Carnarvon and Canning Basins. Despite the risks, unconventional gas exploration continues to expand in WA.

At the time of this report, a range of companies are actively exploring for, or have interests in, unconventional gas resources in WA:

- In the Perth Basin, companies such as AWE Limited, Caracal Exploration, Empire Oil and Gas, ERM Power (ERM Gas), Key Petroleum, Latent Petroleum (Transerv Energy), Norwest Energy and Whicher Range Energy are actively exploring for shale and/or tight gas. AWE Limited followed by Latent Petroleum are considered to be the most advanced unconventional gas explorers operating in this basin.[272]

- In the Canning Basin, several exploration companies, JV partners and entities including Buru Energy, ConocoPhilips, FAR Limited (First Australian Resources), Green Rock Energy, Hess, Key Petroleum (via Gulliver Productions Pty Ltd), Kingsway Oil, Mitsubishi Corporation, New Standard Energy, Oil Basins Limited, Oilex Ltd, Pancontinental Oil and Gas and Rey Resources have permits or JV interests in this basin.[273] From this list of explorers, Buru Energy and New Standard Energy are known to be actively drilling in the Canning Basin with their JV partners, Mitsubishi Corporation (with Buru Energy), ConocoPhilips and PetroChina (with New Standard Energy).[274]

- In the onshore Carnarvon Basin, only Rusa Resources and Tap Oil are known to be exploring for unconventional resources after the WA Government awarded two special prospecting licenses covering a total of 38,000 square kilometres. Tap Oil is expected to commence exploration in 2013.[275]

The following sections provide an overview of WA's shale and tight gas resources.

Shale Gas

At the time of this report, Australia has not ascertained its reserves of shale gas. Despite this, at the end of 2011, Geoscience Australia estimates there are approximately 435,600 PJ (396 Tcf) of technically recoverable shale gas located in Australia.[276]

In a report released by the EIA, it is estimated there are 288 Tcf of shale gas residing within the onshore Canning and Perth Basins, more than twice the amount of WA's conventional gas reserves. Another report by the ACOLA, suggests there are more shale reserves (475 Tcf) located in WA (see Table 26).

Table 26 – Estimated Shale Gas Resources in Western Australia, 2011

Basin	EIA (2011) – Tcf	EIA (2011) – PJ	ACOLA (2013) – Tcf	ACOLA (2013) – PJ
Canning	235*	249,100	450	477,000
Perth	33**	34,980	16	16,960

[272] According to AWE Limited's ASX announcement on 6 February 2013 (http://www.awexp.com.au/IRM/Company/ShowPage.aspx/PDFs/2779-67683348/Seneciofeasibilitystudyunderway), AWE Limited managed to demonstrate a commercial gas flow capacity at its Senecio tight gas field. According to Transerv Energy's (Latent Petroleum) ASX announcement on 5 November 2012 (http://www.latentpet.com/_content/documents/600.pdf), Latent Petroleum's Warro gas field is estimated to contain 3 to 4 Tcf of recoverable gas.
[273] This represents an increase in interest in the Canning Basin. In May 2012, WA Business News (2012) reported only six entities were exploring unconventional gas in the Canning Basin; Buru Energy, ConocoPhilips, Mitsubishi Corporation, New Standard Energy, Hess and Kingsway Oil.
[274] According to The Australian (2013), in February 2013, PetroChina joined ConocoPhilips and New Standard Energy in its Goldwyer JV.
[275] According to Tap Oil's corporate website, it has entered into a binding agreement with Rusa Resources to farm into Rusa's special prospective areas.
[276] See Geoscience Australia (2012) for details.

Carnarvon	-	-	9	9,540
Total	**268**	**284,080**	**475**	**503,500**

Source: EIA (2013), Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States, *http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=85447655*, accessed 23 July 2013 and ACOLA (2013), Engineering Energy: Unconventional Gas Production report. **Note:** EIA quantities are estimates of technically recoverable resources from Advanced Resources International's report for the EIA derived from comparing geological characteristics of shale formations in the Canning and Perth Basins against shale formations observed in the US and may not be an accurate portrayal of actual reserves. Similar estimates are also reported in Gas Today (2013). ACOLA (2013) estimates are dry gas estimates in the respective basins. **Note:** *EIA (2011) reports a lower estimate of 229 Tcf for the Canning Basin. **EIA (2011) and Bell Porter Securities (2011) reports a higher estimate of 59 Tcf for the Perth Basin. Conversion 1 Tcf = 1060 PJ. Estimated shale resources are similar to those estimates provided by Santos (2012).

Shale gas exploration activities are currently occurring within the Canning and Perth Basins. The most advanced shale explorer is believed to be AWE Limited, as the company reports it may be able to access approximately 13 to 20 Tcf of shale gas within its Perth Basin acreage.[277] Other prospective basins for shale gas in WA include the Amadeus, Officer and onshore Bonaparte Basins.[278]

Tight Gas

Similar to shale gas, Australia has not ascertained its reserves of tight gas resources. As such, there is a lack of published information on WA's tight gas reserves. Geoscience Australia estimates there is approximately 22,052 PJ (20 Tcf) of tight gas reserves in Australia, out of which DMP deems that most of WA's tight gas reserves are located in the Perth Basin. The latest report from DMP estimates the Perth Basin contains approximately 12 Tcf of tight gas.[279]

The low official estimates have not deterred companies from exploring for tight gas in WA. Estimates obtained from public statements of existing tight gas explorers in WA suggest that estimates reported by Geoscience Australia and DMP are conservative.[280] In addition to the Perth Basin, ASX announcements from Buru Energy (shown in Table 27) suggest the Canning Basin may contain more tight gas than previously estimated.

Table 27 – Estimates of Tight Gas Reserves in Western Australia, 2012

Basin	Official Estimated Reserves (Tcf) – DMP (2013c)	Estimated Recoverable (unproven) Reserves reported by existing Companies (Tcf)	Estimated Recoverable Reserves (unproven) reported by Existing Companies (PJ)
Perth	12	26.1*	27,666*
Carnarvon	None Reported	None Reported	None Reported
Canning	None Reported	14.1**	14,946**
Total	**~12**	**~40.2**	**~42,612**

Source: DMP (2013c), Buru Energy Corporate Update 30 April 2013, ASX Announcements. **Note:** This table of tight gas estimates assumes a simple recoverability factor of 30% [EIA (2011) used a factor of 20-30%]. It is acknowledged that the recovery factor is affected by formation and gas characteristics. *This is the sum of a proportion (30%) of the low estimate of AWE Limited's (2010) estimate (13 Tcf) for its Perth Basin tenements, a proportion (30%) of Norwest Energy's unrisked estimate of North Erregulla (32 Tcf), http://www.asx.com.au/asxpdf/20130515/pdf/42fwvxt79x0k49.pdf, accessed 15 May 2013, and the low estimate of recoverable tight gas (3 Tcf) for Latent Petroleum's Warro Gas field, http://www.latentpet.com/_content/documents/600.pdf, accessed 15 May 2013. The tight gas estimate does not include potential shale/tight gas estimates for Empire Oil and Gas of EP440 (36 Tcf) and EP368/EP426 (32 Tcf)

[277] See AWE Limited's (2010) ASX announcement dated 9 November 2010 on shale gas. The figures reported represent gas-in-place and ultimate recoverability is still unknown.
[278] According to CISRO (2012), these other basins may also contain shale gas.
[279] This is an increase from the previous estimate outlined in DMP (2007, 2008) [7 Tcf of tight gas] and PESA (2009) [10 Tcf of tight gas] and is broadly consistent with estimates reported in EISC (2011). Estimates of Buru Energy's unconventional gas are acquired from Buru Energy's March 2013 Corporate Update, http://www.buruenergy.com/download/recent-presentations/Buru%20Group%20Presn%20March%202013v1(2).pdf, accessed 16 April 2013. The latest report refers to DMP (2013c).
[280] See Geoscience Australia (2012) and DMP (2013c) reports.

reported to the ASX in May 2013, Origin Energy's or Bharat Petroleum's estimates. **This is a proportion (30%) of the approximated reported figure of Buru Energy's independent Review of Laurel Formation tight gas resources outlined in Buru Energy's Corporate Update, April 2013. Conversion 1 Tcf = 1060 PJ.

Other Unconventional Gas

In addition to shale and tight gas, there are two other gas projects in WA investigating the potential of extracting CSG for domestic usage and developing synthesis gas (syngas) through underground coal gasification.

According to SKM-MMA's report,[281] Westralian Gas and Power is still investigating the potential of CSG in the Perth Basin, while Eneabba Gas Limited is investigating the prospect of developing syngas as a feedstock for gas-fired power stations.[282]

The following sections provide a brief discussion of basins in WA that may contain unconventional gas.

Perth Basin

Although gas production from the Perth Basin is declining, the Perth Basin is believed to be a very prospective area for shale and tight gas. Reports by EIA and ACOLA suggest this basin holds between 16,960 PJ (16 Tcf) and 62,547 PJ (59 Tcf) of recoverable shale resources. The CarngInia Shale and Kockatea Formations are believed to be the most prospective areas of the basin. Other prospective areas of the basin include the Whicher Range,[283] south of Busselton, which is estimated to hold approximately 4,900 PJ of tight gas resources and the Warro gas field, north of Perth, that is estimated to hold 5,400 PJ of tight gas resources.[284]

Carnarvon Basin

According to ACOLA, this basin is estimated to hold approximately 9,540 PJ (9 Tcf) of shale resources. Although estimated unconventional resources are small in comparison to other basins, conventional gas resources discovered in this basin remain the largest in WA.

Canning Basin

The Canning Basin is believed to contain the largest shale resources in WA. According to the EIA and ACOLA reports, it is estimated to contain between 249,100 PJ (235 Tcf) to 477,000 PJ (450 Tcf) of recoverable shale resources.[285] According to the EIA, the most prospective formations for shale are the Goldwyer and Laurel Formations. The formations are is believed to be a deep marine shale that is roughly analogous with the shale-rich Bakken, Michigan and Baltic Basins and liquid-rich Eagleford Formation in the US.

8.4. Remaining Reserves

Based on the total estimates of conventional and unconventional reserves outlined above, Table 28 provides estimates of how long the remaining reserves are expected to last based on existing and future expected production of domestic gas and LNG sales.

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[281] See SKM-MMA (2011)
[282] See Eneabba Gas Limited's Company Presentation - August 2012, The Future of Energy, http://www.openbriefing.com/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20120803%2F01320135.pdf, accessed 5 July 2013.
[283] This was also outlined in the Energy for Minerals Development in the South West Coast Region of WA Report, http://www.dmp.wa.gov.au/documents/EMDS-ExecSummary_v2(1).pdf, accessed 19 July 2013.
[284] These figures were extracted from PESA (2009), EIA (2011) and EISC (2011) reports.
[285] See EIA (2013) and ACOLA (2013).

The results are reported in two forms; remaining years based on the most recent gas production figures reported by BREE for WA[286] and remaining years based on forecasted WA total gas production for 2022. Both calculations assume production of gas is maintained at the same level *ad infinitum*.

Table 28 – Estimated Remaining Years based on Production for Western Australia, 2012 and 2022

Reserves	McKelvey's Economic and Sub-Economic Reserves + EIA (2013) Shale Reserves (PJ)	2011-2012 Production (PJ)	Remaining Years beyond 2012 (based on 2012)	Forecasted 2022 Total Gas Demand (PJ)	Remaining Years beyond 2022 (based on 2022 Forecasts)
	443,080*	1,458	304	3,395	131

***Note:** Reserves total does not include any estimate of tight gas.

Using the 2011-2012 production figures reported by BREE, this GSOO reports estimated gas reserves in WA are sufficient to meet WA's domestic gas and LNG export needs for approximately another 304 years from 2012, assuming gas production remains unchanged from the 2011-2012 level.

However, as WA is expected to increase its total gas production in the 2013 to 2022 period (see chapter 5), estimates of the remaining reserves are more insightful if the remaining years are calculated with forecasts of total gas demand for 2022.

Based on forecast gas demand levels in 2022, gas reserves in WA are estimated to be sufficient to meet future expected domestic demand and forecasted LNG exports for another 131 years beyond 2022.

Remaining Reserves by Processing Facility

To ensure there are also sufficient reserves available to each processing facility, this GSOO compares the quantity of estimated reserves against the estimated domestic production for 2012 reported by EnergyQuest.

Table 29 suggests there are sufficient gas reserves supporting gas processing facilities supplying to the domestic market, assuming 2012 production levels are maintained for the 2013 to 2022 period.

Table 29 – Estimated Gas Reserves linked to Domestic Processing Facilities, May 2013

Processing Facilities	Gas Field	Operator	Basin	Estimated 2P Reserves (PJ)	Estimated Domestic gas Production – 2012 (PJ)
Operational					
Karratha Gas Plant	NWS JVs fields	Woodside	Carnarvon	15,173%%	190.7
Varanus Island	John Brookes, Harriet gas fields and Spar/Halyard	Apache Energy	Carnarvon	1,451	115.5
Devil Creek	Reindeer	Apache Energy	Carnarvon	451#	33.3
Dongara	Dongara, Yardarino and Elegans	AWE Limited	Perth	<39.9^	6.6
Beharra Springs	Beharra Springs, Beharra Springs North and Tarantula	Origin Energy	Perth		
Red Gully^^	Red Gully and Gingin	Empire Oil and Gas	Perth	228**	0

[286] BREE (2013) reports gas production for 2011-2012 is approximately 1,458 PJ/annum.

Under Construction/ Consideration/ Recently Completed					
Macedon	Macedon	BHP Billiton	Carnarvon	570[%]	0
Gorgon Domestic*	Gorgon, Jansz, Io, Chrysaor, Dionysius and Eurytion	Chevron	Carnarvon	40,969	0
Wheatstone Domestic*	Wheatstone and Julimar Brunello	Chevron	Carnarvon	7,490	0
Pluto Domestic***	Pluto	Woodside	Carnarvon	5,719	0
Total				**71,862.9**	**346.1**

Source: EnergyQuest (2013b) and 2012 Corporate Annual Reports. *At the time of this report, these facilities are not operational. [%%]Deutsche Bank (2012) estimates there are approximately 18,028 PJ (17 Tcf) remaining in the NWS JVs fields. ** Estimates include Gingin gas fields and do not take into account Empire's potential in unconventional gas. [#] Does not include Caribou field. ^Summation of Reserves reported in AWE and Origin's 2012 Annual Reports for Perth Basin. [%]Reserves for Macedon may be significantly higher than figures suggest as DMP (2013c) reports that gas extracted from the BHP Billiton operated Pyrenees FSPO project is re-injected at 60 Mcf/day into the nearby Macedon field for future recovery. ^^According to the ABC News (2013), these facilities are currently being commissioned. Macedon JV and the WA Government have a 25 year agreement that formalises key commitments for the Macedon facility. ***Woodside has entered into an arrangement with the WA Government that commits to the supply of domestic gas, which begins five years after LNG is first exported, and providing it is commercially viable to do so. **Note:** Table does not consider LNG production for NWS. Existing NWS LNG contracts are outlined in GIIGNL (2013). The estimates for NWS also do not consider the NWS Extension project that is estimated to extend the life of North Rankin and Perseus fields to 2041, BMI (2013).

Reserves by Company

Table 30 reports the estimated quantity of reserves reported by EnergyQuest. This table show 10 companies currently own approximately 92.3% of all WA 2P gas reserves. From the quantum of 2P reserves outlined, it is estimated approximately 99.9% of all 2P reserves are located offshore.[287] Offshore gas, being more capital intensive, is likely to face a higher cost of extraction.

Table 30 – Natural Gas Reserves by Company (Western Australia and Northern Territory), May 2013

Company	2P Reserves (PJ)	% Share
Chevron	26,101	28.9%
Shell	14,995	16.6%
ExxonMobil	10,242	11.3%
Inpex	9,650	10.7%
Woodside	7,950	8.8%
TOTAL	4,070	4.5%
BP	2,960	3.3%
BHP Billiton	2,708	3.0%
Apache	2,618	2.9%
MIMI	2,204	2.4%
Santos	972	1.1%
Eni	914	1.0%
Tokyo Gas Co	909	1.0%
Kufpec	771	0.9%
CNOOC	752	0.8%
Osaka Gas	675	0.7%
Tokyo EP	551	0.6%

[287] Although this is not shown, EnergyQuest (2013b) reports that approximately 90,431 PJ of the total 2P reserves are located offshore.

Kogas	382	0.4%
Kansai Electric	286	0.3%
Chubu Electric Power	271	0.3%
CPC	191	0.2%
Kyushu Electric Power	98	0.1%
ConocoPhillips	90	0.1%
Toho Gas	57	0.1%
Origin Energy	26	0.0%
Magellan	15	0.0%
AWE	14	0.0%
Total	**90,472**	**100.00%**

Source: EnergyQuest (2013b). Although the table includes 2P reserves from Northern Territory, only 138 PJs from the Northern Territory is included in this table (<1% of the total), the market shares of the companies are largely unaffected.

9. Supply and Demand Assessment

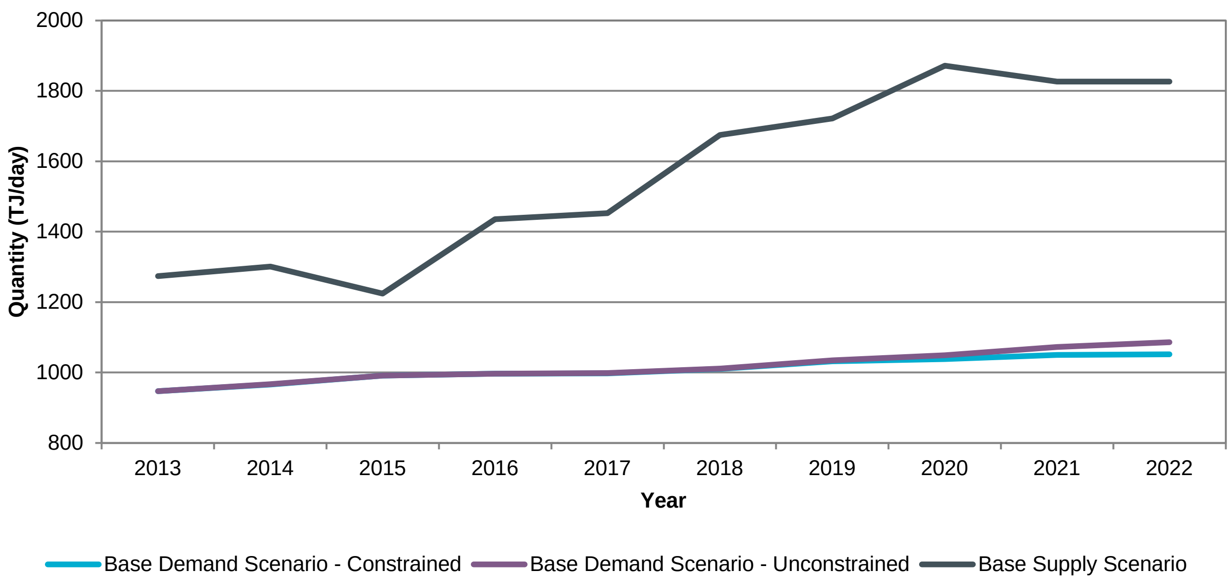
This chapter compares the domestic demand and supply forecasts outlined in sections 5.2 and 7.3 to determine the adequacy of gas supply to the domestic gas market for the 2013 to 2022 period. This comparison seeks to outline any potential constraints and highlight opportunities for future investment.

The supply-demand balance assessment is based on gas supply forecasts that are projected on the basis of assumed market conditions including price. Forecasts of gas demand have also been prepared, including these price assumptions (“constrained” demand) and excluding the price assumptions (“unconstrained”). Supply-demand assessments in this chapter are performed using the gas supply forecasts and constrained demand.

9.1. Domestic Outlook 2013 – 2022

Base Case Demand and Supply

Figure 54 – Comparison of Forecast Base Demand and Base Supply Scenarios, 2013 – 2022



Source: NIEIR Forecasts 2013-2022

Figure 54 compares the forecasts generated for the Base gas demand scenario and the Base gas supply scenario. The results suggest there is more than adequate supply available to the domestic gas market in the 2013 to 2022 period.

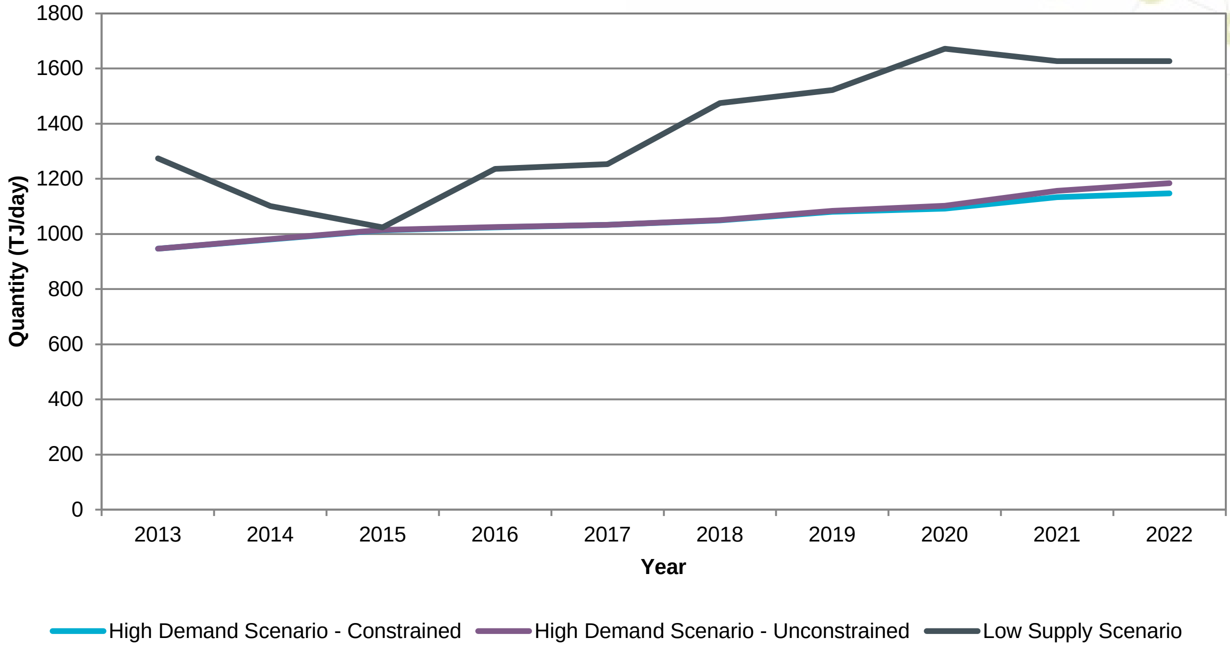
The gap between domestic supply and demand shown in Figure 54 outlines the level of uncontracted supply available to the market at the forecast price. The supply-demand gap (the difference between domestic supply and domestic demand) is forecast to increase from approximately 327 TJ/day in 2013 to about 827 TJ/day in 2022.

The supply-demand gap is the finest in 2015 (233 TJ/day). This suggests incremental gas demands can still be met in the domestic market as long as gas consumers are willing to accept the gas prices offered for the outlined period and there is sufficient gas transmission capacity available.

At higher gas prices, certain WA industries may be affected financially.[288] However, historical gas consumption data for the domestic market suggests this is unlikely due to the inelasticity of gas demand (see section 5.1). The demand forecasts for the outlined period also present a similar conclusion.

High Demand-Low Supply Scenario

Figure 55 – Comparison of Forecast High Demand and Low Supply, 2013 – 2022



Source: NIEIR Forecasts 2013-2022

NIEIR's forecasts of the High gas demand against the Low gas supply scenario in Figure 55 show a similar result to the Base scenario. There is not expected to be a shortage of gas supply in the 2013 to 2022 period as long as gas consumers are willing to pay the forecast gas prices.

While there is sufficient supply, NIEIR's forecasts suggests if the High gas demand and Low gas supply scenarios were to occur, in 2015 the domestic market will just be in balance with about 10 TJ/day of additional supply to meet forecast domestic demand. This is as gas suppliers may not be willing to allocate more gas to the domestic market unless contracted domestic gas prices exceed NIEIR's forecast gas prices for the Low gas supply scenario in 2015. Hence, if this situation were to occur, it is likely that gas prices for 2015 may be higher than the forecast gas prices for the Low gas demand scenario for 2015.

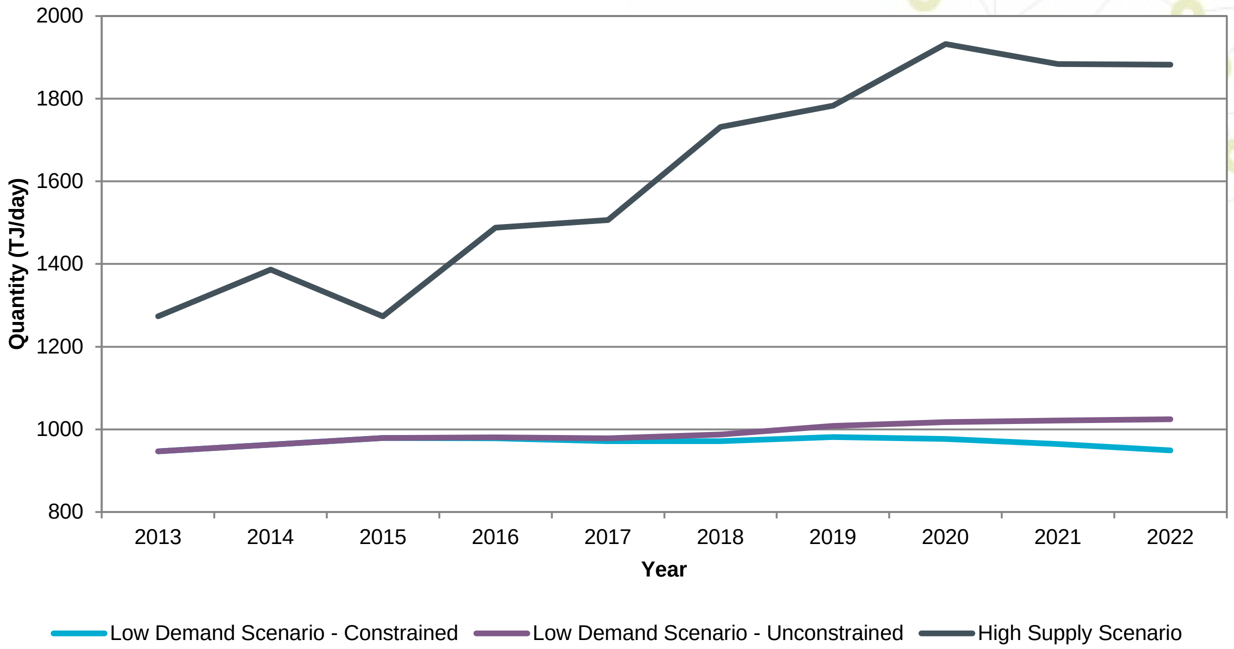
This scenario is unlikely to eventuate as there is more than sufficient gas processing capacity available to the domestic gas market (see section 7.2) and gas suppliers (especially those without the ability to export LNG) with excess supply are more likely to provide additional gas supply to the market if higher domestic gas prices were offered.

The availability of gas storage capacity may present an opportunity for gas customers to prepare against such an outcome.

[288] These industries are outlined in EISC (2011) and SKM-MMA (2011).

High Supply-Low Demand Scenario

Figure 56 – Comparison of Low Demand and High Supply, 2013 – 2022



Source: NIEIR Forecasts 2013-2022

Figure 56 presents NIEIR's Low gas demand and High gas supply scenario forecasts. Similar to the Base gas demand and supply scenario, there is expected to be more than sufficient gas supply available for purchase in the domestic market over the 2013 to 2022 period.

In this situation, the supply-demand gap at its widest is approximately 922 TJ/day in 2020. If this situation were to occur, the large gas supply overhang may provide some downward pressure on domestic gas prices, causing gas prices to be lower than the forecast gas prices for the High supply scenario. If gas prices were to fall, it is likely that WA may see a higher than anticipated increase in domestic gas demand in the latter half of the outlined period (not shown in the Figure).

Special Assessment – A Fall in Gas Supply from Major Producer

Currently, the majority of domestic gas supply is supplied by two operators, Woodside Energy and Apache Energy, with approximately 98.3% of domestic demand supplied by the KGP, Varanus Island and Devil Creek processing facilities (see chapter 7 for details).

These facilities provide a total of 1,170 TJ/day of gas processing capacity to the domestic market, of which the KGP is the largest, supplying approximately 55.5% of the total market. Due to the potential of KGP to influence the availability of domestic gas supply,[289] the utilisation of this facility in the 2013 to 2022 period provides an opportunity to assess an additional scenario, similar to a sensitivity test, to determine if the results of the Base supply-demand conclusions have changed.

Currently, the gas processing capacity of the KGP is known to have five long-term contracts with four major market participants (see Table 31).[290]

[289] The West Australian (2013d) also reports the gas market is concerned about NWS JVs' ability to reduce gas supply to the market.
[290] See DomGas Alliance (2013) for KGP's contracts and other domestic gas contracts in WA.

Table 31 – North West Shelf – Long-Term Contracts

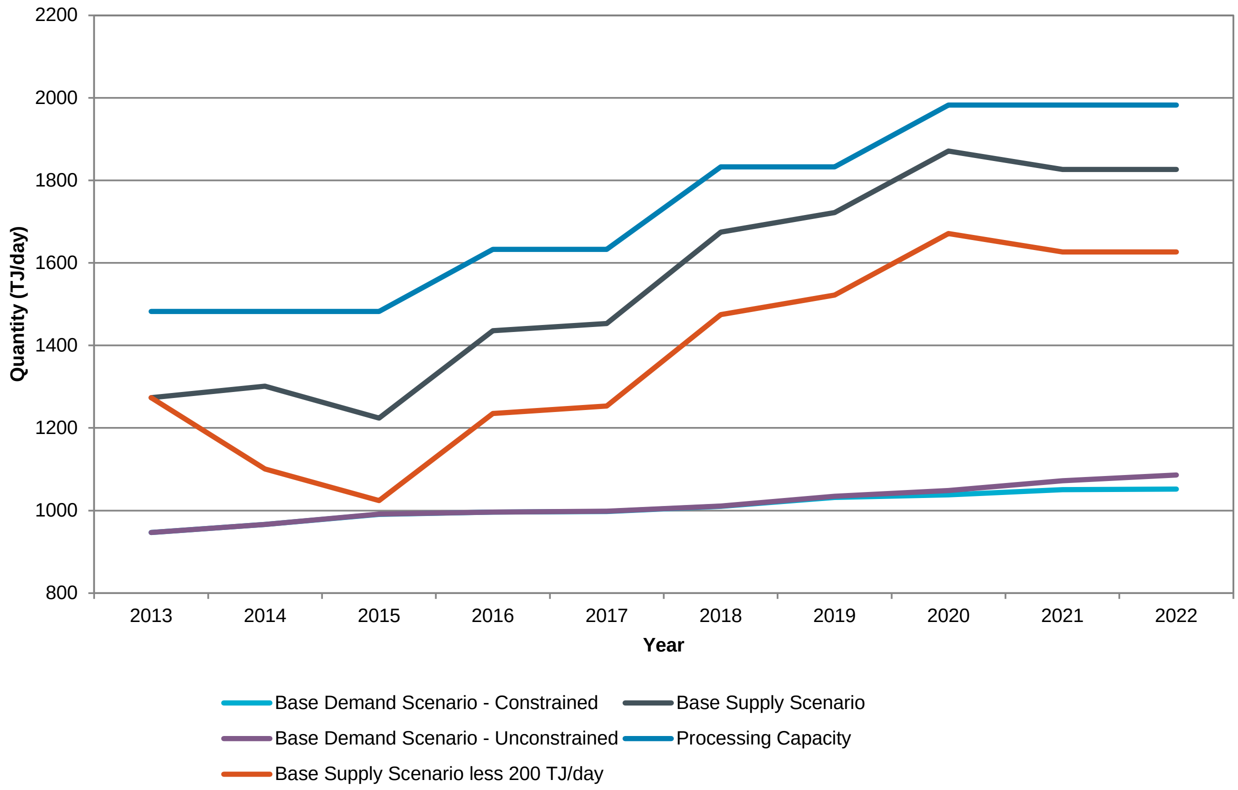
Purchaser	Estimated Contract Expiry	Estimated Quantity
Alcoa Australia	2020	175
Alinta Energy (probably expired)	2012 or 2020	62*
Alinta Energy	2012 or 2020	90
BHP Billiton	2013	110
Verve Energy	700 PJ or 2020	135
Total		**572**

Source: DMP (2002), DomGas Alliance (2013). ***Note:** This figure is from DMP (2002). The second contract is believed to have expired as reported NWS production since Q4 2012 is approximately 510 TJ/day. See Woodside's 2012 Fourth Quarterly Production Report http://www.woodside.com.au/Investors-Media/Announcements/Documents/17.01.2013%20Fourth%20Quarter%202012%20Report.pdf, and 2013 First Quarterly Production Report http://www.woodside.com.au/Investors-Media/Announcements/Documents/18.04.2013%20First%20Quarter%202013%20Report.pdf, accessed 14 July 2013.

Recent production data published by Woodside for the NWS JV suggest one of these long-term contracts has already expired and may not be renewed. BHP Billiton's contract with the NWS is also due to expire by the end of 2013 and not be renewed as it has a long-term contract with Macedon JV to meet its future gas needs. [291]

To ascertain whether a fall in KGP's supply availability to the domestic market will affect the supply-demand representation outlined under the Base demand and supply scenarios, NIEIR's Base supply forecasts are reduced by 200 TJ/day[292] from 2014 to 2022 to imitate the unavailability of KGP's supply to the domestic market due to expiry of the Alinta Energy and BHP Billiton's contracts.

Figure 57 – Comparing Modified Base Demand (less 200 TJ/day) and Supply, 2013 – 2022



[291] This was confirmed by the DomGas Alliance.

[292] The quantity of 200 TJ/day is applied as it is the maximum quantity of the two contracts that would have expired by the end of 2013.

The results presented in Figure 57 are revealing. It shows despite a reduction in gas supply of 200 TJ/day to the domestic market for the entire 2014 to 2022 period, gas supply continues to be able to meet forecast gas demand and the market remains adequately supplied.

Figure 57 shows despite a reduction in gas supply of 200 TJ/day to the domestic market for the entire 2014 to 2022 period, gas supply continues to be able to meet forecast gas demand.

NWS JV partners have indicated to the IMO that this situation is unlikely to occur as they will continue to make gas available to the domestic market as long as it is commercially viable. However, if this unlikely event were to occur over the entire 2014 to 2022 period, it is projected that the supply-demand gap will be small (approximately 33 TJ/day) in 2015 which may lead to gas prices being higher than the forecasts produced by NIEIR.

Similar to the results of the High Demand-Low Supply scenario, the availability of gas storage capacity may present an opportunity for gas customers to prepare against such an outcome.

Reserves Assessment

In addition to determining the adequacy of supply, the quantity of reserves supporting domestic gas existing processing facilities for the 2013 to 2022 period are also reviewed in section 8.4.

This GSOO finds there are more than adequate gas reserves in WA. Assuming no additional gas reserves are discovered by 2022, gas reserves in WA have the potential to last at forecast 2022 levels for another 131 years beyond 2022 (see section 8.4). A review of 2P reserves linked to gas processing facilities currently servicing and anticipated to be servicing the domestic gas market in the 2013 to 2022 period also suggests there are more than adequate gas supplies to meet the projected domestic demand.

9.2. Gas Transmission

This section focuses on the gas transmission segment of the domestic market to determine whether gas supplies can be reliably shipped to nominated delivery points on the pipeline network.

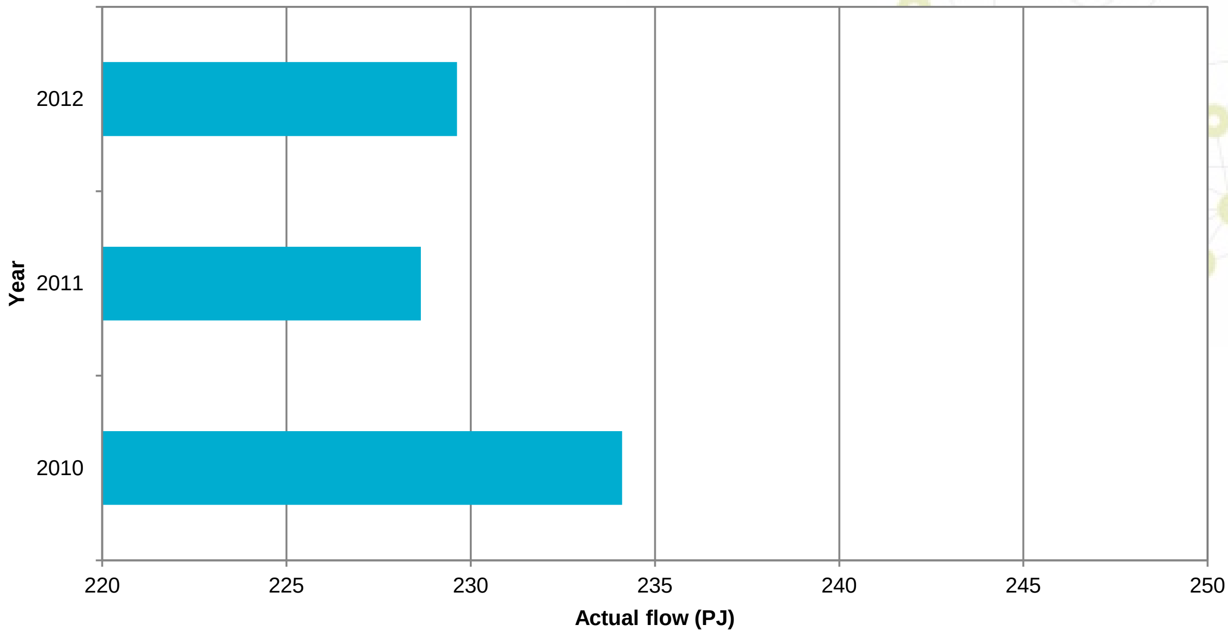
For this first GSOO, no analysis was performed to determine if there was sufficient gas transmission capacity within the existing pipeline network to meet projected growing demand. It was assumed there was sufficient capacity in the pipeline network. For subsequent GSOOs, this issue will be investigated to determine if there are any potential constraints on WA's gas transmission network.

This section reviews the transmission capability and the utilisation of the main transmission pipelines (the DBNGP and the GGP).

Figure 58 shows the quantity of gas shipped on the DBNGP on a full-haul[293] basis from 2010 to 2012. In 2012, the DBNGP shipped a total of approximately 230 PJ of gas from inlet points mostly located in the Carnarvon Basin to the south of compressor station nine.

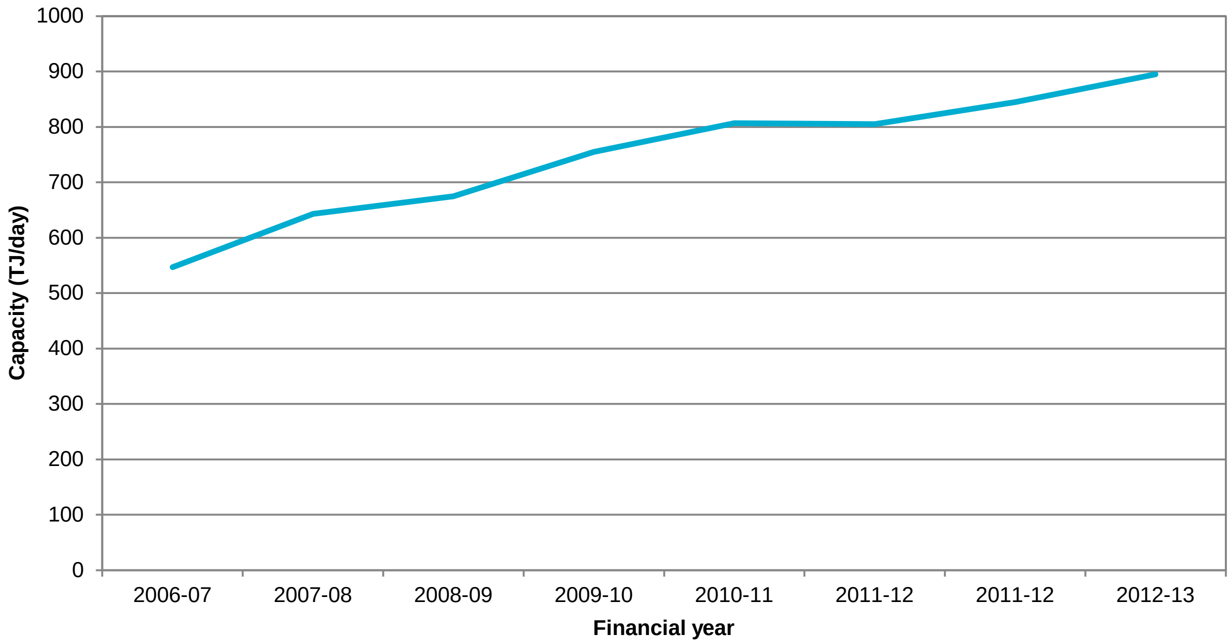
[293] Full-haul (sometimes known as T1) means the shipping of gas to on the DBNGP to any gas outlet beyond compression station 9.

Figure 58 – Quantity of Gas Shipped (full-haul only) by DBNGP, 2010 – 2012



Source: DBP Limited, T1 gas flow data. **Note:** The figure only shows full-haul transmission through the DBNGP and is only a representative of total gas shipped.

Figure 59 – Estimated Annual Full-Haul Capacity (T1) of DBNGP, 2006-2007 to 2012-2013



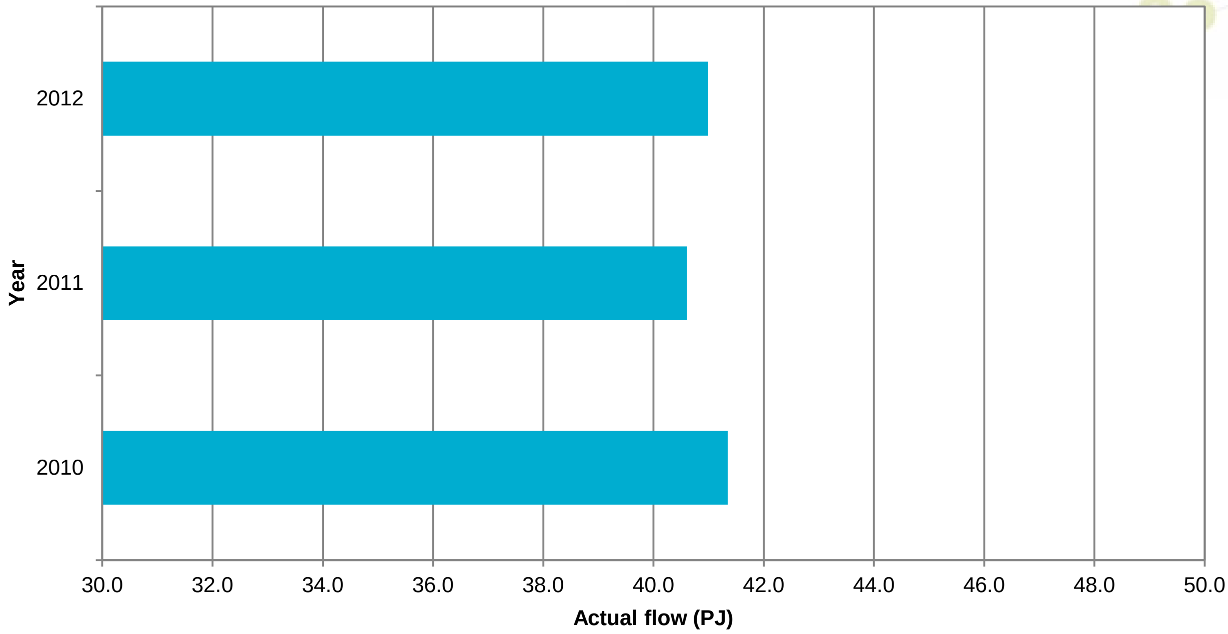
Source: Compiled from information from Duet Group's Presentations (2011 to 2013), AER (2007 to 2012) and SKM-MMA (2011). **Note:** Reported capacity figures in the figure do not match nameplate capacity as provided for the upcoming GBB, as they include interruptible capacity.

Figure 59 shows the estimated annual full-haul capacity of the DBNGP from 2006-2007 to 2012-2013. Despite increasing the DBNGP's average annual capacity through three major expansion projects between

2005 and 2010, DBP Limited reports there is currently no uninterruptible gas transmission capacity on the pipeline and all firm capacity is fully contracted until 2019.[294] While DBP Limited is considering an expansion project to complete the duplication of the DBNGP (called Expansion Stage 5C), DBP Limited has publically indicated that gas pipeline capacity on the DBNGP may not be expanded for the next five years.[295]

Figures 60 and 61 show the estimated annual capacity and the quantity of gas shipped, respectively, by the GGP. Despite only shipping approximately 41 PJ of gas in 2012, uninterruptible capacity is unavailable.[296]

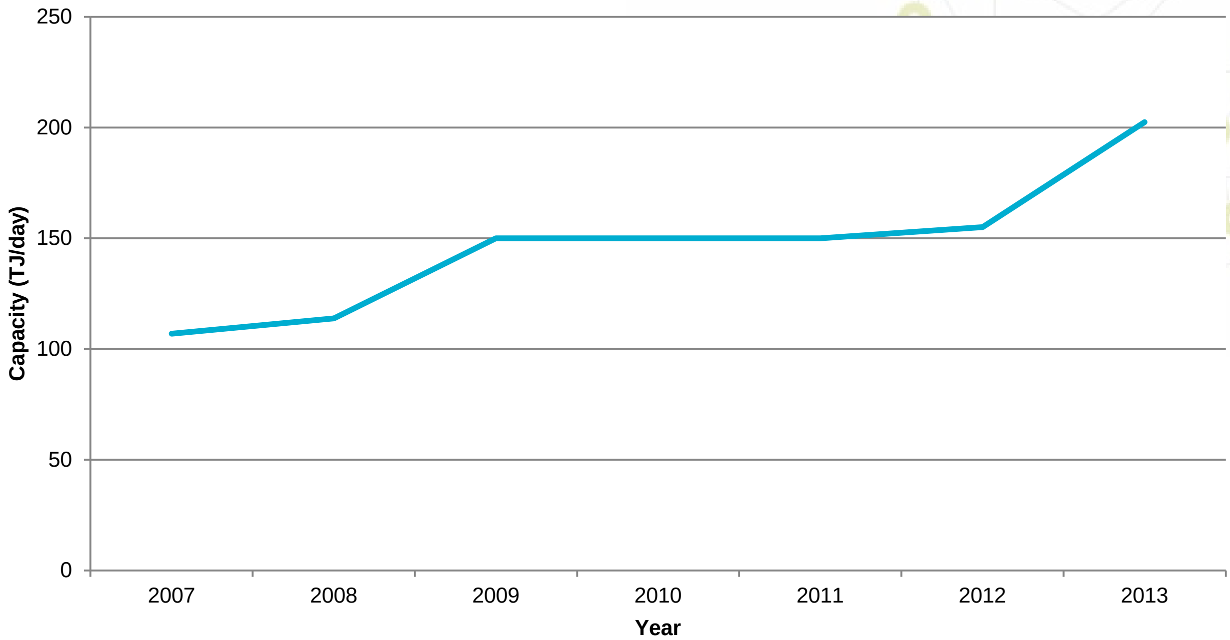
Figure 60 – Quantity of Gas Shipped by GGP, 2010 – 2012



Source: APA Group, actual pipeline flow data.

[294] See DBNGP's Spare Capacity Register, http://www.dbp.net.au/access.aspx , accessed 28 March 2013. This was also reported in EISC (2011).
[295] This was indicated to attendees at the DBNGP Shipper Forum at the Melbourne Hotel on 25 March 2013.
[296] See GGP's Spare Capacity Register, http://www.apa.com.au/media/191459/2011%20ggp%20public%20register%20october%202011.pdf, accessed 28 March 2013.

Figure 61 – Estimated Annual Capacity of GGP, 2007 – 2013



Source: GGP's pipeline capacity is estimated from AER (2007-2012), information provided by APA Group, APA Group's public announcements and ERA submissions. **Note:** According to APA Group, GGP's pipeline capacity at the time of this report is 155 TJ/day. Its capacity is expected to increase to approximately 202.4 TJ/day by the end of 2013.

APA Group is currently increasing the capacity of the GGP. However, the majority of the expanded firm capacity (of 47.4 TJ/day) has already been secured through 15 and 20 year contracts with BHP Billiton (24 TJ/day) and Rio Tinto (20 TJ/day), respectively, and contracts with other customers.[297] This means firm capacity on the expanded GGP of approximately 202.4 TJ/day is estimated to be fully contracted until the end of 2022.

The lack of available uninterruptible capacity on these major transmission pipelines represents a significant challenge to the growth of WA gas consumption as projects typically require a reliable supply of gas. It is understood that due to a lack of gas trading, storage and aggregators, existing or potential users of gas intending to secure gas for their own consumption have limited options available except to consider contributing financially towards expanding the transmission capacity of these pipelines. This limits gas consumption growth to the timing and willingness of multiple parties to contribute to the pipeline infrastructure collectively, or to very large new gas consuming projects.

Despite a lack of uninterruptible capacity on both transmission pipelines, it is understood there is readily available interruptible capacity on these two pipelines as their nameplate capacity (at normal operating conditions) is rarely reached.[298] This is shown for the DBNGP and GGP in Figure 62 and 63 respectively, and summarised in Table 32.

To highlight the utilisation rates of the DBNGP and the GGP, the utilisation of these pipelines is measured by comparing the average monthly gas flows against the nameplate capacity.[299]

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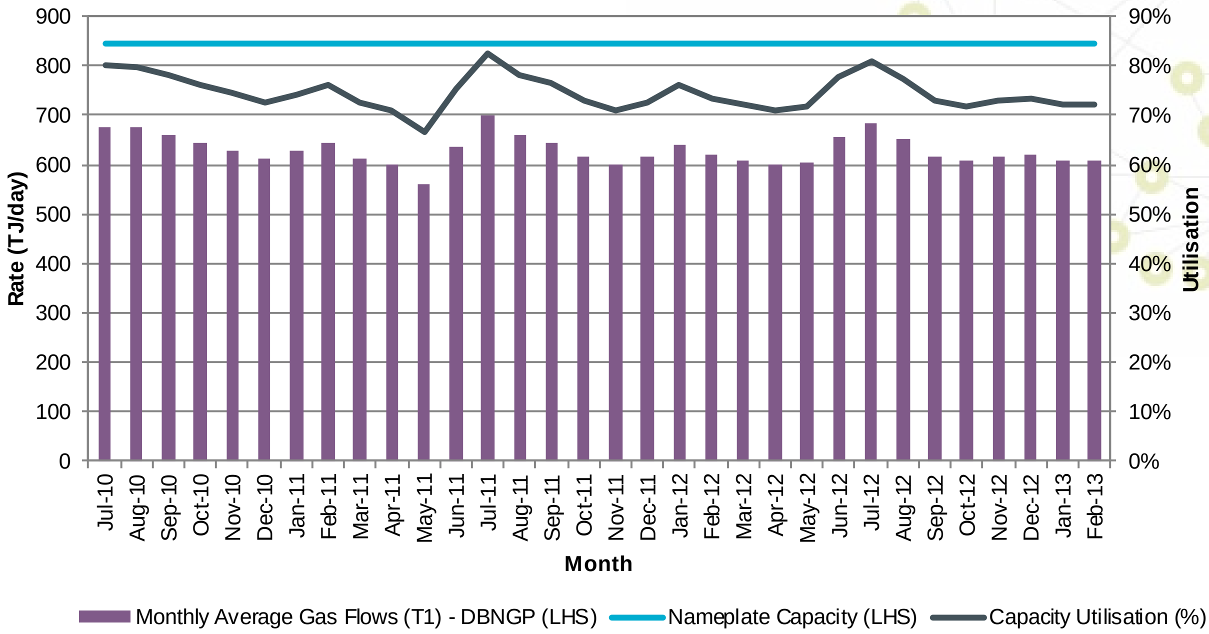
[297] See APA Group's (2011, 2012) announcements on the planned expansion of the GGP and long-term contracts with Rio Tinto and BHP Billiton.

[298] Ambient operating temperature of the pipeline is a factor in the actual capacity for a particular gas day. Other known factors include pipeline diameter and length, gravity, density, compressibility, flowing temperature and viscosity of gas, pressure and friction.

[299] Capacity utilisation may be measured using three methods; as a measure of the average-monthly/daily natural gas throughput relative to estimates of system capacity at pipeline boundaries; as a system peak-day usage rate, which generally reflects peak system deliveries relative to estimated system capacity, or by measuring system-wide pipeline flow rate, which highlights variations in system usage relative to an estimated system peak throughput level.

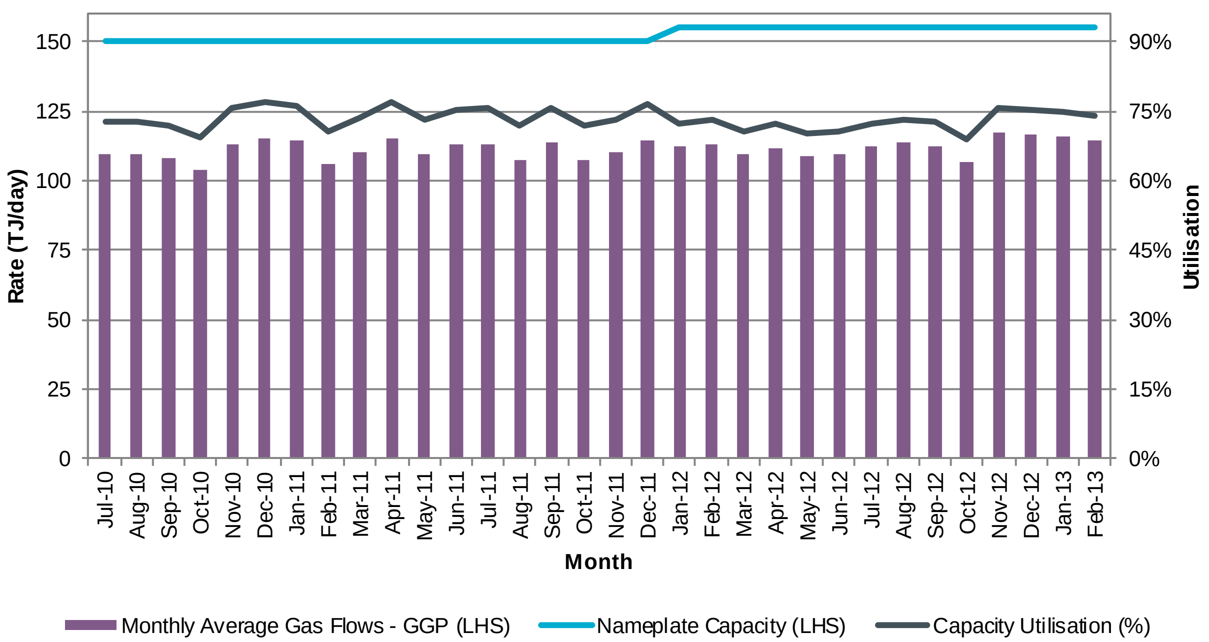
Figure 62 – Estimated Utilisation Rates of DBNGP (full-haul only), July 2010 – February 2013



Source: DBP Limited (2013), Full-Haul monthly averages. **Note:** The nameplate capacity of 845 TJ/day is used for the DBNGP. Actual gas flows are monthly averages calculated on actual gas flows.

The reported utilisation rates shown in Figure 62 are typically lower for various segments of the DBNGP as some part-haul customers only require the shipping of gas from the Pilbara to the Mid-West. Part-haul is estimated to be approximately 3% to 5% of the total shipped volume of the DBNGP.[300]

Figure 63 – Estimated Utilisation Rates of GGP, July 2010 – February 2013



[300] This is estimated by identifying the part-haul customers and estimating the use of these customers.

Source: APA Group. **Note:** A nameplate capacity of 150 TJ/day was used for 2010 and 2011 (as reported by AER 2011 and 2012). A nameplate capacity of 155 TJ/day is used for 2012. Actual gas flows are monthly averages calculated on actual gas flows.

Although ambient operating temperature is a significant factor in the determining the actual capacity of a pipeline for any particular gas day, it is understood that ambient operating temperature affects no more than 10% of nameplate capacity.[301] As such, data in Figures 62 and 63 suggest the capacity of the DBNGP and GGP are not fully utilised.

Table 32 – Main Transmission Pipeline, Estimated Capacity Utilisation, July 2010 – February 2013

Key Transmission Pipelines	Average Capacity (TJ/day)	Estimated Utilisation Rate (Min-Max) for July 2010 to Feb 2013 (%)*
Dampier to Bunbury Pipeline	845	66% - 83%
Goldfields Gas Pipeline	155	69% - 77%
Average Utilisation Range		**67% - 80%**

Source: DBP Limited and APA Group. **Note:** Utilisation rates are calculated solely based on nameplate capacity. Capacity of a pipeline may vary over the course of a year due to weather conditions. *Due to the sensitive nature of the pipeline data, only a range of minimum and maximum utilisation rates are reported, representing the minimum and maximum utilisation rate of the pipeline's monthly average gas flow.

Despite the high contracted capacity, the low utilisation of the main transmission pipelines suggests further examination may be warranted into the structure of existing shipping contracts and the operation of the WA gas transmission sector in a bid to improve the utilisation of gas transmission infrastructure in WA.[302]

To improve capacity utilisation in gas pipelines, a recent report by the Grattan Institute suggests the implementation of a more transparent mechanism to support a more competitive WA gas market; a platform for trading pipeline capacity to support short-term access to pipeline capacity.[303]

[301] The actual capacity of the pipeline is higher during winter months when lower atmospheric temperatures allow the power output of gas turbines driving the compressors on the pipeline to be higher.

[302] Experience gained during the operation of the GBB by the IMO in 2008 suggested that existing clauses in shipping contracts may hinder the ability to reassign unused capacity to other unregistered parties. Other potential impediments may include the existing market structure (contract carriage) of the WA gas transmission sector.

[303] Grattan Institute (2013) recommends for WA to adopt the Australian Energy Market Operator's model being developed for trading capacity in gas pipelines.

10. Other Issues

This chapter highlights other issues that may potentially influence and impact the medium to long-term demand and supply of gas in WA. In this GSOO, the IMO reviews current Commonwealth and State Government policies that impact on the WA gas market.

10.1. Commonwealth Government Policies

Retention Leases and Reserves

Retention leases are complex as different legislation (Commonwealth and State) governs onshore and offshore gas resources. The intent of retention leases is to grant an entity a security of title on discovered resources that are currently uneconomic but have genuine commercial potential within the next 15 years.[304] These leases encourage continued investment to improve the commercial viability of any discovered resources to allow for future exploitation and provide some certainty for holding entities to invest and appraise these uneconomic resources, albeit these leases are typically subject to some stringent conditions.[305]

Retention leases are awarded to companies by Commonwealth or State authorities after meeting criteria outlined in sections 142 to 147 of the *Offshore Petroleum and Greenhouse Storage Act 2006* (Cwth) (or its preceding Commonwealth legislation), Division 2A of the *Petroleum (Submerged Lands) Act 1982* for offshore leases and Division 2A of the *Petroleum and Geothermal Energy Resources Act 1967* for onshore leases.[306]

The Productivity Commission has suggested that existing Commonwealth and State legislation and accompanying guidelines are vague and lack procedural consistency and specifics to objectively assess each retention lease application.[307] While this was clarified by retention lease guidelines released by the Commonwealth Department of Resources, Energy and Tourism (DRET) in 2012, the DomGas Alliance has suggested that these governing guidelines for commercial viability, market issues and proven technology are not sufficiently objective and are subject to varying interpretation.[308] In particular, the DomGas Alliance highlighted that the criteria for the inability to complete gas sales contracts, access agreements and the demonstration of the lack of resources on the part of the producer is subject to misuse, allowing gas producers to effectively "bank" resources, retaining these resources for future development and sales while impeding current gas supply.[309]

The DomGas Alliance also noted that current retention leases, especially offshore leases, do not explicitly distinguish between the commerciality of domestic and international gas demand.[310] Hence the Alliance advocated that all gas resources currently held under retention be assessed with a focus on domestic requirements (whether the resources held under retention are capable of supplying the domestic market commercially) in the first instance, prior to considering international gas demand.[311]

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[304] As defined under the Commonwealth's *Offshore Petroleum and Greenhouse Storage Act 2006* and the WA's *Petroleum and Geothermal Energy Act 1967* for onshore and internal waters and *Petroleum (Submerged Lands) Act 1982* for coastal waters.

[305] Note, the titleholder is normally obliged to omit half the area from the existing permit from the renewal application, unless there was a successful petroleum discovery within the exploration area. The discovery may be exempt from the 50% relinquishment requirement and can be held in addition to what the rules allow. Special provisions also allow permit holders with six or fewer blocks a maximum opportunity to explore the remaining area. Conditions vary across retention leases, however, they are typically time and investment related.

[306] According to DRET (2012), offshore retention leases were introduced in 1985 to encourage hydrocarbon exploration entities to explore more offshore regions that are commercially challenging. Note, the Commonwealth *Offshore Petroleum and Greenhouse Storage Act 2006* is supplemented by the *Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009*, *Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009* and the *Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011*.

[307] This was outlined in Productivity Commission (2009). For a list of Commonwealth and State legislation relevant to gas exploration, see Productivity Commission (2013).

[308] See DRET (2012), Interim Offshore Petroleum Guideline for Grant and Administration of a Retention Lease, http://www.nopta.gov.au/_documents/guidelines/OffshorePetroleumGuidelineGrantAdministrationRetentionLease.pdf, accessed 14 May 2013.

[309] See DomGas Alliance (2012), 2011 Domestic Gas Scorecard, http://www.domgas.com.au/pdf/Alliance_reports/Scorecard%20Dec%202011.pdf, accessed 19 February 2013.

[310] Ibid.

[311] The Domgas Alliance also suggests this should be reinforced by existing administrative guidelines and legislation. Ibid

In addition to the recommendations, the Alliance also proposed that retention lease determinations be made more transparent by including third party participation in the retention lease review process (such as prospective gas producers, infrastructure investors or gas consumers). Other entities such as the CCIWA have proposed a gazetting process for retention leases to allow for other parties to provide an undertaking or make submissions towards developing the potential resource and the Productivity Commission proposed an auction mechanism, but such procedures are currently not allowed under Commonwealth and State approval processes.[312]

Despite the concerns about retention leases, gas producers have indicated these perceptions of "banking" gas resources under retention leases are highly inaccurate. Gas producers assert that cost considerations vary for each gas field as the quality and quantum of each resource varies.[313] Resource characteristics and other synergistic factors (whether adjacent fields may also be extracted) drive cost considerations when considering infrastructure for each gas field. Hence, they assert that a specific approach to the assessment of retention lease applications would be inappropriate and would have a negative impact on gas exploration.

Gas producers have also indicated the decision to proceed with each potential gas project is typically considered in the context of the international and domestic market outlook, field profitability, its existing capital structure, its international resource and production portfolio, existing risks considerations, and not simply the result of domestic demand.[314,315]

Notwithstanding the debate on the efficacy of retention lease legislation and guidelines, any changes or modification to existing retention lease legislation have the potential to impact on the supply of gas to the WA market.

Joint Marketing of Gas Supply

The joint marketing of gas has been a feature of the WA domestic gas market since it was approved in 1977 by the Commonwealth's former Trade Practices Commission under the former Commonwealth *Trade Practices Act 1974*.[316] Since joint marketing was permitted for the NWS Domgas JV (DGJV), this authorisation was extended to include the Incremental Pipeline JV (IPJV) in July 1998.[317] Although the Australian Consumer and Competition Commission's (ACCC) authorisation for the IPJV expired in 2005 and the DGJV voluntarily revoked its authorisation in 2007, joint marketing was subsequently reapproved by the ACCC under the *Competition and Consumer Act 2010* in 2010 until 31 December 2015.[318] In November 2009, the Gorgon JV was also authorised to jointly market its gas to the domestic market until 31 December 2015.[319]

The authorisation of joint marketing by the ACCC for the NWS JVs has been a controversial issue in WA as joint marketing is typically allowed in immature markets when a single party effectively yields substantial market power in negotiations, allowing this party to dictate agreement terms.[320]

This was the state of affairs when the NWS JV project was first initiated. The WA domestic gas market and the international LNG markets were not well developed and the project viability of the NWS hinged on a gas

[312] See CCIWA (2007) for its suggested gazetting process and Productivity Commission (2009) for its proposed auction mechanism. In its response to the Productivity Commission (2009), DRET (2011) indicated that the proposed auction mechanism was unclear in how it may provide a more objective test of commerciality.
[313] This view is also outlined in CCIWA's (2007) report.
[314] This sentiment was also outlined in CRA International (2007)'s report.
[315] A gas stakeholder cited the timeframe upon which the Wheatstone project was approved and moved into development casts doubt over assertions that gas producers "warehouse" gas reserves under retention leases.
[316] This is now replaced by the Australian Consumer and Competition Commission (ACCC) and the *Competition and Consumer Act 2010 (Commonwealth)*.
[317] See ACCC authorisation (A90624), http://www.accc.gov.au/media-release/accc-releases-draft-determination-on-north-west-shelf-gas-authorisation-application, accessed 26 March 2013.
[318] Australia Consumer and Competition Commission (2010) approved joint marketing for both the Domgas JV and the Incremental Pipeline gas JV, http://www.accc.gov.au/content/index.phtml/itemId/945999, accessed 1 November 2012.
[319] See ACCC (2009), ACCC allows joint marketing of natural gas for the Gorgon JV, http://www.accc.gov.au/media-release/accc-allows-joint-marketing-of-natural-gas-from-the-gorgon-gas-project, accessed 5 March 2013.
[320] The Allen Consulting Group (2009) also indicated joint marketing was typical in markets that had; term contracts with long tenure, small and illiquid markets, little price transparency and few delivery alternatives.

sales agreement between the NWS JV and the vertically integrated SECWA, Alcoa and other industrial users, outlined in the NWS Development Agreement 1979, whom collectively had a greater influence on negotiations.

Since the Agreement, SECWA has disaggregated into five separate entities, gas transmission infrastructure and transmission capacity has expanded significantly and the number of large domestic gas consumers in WA has steadily increased from one to around 60. In addition, the number of gas suppliers (processing facilities) has grown from one to seven in 2013 (see chapter 3 for details). These changes have transformed the WA gas market from a single producer supplying a handful of dominant purchasers to a market with multiple gas suppliers and consumers – a trend set to continue. Despite experiencing a steady increase in gas suppliers since 1984, the NWS JV remains the dominant provider of WA domestic gas supply; supplying approximately 55.5% of the market.

CCIWA conducted a review of the WA gas market in 2007 and found that unbundling of the gas contracts of SECWA in the 1990s into multiple smaller contracts improved the competitive landscape for domestic gas demand and reshaped the dynamics of the WA gas market.[321] However, it suggested that there had been minimal improvement to the gas supply dynamics and called for the discontinuation of the joint marketing of domestic gas.

A study commissioned by the DomGas Alliance also suggested that joint marketing limits potential gas supply innovations (in contracts) and secondary market developments as it reduces the diversity of risk preferences across producers and limits intra-basin competition across WA (Perth and Carnarvon).[322]

The DomGas Alliance, in its submission to the ACCC in 2010 suggested joint marketing in WA effectively reduces the number of suppliers in the market and confers market power and noncommittal risk to the JV partners as they effectively do not compete with each other when supplying to the domestic market.[323] The Grattan Institute also objects to the continuation of joint marketing by highlighting the success of smaller gas producers' ability to sell their gas separately to the domestic market.[324]

Although pure economic principles suggest that joint marketing discourages competition, reports by Concept Economics and Frontier Economics contend that joint marketing is cost effective.[325] These studies suggest joint marketing is necessary due to the high capital costs associated with gas extraction. It also allows the JV to continually mitigate business and financial risks and does not prevent the development of other commercially viable projects.[326] These reports contend that joint marketing partners face the same extraction costs and any separate marketing of gas will increase operational costs of all partners (through gas balancing, marketing and contract management) that would be passed onto end consumers.[327]

In addition, the Concept Economics study suggests separate marketing by existing JV partners would create gas imbalances amongst JV participants that cannot be easily rectified due to a lack of a liquid short-term market, gas storage or balancing agreements to curtail and moderate these imbalances.[328] The study also suggests the lack of transmission capacity on existing pipelines also impedes the separate marketing of gas by existing JV partners as existing shipping contracts prevent the reassignment of unused capacity on the transmission pipelines.

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[321] CCIWA (2007) also suggests the GGP was a key contributing factor to the changing gas demand dynamics in the WA gas market.
[322] This excerpt is from Synergies Economic Consulting (2007). While the reasons are valid, the Perth Basin may not be able to supply large quantities of gas to a large consumer base over a long-term contract.
[323] DomGas Alliance (2010) North West Shelf joint selling authorisation - submission to the ACCC and Appendix, 30 April 2010, http://www.domgas.com.au/pdf/Subs_pres/NWSJV%20authorisation%20submission%20-%20FINAL-30-4-10.pdf, accessed 6 March 2013.
[324] See Grattan Institute (2013) for more details.
[325] See Concept Economics (2008) and Frontier Economics (2010) for more details. Frontier Economics (2010) also suggests if joint marketing was discontinued, the impact on domestic gas prices is uncertain.
[326] Obtaining financing for LNG facilities requires the stable cash flows that are more easily achieved from joint marketing and production.
[327] While the argument proposed by Concept Economics (2008) and Frontier Economics (2010) is valid, it is unclear whether additional costs incurred by JV partners through separate marketing are higher or lower than the non-competitive gas premium.
[328] In practice, gas imbalances amongst JV partners are balanced against deliveries to common customers by way of a gas balancing agreement that clearly outlines each party's costs, lifting arrangements, gas entitlements, mechanisms to dispose of gas, timing and actions to rectify uplift and downlift imbalances and nominal prices for settlements.

The ACCC is scheduled to review the joint marketing authorisations for the Gorgon JV and the NWS JVs in 2014. It is anticipated a decision on this issue will be made before the expiry of both authorisations on 31 December 2015.

Extension of Petroleum Resource Rent Tax (PRRT) to North West Shelf and Onshore Projects

Since 1987, all petroleum production facilities (including gas only production facilities) in Australia were subject to the Commonwealth's *Petroleum Resource Rent Tax Assessment Act 1987* and had to pay royalties to the Commonwealth Government for the extraction of hydrocarbons located in areas under the Commonwealth's jurisdiction (with the exception of the NWS project and the Joint Petroleum Development Area (JDPA) in the Timor Sea).

In 2012, the Commonwealth Government approved changes to extend the coverage of the PRRT to include all onshore and offshore oil and gas production except for oil and gas production located within the JDPA in the Timor Sea. The extension of the PRRT regime applies to all conventional and unconventional (shale and tight) oil and gas exploration and production entities operating in WA, including the NWS JVs. The PRRT amendments also clarified previously ambiguous sections of the PRRT in the calculation of liability.

APPEA's response[329] to the Commonwealth's Draft Energy White Paper suggests other unresolved issues in the extended PRRT and alluded to the complexity and cost associated with adhering to the new PRRT, suggesting that the regime may be unsustainable in the long-term and may inadvertently affect gas exploration projects that are mostly in WA.[330]

10.2. Western Australia Government Policies

Since the Varanus Island incident in 2008 that disrupted 30% of WA's domestic natural gas supply and cost the WA economy approximately $2.4 billion during June and July 2008, the WA Government has been concerned about the impact of higher natural gas prices in the WA domestic gas market.[331]

Although a report by the EISC in March 2011 suggests domestic gas capacity constraints are easing, the WA Government's gas market policies remain focused towards increasing the availability of gas supply to the domestic market.

Strategic Energy Initiative

The WA Government released its Strategic Energy Initiative (SEI) policy document in August 2012 (also known as Energy2031), outlining the State Government's 20-year vision for the WA energy sector its goals and guiding principles on how to achieve this vision.[332]

The SEI policy paper also outlines five key directions on how to achieve the WA Government's vision:

- encouraging a diverse and secure energy supply;
- integrated and pro-active energy planning;
- effective and efficient energy delivery;
- informed and responsible energy use; and
- capacity building with technology.

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[329] APPEA's submission is available at http://www.appea.com.au/policy/submissions-a-reports/2012.html, accessed 19 June 2013.
[330] According to ABS (2012), Cat 8412.0 Mineral and Petroleum Exploration, Australia, as at December 2012, WA's petroleum exploration makes up 70.4% of total petroleum exploration in Australia.
[331] Varanus Island disruption estimates are acquired from CCIWA's submission for the Inquiry into Matters relating to the Gas Explosion at Varanus Island, September 2008.
[332] The WA Government's Strategic Energy Initiative Paper (Energy2031) is available at http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3813100cb1e5bc616f7914cc48257855000f71a1/$file/3100-15.03.11.pdf.

The SEI provides suggestions on how the WA Government's objectives are expected to be met. Of particular interest to the WA gas industry will be the WA Government's commitment to:

- grow cleaner renewable energy that will lower emissions and energy intensity for WA. This may increase WA's requirements for gas generators;
- support the exploration and production of natural gas by enhancing the Government's approvals systems to encourage exploration and development of conventional and unconventional gas reserves;
- enhance regulatory arrangements to ensure best practice in extraction of unconventional gas supply through research on environmental impacts associated with unconventional gas;
- coordinate planning and encourage improved usage of gas transmission and distribution infrastructure through regulatory arrangements, incentives or technology to improve existing capacity and develop flexible access;
- facilitate evolution towards transparent, effective and efficient wholesale gas markets in WA that are aligned with the national gas market;
- ensure a robust emergency management system exists for gas markets;
- convergence of the wholesale and retail market arrangements for electricity and gas, where it is practical and beneficial; and
- review the WA Government's domestic gas reservation policy in 2014-2015.

Western Australia Government's Gas Reservation Policy

The Commonwealth Government currently does not have a national reservation policy for the national gas market and does not support this "market intervention".[333] This means that Australia is the only country, amongst the 20 countries with the highest gas reserves globally, where gas companies can access and export gas without prioritising domestic supply.[334] As such, the pricing of gas in Australia, especially WA, is likely to be more influenced by international gas market practices and market forces than other countries.

Due to concerns over a lack of gas supply, the WA Government instituted a domestic gas reservation policy called the WA Government Policy on Securing Domestic Gas Supplies in 2006, making WA the only State in Australia that currently operates a reservation policy.[335] Although this policy is not formalised in legislation, it has support from the two major political parties in WA.

Under this policy, the WA Government requires gas producers to reserve 15% of gas produced from each field for supply to the domestic market in exchange for permission to situate their processing facilities on State-owned land.

Although the domestic gas reservation policy preserves a portion of WA's gas supply for domestic use, the impact of this policy is limited, as it only applies to onshore and offshore producers that intend to process gas on State owned land.[336] Gas producers can circumvent this policy by considering other methods of processing gas, such as building FLNG production facilities (e.g. Shell's Prelude Project). The policy remains unclear on whether further expansions of each gas field already committed to providing gas to the domestic market is excluded from the policy.

The SEI policy paper released in August 2012 provides some clarity on the Gas Reservation Policy:

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[333] In August 2012, the Commonwealth indicated it does not support a national gas reservation policy. See http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/7986077. This is reiterated in DRET's (2012b), Energy White Paper 2012 released on 8 November 2012.

[334] See DomGas Alliance's (2012), Australia's Domestic Gas Security Report 2012 for more information.

[335] WA Government's 15% domestic gas policy is outlined in Department of Premier and Cabinet's, *WA Government Policy on Securing Domestic Gas Supplies,* http://www.dmp.wa.gov.au/documents/DomGas_Policy(1).pdf. QLD has some type of gas reservation known as the Prospective Gas Production Land Reserve (PGPLR) policy, through this policy is ineffective as no known gas field has been set aside under this policy for domestic consumption (DomGas Alliance, 2012). The Hon. Chris Hartcher MP., Minister for Resources and Energy for NSW and the Hon. Mark McArdle MP., Minister for Energy and Water Supply for QLD at the Australian Domestic Gas Outlook 2013 conference also outlined they both did not support a gas reservation policy. Gas Today (2013c) also indicates the NT does not support a gas reservation policy.

[336] Most offshore gas production is within the Commonwealth's jurisdiction where the WA gas reservation policy does not apply and may be bypassed.

- the reservation of domestic gas is equivalent to 15% of LNG production from each LNG export project;
- reservation of gas supply is required prior to obtaining access to required infrastructure;
- producers must operate with diligence and good faith when marketing gas to the WA domestic market;
- producers should undertake actions such that domestic gas availability coincides with the start of LNG production. However, this timing may vary depending on circumstances;
- prices and contracts for domestic gas are expected to be market determined;
- producers may offset their domestic gas commitment by supplying gas from an alternative source, rather than a specific LNG project. However, producers will have to demonstrate the proposed offset represents a net addition to the State's domestic energy supply;[337] and
- the policy will be reviewed by the WA Government in 2014-15.[338]

Despite industry resistance to the policy, it can be argued that it has helped secure gas supply for the domestic market. Table 33 provides a summary of domestic obligations applicable to LNG projects in WA.

Table 33 – Domestic Obligations Applicable to Western Australia LNG Projects, 2013

Project	Domestic Gas Obligations
North West Shelf JV	State Agreement: 5,064 PJ to be supplied over the life of the project, commitments are due to be met around 2014.*** Provisions are understood to exist in the revised agreement for further supplies to be negotiated.
Gorgon JV	State Agreement: 2,000 PJ supplied over the life of the project. Domestic gas facility with a 300 TJ/day capacity will be constructed onshore. Delivery of 150 TJ/day is expected to commence in 2016 with a further 150 TJ/day to be supplied by 2021. Domestic gas supply is subject to commercial viability provisions.*
Pluto JV	Reservation Policy: 15% of LNG production to be supplied with a commencement date five years after first LNG export (shipments commenced May 2012) or after 30 million tonnes of LNG has been shipped. Mode of domestic gas supply delivery is subject to further negotiations and commercial viability provisions.
Wheatstone JV	Reservation Policy (Domestic Gas Producers Agreement): Proponents are required to construct a domestic gas plant with production capacity equivalent to 15% of total LNG production. Consistent with the domestic gas policy, all producers are required to make available domestic gas to domestic consumers by reserving and marketing gas equivalent to 15% of their share of LNG production.^
Buru Energy and Mitsubishi	State Agreement: Objective to supply 1,500 PJ over the first 25 years of operation.**In the event of LNG export, the JV partners are obliged to make available domestic gas consistent with the domestic gas policy.^ The JV partners are required to submit a proposal for development of domestic gas facility and pipeline by 30 June 2016. Mode of domestic gas supply delivery is subject to further negotiations and proving up sufficient reserves.[%]

Source: EISC (2011), DSD, Chevron Australia, Verve Energy and Buru Energy's corporate websites. * Most of the first tranche of supply has already been contracted to Verve Energy and Synergy. **This is subject to the JV proving the availability of sufficient reserves, project technical or commercially viability of the project. Buru Energy has the option of seeking an 18 month extension of time to submit a proposal or terminating the State Agreement on or before 31 March 2016. ^Information provided by DSD. ***According to SKM-MMA (2011) and Grattan Institute, SECWA only contracted 3,023 PJ of the 5,064 PJ, the remainder is reserved for domestic use. Frontier Economics (2010) and DSD report this constraint is no longer binding on the NWS JV. Information provided by DSD indicates the NWS JV will continue to provide over and above this obligation. Information is also on Verve Energy's website, Verve News, 30 Nov 2011, http://www.verveenergy.com.au/news/201111, accessed 10 May 2013 and DomGas Alliance (2013) outlines domestic gas supply to Verve is anticipated to end in the 2016 to 2017 period. [%]This agreement has been passed by the WA Parliament, see Premier's Media Statements (2013).

While the WA reservation policy has arguably had some success in increasing the availability of domestic gas to WA, it may need to be constantly evaluated to consider its impact on the total domestic market.

An APPEA-funded study by EnergyQuest, investigating the impact of government interventions in various domestic gas markets in OECD and non-OECD countries, found government interventions do not

[337] The criteria for domestic gas offset have not been pursued by any producer and are still undeveloped.
[338] A particular gas market participant suggested that the reservation policy should be expanded to consider other proposals such as supplying a proportion of LNG produced to the domestic LNG market to encourage the use of LNG domestically.

consistently lead to lower gas prices.[339] The Grattan Institute suggests the reservation policy hinders the competitive dynamics of the gas supply market that would ultimately lead to short-term gains through lower gas prices in the near term and higher gas prices in the long-term.[340] A recent study by ACIL Allen also suggests the reservation policy misallocates resources, causing economic waste or deadweight loss.[341]

In addition, the reservation policy may impact on the financial viability of marginal projects. It is unclear as to whether the policy may have discouraged INPEX and Total's Ichthys, Shell's Prelude and Woodside's Browse projects from constructing gas processing facilities onshore in WA.[342]

Western Australia Government's Exploration Incentive Scheme

In April 2009, the WA Government launched an $80 million Exploration Incentive Scheme (EIS), an initiative to encourage minerals exploration in WA's frontier areas.[343] This five-year government initiative intends to stimulate private investments by co-investing with industry to encourage the exploration of minerals and energy in Greenfield areas that will contribute to the knowledge of WA's geology.

The EIS is made up of six distinct programs that target improvements to tenement applications, access to geological (surveys), geographical (mapping) and research data, co-investment in drilling programs and assistance with indigenous clearances for projects.

At the time of this report, six oil and gas exploration projects have obtained funding under the program for co-investment in drilling.[344] The EIS is expected to run for one last round with the EIS funding expected to be awarded by December 2013.[345]

10.3. IMO's Temporary Gas Trading Bulletin Board in 2008

In June 2008, due to the Varanus Island incident, the IMO operated a temporary GBB platform that facilitated the trading of short-term gas between gas producers and consumers from 3 July 2008 to 13 October 2008. During this period, the IMO's temporary system recorded 32 trades totalling 47.8 TJs.[346]

The IMO became aware of a number of impediments to trading short-term gas in WA while operating the temporary GBB in 2008, such as;

- there were impediments to the negotiation of commercially acceptable gas shipping agreements for short-term gas due to capacity reservation on key gas transmission pipelines;
- the logistics of concurrently arranging the shipping of gas on multiple networks to reach customers with existing contractual arrangements is complex;
- the existence of contractual restrictions curtailed the ability of some gas consumers to on-sell surplus gas to other parties requiring short-term gas; and
- a lack of liquidity in the short-term gas market and competitive concerns prevented an unnamed gas industry participant from aggregating its customer's gas supply requirements and entering the short-term market.

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[339] EnergyQuest (2013), Domestic Gas Market Interventions International Experience, http://www.appea.com.au/images/stories/Reports/energyquest%20appea%20report_april%202013_final.pdf, accessed 16 April 2013.
[340] Grattan Institute (2013) acknowledges while gas prices will be lower in the short term, it suggests in the long term, interventions will result in higher prices.
[341] See ACIL Allen (2013), Attachment to Australian Pipeline Industry Association's Gas Policy, http://www.apia.net.au/wp-content/uploads/2013/01/gaspolicy-jul13-APIA-2.pdf.
[342] While comments reported by the EISC (2011) suggest the reservation policy did not influence any investment decision, The West Australian (2013) suggests otherwise.
[343] Former Minister Hon. Norman Moore, Ministerial Statement, Mining exploration sector gains $80million boost from Royalties for Regions, http://www.mediastatements.wa.gov.au/Pages/StatementDetails.aspx?StatId=863&listName=StatementsBarnett, accessed 12 February 2013.
[344] According to DMP (2013), the EIS supported the oil and gas exploration projects such as Backreef Oil Pty Ltd's for its Emika-1 drilling in 2011, Buru Energy's Hope-1 and Woolnough-1 exploration projects, New Standard Onshore Pty Ltd's Teichert Crostella #1 well in 2012 and Condon #1 in 2013.
[345] At the time of this report, the seventh round for the Government co-funded Innovative Drilling program is closed and winning applicants were announced 12 June 2013, See http://www.mediastatements.wa.gov.au/Pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7468 and http://www.dmp.wa.gov.au/7748.aspx, accessed 17 June 2013.
[346] See the IMO's Gas Bulletin Board Report, available at http://www.imowa.com.au/f226,3224/GasBulletinBoardFinalReport.pdf, accessed 1 November 2012.

11. Appendices

11.1. Appendix 1 – Abbreviations Used

- ABS – Australian Bureau of Statistics
- APPEA – Australian Petroleum Production Exploration Association
- ASX – Australian Stock Exchange
- BAP – Bunbury to Albany Pipeline
- Bcf – Billions of cubic feet
- Bcm – Billions of cubic metres
- BREE – Bureau of Resources and Energy Economics
- Btu – British Thermal Unit
- CCGT – Combined Cycle Gas Turbine
- CSG – Coal seam gas
- DBNGP – Dampier to Bunbury Natural Gas Pipeline
- DMP – Department of Mines and Petroleum (WA)
- DOE – Department of Energy (US)
- DSD – Department of State Development (WA)
- EIA – Energy Information Administration (US)
- EISC – Economics and Industry Standing Committee
- ERA – Economic Regulation Authority (WA)
- ESOO – Electricity Statement of Opportunities Report (WA)
- EU – European Union
- FID – Final Investment Decision
- FLNG – Floating LNG
- FTA – Free Trade Agreement
- GBB – Gas Bulletin Board
- GDP – Gross Domestic Product (Australia)
- GFC – International (Global) Financial Crisis
- GGP – Goldfields Gas Pipeline
- GISP – Gas Information Services Project
- GJ – Gigajoule
- GNP – Great Northern Pipeline
- GSOO – Gas Statement of Opportunities
- GSP – Gross State Product (WA)
- GWh – Gigawatt-hour
- IGU – International Gas Union
- IMO – Independent Market Operator
- JV – Joint Venture
- KEP – Kambalda to Esperance Pipeline
- KGP – Karratha Gas Plant
- KKP – Kalgoorlie to Kambalda Pipeline
- Km – Kilometre
- LNG – Liquefied Natural Gas
- LPG – Liquefied petroleum gas
- Mcf – Millions of cubic feet
- Mt – Million tonnes (Megatonne)
- Mtpa – Million tonnes per annum
- MW – Megawatt
- MWP – Mid-West Pipeline
- NIEIR – National Institute of Economic and Industry Research
- NSW – State of New South Wales
- NT – Northern Territory

- NWS – North West Shelf
- NWS JVs – North West Shelf JVs (includes DomGas JV, Incremental Pipeline JV and Extended Interest JV)
- OCGT – Open Cycle Gas Turbine
- PJ – Petajoule
- PJ/a – Petajoule per annum
- PPS – Pilbara Pipeline System
- QLD – State of Queensland
- RET – Renewable Energy Target
- SA – State of South Australia
- SECWA – State Energy Commission of Western Australia
- SEI – Strategic Energy Initiative
- STEM – Short Term Energy Market
- SWIS – South West interconnected system
- TAS – State of Tasmania
- Tcf – Trillions of cubic feet
- TGP – Telfer Gas Pipeline
- TJ – Terajoule
- TJ/day – Terajoule per day
- US – United States
- VIC – State of Victoria
- WA – State of Western Australia
- WEM – Wholesale Electricity Market

11.2. Appendix 2 – Forecasts of Economic Growth

12. Table I – Growth in Australian Gross Domestic Product (% Year on year growth)

Year	Actual	Expected	High	Low
2006-2007	3.8			
2007-2008	3.8			
2008-2009	1.6			
2009-2010	2.1			
2010-2011	2.4			
2011-2012	3.4			
2012-2013		3.2	3.4	2.8
2013-2014		3.1	4.0	2.5
2014-2015		3.2	4.4	2.3
2015-2016		3.3	4.6	2.3
2016-2017		3.5	4.3	2.4
2017-2018		3.7	4.2	2.8
2018-2019		3.0	3.0	2.4
2019-2020		2.7	3.1	1.9
2020-2021		2.6	3.1	1.7
2021-2022		2.0	2.5	1.0
2022-2023		1.4	2.0	0.5
Average Growth %		**3.0**	**3.7**	**2.2**

13. Table II – Growth in Western Australian Gross State Product (% Year on year growth)

Year	Actual	Expected	High	Low
2006-2007	6.2			
2007-2008	3.9			
2008-2009	4.3			
2009-2010	4.3			
2010-2011	4.0			
2011-2012	6.7			
2012-2013		6.5	7.2	5.9
2013-2014		3.1	5.3	1.2
2014-2015		1.6	3.9	-0.7
2015-2016		0.4	2.9	-1.2
2016-2017		6.4	7.3	4.6
2017-2018		6.1	4.9	5.5
2018-2019		4.7	4.4	3.8
2019-2020		3.3	4.8	1.9
2020-2021		1.8	2.5	-0.1
2021-2022		1.5	1.6	-1.6
2022-2023		2.0	3.4	1.0
Average Growth %		**3.1**	**4.1**	**1.4**

11.3. Appendix 3 – List of Upcoming Gas Related Projects considered in Gas Demand Forecasts 2013 – 2022

Project	Operator	Capacity of Gas-fired Generator (MW)	Anticipated Start-up	Capital Expenditure ($ million	Mtpa
Rio Tinto's Mine Expansions – Pilbara 290 Iron Ore Expansion (near Paraburdoo and West Angeles)	Rio Tinto	Unknown	2013	$10,200	53
Rio Tinto's Cape Lambert Power Facility Replacement at Port Hedland	Rio Tinto	120	2013	$287	N.A.
Yarnima Power Station	BHP Billiton	190	2014	$597	N.A.
Roy Hill Iron Ore Mine and Infrastructure	Hancock Prospecting	Unknown	2015	$9,500	55
Rio Tinto – Pilbara 360 Iron Ore Expansion	Rio Tinto	Unknown	2015	$6,100	70
Karratha Temporary Power Station	Horizon Power	20	2013	$30-40	N.A.
South Hedland Power Station	Horizon Power	67	2014	$125	N.A.
Macedon Gas Processing Facility	BHP Billiton	Unknown	2013	$1,500	N.A.
Red Gully Gas Processing Facility	Empire Oil and Gas	Unknown	2013	$29.1	N.A.
Mungullah Power Station	Horizon Power	18	2013	$73	N.A.

Source: APA Group (2011, 2012), BREE (2012) and other respective corporate websites. **Note**: N.A. – Not Applicable

11.4. Appendix 4 – Gas Demand Forecasts, 2013 – 2022

	Demand Forecasts – Domestic – Constrained (TJ/day)		
Year	**Low**	**Base**	**High**
2013	947.1	947.1	947.1
2014	962.6	966.1	980.2
2015	978.8	990.8	1013.9
2016	980.0	996.2	1024.0
2017	978.2	997.9	1032.4
2018	986.8	1010.5	1049.6
2019	1006.4	1031.5	1080.6
2020	1009.9	1037.9	1091.3
2021	1004.7	1050.3	1133.3
2022	999.4	1051.9	1147.5

	Demand Forecasts – Domestic – Unconstrained (TJ/day)		
Year	**Low**	**Base**	**High**
2013	947.1	947.1	947.1
2014	963.0	966.5	980.6
2015	979.2	991.2	1,014.3
2016	980.4	996.6	1,024.4
2017	978.6	998.3	1,032.9
2018	987.2	1,010.9	1,050.0
2019	1,008.3	1,034.9	1,083.8
2020	1,017.4	1,048.5	1,102.2
2021	1,021.0	1,072.2	1,156.2
2022	1,024.5	1,085.8	1,183.6

	Demand Forecasts – SWIS – Constrained (TJ/day)		
Year	**Low**	**Base**	**High**
2013	704.2	704.2	704.2
2014	703.2	705.2	717.5
2015	701.8	710.5	730.2
2016	699.4	710.3	733.9
2017	694.1	708.2	737.8
2018	698.5	715.7	749.4
2019	709.1	727.5	770.0
2020	711.2	731.6	776.9
2021	707.0	744.7	818.6
2022	699.3	743.7	828.7

	Demand Forecasts – Outside of SWIS – Constrained (TJ/day)		
Year	**Low**	**Base**	**High**
2013	242.9	242.9	242.9
2014	259.4	260.8	262.7
2015	277.0	280.3	283.7
2016	280.6	285.9	290.1
2017	284.1	289.7	294.6
2018	288.4	294.7	300.2
2019	297.3	304.0	310.6
2020	298.7	306.3	314.5
2021	297.6	305.5	314.7
2022	300.0	308.2	318.9

11.5. Appendix 5 – List of Processing Facilities included in Projected Gas Supply, 2013 – 2022

Processing Facility	Operator/Expected Operator	Basin	Estimated Gas Processing capacity (TJ/day)	Estimated Start-Up	Comments
Karratha Gas Plant (North West Shelf)	North West Shelf JVs	Carnarvon	630	N.A.	
Varanus Island – East Spar	Apache Energy	Carnarvon	270	N.A.	
Varanus Island – Harriet	Apache Energy	Carnarvon	120	N.A.	
Devil Creek	Apache Energy	Carnarvon	220	N.A.	Currently reported to be operating at 110 TJ/day
Macedon	BHP Billiton	Carnarvon	200	2013	
Gorgon Domestic	Chevron	Carnarvon	300	2016 (150 TJ/day only)	Capacity is anticipated to be 150 TJ/day until 2020
Wheatstone Domestic	Chevron	Carnarvon	200	2018	
Dongara	AWE Limited	Perth	7	N.A.	Facility may be expanded in the future due to Senicio and Corybas field exploration.
Beharra Springs	Origin Energy	Perth	25	N.A.	
Red Gully	Empire Oil and Gas	Perth	10.6	N.A.	Facility has provisions to expand capacity to approximately 21.2 TJ/day (20 MMcf/day)
Total Gas Processing capacity			**1,982 TJ/day**		

Source: Public announcements and respective corporate websites. **Note**: N.A. – Not Applicable.

This GSOO notes that BREE (2012c) expects gas production in WA to continue to grow at 2.2% per annum from 2012-2013 to 2049-50.

11.6. Appendix 6 – Gas Price Forecasts, 2013 – 2022

	Forecast Gas Prices (Nominal)		
Year	**Low**	**Base**	**High**
2013	$ 6.73	$ 6.73	$ 6.73
2014	$ 4.64	$ 4.64	$ 5.73
2015	$ 4.07	$ 4.08	$ 4.74
2016	$ 4.95	$ 5.58	$ 6.05
2017	$ 6.04	$ 6.27	$ 6.88
2018	$ 6.91	$ 7.17	$ 7.97
2019	$ 8.16	$ 8.44	$ 9.72
2020	$ 8.67	$ 9.27	$ 9.86
2021	$ 6.41	$ 7.09	$ 8.57
2022	$ 6.55	$ 7.19	$ 9.03

	Domestic Supply Forecasts (TJ/day)		
Year	**Low**	**Base**	**High**
2013	1273.8	1273.8	1273.8
2014	1101.0	1301.0	1386.1
2015	1023.8	1223.8	1273.6
2016	1235.4	1435.4	1487.6
2017	1253.0	1453.0	1506.3
2018	1474.8	1674.8	1731.5
2019	1521.8	1721.8	1782.8
2020	1671.1	1871.1	1932.2
2021	1626.5	1826.5	1883.4
2022	1626.3	1826.3	1882.2

11.7. Appendix 7 – List of Committed Gas Projects in Western Australia

Project	Location	Type	Estimated Start-Up	Estimated New Capacity	Indicative Cost ($ millions)
Gorgon LNG	Carnarvon Basin	New Project	2015	15.6 Mt	$52,000
Greater Western Flank – Phase 1*	Carnarvon Basin	Expansion	2016	Not applicable	$2,500^
Julimar Development Project^	180 km north west of Dampier	New Project	2016	1.65 Mt	$1,200
Macedon	100 km west of Onslow	New Project	2013	75 PJ/a	$1,470
North West Shelf North Rankin B**	150 km north west of Dampier	Expansion	2013	967 PJ/a	$5,000
Prelude Floating LNG	Offshore	New Project	2017	3.6 Mt	$12,600
Spar#	120 km west of Onslow	New Project	2013	18 PJ/a	$200^
Wheatstone LNG	145 km north west of Dampier	New Project	2016	8.9 Mt	$29,000
Total					**$103,970**

Source: BREE (2013c). ***Note:** The Greater Western Flank Phase 1 project is an extension of the North West Shelf project by connecting the Goodwyn GH and Tidepole fields to the offshore Goodwyn A platform. **The North Rankin B project is also an extension of the North West Shelf by installing gas reinjection to recover remaining gas from North Rankin and Perseus gas fields. ^The Julimar Development Project is linked with Wheatstone's LNG and domestic gas facility. #Santos' Spar project is an extension to East Spar that is linked with the Varanus Island processing facility. ^Indicative costs are reported in Business News (2013).

11.8. Appendix 8 – LNG Requirement Forecasts, 2013 – 2022

	LNG Feedstock Estimates (PJ/annum)		
Year	Low	Base	High
2013	1141.9	1141.9	1141.9
2014	1141.9	1141.9	1141.9
2015	2006.6	2006.6	2006.6
2016	2253.2	2253.2	2253.2
2017	2499.9	2499.9	2499.9
2018	2499.9	2499.9	2788.1
2019	2499.9	2788.1	2788.1
2020	2499.9	2788.1	3034.8
2021	2499.9	2788.1	3156.7
2022	2499.9	2788.1	3156.7

	LNG Processing Estimates – 8% of Feedstock (PJ/annum)		
Year	Low	Base	High
2013	91.3	91.3	91.3
2014	91.3	91.3	91.3
2015	160.5	160.5	160.5
2016	180.3	180.3	180.3
2017	200.0	200.0	200.0
2018	200.0	200.0	223.1
2019	200.0	223.1	223.1
2020	200.0	223.1	242.8
2021	200.0	223.1	252.5
2022	200.0	223.1	252.5

	Total LNG Requirement Estimates (PJ/annum)		
Year	Low	Base	High
2013	1578.9	1578.9	1578.9
2014	1584.6	1585.8	1591.0
2015	2524.4	2528.7	2537.2
2016	2791.2	2797.1	2807.3
2017	3056.9	3064.1	3076.7
2018	3060.1	3068.7	3394.3
2019	3067.2	3387.7	3405.6
2020	3068.5	3390.0	3675.9
2021	3066.6	3394.5	3822.9
2022	3064.7	3395.1	3828.1

11.9. Appendix 9 – Conversion Factors Applied

The following conversion factors have been applied to this GSOO:

	To						
Natural Gas and LNG	Billion cubic meters NG	Billion cubic feet NG	Million tonnes oil equivalent	Million tonnes LNG	Trillion British Thermal Units	Million barrels oil equivalent	Petajoules
From	**Multiply by**						
Billion cubic meters NG	1	35.3	0.9	0.74	35.7	6.6	37.45
Billion cubic feet NG	0.028	1	0.025	0.0216	1.01	0.19	1.06
Million tonnes oil equivalent	1.11	39.2	1	0.82	39.7	7.33	-
Million tonnes LNG	1.36	48	1.22	1	48.6	8.97	55.43
Trillion British Thermal Units	0.028	0.99	0.025	0.021	1	0.18	1.06
Million barrels oil equivalent	0.15	5.35	0.14	0.11	5.41	1	5.82
Petajoules	0.027	0.943	-	0.018	0.943	0.172	1

Note: NG = Natural gas

11.10. Appendix 10 – References

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