INDEPENDENT MARKET OPERATOR

Gas Statement of Opportunities

December 2014

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[1] Gas referred to throughout this report refers to natural gas.

Preface

Since the publication of the IMO's second Gas Statement of Opportunities in January 2014, the domestic gas market in Western Australia (WA) has further developed, with completion of an expansion to the Goldfields Gas Pipeline, construction commencing on the Fortescue River Gas Pipeline and the announcement of the Eastern Goldfields Gas Pipeline. Several new gas production facilities are transitioning from construction into production over the 2015 to 2024 period. In addition, the recent announcement by the WA Government has given a clear indication that the North West Shelf Joint Ventures will continue to supply the domestic gas market in the future.

Over the forecast period, growth in gas demand is expected to be driven by growth in the mining industry, from a combination of new mines, mine expansions and the conversion of existing facilities from diesel to natural gas.

With inextricable linkages between WA's domestic gas and LNG sectors, the IMO also continues to monitor international gas markets to understand the factors affecting WA's LNG sector. Competitive pressure from the emergence of unconventional gas as an international source of supply, and the risk of a fall in Asia Pacific gas prices, have the potential to materially impact the domestic gas market.

These future developments, coupled with the recent volatility in commodity prices (especially for iron ore and oil), makes the preparation of this GSOO extremely challenging. The IMO has carefully considered these risks in order to ensure the forecasts contained in the GSOO are as robust as possible.

The IMO would like to thank all those who took the time to provide feedback on the previous GSOO reports and attended the stakeholder forum in March 2014. This feedback has led the IMO to make further refinements to its approach to forecasting for the GSOO.

In August 2014, the IMO also celebrated the first full year of operation of the Gas Bulletin Board (GBB). The GBB provides an invaluable insight into daily gas flows in the WA domestic gas market and information sourced from the GBB has been used in the development of this GSOO.

The IMO looks forward to continuing to provide information to further develop the WA domestic gas market, to enhance market transparency and to inform an ongoing, lively debate about the future of the WA natural gas sector.

John Kelly
Chair
Independent Market Operator

Allan Dawson
Chief Executive Officer
Independent Market Operator

Executive summary

This Gas Statement of Opportunities (GSOO) has been prepared in accordance with the Gas Services Information Rules to provide an independent insight into the Western Australian (WA) domestic gas market and assess the adequacy of medium to long-term supply to meet forecast gas demand. The GSOO provides forecasts of supply and demand in the market for the period from 2015 to 2024 (the forecast period), to identify any potential shortfalls, constraints and opportunities for existing and potential market participants.

The Independent Market Operator (IMO) has again retained the services of the National Institute of Economic and Industry Research (NIEIR) to perform the modelling of gas demand and prices. The modelling of potential gas supply was performed by the IMO, with key data inputs provided by NIEIR and Wood Mackenzie.

Key finding

Forecasting is particularly challenging in the current environment, for a number of reasons. Commodities prices have fallen rapidly, including iron ore, gold and oil – with oil prices falling by more than United States (US) $40 per barrel between 1 September 2014 and the publication of this report.

Despite this uncertainty, the IMO has considered the range of factors that have been identified as having the potential to affect the domestic gas market, and this GSOO makes the following key finding for the supply-demand balance in the WA domestic gas market for the forecast period:

The supply of gas to the domestic market is expected to be adequate to meet demand over the forecast period.

The uncertainty relating to the continuation of supply from the NWS JVs, highlighted in the January 2014 GSOO, has reduced considerably following the recent announcement by the WA Government about the agreement reached with the NWS JVs. This agreement supports continued supply from the NWS JVs to the domestic gas market well into the future. In addition, the announcement by the Hess Corporation (Hess) stating its intention to develop and toll its WA reserves through the NWS JVs' processing facilities may indicate additional supply of gas to the domestic market towards the end of the forecast period. However, with several investment decisions yet to be made by both the NWS JV and Hess regarding gas fields to be used, and by the NWS JVs regarding the refurbishment of its aging LNG and domestic gas facilities, the extent of any future supply from the NWS JVs is not yet known with certainty.

Supply-demand balance

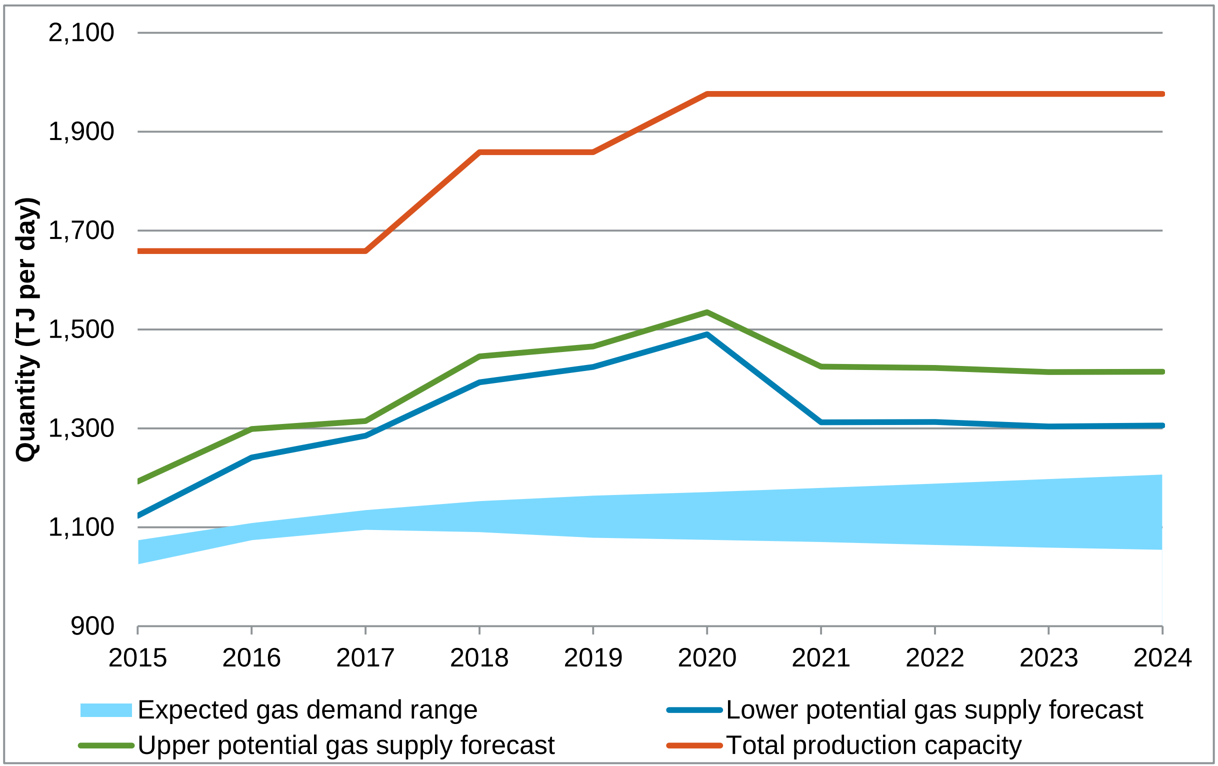
In recognition of the continued uncertainty about the extent of supply from the NWS JVs beyond 2020, two supply scenarios were developed for this GSOO:

- the Lower potential supply forecast, which assumes the NWS JVs will only make sufficient gas available to the domestic market after 2020 to fulfil their domestic gas obligation recently agreed with the WA Government, around 100 TJ per day, and assumes the Base forecast gas prices; and

- the Upper potential supply forecast, which assumes the NWS JVs will be willing to make additional gas available to the domestic market after 2020 above the minimum required to fulfil their recently agreed domestic gas obligation, and assumes the High forecast gas prices.

Figure ES.1 shows the supply-demand balance for the WA domestic gas market for the forecast period, comparing the two potential supply scenarios with gas production capacity and the range of expected demand outcomes.

Figure ES.1: Supply-demand balance, 2015 to 2024



Source: NIEIR and IMO forecasts 2015 to 2024.

This GSOO finds that, in all of the forecast scenarios, supply will exceed demand – by at least 50 TJ per day in 2015 and 320 TJ per day in 2020.

Domestic production capacity is projected to be almost double the forecast level of domestic gas demand by the end of 2024, as shown in Figure ES.1 above. WA's domestic gas production capacity is not expected to be fully utilised during the forecast period.

Gas demand

The IMO has developed two gas demand scenarios, Base and High, and considers it likely that actual demand will be somewhere within the range bounded by these scenarios – the expected gas demand range shown in Figure ES.1 above.

The quantity of gas forecast to be consumed by the domestic gas market is shown in Table ES.1 below.

Table ES.1: Domestic gas demand forecasts (TJ per day), 2015 to 2024

Scenario	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Base	1,026	1,074	1,095	1,090	1,079	1,075	1,071	1,065	1,059	1,055
High	1,074	1,109	1,135	1,153	1,164	1,171	1,180	1,188	1,198	1,207

Source: NIEIR forecasts, 2015 to 2024.

Over the forecast period, gas demand is expected to grow at an average annual rate of between 0.3 per cent in the Base demand scenario and 1.3 per cent in the High demand scenario.

The majority of projected gas demand growth in the early years of the forecast period, shown in Figure ES.1 and Table ES.1 above, is driven by large gas-consuming projects that have reached final investment decision (FID) since the writing of the January 2014 GSOO. These projects include:

- Sub161's compressed natural gas (CNG) supply facility;
- the Fortescue River Gas Pipeline (FRGP);
- the Eastern Goldfields Gas Pipeline (EGGP);
- The restarting of Alinta Energy's Newman Power Station which will supply electricity to Hancock Prospecting's Roy Hill iron ore mine; and
- operation of TransAlta's South Hedland Power Station.

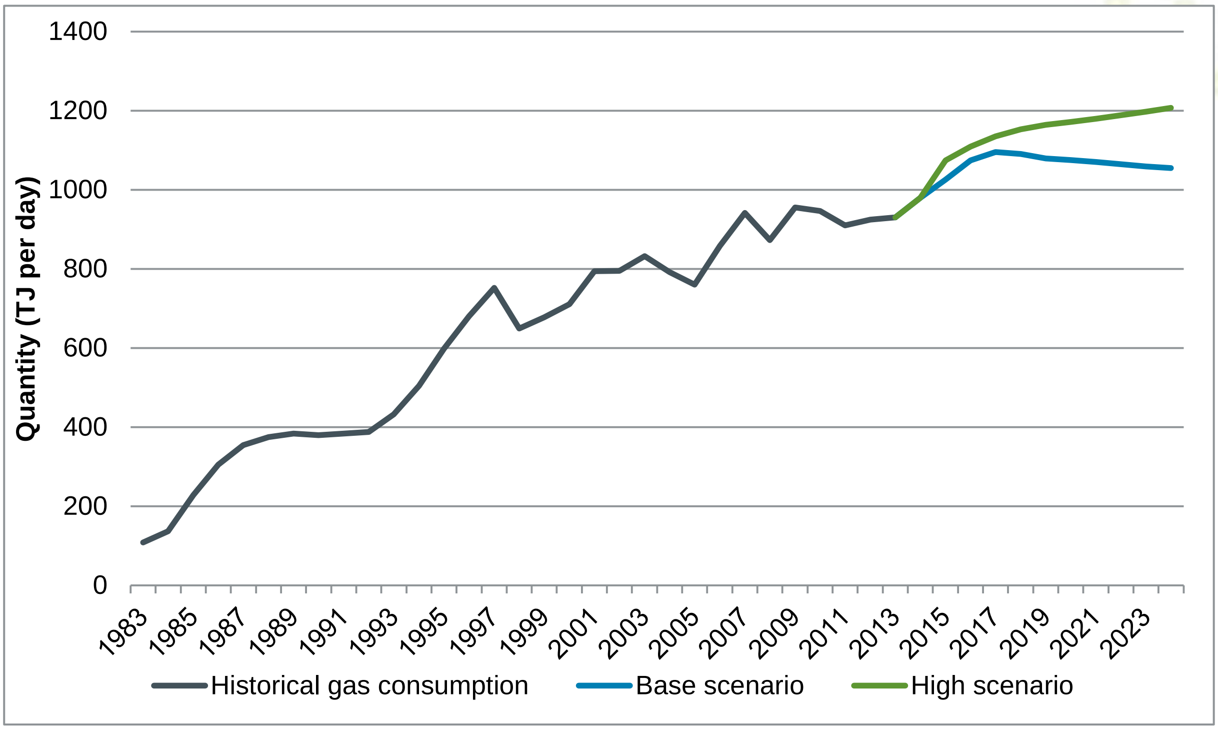
In addition, previously announced projects such as the Pilbara Temporary Power Station and CITIC Pacific's Sino Iron magnetite mine are also expected to drive growth in gas demand in this forecast.

These projects are expected to contribute almost three quarters of the forecast gas demand growth over the forecast period, with most of this growth occurring in the period between 2015 and 2017.

An estimate of gas demand from a number of prospective projects, which have not yet reached FID, is also included in the High demand scenario.

NIEIR's Base and High demand forecasts are shown in the context of historical gas demand in WA in Figure ES.2 below.

Figure ES.2: Domestic gas demand forecasts in relation to historical gas demand, 1983 to 2024



Source: Department of Mines and Petroleum (DMP) and NIEIR forecasts 2015 to 2024.

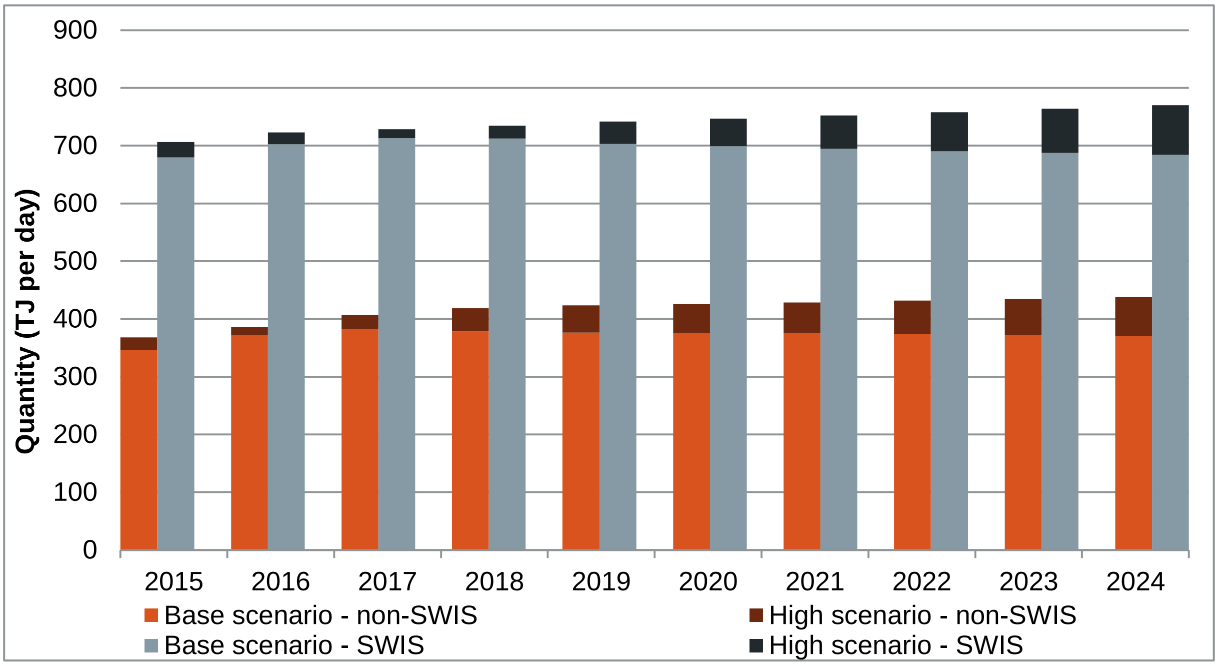
Gas demand in WA tends to have a cyclical growth pattern, with periods of high growth followed by periods of slower growth. This is due to the scale of many gas-consuming projects in WA, with a relatively small number of individual gas consumers accounting for a significant proportion of overall gas demand.

Gas demand by area

New gas-consuming projects, noted above, located in the Pilbara and Goldfields regions of WA are expected to lead to higher gas demand growth in areas located outside the South West Interconnected System (SWIS) than within, as shown in Figure ES.3 and Table ES.2.

For the Base gas demand scenarios for both areas, Figure ES.3 shows a slow decline in gas consumption after growth in the initial years. This is due to the limited expected growth in demand for gas as a fuel for electricity generation within the SWIS, and the increased focus on energy efficiency as WA businesses seek to reduce costs in the current economic environment. By contrast, the High gas demand scenario for both the SWIS and the non-SWIS areas show continued growth, due to the lesser impact of energy efficiency measures and, in the non-SWIS area, the development of additional projects yet to reach FID.

Figure ES.3: Gas demand forecast by area, 2015 to 2024



Source: NIEIR forecasts 2015 to 2024.

The quantity of gas forecast to be consumed in the SWIS and non-SWIS regions of WA is shown for each year of the forecast period in Table ES.2 below.

Table ES.2: Domestic gas forecasts, SWIS and non-SWIS (TJ per day), 2015 to 2024

Scenario		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Non-SWIS	Base	346	372	382	378	376	376	376	374	372	370
	High	368	386	407	418	423	426	429	432	435	438
SWIS	Base	680	702	713	712	703	699	695	690	687	684
	High	706	723	728	735	742	747	752	758	764	770

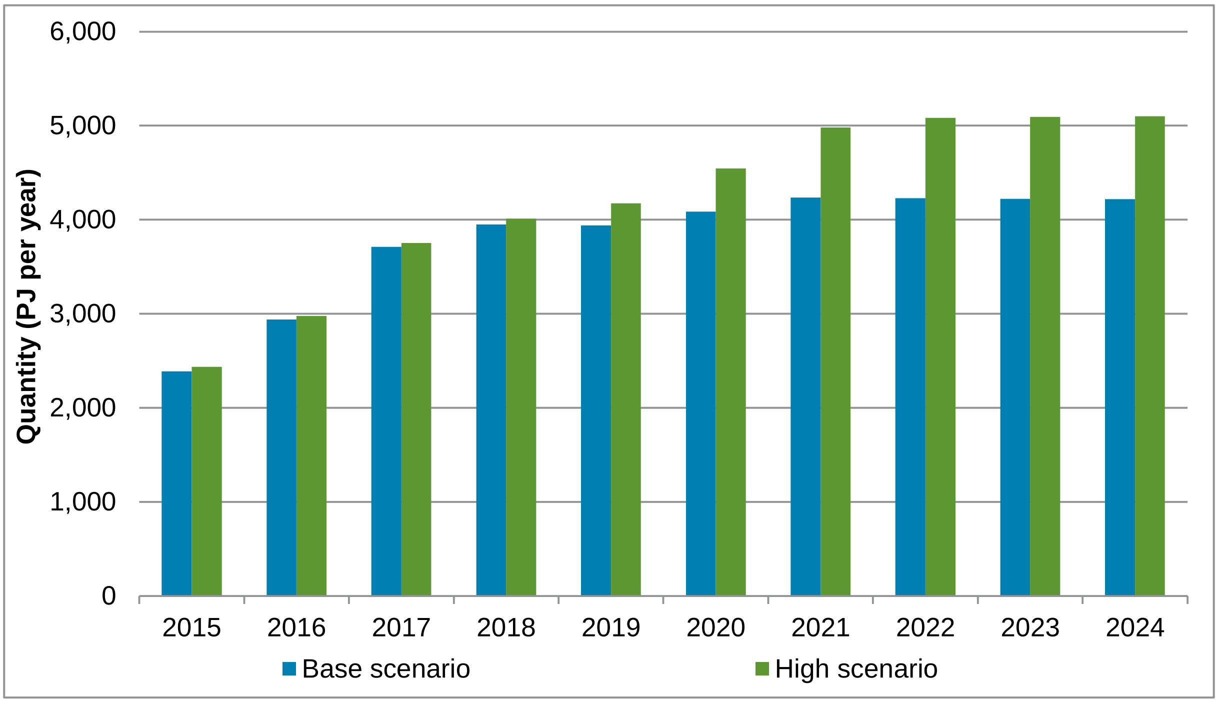
Source: NIEIR forecasts 2015 to 2024.

Note: Numbers may not add to those in Table ES.1 due to rounding.

Total gas demand

Total gas demand includes domestic gas demand plus natural gas for liquefied natural gas (LNG) exports, including feedstock and gas consumed in LNG production. Over the forecast period, total gas demand is forecast to grow strongly at approximately 6.5 per cent per year to 2024, as shown in Figure ES.4.

Figure ES.4: Total gas demand, 2015 to 2024



Source: NIEIR and IMO forecasts 2015 to 2024.

International LNG demand is expected to grow rapidly in the forecast period. As a result, more than half of forecast growth in total gas demand is driven by the gas feedstock and processing requirements relating to the Gorgon and Wheatstone LNG and Prelude floating LNG (FLNG) facilities. These are anticipated to start producing LNG within the forecast period, more than doubling WA's LNG export capacity from approximately 21 million tonnes per year (mtpa) to approximately 49 mtpa.

The additional growth in the High total gas demand scenario reflects both additional demand from prospective domestic gas-consuming projects and additional new or expanded LNG export facilities that have not yet reached FID.

Gas Supply

The potential supply of gas to the domestic market is expected to increase over the forecast period, with the completion of the Gorgon and Wheatstone domestic gas facilities (in 2015 and 2018 respectively) and expansion of the Gorgon facility in 2020. This growth will be offset to some extent by a possible reduction in supply from the NWS JVs after 2020 (when current supply contracts expire).

The total quantity of gas expected to be made available to the domestic market is shown in Figure ES.1 above, and in Table ES.3 below.

Table ES.3: Domestic gas supply forecasts (TJ per day), 2015 to 2024

Scenario	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Lower	1,124	1,241	1,286	1,394	1,424	1,491	1,313	1,313	1,304	1,306
Upper	1,193	1,299	1,315	1,446	1,466	1,535	1,425	1,422	1,414	1,415

Source: IMO forecasts 2015 to 2024.

Overall, average annual growth in supply over the forecast period is expected to be between 1.7 per cent per year in the Lower supply scenario, and 1.9 per cent per year in the Upper supply scenario.

Resources and reserves

In terms of gas resources, WA remains the most gas-endowed state in Australia. BREE (now the Office of the Chief Economist) and Geoscience Australia estimate WA onshore and offshore basins hold a total of 158,373 PJ of economic and sub-economic conventional gas resources.

Based on resource estimates and forecasts of total gas demand (domestic market and the LNG industry) for 2024, conventional gas resources are likely to last between 12 and 38 years beyond 2024, depending on whether all sub-economic resources are able to be developed. This number has decreased significantly since the January 2014 GSOO, primarily due to an update to the calculation method used by the IMO to assess the resources available from the end of the forecast period. The addition of unconventional gas would mean that resources in WA have the potential to last for another 105 years beyond 2024.

At the time of this report, the majority of WA's domestic gas supply comes from a single basin, the Carnarvon Basin. The IMO estimates the Carnarvon Basin is capable of meeting forecast domestic consumption and LNG requirements for approximately another 8 years from 2024 – to 2032. Considering the length of time required to develop and extract gas resources commercially, encouragement of exploration and development of other gas basins may be warranted to promote diversity and reduce WA's supply risk.

Increased availability of pipeline capacity

In September 2014, the APA Group completed an expansion of the Goldfields Gas Pipeline (GGP). The expansion increased the nameplate capacity of the pipeline by approximately 47.5 TJ to 202.5 TJ per day, making the GGP the second largest gas transmission pipeline in WA by capacity.

In 2014, two new pipeline developments were also announced. The first, the FRGP, is expected to be completed in Q1 2015 – allowing gas to be shipped to the middle of the Pilbara region. The other pipeline, the EGGP, was announced in July 2014. This pipeline, scheduled for completion in Q1 2016, extends the Murrin Murrin lateral of the GGP, allowing gas to be shipped to the eastern Goldfields region.

This GSOO also reports an increase in the availability of shipping capacity on the Dampier to Bunbury Natural Gas Pipeline (DBNGP), easing concerns about the ability to obtain gas supply and shipping capacity on this pipeline which was previously fully contracted. At the time of this report, the DBNGP has approximately 89 TJ per day of available firm full-haul capacity.

It is likely that the projects considered in the Base gas demand scenario that have already attained FID can be met by existing pipeline capacity, new pipelines that are under construction (such as the FRGP) or upcoming pipelines (such as the EGGP). However, as the High gas demand scenario incorporates potential demand growth of prospective projects that have not yet attained FID, there may be opportunities for pipeline companies to assist these projects through provision of gas transmission capacity.

Key risks to the GSOO forecasts

In the development of this GSOO, careful consideration has been given to a range of issues that could affect the development of the WA gas market. The number and complexity of the issues and risks that currently face the market make forecasting extremely challenging.

While some of the uncertainty surrounding future supply from the NWS JVs has been removed with the recently announced agreement with the WA Government, the IMO has identified a number of key risks to the findings of this report, and will continue to monitor their development for future GSOOs.

The most significant risks identified are:

- significant changes in the prices of key WA commodities (e.g. iron ore, nickel, alumina or gold), for example a further fall in international oil prices – discussed in more detail in chapter 2;
- further significant changes in the Australian dollar to United States (US) dollar exchange rate;
- a fall in Asia Pacific gas prices, pressuring the relatively high cost LNG producers in Australia, due to one or more of the following factors:
    - a significant increase in North American LNG export capacity, increasing competition among international LNG suppliers;
    - a reduction in LNG demand in the Asia Pacific region due to the suggested, but not yet scheduled, restart of nuclear powered electricity generators in Japan and South Korea;

- o increased competition driven by the development of a short-term LNG trading hub in Singapore; and
- o a change to Asia Pacific purchasing behaviour for gas and LNG (such as joint purchasing or increased short-term contracting).

Key drivers of change from the January 2014 GSOO

Since publication of the January 2014 GSOO, a number of key developments have occurred. The key drivers of the changes to the forecasts are:

- a significant increase in the number of large, gas-consuming projects that have obtained FID and are expected to commence in the forecast period;
- a weakening of the expected Australian dollar to US dollar exchange rate – resulting in an increase in domestic gas prices for most of the forecast period (partly offset by other factors such as lower oil prices) and driving an increased willingness to supply gas to the domestic market; and
- the impact of continued moderation of energy demand in the SWIS, largely due to continued investment in distributed solar generation, energy efficiency and cost reduction measures.

The following changes have also been made to the GSOO forecast approach in response to stakeholder feedback:

- the inclusion of several prospective gas demand projects (those yet to reach FID) in the High gas demand scenario;
- adjustments to the total gas demand estimates to reflect the utilisation of LNG production facilities;
- adjustments to the potential gas supply model to reflect the different commercial drivers of LNG-linked and domestic-only gas production facilities; and
- adjustments to the gas supply model to reflect how gas suppliers with multiple interests in various gas production facilities manage their gas supply contracts.

Future developments for the WA gas market, 2015 to 2024

Further developments in the WA gas market are expected over the forecast period. Known developments include:

- completion of the Gorgon, Wheatstone and Prelude LNG production and export facilities, and the development of the two new domestic gas production facilities associated with the Gorgon and Wheatstone LNG facilities;
- completion of the FRGP and EGGP;
- the Australian Consumer and Competition Commission's (ACCC's) review of any applications for joint marketing of gas from the NWS JVs or Gorgon JV (before the end of 2015);

- completion of access arrangement reviews for ATCO Gas Australia's gas distribution network (2015), the GGP (2015) and the DBNGP (2016);
- possible construction of the proposed Bunbury to Albany Gas Pipeline to service customers in the South West region and the Great Northern Pipeline in the north-west of WA;
- final investment decisions for other domestic gas production facilities including Warro, Pluto and Yulleroo/Valhalla, and the expansion of the Dongara production facility; and
- final investment decisions relating to other LNG export projects, including Browse, Equus, Gorgon Train 4, and Scarborough.

Contents

1. Objectives and purpose of the GSOO

The Gas Statement of Opportunities (GSOO) is published annually by the Independent Market Operator IMO under the Gas Services Information (GSI) Rules made under the *Gas Services Information Act 2012* (GSI Act).

The primary purpose of the GSOO and the objectives of the Gas Bulletin Board (GBB) and GSOO are set out in sections 5(1) and 6 of the GSI Act, respectively:

> *"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 of the GSI Rules:

> *"A GSOO must contain information about:*
>
> *(a) natural gas reserves (including prospective or contingent resources); and*
>
> *(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 third GSOO is prepared and published in accordance with Part 6 of the GSI Rules and contains forecasts for the 10 year period commencing 1 January 2015.

1.1 Approach to forecasting demand and supply

This GSOO provides calendar year forecasts of gas demand and supply for the WA domestic gas market for the 2015 to 2024 period (the forecast period), to enable an assessment of the adequacy of supply to meet forecast demand over this period. While the GSOO focuses on the domestic gas sector, it also considers the outlook for the WA liquefied natural gas (LNG) export sector, due to the inextricable linkages between these sectors.

More specifically, this GSOO provides annual WA forecasts for the forecast period for:

- domestic gas demand (excluding LNG exports and processing);
- total gas demand (domestic gas demand plus estimates of LNG exports and processing); and
- potential supply.

In forecasting domestic gas demand, the IMO has created an expected gas demand range between two scenarios (Base and High). These scenarios are based on:

- differing (Base and High) projections of economic growth in WA;
- the price response by gas-consuming customers to differing (Base and High) forecast gas prices; and
- expectations relating to new large gas-consuming projects, with:
    - projects that have attained final investment decision (FID) included in the Base gas demand forecasts; and
    - prospective (i.e. pre-FID) projects also included in the High gas demand forecasts.

In addition, the IMO has separately considered domestic gas demand in the area of WA that comprises the South West Interconnected System (SWIS) versus the remainder of the state, due to the different drivers of gas demand in these areas. Outside the SWIS, mining activity is the dominant driver of gas demand, while electricity generation is the main driver within the SWIS.

Consistent with the conclusions made in previous GSOOs, this GSOO demonstrates that there is an abundance of gas resources and processing capacity to satisfy domestic demand for the forecast period. However, these are not necessarily the most meaningful measures of gas supply in WA. Rather, it is important to consider the extent to which gas will be made available to the domestic market, which is why this GSOO focuses on 'potential' supply – a measure of producers' willingness to supply – as the principal supply forecast.

Therefore, this GSOO considers the supply of natural gas to the domestic market from three perspectives:

- potential gas supply (often referred to simply as gas supply);

- availability of gas production capacity to the domestic gas market; and
- adequacy of gas resources and reserves to meet total gas demand requirements.

Potential supply is a forecast based on assumptions about production costs, available production capacity and forecast gas prices. Due to uncertainties regarding the future supply of gas to the domestic market by the North West Shelf (NWS) Joint Ventures (JVs), this GSOO presents two potential supply scenarios (Upper and Lower) which adopt different assumptions about supply from the NWS JVs over the forecast period.

Pipeline capacity for the domestic market is also analysed in relation to gas demand forecasts to ascertain if there are further opportunities for new pipeline developments or pipeline expansions in WA over the forecast period.

It is important to note that the scenarios outlined in this GSOO are indicative only. The scenarios have been independently determined and any specific scenario outlined in this GSOO does not directly represent advice or information provided by any current or potential gas market participant.

1.2 Development of this GSOO

This GSOO relies on historical information, public announcements, GBB data, and feedback and confidential data provided by gas market participants. The IMO has sought information from participants where an in-depth understanding of the domestic market was required but this could not be gathered from other sources.

As with previous GSOOs, this GSOO has maximised the use of publicly available data, including Commonwealth and WA Government publications, data from reports by various consultants and information published by gas industry stakeholders.

In developing this third GSOO:

- the IMO held a stakeholder forum on 4 March 2014 to discuss and seek feedback on the January 2014 GSOO;
- economic, gas demand and gas price modelling and analysis work was conducted by the National Institute of Economic and Industry Research (NIEIR);
- gas supply modelling was conducted by the IMO with key inputs such as gas production cost estimates provided by Wood Mackenzie and price forecasts provided by NIEIR; and
- the IMO held more than 30 one-on-one meetings to gather feedback and information from a range of stakeholders, including WA Government agencies, peak bodies and individual gas market participants.

The IMO has not reproduced information provided in confidence in this report unless independently sourced from public reports.

1.3 Acknowledgements

The IMO acknowledges the assistance of gas industry participants – exploration firms, infrastructure providers, peak organisations, producers, retailers and shipping

organisations – including those who provided feedback at the 4 March 2014 stakeholder forum. These parties have provided background information, comments, estimates, research, data, suggestions and guidance to assist with the preparation of this GSOO.

The IMO would particularly like to acknowledge the following industry stakeholders for their assistance in the development of this GSOO:

- Alcoa of Australia (Alcoa)
- Aker Solutions
- APA Group
- Apache Energy
- Argus Media
- Australian Petroleum Production and Exploration Association (APPEA)
- AWE Limited
- BHP Billiton
- Chamber of Minerals and Energy WA (CMEWA)
- Chevron
- CITIC Pacific
- DBNGP (WA) Transmission Pty Ltd (DBNGP Transmission)
- Deloitte Access Economics (DAE)
- Department of Mines and Petroleum (DMP)
- Department of State Development (DSD)
- Economic Regulation Authority of WA (ERA)
- EnergyQuest
- Energy Developments Limited
- Fortescue Metals Group (FMG)
- Gas Trading Australia Pty Ltd (gasTrading)
- HSBC Bank Australia
- ICIS
- Horizon Power
- IHS
- Interfax

- North West Shelf Joint Ventures (NWS JVs)
- Department of Industry (DOI) Office of the Chief Economist (formerly the Bureau of Resources and Energy Economics (BREE))
- PE Wheatstone
- Rio Tinto
- Santos
- Shell
- Wood Mackenzie
- Woodside Energy
- Other participants that have provided feedback during the development of this GSOO, including members of the Gas Advisory Board (GAB).

1.4 Future GSOOs

In accordance with the GSI Rules, the IMO will publish the next annual GSOO by 31 December 2015.

2. Supply and demand assessment

This chapter compares the domestic gas demand and potential gas supply forecasts contained in this GSOO to determine the adequacy of gas supply to the domestic gas market for the forecast period. In addition, this chapter outlines the most significant current areas of uncertainty that may affect this supply-demand position and seeks to outline key risks and any constraints that may exist.

2.1 Key findings

The supply of gas to the domestic market is expected to be adequate to meet demand over the forecast period.

In particular, the domestic gas market will be well supplied for the period from 2015 to 2020, the year in which the last of the existing NWS JVs domestic gas supply contracts are estimated to expire. Supply is also expected to be adequate to meet demand for the 2021 to 2024 period, although the balance of supply and demand may tighten, depending on the extent to which additional supply is made available by the NWS JVs.

Supporting this finding, this GSOO finds that the domestic gas production capacity is anticipated to be almost double the forecast level of domestic gas demand by the end of 2024. This GSOO also finds that there are more than adequate economically accessible gas reserves to meet the projected domestic gas demand for the forecast period.

Finally, this GSOO finds that there is likely to be sufficient transmission pipeline capacity to meet the forecast gas demand in the Base demand scenario. However, there may be an opportunity for further pipeline investment should other new gas-consuming projects that are yet to reach FID (i.e. those in the High demand scenario) go ahead in the forecast period.

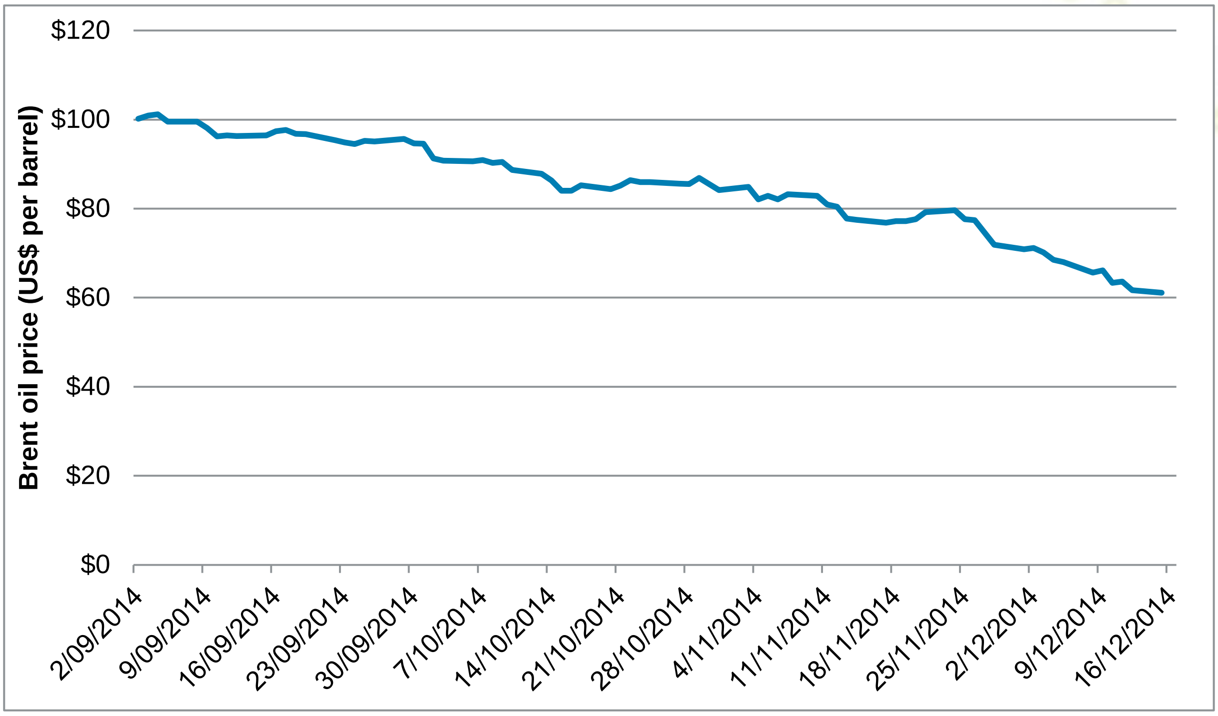
In reaching these conclusions, this GSOO has considered a range of factors that currently make forecasting an extremely challenging task. The next two sections outline two of the major areas of uncertainty, which present risks to the supply and demand forecasts in this GSOO.

2.2 Recent fall in oil prices

The second half of 2014 saw a rapid fall in international oil prices. Brent oil prices fell from over US$100 per barrel in September 2014 to lows of approximately US$60 per barrel by mid-December. The LNG netback price applied in this GSOO is directly influenced by forecast oil prices. For this reason, further sustained changes in oil prices would have a material effect on the forecasts contained in this GSOO (although a decline in Australian to US dollar exchange rates would moderate this to an extent). For more information see section 5.3.

The Brent oil price for the September to December 2014 period is shown in Figure 2.1.

Figure 2.1: Oil prices Free on Board (Brent) US$, September 1 to December 16



Source: EIA (2014a).

On the supply side, the US has rapidly expanded its oil production due to the improvement of hydrocarbon exploration and extraction technologies that have allowed more efficient extraction of shale oil and gas. This permitted the US to reduce its reliance on oil imports and become the world's third largest oil producer by the end of 2013. More recently, in November 2014, the Organisation of the Petroleum Exporting Countries (OPEC) decided not to cut oil production[2] despite recent price weakness, continuing the strong international supply of oil.

In addition to the growth of oil supply, weak international oil demand has also influenced the price of oil, as:

- the Eurozone continues to experience minimal economic growth (GDP grew by 0.8 per cent, reported in quarter (Q)3 2014);
- China's economic growth continues to slow, with growth of 7.3 per cent, which is close to a 6-year low, reported in Q3 2014; and
- Japan's economy has once again gone into recession, with a contraction of 1.9 per cent, reported in Q3 2014.

While the outlook for oil prices looks bleak, a study by Wood Mackenzie published in October 2014[3] shows sustained Brent oil prices below US$80 per barrel would likely force the top 60 oil and gas companies to curtail supply in the medium-term, effectively keeping the market in balance. However, due to time lags in decision-making and the potential of further weakness

[2] OPEC (2014a).
[3] Wood Mackenzie (2014a).

in oil demand growth, this may not take effect immediately, with further weakness in oil prices in the short-term a possibility.

Despite the difficulties in the oil market, a separate study[4] by Wood Mackenzie indicates that a strong increase in non-OPEC production can be absorbed by the market without causing further price declines. The same study expects oil prices (Brent) to stabilise close to US$90 per barrel in the medium to long-term. While this suggests oil prices are likely to recover within the forecast period, this study was published in October 2014 and oil prices have declined rapidly since. Wood Mackenzie has not published a more recent update.

2.3 North West Shelf update

Since the publication of the January 2014 GSOO, more information has been released in relation to future gas supplies from the NWS JVs. On 26 November 2014, the WA Government introduced a Bill into Parliament[5] to ratify the North West Gas Development (Woodside) Agreement Amendment 2014 (Agreement Amendment) made on 20 November 2014 between the WA Government and the NWS JVs. At the time of this report, the Amendment Agreement has not been ratified.

In addition, on 23 December 2014, the Hess Corporation (Hess) announced its intention to develop and toll its WA reserves through the NWS JVs' processing facilities, having reached a non-binding agreement with the NWS JVs.

2.3.1 North West Gas Development (Woodside) Agreement Amendment

The Agreement Amendment updates the principal agreement (the North West Gas Development (Woodside) Agreement 1979, including its subsequent amendments) between the WA Government and the NWS JVs to include new clauses, including the 'New Domgas Commitment', which requires the NWS JVs to:

- adhere to the WA Government's domestic gas policy – to reserve 15 per cent (12.9 million tonnes, or approximately 715 PJ) of the 86 million tonnes of LNG approved for export, for supply to the domestic market [clause 46A(1)];
- diligently market the committed domestic gas quantities [clause 46A(4)(a-c)];
- upgrade and maintain the NWS JVs domestic gas facilities with sufficient capacity to meet the New Domgas Commitment [clause 46A (4)(d-f)];
- reserve a quantity of gas within the NWS JVs Agreement Area [outlined in clause 47] to meet the New Domgas Commitment [clause 46A(4)(g)]; and
- report to the WA Government annually on the status of the NWS JVs' LNG exports, domestic gas sales and contracts and the maintenance of the NWS JVs domestic gas facilities [clause 46A(4)(h)(i-iii)].

4 Wood Mackenzie (2014b).
5 WA Parliament (2014).

The Agreement Amendment also includes:

- the application of domestic gas obligations to natural gas extracted from wells within and outside the NWS JVs Agreement Area that are processed at the NWS JVs facilities [clause 9(2)];
- the requirement for the NWS JVs to inform the Minister for State Development of any variations, modifications or expansions to the NWS JVs facilities [clause 9(3)];
- a provision to allow a proportion of the domestic gas commitment (estimated to be 43 PJ) to be met through existing gas supply contracts[6];
- an ability for the NWS JVs to request a reduction to their domestic gas obligations [clause 46A(6)]; and
- a provision to allow the NWS JVs to offset all or part of their domestic gas obligations using alternative sources and facilities [clause 46B].

While the Agreement Amendment provides significantly more information regarding domestic gas supply from the NWS JVs after 2020 than was previously known, the gas supply outlook still has elements of uncertainty.

Firstly, the Agreement Amendment only requires the NWS JVs to set aside a quantity of gas reserves (12.9 million tonnes of natural gas) for the domestic market and market the reserves diligently. It does not specify the timing or a minimum amount of domestic gas that must be made available beyond 2020. Therefore, while 100 TJ per day is an approximate measure of supply that would achieve this requirement, actual quantities supplied are likely to vary across the term of the agreement.

In addition, the Agreement Amendment does not specify the minimum level of domestic gas production capacity that must be maintained for the domestic gas market over the forecast period. The NWS JVs are only required to maintain “sufficient capacity” to meet their domestic gas commitments. This means that the NWS JVs have the option to reduce domestic gas production capacity after the expiry of legacy gas supply contracts in 2020. However, it is understood that there are no existing plans by the NWS JVs to retire any domestic gas production capacity in the forecast period.

Finally, to produce up to the 86 million tonnes of natural gas approved by the WA Government, multiple investment decisions still need be made by the NWS JVs, beyond that taken for the Persephone[7] gas field in 2014, and that likely to be taken in 2016 for the Greater Western Flank 2 gas fields.

However, the NWS JVs remain committed to the NWS JVs facilities, with the completion of the 4,058 square kilometre Fortuna 3D marine seismic survey in May 2014[8]. The NWS JVs are also currently undertaking the Karratha Life Extension Project to assess the work and requirements necessary to maintain and extend the production life of the NWS JVs LNG export and domestic gas facilities.

6 This is outlined by the Premier of WA in the (uncorrected) second reading of the North West Development (Woodside) Amendment Bill 2014.
7 Woodside Energy (2014a).
8 Woodside Energy (2014b).

This commitment is strengthened by the recent agreement with the Hess, under which Hess intends to develop and toll its Equus reserves through the NWS JVs' LNG processing facilities. While FID is not expected before 2017, should this go ahead the IMO understands a proportion of the gas processed would be required to be set aside for marketing to the WA domestic gas market (clause 9(2) of the Agreement Amendment). Hess holds 100 per cent interests in both permits containing the Equus fields, although the volume of gas contained is not known. Due to the uncertainty regarding the quantity of gas that may be made available to the domestic market, and the investment decisions yet to be made, the IMO has not attempted to specifically include any gas from the Equus fields in the potential supply forecasts for this GSOO.

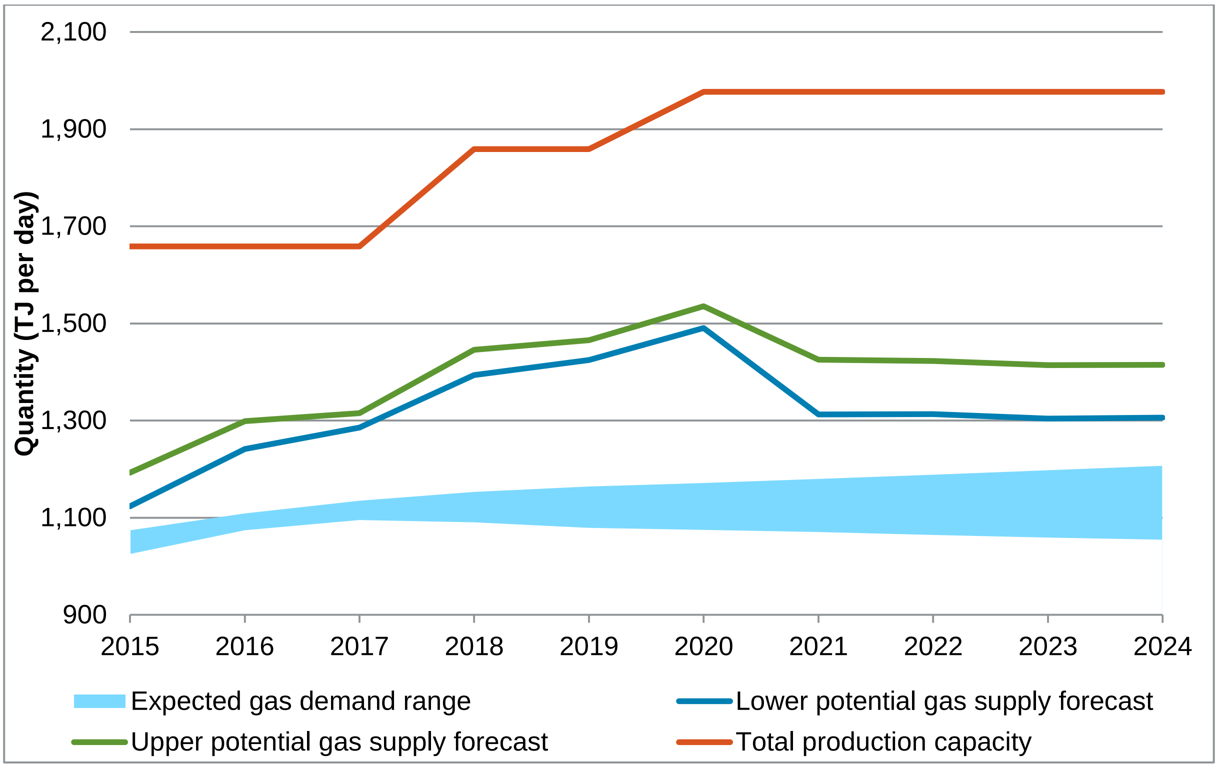
In summary, it now appears likely that some supply will be available from the NWS JVs beyond 2020. However, the continued availability of domestic gas supply from the NWS JVs for the forecast period remains contingent on whether the NWS JVs can profitably and commercially maintain gas supply to the domestic market and the extent of supply will be determined by a series of investment decisions yet to be made by both the NWS JVs and Hess. The IMO will continue to monitor the progress made by both parties in the preparation of future GSOOs.

2.4 Domestic supply-demand outlook, 2015 to 2024

2.4.1 Expected demand range and potential supply forecasts

The supply-demand balance for the WA domestic gas market for the forecast period is shown in Figure 2.2. This figure compares the two potential supply scenarios with total production capacity and the expected demand range.

Figure 2.2: Supply-demand balance, 2015 to 2024



Source: IMO and NIEIR forecasts 2015 to 2024.

The expected gas demand range is bounded by two gas demand forecasts, Base and High. The Base demand scenario, which forms the lower limit of the expected gas demand range, only includes new gas-consuming projects that have attained a favourable FID. The High gas demand scenario, which forms the upper limit of the expected gas demand range, also includes demand growth from new projects that are yet to attain FID.

The decline in demand at the lower end of the expected gas demand range after 2017 reflects a response to higher gas prices, leading to energy efficiency improvements consistent with the focus of many WA businesses on reducing costs and improving productivity.

Both supply scenarios assume that the NWS JVs will operate the Karratha Gas Plant (KGP) at up to a maximum production capacity of 400 TJ per day for the 2015 to 2020 period and 300 TJ per day for the 2021 to 2024 period, although the Lower supply forecast assumes the NWS JVs will only make sufficient supply available to meet the New Domgas Commitment of approximately 100 TJ per day.

Differences in potential supply between the Upper and Lower supply scenarios from 2015 to 2020 are due to the application of the different forecasts of domestic gas prices. The Upper supply scenario assumes higher forecast gas prices, resulting in a greater quantity of price-sensitive supply being made available to the domestic market than in the Lower scenario.

This GSOO suggests that the available supply of gas to the domestic market will be greater than the expected demand range (shown in Figure 2.2), with an excess of potential supply in each year of the forecast period – from at least 50 TJ per day in 2015 up to 320 TJ per day in 2020.

2.4.2 Domestic gas production capacity

Underpinning potential gas supply, domestic gas production capacity is anticipated to be almost double the forecast level of domestic gas demand by the end of 2024 – assuming production capacity at the NWS JVs' KGP remains available to the market – as shown in Figure 2.2 above. This growth is driven by the expected completion of the Gorgon and Wheatstone domestic gas facilities (in 2015 and 2018, respectively) and expansion of the Gorgon facility in 2020.

With significantly more production capacity than required to meet demand, domestic gas production capacity is not expected to be fully utilised, providing choice for current and potential gas consumers.

2.4.3 Resources and reserves assessment

This GSOO finds that there is likely to be more than adequate gas supply to meet the projected domestic demand for the forecast period, with conventional gas resources likely to be sufficient to meet total gas demand for between 12 and 38 years beyond 2024.

2.4.4 Pipeline capacity

It is likely that the gas demand from projects considered in the Base gas demand scenario that have already attained FID can be met by existing pipeline capacity, new pipelines that are under construction (such as the Fortescue River Gas Pipeline (FRGP)) or upcoming pipelines (such as the Eastern Goldfields Gas Pipeline (EGGP)). However, as the High gas demand scenario incorporates potential demand growth of prospective projects that have not yet attained FID, there may be opportunities for pipeline companies to assist these prospective projects through provision of gas transmission capacity.

2.5 Key risks to the supply-demand balance

In the development of this GSOO, careful consideration has been given to a range of issues that could affect the development of the WA gas market. The number and complexity of the issues and risks that currently face the market make forecasting WA domestic gas supply and demand extremely challenging.

While the uncertainty surrounding future supply from the NWS JVs has reduced due to the recently announced agreement with the WA Government, the IMO has identified a number of key risks to the findings of this report, and will continue to monitor their development to inform the development of future GSOOs:

- the results of further investment decisions yet to be made by the NWS JVs regarding the level of supply made available to the domestic market after 2020;
- any delays to the construction of new domestic gas and LNG production facilities;
- further significant changes in the Australian dollar to US dollar exchange rate;
- a fall in Asia Pacific gas prices, notwithstanding the generally positive outlook for international gas demand, due to one or more of the following factors:
    - a further fall in oil prices – discussed in more detail in this section (above);
    - a significant increase in North American LNG export capacity, increasing competition among international LNG suppliers;
    - a reduction in LNG demand in the Asia Pacific region due to the restart of nuclear powered electricity generators in Japan and South Korea;
    - increased competition driven by the development of a short-term LNG trading hub in Singapore; and
    - a change to Asia Pacific purchasing behaviour for gas and LNG (such as joint purchasing or increased short-term contracting).
- for WA LNG producers, the challenge of remaining competitive in light of the pressures on Asia Pacific gas prices, given the relatively high cost of LNG production in Australia.

Demand-side risks include:

- delays to the construction of new or expanding gas-consuming projects;

- significant changes in the prices of key WA commodities (e.g. iron ore, gold , alumina, LNG or nickel);
- increased access to gas supply through establishment of mobile LNG or pipeline expansions, enabling faster than anticipated fuel conversion for mining operations;
- a significant increase in the installation of renewable energy generation in remote gas-consuming areas (e.g. mine sites);
- reduction or stagnation in SWIS electricity demand reducing gas consumption by electricity generators; and
- a significant change in the composition of electricity generation within the SWIS, such as a change in the proportion of coal or renewable generation, changing the requirement for gas.

3. WA gas market and infrastructure overview

The WA gas market features several integrated segments which operate together in a supply chain as follows:

- exploration;
- production and processing;
- transmission, storage and distribution; and
- consumption – including large customer demand and retail markets.

This chapter provides a description of the WA gas market including its history, size, structure and associated production, processing, transmission and storage infrastructure.

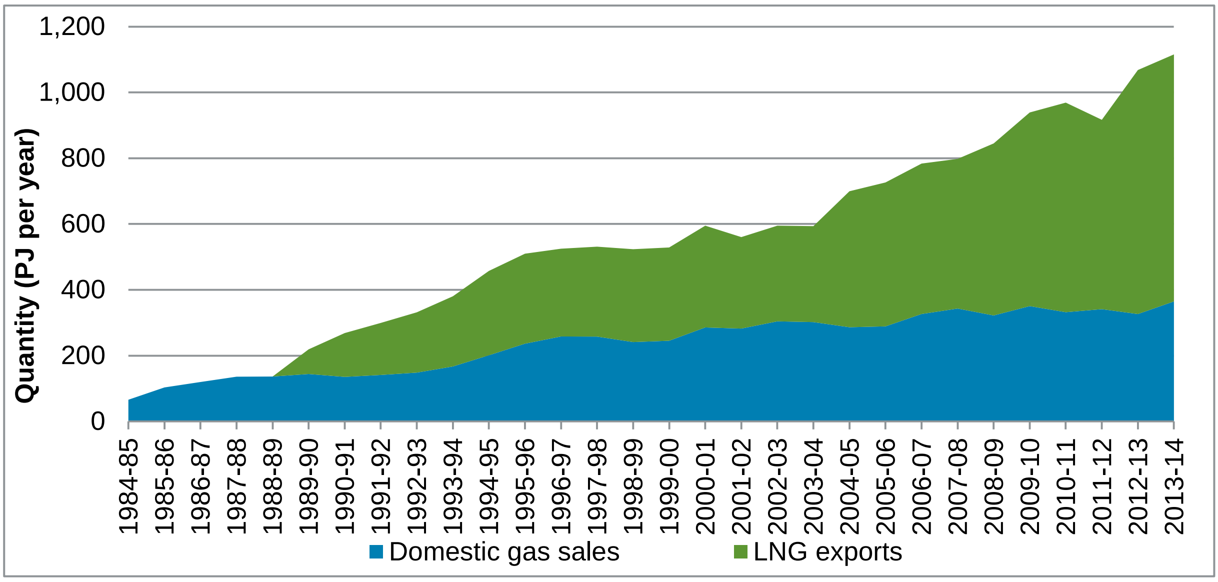
3.1 Overview of the WA gas market

WA is the largest producer of natural gas in Australia, historically accounting for approximately 60-65 per cent of total national production. In addition, WA has the largest domestic gas consumption of any Australian state (approximately 40 per cent in 2012-13). Natural gas is WA's most important source of energy, with over half of the state's energy consumption in 2012-13 fuelled by natural gas.

LNG has been an important export commodity for WA since August 1989, when the first shipment of LNG bound for Japan left the NWS JVs LNG facility. By 1990-91 the volume of gas exported equalled the quantity produced for domestic consumption. In 2013-14, LNG exports were more than double domestic consumption. This reflected a rapid increase in exports over the previous six years (an increase of 65 per cent from 2007-08 to 2013-14), predominantly due to the start-up of NWS JVs LNG Train Five and the Pluto LNG facility.

Domestic gas sales and LNG exports from 1984-85 to 2013-14 are shown in Figure 3.1.

Figure 3.1: Total gas production (excluding petroleum processing), 1984-85 to 2013-14



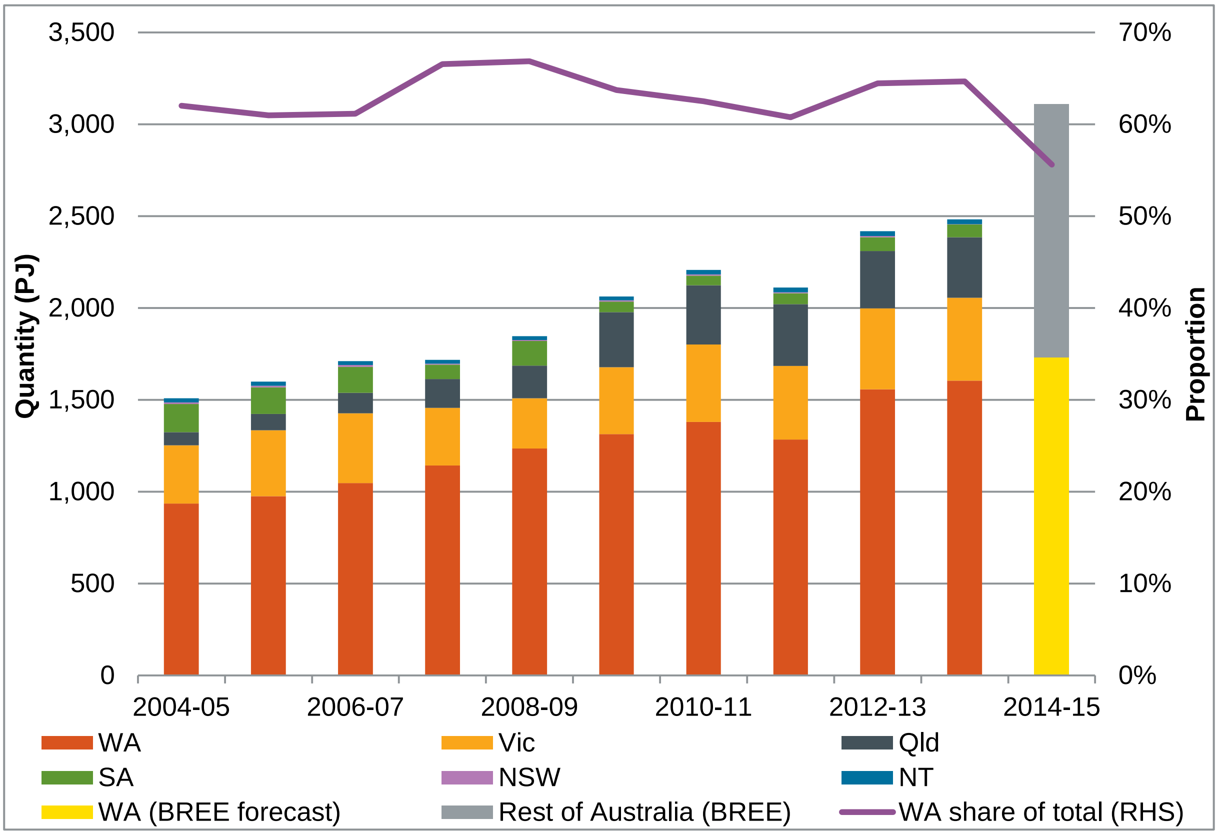
Source: DMP (2014c).

Growth in these two gas sectors over this period has been strong, although domestic gas demand growth is slow in comparison to growth in LNG exports. Growth in LNG exports is anticipated to continue to outpace growth in domestic consumption for the next ten years.

3.1.1 Gas production in WA

As mentioned above, WA has historically been Australia's largest producer of natural gas – accounting for approximately 60-65 per cent of the nation's total production. Figure 3.2 shows total Australian natural gas production by state between 2004-05 and 2013-14, as well as WA's share of total Australian gas production.

Figure 3.2: Australia's gas market production (includes domestic gas, LNG and petroleum processing), 2004-05 to 2014-15



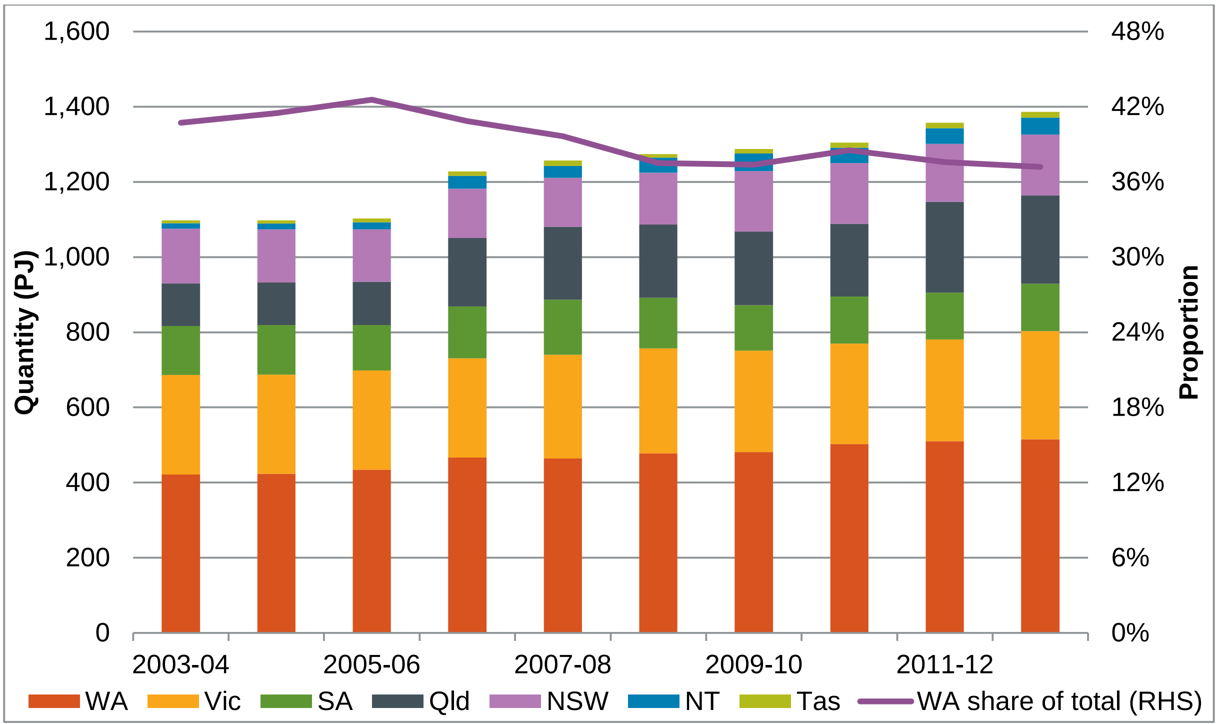
Source: BREE (2014a, 2014b, 2014g).

Despite ongoing strong growth in WA production, as a result of new domestic gas and LNG facilities, commencement of new LNG projects in Queensland and the Northern Territory mean that WA's overall share of national gas production is expected to decrease to 56 per cent in 2014-15, and persist at this level throughout the forecast period.

3.1.2 *Gas consumption in WA*

As well as being Australia's largest producer of natural gas, WA has also historically been Australia's largest consumer of gas by state, as shown in Figure 3.3. Between 2003-04 and 2012-13, WA has accounted for approximately 40 per cent of total Australian annual average consumption. Victoria is the second largest consumer at 20 per cent, while Queensland accounts for approximately 17 per cent.

Figure 3.3: Australia's gas consumption, 2003-04 to 2012-13

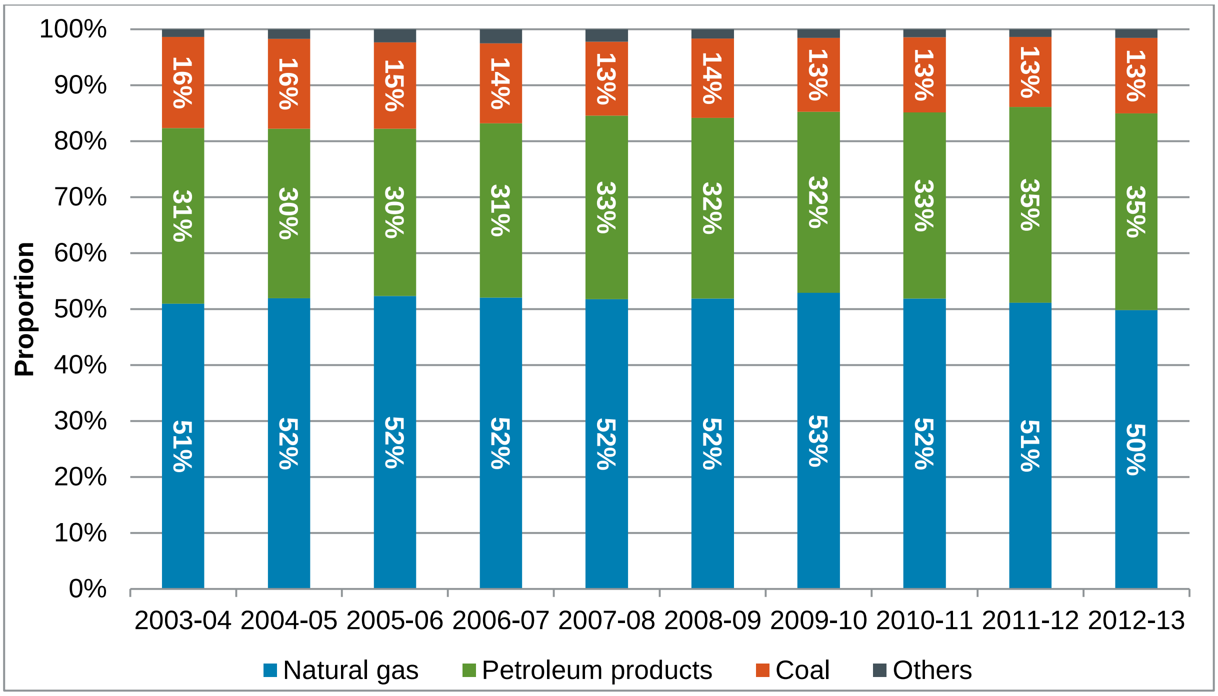


Source: BREE (2014a).

Approximately 500 PJ of gas was consumed in WA in 2012-13 (including for petroleum processing). Of this, more than 90 per cent was consumed for industrial use, as a fuel for electricity generation, minerals processing, other manufacturing or as a feedstock. Less than 10 per cent is consumed within the low-pressure distribution network, with residential gas use in WA comprising a relatively small portion of total WA gas consumption – only 2 per cent according to BREE's 2014 energy statistics shown in Figure 3.3. More information about trends in consumption is included in chapter 6.

The shares of primary fuel consumption by energy source in WA for the 2003-04 to 2012-13 period are shown in Figure 3.4, highlighting the importance of natural gas as a source of energy. Natural gas accounts for a little over half of WA's total fuel consumption, while petroleum products and coal account for around 35 per cent and 13 per cent respectively. Renewables and other fuel sources account for the remaining 2 per cent.

Figure 3.4: WA's primary fuel consumption by energy source, 2003-04 to 2012-13



Source: BREE (2014a).

3.2 Market structure

The WA wholesale gas market operates predominantly under a contract carriage model via pipelines, with an estimated 98 per cent of all domestic gas sales in WA made through long-term bilateral contracts. Where consumption is lower than maximum contracted quantities, secondary gas may be available.

Contracted gas prices and quantities are generally not made public unless required by legislation, stock market regulations or energy market rules. In addition, bilateral medium to long-term contracts between gas suppliers and consumers vary and are agreed for different time periods, terms, durations, prices and service elements, making contracts difficult to compare. Previous GSOOs have outlined some of the variations that may exist between gas contracts[9].

Unlike Australia's eastern states, there is currently no legislated exchange framework for short-term trading of gas in WA. Gas market participants balance their short-term gas requirements directly through gas swaps or via short-term agreements in an over-the-counter market. It is understood that short-term gas demand and supply requirements are typically traded between existing gas market participants, through one of the following methods:

[9] For example, see section 4.2 of the January 2014 GSOO.

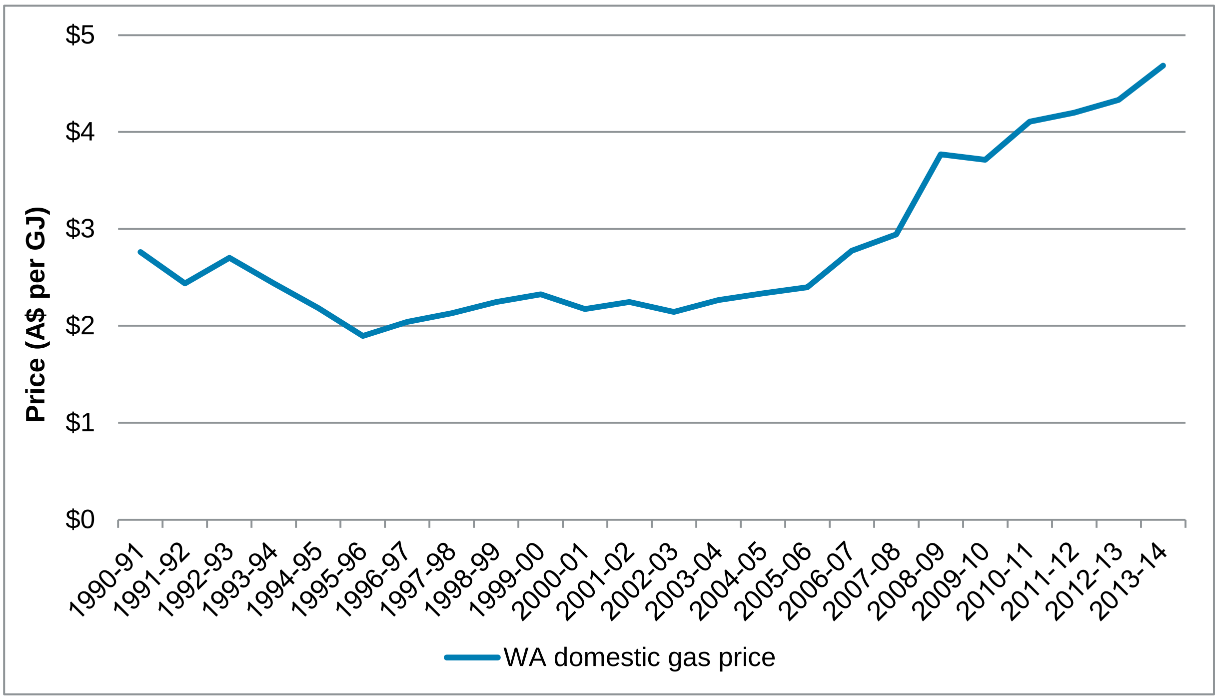
- either directly with each other (bilaterally, including spot trading arrangements operated by individual gas producers or DBNGP Transmission, or directly with a gas supplier under a short-term master sales agreement);
- via a broker such as gasTrading; or
- through energy trading platforms such as the platform managed by Energy Access Services Pty Ltd.

Short-term trading is fragmented across these platforms with little transparency (apart from the gasTrading spot market) around gas prices or quantities traded. Approximately 6 to 10 TJ per day (approximately 1 per cent of total quantities) is traded on the gasTrading spot market.

3.2.1 Historical gas prices

Average domestic gas prices between 1990-91 and 2013-14 in WA are shown in Figure 3.5. Between 1990-91 and 2013-14, gas prices increased at an average annual rate of 2.3 per cent. However, most of the growth in gas prices has occurred in the last ten years during which prices grew at an average annual rate of 7.5 per cent from 2003-04 to 2013-14.

Figure 3.5: WA average natural gas prices (nominal), 1990-91 to 2013-14



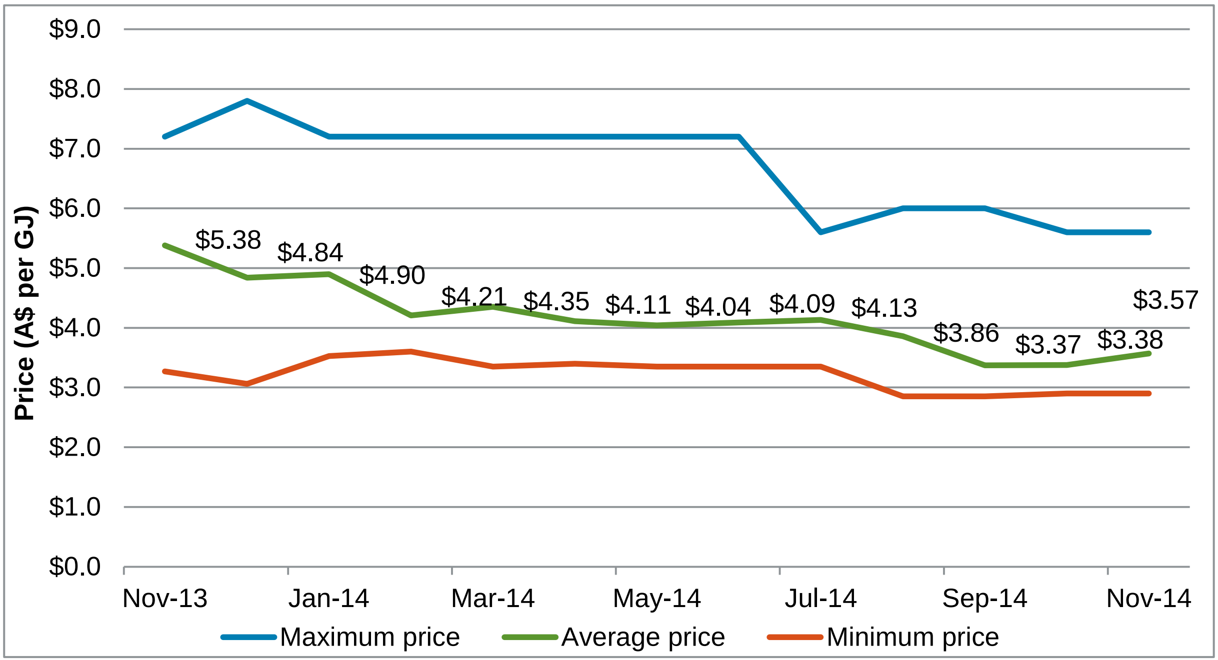
Source: DMP (2014c).

Note: The data represents a volume weighted average price of all existing gas sales contracts. Given the variability of gas prices between contracts, and the lack of a reference market price for domestic gas in WA, only average contract prices are published by DMP.

Recent increases in gas prices are driven by a variety of factors, including increases in the costs of gas exploration and development and increases in the costs of gas production for some suppliers. It is understood that the increase seen in average gas prices is reflective of the expiry of several long-term legacy gas supply contracts and the signing of new gas supply contracts under new arrangements – which include these increases in the cost of gas production.

While medium to long-term gas prices are driven by long-term trends, short-term gas prices are driven by very different factors. Figure 3.6 below shows a comparative picture of short-term gas prices, as recorded on the gasTrading spot market. Over the last year, these prices have ranged from a maximum of almost $8 per GJ in late 2013 to less than $3 per GJ more recently.

Figure 3.6: Short-term gas prices on the gasTrading spot market (nominal), November 2013 to November 2014



Source: gasTrading.

Short-term gas prices are driven predominantly by the availability of short-term gas to the domestic market that can be offered by existing gas market participants or gas producers with additional capacity. With short-term trading currently accounting for a small portion of gas sales in WA, prices may be influenced by a single market participant reselling gas in the short-term market to balance its gas portfolio.

3.3 Market participants

The WA domestic gas market is made up of two distinct segments, the wholesale (gas consumers that have direct connection to gas transmission infrastructure) and the retail (within the low pressure distribution networks – typically behind the gate station) segments. There are currently 56 wholesale gas market participants[10] operating within the wholesale gas segment that are registered with the IMO under the GSI Rules. Of these, 49 are gas shippers, five are gas producers and two are pipeline operators. Since the January 2014 GSOO, the number of registered market participants has increased by three.

[10] The list of market participants is on the IMO website at http://www.imowa.com.au/home/gas/gas-market-participants .

It is estimated that there are currently more than 80 industrial, manufacturing, electricity generation and transport-related facilities purchasing gas either via gas shippers or third parties and using gas in the domestic market. Thirty-six of these are large users consuming more than 10 TJ per day[11] are registered to provide daily consumption data on the GBB.

The number of commercial and residential consumers within the retail segment is outlined in sections 6.1.4 and 6.1.5.

3.3.1 Gas production facilities

At the time of writing this report, the WA domestic gas market is serviced by eight gas production facilities with a total gas production capacity of 1,477 TJ per day. The KGP, Varanus Island (East Spar and Harriet), Devil Creek and Macedon gas production facilities, all located in the Carnarvon Basin, account for about 97 per cent of total domestic gas production capacity. Three smaller facilities – Dongara, Beharra Springs and Red Gully, located in the Perth Basin – account for the remaining 3 per cent of total capacity.

In the forecast period, gas production capacity is anticipated to increase with two large domestic gas production facilities, Gorgon and Wheatstone, starting production. These facilities will provide additional supply capacity to the domestic market in conjunction with the completion of their respective LNG facilities. These projects are currently under construction and are anticipated to be completed mid to late 2015 and 2018, respectively, with an expansion to the Gorgon project anticipated to be completed by 2020. These facilities are expected to add combined production capacity of 500 TJ per day when completed, increasing total domestic gas production capacity in WA to 1,977 TJ per day by the end of 2024 (see section 8.2.3).

The existing and planned domestic gas production facilities in WA are summarised in Table 3.1.

Table 3.1: Existing and planned domestic gas production facilities, December 2014

Facility	Operator	Estimated Capacity (TJ/day)	Basin	Status	Pipeline Connection	Comments
Operational and under construction						
Karratha Gas Plant	Woodside	630	Carnarvon	Operational	DBNGP, Burrup Extension Pipeline	
Varanus Island (East Spar JV)	Apache Energy	270	Carnarvon	Operational	DBNGP and GGP	
Varanus Island (Harriet JV)	Apache Energy	120	Carnarvon	Operational	DBNGP and GGP	
Devil Creek	Apache Energy	220	Carnarvon	Operational	DBNGP	

[11] The list of large gas users is available on the IMO's GBB at https://gbb.imowa.com.au/#participants.

Facility	Operator	Estimated Capacity (TJ/day)	Basin	Status	Pipeline Connection	Comments
Macedon	BHP Billiton	200	Carnarvon	Operational	DBNGP	
Dongara	AWE Limited#	7	Perth	Operational	Parmelia	
Beharra Springs	Origin Energy	19.6	Perth	Operational	Parmelia	
Red Gully	Empire Oil and Gas	10	Perth	Operational	DBNGP	
Gorgon Domestic	Chevron	182	Carnarvon	Under construction, anticipated to be available in mid-late 2015	DBNGP	Facility is anticipated to be expanded to 300 TJ/day by 2020[@]
Wheatstone Domestic	Chevron	200	Carnarvon	Under construction, anticipated to be available in 2018	DBNGP	
Under consideration						
Pluto Domestic	Anticipated to be Woodside^	Information unavailable	Carnarvon	Under Consideration	DBNGP	Subject to commercial viability conditions
Buru Energy Domestic	Anticipated to be Buru Energy	Information unavailable	Carnarvon	Under Consideration	DBNGP via Great Northern Pipeline	
Warro	Transerv Energy	150	Perth	Under Consideration	Parmelia/ DBNGP	Facility may be operational before the end of 2024*
Total operational capacity by the end of 2015 (excluding Planned)		**1,476.6 TJ per day**	**Total operational capacity (including planned by the end of 2024)**		**1,976.6 TJ per day**	

Source: *IMO GBB standing data, Chevron Australia's Gorgon and Wheatstone websites, Buru Energy (2014a), Empire Oil and Gas website.*

Note: Shaded facilities are proposed. #AWE is evaluating the potential of the Senecio and Corybas fields around this facility. [@]Deutsche Bank (2012). ^Woodside entered into an arrangement with the WA Government to supply domestic gas within five years after first LNG, if it is commercially viable, see the July 2013 GSOO. *IMO Estimated start-up date.

3.4 Gas transmission pipelines

In WA, major gas resources (generally located in the Canning, Carnarvon or Perth Basins) are distant from the majority of gas users (generally located in the Pilbara, Goldfields and

South West regions of WA). Therefore, access to gas transmission pipelines and pipeline capacity is essential for gas consumers.

There are currently eight pipelines shipping gas to customers, with a total shipping capacity of 1,354 TJ per day. The two largest – the Dampier to Bunbury Natural Gas Pipeline (DBNGP) and Goldfields Gas Pipeline (GGP) – account for almost 80 per cent of gas shipping capacity, and approximately 90 per cent of total domestic gas shipped throughout WA. By the middle of 2016, the number of gas transmission pipelines in service is anticipated to grow to ten with the completion of the FRGP and the EEGP, shipping gas to more customers. With the addition of pipeline expansions proposed and underway, WA gas pipelines will have a total shipping capacity of more than 1,630 TJ per day.

This GSOO focuses on the pipeline developments since the January 2014 GSOO, including the recently completed GGP expansion and the new pipelines currently proposed or under construction.

All current, under construction, planned and proposed pipelines in WA are summarised in Table 3.2.

Table 3.2: Summary of operational and planned transmission pipelines, 2014

Pipeline	Operator	Completed/ Planned Completion	Nameplate Capacity (TJ/day)	Length (km)	Compression	Covered by Legislation	Expansion/ Comments
Current and under construction							
Parmelia Pipeline	APA Group	1971	65.4	417	Yes, two compressors currently unused	No	Existing compression has limited capability to be expanded
Dampier to Bunbury Natural Gas Pipeline	DBNGP Transmission	1984	845	1,828 (1,489 km mainline and 339 km laterals)	Yes, 27 compressors at 10 locations	Yes	Approx. 84 per cent (1,252 km) of the DBNGP pipeline is looped
Pilbara Pipeline System	APA Group (Epic Energy)	1995	166	219	No	No	

Pipeline	Operator	Completed/ Planned Completion	Nameplate Capacity (TJ/day)	Length (km)	Compression	Covered by Legislation	Expansion/ Comments
Goldfields Gas Pipeline	APA Group	1995	202.5*	1,380	Yes, six compressors expanding to seven (Turee Creek). Compressors completed in 2014	Yes, main transmission line (excluding expansions) and Newman lateral	Expanded capacity to 202.5 TJ/day in 2014 (APA Group 2011, 2012) for Rio Tinto's Paraburdoo and West Angelas mines, BHP Billiton's Newman mine and other customers
Mid West Pipeline	APA Group	1999	10.6	365	No	No	
Telfer Gas Pipeline	APA Group	2004	29	443	Yes, one compressor station	No	
Kalgoorlie to Kambalda Pipeline	APA Group	1999	29.3	44	No	Yes, light regulation	
Kambalda to Esperance Pipeline	Worley Parsons Asset Management Pty Ltd	2004	6^	336	No	No	
Fortescue River Gas Pipeline[@]	FRGP Joint Venture	Early 2015 (currently under construction)	64	270	No	No	
Planned and under consideration							
Eastern Goldfields Gas Pipeline	APA Group	2016 (construction anticipated to commence late 2015)	Unknown	292	No	No	

Pipeline	Operator	Completed/ Planned Completion	Nameplate Capacity (TJ/day)	Length (km)	Compression	Covered by Legislation	Expansion/ Comments
Bunbury to Albany Pipeline	Anticipated to be consortium (including Synergy)**	2016	~12	350	No	Not applicable at this stage	Planned pipeline
Great Northern Pipeline	Anticipated to be either Buru Energy or a consortium (including Buru Energy)	2020+[@@]	~200[@@]	~550-630	Unknown	Not applicable at this stage	Planned pipeline
Total existing capacity to date		**Approx. 1,354 TJ per day**	**Total capacity – incl. under construction and planned**		**More than 1,630 TJ per day – dependent on EGGP**	**Approx. 6,494-6,574 km (including planned)**	

Source: *GBB Standing Data, APA Group, DUET Group (2014a), Buru Energy (2014a) and other public announcements. ^Information from CCIWA (2007) and AER (2011). **Information is based on the Premier's Media Statement, 29 October 2012 and ABC News (2012). [@]DUET Group (2014c). [@@]Information sourced from Buru Energy (2014).*

3.4.1 Pipeline capacity expansions

3.4.1.1 Goldfields Gas Pipeline

Since the publication of the January 2014 GSOO, the APA Group has twice increased the gas shipping capacity of the GGP. The capacity of the GGP increased from 155 TJ per day to 174.3 TJ per day in July 2014 and then further increased to 202.5 TJ per day at the end of September 2014.

The GGP capacity expansions were undertaken to support the increase in gas consumption at Rio Tinto's Paraburdoo and West Angelas mine operations and BHP Billiton's Newman operations in the Pilbara region. The GGP expansion includes four new compressor units at existing compressor stations in Yarraloola and Paraburdoo, and a new compressor station at Turee Creek[12].

3.4.2 Pipelines under construction and planned

3.4.2.1 Fortescue River Gas Pipeline

The 270 km, 64 TJ per day FRGP[13] is currently under construction and is expected to be completed in Q1 2015. This pipeline will connect to Compressor Station (CS) 1 on the DBNGP and transport gas to TransAlta's 125 MW, dual-fuel power station located at FMG's Solomon Hub. This will allow natural gas to be substituted for diesel for electricity generated at the Solomon Hub.

[12] APA Group (2012).
[13] DUET Group (2014c).

The IMO understands that the FRGP's transmission capacity will not be fully utilised by FMG and can be further expanded with compression. Any additional capacity may be available to other parties in the Pilbara region.

3.4.2.2 Eastern Goldfields Gas Pipeline

In July 2014, APA Group announced it will construct the 292 km EGGP to transport gas to AngloGold Ashanti's Sunrise Dam JV and Tropicana JV gold mines[14]. The new pipeline will connect to the end of the existing gas lateral at the Murrin Murrin mine, and is anticipated to be completed early 2016.

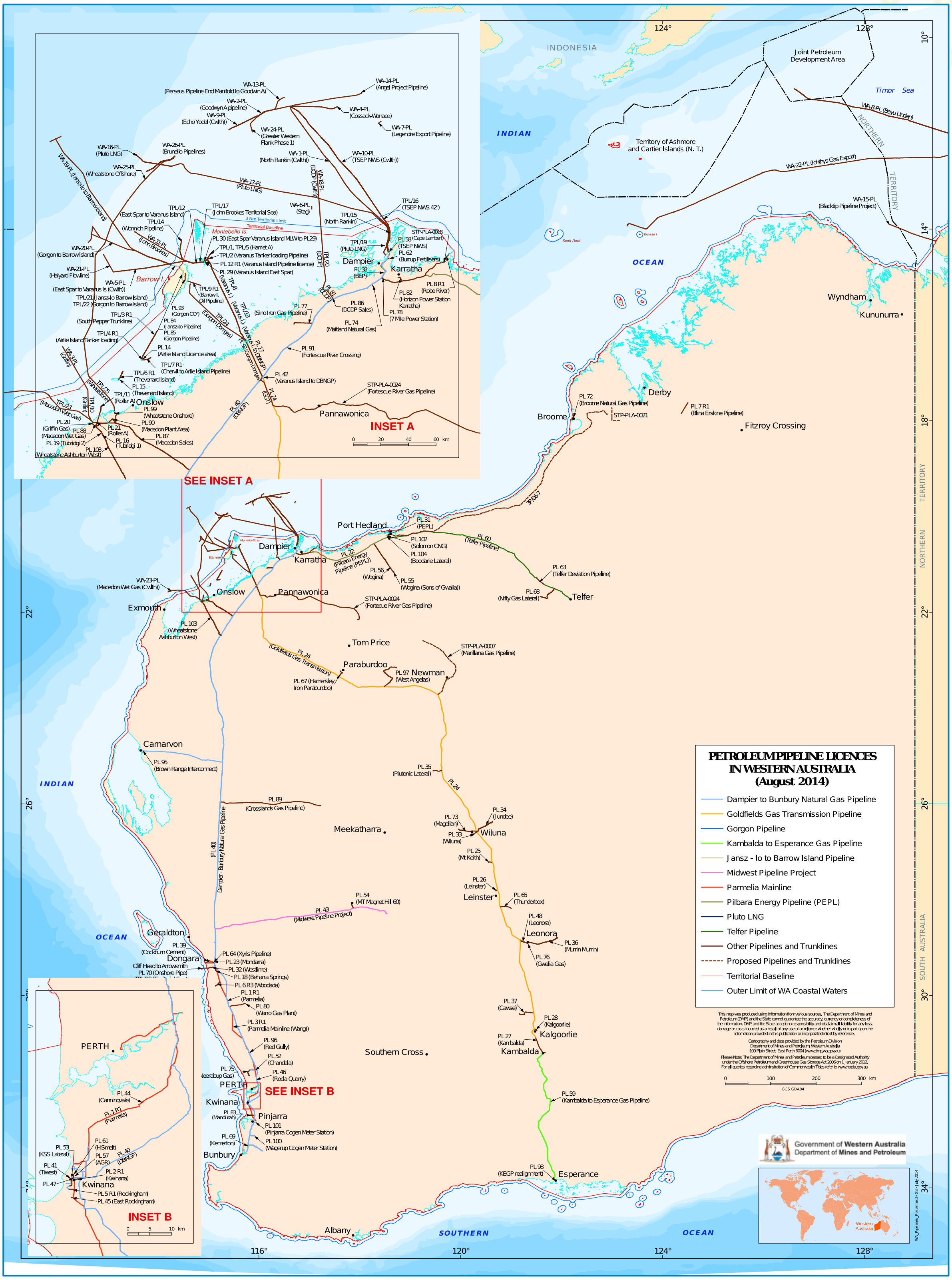
3.4.3 Proposed gas transmission pipelines

Two other transmission pipelines (the Bunbury to Albany Pipeline and the Great Northern Pipeline) have been proposed but remain highly prospective – they are not currently underpinned by any known gas transportation agreements between pipeline proponents and potential customers. These proposed pipelines were discussed in more detail in the January 2014 GSOO and no additional information has been made available since that publication.

[14] APA Group (2014).

Figure 3. outlines the gas infrastructure supplying gas to the WA domestic market, including existing and planned production facilities in WA.

Figure 3.7: Infrastructure map of major existing pipelines, August 2014



Source: DMP (2014d).

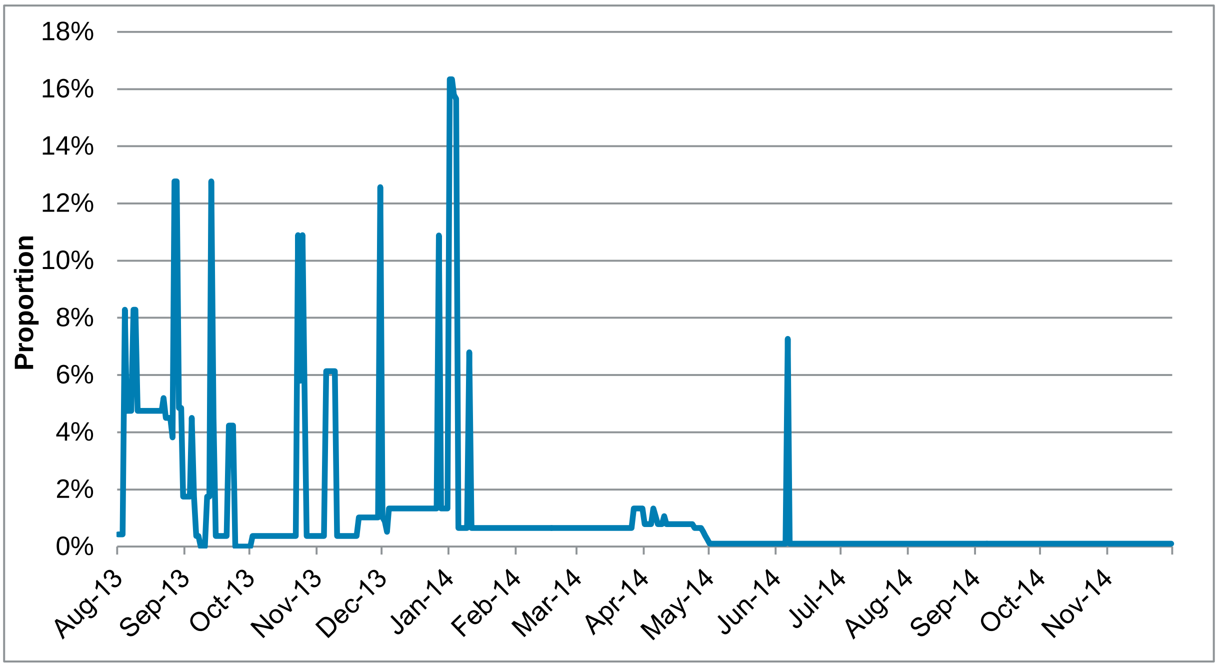
3.5 Availability of production and transmission infrastructure

The short-term capacity outlook report published on the GBB allows availability statistics to be calculated for gas production facilities in WA.

Unavailable capacity at production facilities as a percentage of total nameplate capacity is shown in Figure 3., for the August 2013 to November 2014 period. For the period from August 2013 to February 2014 there were multiple periods where a significant proportion of total production capacity was unavailable to the market.

The reasons for this unavailability is not required to be reported to the IMO, however it is understood that the unavailability of production capacity in January 2014 was associated with repairs and maintenance following heavy storms which affected the Devil Creek facility (nameplate capacity of 220 TJ per day). This event contributed to WA experiencing unavailable production up to a maximum of 16 per cent of total nameplate capacity between 1 January and 4 January. In June 2014, the KGP also experienced an unplanned outage that led to the activation of the Emergency Management Facility on the GBB.

Figure 3.8: Production facility outages as a percentage of total nameplate capacity, 1 August 2013 to 30 November 2014



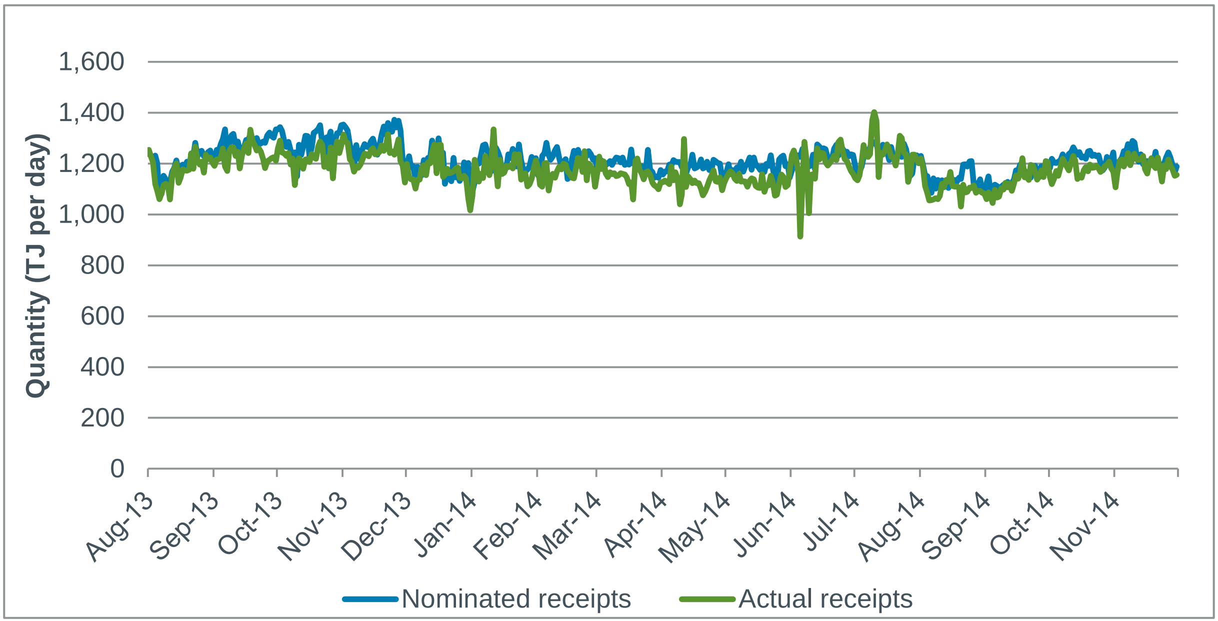
Source: Calculated from IMO GBB data.

Note: Calculated outage rates do not include the Red Gully gas production facility.

Despite the number of outages throughout the 2013-14 year, the existence of spare production capacity available to supply the domestic market meant there were very few significant disruptions to actual pipeline flows, and therefore little impact on gas consumers.

The comparison between the day-ahead pipeline nominations and the actual deliveries to all gas pipelines from the GBB for the 1 December 2013 to 30 November 2014 period is shown in Figure 3.9 below. The higher nominations and deliveries from August 2013 to December 2013 appear to be related to the utilisation of the Mondarra Gas Storage Facility (MGSF) over this period (see also section 3.6).

Figure 3.9: Nominated and actual pipeline receipts, 1 August 2013 to 30 November 2014



Source: Calculated using IMO GBB data.

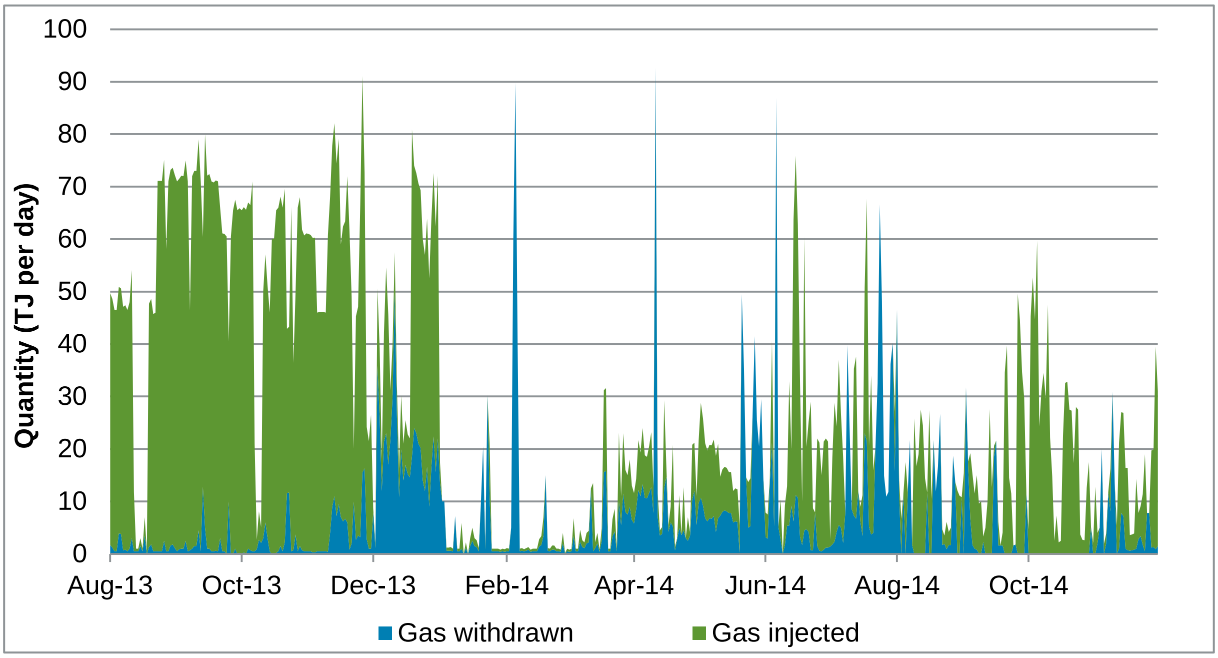
In addition, the data shows that there is a tendency for gas nominations (day ahead) to be slightly higher than actual receipts into the pipelines. Lower actual than nominated receipts in June 2014 are a result of the unplanned outage at the KGP mentioned above.

3.6 Multi-user gas storage facilities

The APA Group's MGSF is currently the only operational multi-user gas storage facility in WA. While the depleted gas field of Tubridgi is currently being considered by the DBP Development Group for use as a multi-user gas storage facility, any further plans for the development of this facility are currently unknown.

The gas injections and withdrawals from the MGSF between 1 August 2013 and 30 November 2014 are shown in Figure 3.. The facility ran at its maximum injection rate almost every day between August 2013 and December 2013. Since December 2013, daily withdrawals from the MGSF have increased from an average of approximately 2 TJ per day to 8 TJ per day. This increase in withdrawals indicates that the storage facility is being more actively used by gas market participants to manage their day-to-day gas requirements.

Figure 3.10: MGSF injections and withdrawals, 1 August 2013 to 31 October 2014



Source: IMO GBB data.

4. Economic outlook

Economic growth is a key input in the development of gas demand forecasts. Economic conditions affect the amount of energy that is consumed in WA by industrial sectors, driving levels of operation in resource extraction, processing and exports. The future outlook of key commodity exports from WA is also an important driver of gas demand growth, due to the energy intensity of large mining operations, minerals processing and electricity generation, and for many large users is a more significant driver than general economic growth levels. Economic growth also affects the level of discretionary spending by smaller gas-users, whose consumption of gas forms a relatively small part of state gas demand.

The WA economy is driven by the level of investment in the resources and related industries. Economic growth is therefore significantly affected by demand for WA commodities, particularly in Asia. WA has experienced significant growth in resource-related investment over the last decade, peaking at $85 billion in 2013-14. Iron ore remained WA's highest value export commodity in 2013-14, valued at approximately $74 billion. The petroleum sector was valued at approximately $26.5 billion during the same period, with total mineral and petroleum exports comprising 90 per cent of total merchandise exports from WA[15].

Economic growth in WA is anticipated to slow in line with the softening of international commodity markets and the transition of several large resource projects from construction to production. However, continued investment in the expansion of existing projects and optimisation of energy costs of existing operations in the resources industry will likely continue to drive gas consumption in WA in the forecast period.

This chapter provides a summary of the WA economy and reviews the outlook for the WA economy for the 2014-15 to 2018-19 period, in particular the outlook for commodities.

4.1 WA's economy

4.1.1 Historic economic growth

The growth rates of several of the key economic indicators for the WA economy between 2009-10 and 2013-14 are shown in Table 4.1. National gross domestic product (GDP) is also provided for comparison. State final demand, a measure of all domestic consumption, grew at an average annual rate of 5.0 per cent over the past five years, mainly associated with strong growth in business investment in the mining sector. Gross state product (GSP), which measures all of the state's output (taking into account net exports), also grew at an average annual rate of 5.3 per cent between 2009-10 and 2013-14.

In terms of total industry value added, the mining and agriculture sectors reported the strongest growth at an average annual rate of 9.5 per cent and 5.3 per cent, respectively, between 2009-10 and 2013-14. However, output in the agriculture industry is dependent on weather, and can vary significantly year-to-year. The construction and services sectors also showed growth between 2009-10 and 2013-14, averaging 4.6 per cent and 3.7 per cent respectively.

15 DMP (2014a).

Table 4.1: Growth in key economic indicators, 2009-10 to 2013-14

	2009-10 (%)	2010-11 (%)	2011-12 (%)	2012-13 (%)	2013-14 (%)
WA					
State Final Demand	2.7	5.3	14.2	5.2	-1.8
Net exports	14.0	3.2	-1.3	14.7	11.2
Gross State Product	4.2	4.1	7.4	5.1	5.5
Industry gross value added	4.5	4.0	8.4	4.7	5.8
Agriculture	-6.4	-38.2	35.6	-43.7	59.0
Mining	10.1	7.0	9.0	11.1	11.2
Manufacturing	-0.7	5.9	8.2	1.5	-3.2
Electricity, gas, water and waste services	5.0	10.2	9.0	-2.2	0.9
Construction	0.9	0.9	17.6	-0.6	3.6
Services	3.4	4.4	4.9	4.1	2.3
Australia					
Gross Domestic Product	2.0	2.2	3.6	2.7	3.0

Source: ABS (2014).

4.1.2 Forecast economic growth

The IMO engaged NIEIR to provide projections for the WA economy, using available data up to June 2014. The economic outlook produced for the next five years shows a return to long-term average growth from higher than usual growth over the past five years.

NIEIR's Base forecasts of major economic indicators for WA for the 2014-15 to 2018-19 period are shown in

Table 4.2 on the following page, with forecasts of national GDP included for comparison. NIEIR forecasts that WA GSP will grow faster than the national economy until 2018-19, supported by strong growth in the minerals and energy commodity exports. While GSP growth is expected to remain moderate to strong, domestic WA consumption, as measured by state final demand, is forecast to weaken relative to the growth observed over the previous five years, driven mainly by a fall in business investment.

The fall in business investment reflects the completion of several major iron ore and natural gas projects over the 2014-15 to 2018-19 period. Total government spending (Commonwealth and WA Government) is also expected to fall from recent high levels as large public infrastructure works are completed.

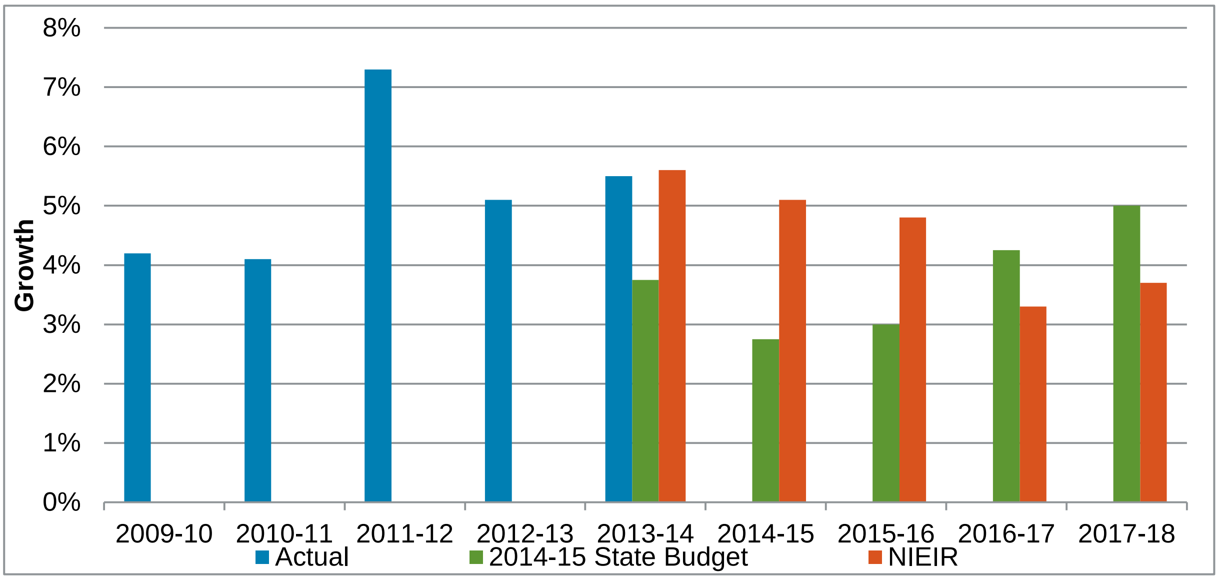
Table 4.2: Forecasts for growth in key economic indicators, Base scenario, 2014-15 to 2018-19

	2014-15 (%)	2015-16 (%)	2016-17 (%)	2017-18 (%)	2018-19 (%)
WA					
Private consumption	4.0	5.2	3.0	2.2	3.3
Private dwelling investment	6.8	2.7	-6.2	-2.2	-3.7
Business investment	-11.7	-2.3	-13.0	-2.0	8.5
Government consumption	2.7	2.6	2.9	3.6	2.5
Government investment	-0.1	-2.6	7.0	6.8	4.3
State final demand	-1.4	2.2	-1.9	1.3	4.3
Gross State Product	5.1	4.8	3.3	3.7	2.3
Population	2.5	2.5	2.2	2.2	2.2
Employment	2.0	1.8	1.4	1.4	1.6
Australia					
Gross Domestic Product	2.8	2.3	2.2	2.5	2.2

Source: NIEIR.

The actual growth in GSP for WA between 2009-10 and 2013-14 is shown in Figure 4.1, which also compares NIEIR's base GSP forecasts against WA Treasury forecasts (published in the 2014-15 State Budget) for the 2014-15 to 2017-18 period.

Figure 4.1: Comparison of GSP forecasts, NIEIR and WA Treasury, 2009-10 to 2017-18



Source: ABS (2014), WA Department of Treasury (2014) and NIEIR.

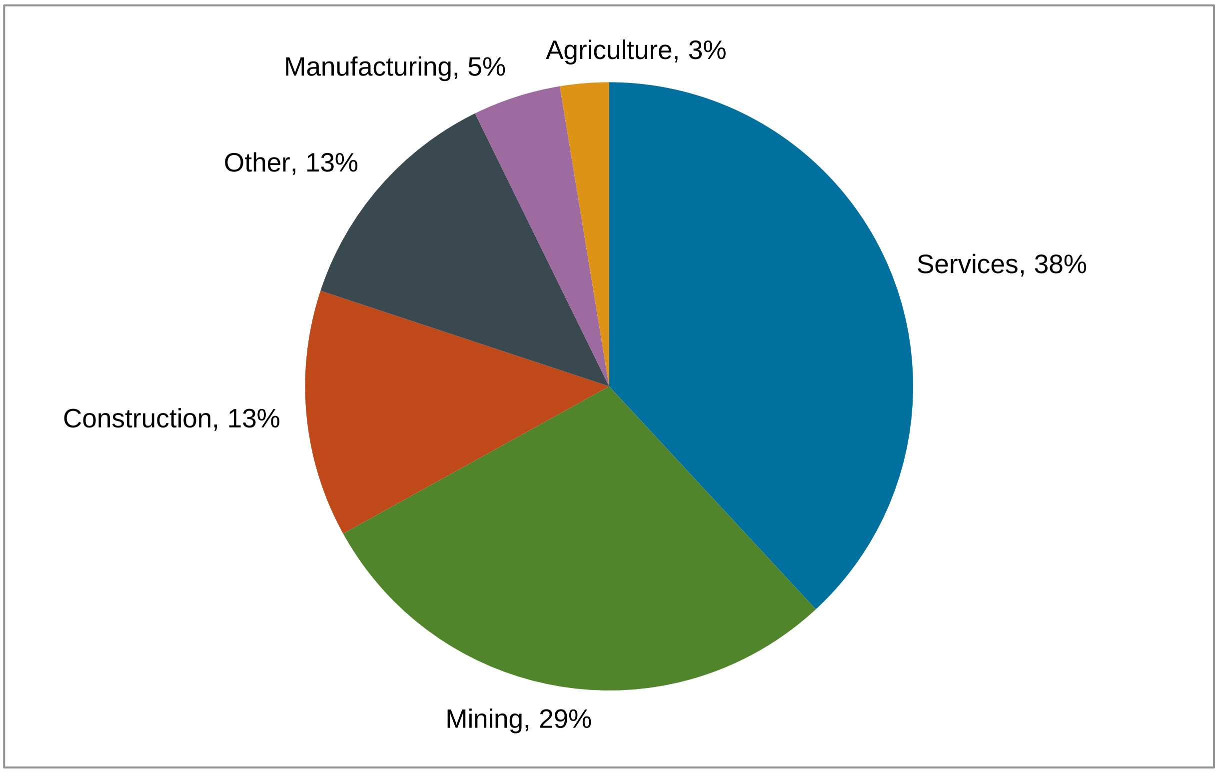
GSP growth for 2013-14 was 5.5 per cent, in line with NIEIR's most recent forecasts. The future comparison shows that NIEIR forecasts higher growth than the WA Treasury by around 2 percentage points for the first two years, and about one percentage point lower for 2016-17 and 2017-18.

See Appendix B for NIEIR's High economic forecast scenario values.

4.2 Resources sector outlook

The dependence of the WA economy on each of the major industry sectors is shown in Figure 4.2. According to the Australian Bureau of Statistics (ABS), the mining and services industries contribute the largest proportions of gross value added to the WA economy, while construction, manufacturing, agriculture and others make up much smaller shares. Given the importance of the mining sector to the state economy, any changes to its future outlook will influence domestic gas consumption in WA.

Figure 4.2: Share of industry gross value added, by sector, WA, 2013-14



Source: ABS (2014).

Resource-related investment is expected to return to average levels (around $60 to $68 billion per year) for the remainder of the decade as major LNG and mining projects currently under construction become operational. Given the high dependence of the WA economy on the resources sector, it could reasonably be anticipated that this will be the key factor leading economic growth rates in WA to revert towards a longer-term average growth rate, as outlined above.

In the forecast period, forecasts of lower international commodity prices are anticipated to drive increased cost-cutting efforts in the resources sector. This includes energy efficiency and cost-cutting initiatives, especially in the area of electricity generation and haulage. These initiatives are likely to impact on future demand for natural gas and an allowance for known fuel conversions has been accounted for in the IMO's demand forecasts.

4.2.1 Iron ore

Iron ore remains the state's most valuable mineral commodity, accounting for around 61 per cent of WA's mineral and petroleum exports in 2013-14[16]. The scale of this sector means that changes to iron ore production in WA will have a material impact on gas consumption.

DOI (formerly BREE) forecasts iron ore prices to average $63 per tonne in 2015[17]. According to DOI, the recent fall in iron ore prices is considered to be reflective of normal cyclical patterns, combined with global oversupply and a slowdown in growth in China's steel production.

DOI expects higher cost mines, mostly located in China, to close as a result of the fall in the iron ore price, reducing the oversupply in the sector. While this may mean less competition for WA mines, DOI does not expect iron ore prices to recover to the levels observed in the previous five years (above $100 a tonne) in the short-term.

Despite the fall in iron ore prices, gas consumption in the iron ore sector is expected to grow in the forecast period. Rio Tinto and BHP Billiton – the lowest cost iron ore producers in the world – have separately announced that they will continue to expand iron ore production in the Pilbara region[18], while FMG is also considering expanding its gas consumption in the Pilbara[19]. Gas consumption in the iron ore sector will be further supported by the upcoming Roy Hill project[20] in the Pilbara and the continued expansion of CITIC Pacific's Sino Iron magnetite mine[21] in the 2015 to 2017 period.

While Rio Tinto and BHP Billiton are expanding their operations, they, FMG, and many other iron ore producers in WA are implementing cost-cutting measures to maintain profitability in this low iron ore price environment[22]. These measures include considering substitution of natural gas as a fuel for electricity generation, as well as other measures such as improving productivity, corporate restructuring and mine automation.

FMG, the third largest producer of iron ore in Australia, is in the process of transitioning electricity generation at its Solomon Hub from diesel to gas, which has underpinned the construction of the FRGP[23]. Rio Tinto and BHP Billiton are also reported to be considering an increased use of gas in their mining operations[24], although the substitution of fuel is highly dependent on the location of the project relative to gas pipeline infrastructure.

4.2.2 Gold

Gold is WA's second most valuable mineral commodity, accounting for approximately 7 per cent of total mineral and petroleum exports in 2013-14[25]. DOI forecasts gold prices to fall to approximately A$1,154 per ounce[26]. Currently, four gold mines in WA use natural gas to generate electricity, with the Sunrise Dam and Tropicana gold mines anticipated to

16 DMP (2014a).
17 DOI (2014b).
18 AFR (2014a), AFR (2014b).
19 FMG (2014a).
20 Roy Hill Holdings (2014).
21 CITIC Pacific (2014).
22 AFR (2014a).
23 FMG (2014b). While the FRGP is not completed, since August 2014, FMG started using gas from Sub161's CNG plant for the Solomon Hub power station.
24 AFR (2014a).
25 DMP (2014a).
26 DOI (2014b).

commence using gas when the EGGP is completed, which is expected to be by January 2016[27].

Without any prospect of further increases in gold price, the gold sector, similar to the iron ore sector, is focusing on cost-cutting measures to remain profitable. However, the fact that the majority of gold mines in WA already use gas for electricity generation, coupled with a tepid outlook for gold prices and the lack of new major gold projects at an advanced stage of development, the gold sector is unlikely to be a significant contributor to gas consumption growth in the forecast period.

4.2.3 Alumina

In comparison to iron ore, alumina may not be a large export commodity for WA, only accounting for 3.5 per cent of mineral exports in 2013-14. However, the production of alumina is energy intensive, making it the largest gas-consuming sector in WA. This industry accounts for approximately one third of total domestic gas consumption (see section 6.1.1 for more details).

DOI forecasts alumina prices to increase to approximately US$335 in 205[28] underpinned by continued strong demand from China. Additional alumina production growth is still occurring in developing countries, assisted by low energy prices.

Production from Alcoa's WA refineries – Kwinana, Wagerup and Pinjarra – is also expected to remain stable.

There are currently no major development projects for bauxite, alumina or aluminium at an advanced stage of development in WA. As a result, gas consumption related to alumina production is not expected to change materially over the forecast period.

4.2.4 Other base metals

Other base metals mined in WA include copper, nickel and lead. These commodities are less valuable to the state than iron ore, gold or petroleum, but still accounted for approximately 4.2 per cent of WA mineral and petroleum exports in 2013-14[29].

The price outlook for base metals is mixed, with DOI forecasting copper prices will fall in 2015 because of global oversupply, while nickel prices are anticipated to rise moderately with increases in global demand and falling international inventories. DOI does not forecast lead prices.

Domestic gas consumption relating to these commodities mostly occurs in nickel mines, with the Murrin Murrin nickel-cobalt mine being the largest gas consumer in this sector. While the outlook for base metals is considered in the IMO demand forecasts, they are not expected to be a key driver of gas demand in the forecast period.

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27 APA Group (2014a),
28 DOI (2014b)
29 DMP (2014a).

5. Forecast methodology and input assumptions

This chapter provides a brief description of the forecast methodology used to forecast domestic gas demand and potential gas supply for the forecast period. The chapter also outlines the key input assumptions applied in the forecasts.

5.1 Approach to forecasting gas demand

The IMO engaged NIEIR to forecast domestic gas demand. While NIEIR has applied a similar approach to forecasting gas demand to that used in the previous two editions of the GSOO, the forecasting assumptions for each GSOO have been updated and improved as more data has become available. In this GSOO, additional GBB and pipeline data has allowed NIEIR to further revise their assumptions relating to gas consumption by the minerals processing, industrial and manufacturing industries.

WA domestic gas demand is difficult to forecast. Gas demand in WA is 'lumpy' and is largely driven by the size, energy requirements and start-up and completion timeframes of individual projects in the mining, LNG, and electricity generation sectors. Expansion and contraction in the first two industries are driven by the future prospects of a range of (often) internationally traded commodities, while growth in the third is heavily impacted by changes to the energy consumption behaviour of residents of the state. State gas demand is also directly and indirectly affected by local, national and international economic events, which have the potential to fluctuate considerably over the forecast period.

5.1.1 Assumptions applied in the gas demand forecast model

NIEIR produced two gas demand forecasts – Base and High – which the IMO presents an expected range of future gas demand outcomes. Domestic gas demand for the forecast period is determined by a range of factors, including the:

- completion of gas-consuming projects;
- domestic gas prices;
- projected WA economic growth;
- Australian dollar to US dollar exchange rate;
- growth in the international economy; and
- international prices of key WA export commodities (including iron ore, alumina, gold and LNG).

These factors influence business investment decisions relating to resources projects that will contribute to future gas demand.

The Base gas demand forecast does not attempt to predict which gas-consuming projects are viable and likely to go ahead in the forecast period and includes only projects that have attained FID. These projects have either been publicly announced by the proponents or reported by BREE[30] by the end of September 2014.

In response to stakeholder feedback, this GSOO also considers and includes an estimate of gas demand from several prospective gas-consuming projects – that have not attained FID – within the High gas demand scenario. The methodology for identifying prospective projects for inclusion is outlined in section 5.1.3.

It is also important to note that the continued growth of domestic gas prices, coupled with an increasing interest in energy efficiency and cost-cutting initiatives, suggests that future gas demand is likely to be more responsive to gas price increases than has been the case historically.

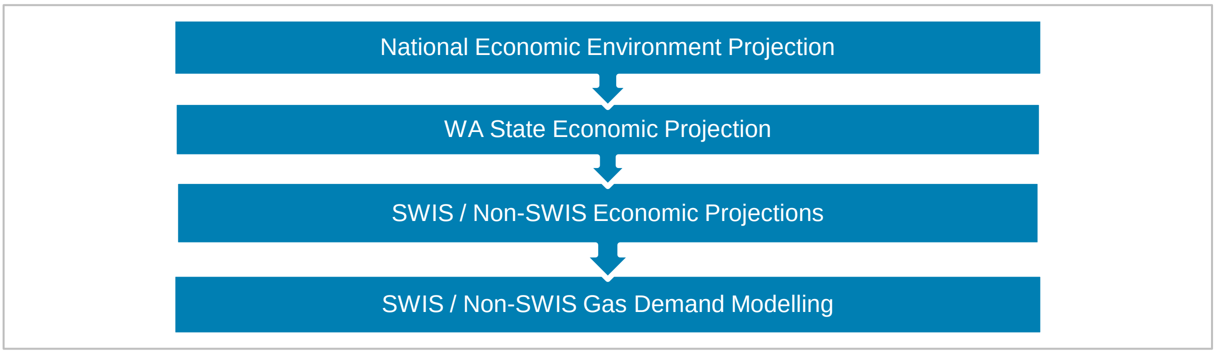
5.1.2 NIEIR's domestic gas demand model

To develop a good representation of future WA gas demand, NIEIR combines top-down and bottom-up approaches in the forecast model.

The top-down forecasting approach – summarised in Figure 5.1 below – first considers the international economic environment and how it impacts Australia. As part of this consideration, NIEIR forecasts the future prices for various commodities exported by Australia and WA. This is followed by the application of NIEIR's national econometric model of the Australian economy, which forecasts national economic growth using inputs from various statistical sources including the ABS and the Australian Taxation Office.

The national economic growth projections are used as inputs into a state economic projection model which provides an estimate of GSP and other indicators for the WA economy, as set out in the previous chapter. These state economic forecasts are then further disaggregated into the statistical subdivisions that make up the areas served by the SWIS and outside the SWIS. NIEIR then links the regional economic projections with gas demand, based on assumptions about the customers or specific industries within each region.

Figure 5.1: NIEIR's gas demand forecast methodology (top-down)

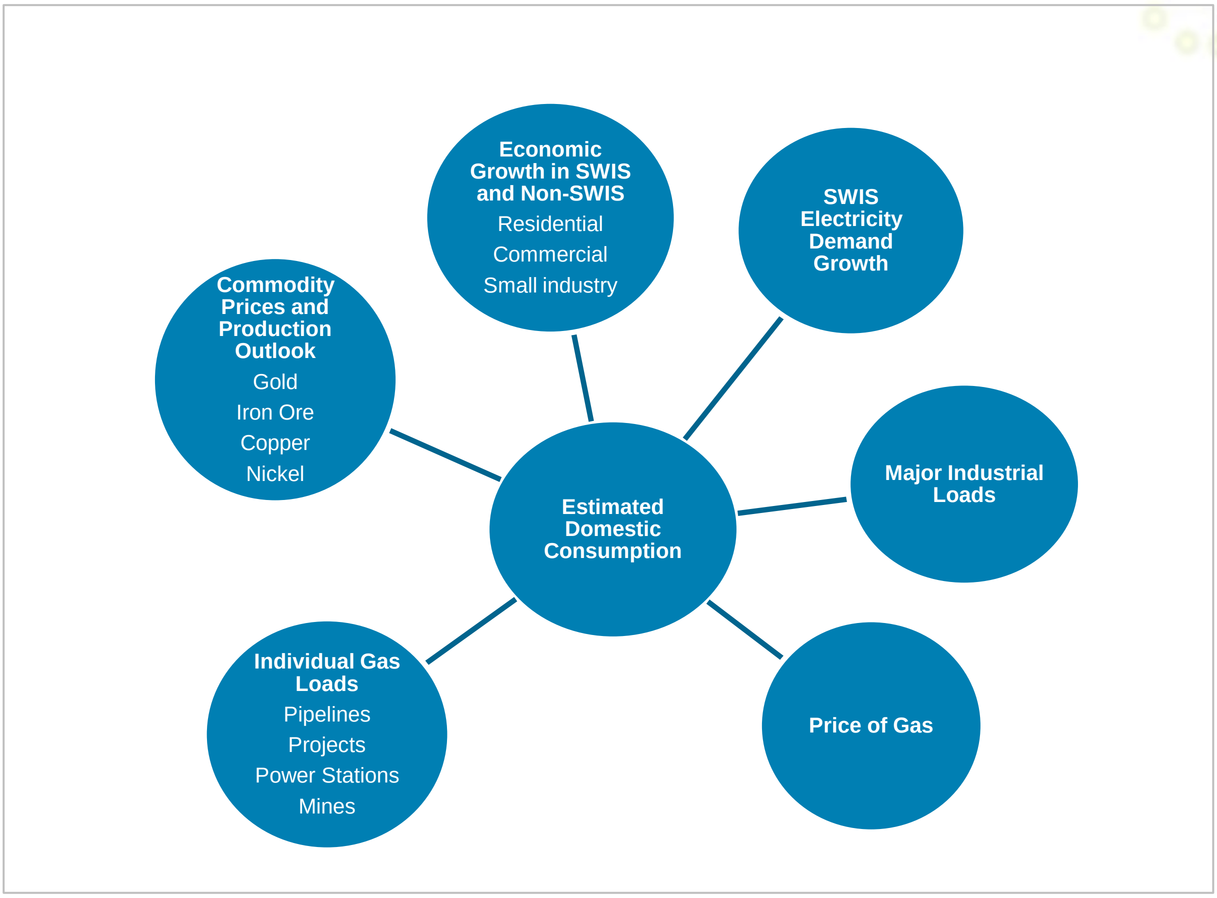


Source: NIEIR.

30 The expected dates of project completion are also from public announcements from these companies.

A summary of NIEIR's bottom-up forecasting approach is shown in Figure 5.2, showing the smaller industry-specific models that NIEIR aggregates to form domestic gas demand forecasts for the forecast period (excluding gas consumption for petroleum processing).

Figure 5.2: NIEIR's gas demand forecast methodology (bottom-up)



Source: NIEIR.

These industry-specific models allow NIEIR to apply different assumptions to individual industries (and potentially to different customers), such as gas use efficiency or price elasticity. This approach also incorporates NIEIR's existing electricity demand forecasting model for the SWIS, which is used to forecast electricity demand for the IMO's Electricity Statement of Opportunities and the 2014 SWIS Electricity Demand Outlook.

NIEIR's gas demand methodology links gas demand forecasts directly to the macroeconomic environment, WA's industry structure, expected industry sector outputs, capital stocks, dwelling formation numbers and population for WA, which are driven by industry growth by sector and projections of population growth. NIEIR's forecast methodology also links WA's regional economic forecast with gas use based on assumptions about gas use efficiency and major industrial gas usage that are estimated using historical pipeline data.

Some gas use efficiency estimates for the resources, manufacturing and minerals processing (particularly alumina) sectors have been updated and adjusted following a review of daily historical pipeline data provided by pipeline operators for the 2008 to 2013 period and the GBB data for the 1 August 2013 to 30 September 2014 period.

5.1.3 Methodology for identifying prospective projects for the High domestic gas demand scenario

This section outlines the methodology applied in identifying prospective projects for inclusion in the High domestic gas demand scenario. First, the IMO shortlisted a selection of eligible gas-consuming projects for consideration, which satisfy at least two of the following criteria:

- potentially consume more than 10 TJ per day;
- located within 20 kilometres of existing pipelines, pipelines under construction or new pipelines that have attained FID;
- the proponent has an existing commercial arrangement with the gas pipeline or gas storage company to connect physical infrastructure to withdraw gas from existing pipelines, pipelines under construction or pipelines that have attained FID;
- have been reported as a customer or potential customer of existing domestic CNG or LNG facilities;
- the proponent has applied to the IMO to receive Capacity Credits as an electricity generator using gas;
- have a project value of greater than A$1 billion;
- have attained funding for the project;
- have been publicly announced;
- the proponent has completed its investigations into converting from diesel to gas for its operations; or
- have been identified by existing pipeline operators as potential gas projects.

Thirty-one eligible projects were shortlisted using the above criteria, but only a handful of projects (called ‘prospective’) were deemed to be sufficiently likely to proceed and subsequently included in the High gas demand forecast. A level of judgement was applied in the process for determining prospective projects.

Some of the shortlisted projects were excluded for one or more of the following reasons:

- they relied on the existence of other infrastructure, which is yet to be committed, to transport their minerals (e.g. Oakajee, Ashburton or Esperance Ports, common user rail system in the Pilbara);
- they relied on improved commodity prices in the future (e.g. uranium, magnetite iron);
- they relied on the availability of project financing;
- no environmental studies had been conducted for the project; and
- the proponent did not appear to have committed to a project commencement date.

Once prospective projects had been identified for inclusion, future gas consumption for these prospective projects was estimated heuristically for the relevant project type and added to NIEIR's High domestic gas demand forecast scenario for the relevant year.

These projects have not been specifically named in this GSOO because it is not appropriate for the IMO to comment on the likelihood of individual projects proceeding. Instead the High gas demand forecast includes a quantity of prospective gas demand which should be considered as indicative of the upper bound of expected gas demand in the forecast period.

The IMO acknowledges that potential exists for increases in gas demand driven by fuel conversion and some conversion projects relating to electricity generation have been included in the High demand scenarios in this GSOO. However, estimates of diesel to gas conversions for mining haulage have not been included at this point. This is as the IMO considers this segment to be relatively small and relatively uncertain at this stage.

5.1.4 Total gas demand assumptions

In addition to forecasting domestic gas demand, the IMO also estimates the amount of gas that is required for WA's LNG sector. Together the domestic gas demand and LNG forecasts make up the forecasts of total WA gas demand. Two scenarios were developed for total gas demand – Base and High.

The assumptions applied in each scenario are outlined in Table 5.1. Beyond the inclusion of domestic gas demand, the scenarios represent the IMO's estimates of the future gas requirements for the LNG market in WA and do not represent any confidential information provided by existing or potential LNG market participants.

Table 5.1: Total gas demand scenarios, 2015 to 2024

Parameter	Base scenario	High scenario
Domestic gas demand	Base	High
LNG feedstock requirements	NWS and Pluto LNG requirements, as well as Gorgon LNG (15.6 mtpa in 2015), Wheatstone LNG (4.45 mtpa Train 1 in 2016, 4.45 mtpa Train 2 in 2017), Prelude FLNG (3.6 mtpa in 2017) and the Gorgon LNG expansion (5.2 mtpa in 2020).	Includes assumptions in Base scenario (except for Gorgon expansion) and Gorgon LNG expansion (5.2 mtpa in 2019*), Bonaparte (2.4 mtpa in 2019), Wheatstone LNG expansion (4.45 mtpa in 2020) and Pluto LNG expansion (2.2 mtpa in 2021).
LNG processing requirements	8 per cent of total LNG feedstock	8 per cent of total LNG feedstock

Source: IMO and NIEIR assumptions.

Note: Processing estimates are assumed by taking the low range of processing estimates outlined in Tusiani, Michael D. and Shearer, Gordon (2007).

It is important to note that the Base scenario for total gas demand is not strictly restricted to LNG projects that have reached FID. This allows for a more conservative estimate of the life of remaining gas reserves in WA (outlined in section 9.4) and is consistent with previous GSOOs.

The prospective Gorgon Train 4 is the only project included in the Base scenario that has yet to reach FID, as this project appears to be the most likely project to proceed. According to news reports, Chevron has obtained WA Government approval to allow the project to utilise more land on Barrow Island[31] and it appears Chevron is already marketing LNG from Gorgon Train 4[32].

In this GSOO, LNG feedstock requirements for existing facilities are adjusted by taking into account an average utilisation rate of operational LNG facilities in WA for the 2010 to 2014 period (inclusive) outlined in Table 5.2.

Table 5.2: LNG utilisation rates (operational facilities only - % of nameplate), 2010 to 2014

Facility	2010	2011	2012	2013	2014 (to date)*	Average
NWS JVs LNG	101.4	98.4	95.5	93.5	101.5	98.1
Pluto	NA	NA	93.6	93.4	108.5	98.5

Source: Woodside (2010 to 2014) quarterly reports.

Note: NA – not applicable. Utilisation is calculated using nameplate capacity, and therefore may periodically exceed 100. *2014 to Q3 inclusive.

For facilities that are under construction, a utilisation rate of 98 per cent of nameplate capacity is applied from the quarter the facilities are anticipated to commence.

5.2 Approach to forecasting potential gas supply

Studies prior to the GSOO have typically presented total production capacity as an indicative measure of gas supply. While this approach may be appropriate in a tight domestic gas market, it is less suitable under current conditions and would overstate the availability of gas supply, as future gas production capacity servicing the domestic market is anticipated to be almost twice projected domestic demand by the end of the forecast period.

The IMO estimates the availability of domestic gas supply from gas producers by estimating their 'willingness to supply' to the WA domestic market. This is done by first estimating the quantity of potential contracted supply and, from remaining available capacity, the quantity of potential price-sensitive supply in the WA market for each domestic gas supplier. Once both are determined separately, the aggregate of these values forms the potential supply estimate.

The WA domestic gas market is currently dominated by confidential medium to long-term bilateral gas supply agreements between wholesale gas suppliers and consumers. As such, the intentions of gas producers to supply to the domestic market are not directly observable and will be influenced by the range of commercial, economic and operational factors. Despite this difficulty, it is understood that as long as gas producers have spare capacity, domestic gas is likely to be available at commercially negotiated prices. Other factors such as the timing of the production capacity, commercial considerations, producer strategy, contractual commitments, contractual terms and operational issues will also influence the availability of gas supply to the domestic market.

31 West Australian (2013), West Australian (2014a).
32 Argus Media (2014).

This approach has been improved in response to stakeholder feedback since the January 2014 GSOO to allow the model to consider potential gas supply from the perspective of each domestic gas supplier; supplying to the domestic market only if it is commercially viable, and managing its operations as a portfolio[33].

Contracted supply is the estimated quantity of gas delivered into the WA market that is pre-sold under existing gas supply contracts. This estimated quantity is expected to be delivered to the domestic market for the full duration of the contract, regardless of fluctuations in long-term gas prices. Solely for the purposes of estimating contracted supply, the IMO has assumed that current arrangements for the marketing of domestic gas by the NWS and Gorgon JVs will continue until the end of the forecast period.

Price-sensitive supply is the estimated quantity of gas supply made available to the domestic gas market after taking into account contracted supply. Price-sensitive supply may be available 'if the price is right'. This estimated quantity is expected to be available only if future domestic gas prices are commercially viable, exceed extraction costs (exploration and development, gas extraction and operating costs, including a required rate of return) and exceed the opportunity cost of future sales.

For the purpose of forecasting potential gas supply for the forecast period, the IMO assumes that there are no constraints to pipeline capacity.

5.2.1 Assumptions applied in the potential supply forecast model

The level of potential supply to the domestic market for the forecast period is influenced by a range of operational and commercial factors.

Operational factors relate mostly to physical infrastructure constraints that restrict the sale of gas to the domestic gas market. For example, if a producer is fully contracted on a firm basis, it cannot increase firm gas supply to the market and may only sell any spare gas on an interruptible, i.e. non-firm, basis.

Operational constraints considered in the supply model include:

- the availability of uncontracted gas production capacity;
- remaining reserves; and
- minimum operational requirements of gas production plants.

In addition, a number of commercial factors are likely to affect the willingness of producers to supply the domestic market. Price-sensitive gas supply is estimated by applying the forecast domestic gas prices, along with the following factors, for each production facility:

- estimated production costs[34];
- availability of production capacity[35];
- estimated contracted level[36];

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33 The model enhancements also allow the consideration of joint and equity marketing by different entities.
34 The production costs for facilities applied in this study are estimated by the IMO using the latest Wood Mackenzie cost estimates.
35 This is calculated using an annualised average of capacity for each facility using GBB data for 1 August 2013 to 30 November 2013.

- the required rate of return on investment (LNG-linked or domestic only) [37];
- the share of gas reserves available to the gas producer;
- cost of alternative fuels;
- the opportunity cost of selling the gas;
- prevailing and projected exchange rates; and
- government regulation.

For each gas producer, the model assumes a linear relationship between the price-sensitive supply and the domestic gas price. This is explained as follows:

- zero price-sensitive supply if the forecast domestic gas price does not exceed the cost of gas production plus the assumed rate of return; and either
- for LNG-linked facilities, all of the uncontracted capacity (subject to the availability rate for the facility) will be available for supply to the domestic gas market if the domestic gas price reaches or exceeds the LNG netback price; or
- for domestic gas only facilities, all of the uncontracted capacity (subject to the availability rate for the facility) will be available for supply to the domestic gas market if the domestic gas price reaches an assumed rate of return[38] on top of the cost of production.

5.2.2 Assumptions of supply from the NWS JVs

The uncertainty regarding future supply to the domestic market from the NWS JVs has reduced considerably following the recently announced agreement with the WA Government, and the announcement by Hess stating its intention to develop and toll its reserves through the NWS JV's processing facilities. The quantity of future supply from the NWS JVs remains the key area of uncertainty in the supply of gas to the domestic market beyond 2020.

Ongoing supply from the NWS JVs beyond the terms of existing contracts is dependent on a range of factors, as outlined in section 2.2. Therefore, two potential supply scenarios have been developed for the forecast period in this GSOO.

The Lower potential supply forecast assumes the NWS JVs will only be willing to make sufficient gas available to the domestic market to fulfil its New Domgas Commitment of approximately 100 TJ per day, while the Upper potential supply forecast assumes the NWS JVs will continue to make additional supply available to the WA domestic market for the full forecast period.

It is important to note that any future domestic gas supply from a potential agreement between Hess and NWS JVs is not included in the supply forecasts as information is not yet available regarding the quantity or timing of supply from Hess' Equus fields and a number of investment decisions are yet to be made by both the NWS JVs and Hess.

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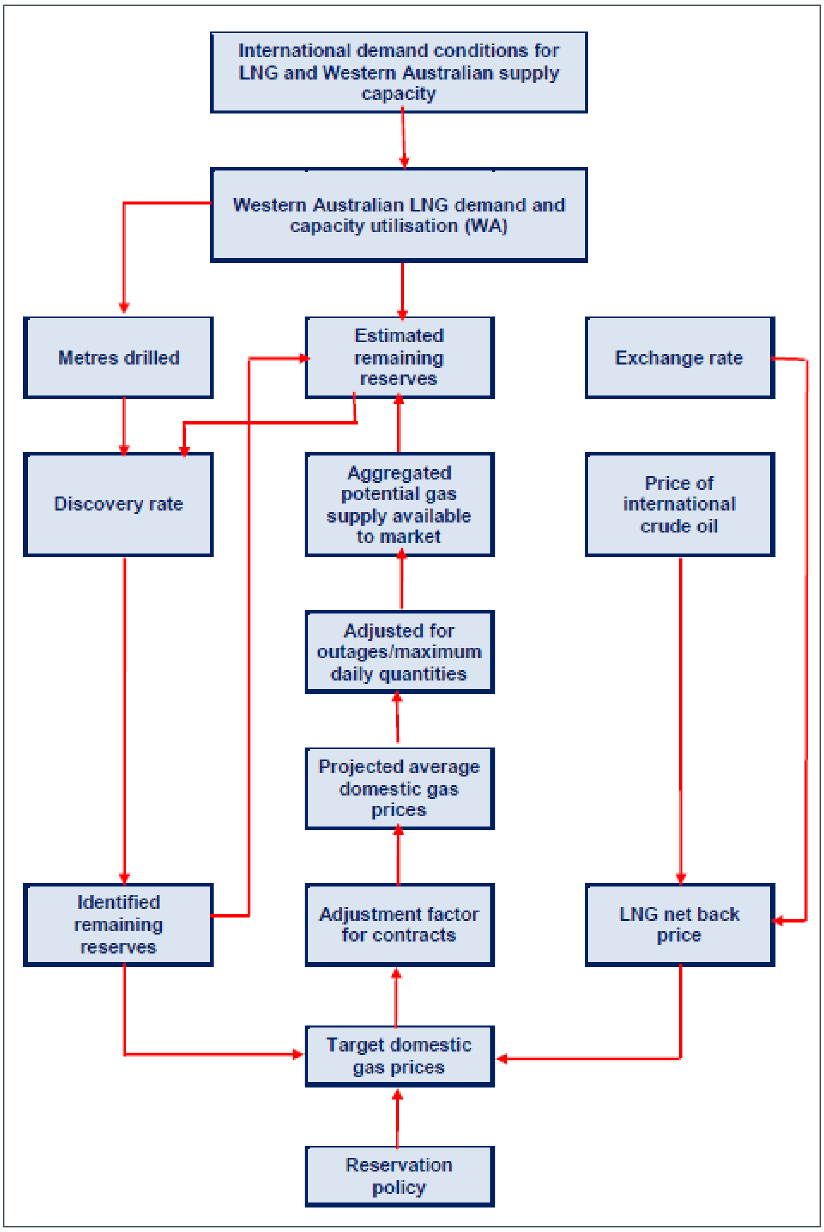
[36] These are IMO estimates.
[37] Assumed to be a minimum of 10 per cent.
[38] Estimated to be 25%.

5.2.3 *The potential gas supply model*

The IMO's model for forecasting potential gas supply was developed with NIEIR for the initial GSOO, and subsequently improved by the IMO. Figure 5.3 shows the structure of the IMO's model for forecasting potential gas supply, including the factors that drive the average medium to long-term prices, which are discussed below in section 5.3.

Figure 5.3: Potential supply forecast model



Source: NIEIR

5.3 Domestic gas price forecasting

As noted previously, forecast domestic gas prices are considered in the development of forecasts of potential supply and gas demand. Domestic gas prices are a key factor for gas producers in achieving a commercial rate of return on gas sales, and in some cases inform the trade-off between sales to the domestic market and the international LNG market. In addition, gas demand is expected to be affected by increases in gas prices, particularly over the medium to long-term.

The IMO engaged NIEIR to forecast average new medium to long-term (four years and longer) gas prices for use in forecasting gas demand and supply in this GSOO. These are determined at the point of supply from the production facility (i.e. ex-plant). Forecast average new contract gas prices are influenced by factors such as the international price of oil, Asia Pacific LNG prices, the availability of reserves and domestic gas market conditions. Figure 5.3 above provides an insight into the factors that have been considered in the medium to long-term average new forecast prices.

Using probability analysis, the following variables are estimated for use in developing the price forecasts:

- future oil prices;
- future LNG prices;
- projected exchange rates; and
- recoverable WA gas reserves.

Once each variable is estimated for the 10-year forecast period, they are then used to forecast average new contract gas prices. This is done by applying a weighted average formula of the LNG netback price and the remaining reserves, and adjusting for domestic conditions[39]. The LNG netback price is therefore directly influenced by forecast oil prices and exchange rates, both currently subject to considerable movement and uncertainty.

Future LNG netback prices (determined by deducting shipping and liquefaction costs from LNG prices) represent the domestic gas price at which producers that supply both markets will be indifferent between supplying to the domestic gas market or LNG export market.

As noted in the January 2014 GSOO, NIEIR's model for forecasting average new contact gas prices assumes that all domestic gas producers would benchmark their operational and sales performance against the international price of gas. While only one existing gas production facility supplies LNG, two more are nearing completion, meaning export prices will be an increasingly important factor in determining domestic gas supply over the forecast period.

While NIEIR's modelling of domestic gas prices assumes an LNG netback relationship, it is recognised that under different circumstances, producers and buyers of gas may be influenced by other considerations, including the required rate of return and the price of alternative fuels (such as diesel), when negotiating gas prices. Regardless, gas producers naturally seek the highest possible prices.

39 Department of Resources Energy and Tourism (2012). 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.

Due to the commercial sensitivity of the assumptions for individual facilities, Table 5.3 only summarises some of the assumptions applied to the gas price forecasts. Two scenarios – Base and High – were developed for price forecasts. These scenarios represent the likely range of average new medium to long-term contract prices for the forecast period that are linked to the forecast Asia Pacific LNG prices.

Table 5.3: Forecast gas price parameters

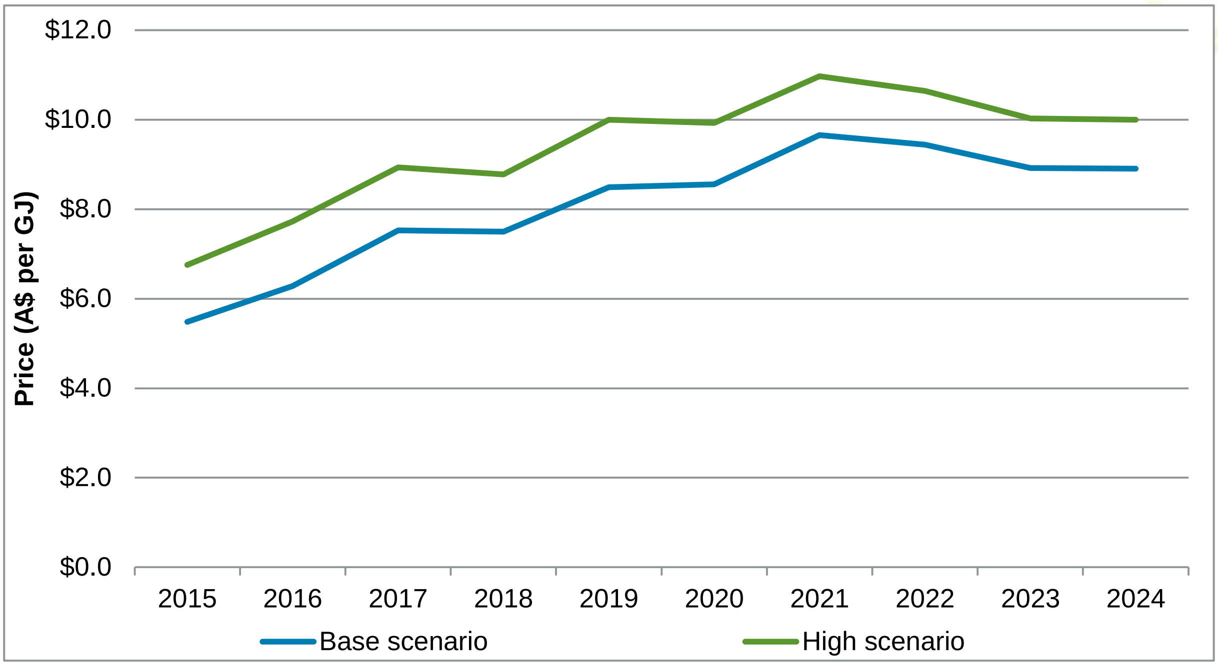
Parameter	Scenario	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
International oil prices (US$/barrel)	Base	64.0	66.0	71.5	74.0	80.0	85.1	86.2	84.6	81.0	78.0
	High	67.1	71.5	77.4	80.2	86.6	92.0	92.9	91.2	87.4	84.3
Asia Pacific LNG prices-real (US$/GJ)	Base	11.78	12.07	12.87	13.23	14.10	14.84	15.00	14.77	14.25	13.81
	High	12.22	12.87	13.72	14.13	15.05	15.84	15.98	15.72	15.18	14.72
Shipping and liquefaction costs (US$/GJ)	All	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
Exchange rates (A$/US$)	All	0.85	0.83	0.81	0.78	0.76	0.78	0.79	0.80	0.81	0.78
Recoverable reserves (bcm)	Base	4,401	4,416	4,407	4,382	4,351	4,310	4,262	4,207	4,149	4,089
	High	4,401	4,418	4,411	4,388	4,359	4,313	4,259	4,198	4,133	4,065

Source: NIEIR forecasts 2015 to 2024.

Note: Scenarios outlined in this table are developed by the IMO and NIEIR and do not represent any information provided by any existing market participants. International oil prices are an average of Brent, Light Sweet Crude and West Texas Intermediate.

The forecasts of medium to long-term average (ex-plant) new contract gas prices for the domestic market for the forecast period are shown in Figure 5.4.

Figure 5.4: Forecast medium to long-term average (ex-plant) new domestic contract gas prices (real), 2015 to 2024



Source: NIEIR forecasts 2015 to 2024.

NIEIR forecasts these gas prices will rise between 2015 and 2024 due to the expected weakening of the Australian dollar. The anticipated stronger growth of the US economy, coupled with higher interest rates in the US, is expected to increase LNG netback prices in Australian dollar terms, driving an increase in domestic gas prices.

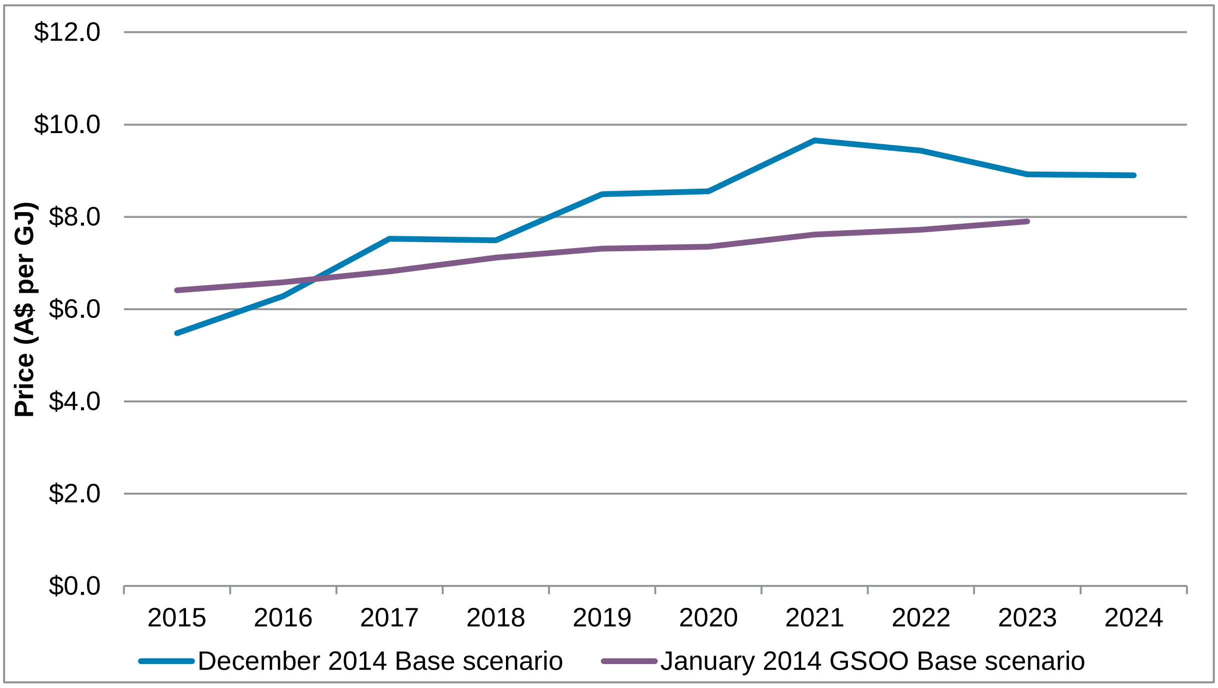
While NIEIR has prepared forecasts of average medium to long-term average (ex-plant) prices for new gas sales agreements, new domestic gas supply contracts are expected to be agreed both below and above those forecast prices. In addition, actual prices negotiated between any two parties will be affected by a range of commercial and competitive factors relevant to those parties.

While the IMO recognises the existence of short-term gas contracts in WA, short-term gas pricing is not considered in this GSOO as gas supply to the WA market is still largely driven by medium to long-term bilateral contracts between gas producers and large consumers. Should the quantity traded in the short-term market grow from current levels – approximately 1 per cent of total domestic gas consumption – the factors driving short-term gas contracting may become more important, warranting further consideration and potential explicit inclusion in the forecasts.

5.3.1 *Comparing gas price projections, January 2014 GSOO and this GSOO*

Figure 5.5 compares the average new medium to long-term contract gas price projections developed for the January 2014 GSOO and this GSOO. The main driver of the increase in forecast gas prices since the January 2014 GSOO is the expected decline in the Australian dollar for the forecast period. However, a rapid fall in oil prices since September 2014, outlined in section 2.2, has eased forecast gas price forecasts for 2015 and 2016, starting the price forecasts from a lower base.

Figure 5.5: Comparison of the medium to long-term forecast contract prices (real), January 2014 and December 2014 GSOOs, 2015 to 2024



Source: NIEIR forecasts, 2014 to 2023 and 2015 to 2024.

6. Current and forecast gas demand

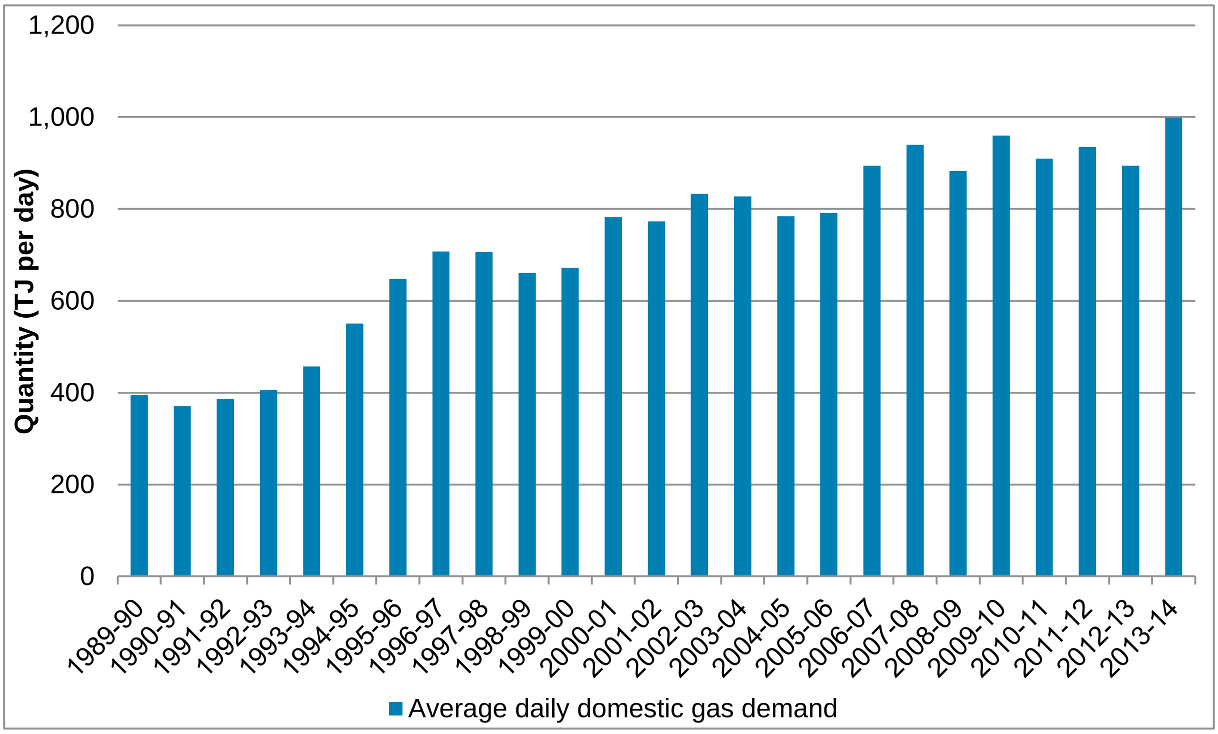
This chapter provides a snapshot of gas demand, an outline of gas consumption by sector and annual demand forecasts for the WA domestic gas market for the forecast period. This chapter also provides annual forecasts of total gas demand in WA over the forecast period. Total gas demand is the sum of the demand for domestic gas, LNG exports and LNG processing.

6.1 Current gas demand

Growth in WA gas demand is typically 'lumpy', largely driven by the electricity generation requirements of new or expanding resource projects. These projects tend to be large in scale and gas requirements are secured through medium to long-term bilateral contracts with one or more gas suppliers. Hence, the entry or exit of a large gas consumer can materially alter the consumption profile of domestic gas demand, creating a cyclical trend of rapid growth followed by slower or declining growth.

As shown in Figure 6.1, domestic gas demand has grown considerably over the last 25 years. Overall, in the 1988-89 to 2013-14 period domestic gas demand grew from approximately 395 TJ per day (144 PJ per year) in 1989-90 to approximately 999 TJ per day (365 PJ per year) in 2013-14.

Figure 6.1: WA average daily gas demand (TJ per day, excluding petroleum processing), 1989-90 to 2013-14



Source: DMP (2014c).

Note: This figure does not take into account gas consumed by petroleum and LNG processing behind the meter (NWS, Pluto, Varanus Island, Cliff Head and others), gas consumed in pipeline compressor stations and unaccounted for gas.

Average annual growth in domestic gas demand is shown in Table 6.1. Each period observed spans a period of rapid expansion and a period of slower growth. As can be seen, overall, growth has slowed in recent years.

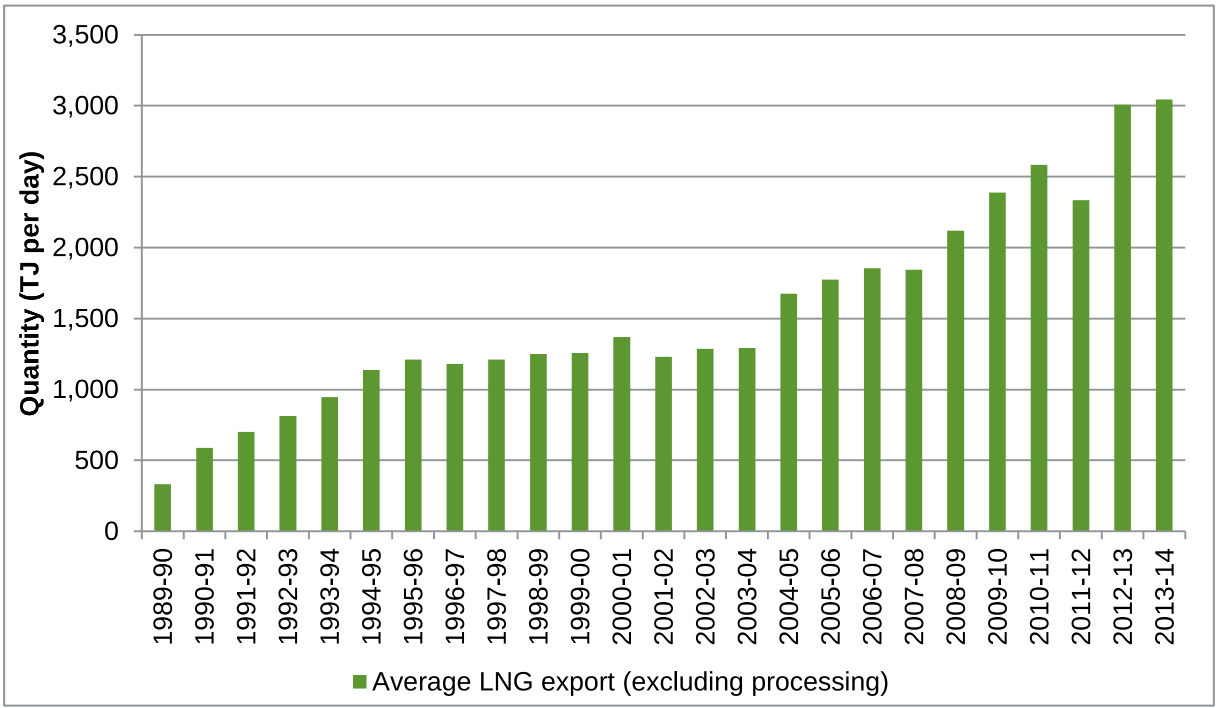
Table 6.1: Domestic gas demand average annual growth (%), 1984-85 to 2013-14

1984-85 to 1989-90	1990-91 to 1999-00	2000-01 to 2009-10	2010-11 to 2013-14
8.69	2.77	2.44	1.02

Source: DMP (1984 to 2014) calculated using domestic gas sales, 1984-85 to 2013-14.

WA's LNG exports also grew strongly over recent decades, as shown in Figure 6.2. LNG exports grew significantly faster than the domestic gas market, at 9.7 per cent average annual growth from approximately 332 TJ per day (121 PJ per year) in 1989-90, to approximately 3,045 TJ per day (1,111 PJ per year) in 2013-14.

Figure 6.2: WA average LNG exports (excluding petroleum processing), 1989-90 to 2013-14



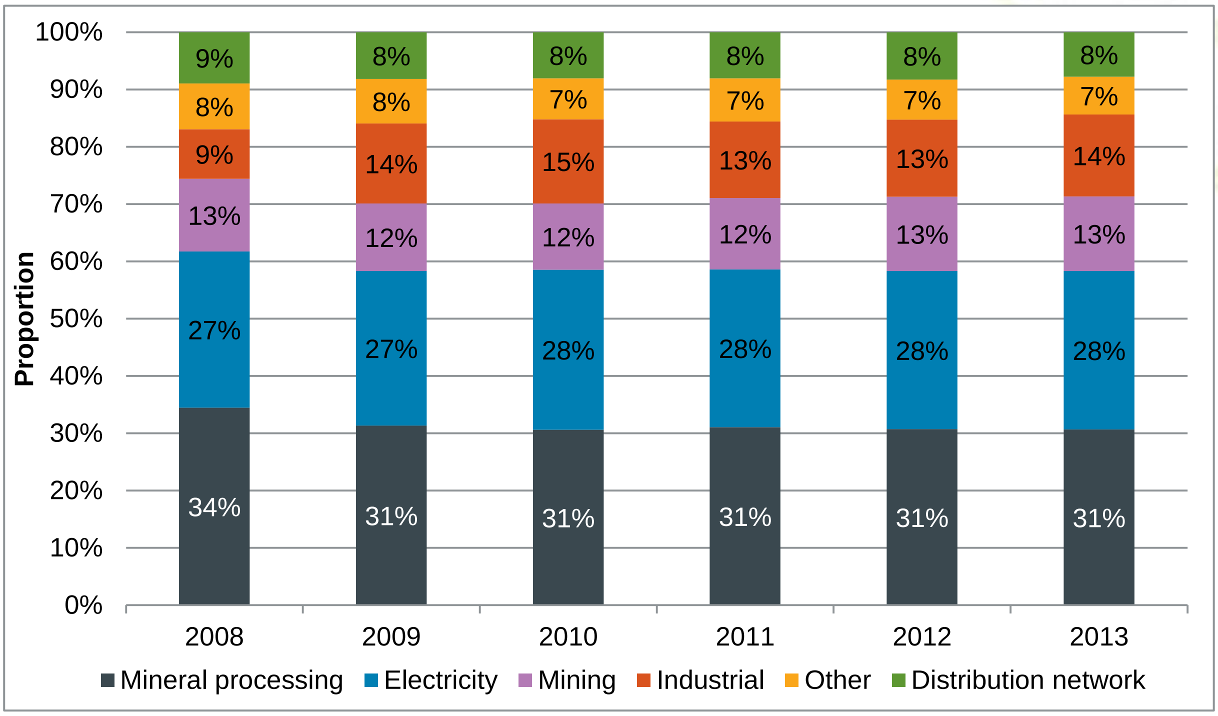
Source: DMP (2014c).

Note: This figure does not take into account gas consumed by petroleum and LNG processing behind the meter (NWS, Pluto, Varanus Island, Cliff Head and others), gas consumed in pipeline compressor stations and unaccounted for gas.

6.1.1 Drivers of domestic gas demand, 2008 to 2013

The components of WA gas demand for the 2008 to 2013 period before the establishment of the GBB are shown in Figure 6.3 below. The figure shows that in the last six years, except for the period between 2008 to 2009 where industrial demand for gas increased, the relative proportions of the WA domestic gas market have not changed significantly.

Figure 6.3: Share of domestic gas demand by sector, 2008 to 2013



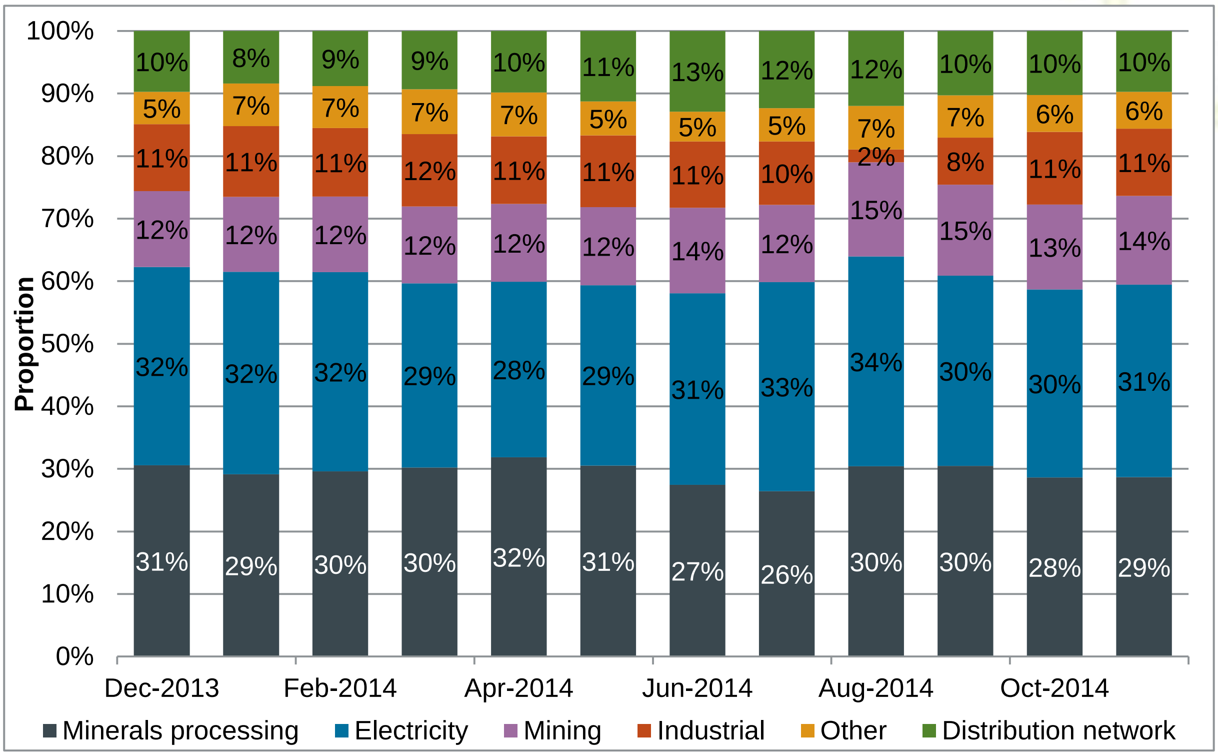
Source: Data from pipeline operators.

This figure shows that the WA domestic wholesale gas market is dominated by large users in the minerals processing, electricity generation, industrial and mining sectors. These customer segments consume more than 80 per cent of domestic gas.

Less than 10 per cent of domestic gas demand is consumed via the gas distribution networks – essentially representing residential and small commercial customer consumption (outlined in sections 6.1.4 and 6.1.5 below). The remaining quantity (represented by the 'Other' category) is made up of consumption from other customers in the wholesale gas market.

The share of domestic gas demand over the last 12 months is shown in Figure 6.4 below.

Figure 6.4: Share of monthly domestic gas demand by sector, December 2013 to November 2014



Source: *IMO GBB data.*

Note: The GBB allows only one industry classification for each large user, which is defined as one consuming 10TJ per day or more. This figure also does not take into account gas consumed by petroleum and LNG processing behind the meter (NWS, Pluto, Varanus Island, Cliff Head and others), gas consumed in pipeline compressor stations and unaccounted gas. Numbers may not add to 100 due to rounding.

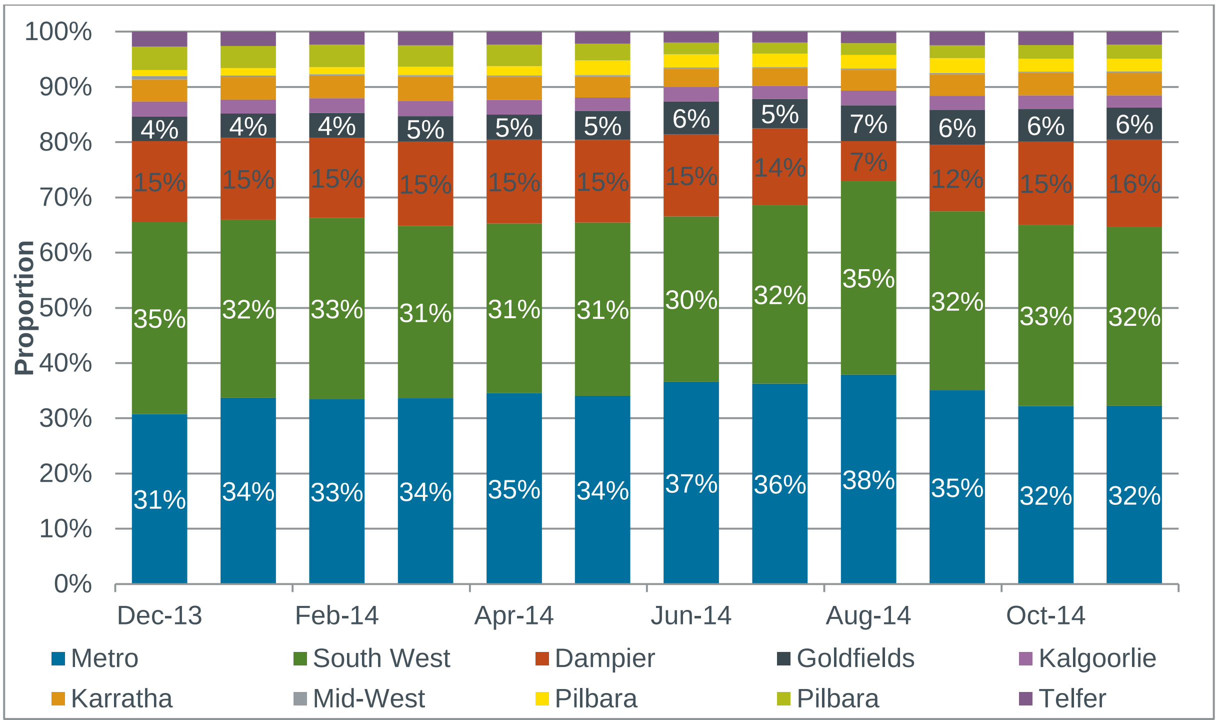
Approximately half of all gas demand in WA is eventually used for electricity generation, represented by the electricity and mining components in Figure 6.4. The scale of these gas users means that a particular operational outage or industry event can cause a material reduction in consumed quantities. For example, Yara Pilbara's Burrup Fertilisers reduced its gas consumption in August 2014, reducing the gas consumed by the 'Industrial' sector in that month. However, as consumption outages are not required to be reported to the IMO, the exact reason for this fall in consumption is unknown[40].

[40] It is likely to be related to major plant shutdown works announced by AusGroup – including mechanical inspections, piping modifications and piping tie-ins across the TAN Burrup Project.

6.1.2 *Gas demand by region*

Approximately 65 to 70 per cent of domestic gas demand occurs in the Metro and South West Zones[41]. These regions contain several key large users – such as Alcoa's Kwinana, Wagerup and Pinjarra alumina refineries, and large SWIS electricity generators – such as NewGen Power's Kwinana power station, Worsley's Multi-Fuel Cogeneration Plant, and Synergy's Cockburn power station, as well as the vast majority of the state's residential gas users. Figure 6.5 shows the proportion of gas consumption by zone for each month from December 2013 to November 2014, as calculated from GBB data. As shown in Figure 6.4 above, the scale of large users in the gas market means that an operational outage can have significant impact. The effect of the reduced consumption by Burrup Fertilisers in August 2014 can be seen below, having the effect of halving gas demand in the Dampier Zone for the month.

Figure 6.5: Share of monthly domestic gas demand by GBB Zone, December 2013 to November 2014



Source: *IMO GBB data.*

Note: This figure does not take into account gas consumed by petroleum and LNG processing (NWS, Pluto, Varanus Island, Cliff Head and others), gas consumed in pipeline compressor stations and unaccounted for gas.

[41] The Zones are defined in Schedule 2 of the GSI Rules.

6.1.3 Natural gas as a fuel for electricity generation in WA

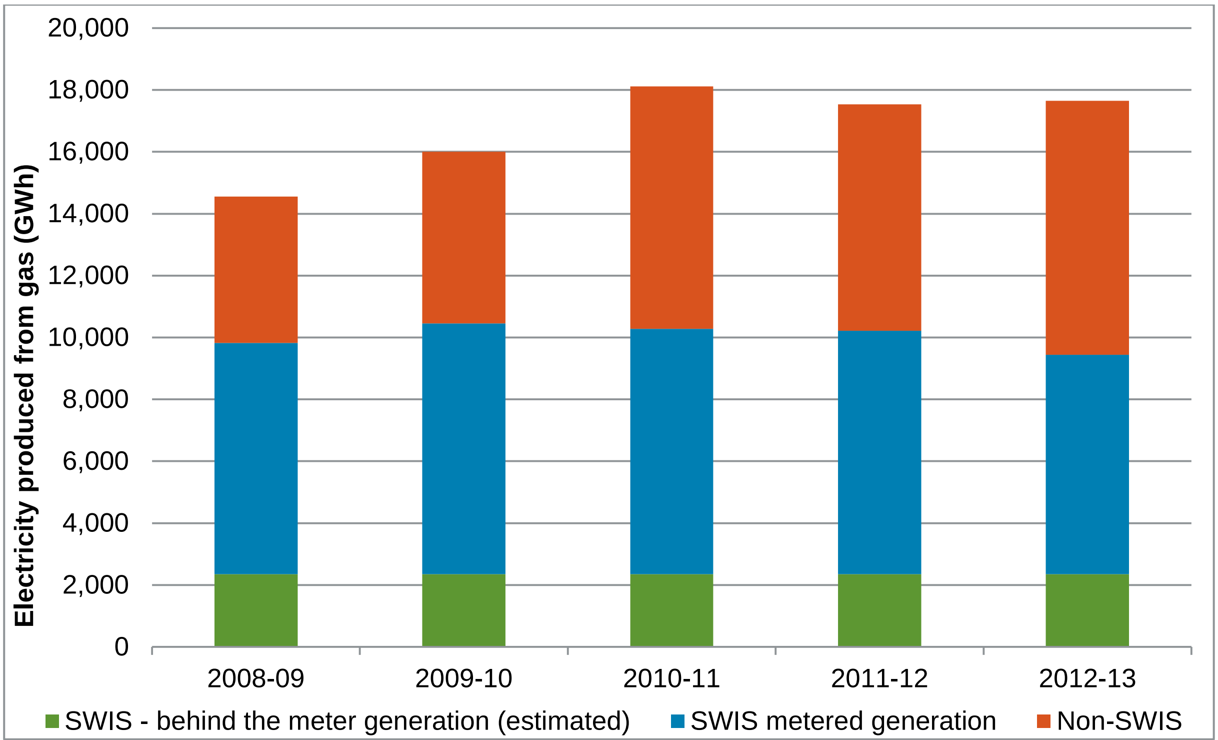
As shown in the sections above, gas is important to the functioning of the state's economy, due to its significant role as a fuel for electricity generation.

There is approximately 5,652 MW of electricity generation capacity in WA capable of consuming gas – including a number of dual-fuel facilities. While 3,242 MW of this generation is connected to the SWIS, 2,410 MW is installed in other parts of the state – 964 MW in the North West Interconnected System and the remaining 1,446 MW in regional and remote communities and mining operations.

In addition to comprising a large proportion of installed capacity, gas-fired generation provides more than 50 per cent of the state's electricity requirements. BREE reports that natural gas was used to generate a total of 16,852 gigawatt hours (GWh) of electricity in WA in the 2012-13 financial year.

Gas consumption for electricity generation has grown more rapidly for areas outside the SWIS in recent years. Figure 6.6 shows significant growth in the 2008-09 to 2012-13 period which is largely related to iron ore mining.

Figure 6.6: Domestic gas demand for electricity generation in WA, 2008-09 to 2012-13



Source: IMO estimates.

Note: The breakdown between SWIS and non-SWIS is estimated by taking the difference between BREE's (2014) Australian Energy Statistics figures, IMO sent out generation data and estimates of electricity generated behind the meter within the SWIS. This figure has been updated from the January 2014 GSOO.

The various types of gas-fired generation facilities in the SWIS are shown in Table 6.2. Of the 5,862 MW of total certified installed capacity in the SWIS at the time of writing this report, more than half is capable of running on gas.

Table 6.2: Gas-fired electricity generation in the SWIS, 2013-14

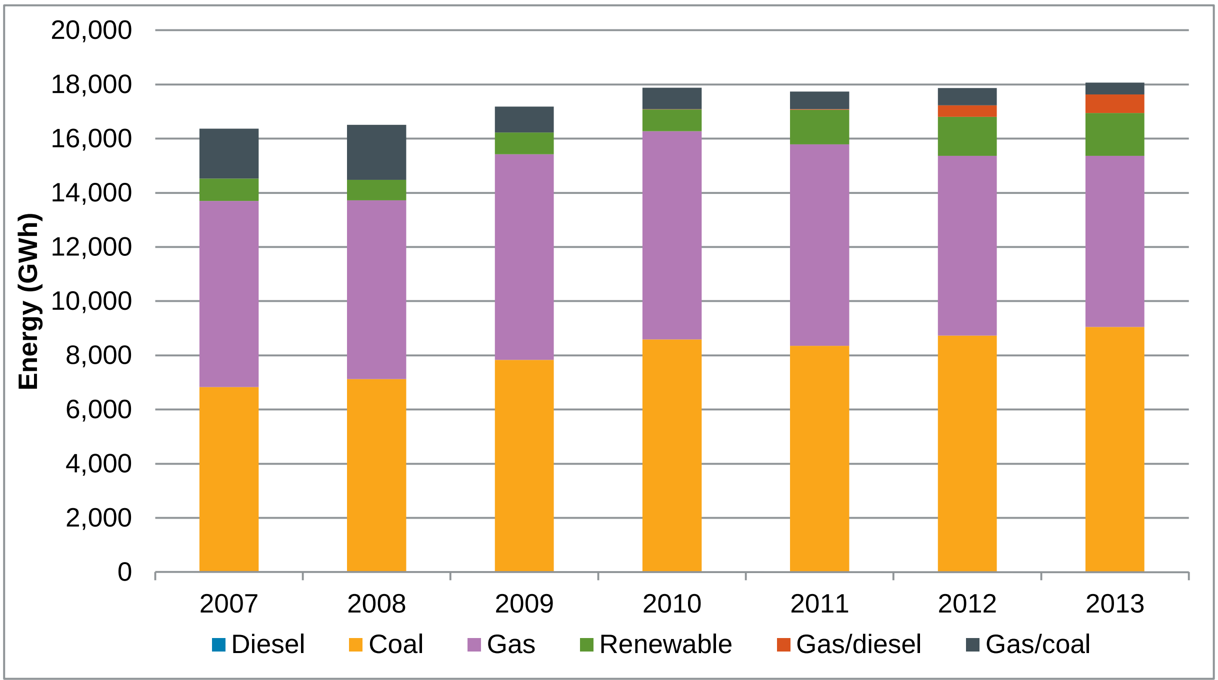
Electricity generation capacity	Dual fuel (gas/liquids)	Dual fuel (coal/gas)	Natural gas only
SWIS total	1,320	184*	1,946

Source: IMO.

Note: *The Kwinana G6 facility is scheduled for retirement in April 2015, after which this will equal zero.

In contrast to growth outside the SWIS, total grid-supplied electricity generation in the SWIS has shown little growth since 2009. Figure 6.7 shows the total sent out electricity for each fuel type for each calendar year since the commencement of the Wholesale Electricity Market (WEM). This shows that energy generation from gas has decreased in relation to other fuel types.

Figure 6.7: Electricity generation by fuel type (SWIS), 2007 to 2013



Source: IMO.

Gas has been partially displaced in recent years by coal and renewable generation in the SWIS. Coal-fired generation has increased by 33 per cent since 2007, predominantly due to:

- the completion of the Bluewaters Power Station in 2009; and
- the recommissioning of the Muja AB facilities in the 2013 to 2015 period.

Renewable generation, aided by incentives such as the Commonwealth Government's Renewable Energy Target (RET) scheme, has increased by 91 per cent since 2007 to represent more than 9 per cent of total sent out electricity in the WEM in 2013[42]. Future growth in renewable energy generation is expected to be affected by final decisions related to the RET as a result of the federal government review.

In addition, the rate of growth in SWIS electricity demand has slowed considerably between 2010 and 2013 due to:

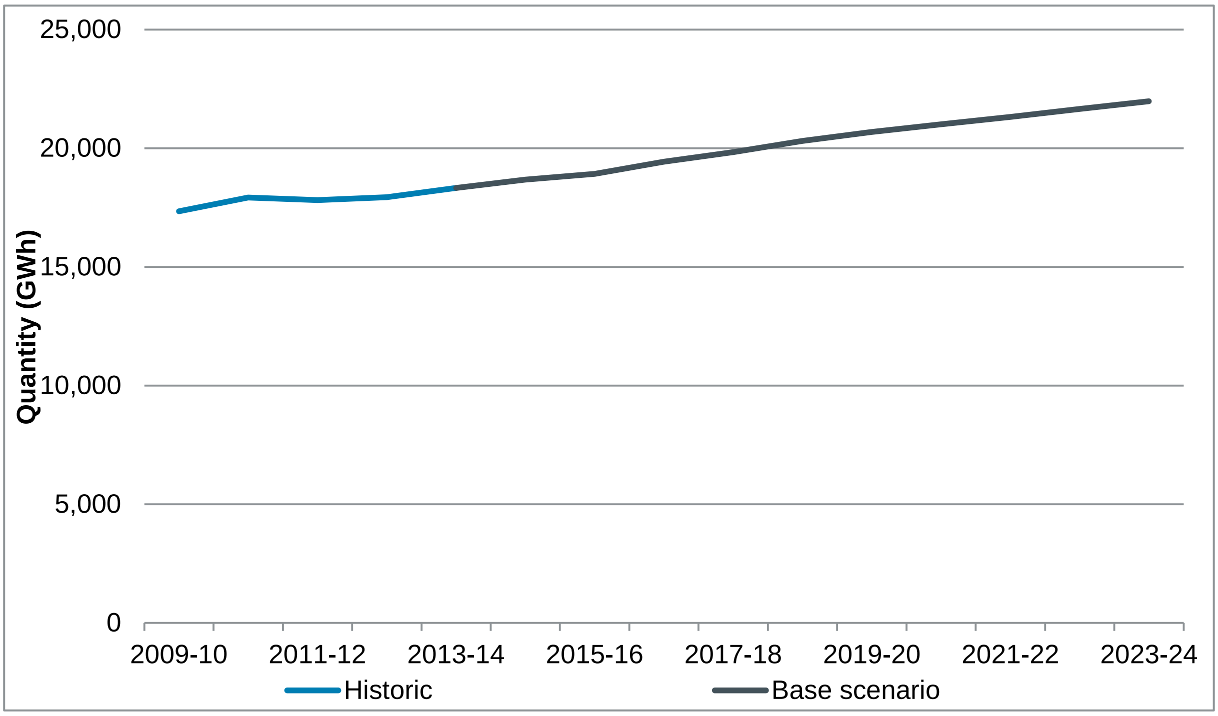
- increases in domestic regulated electricity tariffs;
- the continued growth in the installed capacity of small-scale solar photovoltaic systems;
- commercial participation in demand side management programs;
- commercial management of load to reduce exposure to costs of consumption at system peak, e.g. the Individual Reserve Capacity Requirement;
- the increasing impact of energy efficiency and energy efficient appliances; and
- business energy efficiency programmes.

Electricity demand, and hence generation, is expected to continue to grow at a moderate rate in the SWIS over the forecast period.

[42] This excludes smaller-scale distributed solar PV generation.

The IMO's Base forecast of SWIS sent out electricity, published in the 2014 SWIS Electricity Demand Outlook, is shown in Figure 6.8. Total sent out electricity is forecast to grow at an average rate of 1.8 per cent per year over the next 10 years, although growth is anticipated to be slower in the short-term due to slower growth in the WA economy and the impact of proposed or announced electricity tariff increases.

Figure 6.8: SWIS electricity demand forecast, 2009-10 to 2023-24



Source: *IMO WEM data and NIEIR's forecasts 2013-14 to 2023-24, published in the 2014 SWIS Electricity Demand Outlook.*

While gas-fired generation may continue to be displaced as a fuel source in the SWIS in the short-term, the flexibility and fast response times of gas-fired generators suggest that they will continue to play an important role over the coming decade as mid-merit or peaking generators in the SWIS; as well as in meeting increased demand from mining related electricity generation outside of the SWIS.

6.1.4 Residential gas demand

Although WA has the highest overall gas consumption of any state (approximately 37 per cent of the 2012-13 national total), residential gas demand comprises a small portion of WA domestic gas use.

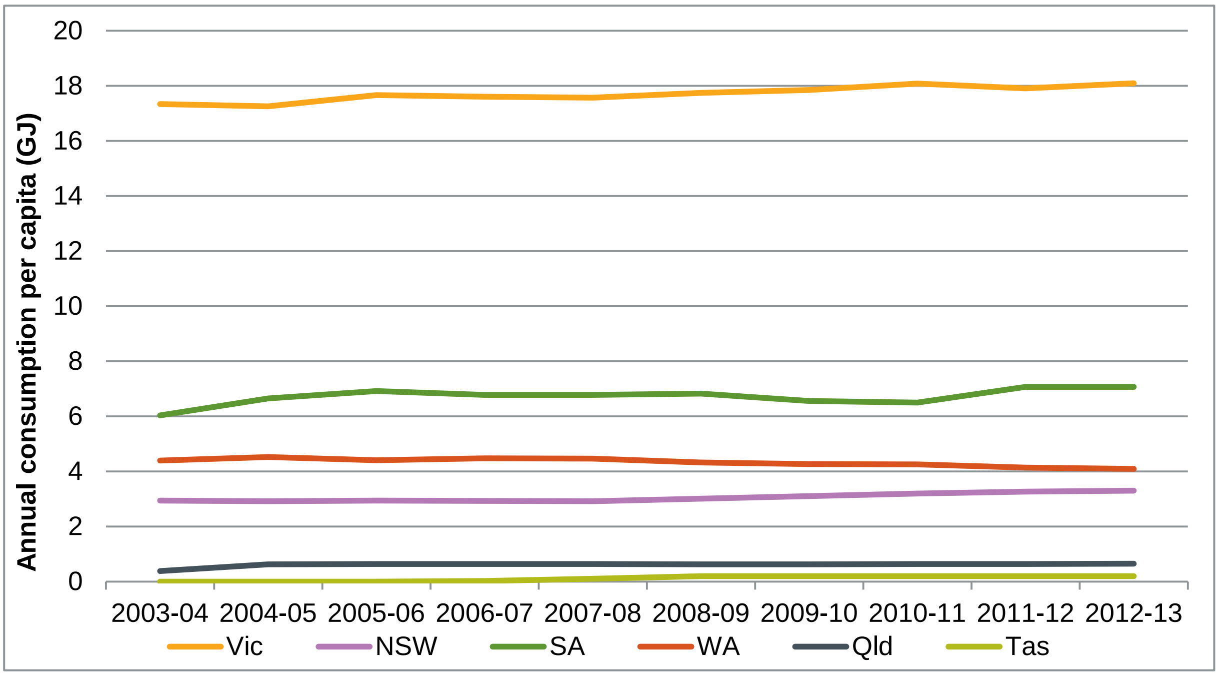
The WA residential sector has only the fourth highest consumption of all Australian states, behind Victoria, New South Wales, and South Australia (SA) – shown in Figure 6.9 below.

Figure 6.9: Australia's residential gas consumption by state, 2003-04 to 2012-13

Source: BREE (2014a).

Residential gas consumption per person for each state for the 2003-04 to 2012-13 period is shown in Figure 6.10.

Figure 6.10: Residential gas consumption per capita by state, 2003-04 to 2012-13



Source: IMO estimates based on ABS (2013) and BREE (2014a).

Victoria has the highest consumption per capita – approximately 18 GJ per year – driving its high overall residential usage. While SA has the next highest per capita usage (7.1 GJ per person per year), lower population numbers mean SA residential customers have only the third highest overall consumption. WA's consumption per person is the third highest in Australia at 4.1 GJ per person per year.

The low level of residential gas use in WA is largely a result of lower demand for heating – a by-product of a warmer climate, as well as more limited access to mains gas (which is generally cheaper than bottled gas) than in some other states. In 2011, around 68 per cent of WA households had access to mains gas, compared with 82 per cent in Victoria. Of households which had heating installed, nearly 70 per cent ran on gas in Victoria, while only 36 per cent of households used gas heating in WA[43].

Key statistics for WA residential customers connected to the gas distribution network are shown in Table 6.3 for the 2009 to 2013 period.

Table 6.3: Key statistics for WA residential connections to the gas distribution network, 2009 to 2014

	2009	2010	2011	2012	2013	2014	6 year annual average growth
Number of connections	585,058	604,609	616,431	629,142	632,822	657,822	1.7%
Total gas consumption (TJ)	10,646	10,815	10,573	9,537	10,027	10,098	-1.1%
Consumption per connection (GJ)	18.2	17.9	17.2	15.2	15.8	15.3	-3.3%

Source: ERA (2013, 2014e, 2014f).

Between 2009 and 2014, total residential gas consumption fell despite an increase in customer numbers each year, leading to a reduction in average consumption per connection. This fall in average gas consumption per customer is likely to be the result of customer response to rising retail gas prices, a switch from gas to solar for water heating due to generous government rebates, and a fall in gas use for space heating.

43 ABS (2011).

6.1.5 Commercial gas demand

The number of commercial gas customers on the gas distribution network is shown by retailer in Table 6.4. These customers consume almost 7 per cent of the gas used in WA – approximately 25 PJ per year.

Table 6.4: Number of non-residential gas customers by retailer, 2008 to 2014

Retailer	2008	2009	2010	2011	2012	2013	2014
Alinta Energy	7,707	8,024	8,191	8,359	8,468	8,355	8,282
Synergy	97	98	112	119	112	141	79
Wesfarmers (Kleenheat Gas)	19	19	2	1	1	20	232
WorleyParsons	28	31	33	34	31	36	33
Total	**7,851**	**8,172**	**8,338**	**8,513**	**8,612**	**8,552**	**8,626**

Source: ERA (2013, 2014e, 2014f).

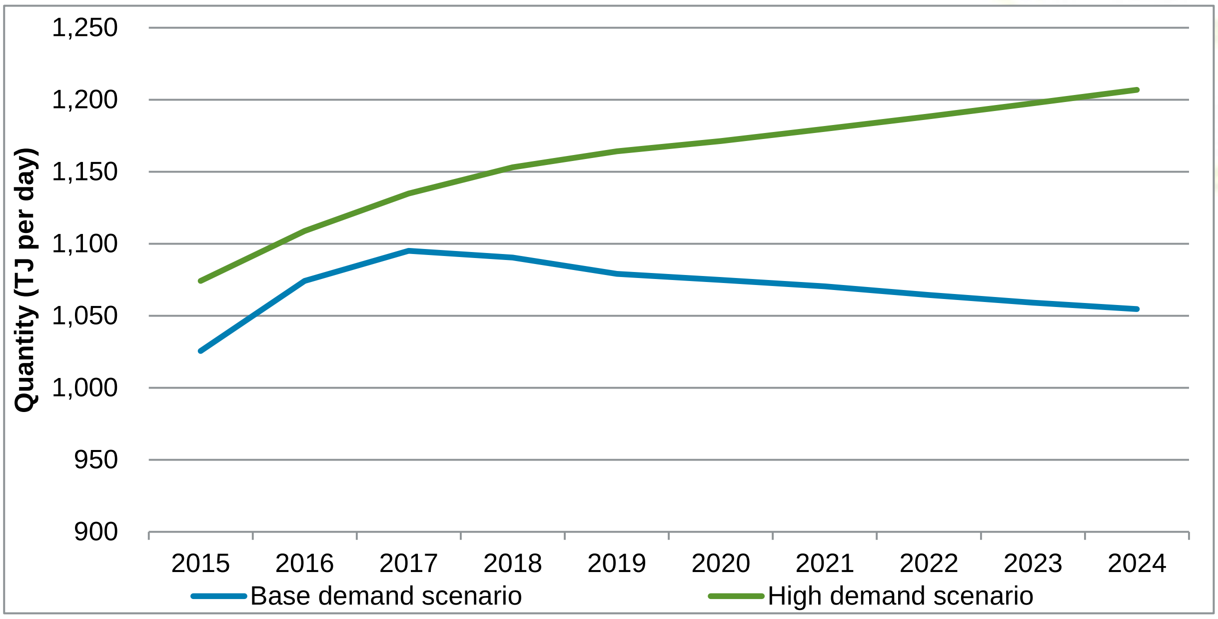
The majority of the commercial customers within the gas distribution networks are supplied by Alinta Energy. Synergy has limited numbers of commercial gas customers due to the Gas Market Moratorium preventing Synergy from supplying gas customers consuming less than 0.18 TJ per year. WorleyParsons supplies natural gas into the Esperance gas distribution network. The growth in the Wesfarmers customer base appears to be largely due to churn from Synergy and Alinta, both of which have experienced reductions in 2014 from 2013 customer numbers and coincides with Westfarmers taking a more active role in the WA gas retail market.

6.2 Forecast gas demand

Significant changes to the domestic gas market are expected over the forecast period. As outlined in chapter 5, gas demand forecasts are driven by assumptions related to underlying economic growth, expected new gas-consuming projects, forecast gas prices and the price elasticity of demand.

Base and High gas demand growth scenarios are provided as a guide to the variability in outcomes that could be anticipated, with future gas demand expected to fall within this range. Figure 6.11 and Table 6.5 show the forecasts of domestic gas demand for the forecast period.

Figure 6.11: Gas demand forecasts for WA, 2015 to 2024



Source: NIEIR forecasts 2015 to 2024.

The quantity of domestic gas demand for each year of the forecast period is shown in Table 6.5 below.

Table 6.5: Forecast gas demand (TJ per day), 2015 to 2024

Scenario	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Base	1,026	1,074	1,095	1,090	1,079	1,075	1,071	1,065	1,059	1,055
High	1,074	1,109	1,135	1,153	1,164	1,171	1,180	1,188	1,198	1,207

Source: NIEIR forecasts 2015 to 2024.

Over the forecast period, gas demand is expected to grow at an average annual rate of between 0.3 per cent in the Base demand scenario and 1.3 per cent in the High demand scenario.

The majority of growth in the early years of the gas demand forecasts is driven by large gas-consuming projects that have reached FID since the writing of the January 2014 GSOO.

These projects include:

- Sub161's CNG supply facility[44];
- the FRGP[45];
- the EGGP[46];
- increased gas consumption relating to Alinta Energy's Newman Power Station which will supply electricity to Hancock Prospecting's Roy Hill iron ore mine[47]; and

44 Sub161 (2014).
45 DUET Group (2014c).
46 APA Group (2014a).

- operation of TransAlta's South Hedland Power Station[48].

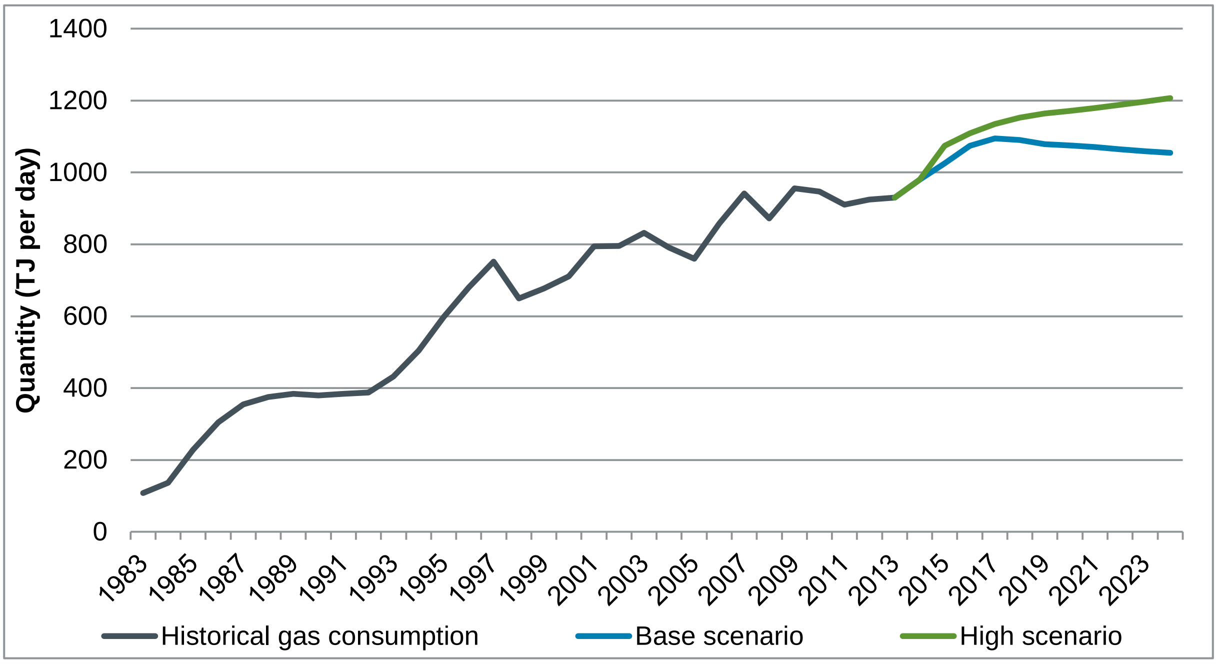
In addition, growth in demand is expected from previously announced projects such as the Pilbara Temporary Power Station[49] and CITIC Pacific's Sino Iron's magnetite mine[50].

In addition, growth in demand is expected from previously announced projects such as the Pilbara Temporary Power Station and CITIC Pacific's Sino Iron's magnetite mine.

These projects are expected to contribute almost three quarters of gas demand growth over the forecast period, with most of this growth occurring in the period from 2015 to 2017. An estimate of gas demand from a number of prospective projects which have not yet reached FID is also included in the High demand scenario.

As can be seen in Figure 6.12, this pattern of growth is not uncommon for WA. As discussed above, gas demand tends to have a cyclical growth pattern, with periods of high growth followed by periods of slower growth. This is due to the scale of many gas-consuming projects in WA, with a relatively small number of individual gas consumers accounting for a significant proportion of overall gas demand.

Figure 6.12: Gas demand forecasts in relation to historical gas demand, 1983 to 2024



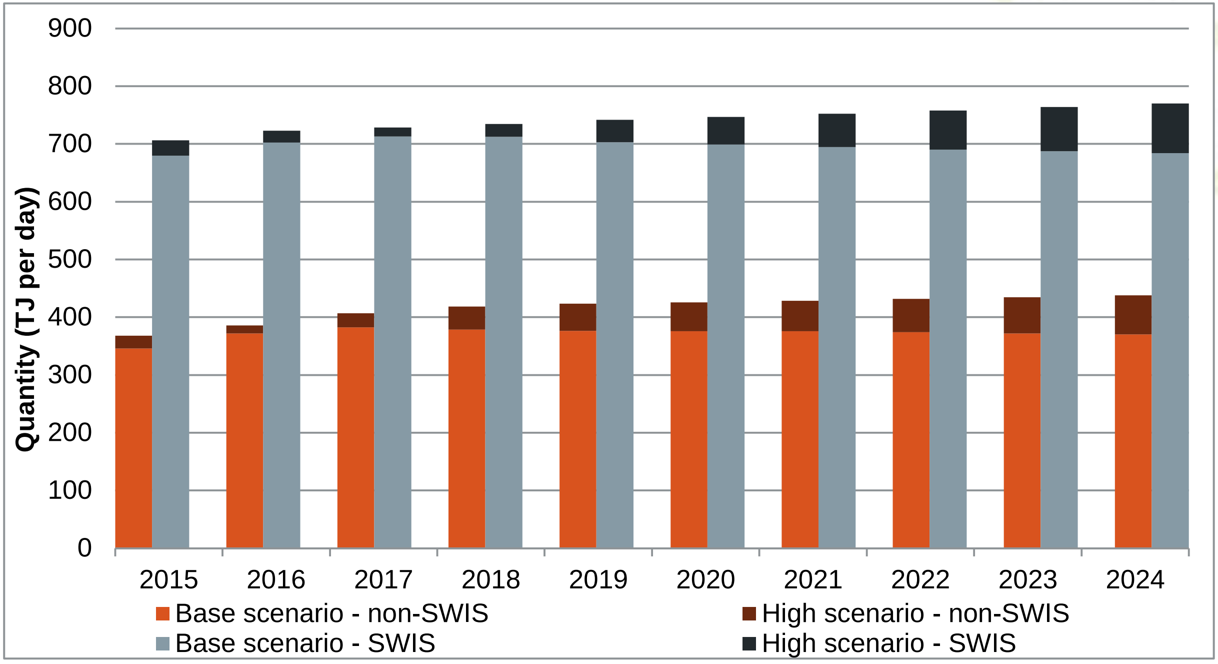
Source: DMP (2014*c), NIEIR forecasts 2015 to 2024.*

6.2.1 Gas demand forecasts in the SWIS and non-SWIS areas, 2015 to 2024

As discussed in section 6.2 above, new gas-consuming projects located in the Pilbara and Goldfields regions of WA are expected to lead to higher gas demand growth in areas located outside the SWIS than within, as shown in Figure ES.3 and Table 6.6.

47 Alinta Energy (2014).
48 TransAlta (2014).
49 Horizon Power (2014).
50 Monadelphous (2014).

Figure 6.13: Comparison of SWIS demand forecasts across different scenarios, 2015 to 2024



Source: NIEIR forecasts 2015 to 2024.

For the Base gas demand scenarios for both areas, Figure 6.13 shows a slow decline in gas consumption after growth in the initial years. This is due to the limited expected growth in demand for gas as a fuel for electricity generation within the SWIS, and the increased focus on energy efficiency as WA businesses seek to reduce costs in the current economic environment. By contrast, the High gas demand scenario for both the SWIS and the non-SWIS areas show continued growth, due to the lesser impact of energy efficiency measures and, in the non-SWIS area, the inclusion of additional projects yet to reach FID.

The quantity of gas forecast to be consumed in the SWIS and non-SWIS regions of WA is shown for each year of the forecast period in Table 6.6 below.

Table 6.6: Domestic gas forecasts, SWIS and non-SWIS (TJ per day), 2015 to 2024

Scenario		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Non - SWIS	Base	346	372	382	378	376	376	376	374	372	370
	High	368	386	407	418	423	426	429	432	435	438
SWIS	Base	680	702	713	712	703	699	695	690	687	684
	High	706	723	728	735	742	747	752	758	764	770

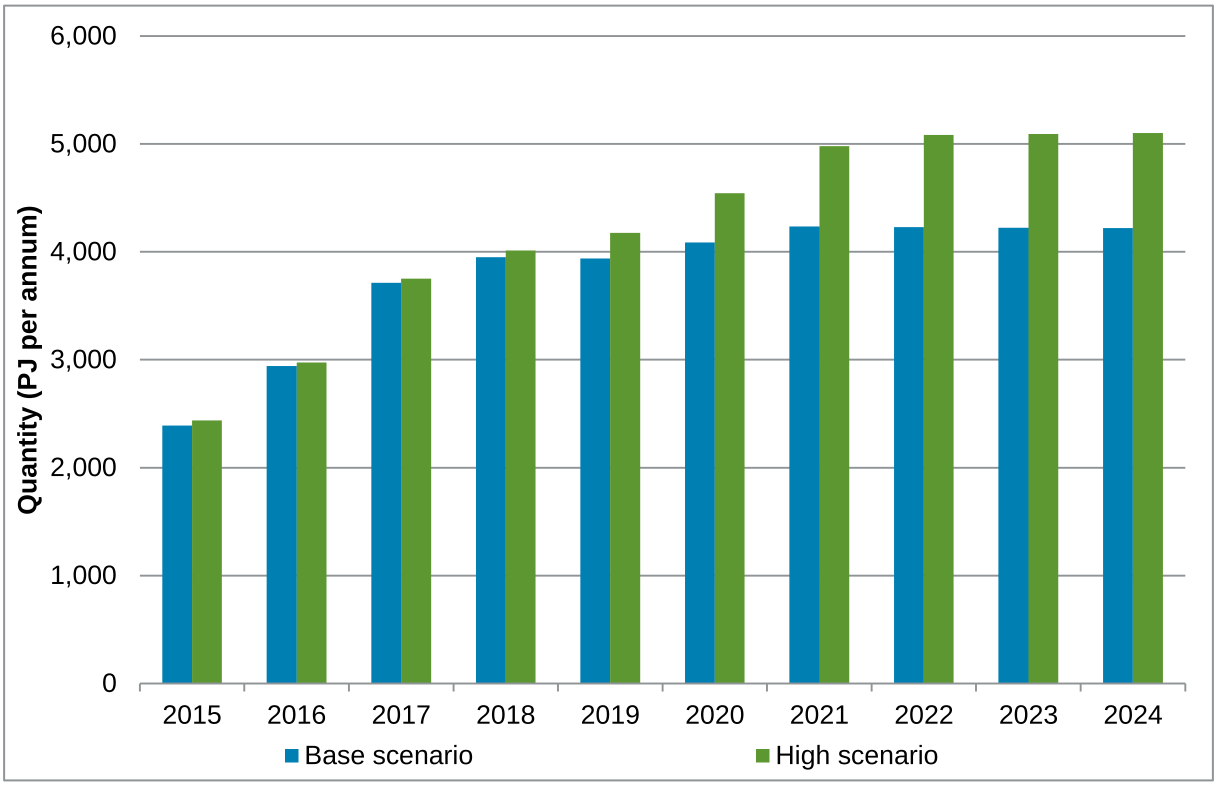
Source: NIEIR forecasts 2015 to 2024.

6.2.2 Total gas demand (domestic and LNG exports)

The forecasts of total gas demand for the Base and High scenarios are shown in Figure 6.14. Total gas demand is the sum of WA's domestic gas demand (discussed above) and LNG export requirements (use as feedstock and in production).

As shown in Figure 6.14, under the Base scenario, NIEIR forecasts total gas demand in WA will grow at an annual average rate of approximately 6.5 per cent from an estimate of 2,389 PJ per year in 2015 to about 4,219 PJ per year in 2024. In the High scenario total gas demand is projected to grow at an annual rate of 8.6 per cent per year to about 5,102 PJ in 2024.

Figure 6.144: Total gas demand forecasts (domestic and LNG), 2015 to 2024



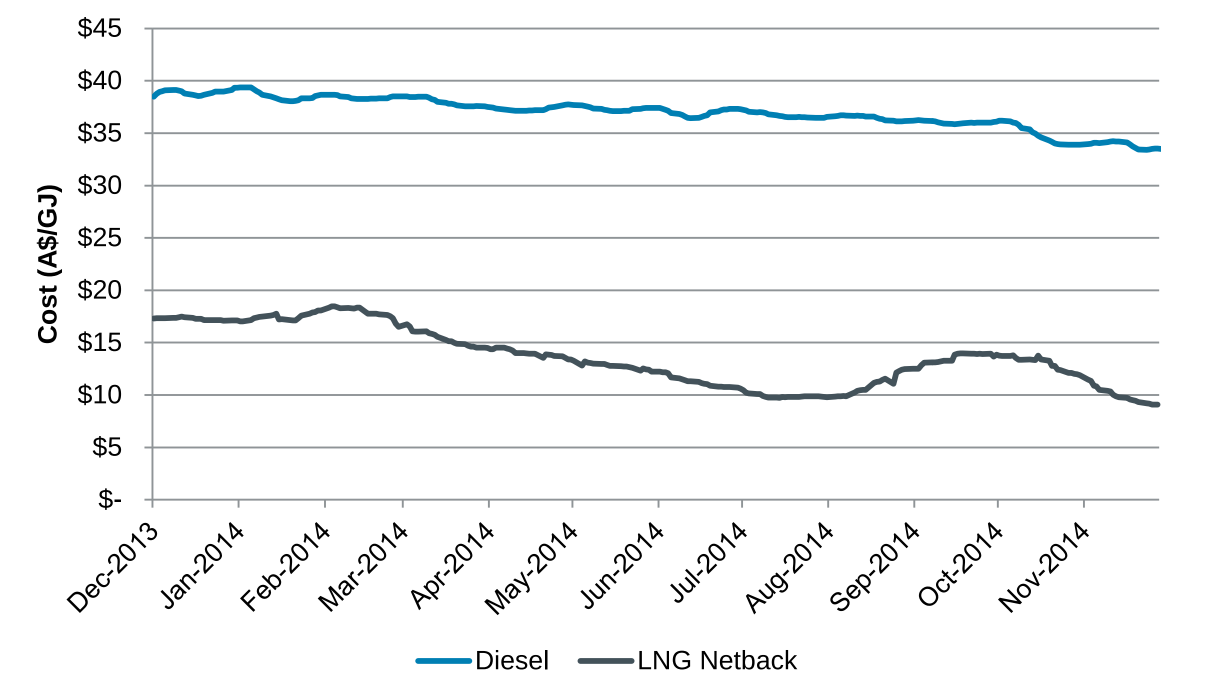
Source: NIEIR and IMO forecasts 2015 to 2024.

Across both scenarios, the strong growth in total gas demand is driven by the expected increasing demand for LNG exports. The most significant driver of increased production in the medium-term is the commencement of production at the Gorgon LNG facility expected to be mid to late 2015, the Wheatstone LNG facility in 2016 and the Prelude FLNG facility in 2017, discussed further in chapter 7. The High total gas demand scenario also assumes the Bonaparte facility starting, and Gorgon LNG, Wheatstone LNG and Pluto LNG expanding in 2019, 2020 and 2021, respectively.

6.2.3 *Possible conversion to gas from other fuel sources in non-SWIS areas*

The costs of generating electricity in remote areas are generally higher than in the SWIS, due to the costs associated with fuel and transport. Diesel is significantly more expensive than gas on a per GJ basis – as shown in Figure 6.15 below – even when compared to LNG netback rates (a proxy for the maximum expected domestic gas price). As a result, there is potential for conversion from diesel to gas for electricity generation or transport (haulage) to increase domestic gas demand over the forecast period.

Figure 6.15: Diesel compared with LNG netback price estimates, 1 December 2013 to 30 November 2014



Source: Courtesy of Argus LNG Daily Report, Argus Media Limited

Fuel conversions in WA from diesel to gas are already occurring. In August 2014, FMG started a project to switch one of its electricity generators to run on natural gas. This decision has underwritten the development of the FRGP in the Pilbara region[51].

Other large mining companies such as BHP Billiton and Rio Tinto are also investigating fuel substitution for their mining operations[52]. In addition, Mobile LNG Limited has indicated that it is considering two domestic LNG terminals (one in the Mid-West/Goldfields region and another in the Pilbara region)[53] to service these areas. These terminals have the potential to improve access to domestic LNG facilities not in close proximity to a pipeline, increasing the potential for further fuel conversions in the future.

A report by DAE in May 2014 also estimated that all diesel consuming operations using electricity generators in WA will be converted to gas by 2022. However, based on discussions with existing stakeholders on the potential for gas conversion, the IMO has established that the distance of relevant facilities from existing transmission pipelines remains a significant barrier. Greater distance from pipelines increases the cost to connect and convert mining operations to natural gas, making large-scale fuel conversion unlikely in

52 Sydney Morning Herald (2014).
53 Mobile LNG News (2014).

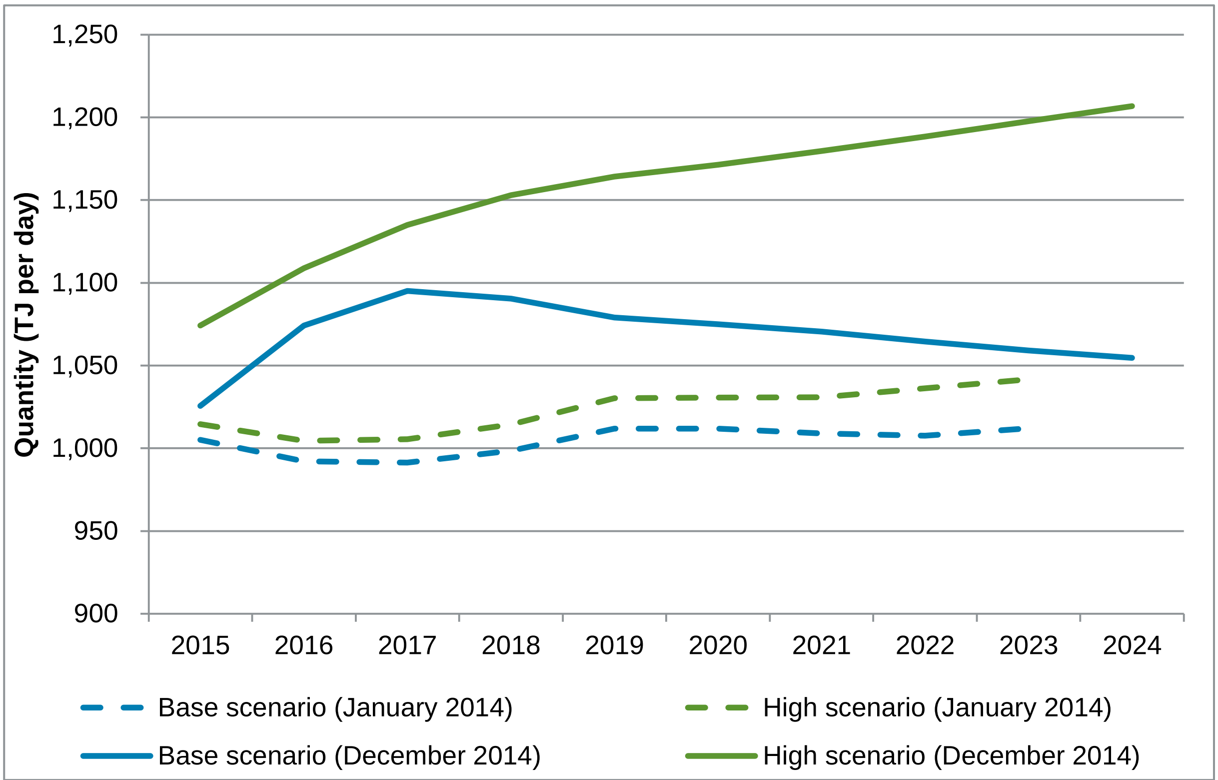
the short to medium-term. Further explanation of current and proposed developments related to the major gas pipelines in WA is contained in chapter 10.

The IMO acknowledges that potential exists for increases in gas demand driven by fuel conversion and some conversion projects relating to electricity generation have been included in the Base and High demand scenarios in this GSOO. However, estimates of diesel to gas conversions for mining haulage have not been included at this point. The IMO will continue to monitor the development of this emerging issue over time.

6.2.4 Comparison with January 2014 GSOO domestic gas demand forecasts

The demand growth forecasts outlined in the January 2014 GSOO and this GSOO are compared in Figure 6.16 below. As can be seen, the expected demand range in this GSOO (between the Base and High scenarios) forecasts growth in gas demand beyond that forecast in the previous edition.

Figure 6.16: Comparison of previous and current gas demand forecasts, 2015 to 2024



Source: NIEIR forecasts 2014 to 2023 (January 2014 GSOO) and 2015 to 2024 (December 2014 GSOO).

The January 2014 GSOO forecast annual average growth in gas demand of 0.4 per cent per year over the 2014-2023 period in the Base scenario, and 0.6 per cent per year in the High scenario. This GSOO expects slightly faster annual average growth in the expected gas demand range, at up to 1.3 per cent per year in the High scenario.

The higher expected growth compared to the January 2014 GSOO can be attributed to the:

- inclusion of more recent consumption data;

- increase in the number of projects that have attained FID and/or for which the proponents have contracted to commence further expansion;
- the inclusion of prospective projects (that have not attained FID) in the High gas demand scenario; and
- increased gas consumption assumptions relating to magnetite iron-related projects, including CITIC Pacific.

This increased growth in gas demand has been partly offset by increases in the forecast gas prices applied in this GSOO compared to those applied in the January 2014 GSOO. These increases have the effect of suppressing gas demand, particularly affecting the outer years of the gas demand forecast.

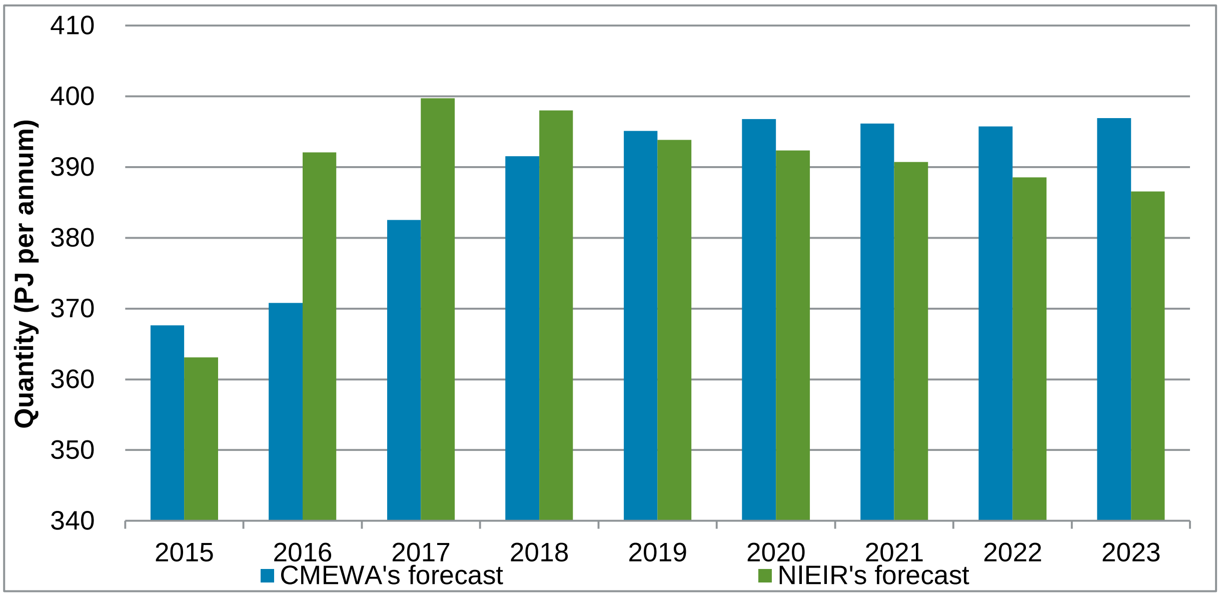
In estimating the effect of cost reduction initiatives driven by increases in gas prices, the IMO has been able to improve its forecast by considering gas efficiency in the demand forecast model separately for each delivery point on the gas transmission network, through understanding of patterns in gas usage, the use of historical pipeline and GBB data and through further discussions with stakeholders.

6.2.5 Comparison of WA 2014 forecasts

This section compares the domestic gas demand forecast developed for this GSOO with forecasts published in CMEWA's WA Resources Outlook in November 2014[54].

CMEWA's forecasts of domestic gas demand are compared against the Base demand forecasts for this GSOO in Figure 6.. The figure shows NIEIR's forecasts for this GSOO and CMEWA's 2014 forecasts are similar for the 2019 to 2023 period despite being developed differently.

Figure 6.15: Comparison of domestic gas demand forecasts, 2015 to 2024



Source: NIEIR forecasts 2015 to 2024 and CMEWA (2014).

[54] CMEWA (2014).

While the differences between the forecasts for the period up to 2019 are likely to be related to the timing of upcoming gas consumption in the respective forecasts, more detailed comparisons of assumptions underlying the forecasts are hard to perform. This is because the IMO collates information from public sources and consults with various key market participants to form its gas demand forecasts, while the CMEWA forecasts are based on a confidential survey of relevant CMEWA members and its consultant's proprietary databases.

7. Liquefied natural gas market

The linkage between the global LNG market and WA domestic gas market is strengthening, with WA expected to host at least four LNG export facilities by the end of 2024. In addition, domestic gas contracts are increasingly being signed at prices closer to LNG netback prices[55].

As a consequence, changes to the international LNG market – especially in the Asia Pacific region – are particularly of interest as they have the potential to shape the LNG export and domestic gas markets in WA.

This chapter reviews WA's LNG export market, presents an overview of the Asia Pacific LNG market, and discusses the risks the WA LNG export market is likely to face in the forecast period. A more detailed description of the international and domestic LNG markets can be found in the July 2013 and January 2014 GSOOs.

While the information outlined in this chapter is principally provided for context, some relevant information on the LNG market has been considered in the modelling of domestic gas prices.

7.1 The international LNG market

Consistent with the January 2014 GSOO, the outlook for the international gas market remains positive with the demand for gas expected to grow strongly[56] over the coming decades. International studies[57] indicate that international gas consumption will increase by 1.4 per cent to 2.6 per cent per year in the forecast period, while the LNG market is expected to grow by approximately 3.0 per cent to 3.9 per cent per year in the same period.

Growth is expected to be strongest in the Asia Pacific region, where gas consumption is anticipated to increase by around 6.5 per cent over the period from 2013 to 2020. The growth prospects for Asia Pacific gas demand reflect a number of considerations, including:

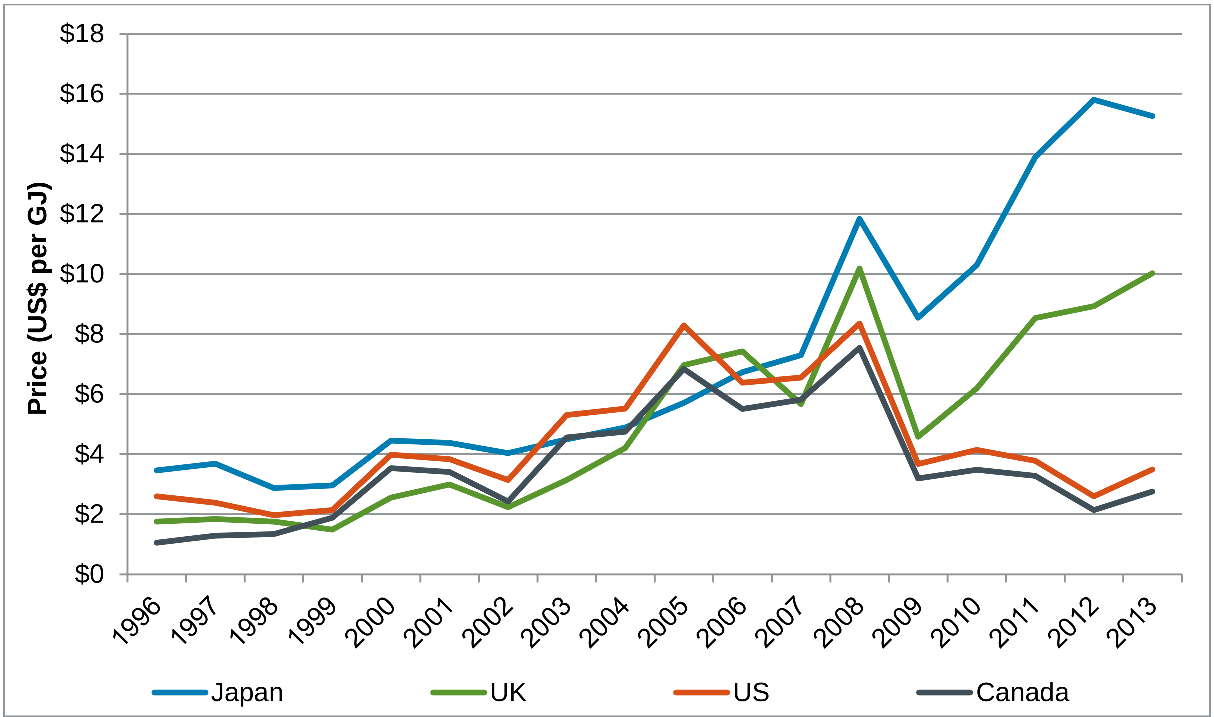
- the expectation that major LNG consumers such as Japan, South Korea and Taiwan will remain the largest international buyers of gas, but face slowing growth rates; while
- China and India, along with other South East Asian countries, will drive growth in gas demand, as they increase their usage of gas in power generation, industrial and residential consumption due to the rapid urbanisation, motorisation, and economic development; as well as government reforms and energy policies of these countries;
- the commitment by various countries to reducing carbon emissions, such as the recent agreement between the US and China to reduce carbon emissions, which will likely see continued increases in gas use as gas-fired generation has a lower emissions intensity than coal-fired generation; and

55 Deloitte Access Economics (2014).
56 BREE (2014f)
57 BP (2014a), EIA (2014c), ExxonMobil (2014), IEA (2014), IEEJ (2013), OPEC (2014b), Royal Dutch Shell (2013), and Statoil (2014a).

- new international emission standards for shipping[58] and the development of an LNG trading and transhipment hub in Singapore that are anticipated to further increase demand for LNG exports in the Asia Pacific region.

In addition, price differentials (shown in Figure 7.1) between the Asia Pacific region (approximated by Japanese LNG prices) and other LNG importing regions will continue to drive the expansion of LNG supply to the Asia Pacific region[59].

Figure 7.1: International gas prices (nominal) by region, 1996 to 2013



Source: *BP (2014b).*

Note: Prices are converted to US$/GJ. Japanese prices displayed are LNG prices while the other prices are for natural gas; prices for the United Kingdom (UK), US and Canada are based on National Balancing Point, Henry Hub and Alberta prices, respectively.

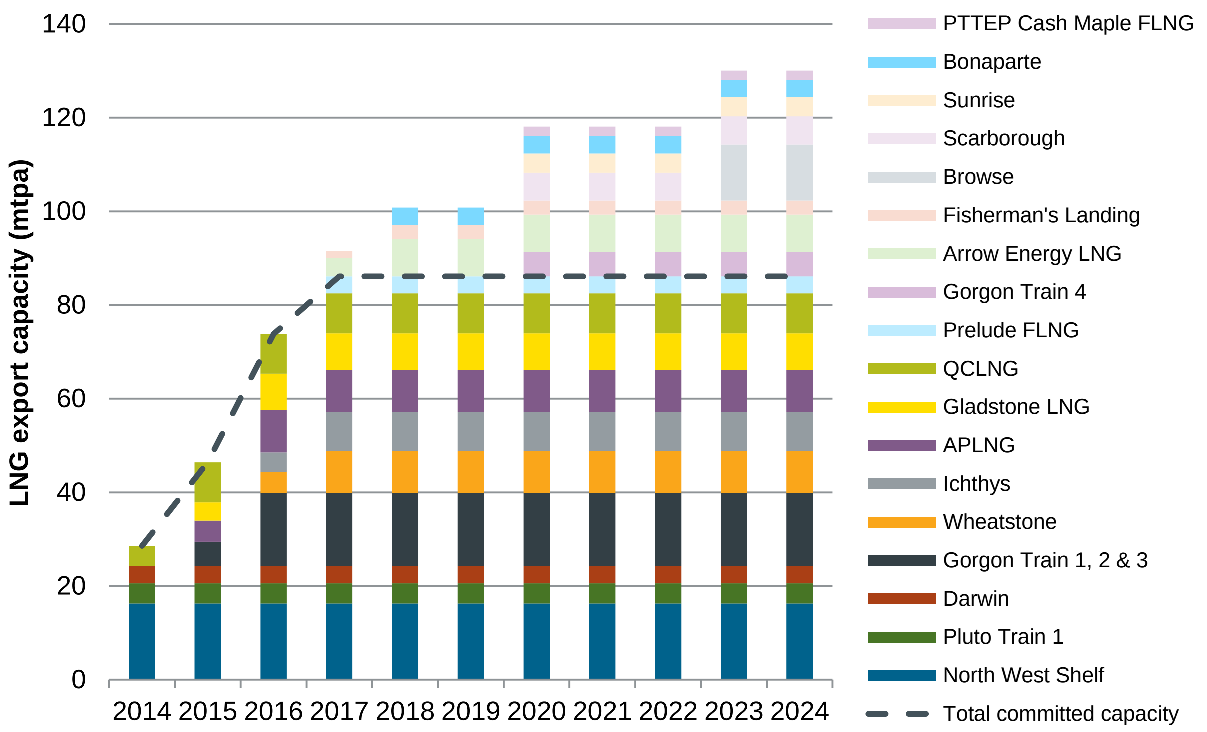
7.2 The Australian LNG market

Australia is currently the third largest LNG exporter in the world, after Qatar and Malaysia[60]. Australia is capable of supplying 24 mtpa, accounting for approximately 8 per cent of the international LNG liquefaction capacity. 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 (with 23.9 per cent of international LNG export capacity)[61]. BREE[62] forecasts that LNG exports from Australia will grow from approximately 27.6 mtpa in 2014-15 to about 86.5 mtpa in 2034-35 and further increase towards 94.6 mtpa in 2049-50.

58 See January 2014 GSOO.
59 As the largest international importer of LNG, Japanese LNG prices are a good benchmark for Asia Pacific LNG prices.
60 IGU (2013), Qatar and Malaysia account for approximately 32.6 per cent and 9.7 per cent, respectively, of total international LNG exports in 2012.
61 Innovative Energy Consulting (2012), assuming existing LNG export capacity that has approvals remains unchanged.
62 BREE (2014g)

Australia's current, soon to be completed and prospective LNG facilities are shown in Figure 7.2. Out of the 18 facilities, 10 LNG facilities are operational or have been committed – 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 (NWS, Pluto, Gorgon, Wheatstone and Prelude LNG facilities).

Figure 7.2: Total estimated LNG export capacity in Australia, 2014 to 2024

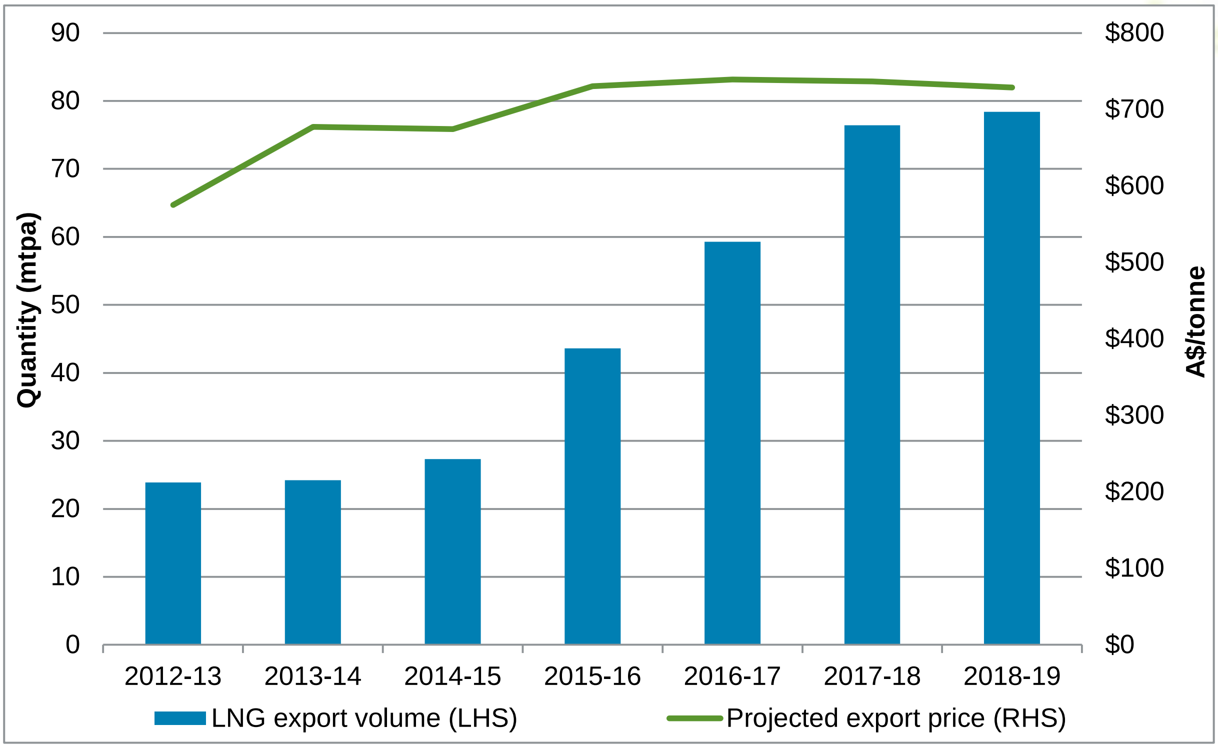


Source: *Respective corporate websites and Groupe International des Importateurs de Gaz Naturel Liquifie (2014).*

Note: Projects above the committed capacity line are speculative (pre-FID) and may not be realised in the 2015 to 2024 period. Other potential LNG projects, including as Caldita-Barossa, Crux, Equus, Poseidon, Thebe and Crown, are not reflected in this figure as there are no known indicative dates and/or export capacities. The recent Hess News Release (2014) for the Equus project does alter the Australian LNG export capacity.

BREE projects that Australian LNG exports will grow at a rate of approximately 22.4 per cent per year from 24.3 to 78.4 mtpa for the period 2013-14 to 2018-19 (see Figure 7.3), with a nominal export value of about $57.1 billion in 2018-19.

Figure 7.3: LNG exports and pricing (nominal), historical and projected (Australia), 2012-13 to 2018-19



Source: BREE (2014d).

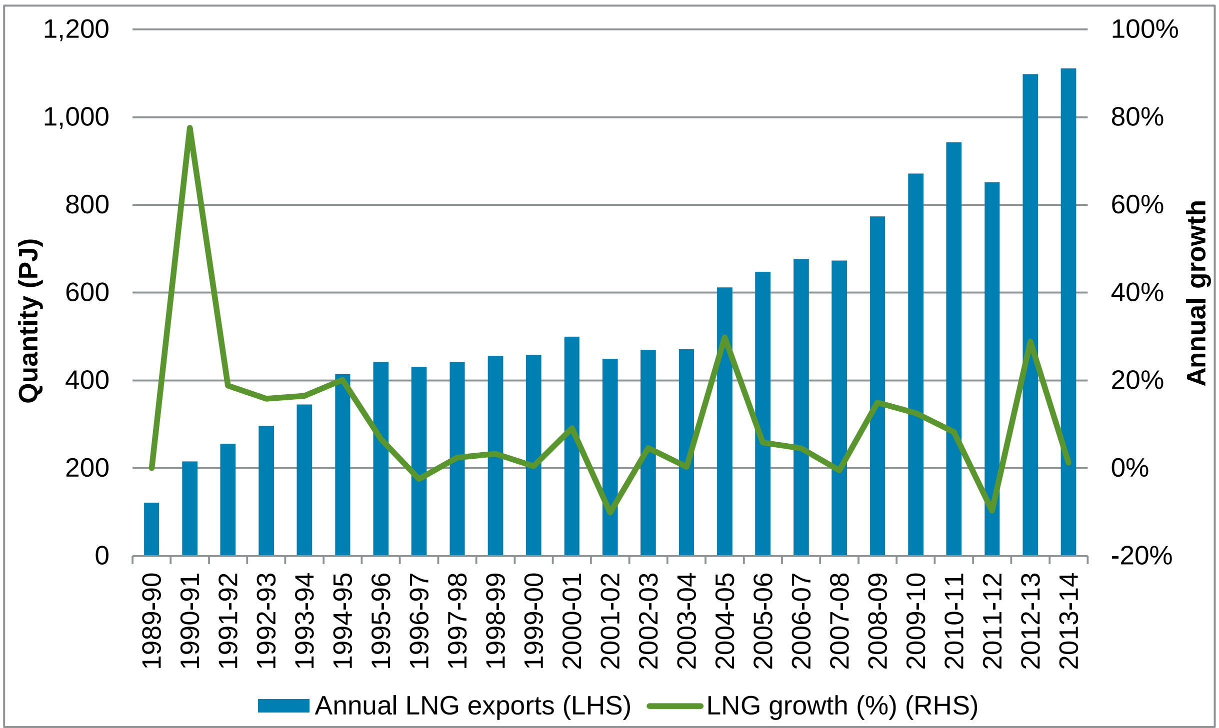
Note: These are BREE's forecasts and are not used in NIEIR's forecasts of LNG netback prices and LNG feedstock requirements.

BREE's updated forecasts for September 2014, shown in Figure 7.3, are consistent with NIEIR's view that LNG prices are expected to rise over the 2015-16 to 2018-19 period.

7.2.1 *WA LNG market*

Since 1989, more than 250 million tonnes (mt) of LNG in total have been delivered to customers under long-term 'take or pay' contracts, short-term contracts or spot cargoes. Figure 7.4 shows LNG exports from WA LNG facilities over the period from 1989-90 to 2013-14. DMP reports WA exported approximately 1,111 PJ (20 mt) in 2013-14 as LNG, a 1.2 per cent increase from 2012-13.

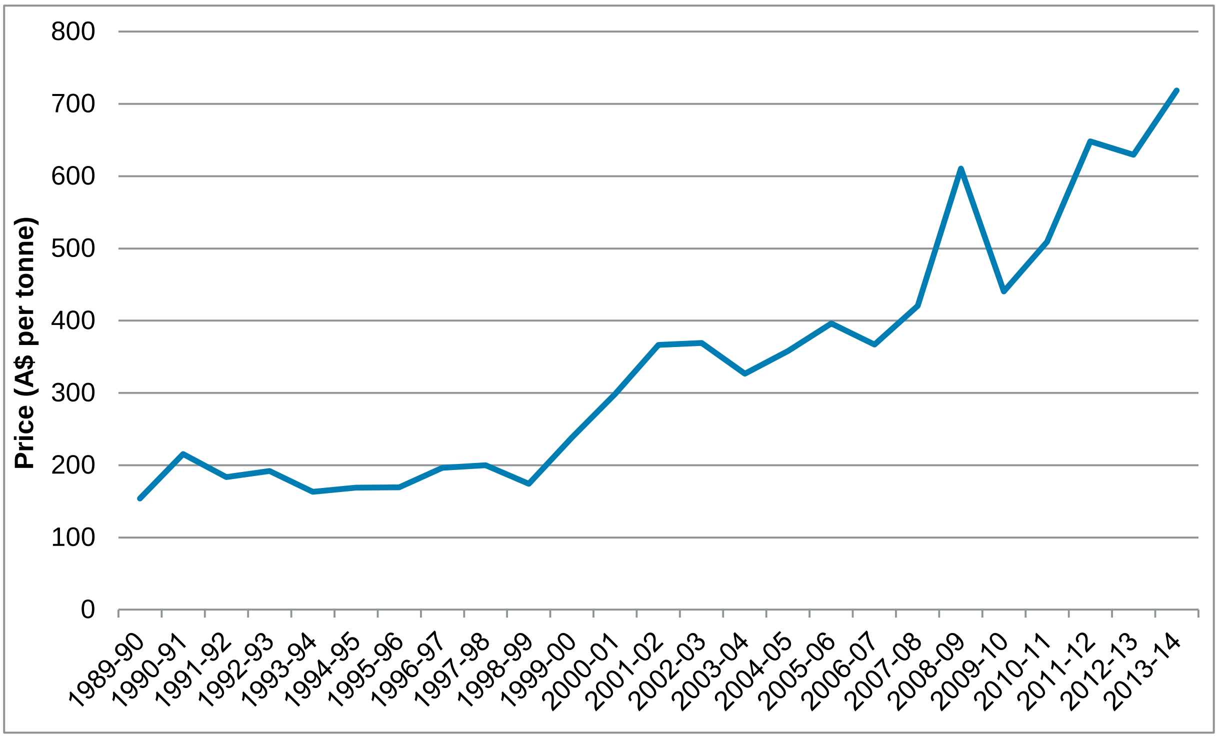
Figure 7.4: WA LNG exports, 1989-90 to 2013-14



Source: DMP (2014c).

Reviewing LNG prices from 1989-90 to 2013-14, Figure 7.5 shows nominal LNG export prices have remained relatively stable from 1989-90 through to 1998-99 before rising from 1999-00 until 2008-09. In 2009-10, world LNG prices fell due to the impact of the Global Financial Crisis on major gas-consuming countries. Since then prices have steadily recovered, reaching in excess of $700 per tonne (approximately $12.63 per GJ) in 2013-14.

Figure 7.5: WA LNG export prices (nominal), 1989-90 to 2013-14



Source: DMP (2014c).

Existing and committed LNG export facilities in WA are shown in Table 7.1. This table shows that WA has an existing total LNG export production capacity of 20.6 mtpa. The NWS JVs' LNG facility is currently the largest operational LNG export facility in Australia, with almost four times the export capacity of the next largest facility – Pluto, also located in WA[63]. Both facilities are operated by Woodside Energy.

Table 7.1: Existing and committed LNG export facilities in WA, 2014

LNG Facility	Nominal capacity (mtpa)	Commissioned date/ Expected commissioning	Status
NWS Train 1	2.5	1989	Operational
NWS Train 2	2.5	1989	Operational
NWS Train 3	2.5	1992	Operational
NWS Train 4	4.4	2004	Operational
NWS Train 5	4.4	2008	Operational
Pluto Train 1	4.3	2012	Operational
Gorgon Train 1	5.2	Anticipated to be operational in 2015 (LNG facility only)	Under construction
Gorgon Train 2	5.2		Under construction
Gorgon Train 3	5.2		Under construction
Wheatstone Train 1	8.9	Anticipated to be operational in 2016	Under construction
Wheatstone Train 2			Under construction
Prelude FLNG	3.6	Anticipated to be operational in 2017	Under construction
Total LNG export capacity (by 2024)	48.7		

Source: North West Shelf corporate, Chevron Australia and APPEA websites.

At the time of this report, two onshore LNG facilities (Gorgon and Wheatstone) and one FLNG facility (Prelude) are under construction. These facilities are expected to add approximately 28.1 mtpa of LNG export capacity in WA by the end of 2024[64], to a total of 48.7 mtpa. This will increase WA's share of international LNG export capacity from 6.3 per cent in 2012[65] to approximately 13.7 per cent by the end of 2017, by which time Australia is expected to provide 23.6 per cent of the world's LNG supply.

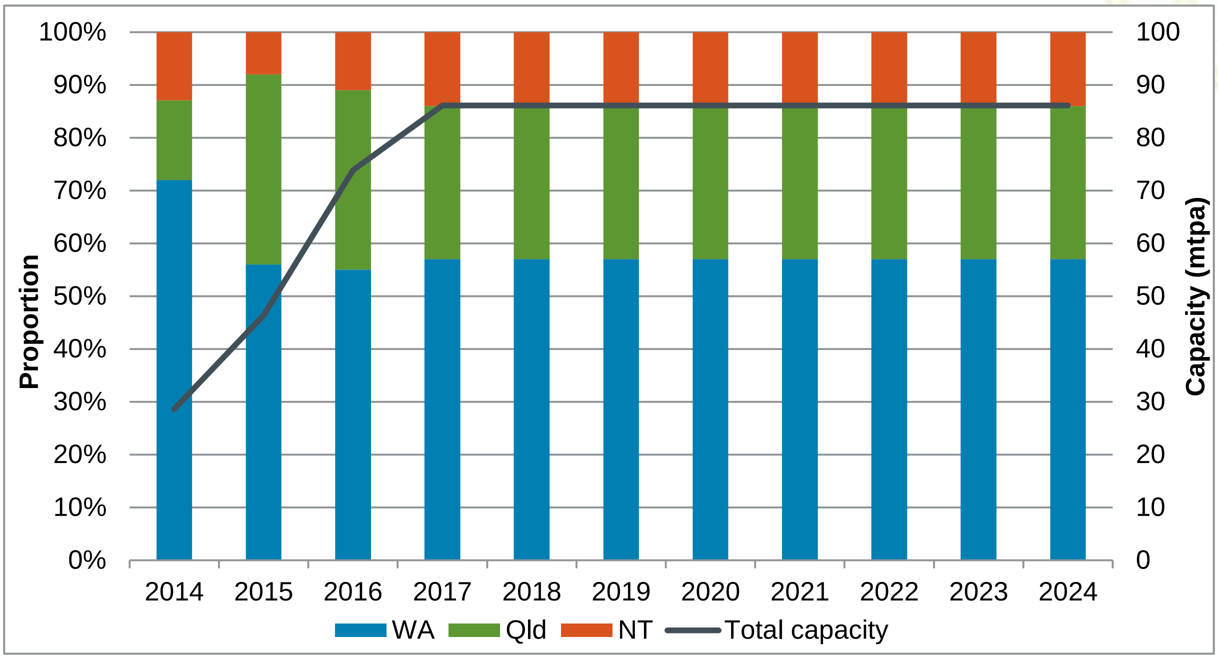
For the 2013 calendar year, WA's LNG production capacity accounted for approximately 85 per cent of Australia's total LNG export capacity.

As shown in Figure 7.6, the expected commissioning of the Queensland and Northern Territory LNG facilities in coming years, coinciding with the start of the new WA LNG facilities outlined in Table 7.1 above, means that WA's share of total Australian LNG

[63] By the end of 2022, Gorgon JV's LNG facility is expected to become Australia's second largest LNG export facility.
[64] Woodside (2012). While the nominal LNG capacities are often reported, these capacities are almost never reached. Typical utilisation rates for WA LNG facilities for 2008 to 2012 have ranged from more than 90 per cent to 97.6 per cent of maximum capacity.
[65] Grattan Institute (2013).

export capacity will fall to just under 60 per cent in 2015 and remain at a similar level throughout the forecast period.

Figure 7.6: Share of LNG export capacity by Australian states and territories, 2014 to 2024



Source: Respective corporate websites.

Note: Shares include the Prelude FLNG project. Proposed LNG projects that have not attained FID approvals are excluded.

7.2.2 *WA LNG capacity - under consideration*

Approximately 38 mtpa of additional LNG export capacity in WA is under consideration, but yet to attain favourable FID. The projects under consideration are listed in Table 7.2.

Table 7.2: Prospective LNG export facilities under consideration in WA

LNG export facility	Expected operator	Expected capacity (mtpa)	Type	Expected FID
Pluto Train 2	Woodside	4.3	Onshore	Unknown
Equus	Hess	Not applicable. However, gas is likely to be tolled through NWS LNG facility@@	Likely to be onshore	Hess has signed a non-binding letter of intent with NWS to toll gas through the NWS LNG facility.@@ FID is expected to be in 2017 or later.
Gorgon Train 4	Chevron	5.2	Onshore	Anticipated to be after the completion of Gorgon Train 3#
Wheatstone Expansion	Chevron	8.6	Onshore	Anticipated to be 2015 or later
Browse	Woodside	12*	Anticipated to be offshore^	Anticipated to be mid-2016[66]
Bonaparte	GDF Suez or Santos	2	Unknown, under review^	Unknown^
Scarborough**	ExxonMobil	6 or 7	Anticipated to be Offshore	Anticipated to be 2015 or later
WA LNG export capacity under consideration		**~38.1**		

Source: Respective corporate websites.

Notes: *See Woodside (2014c). **According to Australian Mining (2014a) the Scarborough project has obtained environmental approval from the Commonwealth Government for an FLNG project. #According to Australian Mining (2014b), the fourth LNG train for the Gorgon project will not be decided until Chevron has gained a better understanding of costs in Australia. ^Santos (2014). @@ Hess News Release (2014).

[66] ABC News (2014c)

7.3 International LNG demand outlook

This section reviews the demand outlook for key international gas consumers in the Asia Pacific region.

7.3.1 Japan

Since September 2013, Japan has not generated any electricity from nuclear energy[67]. Prior to the Fukushima nuclear accident in 2011, nuclear energy had provided approximately 30 per cent of its power generation[68]. The accident and the subsequent plan to decommission Japan's nuclear generation fleet have made Japan more reliant on oil and gas-fired generation to power its economy.

However, the Japanese government has recently reinstated nuclear power in its latest energy policy. According to the Institute of Energy Economics Japan (IEEJ), four power companies have applied to Japan's Nuclear Regulatory Authority to review 19 nuclear facilities under the new nuclear regulations[69]. While the outlook for the potential restart of a first facility is positive[70], it remains unclear how many nuclear powered electricity generators will be restarted.

In a bid to reduce LNG prices paid by Japan and improve market transparency in the Asia Pacific LNG market, Japan has established a multilateral joint study group on LNG and hosted the third LNG Producer-Consumer Conference on 6 November 2014[71].

This bid to reduce prices and the timing and number of nuclear facility restarts has the potential to affect the international LNG market and LNG exporting countries such as Australia. Areas such as WA that export most of their LNG to Japan could be severely affected, facing reduced demand and possibly lower prices.

7.3.2 China

The outlook for Chinese gas demand remains bullish, with BREE forecasting gas consumption to grow from around 138 bcm in 2013 to 287 bcm in 2019[72]. In addition to increasing energy requirements resulting from rapid industrialisation, China's growing concern about the air quality in major cities has led to a pledge to take firm action on reducing carbon emissions[73], suggesting China will seek to reduce its reliance on coal-fired electricity generation in favour of lower emissions sources such as gas. This is consistent with key Chinese energy policies[74] that encourage an increasing proportional consumption of gas.

Although Chinese gas demand is anticipated to be the primary driver of growth in international gas demand, China intends to supply some of this future gas demand indigenously. The remainder of China's future gas consumption is likely to be imported via pipelines or LNG shipments. In May 2014, China signed a US$400 billion gas purchase

67 See BusinessWeek (2014).
68 World Nuclear Association (2013*)*.
69 Reuters (2014), IEEJ (2014).
70 The Guardian (2014b).
71 IEEJ (2014).
72 BREE (2014d*)*.
73 The Guardian (2014a).
74 The 12th Five Year Energy Development Plan, the 12th Five Year Plan for the Nationwide Development of City Gas for the period 2011 to 2015 and the recently published China's National Climate Change Program 2014-2020.

agreement with Russia to purchase 38 bcm of natural gas per year for 30 years from 2018 transported by pipelines[75], while a proportion of China's increasing gas demand is likely to be met by other gas producers from Myanmar, Turkmenistan and Kazakhstan[76]. BREE reports that China's LNG imports more than doubled from 3.1 bcm in March 2011 to 6.5 bcm in September 2014[77].

7.3.3 India

India is anticipated to increase its gas consumption in the forecast period[78] from around 39 mtpa in 2013 to 60 mtpa in 2020[79]. In a bid to improve gas allocation and encourage investment in the supply of gas, the Indian Government has taken steps to establish appropriate market signals, such as ordering an increase in gas prices in May 2014, linking prices of locally produced gas to global benchmarks in 2013, reducing subsidies for domestic buyers, embarking on gas market reform, starting gas exploration initiatives to open oil and gas exploration areas to private investment, approving LNG regasification facilities and permitting foreign investment and ownership of LNG facilities[80]. The Indian Government also permitted gas retail competition to industrial customers on a limited basis.

India may face significant challenges in securing sufficient gas supply to meet future demand, despite expanding its LNG import infrastructure to 25 mtpa. There is currently a lack of cross-country gas pipelines supplying gas to India, meaning the country will need to rely on seaborne LNG to meet some of its growing gas demand[81]. However, future gas demand may be inhibited if delays to planned infrastructure are experienced.

7.3.4 South Korea

South Korea is also expected to increase its gas consumption over the forecast period. South Korea remains the second largest importer of LNG behind Japan, accounting for approximately 16.6 per cent of the international LNG market in 2013[82]. As the third largest importer of Australian LNG, South Korea relies almost exclusively on seaborne shipments of LNG to satisfy approximately 99 per cent of its total natural gas consumption[83].

Gas usage in South Korea is rapidly expanding due to increasing demand in the power generation and residential sectors – accounting for more than 90 per cent of domestic gas consumption (growing from 10.6 mtpa in 1998 to 40.3 mtpa in 2013). As a result, South Korea has increased its LNG imports from 9.1 mtpa in 1998 to approximately 39.9 mtpa in 2013. BREE forecasts gas consumption in South Korea to decline between 2014 and 2015, due to the anticipated restarting of nuclear facilities that were closed due to safety concerns relating to the Fukushima accident, but then return to positive growth after 2015[84].

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[75] Bloomberg (2014).
[76] Reuters (2013b).
[77] BREE (2014c).
[78] BREE (2013)
[79] AFR (2014c).
[80] These are called the New Exploration Licensing Policy 1998, see Directorate General of Hydrocarbons (of India).
[81] At the time of this report, Dahej LNG (12.5 mtpa), Hariza LNG (2.5 mtpa), Dabhol LNG (5.0 mtpa) and Kochi LNG facility (1.5 mtpa) facilities are online. Several new import facilities such as Kakinada FLNG facility (3.5 mtpa, under consideration), Gangavaram LNG facility (5.0 mtpa, planned), Mangalore (5.0 mtpa, planned), Mundra LNG facility (5.0 mtpa, FEED) 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 2015 to 2024 period.
[82] BP (2014b).
[83] According to KEEI (2014), in 2013, out of a total of 40.64 million tonnes of LNG consumed, only 355 thousand tonnes were domestically produced.
[84] BREE (2014e)

7.4 Other LNG exporters

While the international gas demand for the forecast period is expected to remain robust, competition to supply gas to the international market is strong. The following sections provide updates on other LNG exporting countries competing with WA LNG exporters in the Asia Pacific region.

7.4.1 Qatar

Qatar continues to compete for Asia Pacific LNG customers by improving LNG contract terms to potential customers[85]. While competition from Qatar in the Asia Pacific will remain limited, due to its LNG export moratorium, any unexpected changes to the moratorium could affect international LNG supply dynamics in the forecast period. Interfax suggests the LNG export moratorium will not be lifted until 2019[86].

7.4.2 North America

The emerging North American LNG export market continues to show signs of expanding with more LNG export projects proposed to the Canadian and US export regulators. While the potential of Canadian and US LNG supply to the international market is significant, Canada and the US require export licences for gas sales to countries with which they do not have a Free Trade Agreement. Current low oil prices may also dampen or defer investment[87].

Since the January 2014 GSOO, 16 (7 in Canada and 9 in the US) new applications for an additional 141 mtpa and 30.6 mtpa of LNG export capacity have been submitted to Canadian and US regulators respectively, while 12 applications totalling approximately 130.2 mtpa LNG export capacity have obtained approval (8 in Canada and 4 in US).

While the US has not announced a limit to the total LNG quantity the US Energy Information Administration (EIA) is willing to consider, the EIA's 2014 study on LNG exports[88] suggests up to 157 mtpa of LNG exports may be considered.

If US and Canadian regulators approve all existing gas export applications, up to an additional 441.7 mtpa[89] (on top of the capacity that has already been approved in the US and Canada) may enter the LNG supply market between 2017 and 2024. This quantity has the potential to create a glut in international LNG supply[90], and may significantly impact the price of LNG internationally.

According to BREE[91], Australia, Qatar and the US are anticipated to dominate the LNG supply market by 2020.

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85 Reuters (2013a).
86 Interfax (2013b).
87 AFR (2014d).
88 The export scenarios examined in the EIA's (2014b) analysis finds domestic gas prices rises by four to 11 per cent when exports are limited to 12 bcf/day (approximately 80 mtpa) and 20bcf/day (approximately 157 mtpa), which is significantly lower than all the projects under consideration.
89 Some gas export facilities may not be commercially viable if they do not obtain non-FTA export approvals and others may withdraw their applications.
90 Note the total LNG export figures do not include speculative LNG projects in Canada.
91 BREE (2014f).

7.4.3 Russia

Potential gas supply from Russia to the Asia Pacific market continues to be a key factor, due to its proximity to Japan, China and South Korea, three of the largest LNG consumers in the region. While there are ongoing international trade sanctions against Russia over the incursion in Ukraine, gas supply from Russia to some neighbouring countries such as China appears to be unaffected.

According to Nikkei Asia Review, Russia is also proposing to build an undersea gas pipeline from Sakhalin to Hokkaido, to allow Russia to supply gas to Japan[92]. If this is being considered by the Japanese government, it will add a significant competitive pressure for WA LNG exporters.

7.4.4 Singapore

Singapore further progressed into a potential Asia Pacific LNG supply and trading hub with the completion of the second phase of the Singapore LNG (SLNG) terminal expansion in early 2014.

By the end of 2018, phase three of the SLNG terminal is expected to be completed, bringing the storage terminal capacity to 11 mtpa out of a total expected final capacity of 15 mtpa[93]. The increase in LNG storage capacity will allow the SLNG terminal to accept a full cargo from a Q-max LNG carrier – the largest LNG transport ship currently available.

Pavilion Energy, a Singapore Government owned subsidiary, is also working with the Singapore Stock Exchange, International Enterprise Singapore, Singapore's Trade Ministry and regional governments to develop a price indicator for Singapore[94]. The LNG price indicator has the potential to support LNG redistribution, LNG bunkering and the expansion of the LNG spot market in the Asia Pacific and the South East Asian regions.

Singapore's intention to develop its LNG expertise, coupled with its fuel bunkering and shipping expertise (with the assistance of Pavilion Energy) and its location is expected to establish Singapore's unique LNG position in the Asia Pacific market[95], facilitating greater competition in the region. Several international companies have also recently moved their LNG and oil marketing and/or shipping divisions to Singapore[96].

7.5 Risks to the WA LNG export market

7.5.1 The potential end of premium LNG pricing in the Asia Pacific region

Since the January 2014 GSOO, more long-term LNG supply contracts signed between LNG exporters and other countries have been delinked from oil indexes. For example, Tokyo Electric Power Company (TEPCO) recently signed a 17 year LNG agreement with BP Singapore indexing LNG prices to Henry Hub prices in September 2014[97].

[92] Nikkei Asia Review (2014).
[93] As there are three more potential sites for storage tanks reserved for the SLNG terminal, the total capacity of the SLNG storage terminal may exceed 15 mtpa.
[94] NASDAQ (2014).
[95] Singapore is already the largest fuel bunkering location internationally and already commands 17 per cent of the total bunkering market share in 2010.
[96] BG Group, Chevron, Gazprom, Yamal LNG JV and Woodside have recently started their LNG related operations in Singapore.
[97] TEPCO (2014).

7.5.2 The continuing delinkage to oil in the pricing of LNG

While delinking oil pricing from LNG prices is a significant change in the market pricing mechanism, a fall in LNG contract prices is unlikely at this point as the average break-even cost is estimated to be approximately US$14 per mmbtu (around A$15.54 per GJ) for new LNG projects[98]. It is more likely that restrictive destination clauses within LNG sales contracts will be dropped, increasing the flexibility of LNG international trade and re-exports of LNG cargoes. This would allow the management of LNG supply in the Asia Pacific region to be structured similarly to the management of oil products.

However, there are likely to be some limits to this delinking in the short to medium-term as:

- it will depend on the establishment of a proper Asia Pacific LNG price reference (noting that both Singapore[99] and Japan[100] are currently developing new pricing mechanisms for the Asia Pacific region);
- it is likely new LNG pricing formulas will only be introduced to new LNG supply contracts; and
- oil price delinkages are likely to remain limited to certain brownfield LNG redevelopment projects and less established LNG sellers looking to establish a foothold in the international LNG market[101]. Greenfield LNG developments internationally still require stable long-term contracts to facilitate access to financial capital.

7.5.3 High relative costs of LNG production in Australia

BREE recently confirmed that WA has one of the highest long-run marginal costs of gas production and liquefaction when compared to a sample of LNG export locations in the US, East Africa and the Asia Pacific[102]. As a high cost producer of LNG internationally[103], WA is at risk of displacement in the LNG supply chain when several long-term LNG export contracts start to expire from 2016 (see the January 2014 GSOO for more details).

A 2014 report from Oxford University[104] also highlights that Australia's ability to compete globally could be severely undermined by high operating costs, despite critical advantages in terms of geographic location and domestic expertise for LNG. However, the report suggests brownfield developments based on the expansion of existing plants remain economically viable. In addition, the potential of FLNG projects such as Prelude may halt the upward pressure on LNG development costs in WA.

7.5.4 Availability of unconventional gas to international gas supply

The timing and availability of unconventional gas to the international market from other countries apart from the US has the potential to significantly alter international gas supply. According to the EIA's 2013 assessment of shale gas resources for 40 countries, China

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98 Interfax (2013a). The outlined figure is an average (some projects have a break even cost lower than US$12/mmBtu, some between US$12-14/mmBtu, some above US$14/mmBtu).

99 NASDAQ (2014).

100 Interfax (2014).

101 Risk (2013). The pricing slopes of LNG linkages are more likely to be weakened, or a weighted average between oil-linked and hub pricing to be introduced. This is consistent with Credit Suisse's presentation at the Singapore International Energy Week 2013.

102 BREE (2014f).

103 Macquarie Equity Research (2012), Credit Suisse Global Equity Research (2012), Deutsche Bank (2012) and Deloitte (2013b) and McKinsey (2013) also provide a breakdown of cost estimates for LNG projects in Australia.

104 Oxford University (2014).

holds the largest estimated reserves of shale gas followed by Argentina, Algeria, Canada, the US and Mexico[105]. With China exploring intensively for unconventional resources, exports of coal seam gas (CSG) as LNG commencing from Queensland, and the US ready to export shale gas as LNG, the timing and the quantum of unconventional gas contributing to international gas supply could alter the international gas market considerably.

7.5.5 Potential changes to LNG purchasing behaviour in the Asia Pacific region

According to the Energy Market Authority of Singapore, LNG is increasingly being sold in smaller parcels, with shorter contracts and spot cargoes for quantities of LNG of 0.5 mtpa or less[106]. This practice may lead to the corrosion of price advantages associated with purchasing LNG in larger quantities.

In addition, LNG purchasers have started to consider different purchasing arrangements from international LNG sellers. In January 2013, Chubu Electric and Kogas signed the first international joint LNG purchase agreement in Asia with Eni, allowing Chubu Electric and Kogas to share quantities of LNG[107].

According to Interfax, since the first collective purchase agreement concluded, collective purchasing through the formation of an LNG purchasing group has been further discussed by LNG purchasers in the Asia Pacific region, with Japan and India considering forming an LNG buyers group[108]. Other commercial entities such as TEPCO and Chubu Electric formed an alliance[109] in October 2014 to source approximately 40 mt from the international LNG market[110]. This trend, which would be supported by the establishment of an LNG trading hub in Singapore, has the potential to move LNG purchasing toward more flexible short-term arrangements.

105 EIA (2013b) reports China, Algeria, Argentina, Canada, US and Mexico hold 1,115 tcf, 802 tcf, 707 tcf, 573 tcf, 567 tcf, and 545 tcf of shale resources respectively.
106 EMAS (2013).
107 Chubu Electric (2013).
108 Wall Street Journal (2014).
109 Wall Street Journal (2014b).
110 Interfax (2014)

8. Gas supply and capacity forecasts

This section provides an overview of gas supply in the WA domestic gas market at the wholesale level, including an outline of major domestic gas suppliers and change in production capacity over time [111].

In addition, this chapter presents the IMO's forecast of potential supply for the forecast period and projections of likely available domestic gas production capacity.

8.1 WA domestic gas supply overview

8.1.1 Introduction

Natural gas supplied to the WA domestic market is produced by eight domestic gas production facilities owned by various entities and JVs (see section 3.3.1). Domestic gas production has grown rapidly since the completion of the KGP in 1984, Varanus Island in 1986, and Harriet and East Spar domestic facilities in 1996. The smaller Dongara and Beharra Springs facilities were also added in 1971 and 1991, respectively. Domestic gas production capacity further expanded in 2011, with the commencement of the Devil Creek facility, and in 2013, with the commencement of the Macedon and Red Gully facilities. Domestic gas production capacity is expected to increase further over the forecast period when the Gorgon and Wheatstone domestic gas facilities commence operation.

From the eight domestic gas production facilities (named in Table 8.1 below), domestic gas is marketed and sold in a number of different ways, namely;

- jointly via the production facility JV;
- directly by a participant of a production facility JV;
- via intermediary third parties[112]; and
- via short-term and secondary gasTrading platforms.

Although short-term domestic gas sales are increasing, this segment remains a small part of the WA domestic gas market[113] (see section 3.2).

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111 For a brief history of WA's domestic gas supply, please refer to chapter 3 of the January 2014 GSOO.

112 An example of an intermediary third party is Tap Oil. Future intermediaries include parties that toll gas through existing domestic gas production facilities.

113 Based on data reported by gasTrading, short-term trades via its platform has increased from an average of approximately five to 15 TJ per day over the January 2012 to October 2013 period. It is also understood there are also four market participants in the WA domestic gas market that purchase its gas on a month-to-month basis. The IMO has not been provided with the quantity of short-term trades on Energy Access Services Pty Ltd's platform or by Apache Energy's short-term trading arrangements.

The nameplate capacity of each domestic gas production facility can be seen in Table 8.1. This table also shows the peak day and average production of each gas production facility supplying the domestic market from Q4 2013 to Q3 2014.

Table 8.1: Domestic gas production facilities average production, Q4 2013 to Q3 2014

Facility	Nameplate capacity (TJ per day)	Peak production October 2013 to September 2014	Day of peak production	Average production			
				Q4 2013 (TJ per day)	Q1 2014 (TJ per day)	Q2 2014 (TJ per day)	Q3 2014 (TJ per day)
Beharra Springs	19.6	19.8	5/10/2013	10.2	9.2	13.9	18.1
Dongara	7	2.5	4/9/2013	2.1	1.8	1.7	1.4
Devil Creek	220	172.5	22/11/2013	135.6	69.6	65.8	76.2
KGP	630	671.9	1/8/2013	443.6	459.2	470.0	493.7
Macedon	200	213.1	10/9/2013	164.5	141.5	142.9	152.3
Red Gully	10	14.7	14/4/2014	7.6	6.0	4.0	7.7
Varanus Island	390	371.7	3/1/2014	272.5	299.4	271.6	234.9
Total	**1476.6**			**1,036.1**	**986.7**	**969.9**	**984.3**

Source: IMO GBB data.

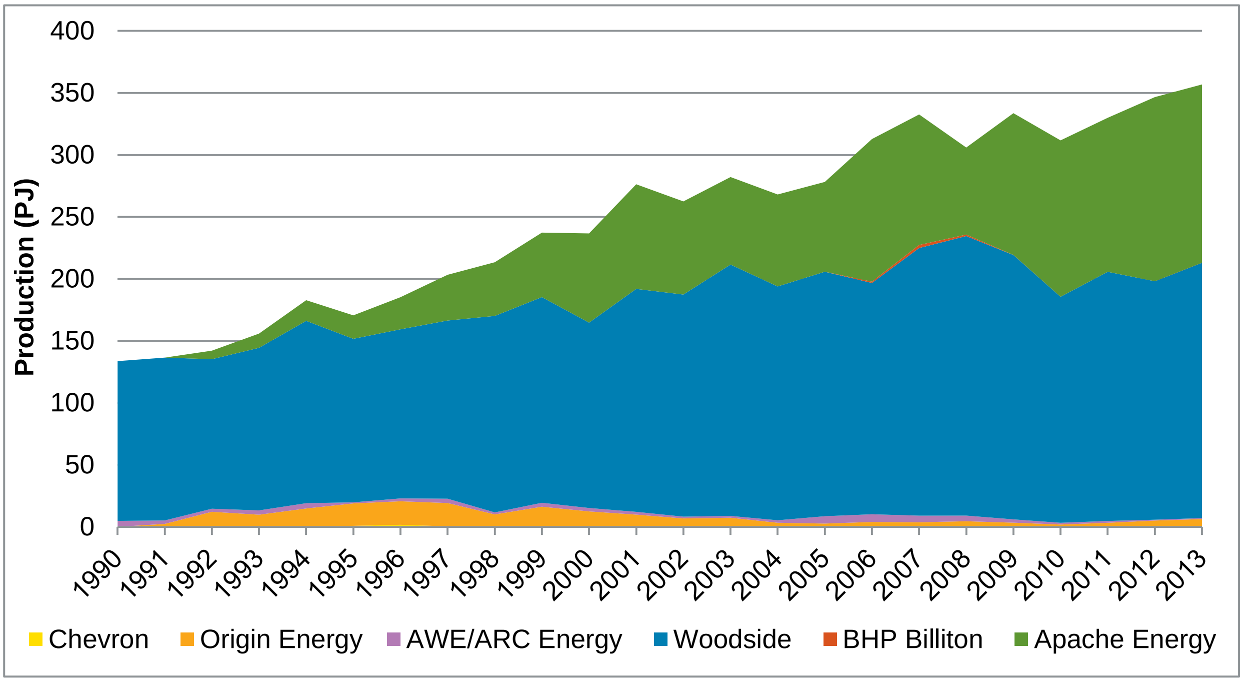
Note: Varanus Island includes Harriet and East Spar production facilities.

This table shows that although all facilities (besides Dongara and Devil Creek) operate near or above their nameplate capacity during peak production periods, their average output is much lower.

8.1.2 Historical gas production

Annual production data by operator for the 1990 to 2013 period is presented in Figure 8.1 and shows that prior to 2013 gas was supplied predominantly by two operators – Woodside (from the KGP facility) and Apache Energy (from the Varanus Island and, since 2011, Devil Creek facilities).

Figure 8.1: WA domestic gas sales by operator, 1990 to 2013



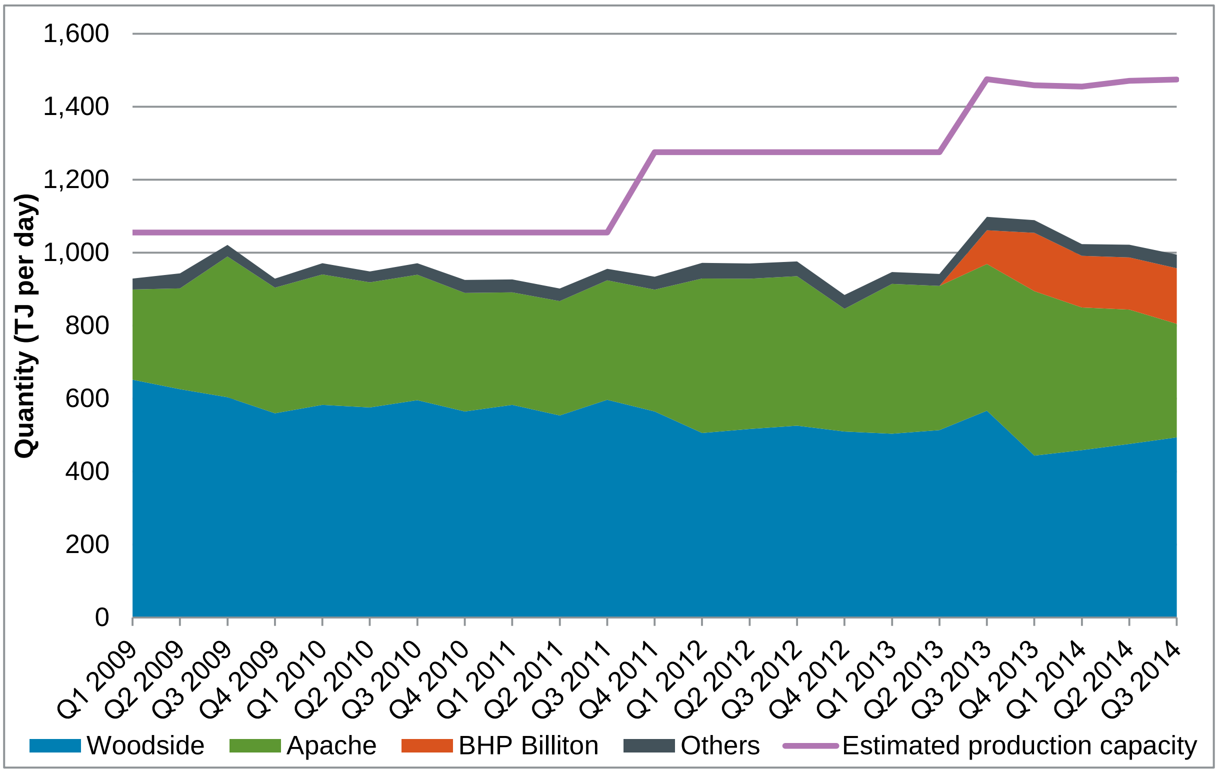
Source: APPEA quarterly production data (1990 to 2013).

While historical domestic gas production was mainly from these three facilities, supply in the upcoming forecast period is also expected to come from the BHP Billiton operated Macedon, Empire Oil and Gas operated Red Gully, and Chevron operated Gorgon and Wheatstone domestic gas facilities. While this introduces a number of new gas producers into the market, these facilities continue the reliance on the Carnarvon Basin as a source of gas for domestic demand (discussed further in chapter 9).

Domestic gas production for the period from Q1 2009 to Q3 2014 is shown in Figure 8.2. The figure shows that while production capacity has increased since Q4 2011 (due to the commencement of the Devil Creek, Macedon and the Red Gully facilities), the total gas production has remained largely unchanged. As a result, spare gas production capacity in the WA domestic market has increased over the same period.

The increase in gas production seen in Q3 2013 is likely associated with the injection of gas into the MGSF.

Figure 8.2: Reported and estimated domestic gas production by operator, Q1 2009 to Q3 2014

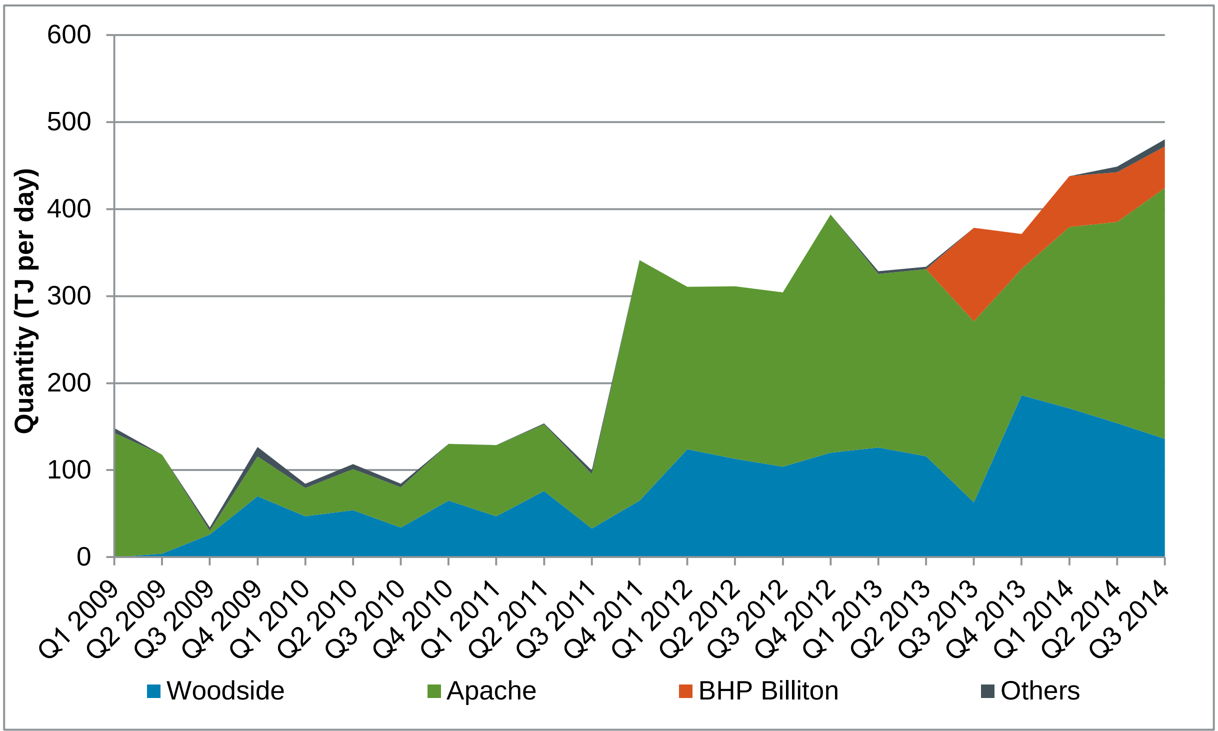


Source: Quarterly production reports from respective corporate websites and IMO GBB data.

8.1.3 *Available production capacity*

Available gas production capacity by operator in the WA domestic gas market for the period from Q1 2009 to Q3 2014 is shown in Figure 8.3. This figure suggests the tight market conditions experienced in the 2009 to 2011 period eased with the start of operations at the Devil Creek gas production facility in Q4 2011. Since the start-up of Devil Creek, the majority of spare capacity in the domestic market is held by Apache Energy and Woodside, which are understood to not be fully contracted at the time of this report.

Figure 8.3: Estimated available gas production capacity (by operator), Q1 2013 to Q3 2014



Source: IMO estimates using quarterly production reports and GBB data for Q3 2014.

Note: Spare capacity is calculated by taking the difference between the nameplate capacity and actual production data.

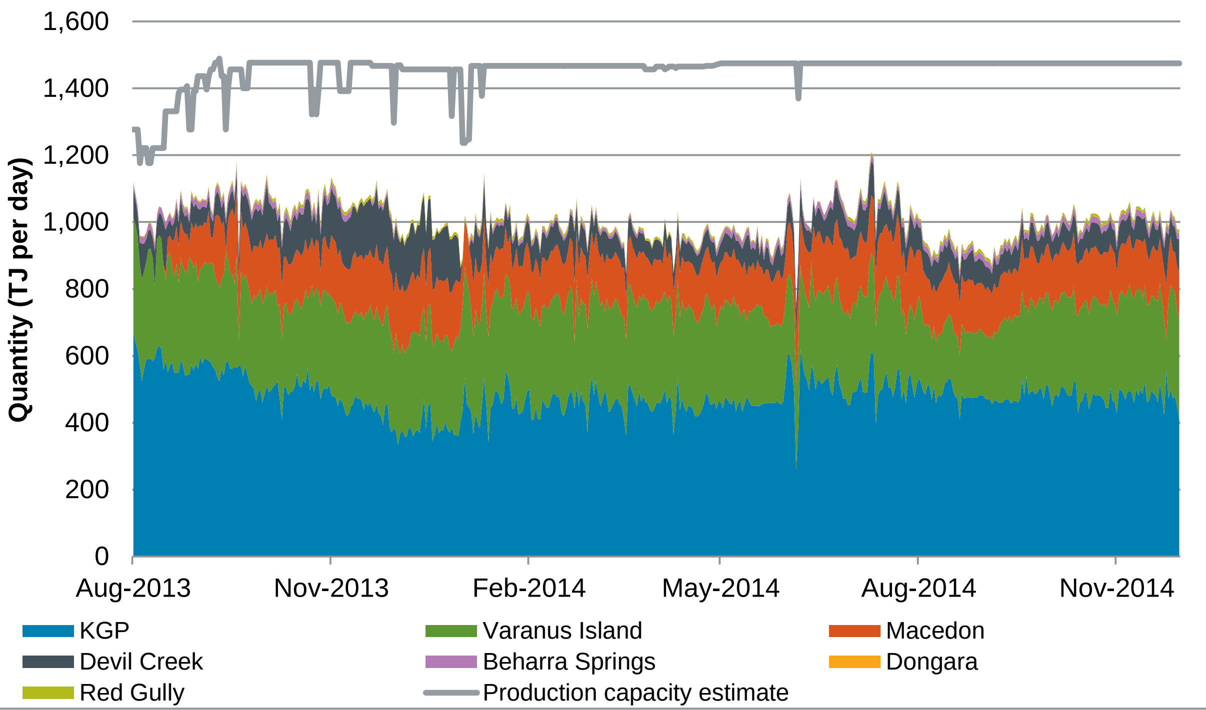
Domestic gas production capacity again increased in Q3 2013 with the commencement of the Macedon and Red Gully facilities. With this increase, it is estimated that the average available production capacity for the entire domestic gas market has increased to approximately 480 TJ per day in Q3 2014 – equivalent to one third of total domestic gas production capacity, or almost two thirds of the production capacity of the KGP.

It should be noted that a portion of this gap between total nameplate production capacity and actual production is accounted for by varying contractual terms within gas sales contracts, gas nominations, seasonal gas demand and facility outages or maintenance. However, the increase in available production capacity reduces the reliance of the market on any one gas production facility operator and means that domestic gas consumers are likely to have a greater range of gas purchasing options.

Available gas production capacity, together with the expanded gas storage capacity at the MGSF and an increase in spare shipping capacity (see chapter 10), means that consumers have choice about the timing of their gas purchases. This may present opportunities for gas market participants to optimise their gas consumption and/or trade in the WA domestic market. Such opportunities may include trading of gas between market participants to balance their daily gas requirements, aggregation of gas purchasing, responding to opportunities to purchase gas through short-term trading, the underwriting of gas supply[114] or purchasing of gas for future use (through greater utilisation of gas storage).

Analysis of daily production and capacity information can also reveal changes in the market on a short-term basis. Figure 8.4 uses GBB data and provides information on quantities of gas delivered daily into pipelines by production facilities for the 1 August 2013 to 30 November 2014 period, as well as short-term changes to production capacity.

Figure 8.4: Domestic gas delivered to pipeline by production facility, 1 August 2013 to 30 November 2014



Source: IMO GBB data.

The daily production quantities in Figure 8.4 show that domestic gas production remains well below the total gas production capacity servicing the WA domestic market. In addition, the increase in production by BHP Billiton's Macedon facility coinciding with reduction from the NWS JVs' KGP suggests that expiring contracts from the NWS JVs were taken over by BHP Billiton.

This data also shows that an outage at the Devil Creek facility in January 2014 coincided with an increase in production from Varanus Island. This shows the spare gas production capacity at other facilities within the Apache Energy portfolio was utilised to reduce the effect of a reduction in gas production at the Devil Creek facility and maintain levels of supply.

A reduction in outages can be seen to have occurred since January 2014. Even when outages have occurred, available production capacity has been sufficient to ensure that supply to domestic gas market customers has not been disrupted.

[114] This is where a market participant (a gas user) enters into a commercial agreement with another market participant to have certainty of gas supply (similar to insurance).

8.1.4 *Breakdown of gas supply to the domestic market*

Despite domestic gas being largely produced by a small number of operators, the gas is marketed by a range of suppliers. These suppliers are listed in Table 8.2 below.

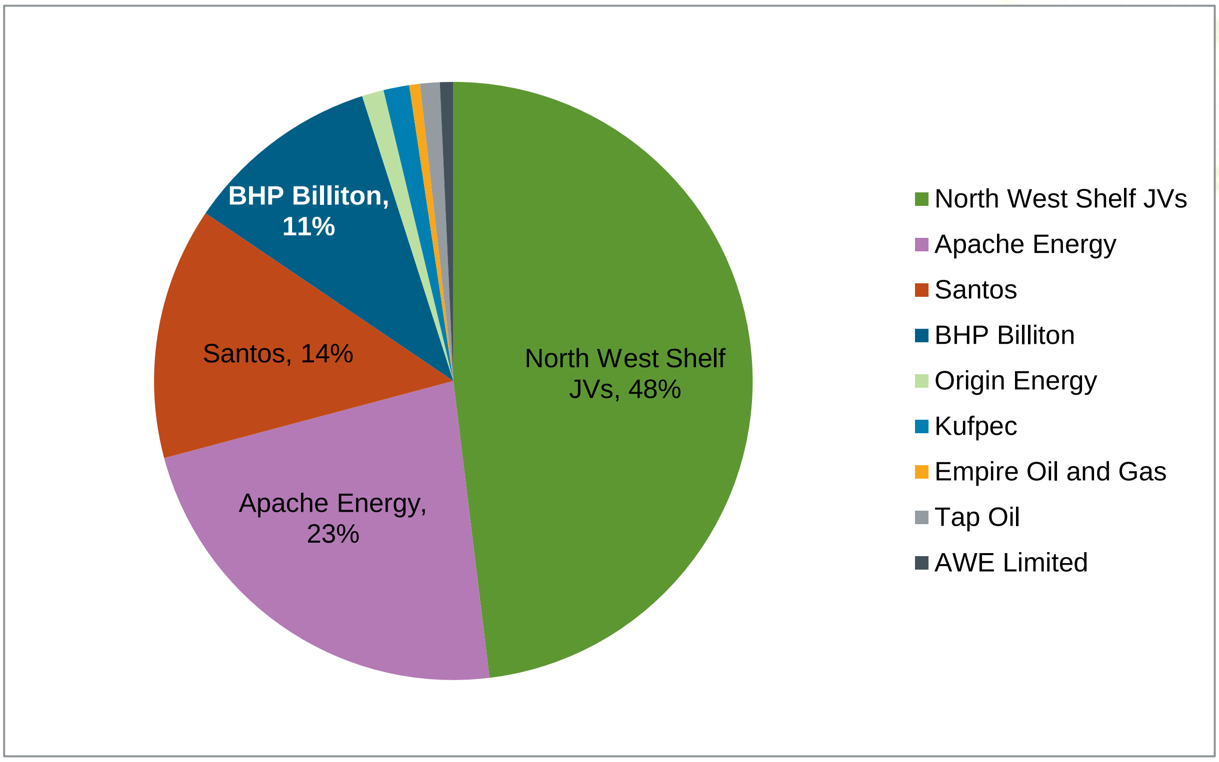
Table 8.2: Domestic gas suppliers, Q3 2014

Company	Estimated average supply to WA domestic market (TJ per day) – GBB data
Apache Energy	233.9
AWE Limited	7.2
BHP Billiton	108.8
Empire Oil and Gas	5.9
ERM Power	1.8
Kufpec	14.3
NWS JVs	494.0
Origin Energy	12.0
Santos	129.4
Tap Oil	10.9
Total	**1,018.2**

Source: IMO estimates based on GBB data and quarterly production reports.

The relative market shares of each of the suppliers to the domestic gas market are provided in Figure 8.5, which shows that the NWS JVs, Apache Energy, Santos and BHP Billiton dominate the WA domestic market.

Figure 8.5: Estimated market shares of WA domestic gas suppliers, Q3 2014



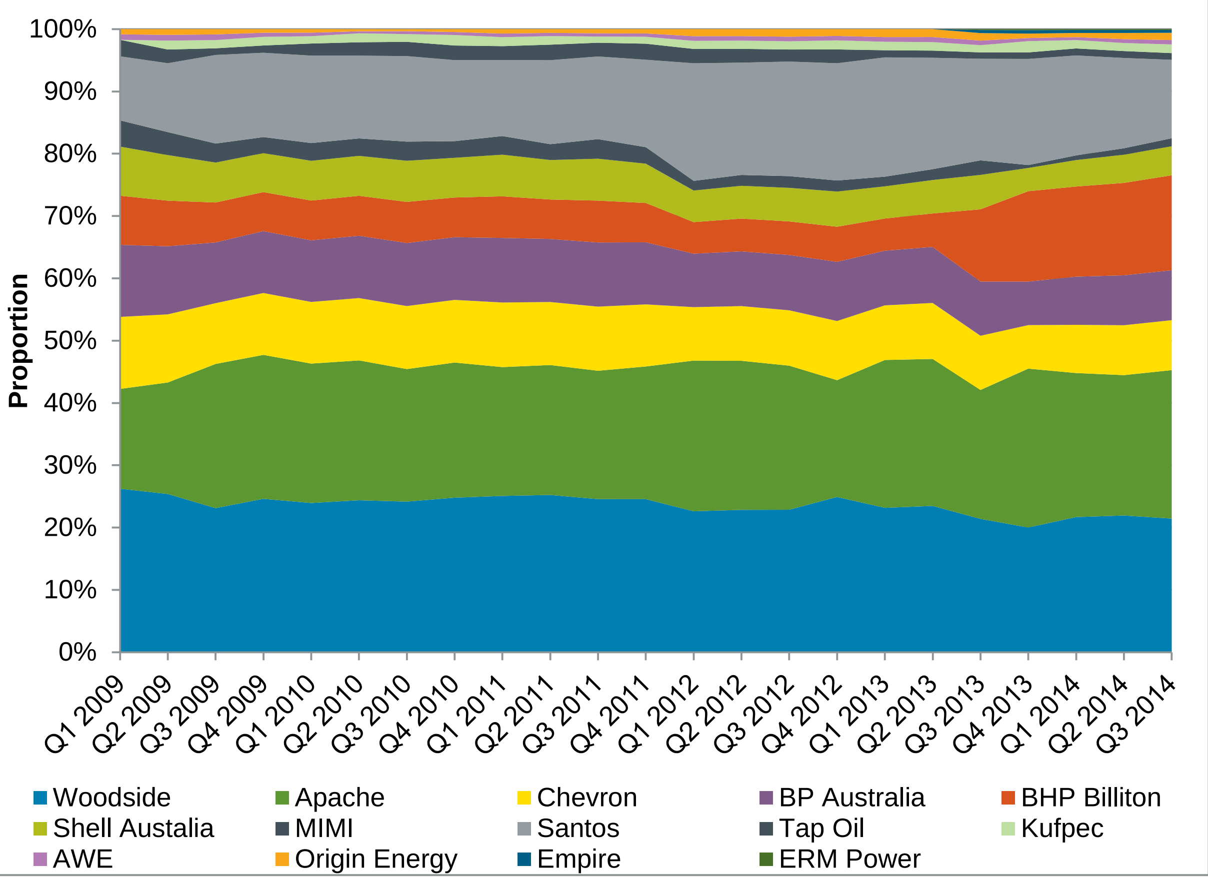
Source: IMO estimates based on GBB data and quarterly production reports.

Note: The percentages may not add to 100 per cent due to rounding.

Table 8.2 and Figure 8.5 show that four of the ten gas suppliers provide approximately 95 per cent of the total gas supplied to the domestic market in Q3 2014, with the other six suppliers providing the remainder.

As a number of the suppliers are JV's, a breakdown of the suppliers by company is shown in Figure 8.6 for Q1 2009 to Q3 2014. This figure presents estimates of the historical market shares of gas production by company, and indicates that the supply of domestic gas may be more evenly distributed if it were to be individually marketed, with Woodside, Apache, Santos and BHP Billiton the largest suppliers.

Figure 8.6: Estimated market shares of all WA domestic gas suppliers, Q1 2009 to Q3 2014



Source: IMO estimates from quarterly production reports and IMO GBB data.

Note: This graph has been updated from the January 2014 GSOO to include Tap Oil's third party gas sales. Respective shares of the domestic market are estimated using gas production from quarterly reports and applying assumptions. NWS JV partners supplying the domestic market are estimated using NWS JVs (Domestic Gas JV (DGJV) and Incremental Pipeline Gas JV) shares outlined in Woodside (2012) and assuming the DGJV retains all legacy contracts outlined in Table 1 of the January 2014 GSOO.

8.2 Gas supply forecasts

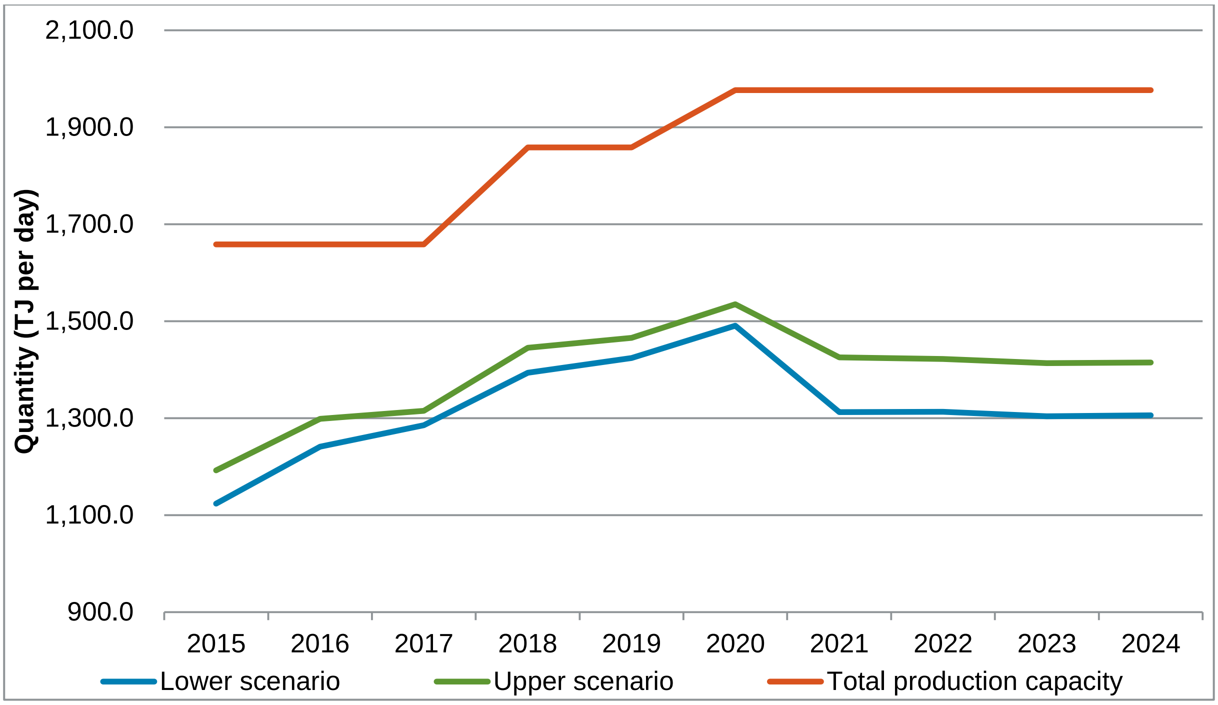
8.2.1 *Domestic gas supply*

The recent agreement between the NWS JVs and the WA Government, and the announcement by Hess of its intention to develop and toll its Equus reserves through the NWS JVs' processing facilities, considerably reduces the uncertainty surrounding future supply to the domestic gas market from the NWS. However, as a number of investment decisions are yet to be made to confirm the extent of supply from the KGP (discussed in chapter 2), this GSOO continues to present two forecasts – an Upper and Lower forecast of potential supply[115].

Both supply scenarios assume that the NWS JVs will operate the KGP at up to a maximum production capacity of 400 TJ per day for the 2015 to 2020 period and 300 TJ per day for the 2021 to 2024 period, although the Lower supply forecast assumes the NWS JVs will only make sufficient supply available to meet the New Domgas Commitment of approximately 100 TJ per day. The scenarios also apply different gas price forecasts.

Based on the information currently available about the future supply from the NWS, it is expected that the willingness of gas producers to supply the domestic market over the forecast period is likely to fall somewhere within the Upper and Lower potential supply forecasts, which are shown in Figure 8.7.

Figure 8.7: Potential domestic gas supply forecasts, 2015 to 2024



Source: IMO's forecasts 2015 to 2024 and IMO estimates.

The quantity of potential domestic gas supply for each year of the forecast period is shown in Table 8.3 below.

115 Neither scenario includes gas supply from Hess.

Table 8.3: Potential domestic supply forecasts (TJ per day), 2015 to 2024

Scenario	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Lower	1,124	1,241	1,286	1,394	1,424	1,491	1,313	1,313	1,304	1,306
Upper	1,193	1,299	1,315	1,446	1,466	1,535	1,425	1,422	1,414	1,415

Source: IMO forecasts 2015 to 2024.

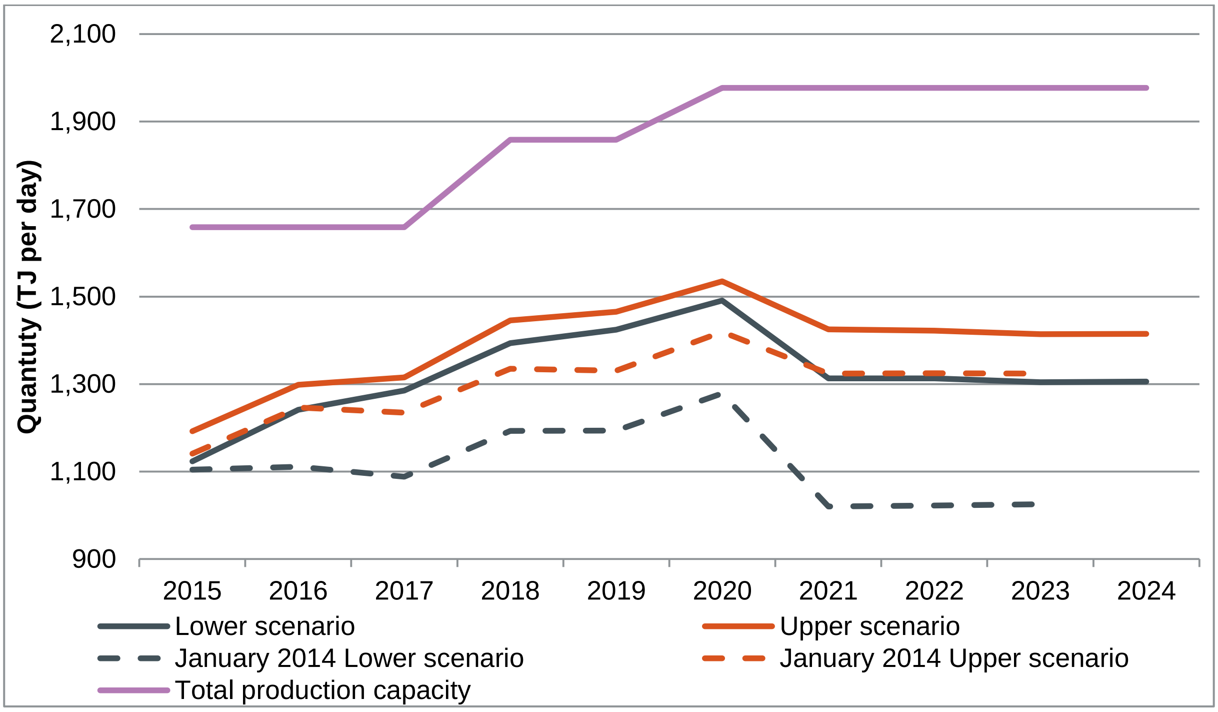
Growth in both the Upper and Lower potential supply forecasts is largely driven by the anticipated start-up of the Gorgon and Wheatstone domestic facilities – anticipated in 2015 and 2018 respectively, with an expansion of the Gorgon facility in 2020 (see Table 3.1 for more information). The commencement of these facilities drives strong growth in the period from 2015 to 2020, with the difference in forecast supply between the Upper and Lower scenarios the result of the different price assumptions applied to these scenarios.

After 2020, supply is expected to decline as a result of reduced supply from the NWS. During this period, the main reason for the difference between the Upper and Lower scenarios is the extent to which the NWS JVs may make supply available to the domestic market.

8.2.2 Comparing the potential supply forecast to the January 2014 GSOO

The forecasts of potential supply are compared with those presented in the January 2014 GSOO in Figure 8.8 below. This comparison shows the impact of changes in key assumptions, including price forecasts and their driving factors, and improvements made to the potential gas supply model (outlined in section 5.2) by the IMO.

Figure 8.8: Comparison of potential supply forecasts between the January 2014 GSOO and December 2014 GSOO



Source: NIEIR forecasts 2014 to 2023 and IMO forecasts 2015 to 2024.

The recent fall in international oil prices has decreased the price of oil-related products such as domestic gas (shown in section 5.3), offset by the anticipated weakening of the Australian dollar against the US dollar. The increased domestic gas price and revised assumptions about the continued supply from the NWS JVs have resulted in an increase in the amount of gas expected to be made available to the domestic market, increasing the potential supply forecasts as shown in Figure 8.8 above and Table 8.4 below. The recent announcement regarding the NWS JVs has also had the effect of reducing the range between the supply forecasts.

Table 8.4: Comparison of projected supply growth rates, January 2014 and December 2014 GSOOs

Annual avg. growth rates	Lower	Upper
January 2014 GSOO	-0.8	1.7
December 2014 GSOO	1.7	1.9

Source: NIEIR forecasts 2014 to 2023 and IMO forecasts 2015 to 2024.

8.2.3 Projected gas production capacity

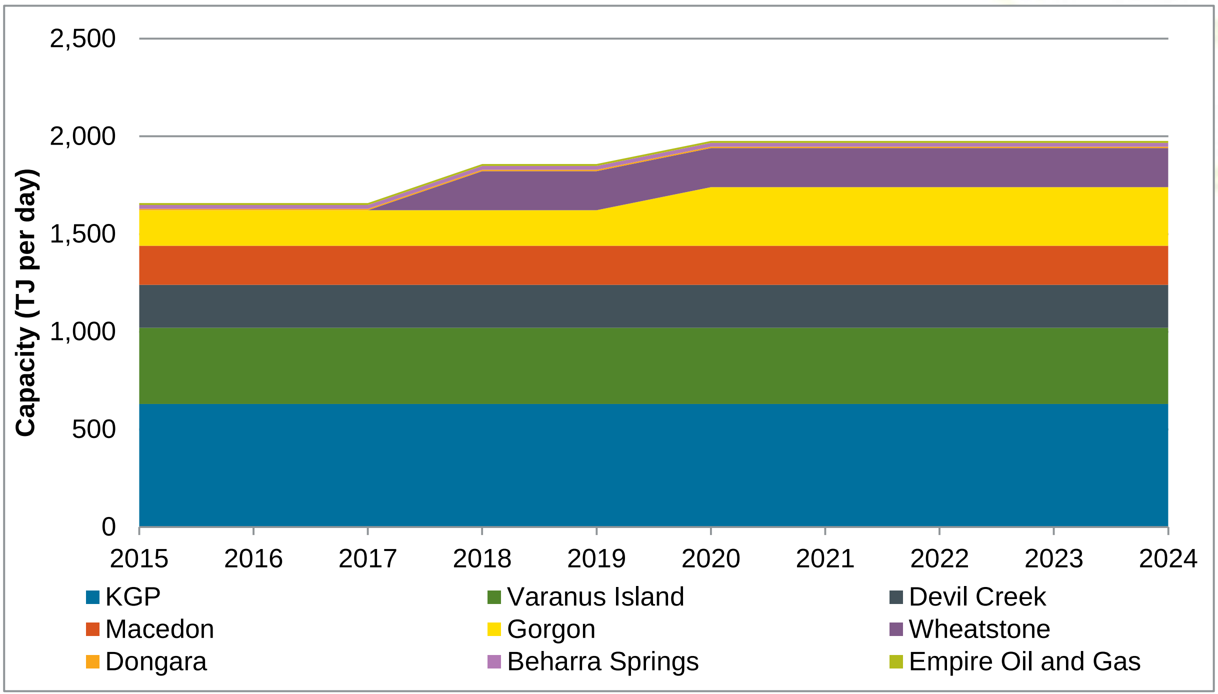
This section considers the projected gas production capacity for the forecast period. Projected production capacity is simply the maximum amount of gas that can be made available to supply the domestic market (if required), estimated by aggregating the nameplate capacities of all domestic gas production facilities in WA that are existing and operational, under construction or committed for the forecast period[116].

Projected domestic gas production capacity for the forecast period is shown in Figure 8.9, based on the expected availability and commencement times of all existing and upcoming gas production facilities. Assuming all domestic gas production facilities remain in service, the domestic gas production capacity is anticipated to increase from approximately 1,659 TJ per day at the end of 2015 to 1,977 TJ per day by the end of 2024. The continued existence of this capacity is expected to provide more flexibility to gas consumers.

The increase in gas production capacity from the January 2014 GSOO is due to the commencement of Phase One of the Gorgon domestic gas production facility for 2015.

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

Figure 8.9: Projected gas production capacity in the WA domestic gas market, 2015 to 2024



Source: IMO and various corporate websites. Start-up dates represented in this chart are Gorgon Phases 1 and 2 (2015 and 2020), Wheatstone (2018).

Despite an increase in domestic gas production capacity, Figure 8.9 shows that the KGP is expected to remain the largest domestic gas production facility in WA – with almost one-third of the total gas production capacity at the end of 2024[117].

8.2.4 Potential increases in domestic gas production capacity, 2015 to 2024

In the forecast period, domestic gas production capacity is anticipated to increase further with the development of the Gorgon and Wheatstone domestic production facilities. In addition to these committed facilities, a number of new and proposed expansions to existing gas production facilities may also eventuate. Expansion to the Dongara production facility is currently being considered, while other new gas production facilities, such as Buru Energy's Yulleroo, Transerv Energy's Warro and Woodside's Pluto, have yet to reach FID. It remains unclear whether these facilities will commence within the forecast period.

[117] Despite the continued uncertainty about the extent of future supply from the NWS JVs, no announcements have been made to indicate a reduction in the nameplate capacity of the KGP.

Table 8.5: Domestic gas production facilities that may be operational or upgraded by 2024

Production facility	Operator	Basin	Existing and proposed pipeline connection	Anticipated completion	Is gas production capacity contracted?
Dongara*	AWE Limited	Perth	Parmelia/DBNGP	Unknown	Information not publicly available
Warro	Transerv Energy	Perth	Parmelia/DBNGP	Unknown	Conditional gas supply agreement with Alcoa
Pluto domestic^	Woodside	Carnarvon	DBNGP	Unknown	Information not publicly available
Yulleroo/ Valhalla	Buru Energy	Canning	Proposed Great Northern Pipeline	Unknown	Conditional gas supply agreement with Alcoa

Source: Respective corporate websites.

Note: * According to AWE Limited (2014c), gas from the Senecio gas field may be used to backfill the expanded Dongara domestic gas production facility. ^The status of Pluto domestic facility is remains unclear.

9. Gas resources and reserves

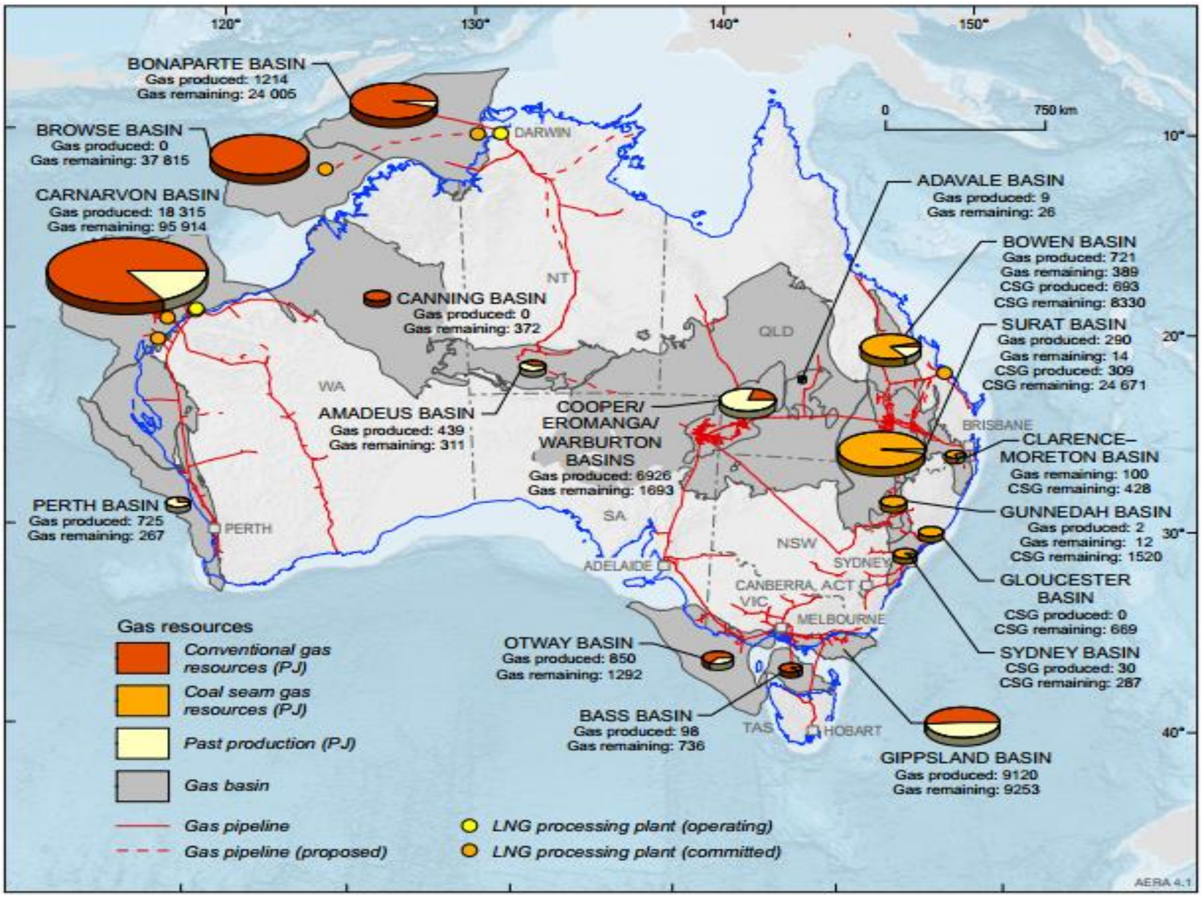
This chapter provides an overview of key hydrocarbon basins in WA, reports on the estimated volume of developed and undeveloped gas resources that lie within each basin and projects how long these resources are anticipated to continue to satisfy future demand for domestic consumption and LNG production in WA.

9.1 Key basins in WA

According to Geoscience Australia, it is estimated that approximately 92 per cent of Australia's total conventional gas resources are located in onshore WA, WA State waters and Commonwealth waters located around WA – some 158,373 PJ. While total Australian unconventional gas resources have not been verified, WA has an estimated 284,092 to 503,512 PJ of tight and shale gas.

There are currently 10 basins within WA[118], of which five are known to contain hydrocarbon resources. These are the Bonaparte, Browse, Canning, Carnarvon and Perth Basins. Figure 9.1 displays their size relative to other key basins in Australia.

Figure 9.1: Key Australian gas basins



Source: Geoscience Australia (2014), gas basins in Australia (offshore and onshore).

118 Government of South Australia (2012). 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 this report. At the time of this report, only Rodinia Oil Corp (Canadian company) and Ahava Energy (Australia) are known to be exploring the Officer Basin. For the prospective potential of the Officer Basin, please refer to DMP (2003).

It is estimated most conventional resources lie in the Bonaparte, Browse and Carnarvon Basins, while the majority of WA's unconventional gas resources (specifically tight and shale gas) are estimated to lie in the Canning and Perth Basins[119].

9.2 Conventional gas resources and reserves

There are approximately 158,373 PJ of conventional gas resources located in the five WA basins[120] shown above, of which approximately 88,786 PJ has been booked as 2P reserves by existing entities. This has decreased from approximately 90,525 PJ as quoted in the January 2014 GSOO, due to domestic gas and LNG production over the year and a reduction in new oil and gas discoveries in WA.

Table 9.1 provides key information about WA's conventional gas reserves.

Table 9.1: Conventional gas basins in WA

Basin	Total area offshore, km^2 (approximate)	Total area, onshore, km^2 (approximate)	Gas reserves, (2P, PJ)	Estimated remaining resources (McKelvey's EDR + SDR) (PJ)	Gas produced to date 2013-2014 (PJ)
Bonaparte	250,000	20,000	981	24,005	1,214
Browse	140,000	0	17,384	37,815	0
Canning	76,000	430,000	Not reported	372	0
Carnarvon	535,000	115,000	70,386	95,914	18,315
Perth	122,500	50,000	35	267	725
Total	**1,123,500**	**615,000**	**88,786**	**158,373**	**20,254**

Source: Geoscience Australia (2014), EnergyQuest (2014) and 2014 January GSOO.

Currently, only the Bonaparte, Carnarvon and Perth Basins are producing gas, with each of these basins producing for domestic use and LNG exports. Of these, only the Carnarvon and Perth Basins produce gas for the WA domestic market, while the Bonaparte Basin produces gas for the Northern Territory domestic market[121].

It is unlikely that the WA domestic market will be supplied by gas resources in other basins until gas transmission infrastructure is constructed to connect other basins[122] to the existing pipeline network. Despite the size and scale of WA's undeveloped conventional gas resources, the distance from most gas basins (except the Perth Basin) to the majority of domestic gas consumers in the South West and Goldfields regions continues to pose a significant barrier.

The following sections provide more information regarding the various basins.

[119] Geoscience Australia (2014).
[120] Geoscience Australia (2014).
[121] Eni (2009) Eni's Blacktip gas field is producing gas from the Bonaparte Basin which is processed at Wadeye for NT's Power Water Corporation. NT's LNG exports from the Bonaparte Basin are produced from the Bayu-Undan gas field.
[122] Gas extracted from the Browse and Canning Basins may otherwise be made available to the domestic market indirectly by negotiating gas swap agreements with existing gas producers that can supply to the domestic market on their behalf.

9.2.1 Carnarvon Basin

The Carnarvon Basin contains the largest known gas resources and is the most extensively explored gas basin in WA. For the 1 December 2013 to 30 September 2014 period, approximately 97.7 per cent of the domestic gas supply and 100 per cent of LNG exports from WA originated from this basin.

Reliance on the Carnarvon Basin is anticipated to continue in the forecast period, with gas from this basin supplying the majority of the WA domestic and LNG export markets[123]. Before the end of 2024, the number of domestic gas production facilities extracting gas from Carnarvon Basin will increase from five to seven facilities (see section 3.3.1 for details), while the number of LNG production facilities is also anticipated to increase from two to four (see section 7.2.1 for details).

Interest in the Carnarvon Basin remains strong with the recent announcement regarding the Hess Equus project, the award of two exploration permits in the Northern Carnarvon Basin to StatOil[124] and Rampart Energy[125], and Bounty Oil and Gas in the process of purchasing Empire Oil and Gas' tenements[126].

9.2.2 Perth Basin

While being closer to gas consumers in the south west of the state than other WA basins, and close to two gas transmission pipelines, the DBNGP and Parmelia Pipeline, the Perth Basin contains a relatively low volume of conventional gas reserves. All hydrocarbon projects in the Perth Basin (except AWE Limited and Roc Oil's Cliff Head project) are onshore, and supply gas solely to the domestic market. In addition, the Perth Basin appears to contain large undeveloped shale and tight gas resources (see section 9.3).

The Perth Basin's less than ideal geological characteristics and relatively small estimated resources also mean it is substantially less significant to WA's gas supply than the Carnarvon Basin[127].

9.2.3 Browse Basin

Despite the WA Government's interest in developing the Browse LNG Precinct in the Kimberley region, the lack of gas transmission infrastructure to connect this region to the rest of the WA gas market presents a challenge for the development of the Browse Basin for the domestic market before 2024.

At the time of this report, only INPEX's Ichthys (to Darwin) and Shell's FLNG Prelude projects are being developed in the Browse Basin[128], with neither of these projects to supply the WA domestic market. Gas projects under consideration in this basin include Woodside's Browse, ConocoPhilips' Poseidon and Santos' Crown and Lasseter projects. While there are

123 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.
124 Statoil (2014b).
125 Rampart Energy (2014).
126 Empire Oil and Gas (2014).
127 Bell Potter 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.
128 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.

several significant gas discoveries in this basin, these discoveries are likely to be considered primarily as potential LNG export projects.

9.2.4 Bonaparte Basin

At the time of this report, there are two projects known to be producing gas from the Bonaparte Basin – Eni's Blacktip and ConocoPhilips' Bayu-Undan Darwin LNG. While these projects are extracting gas from the basin, they are processing the extracted gas for LNG export and domestic consumption within the Northern Territory and are not supplying gas to the WA domestic market. While the Bonaparte FLNG project was previously announced for this basin, GDF Suez and Santos have halted the project and are considering alternative development concepts for the Petrel, Tern and Frigate gas fields in the Bonaparte Basin[129].

Despite the existence of these projects and a large volume of undeveloped gas resources located in the Bonaparte Basin, similar to the Browse Basin, there is no gas production or transmission infrastructure located onshore in the Kimberley region to commercially extract, process and ship gas to domestic customers in the WA market.

Instead, there is a possibility that a proportion of the Bonaparte Basin's gas resources may be developed to supply the domestic gas markets and the LNG projects located in eastern Australia. The Northern Territory Government is currently advocating the construction of a pipeline to connect the Northern Territory to the eastern Australia gas markets[130], which is estimated to cost between $900 million (to Mount Isa) to $1.3 billion (to Moomba) depending on the route selected.

9.2.5 Canning Basin

No permanent gas-related infrastructure is currently known to be located in the Canning Basin[131]. However, there has been increasing interest in exploring for hydrocarbons in the area due to recent discoveries by Buru Energy (onshore at Ungani in 2011) and Apache Energy (offshore at Phoenix-South in 2014)[132].

At the time of this report, several exploration and production companies, including Apache Energy, Buru Energy, Carnarvon Petroleum, ConocoPhillips, Hess, Key Petroleum, Mitsubishi, New Standard Energy, Oilex Limited, Oil Basins Limited and PetroChina continue to explore the Canning Basin for hydrocarbons.

Buru Energy appears to be the most advanced hydrocarbon explorer and producer with two of its oil fields in the Canning Basin – the Blina and the Ungani fields – already in production, while it continues to appraise its gas resources within the Laurel formation[133].

9.3 Unconventional gas resources and reserves

There is currently no commercial production of unconventional gas in WA. The quantum of WA unconventional gas resources, specifically tight and shale gas, is largely unverified, however estimates from various sources collated in this GSOO suggest that there are

129 Santos (2014).
130 ABC News (2014b).
131 Buru Energy (2014b). There are temporary storage facilities (owned by Buru Energy) for crude oil awaiting transfer to the BP refinery located in Kwinana.
132 Apache Energy (2014).
133 Buru Energy (2014).

quantities of approximately 284,092 to 503,512 PJ of shale and tight gas resources in the state. Currently, all shale and tight gas exploration activities have been confined to onshore exploration due to the depth of the potential resource[134].

The size and relatively lower risk of conventional gas resources in WA may indirectly delay the exploration of unconventional gas. Due to the higher risks associated with unconventional gas exploration, such exploration is primarily focused on either well-explored areas for conventional hydrocarbons (such as the Carnarvon and Perth Basins) or within basins of high potential discoveries (onshore Bonaparte 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 known to be actively exploring for, or have interests in, unconventional gas resources in WA. In the onshore Carnarvon Basin, Rusa Resources and Tap Oil are exploring for shale resources in the two special prospecting license areas covering a total of 38,000 square km[135].

In the Perth Basin, a number of companies are actively exploring for shale and/or tight gas. A list of these companies can be found in the January 2014 GSOO, with the addition of Eneabba Gas and UIP Energy. AWE Limited and Transerv Energy are considered to be the most advanced unconventional gas explorers operating in this basin, as they have been drilling and testing the gas flows of their various exploration projects[136].

In the onshore Bonaparte Basin, only Advent Energy is known to be exploring for shale resources at its Waggon Creek field[137].

Several exploration companies, JV partners and/or JV interests have permits in the Canning Basin. Again, a list of these companies can be found in the January 2014 GSOO, with the addition of Finder Exploration. 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 and Apache Energy (with Buru Energy) and ConocoPhilips and PetroChina (with New Standard Energy).

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

9.3.1 Shale gas resources

Within WA, the EIA and the Australian Council of Learned Academies (ACOLA) provide estimates of existing shale gas resources by basin, shown below. The EIA estimates that there are 268 trillion cubic feet (tcf) of recoverable shale gas resources within the onshore Canning and Perth Basins, almost twice the amount of WA's conventional gas resources[138]. According to the EIA, the Goldwyer formation in the Canning Basin could contain approximately 235 tcf of shale gas, while the Carynginia and the Kockatea formations in the Perth Basin are estimated to contain approximately 33 tcf of shale gas.

A 2013 ACOLA report provides a higher estimate for shale resources located in WA (475 tcf), again with the majority located in the Canning Basin.

134 DMP (2014b) .
135 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.
136 AWE Limited (2013), Transerv Energy (2012).
137 DMP (2013a).
138 EIA (2013).

Table 9.2: Estimated shale gas (recoverable) resources in WA, 2013

	EIA		ACOLA	
Basin	**tcf**	**PJ**	**tcf**	**PJ**
Canning	235	249,100	450^	477,000
Carnarvon	-	-	9	9,540
Perth	33	34,980	16	16,960
Total	**268**	**284,080**	**475**	**503,500**

Source: *EIA (2013) and ACOLA (2013).*

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 recoverable resources. ACOLA's figures are dry gas estimates. Conversion factors are outlined in Appendix H. ^Sum of Goldwyer and Laurel dry gas estimates.

As indicated above, there may be a vast resource of shale gas in WA – with the majority of shale gas resources located in the remote Canning Basin. The remote location of this basin, the extreme weather conditions in the Kimberley and a lack of existing infrastructure make development of these gas resources challenging. Other prospective basins for shale gas include the Amadeus, Officer and onshore Bonaparte Basins[139], which have not yet been explored.

Shale gas exploration activities are currently occurring within the Canning and Perth Basins. According to DMP, since 2005 only four shale exploration wells have been drilled – two in the Canning Basin and two in the Perth Basin[140].

The most advanced shale explorers are AWE Limited and New Standard Energy. AWE Limited is exploring for shale gas in its Woodada Deep and Arrowsmith fields located in the Perth Basin, while New Standard Energy is also exploring for shale at its Nicolay and Gibb Maitland fields located in the Canning Basin. AWE Limited reports it may be able to access approximately 13 to 20 tcf of shale gas within its Perth Basin acreage[141].

9.3.2 Tight gas resources

Australia has not fully assessed its reserves of tight gas and as such there are no accurate, published estimates of WA's tight gas resources. According to Geoscience Australia estimates, there are approximately 22,052 PJ (20 tcf) of tight gas reserves in Australia. DMP considers that WA has the majority of this volume, with most of WA's tight gas reserves located in the Perth Basin. The latest report from DMP estimates the Perth Basin contains approximately 12 tcf of tight gas[142], shown below in Table 9.3.

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 the values reported by Geoscience Australia and DMP are conservative[143].

139 CSIRO (2012).
140 DMP (2014b).
141 AWE Limited (2010).
142 See DMP (2007), DMP (2013b).
143 Geoscience Australia (2014), DMP (2013c).

Table 9.3: Estimated tight gas (recoverable) resources in WA, 2014

Basin	Official estimated reserves (tcf)	Estimated recoverable resources (unproven) reported by existing companies (tcf)	Estimated recoverable resources (unproven) reported by existing companies (PJ)
Perth	12	29.21*	30,962*
Carnarvon	None Reported	None Reported	None Reported
Canning	None Reported	14.1**	14,946**
Total	**~12**	**~43.31**	**~45,908**

Source: DMP (2013b), Buru Energy (2014b).

Note: Table of tight gas estimates assumes a recoverability factor of 30 per cent. Recovery factor is affected by formation and gas characteristics. *This is the sum of 30 per cent of the low estimate of AWE Limited's (2014) estimate (11.1 tcf) of its Perth Basin tenements in its 2014 Annual Report, 30 per cent of Norwest Energy (2014) low estimate of gross recoverable volumes in EP413 (1.6 tcf), and the low estimate of recoverable tight gas (3 tcf) for Transerv Energy's Warro Gas field, Transerv Energy (2012). The tight gas estimate does not include shale/tight gas estimates for Empire Oil and Gas within EP440 (36 tcf) and EP368/EP426 (32 tcf), or Origin Energy's or Bharat Petroleum's estimates. **This is 30 per cent of the best estimate of tight gas resources in the Laurel Formation outlined in Buru Energy's (2014) 22 September 2014 corporate presentation.

In September 2014, AWE Limited announced an increase in the development potential of the Senecio gas field as well as the discovery of the new Waitsia (conventional) gas field in the Perth Basin – with a total contingent (2C) P50 resource of 360 bcf[144] of gas and also significant unconventional gas potential. According to the West Australian, the discovery of gas in AWE Limited's Waitsia field has led Alcoa to reconsider accessing its gas supply from the Perth Basin and to continue to support Transerv Energy in further exploring the prospective Warro gas field to reduce its reliance on third party gas providers[145].

9.3.3 Other unconventional gas resources

In addition to shale and tight gas, the January 2014 GSOO reported that Westralian Gas and Power and Eneabba Gas Limited have been investigating the potential of extracting unconventional CSG for domestic consumption and developing synthesis gas (syngas) through underground coal gasification. No new information has been available for these speculative projects since the January 2014 GSOO.

9.4 Remaining resources and reserves

Based on the total estimates of conventional and unconventional resources discussed above, Table 9.4 provides estimates of how long WA's remaining resources are expected to last based on existing and projected production of domestic gas and LNG sales.

144 AWE Limited (2014a).
145 The West Australian (2014b).

Table 9.4: Estimates remaining resource years based on production for WA, 2013-14 and 2024

Reserves and resources – all basins	Resources and reserves – 2013 (PJ)	2013-2014 total gas demand (PJ)	Remaining years beyond 2014 (based on 2013-2014 total gas demand – PJ)	2024 total gas demand forecasts – Base Scenario (PJ)	Remaining years beyond 2024 (based on 2024 total gas demand forecasts – PJ)
2P reserves (see Table 9.1)	88,786	1,476	60.2	4,219	12.1
McKelvey's economic resources only	99,728*	1,476	67.6	4,219	13.7
McKelvey's economic and sub-economic resources	158,373	1,476	107.3	4,219	37.5
McKelvey's economic and sub-economic resources + EIA (2013) shale resources (PJ)	442,453	1,476	299.8	4,219	105.0
McKelvey's economic and sub-economic resources + EIA (2013) shale resources (PJ) & official tight gas estimates (12 PJ)	442,465	1,476	299.7	4,219	105.0

Source: EnergyQuest (2014), Geoscience Australia (2014), BREE (2014a), DMP (2013b) and NIEIR forecasts.

Note: Reserves include gas fields that are not connected to any particular production facility. *Does not include Perth and Canning Basins.

Table 9.4 shows that, based on 2P reserves and economic resources, WA's conventional gas resources are estimated to last approximately 12 to 14 years from 2024, based on NIEIR's total gas demand forecasts for 2024. However, if improvements in technology allow currently sub-economic resources to be developed in the future, Table 9.4 suggests that there may be sufficient conventional resources in WA to last for approximately 38 years from 2024.

When unconventional gas resources are also taken into account, WA's gas resources may be expected to last up to 105 years (at forecast 2024 total gas demand levels). However, at the time of this report, there has not been a successful commercial operation producing domestic gas or LNG exports from unconventional gas sources in WA.

While remaining gas resources appear to be sufficient to meet forecast domestic, LNG and FLNG demand levels for a reasonable period beyond 2024, Table 9.4 suggests that the development of unconventional gas resources will be increasingly important in order to maintain WA gas production well into the future.

9.4.1 Resources and reserves by basin

As noted previously, WA is highly reliant on the Carnarvon Basin for its gas requirements (for both domestic gas and LNG exports), with the vast majority of the state's gas supply originating there. In addition, there is an increasing risk that Carnarvon Basin resources may be depleted more quickly, as a number of additional LNG export projects are being considered for this location.

Conventional resources from the Carnarvon Basin are expected to last for approximately 8 years beyond 2024, as shown below in Table 9.5. This assumes no additional exploration takes place and total gas production continues unchanged from 2024 at forecast levels outlined in this GSOO.

Table 9.5: Estimated remaining resource years based on production for WA, 2014 and 2024

Remaining resource estimate	Bonaparte	Browse	Canning	Carnarvon	Perth
McKelvey's economic and sub-economic resources – conventional only	24,005	37,815	372	95,914	267
McKelvey's economic and sub-economic resources – including EIA (2013) unconventional estimates	-	-	284,452	-	4,047
Estimated 2P gas reserves – EnergyQuest (2014)	981	17,384	-	70,386	35
2024 total gas demand forecasts (PJ)	-	-	-	3,977.3	7.7
Remaining resource years beyond 2024 (based on 2024 total gas demand forecasts) – estimated 2P reserves only	Not estimated	Not estimated	Not estimated	7.7	5 (from 2014)
Remaining resource years beyond 2024 (based on 2024 total gas demand forecasts) – McKelvey EDR+SDR conventional Only	Not estimated	Not estimated	Not estimated	14.1	34.7

Source: Geoscience Australia (2014), EnergyQuest (2014) and NIEIR forecasts.

This highlights WA's reliance on the Carnarvon Basin for its domestic gas needs and LNG exports. Should other prospective LNG export projects (outlined in section 7.2.2) that are being considered commence, or gas production increase unexpectedly, there may be insufficient gas resources to support both LNG exports and domestic gas consumption. A similar situation also exists for the Perth Basin with gas reserves (at the 2P level) expected to expire in 2019.

To ensure there are ongoing gas reserves available for the WA domestic market, gas exploration and production in other WA basins (such as the Canning and Perth Basins) should be encouraged in order to diversify WA's sources of gas supply and secure a continued supply of gas to WA well into the future.

9.4.2 Estimated reserves by production facility

To estimate if there are sufficient reserves available for each gas production facility to continue to supply to the domestic market for the forecast period, this section reviews the volume of 2P reserves connected to each domestic production facility.

Table 9.6 suggests there are likely to be sufficient gas reserves supporting the major domestic gas production facilities located in the Carnarvon Basin for the forecast period, assuming the 2014 production levels are maintained.

Table 9.6: Estimated gas reserves linked to domestic production facilities, November 2014

Production facilities	Gas field	Operator	Basin	Estimated 2P reserves (PJ)	Estimated total annual production (PJ) - 2014 **	Years remaining (implied)
Operational						
Karratha Gas Plant	NWS JVs fields	Woodside	Carnarvon	14,115	903.51 (Maximum 16.3 mtpa LNG Production 171.3 (Domestic)	13.1
Varanus Island	John Brookes, Harriet gas fields and Spar/Halyard	Apache Energy	Carnarvon	1,336	86.1	15.5
Devil Creek	Reindeer	Apache Energy	Carnarvon	415#	30.1	13.8
Dongara/ Beharra Springs	Not outlined in Annual Report^	AWE Limited/ Origin Energy	Perth	35.7^	5.7	6.3@@
Red Gully	Red Gully and Gingin	Empire Oil and Gas	Perth	11.76^^	2.1	5.6
Macedon	Macedon	BHP Billiton	Carnarvon	549@	51.5	10.7

Production facilities	Gas field	Operator	Basin	Estimated 2P reserves (PJ)	Estimated total annual production (PJ) - 2014 **	Years remaining (implied)
Under construction / consideration						
Gorgon Domestic	Gorgon, Jansz, Io, Chrysaor, Dionysius and Eurytion	Chevron	Carnarvon	40,969	0	Not applicable
Wheatstone Domestic	Wheatstone and Julimar Brunello	Chevron	Carnarvon	7,490	0	Not applicable
Pluto Domestic	Pluto	Woodside	Carnarvon	5,480	0	Not applicable
Total						

Source: EnergyQuest (2014), AWE Limited Annual Report and Origin Energy Annual Reserves Report.

Note: Table does not consider LPG production. #Does not include reserves from the Caribou field. ^A sum of gas reserves reported in AWE Limited's (2014) Annual Report and Origin's (2014) Annual Reserves Report for the Perth Basin, the reserves do not include recently discovered Senecio and Waitsia gas fields. @Reserves for Macedon may be significantly higher than figures suggest as gas extracted from the Pyrenees Floating Production Storage and Offloading (FSPO) project is re-injected into the Macedon field for future recovery. BHP Billiton (2013) has also publicly announced that Macedon will produce gas until at least 2033. ^^Empire Oil and Gas's reserves have been updated to reflect gas reserves reported in the March 2014 quarterly report. @@While the estimate is low, AWE Limited's Senecio field is attempting to backfill the Dongara gas production facility. **Estimated using GBB data – 1 October 2013 to 30 September 2014.

Only the production facilities located in the Perth Basin – Dongara, Beharra Springs and Red Gully – appear to have insufficient gas reserves to maintain current production levels until 2024. While there is a possibility that the gas supply from any of these three facilities may cease prior to the end of 2024, the disruption to domestic gas supply would be minimal as their contribution to the domestic market is small and can easily be replaced by other providers that have spare capacity (see section 8.1).

9.4.3 Estimated reserves by company

Estimates of reserves by company are reported in Table 9.7, showing that approximately 76 per cent of WA's known 2P gas reserves are held by five companies.

Table 9.7: Natural gas reserves by company (WA and NT), November 2014

Company	2P reserves (PJ)	Share (%)
Chevron	25,933	29.1
Shell	14,410	16.2
ExxonMobil	10,242	11.5
INPEX	9,289	10.4
Woodside	7,516	8.4

Company	2P reserves (PJ)	Share (%)
TOTAL	4,070	4.6
BP	2,792	3.1
BHP Billiton	2,540	2.9
Apache Energy	2,532	2.8
MIMI	2,061	2.3
Kufpec	1,193	1.3
Santos	900	1.0
Tokyo Gas Co	897	1.0
Eni	882	1.0
CNOOC	703	0.8
Osaka Gas	675	0.8
Tokyo EP	547	0.6
CPC	547	0.6
Kogas	382	0.4
Kansai Electric	274	0.3
Chubu Electric Power	271	0.3
Kyushu Electric Power	98	0.1
ConocoPhillips	64	0.1
Central Petroleum	58	0.1
Toho Gas	57	0.1
Origin Energy	23	0.0
AWE Limited	10	0.0
Empire Oil and Gas	1	0.0
Total	**88,967**	**99.8%**

Source: EnergyQuest (2014).

Note: Although the table includes 2P reserves from Northern Territory, as these only represent 181 PJ (<1 per cent of the total) the market shares of the companies are largely unaffected. New reporting rules for Oil and Gas Companies outlined in ASX (2013), only took effect from 1 December 2013 and do not apply to this table. This table of reserves has not been adjusted to reflect Woodside Energy's agreed purchase of Apache Energy's WA assets.

9.4.4 Additional new gas reserves available to domestic market

On 3 December 2014, the WA Parliament passed the *Petroleum Titles (Browse Basin) Bill 2014,* effectively recognising, based on advice from Geoscience Australia, increased marine boundaries for WA that apply to Scott and Seringapatam reefs located the Browse Basin.

While the purpose of the Bill is to provide the legislative framework for a smooth transition of tenure at the time of renewal of the Commonwealth titles in the Scott and Seringapatam reefs[146], the Bill essentially increases the volume of gas reserves the WA Government would seek to reserve for the domestic gas market currently held under retention and exploration licenses. In addition, the WA Government may have a greater influence over the development of gas fields located in those waters.

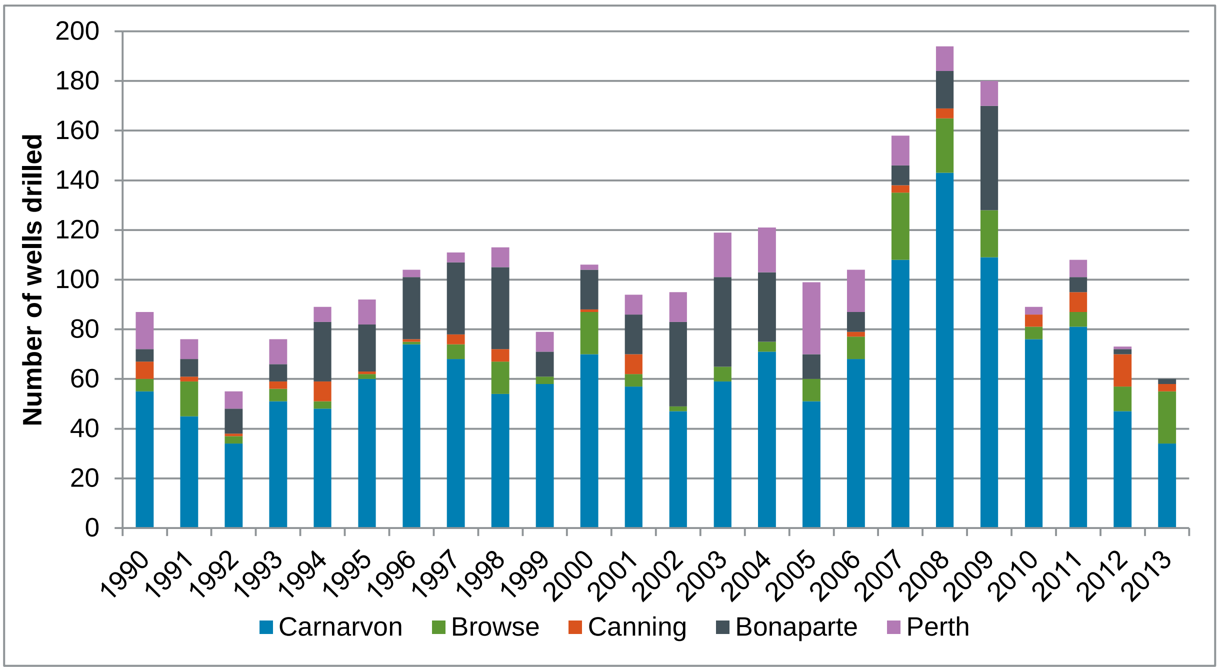
According to the West Australian[147], the new marine boundaries will affect hydrocarbon fields within the Woodside-led Browse and ConocoPhilips-led Poseidon projects. This will allow the WA Government to access royalties and reserve domestic gas from the Torosa gas-condensate field, the biggest of three that make up the Browse LNG project. For the Poseidon project, it is understood the new boundaries will cover the Poseidon and Kronos gas fields.

At the time of this report, it is unclear how much additional gas may be reserved for the domestic market from these prospective projects. For this reason, these fields have not been considered in the calculation of current WA gas reserves.

9.5 Exploration in WA

This section provides an overview of hydrocarbon exploration activity in WA. According to APPEA, over the period 1990 to 2013 a total of 4,964 hydrocarbon wells have been spudded in WA (shown in Figure 9.2) – of which approximately 63.2 per cent are in the Carnarvon Basin, reinforcing that WA exploration is focused on the Carnarvon Basin (for both domestic gas and LNG exports).

Figure 9.2: Number of exploration wells spudded, 1990 to 2013



Source: Compiled using APPEA, Bi-annual/Quarterly Drilling Statistics (1990-2014).

Note: The same well may be counted twice if it is redrilled.

[146] At the time of this report, the Scott Reef retention leases are due to expire on 23 December 2014, while the Seringapatam exploration permits expire in August 2014 and October 2016.

[147] The West Australian (2014c).

The number of wells being drilled has reduced in recent years, expected to be at least partially due to increases in exploration costs. According to APPEA[148] the total cost of drilling offshore wells has increased five-fold in Australia since 2003, with the average cost of each offshore well estimated to be approximately $130 million. For WA, EnergyQuest estimates[149] the average cost of offshore exploration to be approximately $90 million per well, although other sources report higher figures[150], and also reports an increase in the cost of finding and developing (F&D) hydrocarbons.

According to EnergyQuest, F&D costs only represent a portion of the total cost of hydrocarbon development and extraction and do not take into account operating costs, royalties, taxes and the opportunity cost of money.

If the trend of increasing F&D costs continues in WA, the prices of long-term gas contracts to the domestic market are likely to follow a similar trend. Long-term contracts are more likely to be affected by increases in F&D costs as these contracts are generally required to underpin development of new fields.

148 APPEA (2014).
149 EnergyQuest (2014b),.
150 Thomson Reuters (2014). Greenfield wells in WA may be as high as US$170 million per well.

10. Gas shipping and transmission

This chapter focuses on the gas shipping and pipeline transmission segments of the domestic market. It includes a summary breakdown of recent shipping activity by industry, and reviews the utilisation of WA's major transmission pipelines (with particular focus on the two largest pipelines – the DBNGP and the GGP), in order to highlight the capacity for shipping gas supplies through the pipeline network.

The availability of firm shipping capacity has at times in the past represented a challenge for medium to large gas-consuming projects – when all firm capacity on the DBNGP and GGP was fully contracted. However, this GSOO reports that spare shipping capacity has emerged on both pipelines[151] due to the renegotiation of shipping contracts and the expansion of pipeline capacity.

10.1 Gas shippers

There are 49 distinct shippers registered with the IMO in the WA gas market, with seven shippers that ship gas on more than one gas transmission pipeline. The majority of gas in WA is shipped through three major transmission pipelines – the DBNGP, the GGP and the Pilbara Energy Pipeline (PEP). Table 10.1 shows the number of gas shippers recently active, and on which gas transmission pipeline they generally operate.

Table 10.1: Number of active gas shippers, October 2013 to September 2014

Pipeline	Number of Active Shippers
DBNGP	24
GGP	15
All other gas pipelines	16

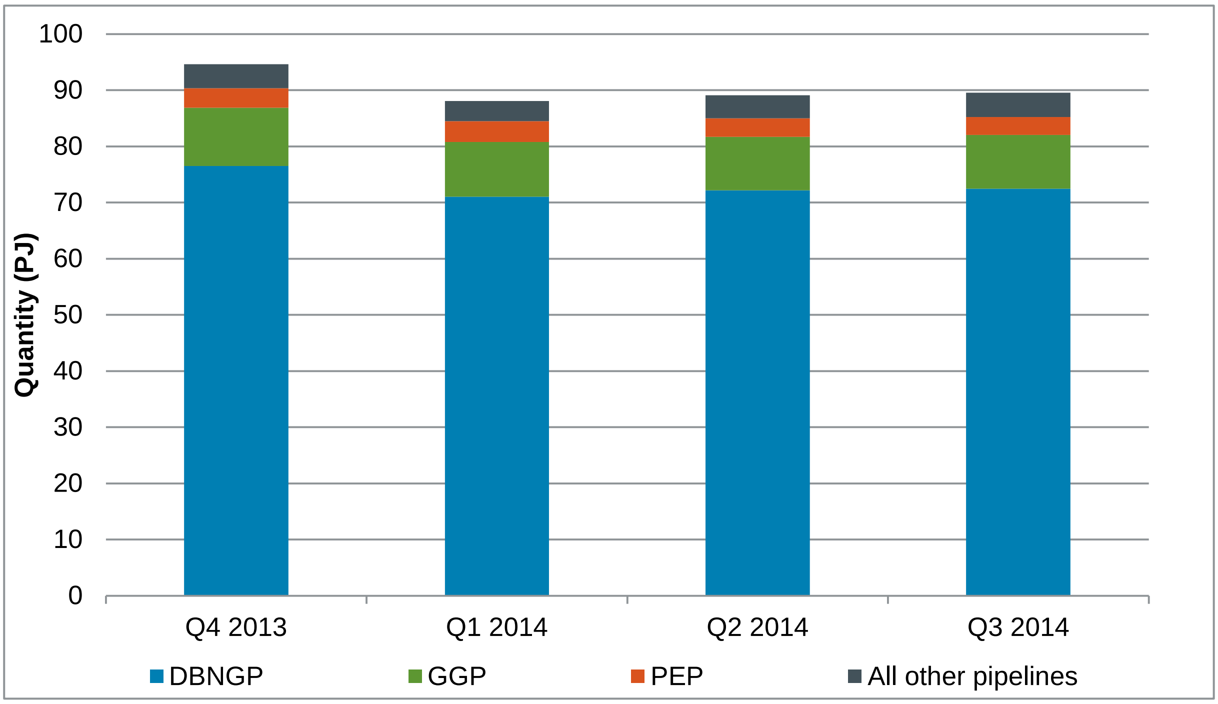
Source: *IMO GBB data.*

Note: A shipper is classified as 'active' if, according to GBB data, it has shipped some gas in the outlined period. Synergy and Verve Energy, who merged on 1 January 2014, are classified as one shipper.

151 DBNGP Transmission (2014) and APA Group (2014b), respectively.

The DBNGP, GGP and PEP have a combined total nameplate gas shipping capacity of approximately 1,214 TJ per day (approximately 443 PJ per year). Figure 10.1 shows that these three pipelines, in aggregate, transported approximately 344.8 PJ during the year ending 30 September 2014 period, accounting for 95.4 per cent of the 361.4 PJ of gas transported in WA during that time.

Figure 10.1: Quantity of gas shipped by pipeline, Q4 2013 to Q3 2014

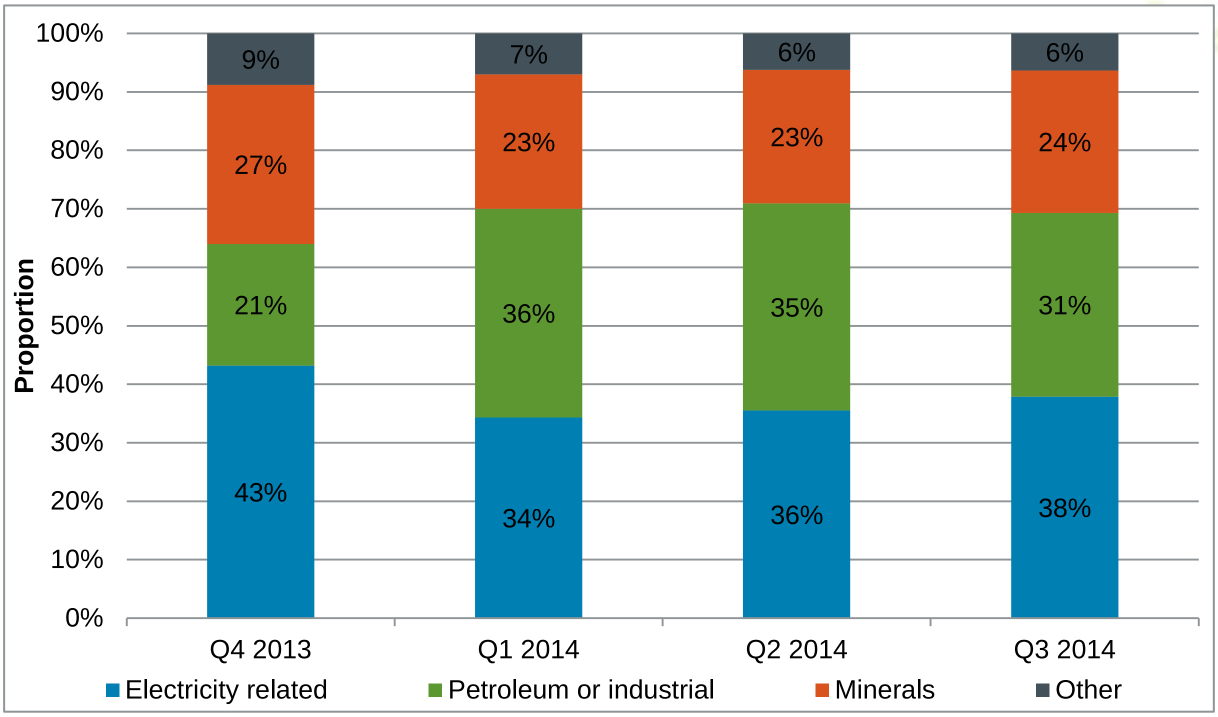


Source: IMO GBB data.

Note: The higher quantity shipped in Q3 2013 was likely to be related the filling of the MGSF over this period.

Using data from the GBB, Figure 10.2 reports the percentage of gas shipped by shippers allocated into four broad categories (Minerals, Petroleum and Industrial, Electricity Related and Others) for the 1 October 2013 to 30 September 2014 period.

Figure 10.2: Proportion of gas shipped according to classification, Q4 2013 to Q3 2014



Source: IMO GBB data.

The figure shows that the largest share of gas is shipped for use by electricity-related entities, such as Synergy and Alinta Energy, and again shows the effect of injecting gas into the MGSF by Synergy as a foundation customer in Q3 2013.

10.2 Gas pipelines

10.2.1 Pipeline utilisation

This section gives an overview of the relative utilisation of each of the WA gas pipelines, as an introduction to their available supply position. Table 10.2 presents the average and peak actual gas flows as a percentage utilisation of each pipeline's nameplate capacity, for the period 1 October 2013 to 30 September 2014. This table highlights that shipping capacity may be available on all major WA transmission pipelines (with the exception of Telfer Gas Pipeline) as the maximum utilisation on the gas peak day does not reach 100 per cent.

Table 10.2: Estimated utilisation rates of pipelines, 1 October 2013 to 30 September 2014

		Peak utilisation		Average utilisation (%)			
Pipeline	Nameplate capacity (TJ per day)	Peak day utilisation (%)	Date of peak day	Q4 2013 (%)	Q1 2014 (%)	Q2 2014 (%)	Q3 2014 (%)
DBNGP	845.0*	92.5	9/7/2014	76.0	75.3	74.5	78.8
GGP	155.0/ 202.0*	82.5	7/6/2014	72.1	69.6	67.3	58.8
PEP**	166.0	46.1	4/1/2014	38.4	37.3	37.6	37.6
Telfer Gas Pipeline	29.0	103	17/10/2013	89.1	83.8	72.4	71.8
Mid West Pipeline	10.6	63.2	21/11/2013	49.1	48.5	49.3	49.3
Parmelia Pipeline	65.4	69.4	31/7/2014	25.8	20.4	33.4	37.5
Kalgoorlie to Kambalda Pipeline	29.3	74.1	9/8/2013	59.8	50.9	45.8	46.5
Kambalda to Esperance Pipeline	6.0	Not Reported^					

Source: *IMO GBB data.*

Note: Utilisation rate of each pipeline is calculated using the assumption that the nameplate capacity of each pipeline applies to the full length of the pipeline. *Full-haul capacity only **Excludes the utilisation of Burrup Extension Pipeline. ^The Kambalda to Esperance Pipeline is exempt from registration under the GSI Rules.

Some underutilisation is to be expected due to fluctuating market demand for gas on a day-to-day basis, which can result from variation in operational requirements (e.g. fluctuation in electricity demand, plant maintenance) or economic conditions (e.g. mines being put into 'care and maintenance'). It is also understood that some customers may over-contract for gas to ensure they have delivery capability at all times which can meet their maximum daily requirement. Some shippers may also be over-contracted as a result of their demand having decreased, potentially due to efficiency improvements or other operational and economic considerations.

Pipeline utilisation can also be managed by shippers to avoid paying for unused capacity**.** Some gas shippers maximise the usage of their contracted pipeline shipping capacity by shipping gas on behalf of other shippers. Alternatively, firm pipeline capacity is sometimes traded bilaterally on a short to medium-term basis[152].

Given the importance of the DBNGP and GGP to the WA domestic gas market as the two largest transmission pipelines, the sections below provide greater detail about their utilisation. As these pipelines are 'covered' by third party access regulation, more information

[152] The trading of shipping capacity is allowed under Standard Shipping Contracts.

is provided regarding contracting levels. Both pipelines are also subject to upcoming access arrangement reviews (see section 11.8).

10.2.2 DBNGP

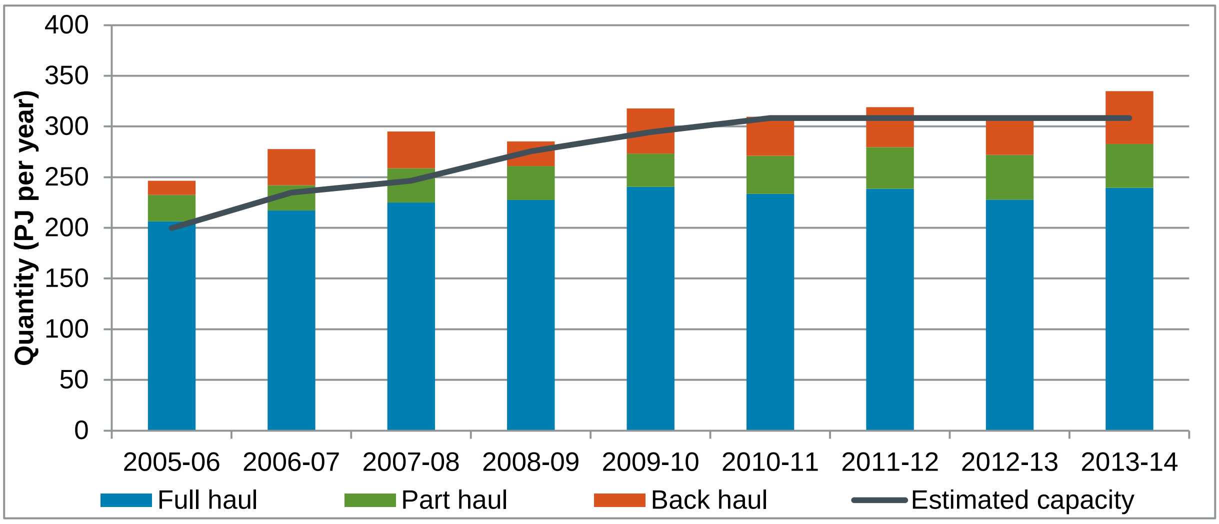
Multiple shipping services are offered on the DBNGP:

- full-haul; the shipping of gas on the DBNGP to any outlet point beyond CS9;
- part-haul; the shipping of gas on the DBNGP to any outlet point before CS9;
- back-haul; the shipping of gas on the DBNGP to any outlet point upstream of the inlet point),
- spot; the purchase of gas transport on a day ahead basis, and
- a Pilbara Service; the shipping of gas from any inlet point to any outlet point between inlet point I101 and CS2).

Full-haul shipment is the dominant service provided by the DBNGP, shipping gas from the gas production facilities located in the north west of WA to gas-consuming facilities located south of CS9.

Actual full-haul gas flows compared to the DBNGP's estimated firm full-haul capacity over the 2005-06 to 2013-14 period are shown in Figure 10.3[153].

Figure 10.3: Estimated firm full-haul capacity of DBNGP compared to quantity of gas shipped (full-haul, part-haul and back-haul), 2005-06 to 2013-14



Source: *Compiled from information from DUET Group (2011 to 2014), DUET Group Management Information Reports (2009-2014) and AER (2007 to 2010).*

Note: The estimated firm full-haul capacity has been revised from the January 2014 GSOO by applying the 845 TJ per day nameplate capacity for 2012-13 and 2013-14 as reported to the IMO.

153 This GSOO focuses on the main shipping services of the DBNGP. The IMO has been advised that DBNGP Transmission also offers other services to shippers (such as spot capacity service, park and loan service, seasonal services and others). Capacity services are also available on the DBNGP on an 'Other Reserved Service' basis. DBNGP Transmission has advised capacity services are highly customised and hence not sufficiently generic to be advertised on the DBNGP Transmission website. They are available by direct inquiry to DBNGP Transmission.

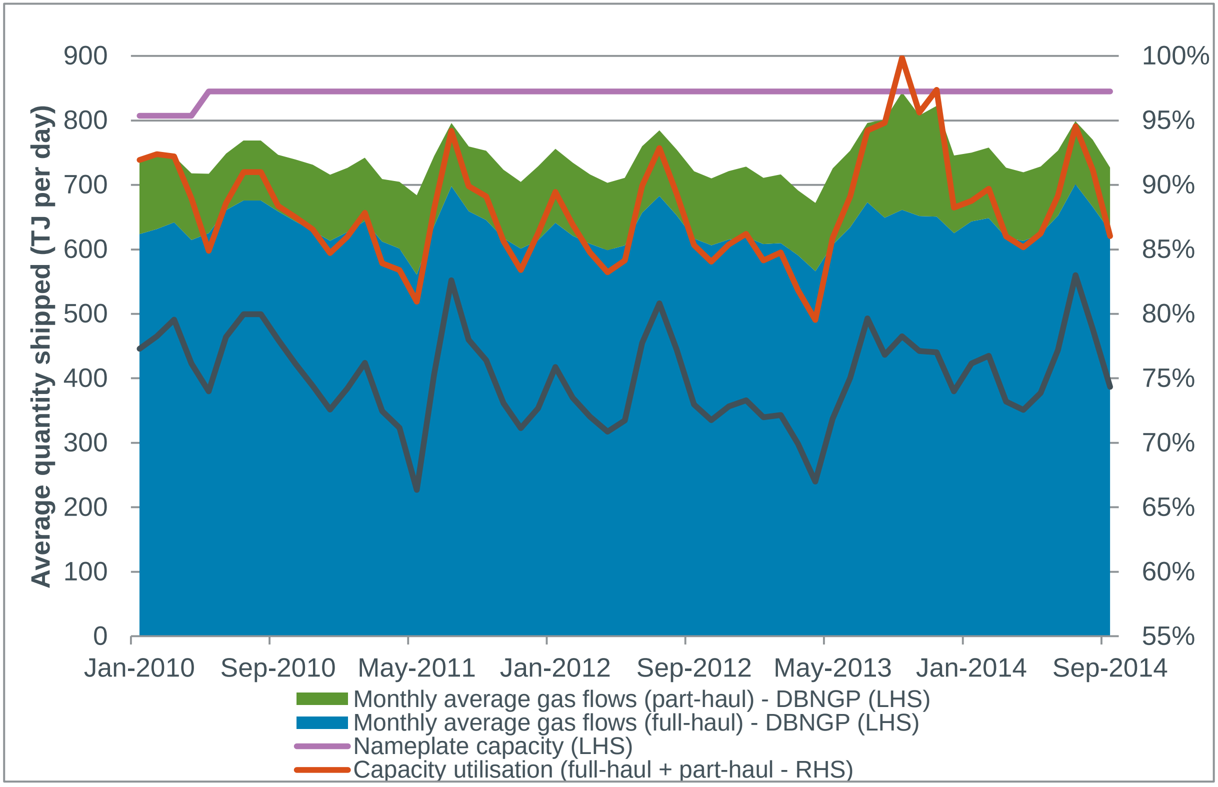
In addition, this figure shows the quantity of gas shipped on the DBNGP on a part-haul and back-haul basis for the same period. The figure shows the increase in the DBNGP's firm full-haul capacity between 2005 and 2010, which was the result of three major expansion projects (DBNGP Expansion Projects 4C, 5A and 5B), and that a surplus now exists.

The expansion projects between 2005 and 2010 have increased the DBNGP's capacity at a faster pace than actual gas deliveries. This is likely to be due to the trend by gas shippers and consumers to over-contract, and commitment to new shipping capacity on gas transmission pipelines to ensure there is sufficient capacity at peak consumption periods and also to allow for growth in gas consumption.

The growth in part-haul shipments is at least partly related to the growth in gas consumption by industrial customers connected to the GGP (shipping gas via the DBNGP to the GGP), while back-haul growth observed in shipping from 2012-13 to 2013-14 is related to BHP Billiton shifting the majority of its gas supply from the KGP to the Macedon production facility.

Utilisation of the various shipping services also fluctuates from month to month. Figure 10.4 shows the utilisation of the full-haul and part-haul services on the DBNGP from January 2010 to September 2014 in monthly resolution. This figure shows that the quantity of gas shipped full-haul has remained relatively stable over the period; apart from seasonal variation (monthly quantities are greater in the winter months, especially for the month of July). Part-haul deliveries have also been relatively stable over the period displayed, aside from shipping related to the filling of the MGSF in late 2013.

Figure 10.4: Gas shipped by product (full-haul and part-haul only), January 2010 to September 2014



Source: DBP Transmission (full-haul and part-haul monthly averages) and IMO GBB data.

Note: Nameplate capacity is as per Figure 10.3. Actual gas flows are monthly average gas flows.

As noted above, spare capacity has emerged during the last two years as a result of the expiry and renegotiation of shipping contracts and the expansion of pipeline capacity. This is shown in Table 10.3, which compares available pipeline capacity with the level of capacity which is contracted on a firm basis, over the last three years, as published in the DBNGP Capacity Register[154]. In addition, this table compares DBNGP's forecasts of pipeline usage compared to the eventual actual throughput for the same period.

Table 10.3: DBNGP contracted capacity, year ending December 2012, June 2014 and June 2015

	For the year ending		
DBNGP – Full-Haul	December 2012 (TJ per day)	June 2014 (TJ per day)	June 2015 (TJ per day)
Available Capacity (Firm and Interruptible)	867.0	867.0*	845.0 (Firm Only)
Contracted Capacity	867.0	856.5*	756.5 (Firm Only)
Contracted Capacity (%)	100%	98.8%	89.5%
DBNGP's Forecast Full-Haul Throughput	651.0	630.0	646.0
Actual Full-Haul Throughput	630.2	656.0**	N.A.
DBNGP – Part-Haul	December 2012 (TJ per day)	June 2014 (TJ per day)	June 2015 (TJ per day)
Contracted Capacity (Firm and Interruptible)	242.2	242.9*	256.4 (Firm Only)
DBNGP's Forecast Part-Haul Throughput	135.7	130.5*	98.4
Actual Part-Haul Throughput	103.3	119.1**	Not available
DBNGP – Back-Haul	December 2012 (TJ per day)	June 2014 (TJ per day)	June 2015 (TJ per day)
Contracted Capacity (Firm and Interruptible)	174.0	174.0*	223.5 (Firm Only)
DBNGP's Forecast Back-Haul Throughput	137.5	137.5*	186.5
Actual Back-Haul Throughput	133.8	101.3**	Not available

Source: DBNGP (WA) Transmission capacity registers (2012-2014).

Note: *As reported previously on the DBNGP Capacity Register. **Reported in DUET Group Management Information Reports.

DBNGP announced in August 2014 that it had recontracted more than 85 per cent of its firm full-haul capacity under the new Standard Shipper Contracts. During this process a number of shippers brought forward a portion of their rights to relinquish shipping capacity, resulting in the total contracted capacity reducing by 58 TJ per day from 1 July 2014[155]. Despite a

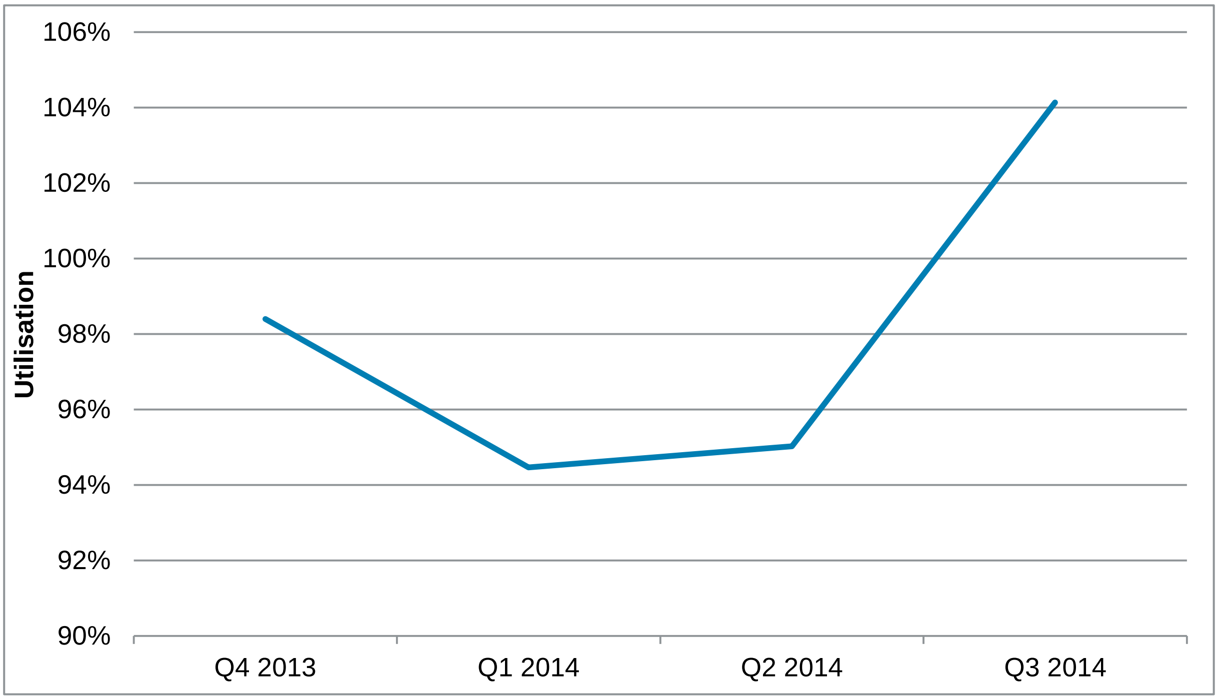
[154] The most recent Capacity Register is DBNGP (WA) Transmission (2014), DBNGP Capacity Register, current as at August 2014.
[155] DUET Group (2014b), DBP Recontracts with its Shippers.

reduction in contracted firm capacity, DBP Transmission has not decreased its forecasts of gas flows on the DBNGP.

It is understood that the terms of some contracts were extended until at least 2025, and that the new contracts provide shippers with greater flexibility in managing their gas shipping requirements. This suggests shippers may be less willing to hold excess shipping capacity in the current environment.

The IMO estimates the contracted capacity of the DBNGP and compares it against actual shipping quantities for the period from October 2013 to September 2014. Based on this assessment, Figure 10.5 shows that contracted capacity was well utilised during Q4 2013 while the MGSF was being filled, before falling in the first half of 2014. As shown in Table **10.2** above, the release of shipping capacity by shippers after June 2014 has resulted in improved utilisation in the July to September 2014 period.

Figure 10.5: Estimated utilisation of DBNGP's contracted capacity, Q4 2013 to Q3 2014



Source: IMO GBB data and DBNGP capacity registers published between 2012 and 2014.

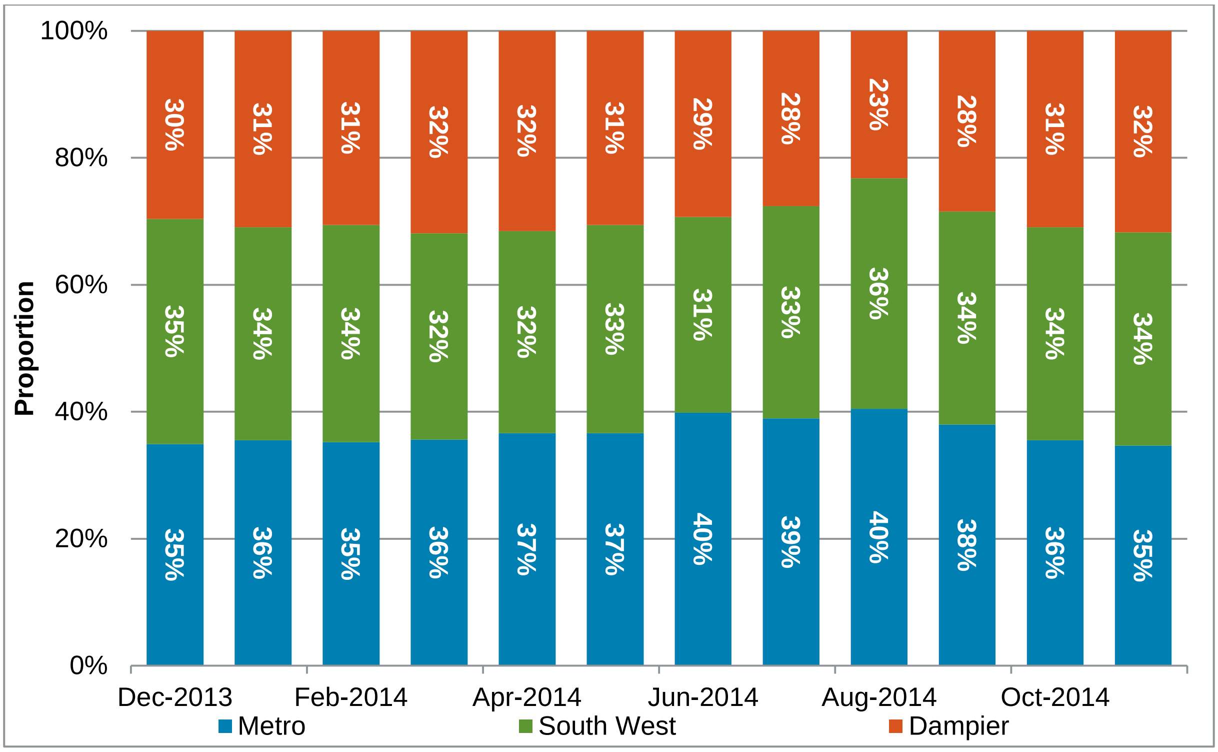
Note: Calculated by dividing total shipped volume for quarter by the contracted firm full-haul capacity. The contracted full-haul capacity is 834.5 TJ per day up to June 2014 and 756.5 TJ per day from July 2014.

Shipments of gas on the DBNGP from inlet points mostly located in the Carnarvon Basin are transported to outlet points located in the Dampier (which includes the connection with the PEP and GGP), Metro (which includes the connection with the Mid-West Pipeline) and South West Zones.

The share of gas deliveries from the DBNGP for the period from August 2013 to 30 November 2014 is shown by GBB zone in Figure 10.6. This figure shows that the largest proportion (between 68 per cent and 77 per cent) of the gas shipped on the DBNGP is delivered to customers in the Metro and South West Zones that are located south of CS7. The increase in shipments to the Metro Zone between August and December 2013 period again relates to the injection of gas into the MGSF.

The Dampier and South West Zones consist mainly of large mining and minerals processing customers, such as Alcoa, BHP Billiton and Rio Tinto. The figure also shows that gas consumption in each region has a relatively regular consumption profile. The exception is August 2014, during which gas deliveries to the Dampier Zone fell significantly as Yara Pilbara's Burrup Fertilisers reduced its gas consumption.

Figure 10.6: Share of gas delivered by zone, DBNGP, December 2013 to November 2014



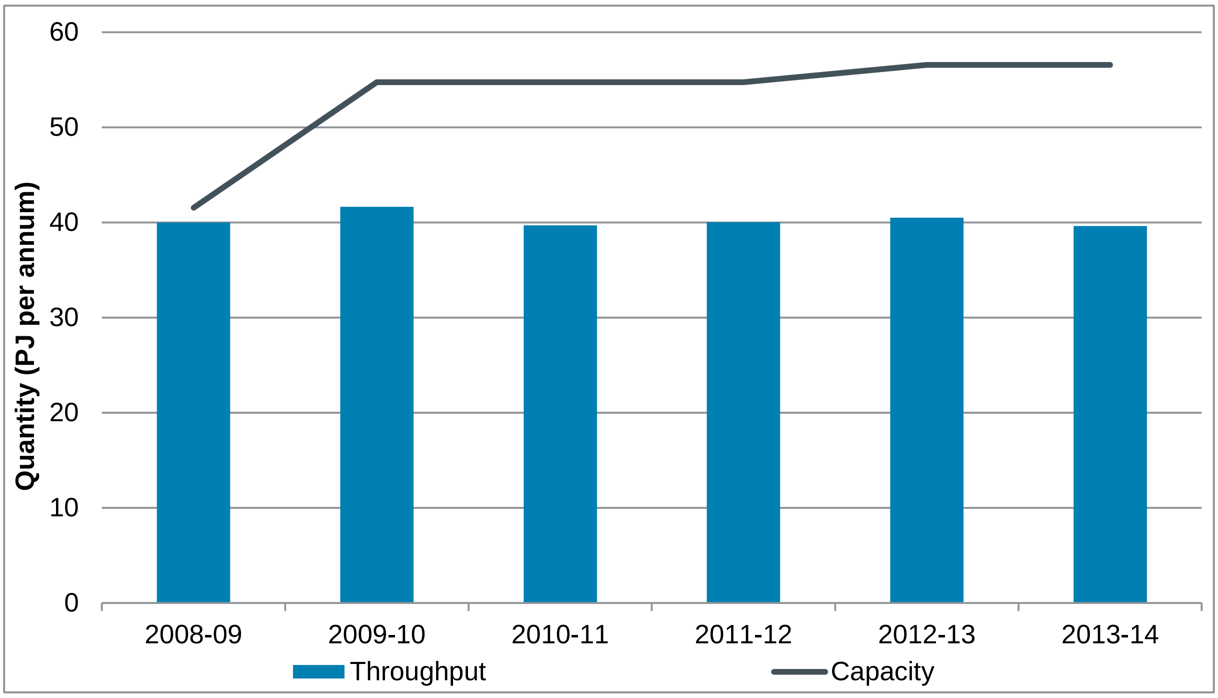
Source: *IMO GBB data.*

Note: Percentages of deliveries by Zone also include deliveries to the PEP and the GGP pipelines.

10.2.3 GGP

After completing an increase to pipeline capacity at the end of September 2014, the GGP now has the second largest transmission capacity of the WA pipelines (202.5 TJ per day). Figure 10.7 reports the estimated annual capacity of the GGP for the 2008-09 to 2013-14 financial years (prior to the most recent expansion) and compares this to the quantity of gas shipped over the same period.

Figure 10.7: Estimated annual capacity of GGP compared to quantity of gas shipped, 2008-09 to 2013-14



Source: *GGP's capacity is estimated from AER (2007-2012), APA Group's public announcements, APA Group submissions to the ERA and information provided to the IMO's GBB. Shipping quantities provided by APA Group.*

The information in Figure 10.7 shows that, similar to the DBNGP, the shipping capacity of the GGP has risen faster than the shipping throughput. Gas shippers on the GGP therefore also appear to have over-contracted shipping capacity to ensure gas demand at peak periods are met, with the increases in pipeline capacity in 2009-10 and 2013-14 not fully utilised.

The APA Group reports in its Spare Capacity Register that there is 3.5 TJ per day of firm transmission capacity available for shipping gas between Yarraloola and Wiluna[156], though its recent access arrangement submission to the ERA suggests that there may be additional spare capacity during the 2015 calendar year.

Contracted capacity levels for only the regulated portion of the GGP are reported below. This is shown in Table 10.4.

[156] APA (2014b). The APA Group also provides other services (such as seasonal services and "as available" services) in additional to firm services on the GGP. APA Group has advised capacity services are highly customised and is dependent on the specific circumstances. They are available by direct inquiry to APA Group.

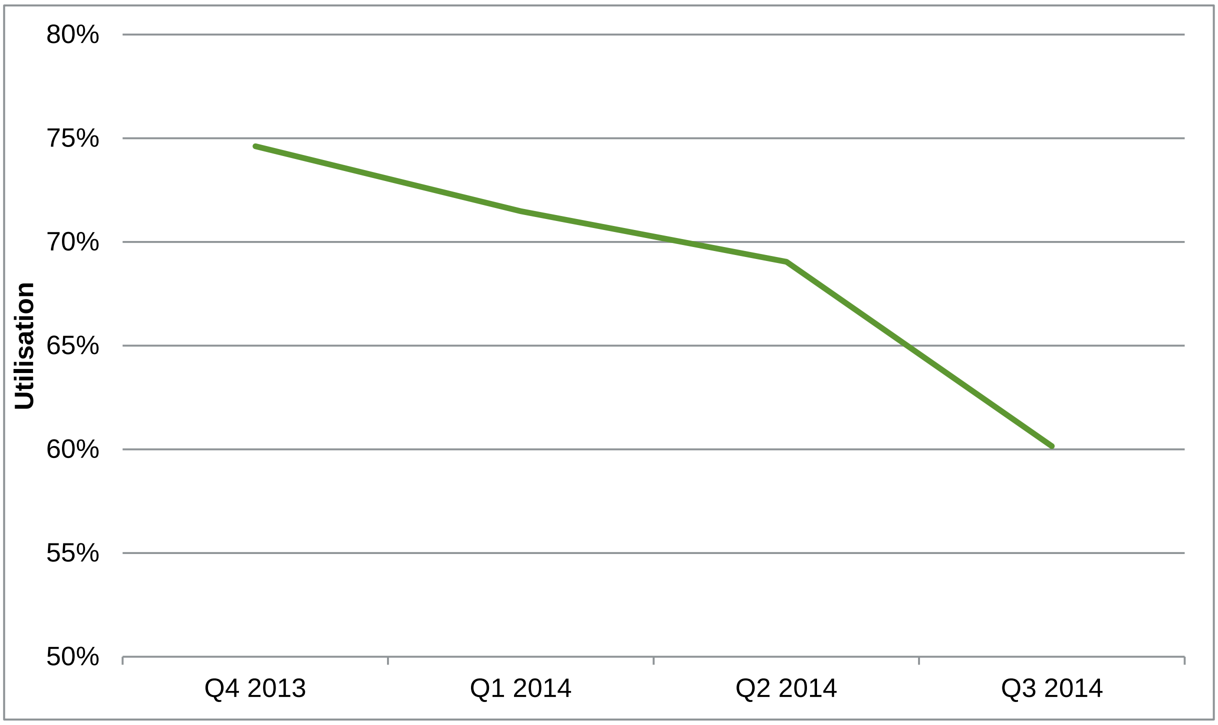
Table 10.4: GGP contracted capacity and forecast throughput (regulated portion only), 2013, 2015 and 2016 calendar years

	2013 (TJ per day)	2015 (TJ per day)	2016 (TJ per day)
Available capacity	108.9		
Contracted capacity	105.4	94.79	105.33
Forecast throughput	89.7	71.42	78.04

Source: APA Group website and ERA website.

A similar estimate of utilisation of contracted capacity can be derived for the GGP from GBB data as was estimated for the DBNGP. Figure 10.8 reports the estimated utilisation of contracted capacity on the GGP for the period from 1 October 2013 to 30 September 2014.

Figure 10.8: Estimated utilisation of GGP's contracted capacity, Q4 2013 to Q3 2014



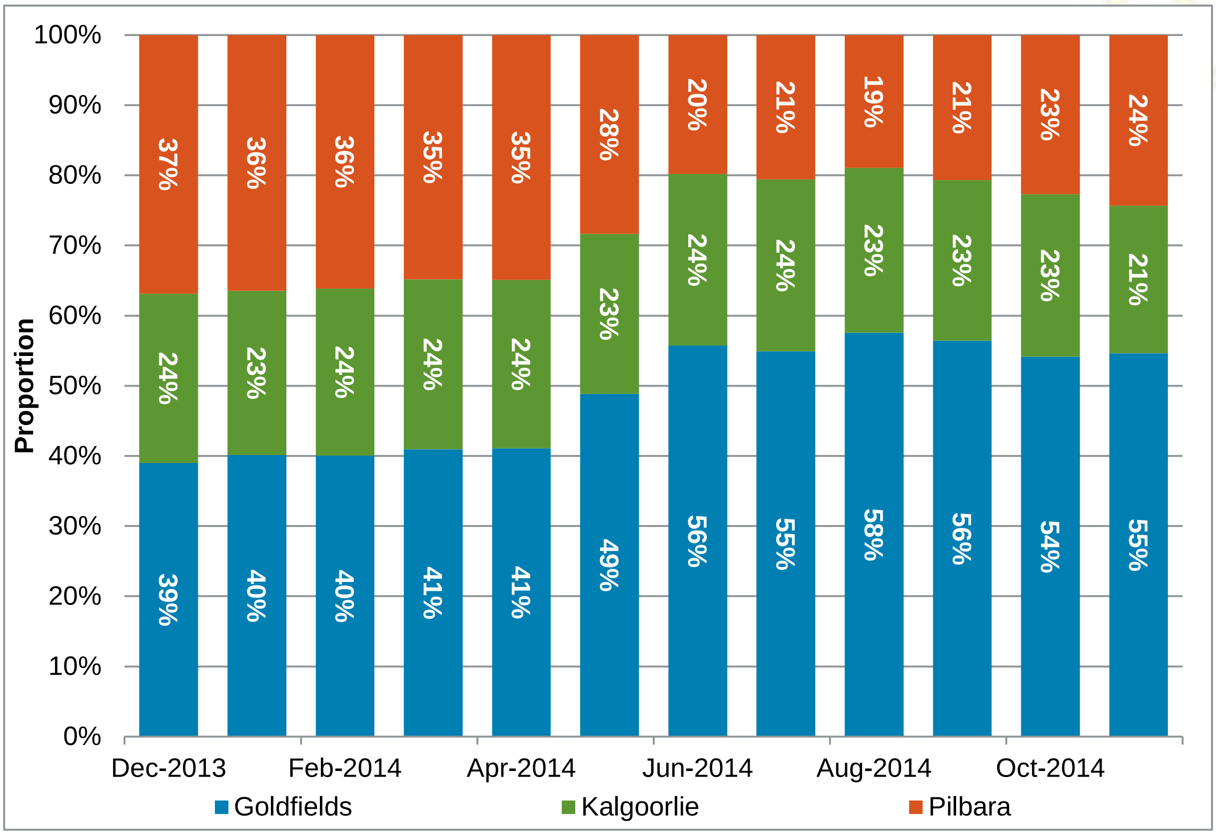
Source: IMO GBB data and IMO estimates.

Note: Calculated by dividing total shipped volume for quarter by the contracted firm full-haul capacity. The contracted full-haul capacity is estimated to be 151.5 TJ per day up to June 2014 and 172 TJ per day from July 2014, based on pipeline capacity reported to the GBB.

Gas shippers on the GGP appear to underutilise their contracted capacity more than on the DBNGP. The underutilisation may be in response to the recent decrease in commodity prices having an effect on operations, as it is estimated that approximately 75 per cent of gas demand on the GGP is understood to be related to gold and nickel mining and processing.

The relative share by Zone of gas shipped along the GGP is shown by month for the period from December 2013 to November 2014 in Figure 10.9 below.

Figure 10.9: Share of gas delivered by zone, GGP, December 2013 to November 2014



Source: IMO GBB data.

The figure shows gas deliveries to the Pilbara Zone have fallen since May 2014, as a result of lower gas demand from Alinta Energy's Newman Power Station that previously supplied power to the township of Newman and BHP Billiton's mining operations. This power station is currently being upgraded and connected to a new high voltage transmission line to allow the station to supply power to Hancock Prospecting's upcoming Roy Hill iron ore mine, and is expected to be operational in March 2015[157].

10.3 Potential opportunities for pipeline investment, 2015 to 2024

It is likely that the projects considered in the Base gas demand scenario that have already attained FID can be met by existing pipeline capacity, new pipelines that are under construction (such as the FRGP) or upcoming pipelines (such as the EGGP). However, as the High gas demand scenario incorporates potential demand growth by prospective projects that have not yet attained FID, there may be opportunities for pipeline companies to assist these prospective projects through provision of gas transmission capacity.

It is understood that additional firm pipeline capacity can be constructed to meet the project timeframes of shippers – as has been shown by recent expansions of both the DBNGP and the GGP. However, continued development of firm gas transmission capacity will depend

[157] UGL Limited (2014). .

upon future gas consumers' requirements for medium to long-term gas supplies, which can underpin investment in new gas pipelines or significant expansions of existing pipelines.

Access to pipeline capacity could be aided by the implementation of a transparent short-term capacity trading platform, as discussed in a 2013 report by the Grattan Institute[158]. An industry-led group of WA gas market participants is currently investigating the potential for gas and capacity trading markets in WA to improve the efficiency of the domestic gas sector. This follows the completion of a consultative, high-level design process for a wholesale spot gas trading market, which was led by the IMO at the request of the GAB[159]. The IMO understands that the potential for wholesale spot gas trading has been identified in the WA Government's Electricity Market Review (EMR) and Commonwealth Energy Green Paper (see chapter 11).

158 Grattan Institute (2013).
159 IMOWA (2014b).

11. Other issues

This chapter discusses other issues that may be relevant to the medium to long-term demand and supply of natural gas in WA.

11.1 Commonwealth Energy White Paper

In December 2013, the Commonwealth Government announced it would develop an Energy White Paper outlining a national energy policy for Australia. A draft White Paper, called the Energy Green Paper, was published in September 2014[160]. The Commonwealth Government intends to release the final Energy White Paper in 2015.

Three policy goals have been outlined in the Green Paper that relate to Australian gas markets:

- facilitate the entry of new domestic gas supply to limit price rises;
- improve market transparency and competition; and
- reform markets to improve flexibility and transparency.

While the majority of the content in the Green Paper on Australian gas markets relates to the gas markets in eastern Australia, the report identifies the potential for developing a gas trading market in WA, in a system similar to the Wallumbilla gas trading hub in Queensland.

11.2 Productivity Commission – examining barriers into efficient gas markets

The Productivity Commission (PC) is currently analysing policy issues in the gas exploration, production and transmission sectors in a bid to uncover impediments that may affect the efficient functioning of Australia's gas markets.

To analyse selected policy issues, the PC's study intends to develop a model of the eastern Australian gas market; in order to investigate:

- the effects of links to global markets for current and future market participants;
- how regulation affects the utilisation, and investment in, gas transmission pipelines; and
- the effects of policies, e.g. environmental, on the location or timing of exploration and development of projects.

Although the study primarily focuses on eastern Australian gas markets, the PC is anticipated to assess barriers for the WA gas market as well. The PC intends to undertake a consultation process and workshop with the gas industry before publishing its research report in March or April 2015[161].

160 Department of Industry (2014a).
161 Productivity Commission (2014).

11.3 Joint marketing of domestic gas sales

The joint marketing of domestic gas has been a feature of the WA domestic gas market since it was approved for the NWS JVs in 1977 by the former Commonwealth Government's Trade Practices Commission under the (then) *Trade Practices Act 1974 (Commonwealth)*. This authorisation was extended to include the Incremental Pipeline JV (IPJV) in July 1998. Although the ACCC authorisation for the IPJV expired in 2005 and the NWS JVs voluntarily revoked its authorisation in 2007, joint marketing was subsequently reapproved by the ACCC in 2010 under the *Competition and Consumer Act 2010* until 31 December 2015[162]. Additionally, in November 2009, the Gorgon JV was also authorised to jointly market its gas to the domestic market until 31 December 2015.

Unless the relevant parties apply to the ACCC for a continuation of these arrangements and the ACCC approves the application, these authorisations will expire on 31 December 2015.

The potential discontinuation of joint marketing of domestic gas may be the most important change to the WA domestic gas market in the upcoming forecast period. If the joint marketing of domestic gas ceases, the number of gas suppliers to the domestic gas market may increase from ten to approximately 17, potentially including Chubu Electric, ExxonMobil, Shell, Osaka Gas, Tokyo Gas (other Gorgon JV partners), BP and Japan Australian LNG (NWS JV partners) by the end of 2024 (after the completion of Gorgon and Wheatstone domestic gas facilities).

At the time of this report, it is not known whether the entities within the Gorgon and the NWS JVs will seek to reapply to the ACCC for extensions to the joint marketing authorisations.

11.4 WA Government inquiry into FLNG

In May 2013, the WA Government instructed the Economics and Industry Standing Committee (EISC) to determine the effect of FLNG projects on the following sectors of the WA economy:

- engineering and design;
- fabrication and manufacturing;
- construction and ancillary services; and
- domestic gas supply and industrial gas users.

The EISC was also instructed to determine the effect of FLNG operations on WA Government revenue. Public hearings were conducted in late 2013 and the report was tabled in Parliament in May 2014[163].

The report suggests the development of FLNG projects is less economically beneficial to WA than onshore LNG processing. This is largely because the construction of the FLNG vessels occurs in South Korea, providing fewer opportunities for WA suppliers and labour to participate in these projects. Despite that, the construction and operation of the onshore supply and support bases for FLNG projects is likely to benefit WA.

162 For more detailed background information about the history of joint marketing in WA, please refer to the July 2013 GSOO.
163 EISC (2014).

The report also notes that the majority of FLNG projects are not subject to the state's domestic gas reservation policy as they are situated in Commonwealth waters. This also means any royalties accruing from the extraction of hydrocarbons will be received by the Commonwealth Government through the Petroleum Resource Rent Tax.

A second inquiry, into the safety of FLNG, is currently being undertaken by the EISC. The report is anticipated to be tabled in Parliament by the end of March 2015.

11.5 WA Government inquiry into hydraulic fracturing ('fracking')

In August 2013, the Standing Committee on Environment and Public Affairs began an inquiry into the use of hydraulic fracturing for the extraction of unconventional gas resources[164]. This inquiry is still in the process of conducting public hearings on the issue. To date, 17 public hearings have been held and some 117 written submissions on the issue have been received.

The aim of the inquiry is to determine the implications of hydraulic fracturing in WA, including studies of:

- the effects on current and future land use;
- the regulations on chemicals used in the activity;
- the use of ground water associated with the activity and the possibility of using recycled water for the activity; and
- the rehabilitation of land that has been hydraulically fractured.

11.6 WA Government Electricity Market Review

In March 2014, the Minister for Energy launched the WA Government's EMR[165]. The EMR seeks to examine all existing structures of the WEM to examine options to:

- reduce the costs of production and supply of electricity and electricity related services, without compromising the safety and reliability of electricity supply;
- reduce the government's exposure to energy market risks, by encouraging the private sector to fund future electricity infrastructure needs without subsidies from government; and
- develop a framework to attract an appropriate level of private sector investment to facilitate long-term stability in the WEM.

Phase One of the review aims to identify and assess the strengths and weaknesses of the current industry structure, market institutions and regulatory arrangements to develop options for electricity market reforms. 'Fuel' is one of the six work streams identified for this phase.

An EMR Discussion Paper was released for public consultation in August 2014, including consideration of the outlook for fuels for electricity generation in the WEM, including gas. The Discussion Paper specifically sought feedback on issues relating to:

164 EISC (2014b).
165 See the website of the Public Utilities Office for more information on the EMR.

- the level of future domestic gas prices in relation to LNG netback prices;
- the sufficiency of reserves for future electricity generation needs;
- how to increase transparency and liquidity in the WA domestic gas market; and
- how downstream markets can best encourage new domestic gas supplies.

The EMR Steering Committee received 49 submissions in response to the Discussion Paper. It is understood that the WA Government received an Options Paper prepared by the Steering Committee in late 2014. Phase Two of the EMR is then intended to involve development of the detailed design of a set of selected reforms and implementation arrangements.

11.7 ERA microeconomic reform inquiry

The ERA completed its microeconomic reform inquiry in July 2014. This inquiry included an assessment of the domestic gas reservation policy that currently requires all LNG producers that operate within state waters or who require onshore gas processing facilities to reserve 15 per cent of total gas production from each export facility for the domestic gas market.

The ERA considers that the economic costs of the policy outweigh the benefits and advocates its removal[166]. However, in response, the WA Government has stated that it is not considering changes to the domestic gas reservation policy. While the WA Government publicly outlined its position on the policy in July 2014, DSD suggests that the WA Government intends to review this policy in 2014-15[167].

11.8 ERA's review of gas access arrangements

Under the *National Gas Access (WA) Act 2009*, the ERA is responsible for the independent regulation of covered gas pipelines in WA, including the approval of access arrangements to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

DBNGP Transmission is required to submit information for a review of its access arrangement for the 2016 to 2020 period to the ERA by 1 January 2015[168]. The ERA is currently reviewing the proposed access arrangement submitted by Goldfields Gas Transmission Pty Ltd[169], the operator of the GGP, for the covered portion of the GGP. A decision is anticipated to be delivered in 2015. The ERA is also currently reviewing the proposed access arrangement submitted by ATCO Gas Australia for the Mid-West and South-West Gas Distribution Systems[170]. A decision is anticipated in 2015.

11.9 WA exploration incentive scheme

In April 2009, the WA Government launched an $80 million Exploration Incentive Scheme (EIS) to encourage minerals exploration in under-explored greenfield areas of WA. The goal

166 ERA (2014b).
167 Department of State Development (2011).
168 ERA (2012). Clauses 14.1 and 14.2.
169 ERA (2014c).
170 ERA (2014d).

of the EIS is to stimulate private investment by co-investing with industry to encourage the exploration of minerals and petroleum that will contribute to the knowledge of WA's geology. The EIS has been extended until 2016-17 with new guidelines and co-investment limits on drilling costs.

Since the commencement of the program, eight oil and gas exploration projects have received co-investment funding under this program. However, since 2012, there has not been an applicant to the EIS from the petroleum industry.

Appendix A. Abbreviations

2P – proven and probable

A$ - Australian dollar

ABS – Australian Bureau of Statistics

ACCC – Australian Competition and Consumer Commission

ACOLA – Australian Council of Learned Academies

AER – Australian Energy Regulator

AFR – Australian Financial Review

APPEA – Australian Petroleum Production and Exploration Association

bcm – billion cubic metres

BREE – Bureau of Resources and Energy Economics

CCIWA – Chamber of Commerce and Industry Western Australia

CMEWA – Chamber of Minerals and Energy Western Australia

CNG – compressed natural gas

CSG – coal seam gas

CSIRO – Commonwealth Scientific and Industrial Research Organisation

DAE – Deloitte Access Economics

DBNGP – Dampier to Bunbury Natural Gas Pipeline

DBNGP Transmission – DBNGP (WA) Transmission Pty Ltd

DMP – Department of Mines and Petroleum

DOI – Department of Industry

DSD – Department of State Development

EDR – economic demonstrated resources

EGGP – Eastern Goldfields Gas Pipeline

EIA – (United States) Energy Information Administration

EISC – Economics and Industry Standing Committee (WA Parliamentary Committee)

EMAS – Energy Market Authority of Singapore

EMR – Electricity Market Review

ERA – Economic Regulation Authority of WA

F&D – finding and developing

FID – final investment decision

FLNG – floating liquefied natural gas

FMG – Fortescue Metals Group

FRGP – Fortescue River Gas Pipeline

GAB – Gas Advisory Board

gasTrading – Gas Trading Australia Pty Ltd

GBB – Gas Bulletin Board

GDP – gross domestic product

GGP – Goldfields Gas Pipeline

GJ – gigajoule

GSI – Gas Services Information

GSOO – Gas Statement of Opportunities

GSP – gross state product

GWh – gigawatt hour

IEA – International Energy Agency

IEEJ – Institute of Energy Economics Japan

IGU – International Gas Union

IMO – Independent Market Operator

IPJV – Incremental Pipeline JV

KGP – Karratha Gas Plant

JV – joint venture

LNG – liquefied natural gas

LPG – liquefied petroleum gas

MGSF – Mondarra Gas Storage Facility

mmbtu – million British thermal units

mt – million tonnes

mtpa – million tonnes per annum

MW – megawatt

NIEIR – National Institute of Economic and Industry Research

NSW – New South Wales

NT – Northern Territory

NWS – North West Shelf

OPEC – Organization of the Petroleum Exporting Countries

PC – Productivity Commission

PEP – Pilbara Energy Pipeline

PJ – petajoule

Q – quarter

Qld – Queensland

RET – Renewable Energy Target

SA – South Australia

SDR – sub-economic demonstrated resources

SWIS – South West Interconnected System

Tas – Tasmania

TEPCO – Tokyo Electric Power Company

tcf – trillion cubic feet

TJ – terajoule

US – United States

US$ - US dollar

Vic – Victoria

WA – Western Australia

WA Treasury – WA Department of Treasury

WEM – Wholesale Electricity Market

Appendix B. Forecasts of economic growth

Table B.1: Growth in Australian gross domestic product (per cent per year)

Year	Actual	Base	High
2006-07	3.8		
2007-08	3.7		
2008-09	1.7		
2009-10	2.0		
2010-11	2.2		
2011-12	3.6		
2012-13	2.7		
2013-14	3.0		
2014-15		2.8	3.3
2015-16		2.3	3.2
2016-17		2.2	3.2
2017-18		2.5	3.2
2018-19		2.2	3.2
2019-20		2.2	3.4
2020-21		2.1	2.9
2021-22		1.5	2.4
2022-23		1.2	2.0
2023-24		1.8	2.6
2024-25		2.5	3.6
Average growth		**2.1**	**3.0**

Source: NIEIR forecasts 2015 to 2024.

Table B.2: Growth in WA gross state product (per cent per year)

Year	Actual	Base	High
2006-07	6.1		
2007-08	4.0		
2008-09	4.2		
2009-10	4.2		
2010-11	4.1		
2011-12	7.4		
2012-13	5.1		
2013-14	5.6		
2014-15		5.1	6.2
2015-16		4.8	6.2
2016-17		3.3	4.7
2017-18		3.7	4.8
2018-19		2.3	3.4
2019-20		2.4	3.7
2020-21		1.6	2.8
2021-22		1.3	2.4
2022-23		2.8	4.2
2023-24		2.9	4.2
2024-25		4.0	5.3
Average growth		**3.1**	**4.4**

Source: NIEIR forecasts 2015 to 2024.

Appendix C. List of production facilities included in potential supply, 2015 to 2024

Table C.1: Production facilities included in potential supply forecasts

Production facility	Operator/ expected operator	Basin	Estimated gas production capacity (TJ per day)	Estimated start-up	Comments
Karratha Gas Plant (NWS)	NWS 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.	
Macedon	BHP Billiton	Carnarvon	200	N.A	
Gorgon Domestic	Chevron	Carnarvon	300	mid/late 2015 (182 TJ per day)	Capacity is anticipated to be 182 TJ per day until 2020
Wheatstone Domestic	Chevron	Carnarvon	200	2018	
Dongara	AWE Limited	Perth	7	N.A.	Facility may be expanded due with the commercialisation of Senecio fields.
Beharra Springs	Origin Energy	Perth	19.6	N.A.	
Red Gully	Empire Oil and Gas	Perth	10	N.A.	Facility has provisions to expand capacity to approximately 20 TJ/day
Total gas production capacity			**1976.6 TJ per day by the end of 2024**		

Source: Public announcements and respective corporate websites.

Appendix D. Medium to long-term average (ex-plant) new gas contract prices

Table D.1: Average medium to long-term gas price forecasts (ex-plant) (real, $ per GJ)

Year	Base	High
2015	$ 5.48	$ 6.75
2016	$ 6.28	$ 7.73
2017	$ 7.53	$ 8.93
2018	$ 7.49	$ 8.78
2019	$ 8.49	$ 9.99
2020	$ 8.55	$ 9.93
2021	$ 9.66	$ 10.97
2022	$ 9.44	$ 10.64
2023	$ 8.92	$ 10.03
2024	$ 8.90	$ 10.00

Source: NIEIR forecasts 2015 to 2024.

Appendix E. LNG requirement forecasts, 2015 to 2024

Table E.1: LNG feedstock estimates (PJ per year)

Year	Base	High
2015	1,262.4	1,262.4
2016	1,728.4	1,728.4
2017	2,422.8	2,422.8
2018	2,647.5	2,647.5
2019	2,647.5	2,788.8
2020	2,788.8	3,123.4
2021	2,930.0	3,519.4
2022	2,930.0	3,606.3
2023	2,930.0	3,606.3
2024	2,930.0	3,606.3

Source: NIEIR forecasts 2015 to 2024.

Table E.2: LNG processing estimates (8 per cent of feedstock) (PJ per year)

Year	Base	High
2015	101.0	101.0
2016	138.3	138.3
2017	193.8	193.8
2018	211.8	211.8
2019	211.8	211.8
2020	211.8	223.1
2021	211.8	234.4
2022	211.8	234.4
2023	211.8	234.4
2024	211.8	234.4

Source: NIEIR forecasts 2015 to 2024.

Table E.3: Total LNG requirement estimates (PJ per year)

Year	Base	High
2015	1,363.3	1,363.3
2016	1,866.7	1,866.7
2017	2,616.6	2,616.6
2018	2,859.4	2,859.4
2019	2,859.4	3,011.9
2020	3,011.9	3,373.3
2021	3,164.4	3,801.0
2022	3,164.4	3,894.8
2023	3,164.4	3,894.8
2024	3,164.4	3,894.8

Source: NIEIR forecasts 2015 to 2024.

Appendix F. Conversion factors

The following conversion factors have been applied when preparing this GSOO.

Table F.1: Conversion factors

	To						
Natural gas and LNG	Billion cubic meters NG	Billion cubic feet NG	Million tonnes of oil equivalent	Million tonnes LNG	Trillion British thermal units	Million barrels oil equivalent	Petajoule
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
Petajoule	0.027	0.943	-	0.018	0.943	0.172	1

Note: NG – natural gas.

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