INDEPENDENT
MARKET
OPERATOR

Gas Statement of Opportunities

January 2014

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

Preface

We are pleased to present the second Gas Statement of Opportunities (GSOO) prepared by the Independent Market Operator (IMO).

The GSOO aims to improve the transparency of the gas market by highlighting opportunities to market participants and policy makers that will assist with the further development of the Western Australian (WA) gas market.

Since the publication of the first GSOO in July 2013, development of the WA gas market has continued with the commissioning of two new gas producing facilities, Macedon and Red Gully, and the completed expansion of WA's only gas storage facility, Mondarra.

This second GSOO provides updated forecasts of gas demand and supply to the WA domestic gas market for the 2014 to 2023 period and also provides an early view of data from the IMO's Gas Bulletin Board. While the GSOO focuses on the domestic natural gas sector, this GSOO also considers the outlook for the WA liquefied natural gas (LNG) export sector, due to the strong linkages between the domestic gas and LNG export sectors in WA.

The GSOO has continued to benefit from valuable feedback and contributions from existing gas market participants and other industry stakeholders. We gratefully acknowledge the gas market participants and members of the IMO's Gas Advisory Board who have provided suggestions and shared information to assist in shaping the GSOO.

Consultation and feedback continue to be important to the further development of the GSOO and we would like to thank all those who took the time to attend the stakeholder forum and feedback session conducted by the IMO in October 2013.

The IMO looks forward to providing future GSOO reports that will continue to inform an ongoing, lively debate about the future of the WA natural gas industry. The IMO will publish its third GSOO in December 2014, for the 10-year period from 2015 to 2024.

John Kelly
Chair
Independent Market Operator

Allan Dawson
Chief Executive Officer
Independent Market Operator

1. Executive Summary and Key Findings

As one of the key information services established under the *Gas Services Information Act 2012*, the Gas Statement of Opportunities (GSOO) provides an independent insight into the Western Australian (WA) domestic gas market, including forecasts of supply and demand in the market, with the aim of highlighting potential shortfalls, constraints and opportunities in the medium to long-term for existing and potential market participants.

Since publication of the July 2013 GSOO, development of the WA gas market has continued with the completed expansion of the Mondarra gas storage facility, commencement of the Macedon domestic gas production facility in August 2013 and the official commissioning of the Red Gully domestic gas production facility in September 2013.

This GSOO provides, for the forecast period from 2014 to 2023:

- a gas supply and demand assessment (Chapter 3);
- an updated overview of WA's gas market infrastructure (Chapter 4);
- an outlook for the WA economy (Chapter 5);
- descriptions of the forecast methodology and input assumptions (Chapter 6);
- forecasts of WA gas demand (Chapter 7);
- an updated view of the international liquefied natural gas (LNG) market (Chapter 8);
- forecasts of potential WA gas supply (Chapter 9);
- estimates of WA gas reserves (Chapter 10);
- a view of transmission infrastructure (Chapter 11); and
- a brief on Commonwealth and WA Government inquiries of relevance to the WA domestic gas market (Chapter 12).

To ensure a comparable, consistent approach is applied for this GSOO, the IMO has retained the services of the National Institute of Economic and Industry Research (NIEIR) to perform the modelling of gas supply and demand. NIEIR is a forecasting consultancy that has spent more than 25 years modelling various gas and electricity markets across Australia, including WA. For this GSOO, NIEIR updated its WA gas forecasting models developed for the July 2013 GSOO to provide revised forecasts of gas demand and supply.

1.1. Key Findings of the GSOO

Key findings for the 2014 to 2023 period are:

- as WA has an abundance of gas reserves and existing and planned gas processing capacity, these are not meaningful measures of supply to the domestic market. Rather, it is important to consider the extent to which this gas will be made available to the domestic market (the 'potential supply');
- there is likely to be adequate potential gas supply to meet existing contracted gas demand and expected growth in gas demand in the domestic market for the 2014 to 2020 period assuming that commercially acceptable terms can be agreed between suppliers and customers;
- **for the 2021 to 2023 period, the availability of gas to the WA domestic market is likely to be sufficient if the North West Shelf (NWS) Joint Ventures (JVs) supply at levels considered in the Upper potential supply forecasts, but may not be sufficient (at forecast prices) to meet forecast domestic demand if the NWS JVs do not supply gas to the domestic market beyond existing contracts (as reflected in the Lower potential supply forecasts)**;
- **estimates suggest while the NWS has sufficient 2P[2] reserves for the forecast period, the availability of gas supply from the NWS JVs is pivotal to the domestic gas supply-demand balance for the 2021 to 2023 period and is dependent on:**
    - **the outcomes of ongoing discussions between the WA Government and the NWS JVs that relate to the status of remaining NWS reserves;**
    - **investment decisions required by the NWS JVs to access remaining undeveloped reserves; and**

[2] Proven and probable gas reserves. 2P is an estimate of reserves with medium confidence, also referred to as 'P50', see Australian Stock Exchange (ASX) (2013), *ASX Listing Rule Amendments – Reporting Requirements for Oil and Gas Companies*, http://www.asx.com.au/documents/asx-compliance/asx-oil-and-gas-asx-presentation-july-2013.pdf, accessed 18 December 2013.

  - **investment required to extend the life of the aging (30-year old) domestic gas production facility the Karratha Gas Plant (KGP),**

  each of which will involve consideration of the commerciality and profitability of ongoing operations at the KGP;
- the average annual growth in WA's potential domestic gas supply is forecast to be between -0.8% and 1.7% per annum, dependent on the availability of gas from the NWS, while the average annual growth in WA's domestic gas demand for existing and sanctioned projects is forecast to be 0.4% per annum;
- consistent with the July 2013 GSOO, gas production capacity is anticipated to be almost double the forecast level of domestic gas demand by the end of 2023;
- gas demand growth is anticipated to be higher in areas located outside the South West interconnected system (SWIS) compared to within the SWIS;
- total gas demand in WA, including both LNG and floating LNG (FLNG) production (feedstock and processing) and domestic demand, is forecast to grow at approximately 9.5% per annum until 2023 as a result of the expected commencement of production at the Gorgon and Wheatstone LNG and Prelude FLNG projects during the 2014 to 2023 period;
- existing gas resources are forecast to be sufficient to meet forecast domestic, LNG and FLNG demand levels for the forecast period, however longer-term supplies rely heavily on WA's unconventional gas resources (tight and shale resources), which have not yet been verified;
- WA is highly reliant on the Carnarvon Basin for gas reserves and resources and more consideration may be warranted to encourage the diversity of gas supply from other gas basins (e.g. the Browse and Canning Basins) within WA; and
- there are several medium to long-term growth challenges confronting the WA LNG market which may have an impact into the future, but are not expected to affect the domestic natural gas sector in the forecast period, such as:
  - the potential end of premium Asia Pacific LNG pricing;
  - a move toward shorter-term LNG contracts in the Asia Pacific region;
  - the high relative cost of LNG production in Australia; and
  - the threat of unconventional gas entering the international gas market.

Each of these findings is explained in more detail in section 1.2 below.

1.1.1.Changes from the July 2013 GSOO – Key Drivers

The key drivers of the changes to the forecasts since the July 2013 GSOO are set out below.

- Domestic gas consumption forecasts have reduced due to improved assumptions for alumina refining and electricity generation, and an increase in the estimated price elasticity of demand. These improvements were informed by data from the Gas Bulletin Board, which commenced operation on 1 August 2013.
- Total gas demand forecasts have increased due to the inclusion of estimated gas requirements for Prelude FLNG in all total gas demand scenarios and the inclusion of Bonaparte FLNG for the High total gas demand scenario only.
- Gas supply forecasts have reduced due to improvements to the potential supply model, which now considers different segments of supply (contracted and uncontracted) for each production facility, with the uncontracted (or 'price-sensitive') segment influenced by a facility's production costs, required rate of return and forecast gas prices.
- Gas supply forecasts have also reduced due to changes in the assumptions about the capability of the NWS to supply to the domestic gas market following the expiry of existing contracts.
- The model for forecasting medium to long-term average (ex-plant) new contract gas prices has been improved through the revised application of exchange rates and oil-LNG relationships and a shorter time lag between movements in LNG and domestic gas prices.

1.1.2. Response to Stakeholder Feedback on the July 2013 GSOO

Feedback on the July 2013 GSOO was received from confidential one-on-one meetings, a stakeholder workshop held on 7 October 2013 and Gas Advisory Board (GAB) meetings held prior to the release of this GSOO. In response to this feedback, the following changes have been implemented in this GSOO:

- an investigation into the capability of the NWS to continue to supply to the domestic market;

- an investigation of the quantum of reserves supporting each production facility;
- improvements to modelling potential supply (such as the consideration of different production costs for each facility and inclusion of an assumed required rate of return);
- changes to the modelled price elasticity of demand in recognition of observed responsiveness to price rises;
- realignment of the medium to long-term average (ex-plant) new contract prices forecast model; and
- other modelling adjustments to potential supply (e.g. reduction in the time lag for LNG prices to influence domestic gas prices).

The following suggested changes by stakeholders have not been implemented:

- the inclusion of speculative projects (those yet to reach favourable final investment decision) in the GSOO forecasts; and
- analysis of the impact of United States (US) LNG exports on LNG pricing in the Asia Pacific region.

Speculative projects are not included in forecasts for this GSOO as the IMO does not speculate on the timing and outcomes of potential projects that have not obtained favourable investment decisions. However, this GSOO includes a non-exhaustive list of potential upcoming projects in WA (outlined in Appendix 3) that may alter gas demand in the forecast period.

The impact of US LNG exports on LNG pricing is not considered in the forecasts in this GSOO as it is uncertain. Japanese LNG purchasers have indicated their preference for lower LNG purchase prices and their preference for LNG supply contracts to be linked to the Henry Hub[3] gas prices in the US, which are comparatively lower than in the Asia Pacific region.

However, financial institutions have revealed that a shift to Henry Hub-linked LNG pricing is unlikely, as market-reliant gas pricing (such as the Henry Hub) prevents these institutions from managing their lending risks and funding new LNG export capacity[4]. This impasse has curtailed the rapid expansion of LNG export capacity internationally. In addition, recent increases in US domestic gas consumption and prices may reduce the price advantage of US LNG exports into the Asia Pacific region.

1.2. Supply-Demand Balance

Since the publication of the July 2013 GSOO, some market participants have voiced concerns about the continued availability of gas from the NWS JVs to the domestic market beyond 2020, citing a lack of new long-term domestic gas supply contracts from the NWS.

Ongoing supply from the NWS JVs beyond the terms of their existing contracts is dependent on a range of factors, including:

- **the outcomes of ongoing discussions between the WA Government and the NWS JVs that relate to the status of remaining NWS reserves;**
- **investment decisions required by the NWS JVs to access remaining undeveloped reserves; and**
- **investment required to extend the life of the aging KGP,**

each of which will involve consideration of the commerciality and profitability of ongoing operations at the KGP.

Due to this uncertainty, two potential supply scenarios have been developed for the 2014 to 2023 period in this GSOO. The first scenario (the Upper potential supply forecasts) assumes the NWS JVs will continue to supply gas to the WA domestic market for the full forecast period, while the second scenario (the Lower potential supply forecasts) suggests the NWS JVs will only supply domestic gas under their remaining contracts.

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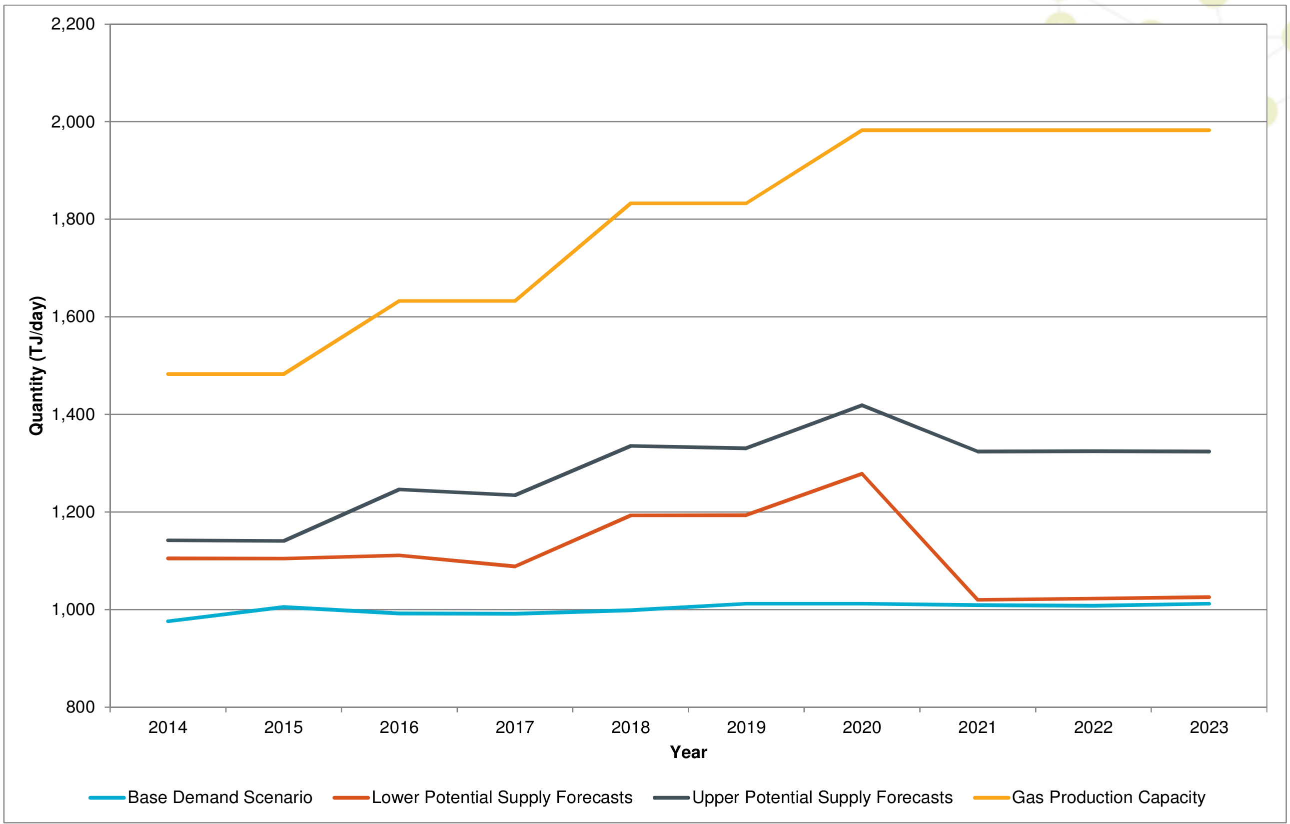
[3] Henry Hub is the main gas price point for the US.
[4] This is consistent with the presentations made by several financial institutions presenting at the 2nd Asia Gas Summit 2013 in Singapore, 30 October to 1 November 2013.

These forecasts are presented in Figure A, which shows the supply-demand balance for the 2014 to 2023 period, comparing the two potential supply scenarios with gas production capacity and the Base demand forecasts.

Figure A – Supply and Demand Balance, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

Figure A suggests the domestic gas market will be well supplied for the period from 2014 to 2020, the year in which the last of the existing NWS domestic gas supply contracts are estimated to expire.

However, for the 2021 to 2023 period, the balance of gas supply and demand in the WA domestic market is contingent on the continuation of supply from the NWS. The Upper potential supply forecasts suggest that the market will continue to be well supplied if the NWS continues to supply to the domestic market. However, the Lower potential supply forecasts suggest tight market conditions (at forecast prices) with the relatively small gap between demand and supply being within the margins of error of the forecasts.

If the NWS continues to supply to the WA domestic market beyond 2020, potential supply to the WA market in the 2014 to 2023 period is forecast to grow at approximately 1.7% per annum from 1,142 terajoules (TJ)/day (417 petajoules (PJ)/annum) in 2014 to 1,324 TJ/day (483 PJ/annum) in 2023, while domestic gas demand is forecast to only grow by 0.4% per annum from 976 TJ/day (356 PJ/annum) to 1,012 TJ/day (369 PJ/annum) in 2023. The supply-demand gap (the difference between the potential domestic supply and domestic demand forecasts) is forecast to increase from approximately 166 TJ/day in 2014 to about 312 TJ/day in 2023. By the end of 2023, potential domestic gas supply is expected to be almost 31% higher than forecast demand for the WA domestic market. The growth in supply is driven by the upcoming Gorgon and Wheatstone domestic gas production facilities.

If the NWS continues to supply the domestic gas market, the potential excess supply of gas in the WA domestic market presents an opportunity to further deepen the gas market through the development of a formalised short-term trading market. A formalised short-term trading market can more rapidly signal gas shortages and excess supply. It may also increase opportunities for trade between gas producers not intending to enter into longer-term gas supply contracts and gas consumers that are considering shorter-term gas requirements for portfolio rebalancing. The GAB has indicated interest in investigating potential gas and capacity trading markets for WA.

However, as shown in Figure A, the supply-demand balance is highly contingent on the NWS JVs being willing to continue to supply gas to the WA domestic market in the forecast period. Recent statements made by the Woodside Energy Chief Executive Officer[5] suggest the NWS is willing to continue to supply to the WA domestic market as long as the price is commercially viable.

If the NWS elects not to supply domestic gas beyond its remaining contracts, it is estimated that the potential supply to the domestic market would increase between 2014 to 2020 from 1,105 TJ/day to 1,278 TJ/day, but would then fall to approximately 1,020 TJ/day in 2021 before increasing slightly to 1,026 TJ/day in 2023. This has the potential to create a very tight WA domestic gas market towards the end of the forecast period which may result in gas prices rising above the forecasts used in this GSOO.

Section 3.1 of this GSOO provides further information on the NWS JVs' existing domestic gas supply contracts, gas reserves and the requirements of the State Agreement with the WA Government.

Forecast supply and demand are further considered below.

1.2.1. Potential Supply

The potential supply forecasts generated for this GSOO are shown in Figure A. These forecasts take into account:

- the timing of upcoming domestic gas production facilities (Gorgon Phases 1 and 2 and Wheatstone);
- the estimated contracted level for each production facility;
- the estimated cost of production (and growth of costs) for each production facility;
- the required rates of return on investment;
- NIEIR's forecast medium to long-term average (ex-plant) new contract prices;
- the continued willingness of the NWS to supply to the WA domestic market; and
- the influence of alternative gas markets (LNG).

The Upper and Lower potential supply forecasts for the 2014 to 2023 period are subject to the assumptions that:

- the start-up timeframes announced for the Gorgon (Phases 1 and 2) and Wheatstone domestic gas production facilities are accurate and remain unchanged;
- there are adequate gas reserves connected to production facilities;
- the performance of each gas field connected to gas production facilities remains unchanged over the forecast period;
- there are no gas supply disruptions to gas production and transmission;
- the estimated new contract prices follow the price path of NIEIR's Base scenario for long-term average (ex-plant) new contract prices; and
- other assumptions applied by NIEIR to the modelling of potential supply are representative of the domestic market.

The Upper potential supply forecasts assume the KGP will supply to the market at a maximum of 470 TJ/day to 2020 (inclusive) and subsequently up to 450 TJ/day to 2023. As domestic gas contracts start to expire from 2015 to 2020, potential supply from the NWS is forecast to fall from 459 TJ/day in 2014 to 299 TJ/day in 2023, assuming none of the 450 TJ/day supply capacity is recontracted between 2021 and 2023[6].

The Lower potential supply forecasts assume the KGP will only supply the NWS JVs' remaining domestic gas supply contracts, with supply declining over the period to 2020 and reducing to zero from 2021 to the end of the forecast period.

In addition to generating a forecast of potential supply as outlined above, this GSOO also considers two other perspectives, namely the availability of gas production capacity and the adequacy of gas reserves to continue to meet gas demand in WA.

[5] According to the West Australia (2013f), *Woodside signals LNG shift*, 11 December 2013, the Chief Executive Office of Woodside Energy has suggested he would like to sell its remaining gas at higher gas prices.
[6] The forecasts of potential supply from the NWS for 2021 to 2023 are 304, 302 and 299 TJ/day.

In the 2014 to 2023 period, a total of 500 TJ/day of domestic gas production capacity is anticipated to be added to existing gas production capacity servicing the domestic gas market, bringing the total gas production capacity to 1,977 TJ/day in 2023. This growth in production capacity, shown in Figure A, is driven by the commencement of the Gorgon (Phases 1 and 2) and Wheatstone domestic gas production facilities.

Figure A also provides a comparison of the forecasts of total gas production capacity, potential supply and the domestic demand for the 2014 to 2023 period. This comparison suggests that over the forecast period, as an aggregate, gas producers are not expected to fully utilise their gas production capacity to supply to the domestic market. It also shows the amount of gas production capacity available to the domestic market in 2023 is predicted to approach almost twice the level of forecast gas demand for that year (see Chapter 9).

1.2.2. Gas Resources and Reserves

In terms of gas resources, WA remains the most gas-endowed state in Australia. The Australian Bureau of Resources and Energy Economics and Geoscience Australia estimate WA onshore and offshore basins hold a total of 159,000 PJ of economic and sub-economic resources in conventional gas, while other studies by the Energy Information Administration in the US report an estimated 305,412 PJ of unconventional gas resources located within WA's basins at the end of 2012. Based on these resource estimates and forecasts of total gas demand (domestic market and the LNG industry) for 2023, and assuming no additional gas resources are discovered by 2023, conventional and unconventional gas resources in WA have the potential to last for at least another 118 years beyond 2023[7].

While there appears to be sufficient gas resources in WA to meet demand well into the future, it should be noted that the majority of reported gas resources (more than 65%) are unconventional (shale and tight gas resources) and have not been properly verified or commercialised. Accordingly, this GSOO takes a conservative approach and only considers conventional gas resources in WA. These conventional gas resources are estimated to last between 27 and 42 years beyond 2023, depending on whether all sub-economic resources will become economic in the future.

Currently 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 domestic consumption and LNG requirements for approximately another 27 years from 2013. 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 in WA's sources of gas supply.

1.2.3. North West Shelf Reserves

In addition to considering the impact on potential supply by the NWS, this GSOO also reviews the continued ability of the NWS to supply to the WA domestic market through the adequacy of gas reserves.

Based on IMO estimates of reserves from public information, the NWS has sufficient 2P reserves to supply the WA domestic market for the 2014 to 2023 period, estimated to be between 12 to 13 years from the end of 2013.

However, it is understood the availability of these reserves will be contingent on the outcome of ongoing discussions between the WA Government and the NWS JVs relating to the status of remaining reserves that have yet to be committed to sale contracts. Under the *North West Gas Development (Woodside) Agreement Act 1979*, the WA Government has to decide the quantum of remaining gas reserves the NWS JVs are allowed to export from WA. This means continued gas supply to the WA domestic market from the NWS is contingent on the outcome of discussions between the State Government and the NWS JVs.

The NWS JVs face increasing costs to produce gas from the aging domestic gas production facility, and to access remaining gas reserves from smaller gas reservoirs. As a proportion of the future capital expenditure relates to capital reinvestment in the domestic gas production plant, a facility that is already more than 30 years old, the IMO considers that the NWS JVs may delay their investment decisions until discussions with the WA Government are completed. If the NWS JVs are unable to agree commercially acceptable terms

[7] The estimate assumes that total gas demand in WA remains constant at approximately 3,596 PJ/annum beyond 2023.

for further sales of domestic gas beyond their existing contracts, they may consider retirement of the domestic gas facility.

Hence, until the outcomes of the discussions and investment decisions of the NWS are established, it remains uncertain whether the NWS JVs will be prepared to commit to longer-term gas supply agreements during the forecast period and the KGP is unlikely to operate at its maximum capacity over the period.

Section 3.1 provides more information on the potential future supply of gas to the domestic market by the NWS JVs.

1.2.4. Domestic Gas Demand

The forecasts of domestic gas demand represent NIEIR's estimates of the quantity of gas required by the domestic market within WA (comprising industrial, commercial and residential demand, but excluding LNG processing consumption) for the 2014 to 2023 period.

Figure A includes the Base demand forecasts for the 2014 to 2023 period prepared by NIEIR. The forecasts predict that domestic gas demand will grow at approximately 0.4% per annum from about 976 TJ/day (356 PJ/annum) in 2014 to about 1,012 TJ/day (369 PJ/annum) in 2023, taking into account NIEIR's forecast average (ex-plant) new contract gas prices in the domestic market.

Domestic gas demand forecasts for the 2014 to 2023 period are based on the following assumptions:

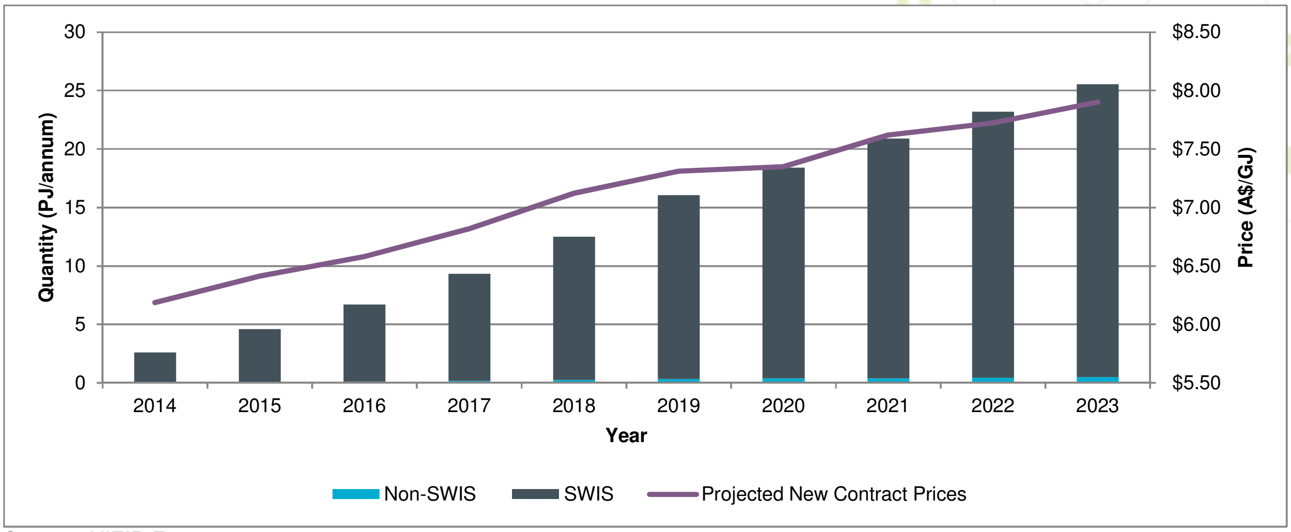
- the WA economy follows the forecast economic growth path;
- the estimated gas consumption forecasts for mining, aluminium, and major industrials are representative;
- the gas consumption for SWIS electricity corresponds with SWIS electricity demand forecasts;
- the price elasticity assumed in the modelling of gas demand is representative; and
- other applied price impacts on gas demand are accurate.

The updated domestic gas demand forecasts in this GSOO suggest that demand will be affected by increasing average new contract gas prices for the 2014 to 2023 period. Whereas the July 2013 GSOO suggested that domestic gas consumption was likely to be quite inelastic, that assumption has been revised for this GSOO as domestic gas sales data for 2012-2013 reported by the Department of Mines and Petroleum suggests recent price increases have started to affect domestic gas demand.

This means increases in average medium to long-term new contract gas prices will be reflected more rapidly by suppression of gas demand over the forecast period. The suppression in gas demand is particularly sharp for areas in the SWIS where there are more readily available substitutes (for example, coal and renewables) for gas consumption for electricity generation.

Figure B presents the suppression of gas demand due to forecast gas prices. This represents additional gas demand that may be realisable if real gas prices remain constant over the forecast period. With constant gas prices, it is forecast that gas consumption in WA in 2023 could be about 27 PJ/annum higher, of which 26 PJ/annum (or 2.5% of total gas demand) is in areas that comprise the SWIS and about one PJ/annum (or 0.1% of total gas demand) is in areas located outside the SWIS.

Figure B – Demand Suppression due to Forecast Real Prices (SWIS and Non-SWIS Demand), 2014 – 2023



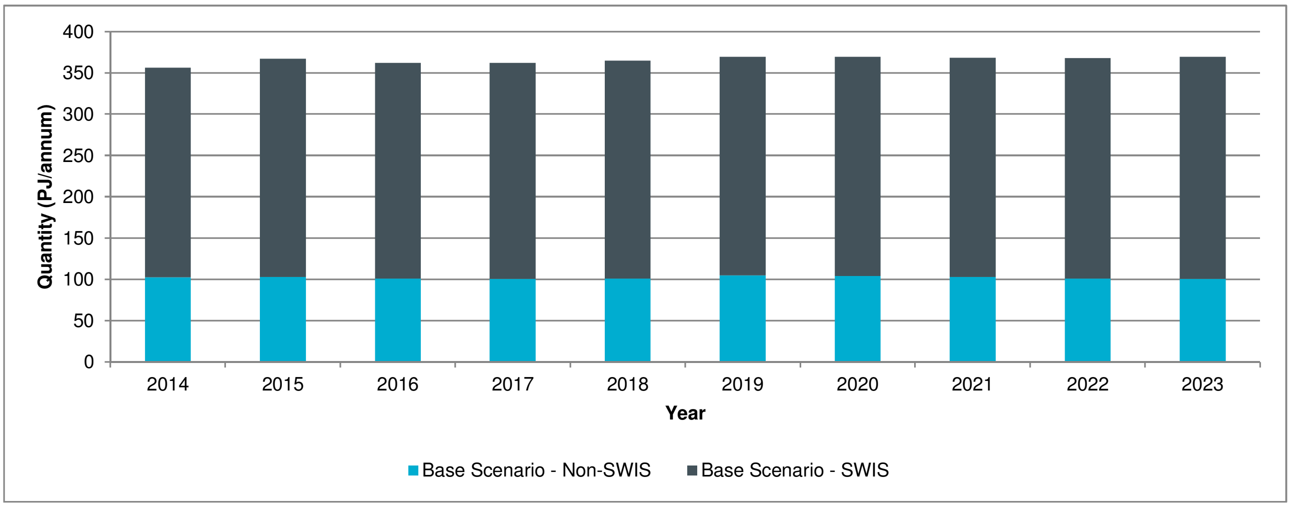
Source: NIEIR Forecasts 2014 – 2023.

1.2.5. Gas Demand by Areas

In assessing domestic gas demand, the IMO has separately considered gas demand in the SWIS and the remainder of the state, recognising that the drivers of gas demand may differ for different areas. For example, demand for gas in the SWIS is heavily impacted by its use for electricity generation, while demand outside the SWIS is largely driven by resource projects that may have limited access to alternative fuels.

Figure C presents the gas demand forecasts for the SWIS and areas outside the SWIS. Gas demand in the SWIS is projected to grow from 254 PJ/annum in 2014 to 269 PJ/annum in 2023. For areas outside the SWIS, gas demand is forecast to be flat from approximately 102 PJ/annum in 2014 to 101 PJ/annum by the end of 2023[8].

Figure C – Gas Demand by Areas, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

1.2.6. Total Gas Demand

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

[8] Noting that only projects that have been approved have been included in the gas demand forecasts.

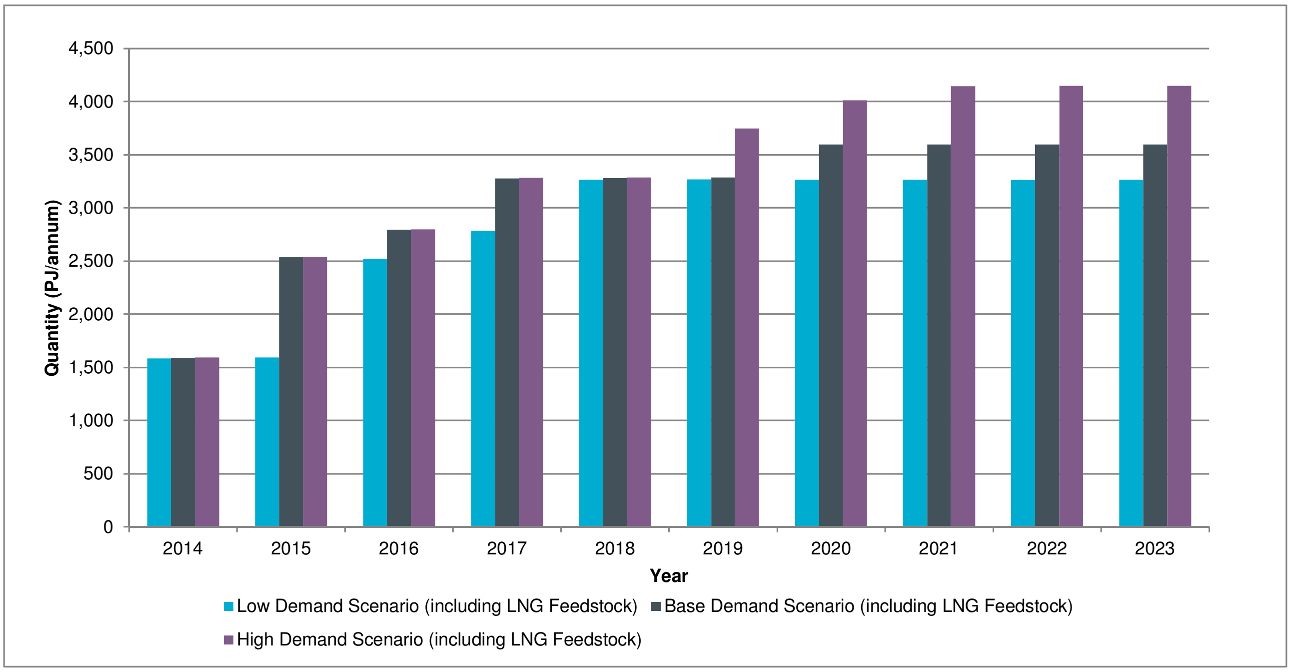
Wheatstone LNG and Prelude FLNG facilities that are anticipated to be completed in the 2014 to 2023 period.

The total gas demand forecasts for the 2014 to 2023 period are based on the assumptions that:

- start-up dates assumed for LNG facilities currently under construction are accurate and remain unchanged; and
- estimates of gas utilised for LNG processing are accurate[9].

This GSOO forecasts total gas demand will increase at approximately 9.5% per annum between 2014 and 2023, from 1,590 PJ/annum in 2014 to about 3,596 PJ/annum in 2023, with LNG requirements projected to increase from 1,142 PJ/annum in 2014 to approximately 2,988 PJ/annum in 2023. Total gas demand for the forecast period is presented in Figure D, with further information available in Chapter 7.

Figure D – Total Gas Demand, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

1.3. Growth Challenges for Western Australia's LNG Exports

Similar to the domestic gas market, WA's LNG export market is also going through a phase of significant expansion and development. In the 2014 to 2023 period, international LNG demand is expected to grow rapidly, with WA's LNG export capacity anticipated to increase from 21 million tonnes per annum (Mtpa) to about 50 Mtpa, more than doubling WA's LNG exports over this period.

Notwithstanding the positive outlook, there are several medium to long-term challenges that are currently confronting the WA LNG industry, including:

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

[9] These forecasts assume LNG processing requirements of 8% of total LNG feedstock. The IMO notes that EnergyQuest (2013) *EnergyQuarterly*, November 2013 Report, suggests a different estimate of 13%.

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

Increasing competition in the supply of LNG to the Asia Pacific market may trigger a reduction in premium LNG prices in the Asia Pacific region relative to the rest of the world. In addition, an increase in LNG exports from North America to the Asia Pacific, which is anticipated towards the end of the forecast period, may weaken LNG prices agreed in existing contracts that are predominantly linked to oil indexes.

Although HSBC Global Research[10] details a slowdown in construction cost increases in Australia, the high cost of LNG production in Australia remains an issue for the LNG export market. McKinsey[11] reports that the cost of developing LNG production and export facilities in Australia is now 20% to 30% higher than that in North America and East Africa. If the cost of developing LNG projects remains high relative to other potential LNG export regions, LNG developments currently planned for WA may be delayed or abandoned.

The emergence of unconventional gas as a new source of gas supply is also a game changer. In the last decade, unconventional gas has transformed the US from a net importer into a net exporter of gas. Unconventional gas is also transforming gas markets in eastern Australia and there are indications that WA is well endowed with unconventional gas resources. While production is still in its early stages around the world, unconventional gas has the potential to transform as well as disrupt the international gas market. The impact of unconventional gas on LNG exports remains unclear and will need to be monitored closely by WA LNG exporters, market regulators and governments.

While these challenges facing the LNG export sector are not expected to affect the domestic supply of natural gas in the forecast period, they may have an impact over the longer-term. More information is provided in Chapter 8.

1.4. Future Anticipated Developments for Western Australia’s Gas Market, 2014 – 2023

Further development of the WA gas market is expected over the forecast period. Known and potential developments include:

- the potential construction and completion of the proposed Bunbury to Albany Pipeline to service customers in the South West, the recently announced Fortescue River Gas Pipeline in the Pilbara to ship gas to Fortescue Metals Group’s Solomon Hub iron ore operations[12] and another potential pipeline, the proposed Great Northern Pipeline in the north-west of WA;
- the Australian Consumer and Competition Commission’s review of the applications for joint marketing of gas (if any) from the NWS JVs and Gorgon JV before the end of 2015;
- the expected submissions to the Economic Regulatory Authority of WA by ATCO Australia, the APA Group and DBNGP (WA) Transmission Pty Limited for gas access arrangements for the WA gas distribution network, the Goldfields Gas Pipeline and the Dampier to Bunbury Natural Gas Pipeline respectively, expected in 2014 and 2015;
- completion of the Gorgon, Wheatstone and Prelude LNG production and export facilities;
- the development of the two new domestic gas production facilities associated with the Gorgon and Wheatstone LNG facilities[13];
- the final investment decisions for potential domestic gas production facilities including Warro, Pluto and Yulleroo/Valhalla; and

[10] HSBC Global Research (2013b), *Downunder Digest, Australia’s growing role in Asian gas markets*, 26 September 2013, https://www.research.hsbc.com/midas/Res/RDV?p=pdf&key=Qae96RMgxq&n=387725.PDF, accessed 18 November 2013.

[11] See McKinsey (2013), *Extending the LNG boom: Improving Australian LNG productivity and competitiveness* http://www.mckinsey.com/global_locations/pacific/australia/en/latest_thinking/extending_the_lng_boom, accessed 20 November 2013.

[12] The IMO’s forecasts were concluded prior to this announcement. It has been estimated that approximately 25 TJ/day of new gas consumption will be transported via the pipeline, which is expected to be completed by the end of 2014 (see DUET Group (2014), *Fortescue River Gas Pipeline Project and $100M Placement, ASX Announcement*, 16 January 2014, http://www.asx.com.au/asxpdf/20140116/pdf/42m4lh487qwc8p.pdf, accessed 16 January 2014 and the West Australian (2014b), *Pilbara pipeline deal a gas for miner*, 17 January 2014).

[13] These facilities are anticipated to proceed as Gorgon’s (Phase 1) domestic facility is already fully contracted to supply domestic gas to Synergy (previously Verve Energy) and an unnamed party, and the Gorgon (Phase 2) and Wheatstone domestic gas production facilities are attached to State Agreements and Domestic Gas Producer Agreements signed between the WA Government and the project partners. See the July 2013 GSOO, available at http://www.imowa.com.au/gsoo, for more details.

- the final investment decisions on other potential LNG projects such as Browse, Equuus, Gorgon Train 4, Scarborough and others located within WA.

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2. Objectives and the 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 gas 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; and
d) the facilitation of competition in the use of natural gas services in the State."

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

"A GSOO must contain information about:

a) natural gas reserves (including prospective or contingent resources);
b) committed and proposed new or expanded:

i. gas production facilities;
ii. gas transmission pipelines and pipeline augmentations;
iii. gas storage facilities; and
iv. large facilities using gas.

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

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

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

This second 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 2014.

2.1. Approach to Forecasting Demand and Supply

This GSOO provides forecasts of gas demand and potential supply for the Western Australian (WA) domestic gas market for the 2014 to 2023 period, to enable an assessment of the adequacy of supply to meet forecast demand over this period. While the GSOO focuses on the domestic natural gas sector, the GSOO also considers the outlook for the WA liquefied natural gas (LNG) export sector, due to the strong linkages between these sectors.

More specifically, this GSOO provides WA forecasts for:

- domestic gas demand (excluding LNG exports and processing) on an annual basis for the 2014 to 2023 period, only considering gas consuming projects that have been sanctioned;

- total gas demand (domestic gas demand plus estimates of LNG exports and processing) on an annual basis for the 2014 to 2023 period; and
- potential supply on an annual basis for the 2014 to 2023 period,

which are conditional on the projections of average domestic gas prices and the availability of gas supply from the North West Shelf (NWS) over the same period.

In forecasting domestic and total gas demand, the IMO considers three scenarios (Base, Low and High) based on corresponding assessments of economic conditions in WA and reflecting the price elasticity of demand by incorporating forecast gas prices.

In projecting domestic gas demand, the IMO separately considers gas demand in the area of WA that comprises the South West interconnected system (SWIS) and the remainder of the state. The drivers of gas demand are likely to be different in these areas and also reflect the substantial use of natural gas for electricity generation in the Wholesale Electricity Market (WEM) which operates in the SWIS.

This GSOO considers the supply of natural gas to the domestic market using three perspectives:

- potential gas supply;
- availability of gas production capacity to the domestic gas market; and
- adequacy of gas resources and reserves.

As this GSOO demonstrates, there is an abundance of gas resources and processing capacity to satisfy domestic demand for the forecast horizon. However, these are not 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. This GSOO focuses on 'potential supply', which is a measure of producers' willingness to supply, as the principal supply forecast.

Potential supply is a forecast based on assumptions about market conditions, including forecast prices. Due to uncertainties regarding the future supply of gas to the domestic market by the NWS Joint Venture (JV) partners, this GSOO presents two potential supply scenarios (Upper and Lower) based on different assumptions about supply by the NWS JVs over the forecast period.

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

2.2. Development of this GSOO

This GSOO relies on historical information, public announcements, GBB data, feedback and data provided by market participants. The IMO only sought information from market participants when an in-depth understanding of the domestic market was required in developing the gas demand and potential supply models and this could not be gathered from other sources of information available to the IMO.

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

In developing this second GSOO:

- the IMO held a stakeholder forum on 7 October 2013, to discuss and seek feedback on the July 2013 GSOO;
- the IMO discussed the July 2013 GSOO with members of its Gas Advisory Board (GAB) at the October 2013 GAB meeting;
- modelling and analysis work was conducted by an independent consultant, the National Institute of Economic and Industry Research (NIEIR); and

- the IMO engaged in more than 20 one-on-one meetings with stakeholders, including WA Government agencies, peak bodies and gas market participants.

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

To assist with this GSOO, the IMO engaged NIEIR, a forecasting consultancy that has spent more than 25 years modelling various gas and electricity markets across Australia, including WA. For this GSOO, NIEIR updated its WA gas forecasting models developed for the July 2013 GSOO to provide revised forecasts for demand and supply.

2.3. Future GSOOs

The IMO will publish the next GSOO by 31 December 2014.

2.4. Acknowledgements

The IMO acknowledges the assistance of gas industry participants: exploration firms, infrastructure providers, peak organisations, producers, retailers and shipping organisations, including market participants that provided feedback at the 7 October 2013 stakeholder forum. These parties have provided background information, comments, estimates, research, data, current information, suggestions and guidance to assist with the preparation of this GSOO. The IMO also acknowledges the IMO staff members who have worked tirelessly to ensure the accuracy of this report.

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

- Alcoa
- Alinta Energy
- APA Group
- Apache Energy
- Australian Petroleum Production and Exploration Association (APPEA)
- BHP Billiton
- Chamber of Minerals and Energy WA (CMEWA)
- Chevron
- DBNGP (WA) Transmission Pty Ltd (DBNGP Transmission)
- Department of Finance, Public Utilities Office (PUO)
- Department of Mines and Petroleum (DMP)
- Department of State Development (DSD)
- Economic Regulation Authority of WA (ERA)
- EnergyQuest
- Fortescue Metals Group (FMG)
- Horizon Power
- NewGen Power Kwinana Pty Ltd
- NWS JVs
- Woodside Energy
- Other participants that have provided feedback during the development of this GSOO, including members of the GAB.

3. Supply and Demand Assessment

This chapter compares the domestic demand and potential supply forecasts outlined in sections 7.2 and 9.2 to determine the adequacy of gas supply to the domestic gas market for the 2014 to 2023 period. This comparison seeks to outline any potential constraints and highlight opportunities for future investment.

The gas supply forecasts in this assessment are projected on the basis of assumed market conditions including forecasts of medium to long-term average (ex-plant) new contract prices (herein referred to as average new contract prices). Forecasts of gas demand in this assessment have also been prepared on the basis of these price assumptions.

The most significant area of uncertainty regarding the supply-demand balance over the forecast period is the continued supply of gas to the domestic market from the NWS JVs' Karratha Gas Plant (KGP). As a result, this chapter commences with a discussion of the issues likely to affect future production at the KGP.

3.1. North West Shelf – Will It Continue to Supply the Domestic Market?

Since the publication of the July 2013 GSOO, several stakeholders have raised concerns about the ability of the NWS JVs to endure and continue to provide gas to the WA domestic gas market once existing contracts expire by 2020[14]. Several of these participants have also suggested that the remaining NWS gas reserves beyond 2020 have already been committed to LNG customers, with no more gas reserves available to the WA domestic market.

At the time of this report, the quantum of domestic gas currently produced by the NWS JVs' KGP constitutes almost half of the total domestic gas market (see section 9.1). Hence, any issues associated with this supply can be expected to affect the availability of supply to the WA domestic gas market. However, it should also be noted that new domestic gas processing facilities related to the Gorgon and Wheatstone LNG developments are expected to be completed during the forecast period.

This GSOO attempts to address the stakeholder concerns by reviewing the capability of the NWS to continue to contribute towards domestic gas production. From an operational perspective, the NWS JVs have assured the IMO that the KGP remains capable of producing at its nameplate capacity of 630 TJ/day. While this may be the case, the quantum of reserves and the utilisation rate of the KGP are key concerns for market participants for the 2014 to 2023 period.

A review of the age of the KGP infrastructure reveals the domestic trains at the KGP started operating in 1984, while the LNG trains started operating in 1989 (Trains 1 and 2), 1992 (Train 3), 2004 (Train 4) and 2008 (Train 5). This means the LNG production capacity at the KGP is newer than the 30-year old domestic gas production facility that may require further capital investment in the upcoming 2014 to 2023 period[15].

The IMO understands that, at the time of this report, the domestic gas and LNG production facilities at the KGP are integrated, with a quantity of gas exiting the LNG process and being diverted into the domestic gas production process. However, the IMO also understands that this integration may not necessarily continue into the future if the NWS JVs decide to use gas exiting the LNG plant for a different purpose. Potential factors that would influence the degree of integration between the production processes include changes in the rate of LNG production or capital investment to separate the processes.

From a contractual perspective, the gas production capacity of the KGP is committed to five gas supply agreements, including two new gas supply agreements that the NWS has recently entered into with unnamed parties. These are provided in Table 1.

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[14] The West Australian (2013b), *Nahan backs gas-guzzling firms over prices*, May 29 2013 also reports the gas market is concerned about the NWS JVs' ability to reduce gas supply to the market.
[15] See http://www.woodside.com.au/our-business/north-west-shelf/Pages/default.aspx, accessed 20 November 2013.

Table 1 – North West Shelf – Gas Supply Agreements, 2013

Purchaser	Estimated Contract Expiry	Estimated Quantity
Alcoa Australia	2020	175
Alinta Energy (probably expired)	2012 or 2020^	62*
Alinta Energy	2012 or 2020^	90
BHP Billiton (expired in October 2013)	2013	110
Synergy (formerly Verve Energy)	2015**	135
Undisclosed Party	Before 2020	Unreported
Undisclosed Party	Before 2020	Unreported
Total		**470-480 TJ/day**

Source: DMP (2002), DomGas Alliance (2013) and information from the NWS. ^The IMO is not certain which of the contracts with Alinta Energy has expired.*This figure is from DMP (2002). **According to the then Verve Energy (now Synergy) website, this contract is due to end in 2015, see http://www.verveenergy.com.au, accessed 1 November 2013.

The total contracted volume is estimated to be between 470 and 480 terajoules (TJ)/day in the near-term and all contracts are estimated to end by 2020, leading to concerns relating to domestic gas production during and beyond the forecast period. Hence, an estimate of remaining NWS gas reserves is crucial to determine if the NWS can to continue to supply to the domestic market for the 2014 to 2023 period.

Table 2 presents the estimates of existing 2P reserves supplying the NWS JVs' KGP. The estimates suggest the NWS has adequate 2P reserves to supply to the domestic and LNG markets for at least another 12 years from 2013 if it produces gas (LNG and domestic gas included) at the estimated 2013 production level of 1,191 petajoules (PJ)/annum[16]. However, it is uncertain whether the NWS will continue to invest in extracting these remaining reserves. As required by the NWS State Agreement (discussed further below), discussions are ongoing between the WA Government and the NWS JVs regarding the status of the remaining reserves, the outcomes of which are not known but are expected to influence investment decisions regarding these reserves. The reserve estimates also assume no additional reserves are found and no additional LNG or domestic gas contracts are signed by the NWS.

Table 2 – Estimates of North West Shelf Reserves and Remaining Years, 2013

Estimated 2P Reserves – NWS	15,173 (reported by EnergyQuest (2013) as at November 2013)	15,547* (estimated by IMO – as at 31 December 2013)
Reserves committed to all LNG exports and 10 years LPG exports (PJ, estimated)	10,256^	10,256^
Remaining Reserves available for Domestic Production (PJ)	4,770**	5,144**
Estimated Domestic Gas Production – 2013 (PJ)	193	
Estimated Total Production – 2013 – Wood Mackenzie (PJ)	1190.7 (including LNG production)	
Years Remaining for Maximum Domestic Gas Production (630 TJ/day) after accounting for LNG/LPG commitments (estimated) from the end of 2013	19.2	20.7
Years Remaining (Implied) from the end of 2013 – using Wood MacKenzie Total Production Estimate for 2013	12.3	13.0***

Source: EnergyQuest (2013), IMO estimates and WA Business News (2013). **Note:** *Calculated using NWS reserve figures of 2,664 billion cubic feet (bcf) reported in Woodside's (2012c) Annual Report. ^See section 8.3.1 for a list of NWS LNG contracts. **Adjusted for estimated liquefied petroleum gas (LPG) production. ***Assume 5% loss at the wellhead and 8% processing requirements.

The reserve estimates in Table 2 also suggest that after taking into account all existing LNG contracts (outlined in section 8.3.1) and assuming no additional LNG contracts are signed, the NWS is able to supply to the domestic market for approximately another 20 years at capacity of 630 TJ/day.

[16] Estimates are from Wood MacKenzie for 2013 that are reported in the WA Business News (2013). EnergyQuest (2013), *Gas projects fire up*, 19 September 2013, also suggests there are sufficient gas reserves of approximately 1,055 PJ remaining after taking into account existing LNG contracts for the 2014 to 2023 period after taking into account existing LNG contracts and potential additional LNG sales of 20.megatonnes (Mt).

While the reserves estimates suggest the NWS is likely to be able to continue to supply to the WA domestic market for the forecast period, it is understood that a large proportion of the NWS JV's developed reserves are committed to existing LNG export and existing domestic gas agreements (with a smaller proportion of reserves used for balancing customer gas requirements and LNG spot trading). The remaining undeveloped gas reserves are located in smaller adjacent gas fields that require further substantial investment by the NWS JVs.

As was highlighted above, the availability of the uncommitted reserves to the domestic market is contingent on a range of factors, including:

- discussions between the NWS JVs and the WA Government regarding the status of these reserves, which may include prioritisation of a portion of gas for the domestic market;
- investment decisions required by the NWS JVs to access remaining undeveloped reserves; and
- investment required to extend the life of the aging domestic gas production facility,

each of which will involve consideration of the commerciality and profitability of ongoing operations at the KGP.

Discussions between the NWS JVs and the WA Government are ongoing under the NWS State Agreement. Clause 46(1A) of the 1985 amendment[17] to the *North West Gas Development (Woodside) Agreement Act 1979 – Schedule 2* states:

"The Joint Venturers shall keep the Minister informed of their intended arrangements for the utilisation of natural gas processed through the onshore facilities during the years 2010 through 2025 and before entering into any arrangements for the sale, use, supply or export of such natural gas during those years the Joint Venturers and the Minister shall consult and reach agreement on the requirements in the State and the manner in which they will be met during those years having regard to requirements for natural gas which the Joint Venturers could make available on arm's length commercial terms".

The IMO anticipates that the discussions between the NWS JVs and the WA Government will have regard to clause 44A of the 1994 amendment[18] of the *North West Gas Development (Woodside) Agreement Act 1979 – Schedule 3*, which outlines the priority of gas supply:

- first priority gas, reserved for delivery and use in WA (the original reservation contract and subsequent replacement contract for disclosed parties only outlined in Table 1 of this GSOO);
- export gas, being 198 billion cubic metres (Bcm) for sale, use or supply outside Australia; and
- third priority gas, reserved for sale, use or supply for consumption in WA.

The remaining contracts that are classified as first priority gas are anticipated to be exhausted by 2017[19]. However, the 1994 amendment to the State Agreement appears to suggest that once the first priority gas contracts are completed and overseas exports reach 198 Bcm, domestic gas could be made available by the NWS to customers at commercial rates[20].

While the NWS State Agreement complex, the IMO understands that the WA Government must approve plans for marketing the remaining undeveloped gas reserves by the NWS JVs once the 198 Bcm export gas quantity is reached[21]. This means the WA Government may elect to allow the NWS JVs to export their entire remaining reserves or impose additional domestic gas obligations onto the NWS JVs. The IMO anticipates that any additional domestic gas obligations imposed on the NWS would follow consideration of the commerciality and likely profitability of domestic gas sales[22].

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[17] See http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_4142_homepage.html, for 1985 amendment, accessed 30 December 2013.

[18] See http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_3246_homepage.html, for 1994 amendment, accessed 30 December 2013.

[19] See Woodside (2012b), *Woodside Investor Site Tour*, ASX announcement, 29 May 2012, http://www.woodside.com.au/Investors-Media/Announcements/Documents/29.05.2012%20Woodside%20Investor%20Site%20Tour.pdf, accessed 20 November 2013.

[20] It should be noted that the IMO did not seek any legal advice on this clause and only interpreted the clause in the 1994 amendment.

[21] Refer to Freehills (2010), *North West Shelf Project, Application for authorisation – supporting submission* http://registers.accc.gov.au/content/trimFile.phtml?trimFileTitle=D10+3402407.pdf&trimFileFromVersionId=1090615&trimFileName=D10+3402407.pdf, accessed 20 November 2013, which indicates this level of exports has already been reached.

[22] Freehills (2010) indicated that the ability of the NWS JVs to continue to supply the market is dependent on the availability of gas reserves; the terms of potential domestic gas sales; the value of alternative uses for the gas (such as LNG); the increasing costs of producing from diminishing fields (involving investments and additional infrastructure) and the assessment of regulatory obligations and regulatory risk, http://registers.accc.gov.au/content/trimFile.phtml?trimFileTitle=D10+3402407.pdf&trimFileFromVersionId=1090615&trimFileName=D10+3402407.pdf, accessed 20 November 2013.

Woodside has signalled that it would like to sell its remaining gas reserves (either domestically or internationally) at higher prices[23]. This is in part driven by the need to further maximise profits for the NWS JVs[24] once the existing domestic supply commitments expire in 2020, and to fund the required capital expenditure to produce gas from remaining reserves, which is estimated to be in the order of US$10 billion. The IMO understands that a proportion of this capital expenditure represents capital reinvestment into the KGP, a domestic gas production plant that is more than 30 years old and is understood to face increasing operational and maintenance costs.

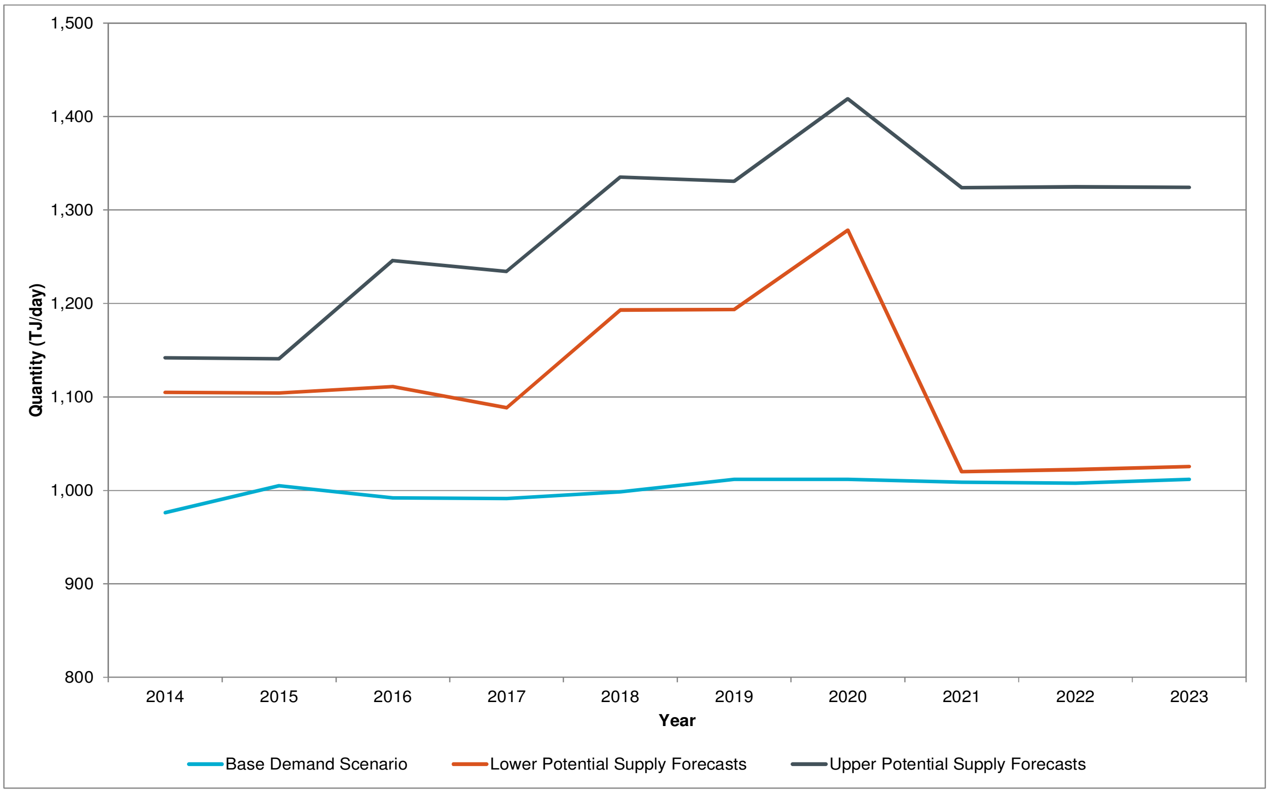
In summary, the continued availability of domestic gas supply from the KGP for the 2014 to 2023 period is uncertain, being largely contingent on whether the NWS JVs can profitably and commercially maintain gas supply to the domestic market[25] and the outcome of the discussions between the WA Government and the NWS JVs.

3.2. Domestic Outlook, 2014 – 2023

3.2.1. Base Demand-Potential Supply Forecasts

Given the uncertainty around future domestic gas supply from the NWS, two potential supply scenarios for the domestic gas market are developed for the 2014 to 2023 period in this GSOO. The first scenario (called the Upper potential supply forecasts) assumes the NWS will continue to supply gas to the WA domestic market for the full forecast period, while the second scenario (called the Lower potential supply forecasts) suggests the NWS will only supply domestic gas under its remaining contracts. These forecasts are presented in Figure 1 below.

Figure 1 – Comparison of Base Demand and Potential Supply Forecasts, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

[23] See the West Australia (2013f), *Woodside signals LNG shift*, 1 December 2013, Woodside Energy's Chief Executive Officer has suggested he would like to sell its remaining gas at higher gas prices.
[24] According to Deutsche Bank the NWS JVs have been cash flow positive since 2004, see Deutsche Bank (2012), *Markets Research, Industry: Global LNG Industry Update*, 17 September 2012, http://view.microbell.com/upfile1/201209/2012920144456915.pdf, accessed 2 May 2013.
[25] Although the LNG and domestic gas segments of the KGP are integrated, it is understood that domestic gas supply from the KGP to WA domestic market can be isolated and shut down.

The grey line in Figure 1 assumes the NWS JVs will operate the KGP at up to a maximum production quantity of 470 TJ/day for the 2014 to 2020 period and 450 TJ/day for the 2021 to 2023 period. This means the NWS JVs will be willing to continue to supply gas to the WA domestic market up to these levels if gas consumers are willing pay the forecast gas prices.

After separately forecasting contracted and price-sensitive supply, the Upper potential supply forecasts for the KGP suggests the NWS is willing to supply 459 TJ/day in 2014 to the WA domestic market (including contracted supply), falling to 299 TJ/day in 2023. These forecasts assume that:

- all existing NWS contracts are honoured;
- the real cost of gas production of the NWS increases by 3% per annum; and
- the full 450 TJ/day available from KGP for the 2021 to 2023 period is price-sensitive.

Figure 1 shows that the domestic gas market will be well supplied for the period from 2014 to 2020, the year in which the last of the existing NWS domestic gas supply contracts are estimated to expire.

However, for the 2021 to 2023 period, the balance of gas supply and demand in the WA domestic market is uncertain. The Upper potential supply forecasts suggest that the market would continue to be well supplied if the NWS continues to supply to the domestic market. However, the Lower potential supply forecasts suggest tight market conditions, within the margins of error of the supply and demand forecasts.

If the NWS ceased supplying the domestic market beyond its existing contracts, it is likely that gas prices in WA would rise substantially for the 2021 to 2023 period due to the tight supply-demand position in the market. Anecdotal evidence suggests that this potential outcome is currently being reflected in discussions related to the renewal of legacy gas contracts beyond 2020.

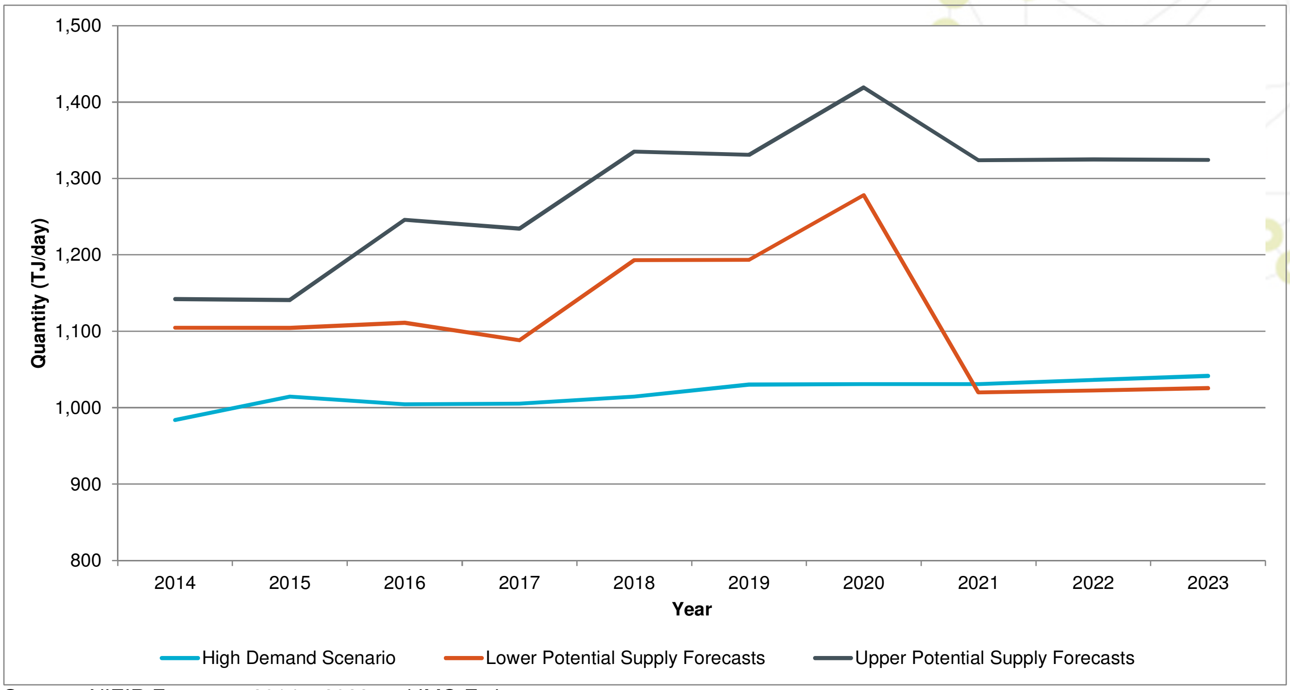
While the uncertainty pertaining to the NWS supply to the WA domestic market remains an issue for the WA domestic gas market, as noted above it is understood the NWS domestic gas facility is integrated with the LNG export facility. However, it is understood there are engineering options available to the NWS JVs (that require investment decisions) to allow them to remove this integration and solely focus on LNG exports. It should be noted the NWS continues to hold several exploration and retention permits within the vicinity of existing production permits[26] and gas production infrastructure that are likely to hold additional contingent gas reserves.

3.2.2. High Demand-Potential Supply Forecasts

Figure 2 compares NIEIR's High demand forecast against the Upper and Lower potential supply forecasts. This figure shows if the NWS does not continue to supply to the WA domestic market, there may be a shortage of gas in the 2021 to 2023 period of approximately 11 TJ/day in 2021 increasing to 16 TJ/day in 2023. This figure also suggests if actual WA domestic gas demand grows faster than the High demand forecast of 0.6% per annum, there may be a more significant shortage of WA domestic gas in the 2021 to 2023 period.

[26] According to the Commonwealth's National Electronic Approvals Tracking System, the NWS JVs still hold one exploration license and four retention leases.

Figure 2 – Comparison of Forecast High Demand and Potential Supply Forecasts, 2014 – 2023



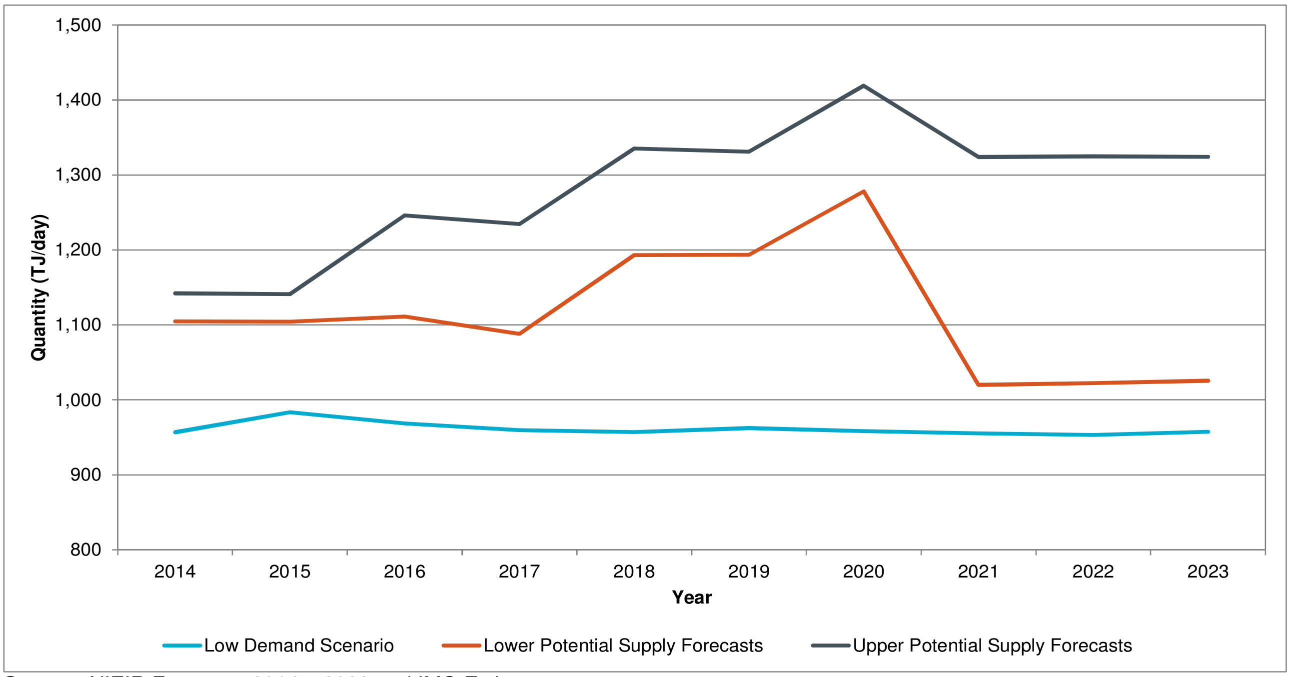
Source: NIEIR Forecasts 2014 – 2023 and IMO Estimates.

However, if the NWS continues to supply to the WA domestic market and the actual gas supply is similar to the Upper potential supply forecasts, it is anticipated there will be sufficient gas supply to the WA domestic gas market with potential excess gas supply increasing from about 158 TJ/day in 2014 to approximately 282 TJ/day in 2023.

3.2.3. Low Demand-Potential Supply Forecasts

Figure 3 presents the comparison of NIEIR's Low demand forecasts with the Upper and Lower potential supply forecasts. If this situation occurs, Figure 3 shows there is sufficient gas supply to the domestic market for the 2014 to 2023 period.

Figure 3 – Comparison of Low Demand and Potential Supply Forecasts, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023 and IMO Estimates.

If the NWS is willing to supply to the WA domestic market for the forecast period, it is estimated the supply-demand gap grows from about 185 TJ/day to its widest, approximately 462 TJ/day, in 2020 before falling to 367 TJ/day in 2023. If this occurs, the additional gas supply may provide some downward pressure on domestic gas prices. However, this is unlikely as WA's gas supply is highly concentrated and any downward pressure on gas prices may be dampened as gas producers may switch their focus to alternative markets such as LNG exports.

3.3. Resources and Reserves Assessment

In addition to determining the adequacy of supply, the quantity of reserves supporting each domestic gas production facility and the quantity of WA resources for the 2014 to 2023 period are also reviewed.

A review of 2P reserves linked to gas production facilities currently servicing and anticipated to be servicing the domestic gas market in the 2014 to 2023 period suggests there are likely to be more than adequate gas supplies to meet the projected domestic demand for the 2014 to 2023 period (see Chapter 10).

This GSOO also finds there are likely to be more than adequate gas resources in WA to continue to meet the projected domestic demand well into the future (see Chapter 10). Assuming no additional gas resources are discovered by 2023, total estimated gas resources (conventional and unconventional) in WA have the potential to last for another 118 years beyond 2023, if production is maintained at forecast 2023 levels of total demand (including LNG feedstock and processing).

While this assessment of resources considers the whole of WA, the majority of WA's conventional and unconventional gas endowment remains untapped within the Bonaparte, Browse, Canning, Carnarvon and Perth Basins. If only conventional resources are considered, the majority of which are located in the Carnarvon Basin, the remaining resources are only projected to last between 27 and 42 years beyond 2023, depending on whether all sub-economic resources will become economic in the future.

Since 1984, the majority of gas supplied to the domestic market has been sourced from the Carnarvon Basin. The reliance on the Carnarvon Basin may become a supply risk for WA in the not too distant future as more LNG and floating LNG (FLNG) export projects are considered for this basin, particularly as domestic gas commercialisation takes a considerable time[27]. This presents an opportunity to consider how other unexploited gas basins may be further explored and developed to increase the diversity of gas resources available to supply the WA domestic market in the future.

[27] Part of the commercialisation process was reported in EISC (2011), *Inquiry into Domestic Gas Prices*, Report No 6 in the 38th Parliament, http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3813232af0e096cabecf9c8e4825785e0004c326/$file/3232.pdf, accessed 20 December 2012, in which APPEA indicated domestic gas projects typically take three to five years to develop once the final investment decision (FID) has been taken. Of the larger domestic gas supply facilities, the Apache operated Devil Creek took approximately 3.5 years and the BHP operated Macedon took approximately three years, while the smaller Empire Oil and Gas operated Red Gully facility took approximately one year after FID.

4. WA Gas Industry, Market Overview and Infrastructure

This chapter provides a description of the WA gas market, its history, size, structure and associated infrastructure (such as pipelines and storage). The WA gas industry features several highly integrated segments which operate together in a supply chain:

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

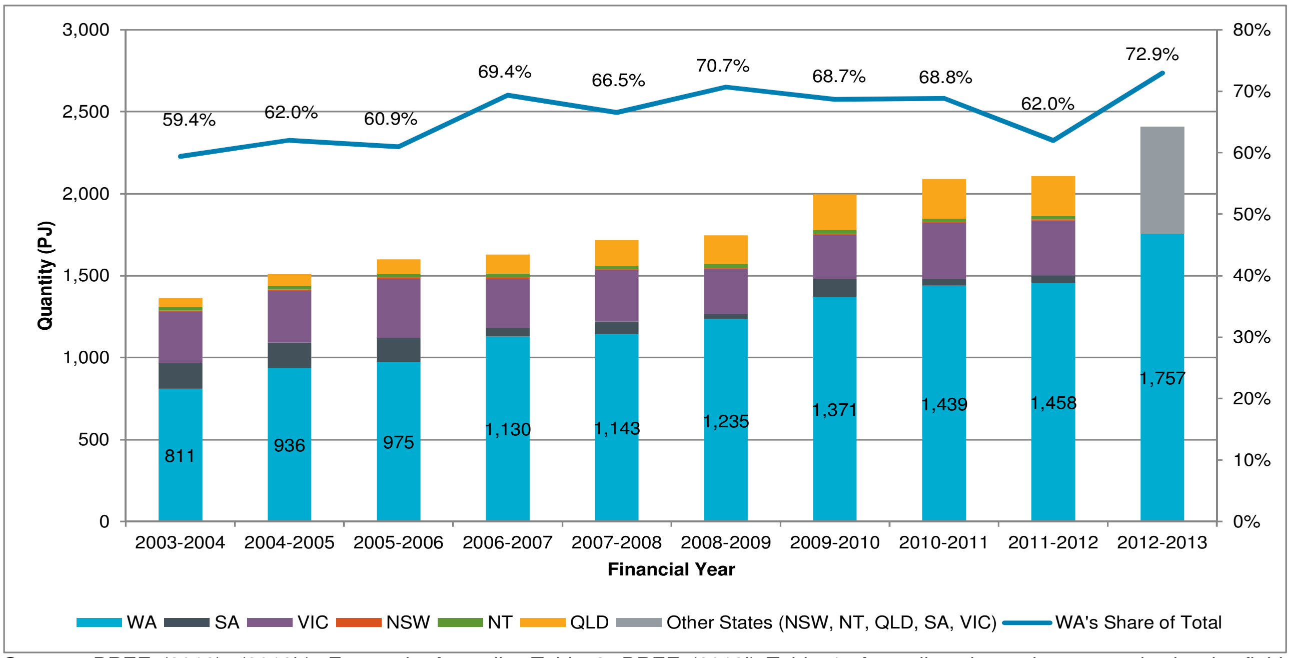
This GSOO focuses on the gas production and processing, transmission, storage and demand segments.

Some of the data presented in this chapter is not directly comparable to the July 2013 GSOO, as it is presented in financial years not calendar years, or is based on National Greenhouse and Energy Reporting Scheme (NGERS) [28] data rather than the Bureau of Resources and Energy Economics (BREE) Fuel and Electricity Survey data.

4.1. Overview of the Western Australian Gas Market

As was noted in the July 2013 GSOO, WA is Australia's largest state gas market and produced an estimated 1,757 PJ of gas for export and domestic usage in 2012-2013, almost 73% of Australian gas production[29].

Figure 4 – Australia's Gas Market Production (Domestic Gas, LNG and Processing), 2003-2004 to 2012-2013



Source: BREE (2012), (2013b), Energy in Australia, Table 2, BREE (2013i) Table 1, Australian domestic gas production by field, 2012-2013 and EnergyQuest (2013) Table 46, Gross Australian LNG production. **Note:** South Australia – SA, Victoria – VIC, New South

[28] While the NGERS (introduced in 2007 to provide data and accounting in relation to greenhouse gas emissions, energy consumption and production) improves the reporting of gas consumption for WA, the scheme does not capture all gas consumption. This is because facilities that fall below reporting thresholds under the Commonwealth's *National Greenhouse and Energy Reporting Act 2007* do not need to report to the Commonwealth's Clean Energy Regulator, as outlined in http://www.cleanenergyregulator.gov.au/National-Greenhouse-and-Energy-Reporting/steps-for-reporting-corporations/NGER-reporting-step-1/Pages/default.aspx, accessed 28 November 2013.

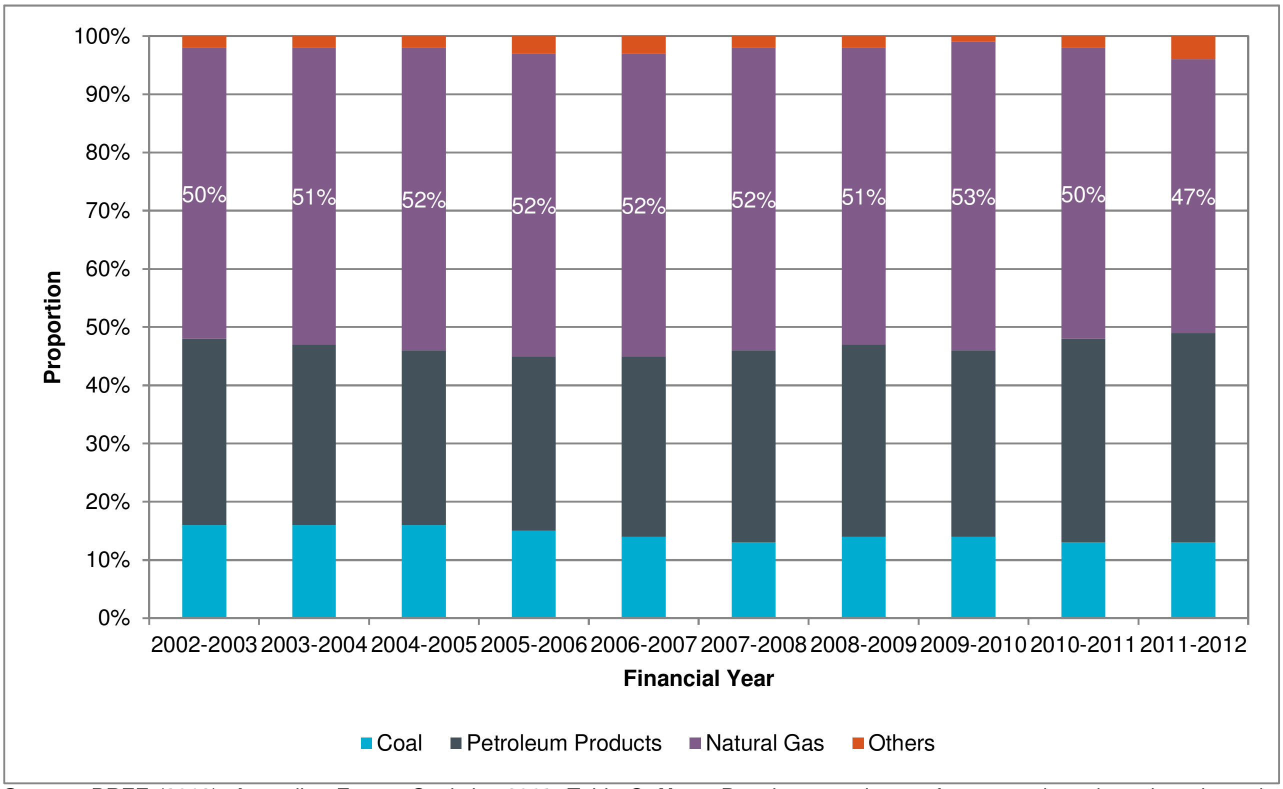
[29] See BREE (2013b), *Energy in Australia 2013, May 2013*, http://www.bree.gov.au/publications/energy-australia, accessed 24 January 2014.

Wales – NSW, Northern Territory – NT, Queensland – QLD. The proportions are different from the July 2013 GSOO as BREE has retired the Fuel and Electricity Survey and now uses data from NGERS.

The majority of WA's gas production is exported as LNG, linking WA strongly to international gas market prices and the exchange rates. This link will be stronger when the domestic supply-demand balance is tight. While WA currently accounts for the bulk of gas production in Australia, its share of total Australian gas production is expected to fall significantly over the 2014 to 2023 period, as LNG projects from Queensland (Australia Pacific LNG, Gladstone LNG and Queensland (Qld) Curtis LNG projects) and the Northern Territory (NT) (Ichthys project) are anticipated to commence production.

WA is a natural gas intensive economy. Gas is the primary fuel for WA with approximately half of WA's energy consumption derived from gas[30]. BREE expects WA gas consumption will continue to grow at approximately 2.2% per annum from 1,777 PJ in 2013-2014 to 4,036 PJ in 2049-2050[31]. Accordingly, the supply of gas is vital to the operation of the WA economy, which has ensured that the WA Government has maintained a focus on the availability of gas supply within WA[32].

Figure 5 – Western Australia's Consumption of Energy by Fuel Source, 2002-2003 to 2011-2012



Source: BREE (2013), Australian Energy Statistics 2013, Table C. **Note:** Petroleum products refer to petroleum-based products that include crude oil, diesel and LPG. The proportions are different from the previous GSOO as BREE now uses NGERS data.

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

As shown in Figure 6, analysing BREE's gas consumption data for the 2002-2003 to 2011-2012 period, it is estimated that the domestic gas market consumed about a quarter (26%) of the total gas produced, while about two-thirds of total gas production in WA (64%) was exported as LNG. The remaining gas production, totalling approximately 377 TJ/day (or approximately 138 PJ/annum), is estimated to be consumed in petroleum (oil, gas and associated products) processing and unaccounted for gas[33].

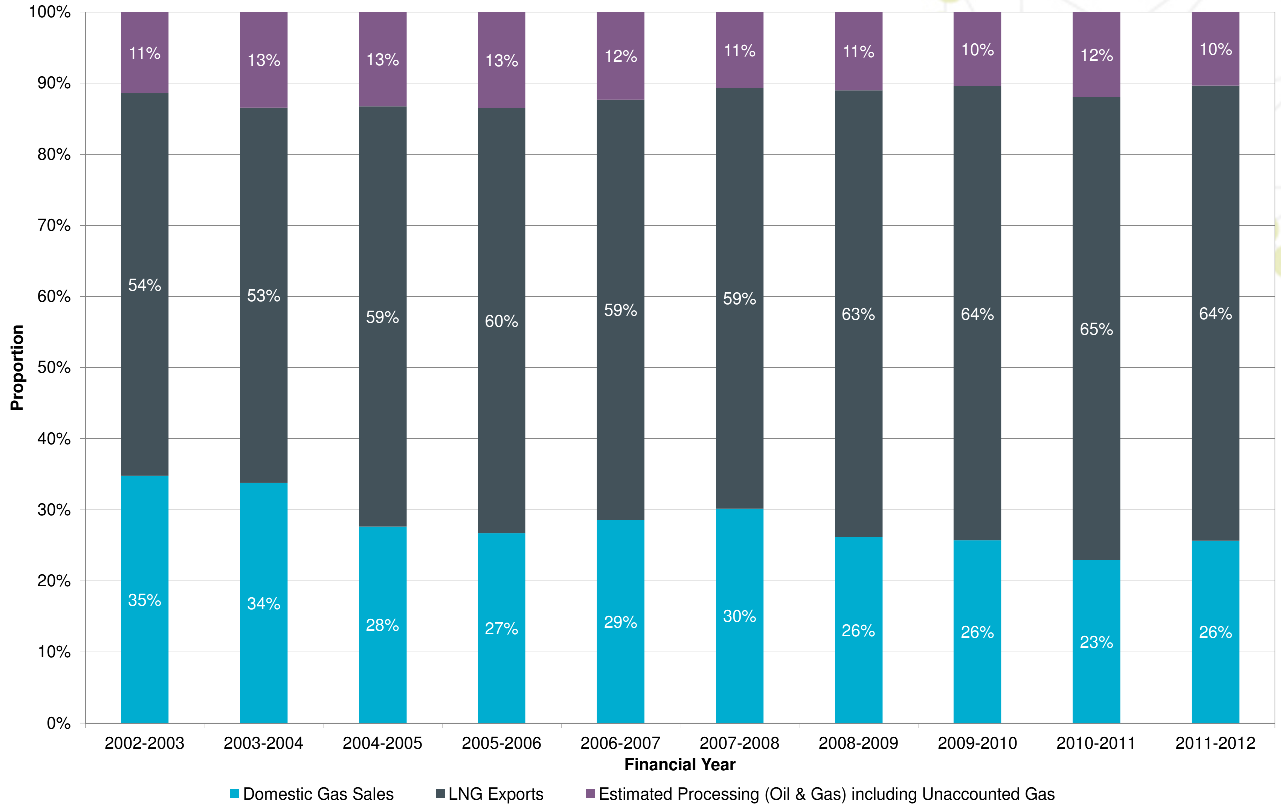
[30] See BREE (2013b).

[31] BREE forecasts suggest WA's future gas consumption will increase at a rate that is slower than the forecasts for the eastern and northern Australian markets over the same period, see BREE (2012b), *Australian Energy Projections to 2049-2050,* December 2012, http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%9350, accessed 24 January 2014.

[32] The West Australian (2013d), *Gorgon's Barrow land grab*, 26-27 October 2013, http://au.news.yahoo.com/a/19560058/, accessed 28 January 2014.

[33] The Commonwealth Government does not report on gas consumed for processing gas in WA LNG facilities. This figure is estimated by deducting

Figure 6 – Estimated Shares of Domestic Gas Consumption, 2002-2003 to 2011-2012



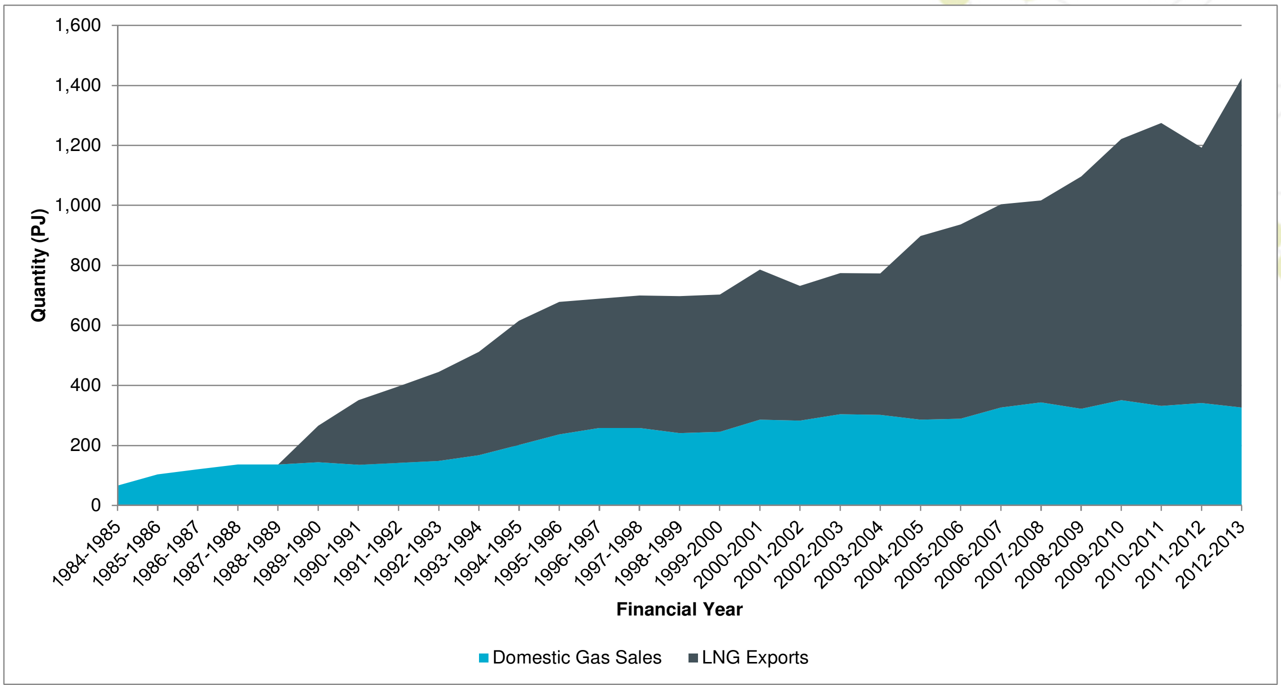
Source: IMO estimates, using BREE's (2013) Energy in Australia 2013, Table C, domestic gas consumption data, APPEA 2007-2012 quarterly production data and DMP 2007-2012 LNG exports data.

Australia's and WA's LNG export market began in August 1989 when the first LNG cargo left the NWS for Japan. Since 1989, LNG has been a critical export commodity for Australia and WA. As shown in Figure 7, by the end of 1990, the quantum of natural gas supplied to the WA LNG export market exceeded the amount supplied to the WA domestic market. By 2012-2013, gas supplied to the LNG market had grown to be more than triple the quantum of gas supplied to the domestic market. It is anticipated the size of the WA LNG market will be approximately seven times the WA domestic market by the end of 2023 (see Chapter 7)[34].

BREE's estimate of 1,513 PJ for 2011-2012 in BREE (2012), *Energy in Australia 2012*, February 2012, http://www.bree.gov.au/publications/energy-in-aust.html, accessed 24 January 2014.

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

Figure 7 – Total Gas Production (excluding petroleum processing), 1984-1985 to 2012-2013

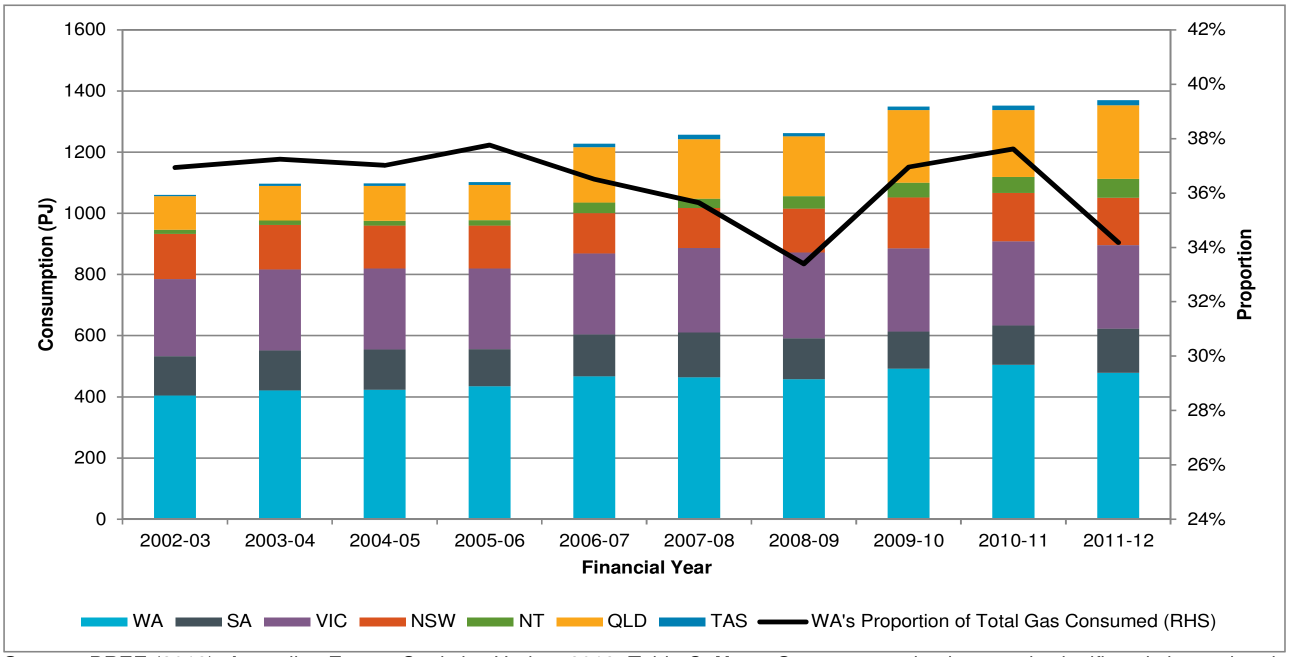


Source: DMP (1990-2013), resources data files, quantity and value, gas sales and LNG exports data, 1984-1985 to 2012-2013. **Note:** This figure is different to that presented in the July 2013 GSOO, which presented this data by calendar years.

4.1.1. Gas Consumption in Western Australia

BREE reports that in addition to providing the majority of Australia's gas production WA is also the largest consumer of domestic gas in Australia. As shown in Figure 8, WA accounted for approximately 34.2% of total Australian domestic gas consumption in 2011-2012, consuming approximately 479 PJ of gas[35].

Figure 8 – Australia's Gas Consumption, 2002-2003 to 2011-2012

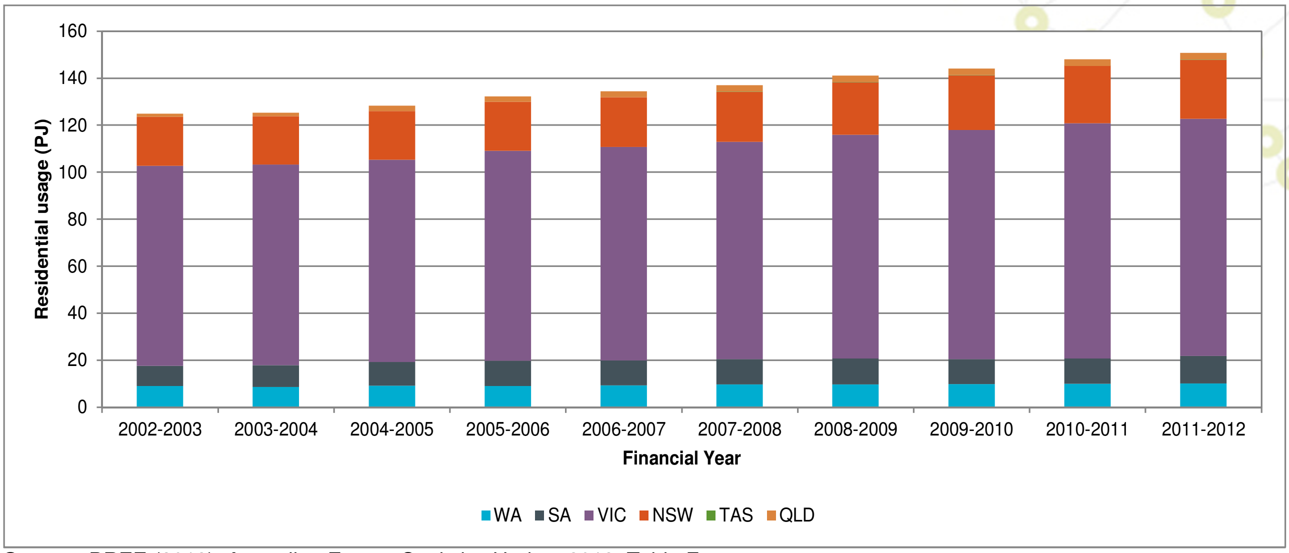


Source: BREE (2013), Australian Energy Statistics Update 2013, Table C. **Note:** Gas consumption by state is significantly lower than in the July 2013 GSOO because BREE now uses NGERS data. Appendix 10 presents the difference between the WA consumption data estimated using these different sources.

[35] See BREE (2013b).

Even though WA is the largest consumer of gas by state, Figures 9 shows that residential gas consumption in WA is low when compared to the other states.

Figure 9 – Australia's Residential Gas Consumption, 2002-2003 to 2011-2012



Source: BREE (2013), Australian Energy Statistics Update 2013, Table F

As shown in Figure 10, gas use per capita in 2010-2011 for the WA residential market is less than a quarter of Victoria's consumption and approximately two-thirds of South Australia's consumption. This is because WA households are less reliant on gas for household heating than households in Victoria and South Australia, and because WA households are using more energy for cooling than for heating[36].

Figure 10 – Residential Gas Consumption Per Capita, Per Annum, 2002-2003 to 2011-2012

Source: IMO estimates using BREE's (2013) residential gas consumption and population figures from the Australian Bureau of Statistics (2013), Australian Demographic Statistics, Mar 2013 Catalogue 3101.0 using June figures. **Note:** Victoria is slightly lower than shown in the July 2013 GSOO due to slightly different population numbers.

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

Residential gas consumption represents only 1.5% of total WA gas use. Gas demand in WA is dominated and driven by industrial gas consumption, as a fuel or feedstock for electricity generation, minerals processing and other manufacturing. Information about the trends in consumption in these sectors is provided in Chapter 7.

4.2. Market Structure and Participants

The WA wholesale gas market currently operates mainly under a contract carriage model via pipelines[37]. This means the bulk of the domestic gas delivered into the pipelines (transmission system) is traded under bilateral contracts (that are typically medium to long-term) for both supply and shipping. As a consequence, if all gas users are consuming close to or at their maximum contracted quantities the short-term availability of firm[38] secondary gas may be low[39].

On the wholesale consumption side, it is estimated there are more than 60 industrial, manufacturing, electricity generation and transport related facilities currently consuming gas in the domestic wholesale market[40]. For the 2014 to 2023 period, the quantum of gas consumed, outside the SWIS, in the north-west of WA could reasonably be expected to increase with the construction of new gas-fired electricity generators at Cape Lambert, West Angelas, Newman, Onslow and South Hedland, the potential restarting of Newman Power Station.

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

Table 3 – Estimated Number of Shippers Operating in Western Australia, as at October 2013

Pipeline	Number of Shippers
Dampier to Bunbury Natural Gas Pipeline (DBNGP)	26
Goldfields Gas Pipeline (GGP)	14
Pilbara Energy Pipeline	8
Telfer Gas Pipeline	2
Mid West Pipeline	3
Parmelia Pipeline	5
Kalgoorlie to Kambalda Pipeline*	2
Kambalda to Esperance Pipeline*	1

Source: IMO GSI registration data and estimates. **Note:** Shippers from the same parent company are included separately in the figures. Certain shippers operate on more than one pipeline. *Shippers on these pipelines do not need to be registered with the IMO and hence the numbers are estimates.

In WA, there is currently no legislated exchange framework for short-term trading of gas. Hence, gas market participants balance their short-term gas requirements via short-term agreements in an over-the-counter market[41].

It is estimated that approximately 98% of total domestic gas sales are traded bilaterally through long-term contracts, with at least 60 separate gas supply agreements active between gas suppliers and consumers within WA[42]. Despite being the largest domestic market in Australia, the WA market is opaque and contracted

[37] Other market structures include common carriage, market carriage, network carriage or a hybrid. See Parson Brinckerhoff Associates (2007), *Contracted Capacity Rights*, http://www.erawa.com.au/cproot/5064/2/ERA%20Contracted%20Capacity%20-%20Final%20Report%20(public).pdf, accessed 30 January 2014, for more information on market models.
[38] Firm capacity is gas transmission capacity that is available at all times during a period covered by an agreement between the pipeline operator and the shipper.
[39] According to DBNGP Transmission, when secondary gas is available it is traded bilaterally amongst the gas shippers.
[40] For the purposes of this report, industrial use includes the processing of minerals (including gas), manufacturing is defined as entities that use gas as a feedstock and transportation includes domestic LNG refuelling facilities. It does not include gas used for compression along transmission pipelines.
[41] It is understood that short-term gas demand and supply requirements are typically traded amongst existing gas market participants either directly with each other, via a broker such as Gas Trading Australia Pty Ltd or through energy trading platforms managed by Energy Access Services Pty Ltd or DBNGP Transmission or directly with Apache. It is understood most market participants trade short-term gas through Gas Trading Australia Pty Ltd and Apache under a Master Spot Agreement, see http://www.apachecorp.com/Operations/Australia/Gas_marketing/Spot_gas_sales/index.aspx, accessed 20 December 2013. These short-term trades are estimated to be between six and 30 TJ/day.
[42] The estimate of bilateral contracts considers pipeline usage and multiple contracts between a single consumer and multiple producers. The proportion of bilateral contracts is estimated by calculating the difference between the average annual consumption and short-term trades of approximately 20 TJ/day (or

gas prices and volumes for existing gas supply agreements are not generally available. Details of these agreements or trades are generally only revealed when it is required by legislation, stock market regulations, legal disputes or energy market rules. The existence of long-term contracts means that unlike gas markets in the eastern Australia, the WA gas market does not have a single observable market clearing price (equilibrium gas price), as agreements between parties for domestic gas contracts are reached for different time periods and also vary with contractual terms and conditions, prices and service elements[43].

Generally, each domestic gas sale contract will vary due to factors such as:

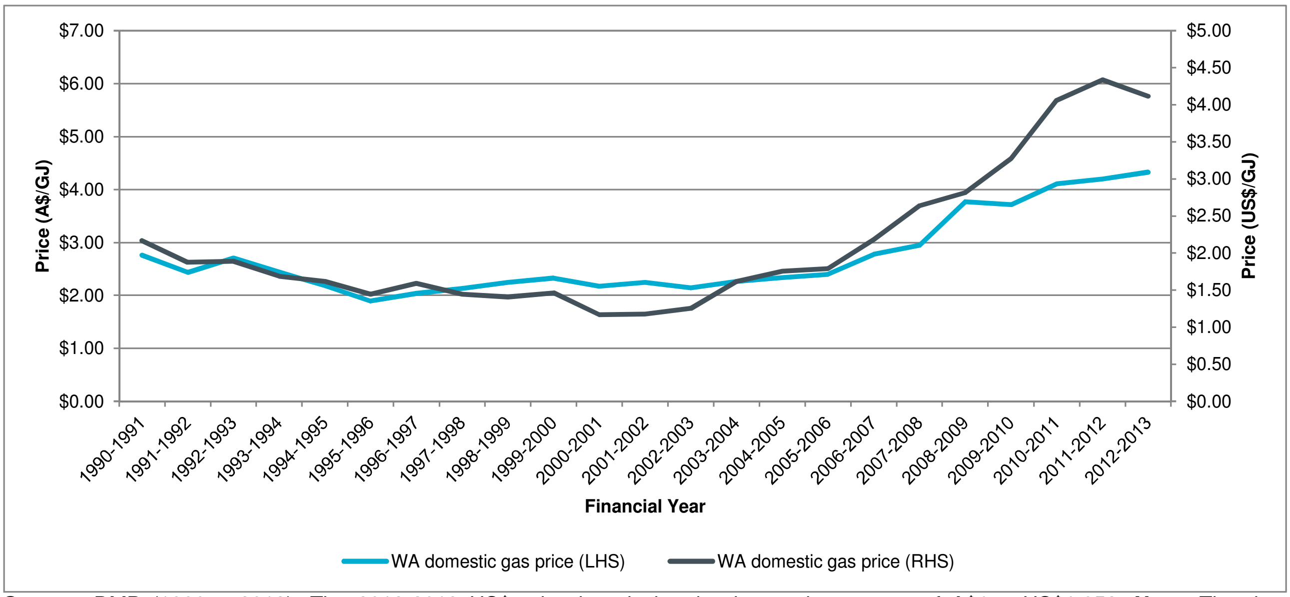
- current and future expected economic conditions;
- future expected costs (e.g. extraction and processing) of gas production;
- the availability of competing fuels to gas;
- the availability of gas from other producers;
- the availability of secondary gas from other gas users;
- the availability of gas storage;
- opportunity costs; and
- alternative uses/markets for the gas.

These factors may also be influenced by:

- the volume of gas requested;
- the length of the contract;
- the reliability of gas supply;
- the availability of gas from the producer;
- the use of the gas;
- the status of the customer (public or private sector); and
- the relationship between the customer and supplier.

As such, and given that there is no equilibrium price in the WA gas market, DMP only publishes an average domestic gas price that is representative of the domestic gas market (including legacy contracts).

Figure 11 – Western Australian Average Natural Gas Prices (nominal), 1990-1991 to 2012-2013



Source: DMP (1990 – 2013). The 2012-2013 US$ price is calculated using exchange rate of A$1 = US$1.052. **Note:** The data represents a volume weighted average price of all existing gas sales contacts. See the July 2013 GSOO for estimates of some contract prices for new contracts executed in the period 2007 to 2011.

7,300 TJ/annum) divided by the total gas sales reported (331,329 TJ) by DMP (1990-2013) for 2012-2013.

[43] EISC (2011) reports the wholesale gas price can be significantly impacted by the terms of an individual contract. These terms and conditions can vary widely and address issues such as contract length; seasonal flexibility around daily volume; take or pay weightings; interruptibility provisions and price review and escalation mechanisms. There can be very large differences between the terms and conditions of different contracts.

4.3. Infrastructure in the Western Australian Gas Market

This section provides an update on gas infrastructure servicing the WA domestic gas market, focusing on existing and future gas production facilities, transmission pipelines and gas storage facilities in WA[44].

4.3.1. Gas Production Facilities

Since the publication of the July 2013 GSOO, the Macedon and Red Gully gas production facilities have been commissioned, in August and September 2013 respectively. At the time of this report, WA hosts eight operational gas production facilities capable of servicing the domestic market, of which five facilities are located in the Carnarvon Basin and three in the Perth Basin. It is anticipated that by the end of 2023 the number of gas production facilities in operation servicing the WA domestic market will increase to at least 10 (with the anticipated completion of the Gorgon and Wheatstone domestic gas production facilities)[45].

Carnarvon Basin

WA's five largest domestic gas production facilities operate from the Carnarvon Basin, close to significant gas reserves. These facilities are the KGP, Varanus Island (East Spar and Harriet JVs), Devil Creek and Macedon production facilities. Together, these facilities provide approximately 1,440 TJ/day gas production capacity out of a total capacity of approximately 1,477 TJ/day in 2013, or approximately 97% of WA domestic gas production capacity. By the end of 2023, gas production capacity located in the Carnarvon Basin is anticipated to increase further with the completion of the 300 TJ/day Gorgon and the 200 TJ/day Wheatstone domestic facilities. Table 4 summarises the existing and planned production facilities in the Carnarvon Basin.

Table 4 – Production facilities (operational, planned and under construction) within the Carnarvon Basin, 2013

Facility	Operator	Estimated Capacity (TJ/day)	Location	Status	Pipeline Connection	Comments
Karratha Gas Plant (NWS)	Woodside	630*	Burrup Peninsula, Pilbara	Operational	DBNGP, Burrup Extension Pipeline and GGP (via others)	Gas production capacity at this facility can be increased short-term, but it will be sub optimal*
Varanus Island (East Spar JV)	Apache Energy	270	Varanus Island, Pilbara	Operational	DBNGP and GGP	
Varanus Island (Harriet JV)	Apache Energy	120	Varanus Island, Pilbara	Operational	DBNGP and GGP	
Devil Creek	Apache Energy	220^	Devil Creek, Pilbara	Operational	DBNGP	
Macedon	BHP Billiton	200	Ashburton North, Pilbara	Operational	DBNGP	Facility is expected to supply WA customers until at least 2033[#]
Gorgon Domestic	Chevron	150	Barrow Island, Pilbara	Under construction, anticipated to be available by 2016	DBNGP	Facility is anticipated to be expanded to 300 TJ/day by 2020[%]
Wheatstone Domestic	Chevron	200	Ashburton North, Pilbara	Under construction, anticipated to start in 2018	DBNGP	Facility is anticipated to commence in 2018

[44] For a list of decommissioned facilities, please refer to the July 2013 GSOO, http://www.imowa.com.au/gsoo.
[45] Other gas production facilities may be sanctioned after the publication of this report.

Pluto Domestic	Anticipated to be Woodside	Information unavailable	Burrup Peninsula	Under Consideration	DBNGP	Subject to commercial viability conditions^^
Buru Energy Domestic	Anticipated to be Buru Energy	Information unavailable	Unknown	Under Consideration	DBNGP	Unknown
	Total Operational Capacity to date (Excluding Planned)	1,440 TJ/day	**Total Operational Capacity (including Planned)**	1,790 TJ/day		

Source: IMO GBB Standing Data, BHP Billiton (2013), Chevron Australia's Gorgon and Wheatstone project websites, Buru Energy (2013), APPEA and the July 2013 GSOO. **Note:** *According to Evans and Peck (2009), the KGP can expand its domestic gas production capacity up to 750 TJ/day (this was achieved after the Varanus Island explosion) under sub-optimal conditions. ^According to GBB data from 1 August to 31 December 2013. ^^Woodside has entered into an arrangement with the WA Government to supply domestic gas within five years after LNG is first exported, providing it is commercially viable, for more information see the July 2013 GSOO. %Deutsche Bank (2012) expects Phase 2 of the Gorgon domestic facility to commence in 2020. #See BHP Billiton (2013).

Perth Basin

Proximity to Perth and major customers in the Perth region is a major advantage for gas producers located in the Perth Basin. It allows these entities to respond quickly to fluctuating gas demand from gas consumers located around Perth. Since the publication of the July 2013 GSOO, the Red Gully production facility has become fully operational.

There are three production facilities operating within the Perth Basin, capable of processing a total of approximately 36.6 TJ/day of gas for the domestic market, or about 3% of gas production capacity. Gas supply facilities in the Perth Basin are estimated to be supplying approximately 30 TJ/day[46], with most of the gas supplied through the Parmelia Pipeline[47]. Despite the comparatively low level of existing production capacity, there are significant prospects for the development of unconventional gas in the Perth Basin (see Chapter 10). Table 5 summarises the existing and planned production facilities in the Perth Basin.

Table 5 – Production facilities (operational, planned and under construction) within the Perth Basin, 2013

Facility	Operator	Estimated Capacity (TJ/day)	Location	Status	Pipeline Connection	Comments
Dongara	AWE Limited	7	Dongara, Mid West	Operational	Parmelia	AWE is evaluating the potential of the Senecio and Corybas fields around this facility
Beharra Springs	Origin Energy	19.6	Mid West	Operational	Parmelia	
Red Gully	Empire Oil and Gas	10	Mid West	Operational[48]^	DBNGP	Facility may be expanded to 20 TJ/day before the end of 2023
Warro	Transerv Energy	150*	Mid West	Under Consideration	Parmelia* / DBNGP	Facility may be operational before the end of 2023**
	Total Operational Capacity to date (excluding Planned)	36.6 TJ/day	**Total Operational Capacity (including Planned)**	186.6 TJ/day		

Source: Evans and Peck (2009) and SKM-MMA (2011), Empire Oil and Gas website and IMO GBB Standing Data. **Note:** *Information from Economics and Industry Standing Committee (EISC) (2011). **This is an estimate of the potential start-up dates and does not constitute any information provided by the respective company. ^See Empire Oil and Gas (2013).

[46] Data is calculated from GBB data and the IMO's estimates of Red Gully's production.
[47] The Dongara and Beharra Springs facilities supply customers along the Parmelia Pipeline, while the Red Gully facility is connected to the DBNGP.
[48] See the West Australian (2013j), *Red Gully gets Alcoa sign off*, 17 September 2013, http://empireoil.com.au/sites/empireoil.com.au/files/ego-news-170913_Red_Gully_gets_Alcoas_sign-off.pdf, accessed 17 October 2013.

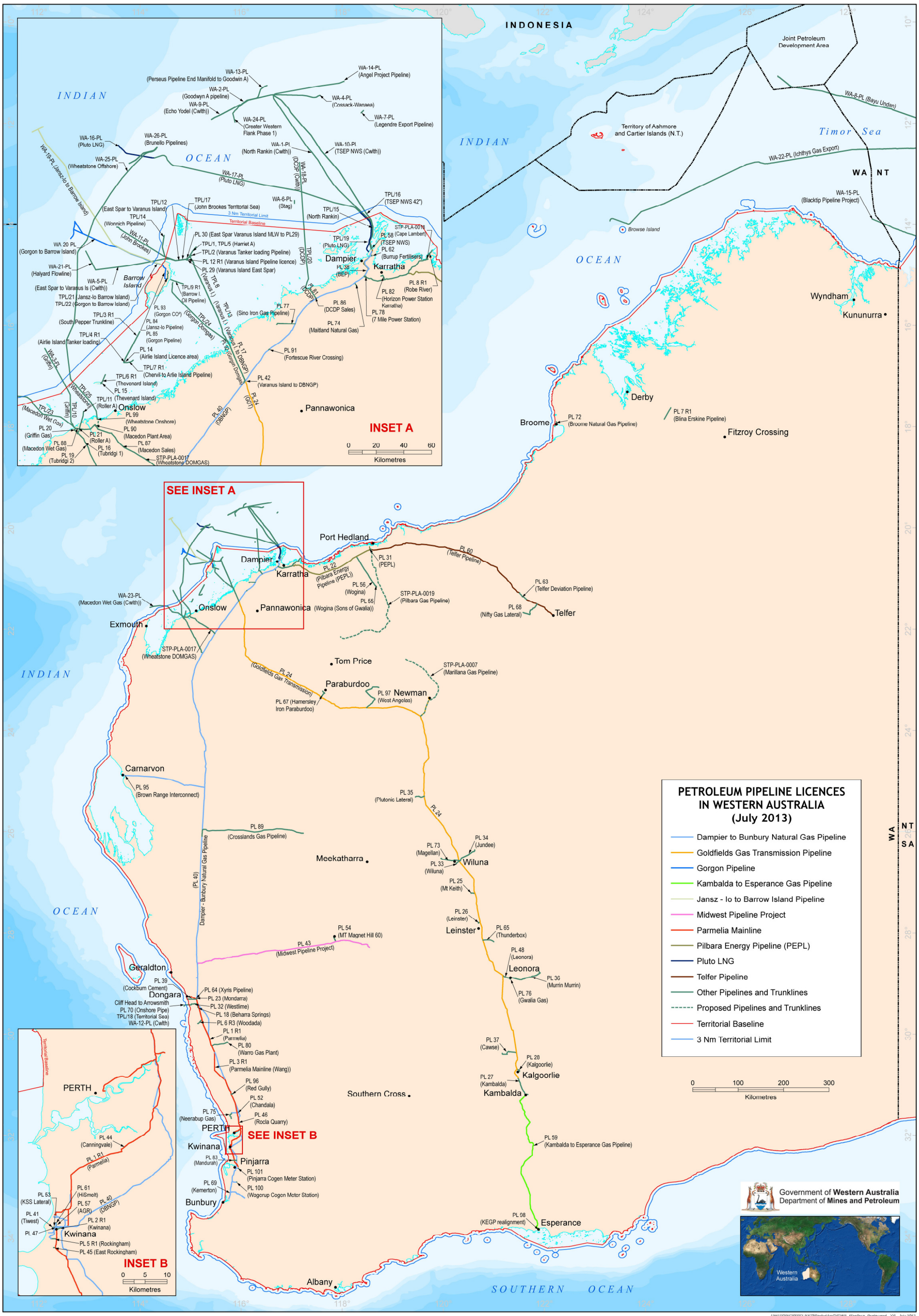
4.3.2. Major Gas Transmission Pipelines

Major gas resources in WA are distant from the majority of gas users. Gas resources are typically located within the Canning, Carnarvon or Perth Basins, while the majority of gas consuming customers (except for Yara Pilbara, mines in the Pilbara region and remote mine sites) are mostly located to the south-west of WA.

In order to allow consumers in the Goldfields, Great Southern, Mid West, Peel, Pilbara and South West regions of WA to access natural gas, there are three main transmission pipelines that transport gas from areas of supply in the north[49]. For an historical view of WA gas transmission pipelines and their respective ownership structure, please refer to the July 2013 GSOO. The Dampier to Bunbury Natural Gas Pipeline (DBNGP) and the Goldfields Gas Pipeline (GGP) are estimated to ship approximately 90% of total domestic gas produced in WA to end users. The following map and table outline all the pipelines in WA.

[49] For the purposes of this GSOO, major transmission pipelines are defined as transmission pipelines that serve more than one customer.

Figure 12 – Infrastructure Map of Major Existing Pipelines, June 2013



Source: DMP (2013d).

Table 6 – Summary of Operational and Planned Transmission Pipelines, 2013

Pipeline	Operator	Completed/ Planned Completion	Nameplate Capacity (TJ/day)	Length (km)	Compression	Covered by Legislation	Expansion/ Comments
Parmelia Pipeline	APA Group	1971	65.4^	417	Yes, two compressors 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	Approximately 84% (1,252 km) of the DBNGP pipeline is looped
Pilbara Pipeline System	APA Group (Epic Energy)	1995	166^	219	No	No	
Goldfields Gas Pipeline	APA Group	1995	155**	1,380	Yes, six compressors, expanding to seven (Turee Creek) compressors are anticipated to be completed in 2014	Yes, main transmission line and Newman lateral	Expanding capacity to 202.4 TJ/day in 2014 (APA Group 2011, 2012) for Rio Tinto's Paraburdoo and West Angelas mines, BHP'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%%	DDG Fortescue River Pty Ltd%%	2014%%	64	270	Unknown	Not applicable at this stage	Announced on 16 January 2014%%
Bunbury to Albany Pipeline	Anticipated to be consortium (including Synergy)***	2016 (Construction announced to begin in 2014)***	~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)	Proposed, unknown%	~200%	~550-630	Unknown	Not applicable at this stage	Planned pipeline
Total		**Approx 1,582.3 TJ/day (including proposed)**	**Approx 1,306.3 TJ/ day (existing)**	**Approx 6,202 km (including planned)**			

Source: GBB Standing Data, DSD (2013c), APA Group, DUET Group (2012b, 2014), Evans and Peck (2009), Buru Energy (2013) and other public announcements. **Note:** Pipeline capacities outlined in this table are nameplate capacity based on normal operating conditions. Actual operating conditions may vary. *Information provided by DBNGP Transmission in Standing Data for the GBB. However, DUET Group (2011) reports an average contracted full-haul capacity of 848 TJ/day, while SKM-MMA (2011) reports a pipeline capacity of 895 TJ/day. ^Information provided by APA Group and GBB Standing Data. **Information provided by APA Group. GGP's capacity is currently being expanded to approximately 202.4 TJ/day. ***Information is based on the Premier's Media Statement, 29 October 2012 and ABC News (2012). ^^Information sourced from CCIWA (2007) and AER (2011). %Information sourced from Buru Energy (2013); consistent with Geoscience Australia (2012). Although Buru Energy (2013) outlines a completion date, it is unclear when this project is likely to commence. %%See the West Australian (2013g), (2014), and DUET Group (2014).

Dampier to Bunbury Natural Gas Pipeline

The DBNGP is the largest gas transmission pipeline in WA, shipping natural gas from the NWS to customers located in the Pilbara, the Mid West and South West of WA[50]. It is operated by DBNGP Transmission, a subsidiary of DBP Holdings Private Limited.

According to DBNGP Transmission, the DBNGP is able to ship approximately 845 TJ/day of compressed gas full-haul (along the entire pipeline) and moves gas along the pipeline to customers using 27 separate gas compressors located at 10 stations[51]. At the time of this report, approximately 84% of the original DBNGP has been duplicated through looping. Currently, the DBNGP has some spare full-haul shipping capacity (see Chapter 11).

The DBNGP is currently connected to six operational gas production facilities via five gas inlets[52]. By 2023, the number of operational gas production facilities connected to the DBNGP is expected to increase from six to eight, with the anticipated completion of the Gorgon and Wheatstone domestic gas production facilities.

The DBNGP also interconnects with the Pilbara Energy Pipeline (PEP) (and onto the Telfer Gas Pipeline (TGP)), the GGP, the Mid West Pipeline (MWP) and the Parmelia Pipeline (via the Mondarra Gas Storage Facility)[53]. The DBNGP has the largest number of interconnections with other pipelines.

According to BREE, DBNGP Transmission is considering the expansion of the DBNGP's capacity under a project known as the 'Stage 5C Expansion Project'. The proposed project would potentially complete the duplication of the DBNGP, increasing its capacity[54]. At the time of this report, DBNGP Transmission has confirmed that there are no current plans to expand the pipeline as there is currently spare shipping capacity on the DBNGP. It is understood that DBNGP Transmission requires commitments of no less than 50 TJ/day of firm capacity and a financial contribution from customers prior to considering an expansion of the pipeline's capacity.

Goldfields Gas Pipeline

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

Interconnected with the DBNGP and Harriet JV pipeline, the GGP starts at Yarraloola, near Compressor Station One of the DBNGP, and heads south-east towards Newman and then south from Newman, passing through the Northern and Eastern Goldfields areas and terminating at Kalgoorlie. The GGP is accessible by three gas production facilities (the KGP and the Harriet and East Spar production facilities) via two gas inlets and services gas consuming customers located east of the DBNGP. The GGP also interconnects with the Kalgoorlie to Kambalda Pipeline (KKP), which in turn interconnects to the Kambalda to Esperance Pipeline (KEP).

According to reports provided to the IMO, the GGP has a current compressed capacity of approximately 155 TJ/day and has some spare capacity shipping to Wiluna[55]. Due to forecast increases in iron ore export capacity in the Pilbara region by 2023 and related demand increases for electricity generation, the GGP is currently in the process of adding an additional compressor at Turee Creek. In 2014, the firm capacity of the GGP is anticipated to increase from 155 TJ/day to approximately 202 TJ/day to support long-term transmission contracts for additional supplies of gas to Rio Tinto and BHP Billiton's mine upgrades

[50] These regions do not correlate with GBB zones defined in the GSI Rules, http://www.imowa.com.au/rules/gsi-rules, accessed 20 November 2013.

[51] For a detailed description of the DBNGP, refer to http://www.dbp.net.au/Libraries/Customer_Access_and_Information/DBNGP_Pipeline_Description_-Standard_Shipper_Contracts_As_At_1_January_2013_Rev_2.pdf, accessed 18 December 2013.

[52] The Harriet and East Spar gas production facilities share a single connection point to the DBNGP.

[53] According to the DBNGP description document outlined in Footnote 42, Griffin and Tubridgi inlet points are inactive. Gas processed by East Spar and Harriet JV facilities located on Varanus Island is understood to enter the DBNGP through the Harriet inlet point.

[54] See BREE (2012).

[55] This is according to APA Group (2013), *GGP Capacity Register,* as at July 2013, http://www.apa.com.au/media/213106/ggp%20capacity%20register%2011-jul-2013.pdf, accessed 26 October 2013.

(a 20-year contract for Rio Tinto's Paraburdoo and West Angelas mines and another 15-year contract for BHP Billiton's new Yarnima power station at Newman) and other customers[56].

Parmelia Pipeline

The Parmelia Pipeline is operated by the APA Group. The Parmelia Pipeline is connected to two operational gas production facilities (the Dongara and Beharra Springs facilities) via two inlet points. This allows gas to be shipped to the Mondarra Gas Storage Facility and to industrial and commercial customers located just north of the Perth Metropolitan area, gas customers connected to ATCO's Metropolitan Gas Network and customers located in the Kwinana and Pinjarra industrial areas.

The Parmelia Pipeline currently has two interconnections with the DBNGP near the Mondarra facility. The Parmelia Pipeline runs approximately parallel to the DBNGP and may be used to 'part-haul' gas from the Carnarvon Basin via the Mondarra interconnection or through other future interconnections to the DBNGP to customers connected to the Parmelia Pipeline. Currently this pipeline is not fully utilised as gas fields supplying production facilities connected to the pipeline are experiencing diminishing gas production. According to GBB data from August to December 2013 approximately 29% of the Parmelia Pipeline's total shipping capacity is being utilised.

Pilbara Pipeline System

Originally, part of the Pilbara Pipeline System (PPS) was constructed to ship gas from Karratha to Port Hedland to power BHP Billiton's iron ore production facility and other planned downstream production facilities for minerals. However, since the first segment was constructed, the PPS has expanded into three different segments, with 114 kilometres (km) of main pipeline: the PEP, from Karratha to Port Hedland that links to the TGP (completed in 1995); 24 km comprising the Burrup Extension Pipeline that connects the KGP to the first segment and the DBNGP (completed in 1999); and approximately 84.9 km of lateral pipelines connecting the Wodgina tantalum mine and Horizon Power's Karratha power station[57].

The PPS is 100% owned by the APA Group through Epic Energy[58]. According to the APA Group, this pipeline is currently not covered by third party access regulation and is understood to be fully contracted[59].

4.3.3. Secondary Pipelines

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

Mid West Pipeline

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

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

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56 APA Group (2012), *APA Goldfields Gas Pipeline - further capacity expansions supporting customer growth*, ASX Announcement 23 January 2012, http://www.apa.com.au/investor-centre/news/asxmedia-releases/2012/apa-goldfields-gas-pipeline-further-capacity-expansions-supporting-customer-growth.aspx, accessed 27 November 2013.

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

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

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

60 Information provided by Horizon Power. Although the MWP ownership is 50/50, according to Horizon Power (2012), output interests and pipeline costs are not shared equally. This is outlined in Horizon Power (2012), *Annual Report 2011/12*, http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3815375adcf718345f70895648257a86000942a3/$file/5375.pdf, accessed 1 February 2013. Australian Pipeline Limited is a wholly owned subsidiary of Australian Pipeline Trust, a wholly owned subsidiary of the APA Group.

61 Capacity utilisation is estimated from gas flow data from GBB and data provided by APA Group. Actual usage only averages approximately 47% (see

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

Telfer Gas Pipeline

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

Currently, the TGP's capacity is understood to be fully contracted. There are two contracted customers: Aditya Birla's Nifty copper mine, approximately 300 km east of Port Hedland, and Newcrest Mining's Telfer gold mine, approximately 400 km east-south-east of Port Hedland.

Kalgoorlie to Kambalda Pipeline

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

The KKP is a covered pipeline (with light regulation)[64] under the *National Gas Access (WA) Act 2009* and the amended National Gas Law. It is currently fully contracted[65] with 90% of total pipeline capacity contracted to supply gas to Mincor Resources' nickel mine and BHP Billiton's Nickel West operations at Kambalda.

Kambalda to Esperance Pipeline

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

The KEP is not covered by third party access regulation and has been operational since 2004. It is currently 100% owned by Energy Infrastructure Trust[66]. The operator of the pipeline is currently WorleyParsons Asset Management Pty Ltd, a wholly owned subsidiary of WorleyParsons, a resources and energy services contract manager.

4.3.4. Proposed Gas Transmission Pipelines

Fortescue River Gas Pipeline

According to two articles in The West Australian[67] and DUET Group's press release[68], DBP Development Group (DUET Group's subsidiary) and TEC Pilbara (TransAlta subsidiary) have formed the Fortescue River Gas Pipeline (FRGP) JV to construct the 270 km FRGP connecting the DBNGP (at Compression Station

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Chapter 11).

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

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

[64] Light regulation means the pipeline operator does not require regulatory approval of terms, conditions and transmission reference tariffs prior to implementation. It only obliges the pipeline operator to publish specific information determined by the regulator that includes price, terms and conditions for access and transmission.

[65] See APA Group (2013b), KKP Spare Capacity Register, http://www.apa.com.au/media/174030/2010%20kkp%20public%20register.pdf, accessed 19 November 2013.

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

[67] The West Australian (2013g), *FMG eyes gas pipe for Solomon*, http://au.news.yahoo.com/thewest/business/a/-/business/20124619/fmg-eyes-gas-pipe-for-solomon/, accessed 3 December 2013 and the West Australian (2013c), *FMG plans gas pipeline to cut costs*, 29 July 2013.

[68] See DUET Group (2014), Fortescue River Gas Pipeline Project and $100M Placement, ASX Announcement, 16 January 2014, http://www.asx.com.au/asxpdf/20140116/pdf/42m4lh487qwc8p.pdf, accessed 16 January 2014.

One) to the 125 megawatt (MW) TransAlta-operated power station at FMG's Solomon mining hub in the Pilbara.

The FRGP will allow FMG to ship gas to lower its cost of operations for its Solomon mining hub by converting its energy consumption from diesel to gas as a foundation customer on the pipeline. The $178 million, 64 TJ/day FRGP is expected to be completed by the end of 2014[69].

The FRGP may potentially increase the consumption of gas in the Pilbara region by connecting with other mining entities or hubs also operating within the Pilbara, that are seeking to lower the energy costs of their mining operations. The West Australian's July 2013 article also suggests the FRGP may be extended in the future to connect to FMG's existing Chichester hub and its future Nyidinghu mines in the Pilbara region.

Bunbury to Albany Pipeline

Originally proposed in 2008, the Bunbury to Albany Pipeline (BAP) is anticipated to be connected to the end of the DBNGP and is likely to be governed under the *Dampier to Bunbury Natural Gas Pipeline Act 1997*[70].

The WA Government has publicly announced it will contribute $135 million towards the construction of the pipeline and is currently attempting to form a consortium to partner with Synergy (formerly Verve Energy) and two other potential parties, ATCO Australia and Alinta Energy[71]. DSD concluded a market sounding process in February 2013 and is expected to proceed towards an expression of interest process as part of its formal procurement exercise[72]. At the time of this report, the preferred corporate structure for the proposed BAP is unknown. It is anticipated this may be decided in 2014.

The WA Government has publicly announced it anticipates the BAP will be completed and operational by 2015[73]. However, the Albany Chamber of Commerce has expressed concerns on the achievability of the timeline for construction[74]. The proposed BAP is expected to use the Bunbury to Albany gas pipeline corridor outlined by the Department of Regional Development and Lands that passes through the towns of Donnybrook, Bridgetown, Manjimup and Mt Barker in the south west of WA[75].

Great Northern Pipeline

The Great Northern Pipeline (GNP) was originally proposed by ARC Energy (now a subsidiary of AWE Limited) in 2007 after it signed a conditional gas sales agreement with Alcoa Australia[76]. However, subsequent to a merger between ARC Energy and AWE Limited, the GNP proposal was assigned to Buru Energy[77].

Although Buru Energy has since discovered potential gas resources in the Canning Basin and has also signed a State Agreement with the WA Government, it is unclear when the construction of the proposed GNP will commence[78].

[69] See DUET Group (2014). Due to the timing of recent announcements regarding this pipeline, gas supplied by the pipeline has not been included in NIEIR's forecasts for this GSOO. The West Australian (2014b) suggests gas demand for FMG may be around 25 TJ/day.
[70] The PUO has suggested that access to the pipeline may be overseen by the ERA, annual corridor charges would be determined by the Department of Finance, PUO and the usage of the BAP corridor and the collection of the corridor charges would be managed by the Department of Regional Development and Lands.
[71] Due to the WA Government's contribution to the BAP, it is understood that Synergy (formerly Verve Energy), a Government owned entity, will own a share of the proposed pipeline.
[72] See DSD (2013c), *BAP*, Website, http://www.dsd.wa.gov.au/8722.aspx, accessed 20 November 2013.
[73] See ABC News (2012), *Gas pipeline extension to start in 2014*, http://www.abc.net.au/news/2012-10-29/project-to-extend-gas-pipeline-to-albany/4339804, accessed 11 December 2013.
[74] ABC News (2013), *Business lobby concerned timeline for gas pipeline extension from Bunbury to Albany will blow out*, http://www.abc.net.au/news/2013-11-19/business-lobby-concerned-pipeline-extension-will-blow-out/5101666?section=wa, accessed 19 November 2013.
[75] For the proposed Bunbury to Albany Gas Pipeline corridor, refer to WA Department of Lands, *Bunbury to Albany Pipeline Corridor*, Website, http://www.lands.wa.gov.au/Dampier-Bunbury-Gas-Pipeline/Bunbury-to-Albany-Gas-Pipeline-corridor/Pages/default.aspx, accessed 24 January 2014.
[76] See Petroleum Exploration Society of Australia (PESA) (2007), *News Resources August/September 2007*, Issue 90, http://www.pesa.com.au/publications/pesa_news/oct_nov_07/pesanews_9012.html, accessed 11 February 2013. According to Buru Energy (2012), Extension of Alcoa Gas Supply Agreement, ASX Release, 29 November 2012, http://www.asx.com.au/asxpdf/20121129/pdf/42bkpxd87wnf9s.pdf, accessed 20 November 2013, this conditional gas sales agreement remains in place with Alcoa Australia.
[77] The current proponent Buru Energy was incorporated for the purpose of acquiring and developing the exploration and production assets of ARC Energy in the Canning Basin.
[78] Buru Energy estimates that the GNP would be completed in 2015. See Buru Energy (2013), *Corporate Update, Investor Presentation*, March 2013 http://www.buruenergy.com/download/recent-presentations/Buru%20Group%20Presn%20March%202013v1(2).pdf, accessed 16 April 2013.

The proposed GNP is anticipated to cost approximately $500 million[79] and is currently anticipated to originate from Buru Energy's Yulleroo field and connect to the DBNGP (and potentially with the GGP via Main Line Valve Seven) around Port Hedland in the Pilbara[80]. This would allow it to fulfil its existing gas supply agreement with Alcoa Australia and also access other potential gas customers located in the south of WA connected to the DBNGP, GGP and other secondary pipelines.

4.3.5. Multi-User Gas Storage Facilities

Since the publication of the July 2013 GSOO, the APA Group has, in August 2013, completed its expansion of the Mondarra gas storage facility from three to 18 PJ[81].

Approximately 30% of the 18 PJ storage capacity[82] is contracted to supplement long-haul pipeline contract capacity and provide for gas peaking requirements and backup emergency gas supplies for Synergy (formerly Verve Energy).

A study by the Allen Consulting Group estimates gas storage requirements of approximately 100 TJ/day for a minimum of 90 to 180 days, or nine to 18 PJ are required for gas balancing services to be offered. A lack of gas storage services may hinder the further evolution of the domestic gas market[83]. The expansion of the Mondarra facility means there may be sufficient storage to enable further evolution of the WA domestic gas market. In addition, there is the prospect of the depleted Tubridgi gas field being developed into a gas storage facility by the DBP Development Group[84], a wholly owned subsidiary of the DUET Group[85].

Multi-user gas storage improves gas security and contingency planning for existing domestic gas consumers, reducing the requirement for disparate and individual gas storage facilities for individual consumers[86]. Although the current focus for gas storage in WA is to utilise depleted gas fields, several other types of gas storage, such as above-ground or underground compressed natural gas and LNG storage facilities, may be considered in the future in WA[87]. Table 7 summarises existing and planned gas storage facilities in WA.

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79 Cost estimates are reported in BREE (2013f), *Resources and Energy Major Projects*, October 2013, http://www.bree.gov.au/publications/resources-and-energy-major-projects, accessed 20 November 2013.

80 The GNP distance was outlined briefly in PESA (2012) *News Resources*, December/January 2011/2012, WA Supplement, http://www.pnronline.com.au/downloads/pdf/edition/74/web.pdf, accessed 11 February 2013 and also outlined in Geoscience Australia (2012), *Australian Gas Resource Assessment 2012*, http://www.ga.gov.au/webtemp/image_cache/GA21116.pdf, accessed 28 February 2013. The specifications of the GNP were previously outlined in the Australian Pipeliner (2007), *Diversity of development key to Australasia's pipeline success*, http://pipeliner.com.au/news/diversity_of_development_key_to_australasias_pipeline_success/012290/, accessed 28 January 2014.

81 Energy Minister Announcement (2013), *Commercial gas expansion boosts WA economy*, http://www.mediastatements.wa.gov.au/pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7754, accessed 17 October 2013.

82 According to the WA Energy Minister Media Statement (2011), *State Government announces key projects to boost energy security*, 26 May 2011, http://www.mediastatements.wa.gov.au/Pages/StatementDetails.aspx?StatId=4229&listName=StatementsBarnett, accessed 7 March 2013, Mondarra has been contracted by Synergy (formerly Verve Energy) to provide up to 90 TJ/day for up to 60 days should WA face a gas supply disruption. This reduces the availability of firm storage capacity for other gas market participants to adequately balance their gas usage when there is a gas supply disruption.

83 Allen Consulting Group also suggests the lack of gas balancing services is one of the factors for the continued joint marketing of gas. See Allen Consulting Group (2009), *Gorgon Gas Project Joint Venture Application for Authorisation of Joint Marketing*, Final Report, Report to the Australian Competition and Consumer Commission, http://www.domgas.com.au/pdf/Subs_pres/Allens%20Consulting%20Group%20report.pdf, accessed 11 December 2013.

84 This subsidiary has changed its name from DBP Services Co.

85 For more information see DUET Group (2013), *2013 Results,* Presentation, 16 August 2013, http://www.duet.net.au/ASX-releases/2013/FY2013-Full-Year-Results-announcements/DUET-2013-Results-Presentation-FINAL-RELEASE.aspx, accessed 20 November 2013. Similar information was also articulated at DBNGP Transmission's Shipper Forum Breakfast on 25 March 2013. It is unclear whether the depleted Tubridgi gas field may be suitable for use as a gas storage facility. BHP Billiton previously indicated to the National Competition Council that Tubridgi's geology is highly stratified. This creates uncertainties to the recoverability of gas injected into the depleted reservoir, see http://www.ncc.gov.au/images/uploads/REGaTGAp-001.pdf, accessed 20 November 2013. DUET Group (2013) suggests otherwise.

86 Some major gas users and producers (such as Barrow Island) have private storage facilities within their operations to allow them to adjust and ensure a smooth flow of gas.

87 These suggestions have not been verified for their suitability for the WA gas market.

Table 7 – Existing and Planned (Under Consideration) Gas Storage Facilities, 2013

Facility	Operator	Total Capacity (PJ)	Input Capacity (TJ/day)	Output Capacity (TJ/day)	Location	Status	Pipeline Connected
Mondarra	APA	18	70	150	Mid West	Operational	DBNGP (inlet and outlet) and Parmelia (outlet only)
Tubridgi	DBP Development Group	Unknown	Unknown	120 or less[%]	Pilbara	Under Consideration	DBNGP

Source: APA Group, DUET Group (2013), IMO GBB data and DBNGP Transmission. **Note:** [%]According to DUET Group (2013), 120 TJ/day is the capacity of the pipeline connected to the potential Tubridgi storage facility.

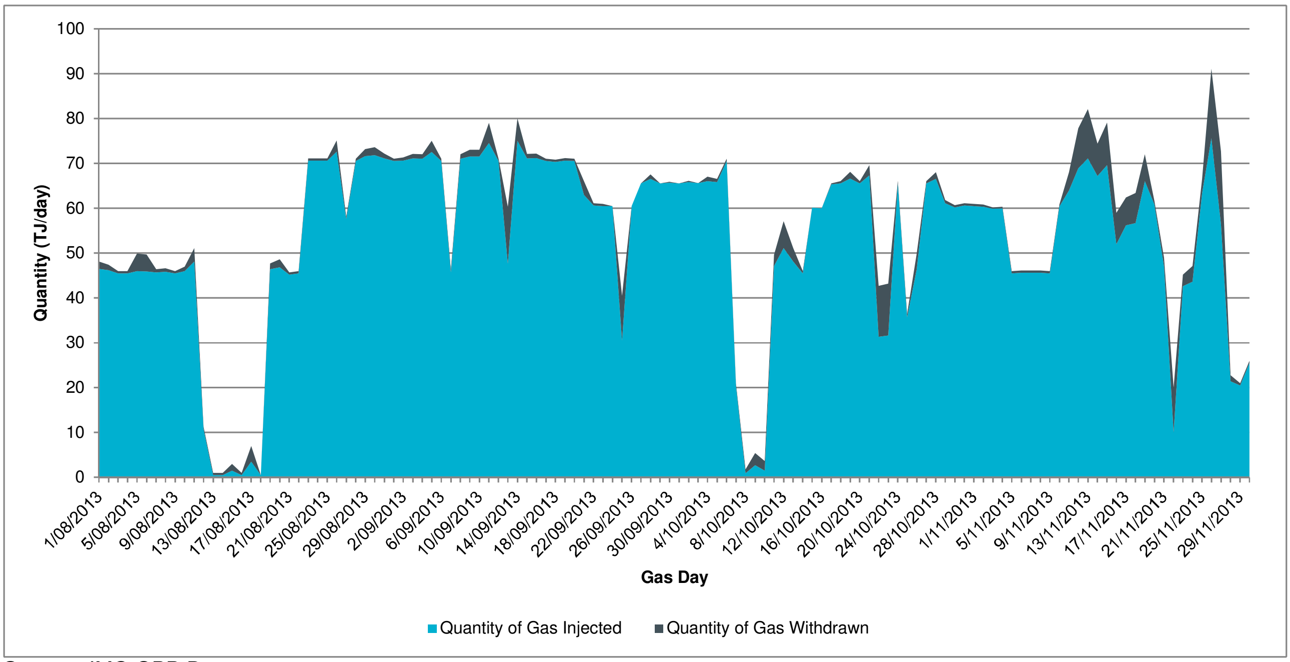
Other potential sites for gas storage facilities include the depleted gas fields of Beharra Springs, Dongara and Woodada located in the Perth Basin.

4.3.6. Mondarra Gas Storage Facility

Figure 13 presents a view of the quantity of gas injected and withdrawn at the Mondarra facility using GBB data for the 1 August to 31 December 2013 period. The data shows the gas storage facility ran at its maximum injection rate almost on a daily basis for the 23 August 2013 to 20 September 2013 period. It is understood the facility is accepting and injecting gas into the storage facility to fulfil the long-term foundation contract signed with Synergy (formerly Verve Energy)[88].

Figure 13 also shows that the quantity of gas withdrawn from the Mondarra facility is slowly rising. This suggests the presence of gas storage may have had an impact on short-term behaviour in the WA gas market. However, without observing or analysing changes to pipeline delivery points by gas shippers, it is difficult to ascertain if gas storage has improved short-term gas trading or improved gas balancing requirements for shippers.

Figure 13 – Mondarra Gas Storage Injections and Withdrawals, 1 August 2013 to 31 December 2013



Source: IMO GBB Data.

88 APA Group (2011b), *APA to expand its underground gas storage facility in Western Australia*, ASX Release, 26 May 2011, http://www.apa.com.au/media/187159/apa%20asx%20release%20-%20mondarra%20expansion%20-%202011%2005%2026%209am.pdf, accessed 26 November 2013.

The IMO understands the Mondarra storage facility is approximately 80% full based on Mondarra's current storage capacity, as it is understood Synergy (formerly Verve Energy) is utilising its gas storage capacity together with gas held by other customers in the facility. This means there is still gas storage capacity available for other market participants.

4.3.7. Strategic Industrial Areas for Gas Production

In 2009, the WA Government announced the establishment of the Ashburton North Strategic Industrial Area, located in the Pilbara, and the Browse LNG Precinct near James Price Point in the north-west of WA, to assist with the development of gas related projects (domestic and LNG)[89].

The recently completed Macedon gas production facility and the Wheatstone LNG and domestic gas production facilities that are currently under construction are located in the Ashburton North Strategic Industrial Area. The proposed Browse LNG Precinct (also known as the Kimberley gas precinct) has been granted state environmental approval and the land for this proposed precinct located at James Price Point has been secured by the WA Government[90]. There are no proposed facilities planned for the site at this stage.

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[89] For more information, please refer to the DSD website, for the Ashburton North Strategic Area, see http://www.dsd.wa.gov.au/8383.aspx and for the Browse LNG Precinct, see http://www.dsd.wa.gov.au/8581.aspx, both accessed 22 February 2013.

[90] See WA Environment Minister Media Statement (2013), *Browse LNG proposal gets environmental nod*, http://www.dsd.wa.gov.au/documents/Browse_-_Media_Statement_-_Browse_LNG_Proposal_gets_environmental_nod.pdf, accessed 12 November and Premier's Media Statement (2013), *State Government secures land for Kimberley gas precinct*, Media Statement, 12 November 2013, http://www.mediastatements.wa.gov.au/Pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7952, accessed 12 November 2013.

5. Western Australia and the External Economic Environment

This chapter outlines the key drivers of the WA economy and provides an economic outlook for the 2014 to 2023 period. The economic projections are then applied in NIEIR's gas demand and potential supply models (described in sections 6.1 and 6.3). For a brief overview of the WA economy, please refer to the July 2013 GSOO[91].

5.1. Western Australia's Economic Outlook

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

Resource extraction, processing and export are important to the Australian and WA economies and are key drivers of gas consumption growth. DMP has reported that resource projects worth an estimated $146 billion were under construction or committed as at September 2013, dominated by LNG developments. Capital expenditure in the resources sector represented 83% of all new capital expenditure in WA in 2012-2013[92].

Given the high dependence of the WA economy on the resources industry, it could reasonably be anticipated that growth rates in WA will remain at more volatile levels, as has historically been the case, compared to more diversified economies. WA has experienced significant growth in resource-related investment over the last decade. It is anticipated that this investment peaked at $90 billion in 2012-2013 with investment expected to be at average levels in the region of $75 billion per annum over the period from 2013 to 2017. This investment is anticipated to decline to levels in the region of $60 billion per annum for the remainder of the decade, as major projects currently under construction become operational. This ongoing investment is expected to be dominated by the further development of LNG export projects.

Economic growth is also driven by demand for WA commodities, particularly in Asia. In 2012-2013 iron ore remained WA's highest value commodity at $56 billion while the petroleum sector was valued at approximately $25 billion during the same period, with total mineral and petroleum exports comprising 89% of total merchandise exports from WA[93]. It is anticipated that investment in the resources industry will remain a key driver for gas consumption in WA in the medium-term.

NIEIR's forecasts are prepared using available economic data up to the June 2013 release of the Australian National Accounts by the Australian Bureau of Statistics (ABS) on 4 September 2013.

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

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[91] See http://www.imowa.com.au/gsoo.

[92] See DMP (2013e), *Mining and Petroleum Investment*, Update as at September 2013, http://www.dmp.wa.gov.au/12410.aspx, accessed 24 January 2014.

[93] See DMP (2013f), *Mineral and Petroleum Industry 2012-13 Review*, http://www.dmp.wa.gov.au/1525.aspx, accessed 24 January 2014.

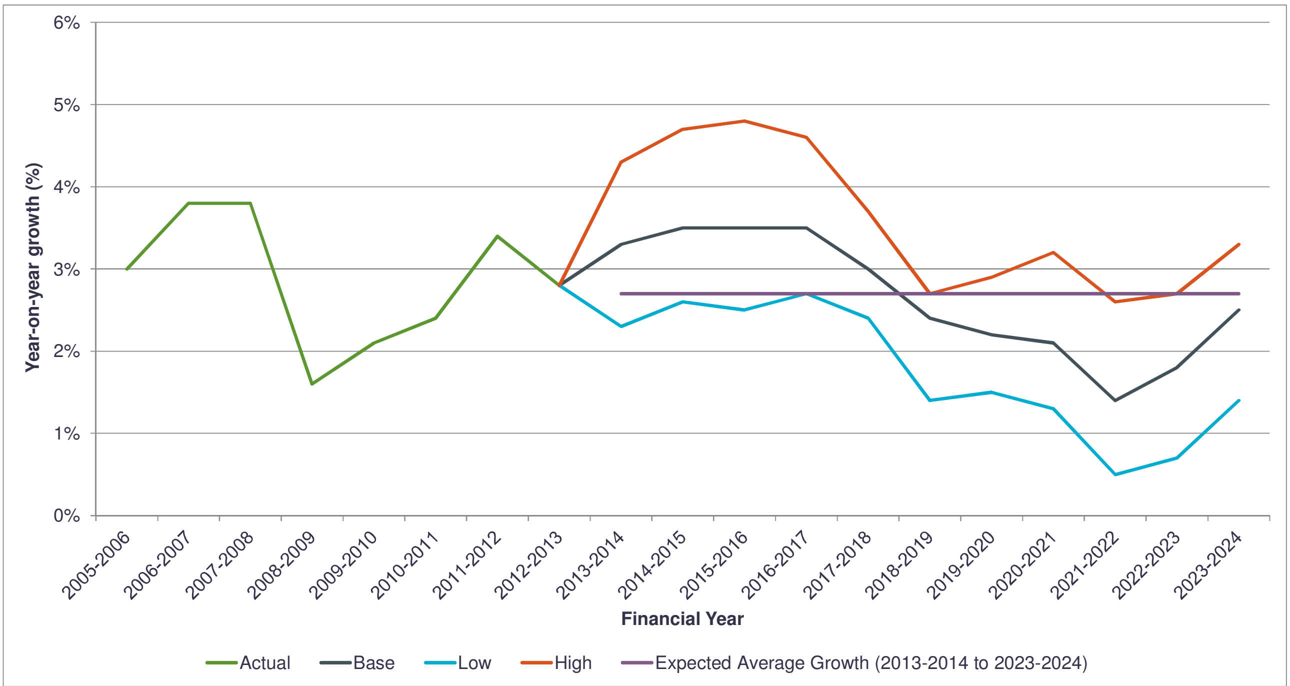
5.2. Economic Projections

Figure 14 shows the forecasts of growth in Australian Gross Domestic Product (GDP) and Table 8 shows forecasts of the key demand and supply drivers of GDP formation for the Base economic growth scenario. In addition to the Base scenario, High and Low economic growth scenarios have been prepared by NIEIR. These scenarios are explained below and growth forecasts for the three scenarios are shown in Appendix 2.

The strength of the Australian dollar since 2009-2010 has led to the 'Dutch disease'[94] with benefits of the mining boom being offset by the high import content of construction and equipment, as well as reducing the competitiveness of exports for non-resource related industries. A forecast depreciation of the Australian dollar, along with an increase in production levels in the resources sector, as forecast by NIEIR, is projected to result in healthy growth in exports in the forecast period.

NIEIR forecasts that Australia's annual average economic growth over the period from 2012-2013 to 2023-2024 will be 2.7% per annum. In the near-term, GDP growth is forecast to remain in a tight 3 to 3.5% range through to the end of 2017-2018.

Figure 14 – Projected Australian Economic Growth, 2013-2014 to 2023-2024



Source: NIEIR Forecasts 2013-2014 to 2023-2024.

Recent growth in GDP since 2010-2011 has been underpinned by the acceleration in mining investment. NIEIR considers that as growth in mining investment slows, growth in dwelling investment and private consumption as well as government investment in infrastructure will accelerate to maintain GDP growth at above 3% until 2017-2018, following which growth in Australia will remain below 2.5% through to 2023-2024.

Table 8 – Australian Growth Projections for Key Economic Parameters, Base Scenario (percentage growth)

Parameter	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Private consumption	3.2	2.6	3.6	3.7	3.5	3.3	3.1
Dwelling investment	-4.0	4.5	5.5	-0.6	-4.9	-3.2	-1.0
Business investment	9.9	-14.0	5.8	2.5	2.4	1.2	-0.1
Government consumption	3.1	2.5	3.4	3.7	3.3	3.1	2.9
Government investment	-2.2	22.6	23.5	14.2	7.3	-4.0	-2.9

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

Domestic final demand	5.0	0.8	6.2	4.3	3.0	1.6	1.5
Overseas exports	6.2	0.4	2.0	5.5	6.6	5.7	5.2
Overseas imports	12.5	-6.1	8.9	7.7	4.9	1.5	1.3
Gross Domestic Product	**3.4**	**3.0**	**3.3**	**3.5**	**3.5**	**3.5**	**3.0**
Population	1.5	1.5	1.6	1.6	1.5	1.5	1.5
Employment	1.4	0.4	1.7	1.9	2.4	2.4	2.3
Exchange rate (A$/US$)	1.03	1.03	0.91	0.88	0.86	0.82	0.77

Source: NIEIR Forecasts 2013-2014 to 2017-2018**.**

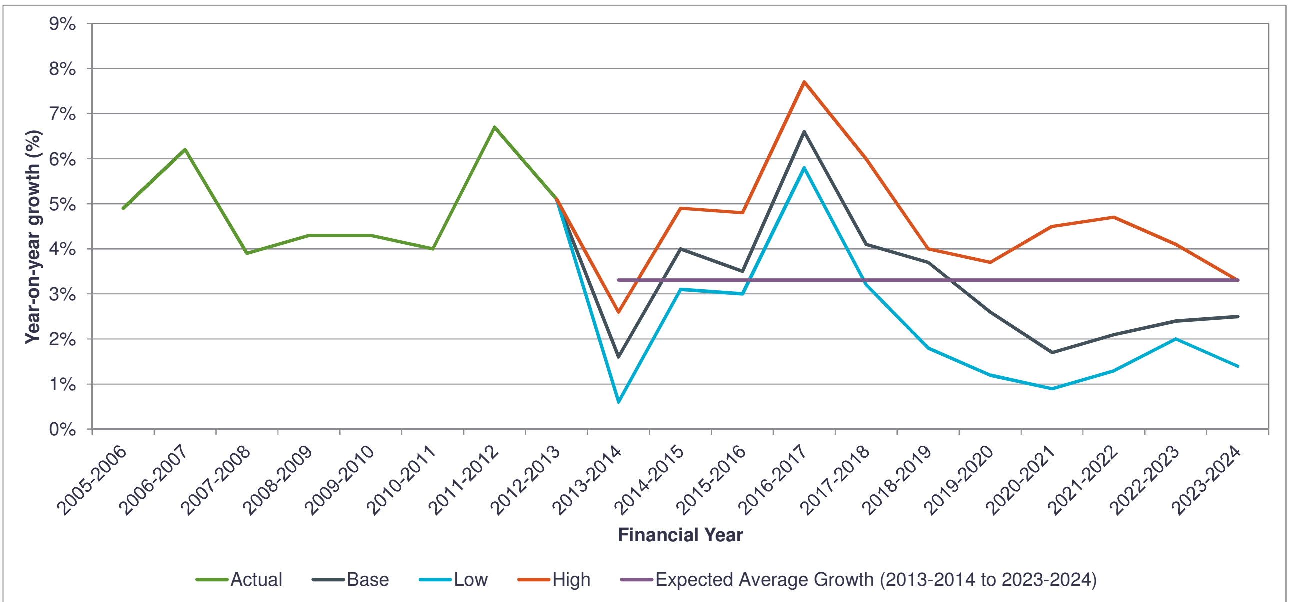
The stabilisation in mining investment over the coming years will contribute negatively to growth. However, NIEIR forecasts that a range of factors will contribute to maintaining GDP growth of over 3% through to 2017-2018, such as:

- a recovery in the dwelling construction market in the short-term;
- robust ongoing growth in private consumption expenditure;
- the replacement of mining related investment with increased mining production levels (following the high level of investment);
- a return to more typical levels of worldwide public demand growth after a period of fiscal withdrawal;
- a continued recovery in the world economy; and
- a significant weakening in the Australian dollar (from levels above parity in the first quarter (Q1) of 2013), by as much as 25% by 2018, boosting the competitiveness of the manufacturing sector and other export industries.

NIEIR projects that growth will moderate after 2018 to levels below 3%, due mostly to slower growth in the world economy as the impact of falling investment levels following the Global Financial Crisis (GFC) and related capacity constraints are most acutely felt. NIEIR predicts that the 'BRIC' (Brazil, Russia, India and China) economies may struggle to sustain recent high levels of growth for varying reasons, including a general slowing in the commodity boom, growing debt levels and an inability to sustain artificially under-valued currency valuations towards the end of the decade.

Figure 15 shows the forecasts of growth in WA Gross State Product (GSP) and Table 9 shows forecasts of the key drivers of GSP for the Base scenario. Forecast average growth for the WA economy over the next 10 years is 3.3% per annum.

Figure 15 – Projected Western Australian Economic Growth, 2013-2014 to 2023-2024



Source: NIEIR Forecasts 2013-2014 to 2023-2024.

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

Parameter	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Private consumption	5.9	4.5	1.9	1.9	5.7	3.5	4.4
Dwelling investment	-15.1	-0.2	5.1	7.9	2.1	-4.6	-5.0
Business investment	37.7	8.1	-16.2	15.5	-5.5	-0.8	2.3
Government consumption	4.8	2.4	3.5	4.4	4.5	4.0	3.7
Government investment	9.8	-6.0	-18.1	5.5	3.2	3.2	3.2
State final demand	13.5	4.9	-4.9	7.0	1.4	1.8	3.1
Gross State Product	**6.7**	**5.1**	**1.6**	**4.0**	**3.5**	**6.6**	**4.1**
Population	3.0	2.6	2.4	2.6	2.5	2.2	2.2
Employment	3.1	4.1	0.5	1.8	2.5	2.8	2.8

Source: NIEIR Forecasts 2013-2014 to 2017-2018.

While growth in WA averaged just below 6% in 2011-2012 and 2012-2013, NIEIR forecasts that growth in WA will moderate considerably over the next three years, reflecting the contraction in large scale mining investment and WA Government spending in 2013-2014. However the housing construction market is expected to recover during this period, stimulating GSP somewhat.

NIEIR notes that the risks to its forecast GSP growth rates are weighted significantly to the upside. The average annual GSP growth in the High scenario is forecast to be 1.3% above the Base scenario, whereas the average growth under the Low scenario is forecast to be 0.8% per annum below Base scenario. This reflects the considerable level of investment in the resources industry in recent history, which is now expected to generate significant growth in income from exports over the forecast period.

5.3. Economic Forecast Comparisons

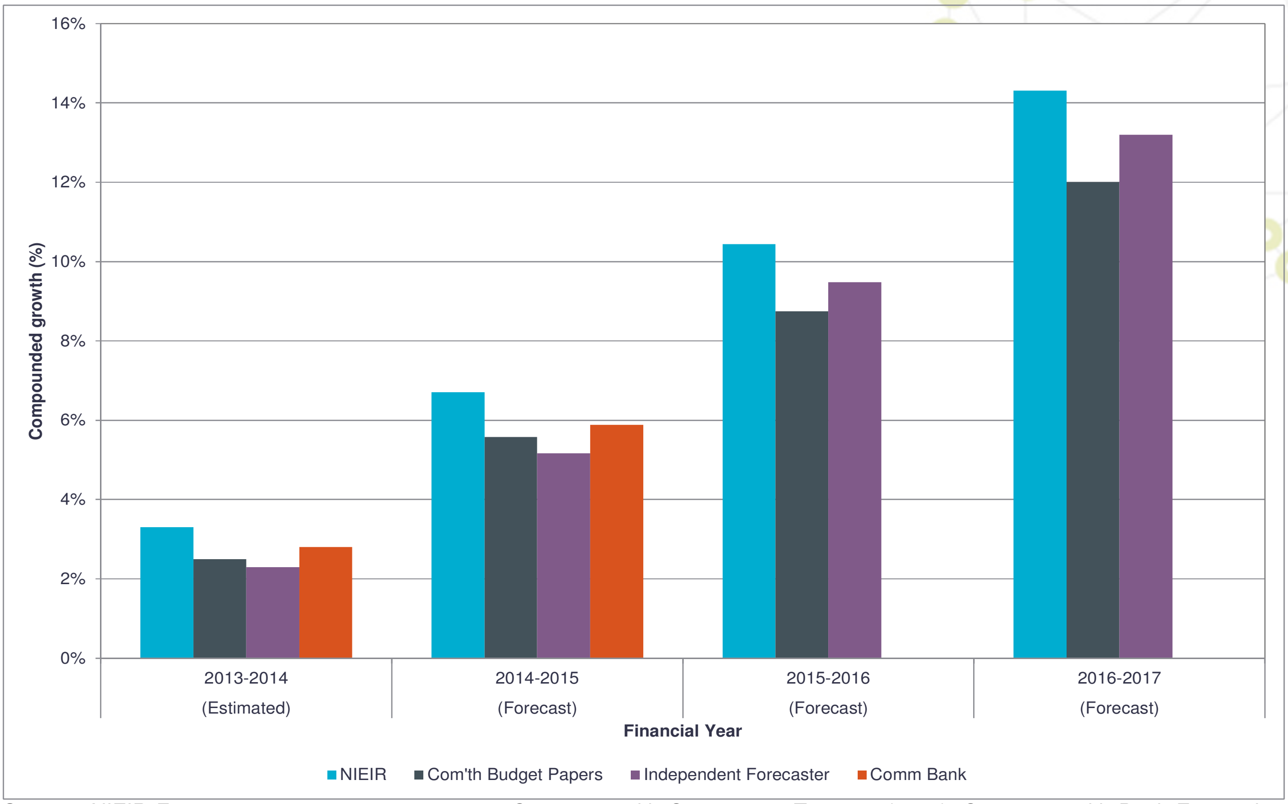
Figure 16 compares NIEIR's Australian economic growth forecasts with those of three other organisations:

- the Commonwealth Government Budget Papers (published May 2013);
- a major Independent Forecaster[95] (published October 2013); and
- the latest Commonwealth Bank Economic Forecast[96] (published October 2013).

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

95 The 'Independent Forecaster' included in the graph has requested that it not be named.
96 The Commonwealth Bank forecast extends only to 2014-2015, so it is excluded from comparison after 2014-2015.

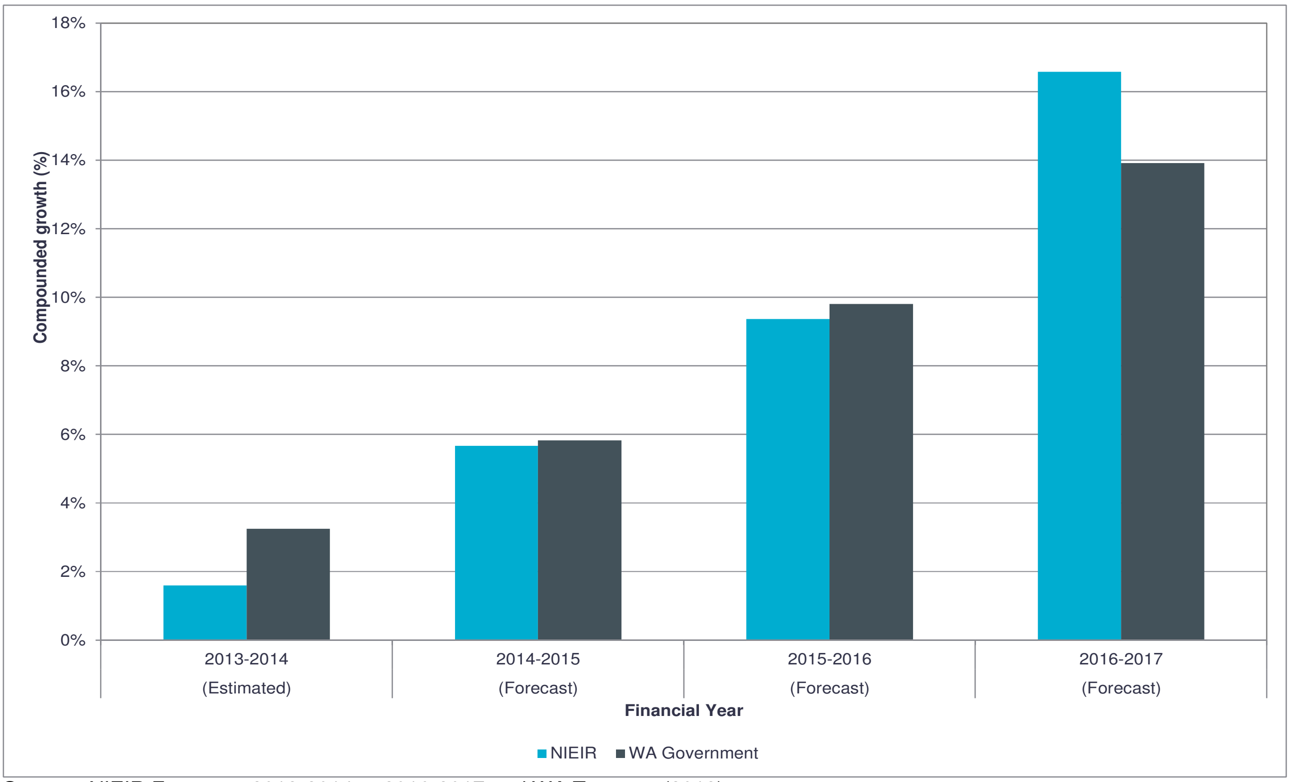
Figure 16 – Comparison of Compound Australian Economic Growth Forecasts, 2013-2014 to 2016-2017



Source: NIEIR Forecasts 2013-2014 to 2016-2017, Commonwealth Government Treasury (2013), Commonwealth Bank Economic Forecast and Independent Forecaster.

Figure 17 compares the NIEIR forecasts of WA GSP growth with those published by the WA Department of Treasury (WA Treasury) in the August 2013 Budget Papers for the 2013-2014 to 2016-2017period.

Figure 17 – Compound WA Economic Growth Forecasts, 2013-2014 to 2016-2017



Source: NIEIR Forecasts 2013-2014 to 2016-2017 and WA Treasury (2013).

This comparison is presented on a compound basis. While NIEIR predicts lower growth up to 2015-2016, NIEIR's forecasts are higher than the WA Treasury forecasts over the entire period up to 2016-2017. This is primarily due to NIEIR forecasting growth of 6.6% in 2016-2017 compared to WA Treasury forecasts of 3.75%.

6. Forecast Methodology and Input Assumptions

This chapter provides a description of NIEIR's forecast methodology and models used to project domestic gas demand and the potential gas supply for the 2014 to 2023 period reported in this GSOO. The chapter also outlines the key input assumptions applied in the forecast models.

6.1. NIEIR's Gas Demand Forecasting Methodology

NIEIR's gas demand forecasting methodology for this report is unchanged from the July 2013 GSOO, using the same gas demand models. However, some forecasting assumptions have been updated since the July 2013 GSOO to take account of GBB data that became available from 1 August 2013, and other information. The revised assumptions relate to gas consumption of the minerals processing, industrial and manufacturing industries and the price elasticity of gas demand.

6.1.1. Gas Demand Modelling

A number of reports prior to the July 2013 GSOO have projected WA's future gas consumption[97], with most of the studies projecting steady increases in domestic gas consumption for the next 10 years.

Due to the industrial structure of the WA economy, WA domestic demand is difficult to forecast. This is because 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, electricity generation and LNG sectors. These industries in turn are driven by future prospects, which may include future prices of resource commodities.

As prospective resource projects are linked to a multitude of commercial considerations and economic factors, the IMO does not attempt to predict which projects are viable and likely to go ahead for the outlined period[98]. Instead, the IMO focuses on projecting domestic gas demand for WA projects that have already been sanctioned and approved by the end of September 2013 (listed in Appendix 3)[99], which does not include gas to be consumed by the recently announced FRGP[100]. As such, **the gas demand forecasts for the 2014 to 2023 period in this GSOO only consider projects that have attained a favourable final investment decision (approved) and have been publicly announced by the proponents**[101].

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

The top-down forecasting approach, summarised in Figure 18, 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. This is followed by the application of NIEIR's national econometric model of the Australian economy, which provides projections of 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. 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.

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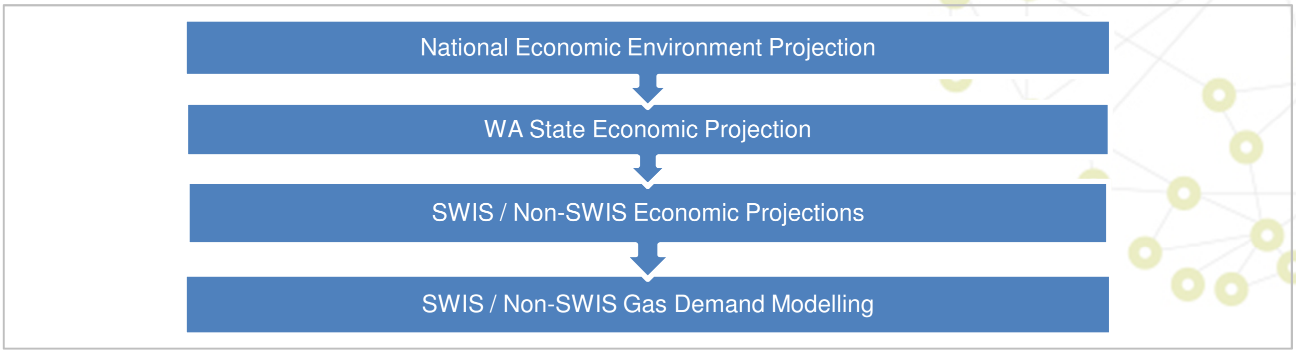
[97] Studies that have projected future gas scenarios include Chamber of Commerce and Industry WA (2007), Synergies Economic Consulting (2007), ECS (2007, 2008, 2010), CMEWA (2008, 2011, 2012), DMP (2010, 2011), Wood Mackenzie (2010), EnergyQuest (2010, 2011, 2011b), EISC (2011), SKM MMA (2011) and ACIL Tasman (2011). For full reference details, refer to Appendix 12.
[98] In addition, there are many potential gas consuming projects (more than 100) that may change the WA domestic gas consumption significantly, see Appendix 3 for a list of potential projects.
[99] Future GSOOs may consider projected gas consumption from a proportion of speculative projects.
[100] The IMO's forecasts were concluded prior to this announcement. It has been estimated that approximately 25 TJ/day will be consumed via the pipeline, which is expected to be completed by the end of 2014 (see DUET Group (2014) and the West Australian (2014b)).
[101] The expected dates of project completion are also from public announcements from these companies.

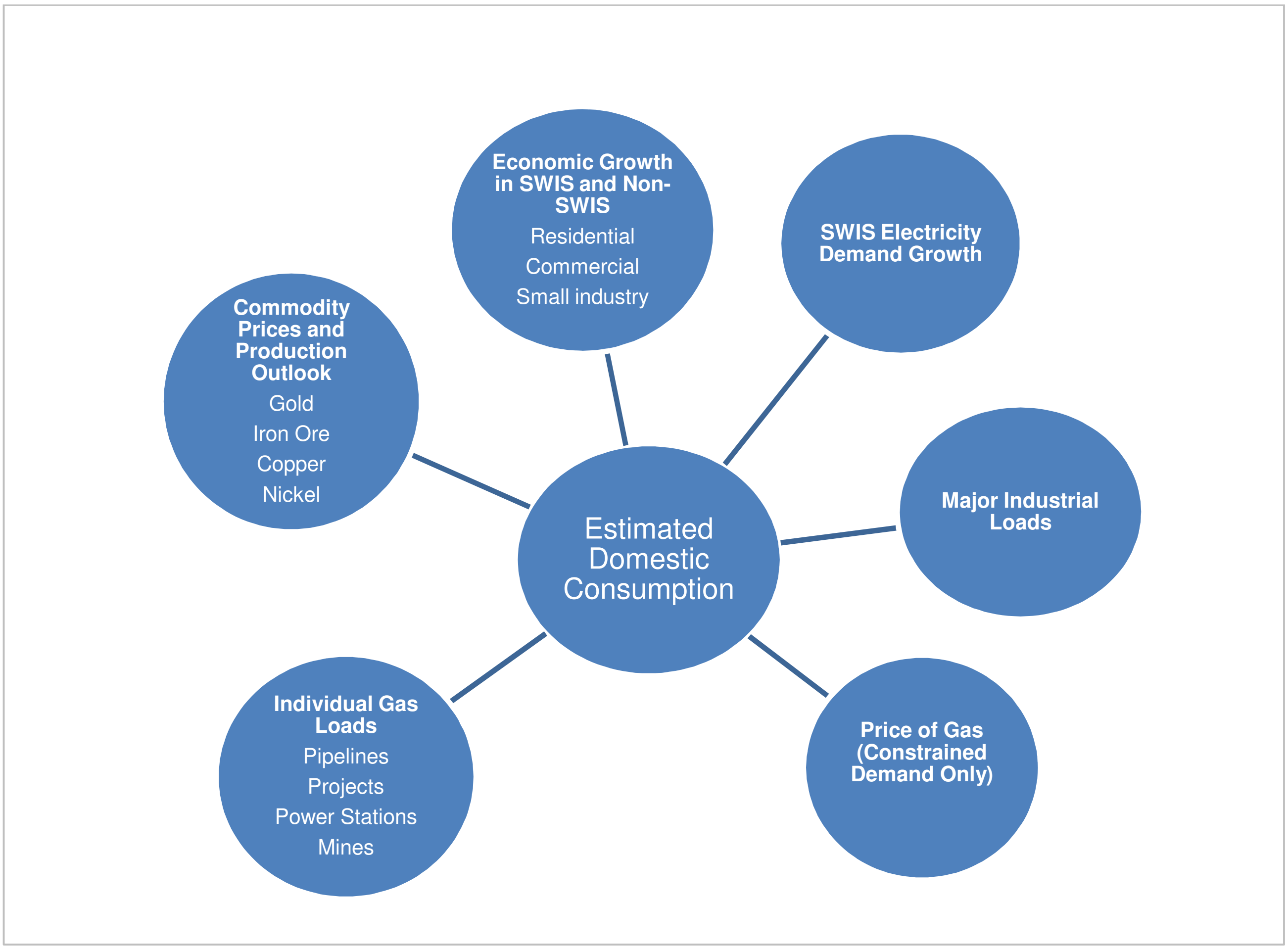
Figure 18 – NIEIR's Gas Demand Forecast Methodology (Top-Down)



Source: NIEIR.

Figure 19 provides a summary of NIEIR's bottom-up forecasting approach, showing the smaller industry-specific models that NIEIR aggregates to form domestic gas demand forecasts for the 2014 to 2023 period (excluding gas consumption for petroleum processing). These industry-specific models allow NIEIR to apply different assumptions to individual industries (or 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 (ESOO).

Figure 19 – NIEIR's Gas Demand Forecast Methodology (Bottom-Up)



Source: NIEIR.

The advantage of NIEIR's methodology is that it 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, dwelling stock composition and projections of population growth. NIEIR's forecasting methodology also links WA's regional economic forecast with gas use based on assumptions about gas use efficiency and major industrial gas usage.

Some gas use efficiency estimates for the resource, manufacturing and resource processing (particularly aluminium) sectors have been updated and adjusted following a review of GBB data. While the availability of the GBB data is advantageous, the limited amount of data available for this GSOO meant NIEIR's gas demand forecasts for specific sectors were only recalibrated. NIEIR's gas demand model remained highly reliant on historical gas shipping data provided by pipeline operators to the IMO for the 1 January 2009 to 31 August 2013 period. With more GBB data available in the future, gas demand estimates in future GSOOs may also consider seasonal and peak gas consumption.

6.1.2. Other Projects That May Contribute to Future Gas Demand – Not Included in Forecasts

A significant proportion of projected demand growth comes from new and existing industrial and mining projects. Appendix 3 lists projects that are included in WA's gas demand forecast for the 2014 to 2023 period. Consistent with the July 2013 GSOO, the forecast gas demand in this GSOO only represents demand from projects that are already sanctioned for the forecast period[102]. Appendix 3 also reports a list of potential projects that may significantly modify the domestic gas demand for the outlined period, such as FMG, Rio Tinto and BHP potential mine expansions, that have not been included in the forecasts.

6.1.3. Non-Price Assumptions Applied in the Gas Demand Forecast Model

As noted previously, the WA economy is heavily dependent on the fortunes of the mining and energy related sectors. With these sectors heavily influencing the outlook for the WA economy, domestic gas consumption for the 2014 to 2023 period is largely dependent on:

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

These factors influence business investment decisions in prospective mining and energy projects that will contribute towards future gas demand[103].

To generate an appropriate representation of future gas demand, this GSOO establishes three forecasts for gas demand (the Base, High and Low demand forecasts). The differences between the three scenarios relate to different economic projections reported in Chapter 5 and Appendix 2 and the input assumptions applied for the three gas demand forecast scenarios presented in Table 10.

Table 10 – Projected Gas Demand Scenario Parameters, 2014 – 2023

		Scenarios		
Parameter	**Unit**	**Low**	**Base**	**High**
WA Economic growth	%	As per economic growth rates outlined in Appendix 2	As per economic growth rates outlined in Appendix 2	As per economic growth rates outlined in Appendix 2
Asia Pacific LNG prices (real)	US$/GJ	12.94 – 17.41	13.81 – 19.24	15.32 – 21.07
Real Commodities prices	Index (Base = 100, 2012)	78 - 92	78 - 92	78 - 92
Exchange rates	A$/US$	0.75 - 0.91	0.75 - 0.91	0.75 - 0.91

Source: NIEIR assumptions. **Note:** Carbon pricing has been considered in the modeling. Projected gas demand is assumed to be readily transported by existing and future pipelines. Commodities Index is an index developed by NIEIR for its modeling. Asia Pacific LNG prices represent estimated LNG prices for the forecast period.

[102] As noted above, gas to be supplied by the FRGP has not been included in NIEIR's gas demand forecasts due to the recent timing of the announcement.
[103] This GSOO acknowledges that the price elasticity of gas demand is also a key factor and the gas demand forecasts account for this.

6.1.4. Price Assumptions Applied in the Gas Demand Forecast Model

NIEIR's gas demand forecasts are developed considering the projections of economic growth outlined in section 5.2 and projected domestic gas prices outlined in section 6.4 for the 2014 to 2023 period. The Base, High and Low gas price forecasts have been applied to the Base, High and Low demand forecasts, respectively.

6.1.5. Total Gas Demand Assumptions

In addition to projecting gas demand for the domestic market, NIEIR also developed gas demand scenarios for WA's LNG sector, which form part of the forecasts of total WA gas demand. The applied assumptions for each scenario for LNG are outlined in Table 11. **The scenarios only represent estimates of the future LNG market in WA and do not represent any confidential information provided by existing or potential LNG market participants**.

Table 11 – Scenarios Applied to LNG Facilities in WA, 2014 – 2023

	Scenarios		
Parameters	**Low**	**Base**	**High**
LNG feedstock requirements	Only LNG facilities that have been approved. Gorgon LNG commences (15.6 Mtpa) in 2015, Wheatstone LNG commences (4.45 Mtpa) in 2016, and completes (4.45 Mtpa) Train 2 in 2017, Prelude FLNG commences (3.6 Mtpa) in 2017.	Encapsulates assumptions in Low scenario and Gorgon LNG expands (5.2 Mtpa) in 2020.*	Includes assumptions in Low scenario and Gorgon LNG expands (5.2 Mtpa) in 2019*, Bonaparte FLNG commences (2.4 Mtpa) in 2019, Wheatstone LNG expands (4.45 Mtpa) in 2020 and Pluto LNG expands (2.2 Mtpa) in 2021.
LNG processing requirements	8% of total LNG feedstock	8% of total LNG feedstock	8% of total LNG feedstock

Source: IMO and NIEIR's assumptions. **Note:** Processing estimates are assumed by taking the low range of processing estimates outlined in Tusiani, Michael D. and Shearer, Gordon (2007). *According to Reuters (2013c), Chevron is considering expanding the Gorgon LNG plant despite cost pressures.

6.2. The Relationship between Domestic Gas Supply and LNG Processing

This section provides further clarity around the relationship between LNG and domestic gas production for an LNG-linked domestic gas production facility.

At the time of this report, the only LNG-linked domestic gas production facility supplying the domestic gas market is the KGP that is operated by the NWS JVs. The KGP has a capacity of 630 TJ/day out of the total capacity of 1,477 TJ/day (approximately 43%) and provides approximately 44% of total domestic gas flow (based on the fourth quarter (Q4) of 2013).

The anticipated completion of the Gorgon and Wheatstone domestic gas production facilities by 2018 will increase the number of LNG-linked domestic gas production facilities operating within the WA domestic market to three (including the KGP). It is anticipated that the addition of these facilities will increase the concentration of LNG-linked facilities to approximately 57% of the total domestic gas production market (1,130 TJ/day of 1,977 TJ/day). Hence, there is a need to understand decisions relating to these facilities.

Commercial and investment decisions of gas producers in WA are driven by the availability of gas resources, the availability of gas production capacity and a time-based valuation of the resources based on the market opportunities to sell either internationally or domestically[104].

[104] This was outlined in reports by Marchment Hill Consulting (2009), G*as Market Development Working Group Western Australian Gas Market Developments*, Final Report, 10 September 2009 and Frontier Economics (2010), *Joint Marketing of NWS domestic gas, A report prepared for NWS Project participants*, 31 March 2010. This sentiment was also reiterated by a large market participant to the IMO verbally. It should be noted that despite this assertion, the export capacity of an LNG terminal is a limitation.

From the perspective of the domestic gas producer, the price of domestic gas (for primary gas supply contracts, not the secondary market) would be influenced by the cost of extraction, domestic demand and supply conditions and varying international LNG prices[105].

The commercial viability of LNG projects, in simple terms, is driven by the quantum of gas resources that can be extracted, the price that can be obtained for the discovered and extracted resources and the ability to make a return on the capital investment. To ensure a stable return, the projected timing of cash flows from an LNG production facility (and its domestic related production facilities) will be important.

For example, an operator of an LNG-linked domestic gas production facility may be fully utilising its LNG facility but have spare domestic gas production capacity. When faced with the choice to sell a volume of gas domestically or as LNG, it would compare the present value that can be realised today for selling the gas domestically with the present value that may be realised for selling LNG following the expiry of an LNG contract, which may be many years in the future.

The NWS has been producing and supplying gas to the domestic gas and international LNG markets from the Burrup Peninsula since 1984 (LNG since 1989). After approximately 29 years of gas production, this project is anticipated to be facing a decline in gas reserves (see section 3.1) within the next 12 to 13 years[106]. While there appear to be sufficient 2P gas reserves for the 2014 to 2023 period for the NWS JVs to provide gas to both the international and domestic markets, the domestic gas facility is not anticipated to be producing at maximum capacity for the forecast period. In addition, remaining gas reserves are contained in comparatively smaller gas fields[107]. For example, Greater Western Flank Phases 1 and 2 are known to be made up of 16 separate small fields[108] that are located further from production facilities and are likely to be more costly to extract. The IMO estimates future capital expenditure for the NWS will be in the order of $10 billion.

The NWS JVs have recovered their initial capital outlay becoming cash flow positive around 2004[109], and will have fulfilled their domestic gas obligations by 2015 under existing contracts. Due to the finite quantum of remaining, accessible reserves, potential contracts for the supply of domestic gas are expected to be compared against the present value potential revenue from the LNG spot market or future LNG contracts in order to maximise revenue for the JVs.

With the decline in remaining gas reserves, it is anticipated that the NWS JVs may prefer shorter-term contracts in the future and may be unlikely to offer the longer-term (10-year, or longer) contracts that previously dominated the WA domestic gas market. The NWS JVs are expected to be cautious when considering potential long-term domestic gas supply contracts, evaluating whether the supply risks of these contracts can be sufficiently mitigated and managed though other measures (such as purchasing gas on the short-term markets from other producers or entering into other back-to-back supply contracts) or if there is a sufficiently high-risk premium (above its costs) to compensate the NWS JVs for providing additional gas supply to the WA domestic market.

Gorgon and Wheatstone, which are anticipated to start producing gas for the domestic gas market in 2016 and 2018 respectively, do not face the same medium-term reserves constraints as the NWS JVs. The Gorgon and Wheatstone JVs have more than sufficient gas reserves to cater for both the international and domestic markets for the 2014 to 2023 period, and so are more likely to agree to longer-term gas supply contracts with domestic gas consumers in order to monetise reserves in the present rather than to wait for an equivalent value in the future. In addition, the Gorgon and Wheatstone JVs may see benefits in delivering domestic gas quickly to meet their domestic gas reservation obligations with the WA Government[110], which would facilitate the quicker repayment of capital costs of the LNG and domestic gas production facilities.

6.3. NIEIR's Potential Gas Supply Forecasting Methodology

[105] There are other factors such as government regulation and prices of alternative fuels.

[106] This is an estimate. There is some uncertainty regarding the quantity of gas reserves held within its remaining exploration and retention licenses.

[107] Woodside (2013b) *Half Year Results* Briefing, 21 August 2013, http://www.woodside.com.au/Investors-Media/Announcements/Documents/21.08.13%202013%20Half-Year%20Results%20Briefing%20Slide%20Pack.pdf, accessed 20 November 2013.

[108] Woodside (2013d), *Greater Western Flank*, website, http://www.woodside.com.au/our-business/north-west-shelf/projects/pages/greater-western-flank.aspx, accessed 20 November 2013.

[109] This is reported in Deutsche Bank (2012).

[110] See Chapter 10 of the July 2013 GSOO for more details on the reservation policies that relate to the Gorgon and Wheatstone projects.

The WA domestic gas market is currently dominated by medium to long-term bilateral gas supply agreements between wholesale gas suppliers and gas consumers (as outlined in section 4.2), with few customers purchasing on a month-to-month basis. The availability of gas supply may be impacted by a multitude of commercial, economic and operational factors within these contracts. As such, the intentions of gas producers to supply to the domestic market are not directly observable and difficult to estimate. Despite this difficulty, it is understood that gas is available for new or replacement domestic gas supply contracts at a commercially negotiated price.

Due to the difficulty in estimating the availability of gas supply in the WA market, past studies including the ESOO have typically presented total production capacity as a measure of gas supply. While this approach may be appropriate in a tight domestic gas market, it is less suitable for the current WA market and would significantly overstate the availability of gas supply, as future gas production capacity servicing the domestic market is anticipated to be higher than projected domestic demand (see section 9.2.3).

To overcome this, NIEIR estimates the availability of domestic gas supply from gas producers (the main source of gas supply) by estimating their 'willingness to supply' to the WA domestic market. This is done by first estimating both the quantity of potential contracted supply and the quantity of potential price-sensitive supply for each domestic gas production facility in the WA market. Once both are determined separately, the aggregate of these values form the potential supply estimate.

Potential 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 gas prices on offer from time to time.

Potential price-sensitive supply on the other hand is the estimated quantity of gas supply that is sensitive to price and may be available to the market 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.

The potential price-sensitive gas supply is estimated for each facility by applying the forecast domestic gas prices with the following assumptions:

- average cost of gas production for each production facility[111];
- availability rates of each production facility[112];
- an assumed rate of return on investment for each production facility[113]; and
- contracted rates of each production facility[114].

For each facility, the model assumes a relationship between the potential price-sensitive supply and the domestic gas price, between two end points.

- Zero potential price-sensitive supply is assumed to be available from a facility if the forecast domestic gas price does not exceed the cost of gas production plus the assumed rate of return.
- 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.

Figure 20 shows the structure of NIEIR's model for forecasting potential supply and provides insight into the factors that drive the average medium to long-term prices, which are discussed in section 6.4.

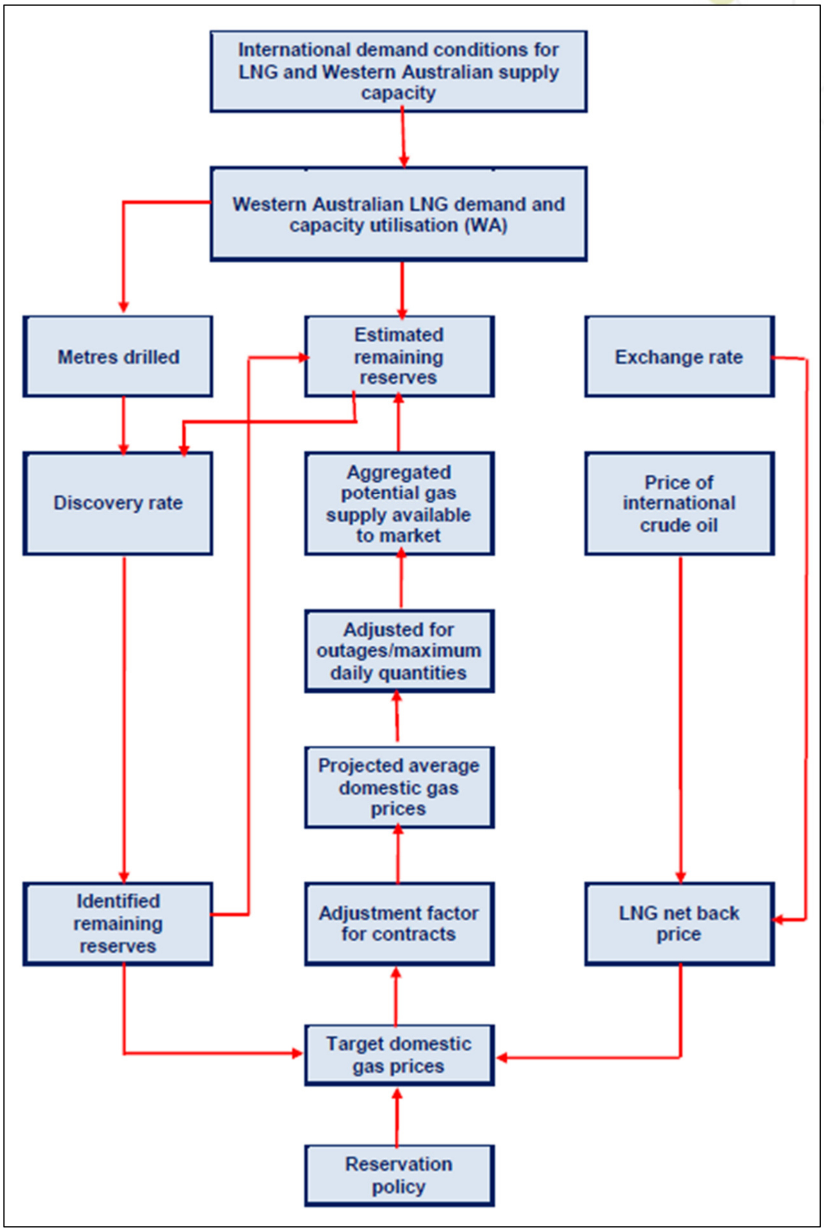
[111] The production costs for facilities applied in this study are estimated or acquired from EnergyQuest (2011b), *ESAA Domestic Gas Study Stage 2*, http://www.esaa.com.au/Library/PageContentFiles/8e0b523c-55c2-4978-a582-d2441cac02c8/110919DomesticGasProject_Stage2Report.pdf, accessed 11 March 2013. Cost estimates are developed for production facilities that are not reported in EnergyQuest (2011b).

[112] This is calculated using an annualised average of capacity for each facility using GBB data for the 1 August 2013 to 30 November 2013.

[113] The rate of return for each facility is assumed to be 10%.

[114] These are IMO estimates.

Figure 20 – NIEIR's Potential Supply Forecast Model, 2013



Source: NIEIR.

The potential supply forecasting model applied in this report has been updated to incorporate various suggestions provided by market participants at and after the 7 October 2013 stakeholder forum. While the logic behind the potential supply forecasting model remains unchanged, several enhancements have been implemented since the July 2013 GSOO, including differing production cost assumptions for each production facility, including a rate of return, and the separation of potential supply into contracted and price-sensitive quantities.

In summary, potential supply to WA is complex and while price is an important determinant, other factors such as the timing of the production capacity, commercial considerations, producer strategy, contractual commitments, contractual terms and operational issues influence the availability of gas supply to the domestic market. **Potential supply forecasts are a composite representative of gas supply to the WA domestic market, which are highly sensitive to the assumptions applied and are only intended to be applied for assessing the availability of gas supply to the WA market.**

It is understood that domestic gas producers remain willing to supply gas to the domestic market if commercially acceptable prices can be agreed with existing or potential gas consumers.

It is important to note that the potential supply forecasts do not take into account the availability of gas traded in the secondary market. Under the current structure, the secondary market is expected to remain relatively small in the short to medium-term, in comparison to the primary bilateral gas market[115]. However, changes to the current structure may increase the volume of short-term trading.

It is also important to note that this GSOO does not project pipeline capacity for the gas transmission system[116]. Pipeline operators have indicated that they are unlikely to increase the transmission capacity of existing pipelines unless incremental increases in gas transmission are secured by financial commitments via long-term agreements from gas shippers.

Transmission capacity for the 2014 to 2023 period is assumed to be available to ship gas for domestic consumption. This means gas supply forecasts reported in this GSOO are estimated on the assumption that there are no constraints to pipeline capacity. The IMO has not modelled the capacity of the pipelines to transport forecast quantities of gas demand over the forecast period. Pipeline capacity is not expected to be a constraint over this period given the current levels of utilisation of the major gas transmission pipelines (see Chapter 11).

The following two sections review the non-price and price assumptions and factors applied in forecasting potential supply for the 2014 to 2023 period.

6.3.1. Non-Price Assumptions Applied in the Potential Supply Forecast Model

As suggested in the previous section, the level of potential supply to the domestic market is influenced by a multitude of factors. Most of these factors affect domestic gas supply at the individual facility and at the corporate level.

Apart from gas prices, potential supply may be driven by:

- commercial and strategic factors; and
- operational factors.

Commercial and strategic factors are short and long-term influences that a producer will consider in seeking to maximise its return. Some of these factors include:

- costs involved in supplying gas to the domestic market;
- the required rate of return on investment;
- the opportunity cost of selling the gas as LNG exports;
- projected exchange rates;
- view of future gas demand;
- existing contracted supply;
- contractual terms accepted by gas consumers;
- availability of gas production capacity in the market;
- government regulation; and
- the level of concentration and competition in the domestic gas market.

Operational factors are the physical infrastructure constraints that restrict the sale of additional 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 on an interruptible basis.

Operational constraints include:

- availability of uncontracted gas production capacity (producer);
- remaining reserves;
- minimum operational requirements of gas production plants; and

[115] While the secondary short-term market is estimated to be no more than 2.5% of the total market, this figure may be understated as the IMO is unable to observe all bilateral trades that occur in the WA domestic gas market due to the existence of four separate proprietary short-term trading systems that are only available to existing market participants that sign agreements with the operator of these systems. Other factors may influence the volume of trade in the secondary market for domestic gas. For example, it is understood that short-term gas prices were affected recently by an existing large user that could not utilise its gas under its take or pay gas purchase agreement, opting to sell its gas at low prices on the short-term gas market.
[116] Only announced expansions to pipeline capacity have been considered in the potential supply model.

- transmission capacity of pipelines.

In forecasting the potential supply, NIEIR considers most of the abovementioned factors, except the transmission capacity of pipelines and the potential for higher prices to attract more competition to supply gas to the WA market.

Since the publication of the July 2013 GSOO, some market participants have voiced concerns about the continued availability of gas from the NWS to the domestic market beyond 2020, citing a lack of new long-term domestic gas supply contracts from the NWS.

Ongoing supply from the NWS JVs beyond the terms of their existing contracts is dependent on a range of factors, including:

- the outcomes of ongoing discussions between the WA Government and the NWS JVs that relate to the status of remaining NWS reserves;
- investment decisions required by the NWS JVs to access remaining undeveloped reserves; and
- investment required to extend the life of the aging KGP,

each of which will involve consideration of the commerciality and profitability of ongoing operations at the KGP.

Due to this uncertainty, two potential supply scenarios have been developed for the 2014 to 2023 period in this GSOO. The first scenario (the Upper potential supply forecasts) assumes the NWS will continue to supply gas to the WA domestic market for the full forecast period, while the second scenario (the Lower potential supply forecasts) suggests the NWS will only supply domestic gas under its remaining contracts.

6.3.2. Price Assumptions Applied in the Potential Supply Forecast Model

Both the Upper and Lower potential supply forecasts are estimated by applying the Base scenario price assumptions for the 2014 to 2023 period (see section 6.4).

6.4. Applied Price Assumptions

As noted previously, price forecasts are considered in developing forecasts of potential supply and gas demand as:

- 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; and
- gas demand is somewhat elastic to prices, particularly over the medium to long-term.

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 20 in section 6.3 above provides an insight into the factors that drive the medium to long-term average new forecast prices.

To develop the forecasts of domestic prices, future LNG export prices are first estimated. This is important as future LNG netback prices (determined by deducting shipping and liquefaction costs[117] from LNG prices) represent the domestic gas price that gas producers are likely targeting to achieve, at which point they will be indifferent between supplying to the domestic gas market or LNG export market.

Some stakeholders have suggested to the IMO that international gas prices should not drive WA domestic gas prices, as there is only one LNG-linked domestic producer at the time of this report. However, with two additional LNG-linked gas producers anticipated to significantly contribute to domestic gas supply within five years and the existence of gas supply facilities operated by international producers, NIEIR's model for

[117] The shipping and liquefaction cost applied in this GSOO is \$5.30/GJ as outlined in EnergyQuest (2011b).

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[118].

While NIEIR's modelling of domestic gas prices assumes an LNG netback relationship, it is recognised that under different circumstances, producers may seek to achieve prices for domestic gas sales based on other considerations, including the price of alternative fuels (such as diesel). Regardless, gas producers naturally seek the highest possible prices.

However, gas producers recognise there are limitations to the increases. Increases may suppress price-sensitive gas demand or could attract additional competition to the provision of domestic gas to the WA market. In addition, while there may be a preference for LNG exports (due to currently high Asia Pacific LNG prices), export capacity is limited and domestic gas sales allow an LNG-linked gas producer to increase cash flow, justifying investment made in production and production facilities.

Once LNG prices are forecasted, the domestic gas price is then projected by adjusting for the availability of reserves in WA (after taking account of LNG exports) and local conditions (such as estimated average contract length) to produce the average new contract price projections for the forecast period.

Using probability analysis, the following variables are estimated:

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

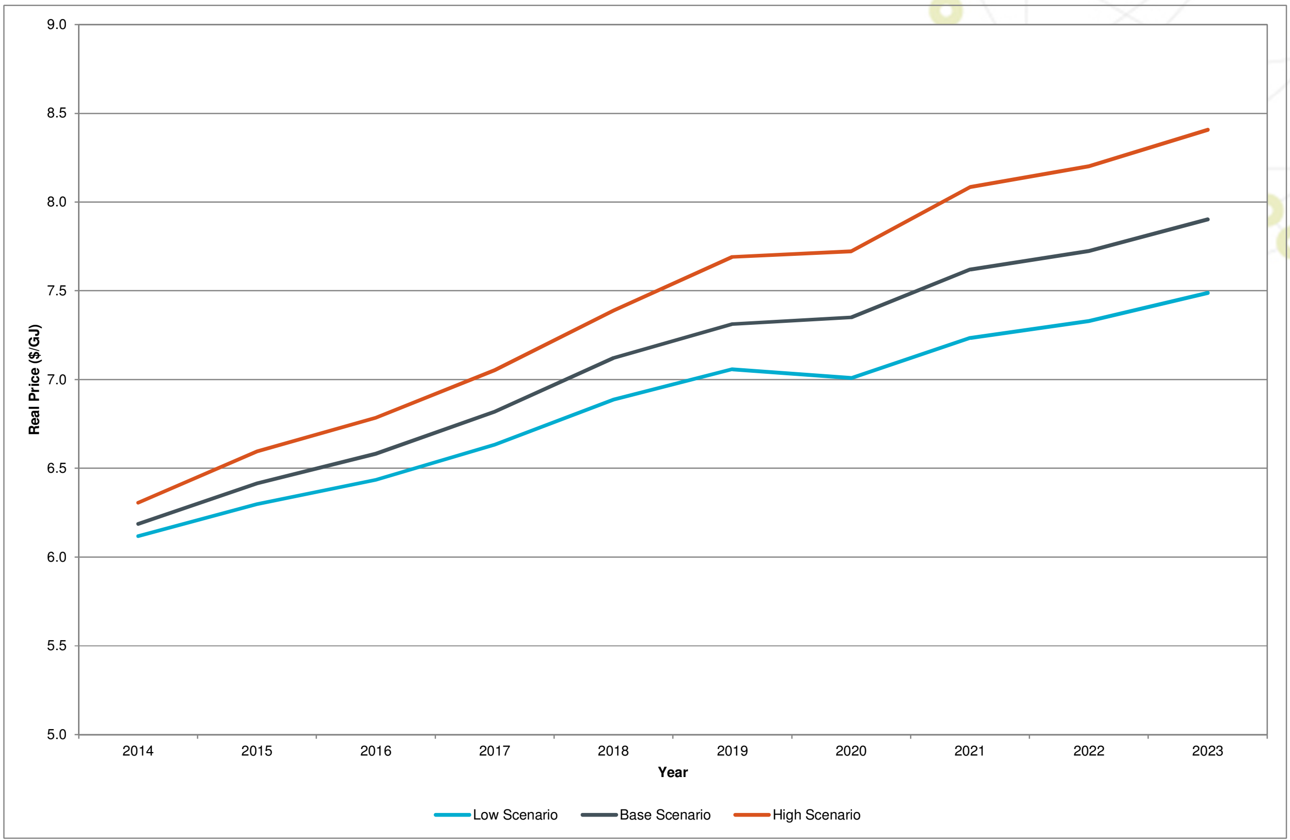
Once each variable is estimated, the variables are then used to forecast average new contract gas prices. This is done by applying a weighted average formula of the LNG netback price[119] and the remaining reserves and adjusting for domestic conditions[120]. The LNG netback price is estimated from projected LNG prices that are influenced by forecast oil prices[121], exchange rates and world inflation.

Figure 21 presents the forecasts of medium to long-term average (ex-plant) new contract gas prices for the domestic market for the 2014 to 2023 period. NIEIR forecasts these gas prices will rise slowly between 2014 and 2023 due to increases in LNG netback prices as the linkage between average gas prices and LNG netback prices increases with the commencement of Gorgon and Wheatstone LNG export facilities, which are expected to be operational in 2015 and 2016. **The different scenarios of price forecasts represent a likely range of average new contract prices for the 2014 to 2023 period**.

It should be noted that **the forecast domestic gas prices applied represent forecasts of medium to long-term (four years and longer) average (ex-plant) prices for new gas sales agreements and are reliant on a set of assumptions**. This means that new domestic gas supply contracts are expected to be agreed both below and above this forecast price**.**

[118] The IMO will further analyse this linkage and investigate improvements to the forecast model for future GSOOs.
[119] EISC (2011) and SKM-MMA (2011), *WA Domestic Gas Market Analysis for the Strategic Energy Initiative*, SKM report to Office of Energy, May 2011 http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/WAs_Energy_Future/SKM%20WA%20Domestic%20Gas%20Market%20Analysis.pdf, accessed 11 March 2013, find domestic gas prices track LNG netback prices. Netback prices exclude the costs of LNG liquefaction and transport.
[120] The weights are determined by the ratio of current production to production rate of 20 years. This means that as LNG exports increase the domestic price draws closer to the LNG netback prices. This is consistent with price changes described in the Department of Resources Energy and Tourism (2012), *Energy White Paper 2012, Australia's Energy Transformation*, http://www.ret.gov.au/energy/facts/white_paper/Pages/energy_white_paper.aspx, accessed 9 November 2012: "*demand competition from LNG expansion is also expected to become a more significant driver of prices, which are widely forecast to increase towards netback levels by the second half of the decade*".
[121] NIEIR estimates show a 1% rise in the price of international oil prices leads to an approximate 0.9% increase in international LNG prices.

Figure 21 – Forecast Medium to Long-Term Average (Ex-Plant) New Contract Gas Prices (real) for Domestic Market, 2014 – 2023



Source: NIEIR's Forecasts 2014 – 2023.

While the GSOO forecasts medium to long-term new contract gas prices for the purposes for forecasting gas demand and supply, it is possible that actual prices contracted may differ from the forecast prices due to the relatively high levels of concentration in the domestic gas market. As such, actual contracted prices may not represent an efficient price. The forecast gas prices appear to be consistent with gas prices outlined in Department of Industry's Eastern Australian Domestic Gas Market study published in January 2014[122].

Due to the commercial sensitivity of the assumptions for individual facilities, Table 12 only summarises some of the assumptions applied to the potential gas price forecasts.

Table 12 – Projected Potential Gas Prices Parameters

		Scenarios		
Parameter	**Unit**	**Low**	**Base***	**High**
International oil prices	US$/barrel	85.71 – 95.00	91.43 – 105.00	101.4 – 115.1
Asia Pacific LNG prices (real)	US$/GJ	12.94 – 17.41	13.81 – 19.24	15.32 – 21.07
Exchange rates	A$/US$	0.75 - 0.91	0.75 - 0.91	0.75 - 0.91
Recoverable reserves	Bcm	4186.1 – 4370.2	4171.1 – 4371.4	4154.4 – 4347.3
Forecast average new contract gas price	A$/GJ	Reported in Appendix 8	Reported in Appendix 8	Reported in Appendix 8

Source: NIEIR Forecasts 2014 – 2023. **Note:** Carbon tax has been considered in the modeling. 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. Asia Pacific LNG prices represent an estimate of Asia Pacific LNG prices in the forecast period. *Base price projections have been applied in both the Upper and Lower potential supply forecasts.

[122] See Department of Industry (2014), *Eastern Australia Domestic Gas Market Study*, http://www.industry.gov.au/Energy/EnergyMarkets/Documents/EasternAustralianDomesticGasMarketStudy.pdf, accessed 3 January 2014.

While the GSOO recognises the existence of contracts with short-term gas pricing in WA, short-term gas pricing is not considered in this GSOO as different factors drive the demand for and the availability of short-term gas in the secondary gas market. Pricing in the secondary gas market is also likely to be more volatile than the medium to long-term average new contract gas prices that are projected for this GSOO. Gas supply to the WA market is still largely driven by medium to long-term bilateral contracts between gas producers and consumers. However, as the volume traded in the short-term market grows, the factors driving short-term gas contracting will be considered for future iterations of the potential supply model.

6.4.1. Comparing Gas Price Projections, July 2013 GSOO and January 2014 GSOO

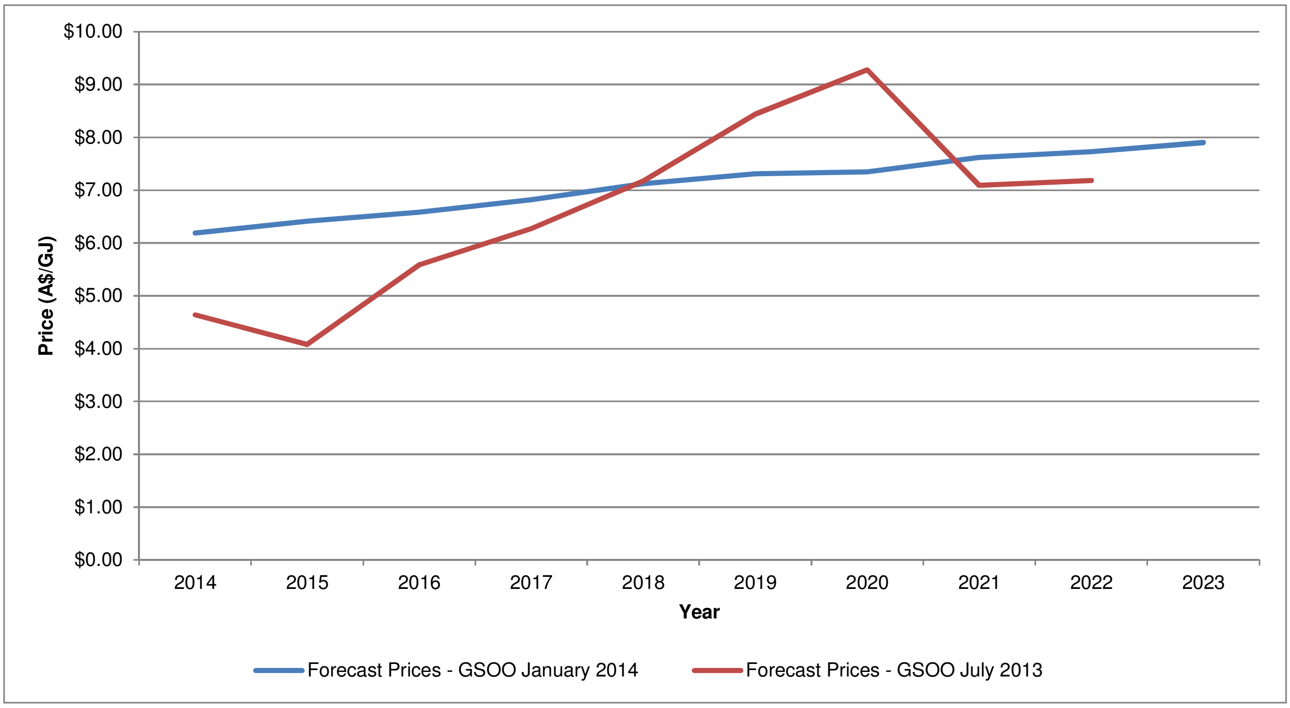
NIEIR has implemented three major improvements to the model for forecasting average new contract gas prices since the July 2013 GSOO[123].

The three improvements are in:

- exchange rate modelling;
- oil-price modelling; and
- reduction in the time lag for Asia Pacific LNG prices to influence domestic gas prices.

Figure 22 compares the average new contract gas price projections developed for the July 2013 GSOO and this GSOO. **The applied improvements in gas price modelling have reduced volatility in average new contract gas price forecasts for the 2014 to 2023 period, compared to the July 2013 GSOO.**

Figure 22 – Comparison of the Forecast New Contract Prices (real), July 2013 and January 2014 GSOO, 2014 – 2023



Source: NIEIR's Forecasts 2013 – 2022 and 2014 – 2023.

While the average prices are not directly comparable due to changes in the forecasting model, Figure 23 presents domestic gas sale price data published by DMP together with NIEIR's price projections using the improved potential supply model for the 2014 to 2023 period.

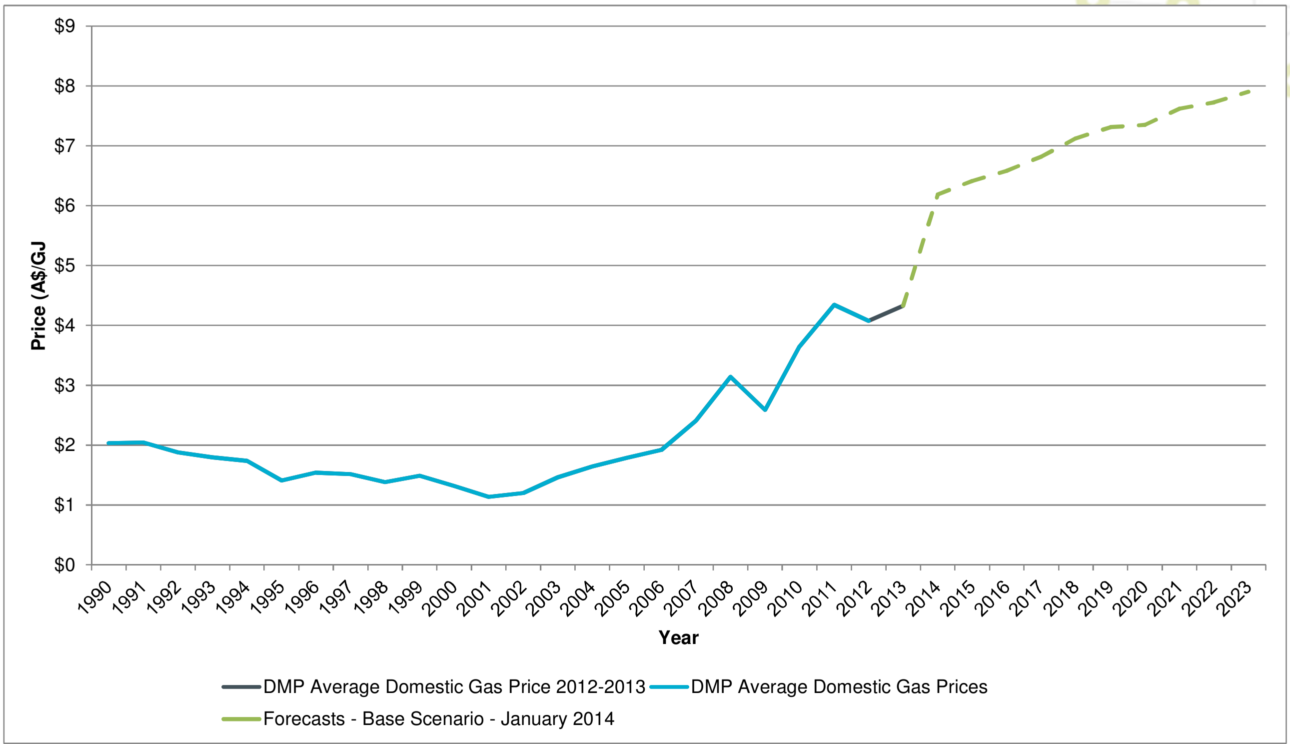
With the expiry of several large gas supply contracts that were re-contracted at higher gas prices in the last few years, and the signing of several new gas supply contracts in 2013, the average new contract gas prices

[123] Including suggestions in the EnergyQuest (2013b), *Report on the Western Australian Gas Statement of Opportunities,* report commissioned by APPEA, http://www.appea.com.au/wp-content/uploads/2013/11/EnergyQuest_IMO-Report_Final.pdf, accessed 1 November 2013.

are expected to rise rapidly in the upcoming 2014 to 2023 period, particularly in the early years of the forecast period.

Figure 23 also suggests NIEIR's updated model for forecasting average new contract gas prices for the WA domestic gas market is more consistent with historical price data published by DMP.

Figure 23 – Historical (actual) and Forecast Average New Contract Prices (real), 1990 – 2023



Source: DMP (2012, 2013), Domestic Gas Prices, NIEIR forecasts. **Notes:** The 2013 price for domestic gas is as reported for the 2012-2013 financial year reported by DMP. DMP prices are average of all contracts, including legacy contracts, NIEIR forecasts are new contract prices in each year.

7. Current and Projected Gas Consumption

This chapter provides a snapshot of demand in the WA domestic gas market, an outline of domestic gas consumption by sector and annual demand forecasts for the WA gas market for the 2014 to 2023 period. This chapter also provides forecasts of total gas demand in WA – that is, including for LNG exports and processing.

7.1. Current Gas Demand

Growth in WA gas consumption is typically 'lumpy', being largely driven by the electricity generation requirements of new or expanding resource projects. Typically these projects are large in scale and the gas required is secured through 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. Smaller mining or industrial gas consumers tend to be overlooked by large gas suppliers and are typically serviced by gas retailers such as Alinta Energy and Synergy.

Table 13 –Domestic Gas Consumption Annual (Compounded) Growth, 1984-1985 to 2012-2013

1984-1985 to 1989-1990	1990-1991 to 1999-2000	2000-2001 to 2009-2010	2007-2008 to 2012-2013
16.9%	6.8%	2.3%	-1.0%

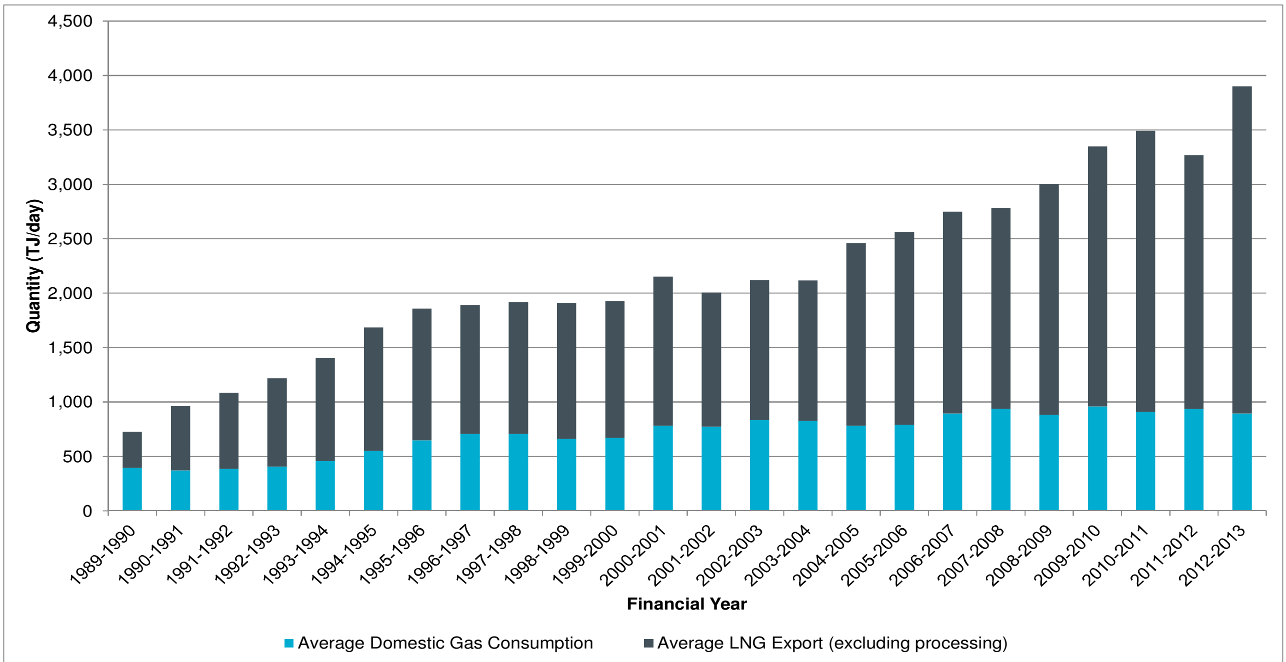
Source: DMP (1984 to 2013), calculated using domestic gas sales, 1984-1985 to 2012-2013. **Note:** This growth rate is different to that presented in the July 2013 GSOO as the growth rates shown here are by financial years not calendar years.

As shown in Table 13, according to data from DMP, between 1984-1985 and 1989-1990 domestic gas consumption grew rapidly at 16.9% per annum. The rate of growth reduced in subsequent years, with consumption contracting by 1% per annum between 2007-2008 and 2012-2013.

Overall, in the 1984 to 2012 period annual domestic gas consumption grew from 66 PJ (approximately 181 TJ/day) in 1984-1985 to approximately 326 PJ (approximately 893 TJ/day) in 2012-2013. The LNG export market, however, grew significantly faster than the domestic gas market from 121 PJ (approximately 332 TJ/day) in 1989-1990 to 1,098 PJ (approximately 3,008 TJ/day) in 2012-2013.

As shown in Figure 24, according to DMP total gas consumption (including domestic sales and LNG exports, excluding oil and gas production) in 2012-2013 is estimated at 3,902 TJ/day (1,424 PJ/annum).

Figure 24 – WA Gas Demand (TJ/day, excluding petroleum processing), 1989-1990 to 2012-2013



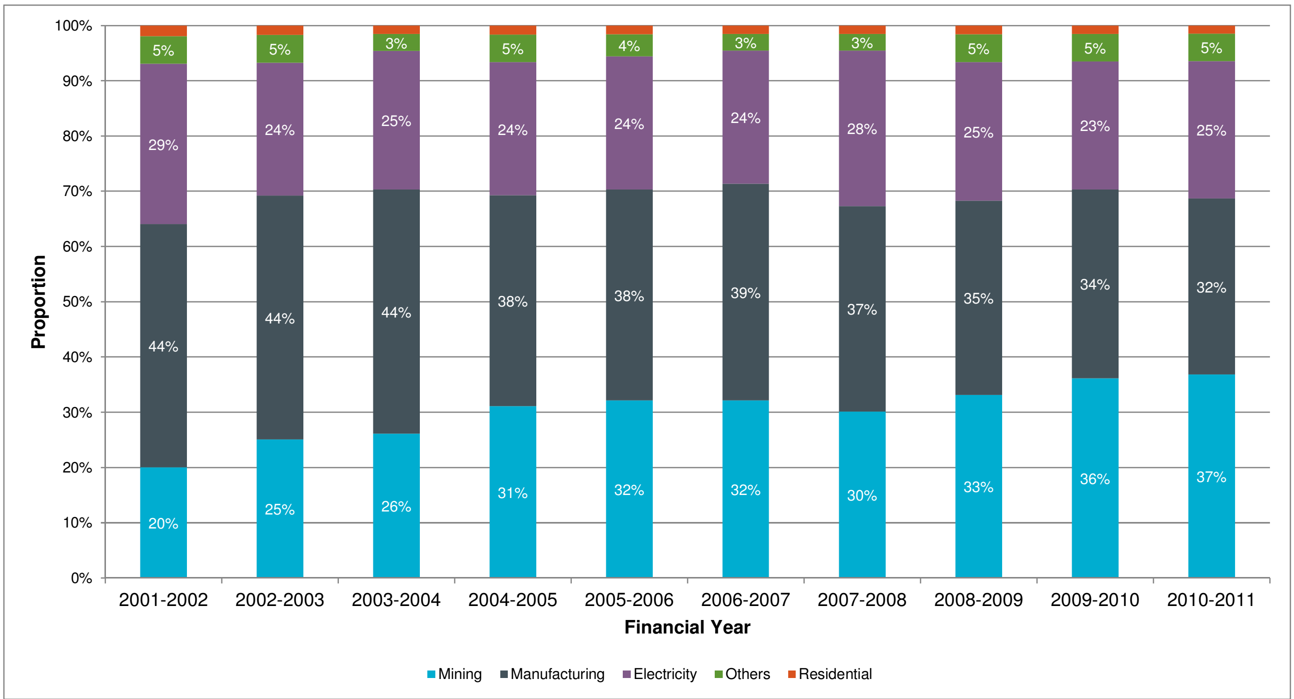
Source: DMP Petroleum Statistics (1989 – 2012), Gas sales and LNG. **Note:** this excludes oil and gas production. This figure is different to the figure presented in the July 2013 GSOO as this data is presented by financial years, not calendar years.

Significant changes to the domestic gas market are expected over the forecast period, as new sources of supply emerge, coinciding with the expiry of some legacy supply contracts and the NWS JVs' domestic supply obligation reaching fulfilment[124].

7.1.1. Characteristics of Domestic Consumption

According to data from BREE shown in Figure 25, WA gas consumption is dominated by three sectors; electricity generation, mining (mostly electricity generation) and manufacturing (including minerals and petroleum processing). Between 2001-2002 and 2010-2011, the proportion of gas consumption related to mining almost doubled from 20% to 37%. As most mining operations that use gas do so principally to generate electricity for their operations, this implies that more than 60% of WA's gas consumption is related to electricity generation.

Figure 25 – Share of Gas Consumption, Western Australia, 2001-2002 to 2010-2011



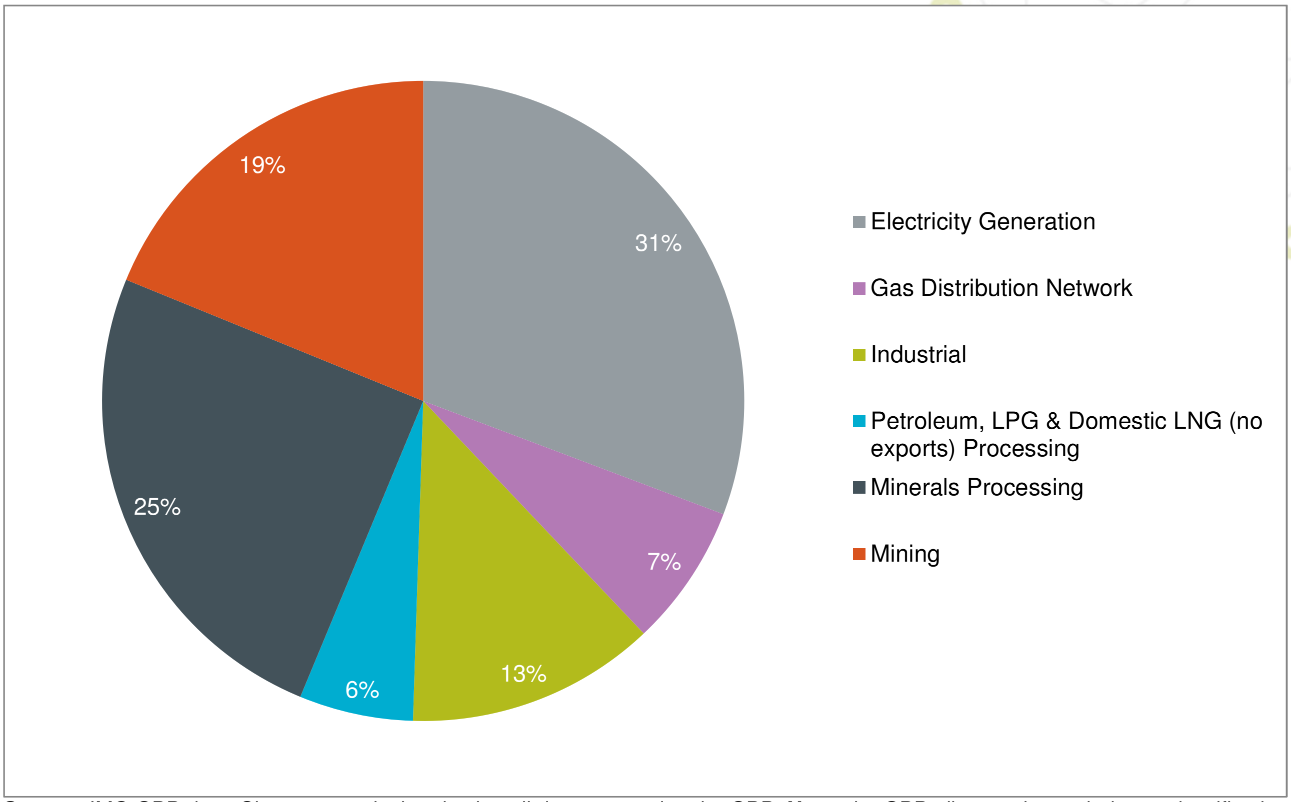
Source: Shares are calculated from BREE (2012), Australian Energy Statistics Update 2012, Table F. **Note:** According to BREE, the manufacturing segment includes ferrous and non-ferrous minerals processing, iron and steel processing, petroleum (oil and gas) processing, chemicals, ceramics, glass, lime,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

GBB data from 1 August 2013 to 31 December 2013 presents a similar picture. Figure 26 shows the largest use of WA domestic gas is related to electricity generation, making up approximately half of the WA domestic market (electricity generation and mining combined). The second largest segment is related to minerals processing, consuming approximately 28% of total domestic gas, followed by the industrial sector and the petroleum processing sectors, which together make up approximately a fifth of the WA domestic market. The remaining gas is delivered to gas distribution networks.

The differences between the industry demand shares between BREE and the GBB data are due to differences in industry definition, seasonality and sample size (the GBB data covers less than a year) and the fact that the GBB only focuses on gas consumption in excess of 10 TJ/day.

[124] According to DSD, the obligations to supply domestic gas have been fulfilled; current gas supply from the NWS is via the exercise of contractual extension options by Synergy (formerly Verve Energy). This is also considered to be a domestic gas obligation and is expected to be fulfilled between 2014 and 2017. See Chapter 10 of the July 2013 GSOO for details.

Figure 26 – Estimated Shares of WA Wholesale Gas Demand (excluding behind the meter Petroleum and LNG processing), 1 August 2013 – 31 December 2013



Source: IMO GBB data. Shares are calculated using all data reported to the GBB. **Note:** the GBB allows only one industry classification for each Large User. Following advice provided by Alcoa, the IMO has apportioned its consumption between minerals processing and electricity generation. Calculations are based on total gas delivered for the outlined period and may vary for the entire calendar year due to seasonality, economic conditions and facility utilisation for the outlined industries. 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), shipping of gas within pipelines, gas consumed in pipeline compressor stations and unaccounted gas.

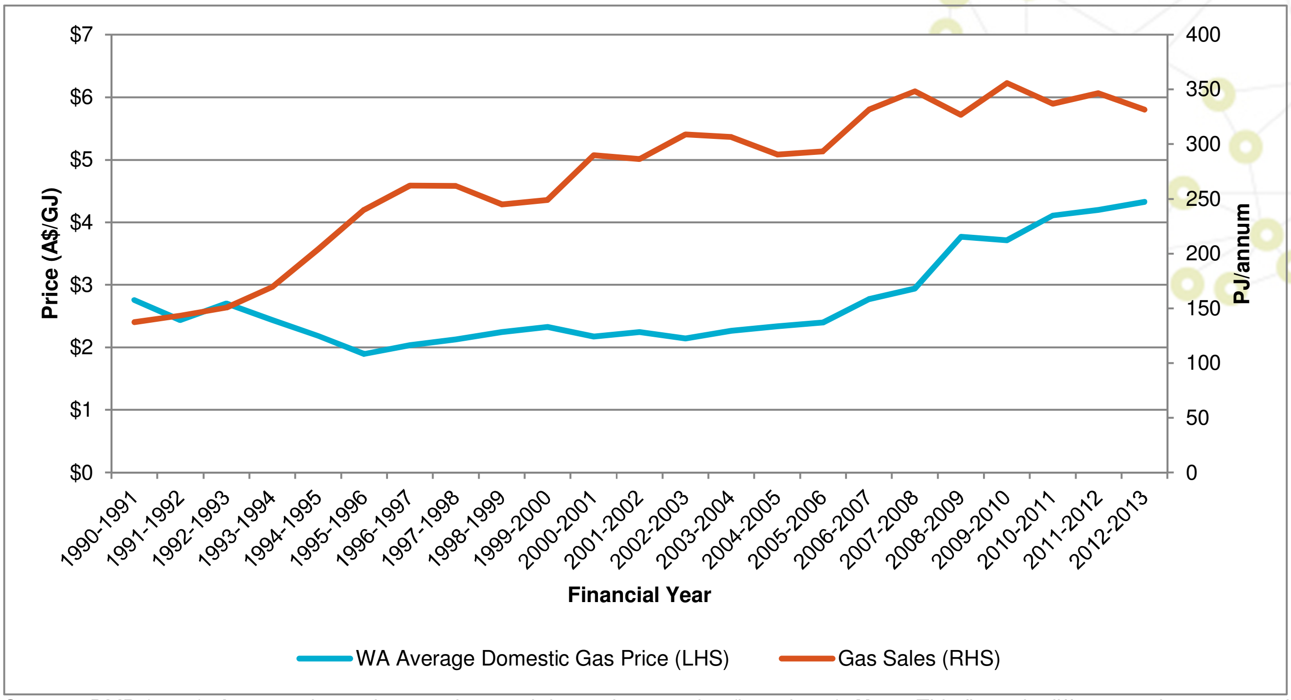
7.1.2. Price Elasticity of Domestic Demand

Figure 27 compares the WA average domestic gas price with total domestic gas sales as reported by DMP for the period from 1990-1991 to 2012-2013. Figure 27 suggests that the price increases observed since 2008 have started to affect the growth of domestic gas consumption in WA, with gas sales decreasing during that period[125]. This suggests the price elasticity of demand for domestic gas is more significant than modelled in the July 2013 GSOO. The IMO has observed a similar increase in the responsiveness of electricity demand to price in recent years, contrary to the view that gas and electricity demand are relatively inelastic to price changes.

However, the price elasticity of gas demand remains relatively mild. Gas consumption is dominated by the capital-intensive mining, minerals and petroleum processing sectors. Many of these customers have already committed capital for existing infrastructure and seek to procure gas through long-term contracts.

[125] Other factors such as the GFC, energy efficiency drives, carbon tax or changes in exchange rates may also have impacted the growth of domestic gas consumption.

Figure 27 – Comparison of Domestic Gas Demand against Average Domestic Gas Prices (actual), 1990-1991 to 2012-2013



Source: DMP (2012), Average domestic gas prices and domestic gas sales (by volume). **Note:** This figure is different to that presented in the July 2013 GSOO. The July 2013 GSOO presented this data by calendar years, while this figure is by financial years.

Alcoa, for example, remains in long-term gas contracts that represent one-fifth of total domestic gas and is subject to State Agreements with the WA Government[126]. This means it is unlikely to change its consumption significantly until the gas supply contracts start to expire towards the end of the 2014 to 2023 period. Contract renewals by large gas users such as Alcoa are critical to the gas consumption assumptions in this GSOO.

It is anticipated that as these long-term gas contracts approach expiry[127], large gas consuming companies, both existing and potential, will improve the efficiency of gas usage in their operations, obtain and utilise alternative sources of energy (if available) to reduce reliance on gas consumption, or may attempt to hedge against future price rises by investing in JVs with gas exploration or gas supply companies[128]. This means the price elasticity of gas demand in WA could change significantly if large gas consumers re-contract at different prices.

7.1.3. Electricity Generation and Domestic Gas Consumption

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

[126] According to DMP (2002), Alcoa's contract with the NWS will expire in 2020. According to evidence provided by Alcoa to the WA parliamentary inquiry into the Economic Implications of Floating Liquefied Natural Gas Operations on 15 November 2013, Alcoa is required under various State Agreements with the WA Government to process all bauxite mined in WA locally. See http://www.parliament.wa.gov.au/Parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/1D4220622266D4F548257C40000EAC4E?opendocument, accessed 28 December 2013.

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

[128] This has already commenced with Apache Energy and BHP Billiton forming a JV to supply gas to the domestic gas market through the Macedon domestic gas production facility. Alcoa has also farmed into and provided capital for Empire Oil and Gas' gas fields and the Red Gully production facility and into Transerv Energy's Warro project, and has also signed conditional gas contracts with Buru Energy. ERM Power has also invested in upstream gas licenses and assets. FMG also previously considered purchasing a stake in Oil Basins Limited in 2012.

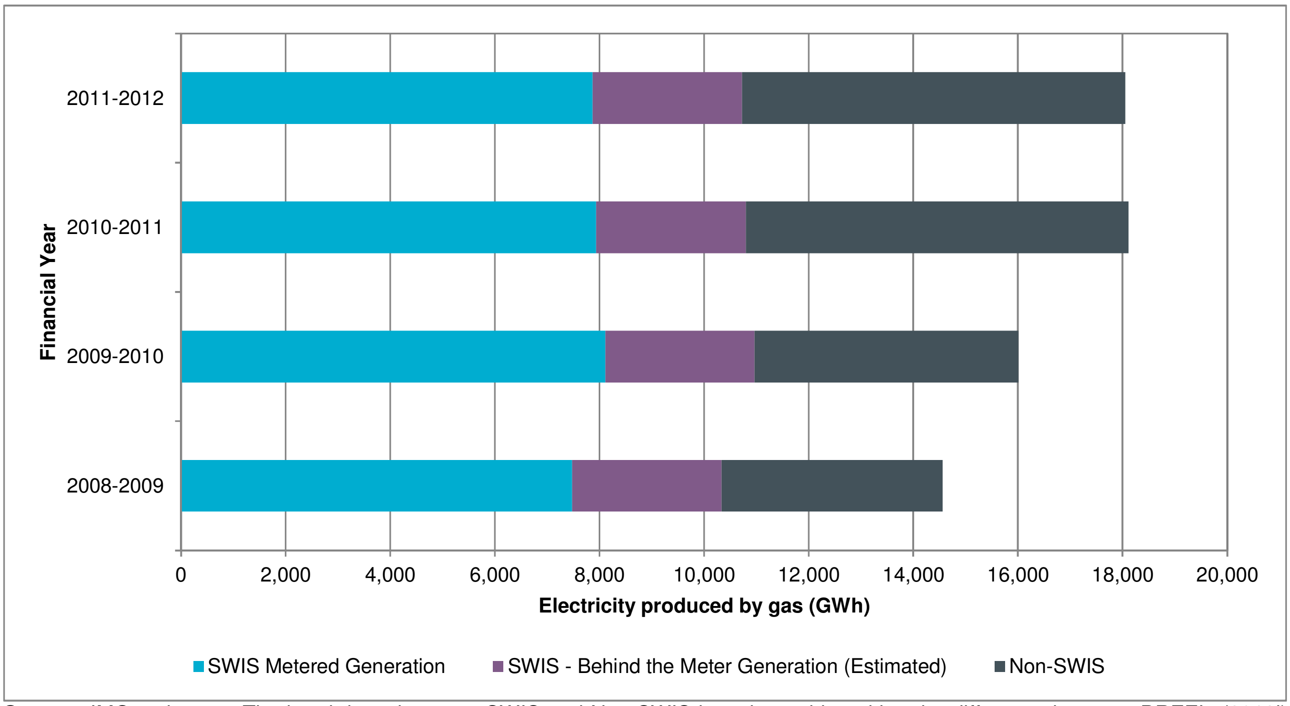
Table 14 – Gas-Fired Electricity Generation, 2011-2012

Electricity Generation Capacity	(SWIS) MW	(NWIS) MW	Rest of WA
Steam	268	Not Stated	Not Stated
Open Cycle Gas Turbine	1,891	Not Stated	Not Stated
Combined Cycle Gas Turbine	680	Not Stated	Not Stated
Natural Gas	Not Stated	964	1,446
Total	**2,839**	**964**	**1,446**

Source: ESAA (2013), *Electricity Gas Australia 2013* and BREE (2013). The SWIS figures differ slightly from those reported in ESAA (2013) as Perth Energy's Kwinana Swift Power Station was classified as a combined cycle gas turbine in the report. See http://www.perthenergy.com.au/index.php/about-perth-energy/western-energy. **Note:** The totals for the North West Interconnected System (NWIS) and the rest of WA are reported in BREE (2013) and are higher than the figure of 2,028 MW reported in ESAA (2013). ESAA figures also include LNG powered electricity generation.

BREE reports that natural gas was used to generate a total of 18,048 gigawatt-hours (GWh) of electricity in WA in the 2011-2012 financial year. Applying the IMO's data on sent out electricity by fuel type for the SWIS in the 2008-2009 to 2011-2012 period and estimating electricity generated behind the meter, it is estimated that approximately 59%[129] of total gas-fired electricity generated in WA was generated within the SWIS (approximately 10,724 GWh), with the remainder generated outside the SWIS area.

Figure 28 – Gas Demand for Electricity Generation in WA (GWh), 2008-2009 to 2011-2012



Source: IMO estimates. The breakdown between SWIS and Non-SWIS is estimated by taking the difference between BREE's (2013j) Australian Energy Statistics, Table O, IMO sent out generation data and estimates of electricity generated behind the meter within the SWIS that is consistent with Table 15. This figure has been updated from the July 2013 GSOO. **Note:** SWIS gas generation figures do not correspond to figures outlined in the ESOO published in June 2013 as sent out generation has been adjusted to report by financial year.

Figure 28 shows that gas consumption for electricity generation for areas outside the SWIS has grown more rapidly than for areas within the SWIS in the 2008-2009 to 2011-2012 period. Areas outside the SWIS are more reliant on gas-fired generation (where it is available) as the available fuel substitutes for electricity generation, generally oil or diesel, have significantly higher costs per gigajoule (GJ) than gas[130].

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

[130] According to the Australian Institute of Petroleum, the terminal gas price (wholesale) for diesel as at 17 January 2014 in Perth is 143.5 cents/litre of diesel. This converts to A$37.17/GJ (using 38.6 MJ/litre of diesel, including GST and excise). Actual diesel costs increase for areas located outside of the SWIS as it needs to be transported, see http://www.aip.com.au/pricing/tgp.htm, accessed 17 January 2014.

A recent study commissioned by BREE confirms the reliance on gas and liquid fuels for electricity generation outside the SWIS. Table 15 shows the total electricity generation for each fuel type for the 2011-2012 financial year.

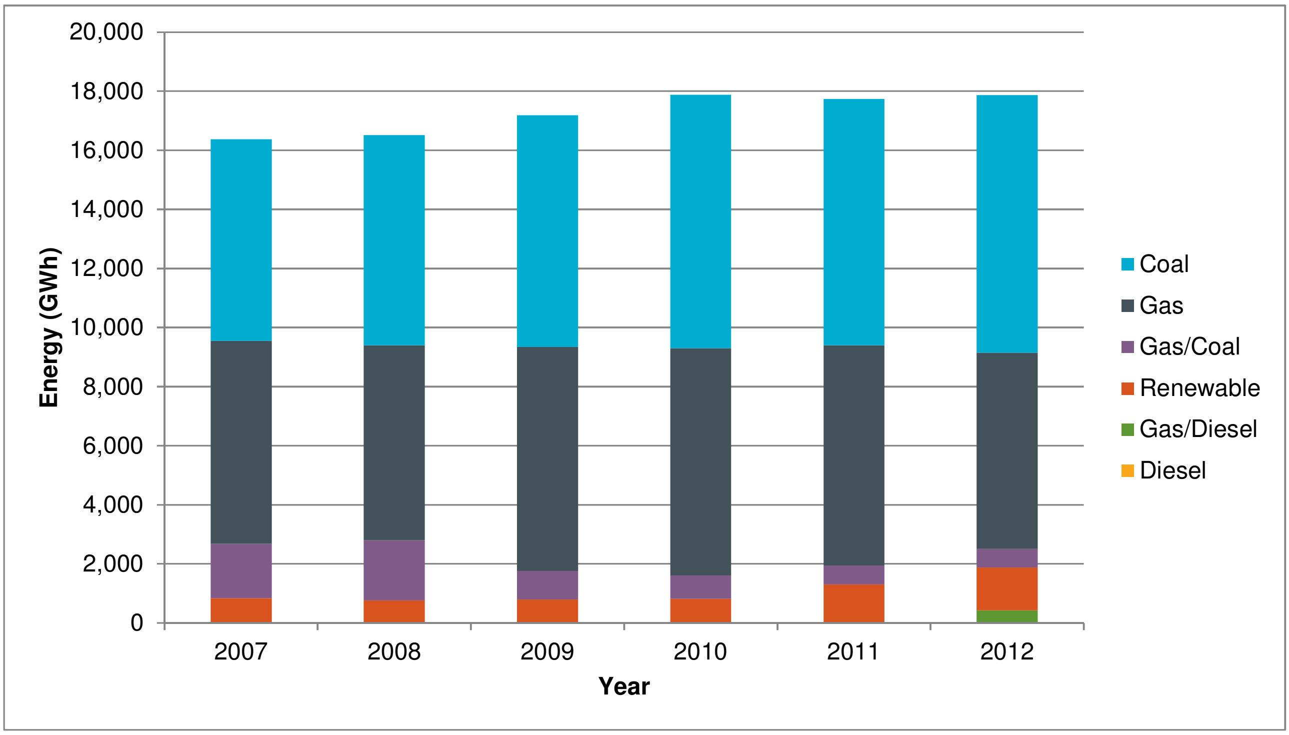
Table 15 – Electricity Generation Outside the SWIS (GWh), 2011-2012

Region	Natural Gas	Liquid Fuels	Renewables
NWIS	2,426	4,898	0.4
Rest of Western Australia	4,898	1,254	262
Total	**7,324**	**6,152**	**262.4**

Source: BREE (2013g). **Note:** This data is applied in Figure 28.

By contrast, the SWIS has a more diverse fuel mix, shown in Figure 29, with gas-fired generation production declining since 2009. Figure 29 shows the total sent out electricity for each fuel type for each calendar year since the commencement of the WEM.

Figure 29 – Electricity Generation by Fuel Type (SWIS), 2007 – 2012



Source: IMO Wholesale Electricity Market System data. **Note:** Diesel is a very small component of SWIS generation due to the high cost of diesel relative to other fuels.

The rate of growth in SWIS electricity demand has slowed considerably in recent years, dampened by:

- the sharp increases in domestic regulated electricity tariffs;
- the effects of the GFC;
- the growth in small-scale photovoltaic systems;
- the increasing impact of energy efficient appliances;
- business energy efficiency programmes; and
- changing consumer behaviour.

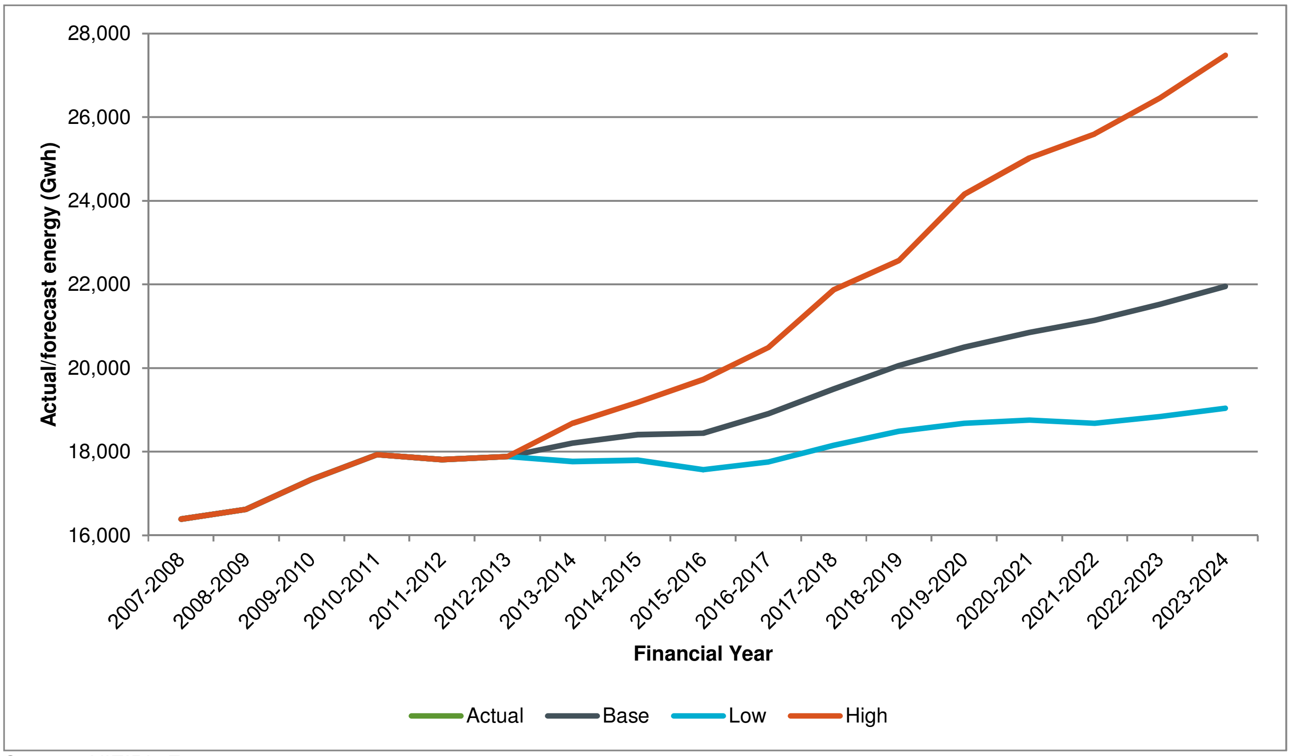
In addition, gas has been displaced in recent years by other generation fuels in the SWIS.

- Coal-fired generation has increased by 28% since 2007, predominantly due to the completion of the Bluewaters Power Station in 2009. Coal-fired generation would be expected to increase in the near-term with the refurbishment of the Muja AB facilities (two of the four units, of 55 MW each, are operational as at December 2013), but may decrease from 2016 following the planned decommissioning of the 400 MW Kwinana C power station.
- Renewable generation, aided by incentives such as the Commonwealth Government's Renewable

Energy Target scheme, has increased by 75% since 2007 to represent more than 8% of total sent out electricity at the wholesale level in 2012. As reported in the 2013 ESOO, significant new investment is expected in renewable generation in Australia to meet a projected shortfall in large-scale generation certificates from 2016 onwards[131].

The IMO's forecasts of SWIS electricity demand, published in the ESOO, are shown in Figure 30. Total sent out electricity is forecast to grow at an average rate of 1.9% per annum over the next 10 years, although growth is anticipated to be slow in the near-term due to declining growth in the WA economy and the continued impact of electricity tariff increases. Under the High economic growth scenario, sent out electricity is forecast to grow at 3.9% per annum, while in the Low economic growth scenario it is forecast to increase at just 0.7% per annum on average.

Figure 30 – SWIS Electricity Demand Forecasts, 2007-2008 to 2023-2024



Source: NIEIR's Forecasts 2012-2013 to 2023-2024.

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

7.2. Projected Gas Demand

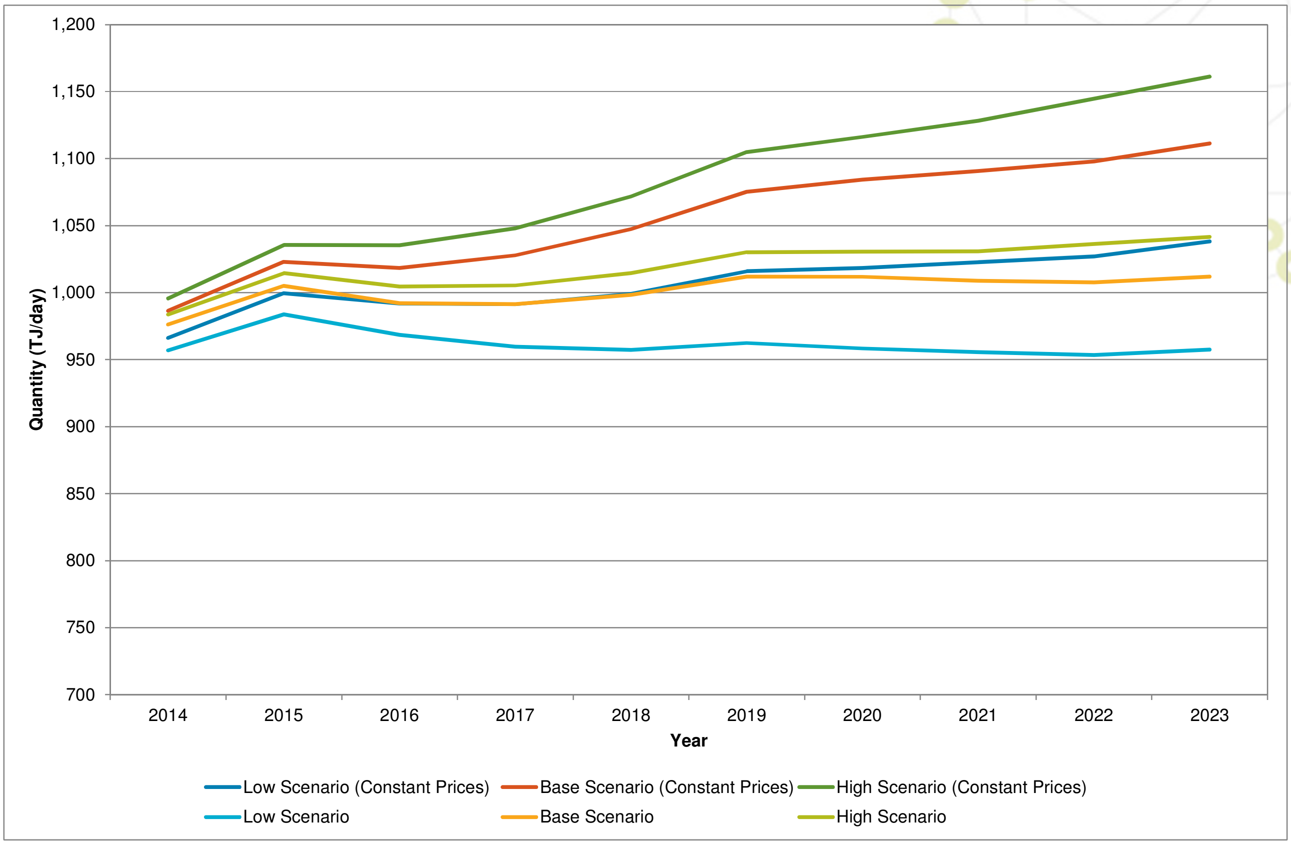
As outlined in the previous sections, the underlying economic assumptions, gas price forecast assumptions and the price elasticity of demand are the key drivers for gas consumption forecasts. Forecasts associated with High or Low economic growth scenarios are provided as a guide to the variability in outcomes that could be anticipated.

Figure 31 presents NIEIR's gas demand forecasts for the 2014 to 2023 period. To demonstrate the sensitivity of gas demand to price, two sets of gas demand forecasts are presented; one set considers the affect of gas price forecast assumptions outlined in section 6.4 (and reported in Appendix 8),while the other assumes prices are constant (in real terms)[132]. The gas demand forecasts are provided in Appendix 4.

[131] See http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(soo). See section 8.9.1 of the ESOO.

[132] While pipeline capacity may be a potential constraint on future gas demand, pipeline capacity was not considered as a constraint in the development of these forecasts.

Figure 31 – Gas Demand Forecasts for WA, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023. **Note:** Demand forecasts include projected gas demand along the proposed BAP from 2016.

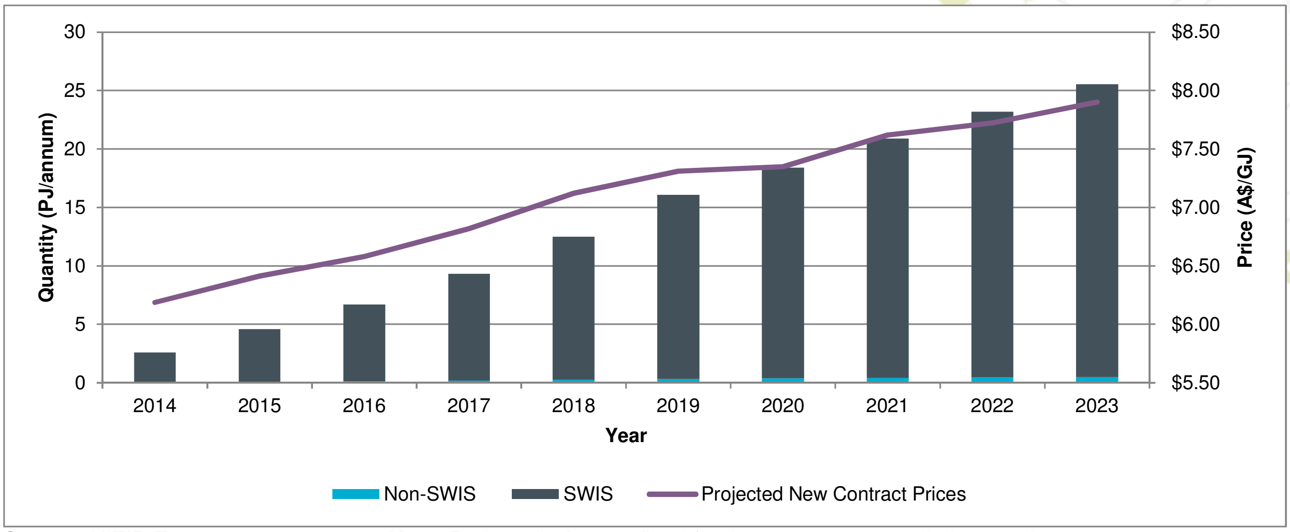
Over the forecast period and taking into account the effect of forecast gas prices, domestic gas consumption is forecast to grow on average by 0.4% per annum from approximately 976 TJ/day (356 PJ/annum) in 2014 to about 1,012 TJ/day (369 PJ/annum) by 2023. Under the High demand forecasts, the annual growth in gas consumption is forecast to be approximately 0.6%, with consumption increasing to 1,042 TJ/day or 380 PJ/annum by 2023, which is approximately 11 TJ higher than the Base demand forecasts. In the Low demand forecasts, due to a forecast fall in 2014, gas consumption is forecast to be relatively flat, reducing slightly to 958 TJ/day or 350 PJ/annum in 2023, which is approximately 19 TJ lower than the Base demand forecasts.

7.2.1. Impact of Price Elasticity of Demand Assumption

If, however, demand is not assumed to be responsive to price change over the forecast period (i.e. assuming constant prices in real terms), domestic gas consumption for the Base demand forecasts is projected to grow on average by 1.3% per annum from approximately 986 TJ/day (360 PJ/annum) in 2014 to about 1,111 TJ/day (406 PJ/annum) by 2023. For the High demand forecasts (constant prices), annual growth in gas consumption is forecast to be approximately 1.7% (with consumption increasing to 1,161 TJ/day or 424 PJ/annum by 2023), while the Low demand forecasts (constant prices) predict growth of approximately 0.8% (to 1,038 TJ/day or 379 PJ/annum).

Figure 32 reflects the expectation, incorporated into the revised price elasticity of demand assumptions in the gas demand modelling, that increases in average new contract gas prices will have a more significant impact than projected in the July 2013 GSOO. The majority of demand suppression is predicted to come from areas that comprise the SWIS, where gas consumers have greater access to alternative fuel sources and energy supply options.

Figure 32: Estimated Loss of Gas Demand due to Forecast Prices (real), SWIS and Non-SWIS, 2014 – 2023

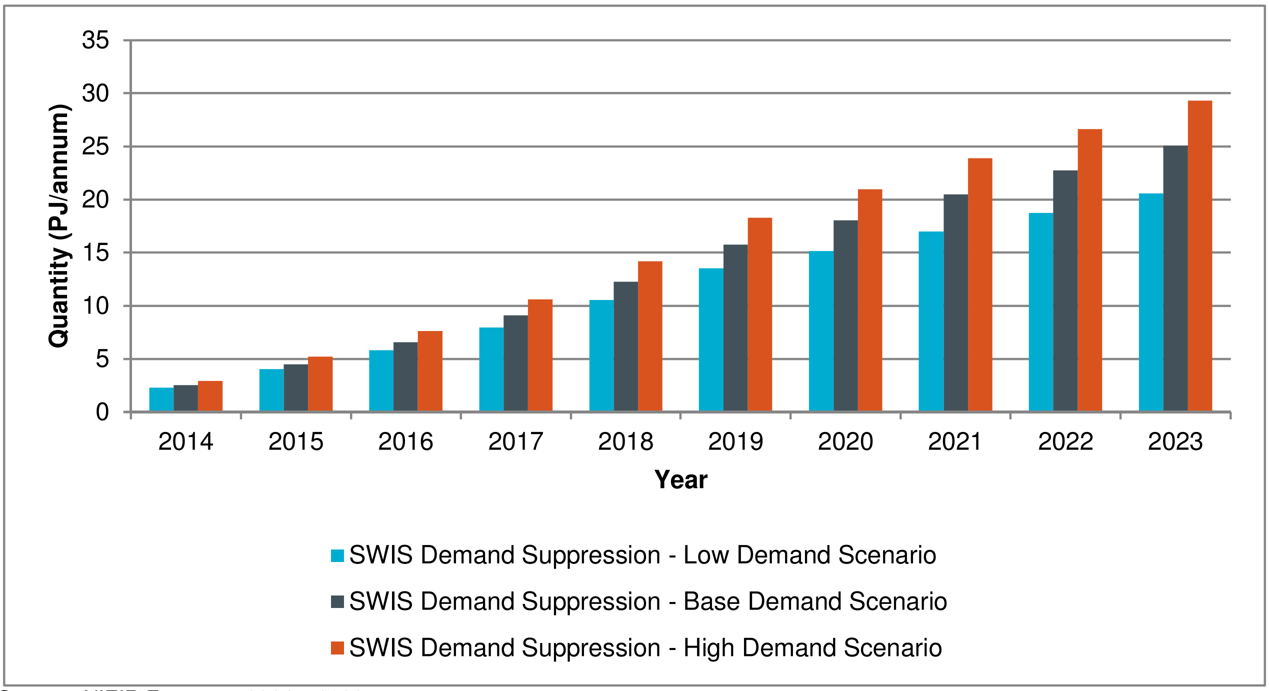


Source: NIEIR Forecasts 2014 – 2023. **Note:** Projected prices outlined for the 2014 to 2023 period are real average new contract gas prices as outlined in section 6.4.

Gas demand suppression for areas located outside the SWIS is expected to be minimal as there are often no viable alternatives (such as coal and renewables) to gas consumption[133]. Any reduction in demand is likely to be the result of more efficient use of gas through minor upgrades or lowered production.

Figures 33 and 34 show the impact of increasing average new contract gas prices for areas that comprise the SWIS and areas outside the SWIS for each of the Base, High and Low scenarios. The results are also reported in Appendix 4.

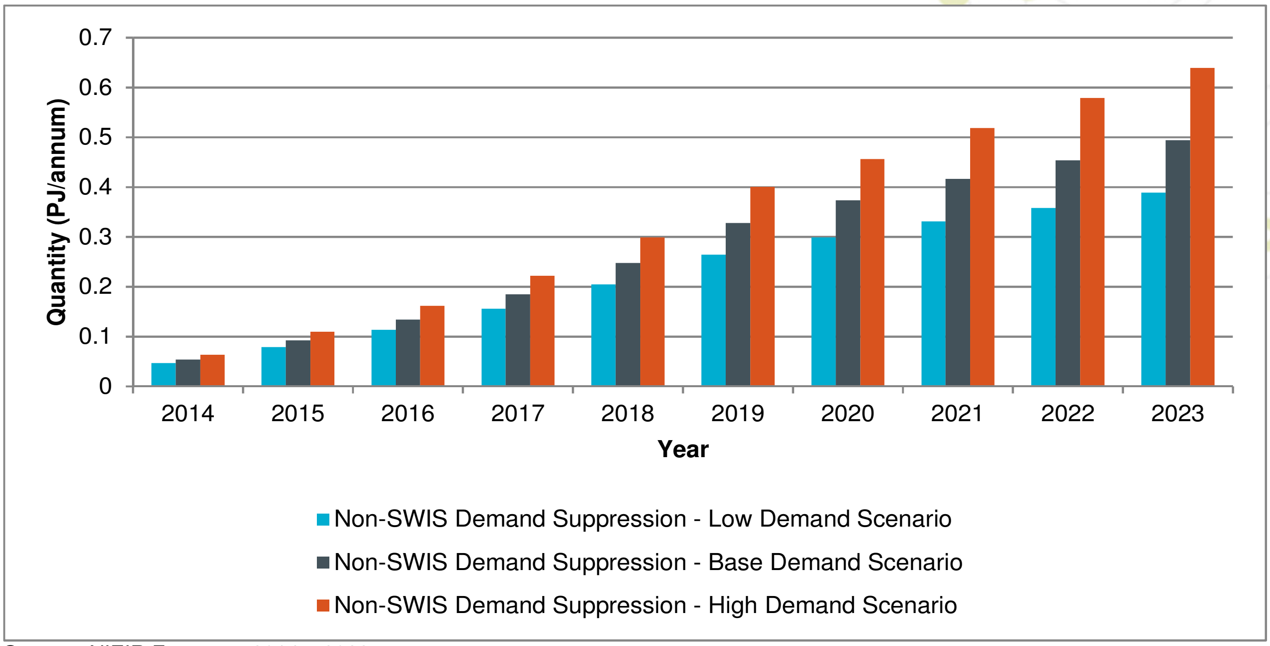
Figure 33 – Demand Suppression due to Domestic Average New Contract Gas Price Forecasts (SWIS), 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

[133] This was also outlined in Woodside (2010), *Submission to the State Parliamentary Inquiry – Domestic Gas Prices*, http://www.parliament.wa.gov.au/parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/3D2E2BC9065F66704825785D0012353A/$file/Sub+15+-+Woodside+Energy+Ltd+-+20100702.pdf, accessed 5 December 2013.

Figure 34 – Demand Suppression due to Domestic Average New Contract Gas Price Forecasts (Non-SWIS), 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

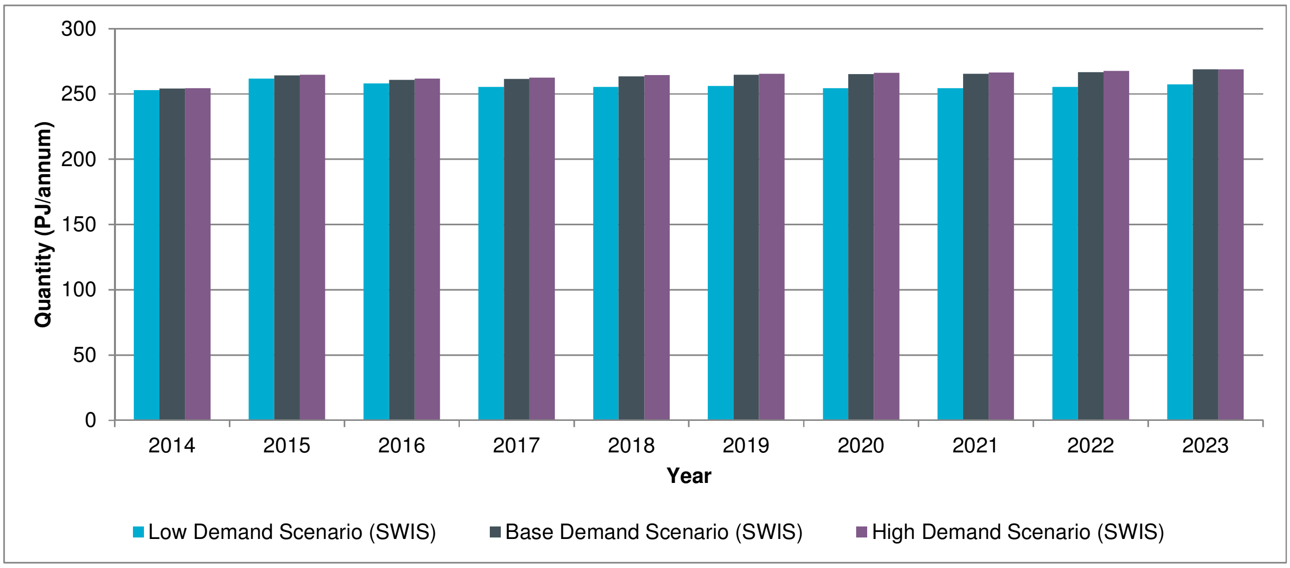
The constant price demand scenarios are included here for comparison only. **Gas demand forecasts presented throughout the remainder of this GSOO are those that consider the impact of gas price forecast assumptions outlined in section 6.4.**

7.2.2. Gas Demand Forecasts in the SWIS and Non-SWIS Areas, 2014 – 2023

Figures 35 and 36 present the breakdown of gas demand forecasts by SWIS and non-SWIS areas. The forecasts show future gas consumption is expected to grow more rapidly in the non-SWIS areas of WA, especially within in the Pilbara, Mid West and Goldfields regions that will be driven by mining expansions.

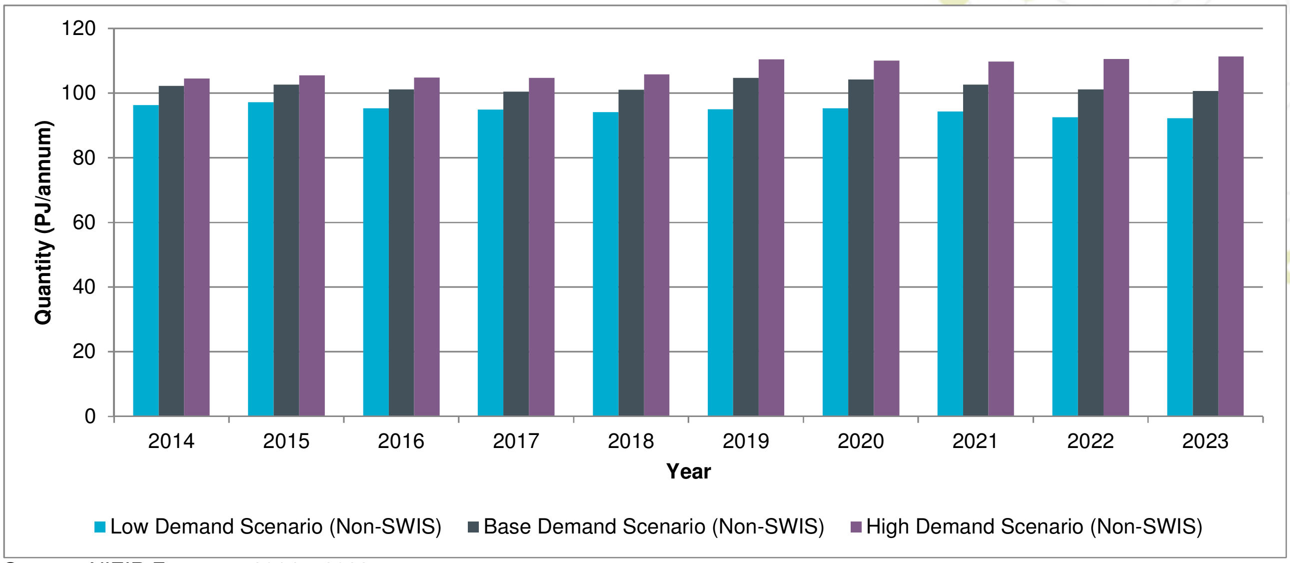
Figure 35 shows gas demand for the SWIS is forecast to almost grow at a similar rate for the Base and High scenarios. The Base demand forecasts predict gas consumption will grow from approximately 254 PJ/annum to 268 PJ/annum (0.6% per annum), while the High demand forecasts predict growth in gas consumption of approximately 0.61% (to about 269 PJ/annum). In the Low gas demand forecasts, gas consumption is only forecast to grow by about 0.2% (to about 257 PJ/annum in 2023).

Figure 35 – Comparison of SWIS Demand Forecasts across Different Scenarios, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

Figure 36 – Comparison of Non-SWIS Demand Forecasts across Different Scenarios, 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023.

For areas outside the SWIS, Figure 36 shows the Base demand forecasts to be flat from approximately 102 PJ/annum to 101 PJ/annum by 2023. In the High demand forecasts, the growth in gas consumption is forecast to be approximately 0.6% (to about 111 PJ/annum by 2023), while the Low demand forecasts predict gas consumption will fall by 0.4% annually (to about 92 PJ/annum). Gas demand forecasts by region are provided in Appendix 4.

7.2.3. Comparison with July 2013 GSOO Gas Demand Forecasts

Table 16 – Comparison of Forecast Demand Growth Rates (July 2013 GSOO and January 2014 GSOO)

	Growth Rates (%)		
Gas Demand Forecast	**Low**	**Base**	**High**
July 2013 GSOO	0.5	1.1	1.9
January 2014 GSOO	0.01	0.4	0.6

Table 16 compares the demand growth forecasts outlined in the July 2013 GSOO and this GSOO. NIEIR's demand forecasts for the Base demand forecasts in this GSOO have a growth rate of approximately 0.4% per annum, a fall from 1.1% reported in the July 2013 GSOO[134].

In addition, NIEIR's revised High and Low demand forecasts suggest growth of approximately 0.6% and 0.01% per annum respectively, lower than the 1.9% and 0.5% growth forecast in the July 2013 GSOO (see Figure 37). The reduction in growth rates between the July 2013 and January 2014 GSOO can be attributed to three changes to NIEIR's gas demand model:

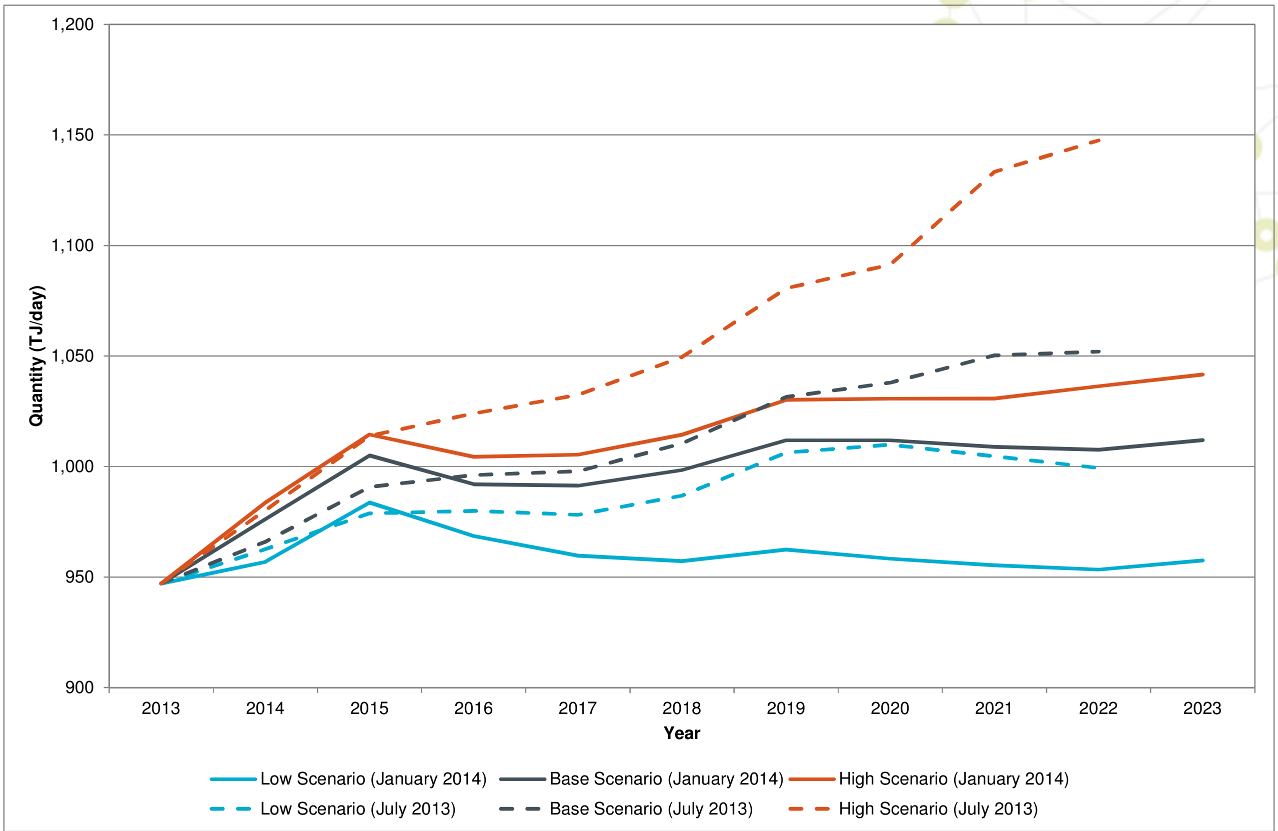
- modifying the assumptions of gas consumption relating to aluminium processing;
- modifying the assumptions of gas consumption relating to SWIS electricity generation; and
- modifying the price elasticity of demand assumption.

The improved visibility of gas consumption by consumers using GBB data has allowed these changes to be implemented. BREE's report[135] has also assisted with understanding gas consumption outside the SWIS.

Further improvements in gas demand forecasts are expected in future GSOOs as additional GBB data becomes available.

[134] BREE's growth rate was reported in BREE (2012b).
[135] BREE (2013g), *Beyond the NEM and the SWIS 2011-12 regional and remote electricity in Australia* http://www.bree.gov.au/publications/beyond-nem-and-swis-2011%E2%80%9312-regional-and-remote-electricity-australia, accessed 20 November 2013.

Figure 37 – Comparison of Previous and Current Gas Demand Forecasts, 2013 – 2023



Source: NIEIR Forecasts 2014 – 2023. **Note:** Demand forecasts include projected gas demand along the proposed BAP from 2016.

7.2.4. Total Gas Demand (Domestic and LNG)

Figure 38 presents the forecasts of total gas demand for the Base, High and Low scenarios, derived from the assumptions outlined in section 6.1.5. Total gas demand is the sum of domestic gas demand reported in Appendix 4 and projected LNG requirements provided in Appendix 9 for each scenario.

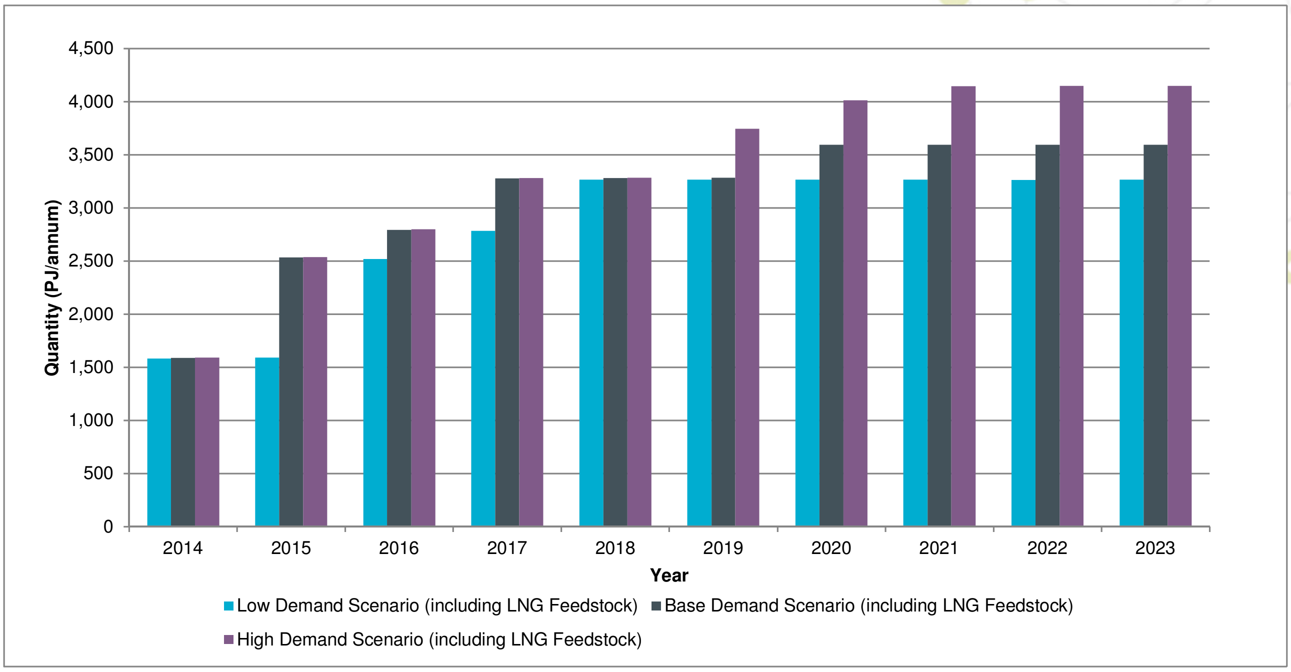
Since the publication of the July 2013 GSOO, the Gorgon project has lost Korea Gas as a long-term LNG purchaser[136] and has publicly indicated that the Gorgon expansion project has been put on hold[137]. However, the continued activity to obtain approval to utilise more land on Barrow Island[138] suggests the Gorgon project expansion remains a possibility for the 2014 to 2023 period. In addition, expected growth in international demand remains robust and the wage inflation for major projects in Australia is abating (see Chapter 8).

All three total gas demand scenarios have been slightly modified from the July 2013 GSOO. All the scenarios now include the Prelude FLNG project, which is expected to commence in 2017. The Base and High scenarios have also been modified by delaying the potential start-up of Gorgon Train 4 by a year due to the recent news. The Base scenario now assumes Gorgon Train 4 may commence in 2020 (previously 2019) while the High scenario now assumes the project may commence in 2019 (previously 2018). The High scenario also includes the potential Bonaparte FLNG project in 2019.

As shown in Figure 38, under the Base scenario, NIEIR forecasts total gas demand in WA will grow at an annual compounded rate of approximately 9.5% from an estimate of 1,590 PJ/annum in 2014 to about 3,596 PJ/annum in 2023, while in the Low scenario total gas demand is forecast grow at an annual compounded rate of approximately 8.4% per annum to about 3,265 PJ/annum in 2023. In the High scenario total gas demand is projected to grow at an annual rate of 11.2% per annum to about 4,149 PJ/ annum.

[136] See the West Australian (2013i), *Gorgon gas sales fall short*, http://au.news.yahoo.com/thewest/a/-/breaking/17368370/gorgon-gas-sales-fall-short/, accessed 20 October 2013.
[137] See the West Australian (2013h), *Chevron puts Gorgon on hold*, 4 November 2013, http://au.news.yahoo.com/a/19666060/, accessed 28 January 2014.
[138] See the West Australian (2013d) and the West Australian (2014c), *Gorgon's Barrow expansion approved*, 7 January 2014, http://au.news.yahoo.com/thewest/business/wa/a/20630790/gorgons-barrow-expansion-approved/, accessed 28 January 2014.

Figure 38 – Total Gas Demand Forecasts (Domestic and LNG), 2014 – 2023



Source: NIEIR Forecasts 2014 – 2023. **Note:** Total gas demand has been updated to include Prelude FLNG in 2017 for all scenarios and Bonaparte FLNG in 2019 for the High scenario.

Across all three scenarios, the rapid growth in total gas demand is the result of the increasing demand for gas for LNG exports. In the Base scenario, demand for LNG feedstock is expected to more than double from 1,142 PJ/annum in 2014 to approximately 2,988 PJ per annum in 2023. In the High scenario, LNG demand is forecast to be approximately 3,489 PJ/annum by 2023, while in the Low scenario, LNG demand is forecast to be approximately 2,988 PJ/annum.

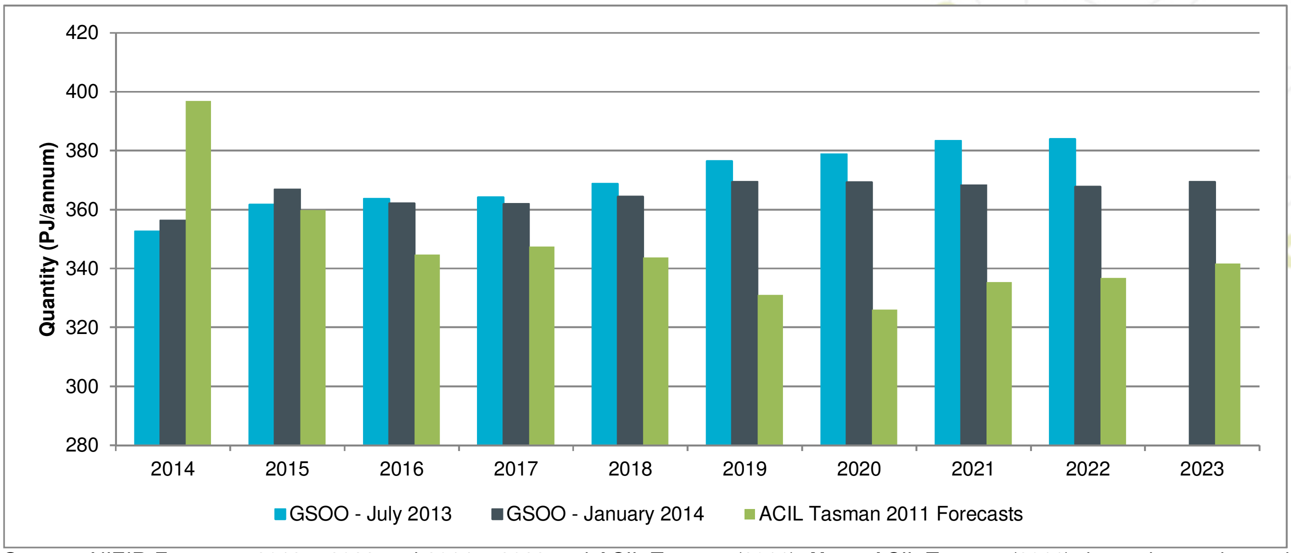
7.2.5. Comparison of July 2013 GSOO, January 2014 GSOO and ACIL Tasman 2011 Forecasts

This section compares the domestic gas demand and total gas demand forecasts developed for this GSOO against forecasts developed for the July 2013 GSOO and ACIL Tasman's 'current policies' forecasts prepared in 2011 for the PUO[139].

Figure 39 compares ACIL Tasman's forecasts of domestic gas demand against the Base demand forecasts performed for the July 2013 GSOO and this GSOO, showing that NIEIR's forecasts for the July 2013 GSOO and the current GSOO are higher than ACIL Tasman's 2011 forecasts from 2015 onwards. While NIEIR's latest forecasts estimate that domestic demand will grow at approximately 0.4%, ACIL Tasman's forecasts expect the domestic gas market to decline at a rate of 1.5%, to only 342 PJ/annum by 2023.

[139] See ACIL Tasman (2011), *Energy Futures for Western Australia, Scenario development and modelling outcomes*, prepared for the Office of Energy, September 2011. This is also reported in Grattan Institute (2013), *Getting Gas Right, Australia's Energy Challenge,* 16 June 2013, http://grattan.edu.au/static/files/assets/935979e0/189_getting_gas_right_report.pdf, accessed 17 June 2013.

Figure 39 – Comparison of Domestic Gas Demand Forecasts (excluding LNG and Petroleum Processing), 2014 – 2023

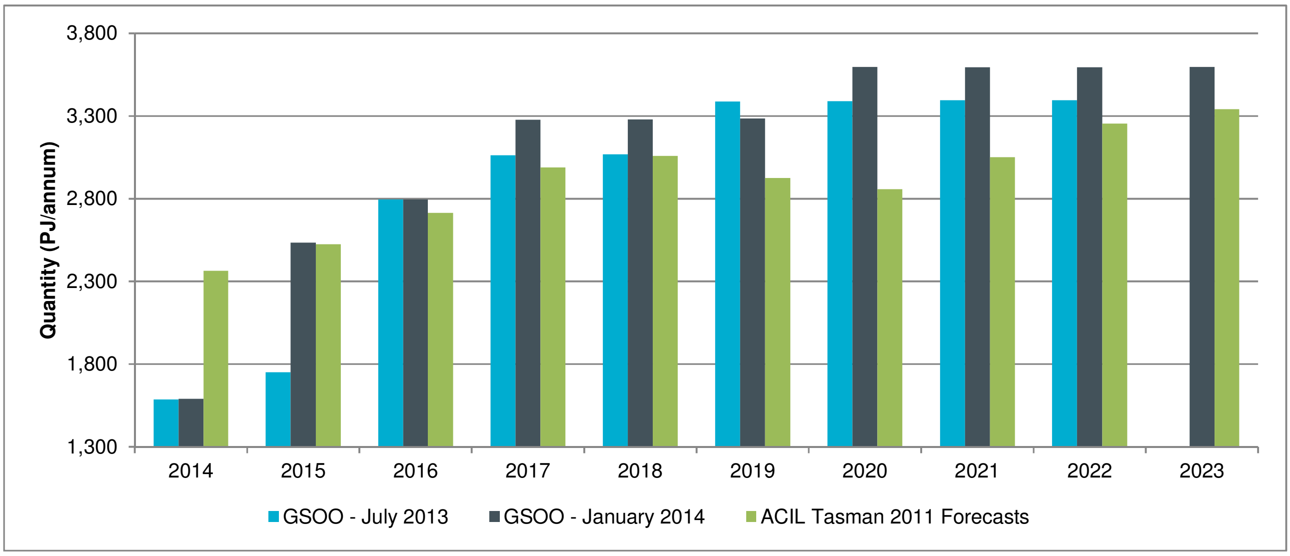


Source: NIEIR Forecasts 2013 – 2022 and 2014 – 2023 and ACIL Tasman (2011). **Note:** ACIL Tasman (2011) domestic gas demand figures were re-calculated by removing estimates of LNG and petroleum processing from their estimates and converting to calendar years.

Figure 40 compares ACIL Tasman's current policies forecasts of total gas demand against the Base scenario forecasts performed for the July 2013 GSOO and this GSOO, showing NIEIR's forecasts are significantly higher for total gas demand.

NIEIR estimates total gas demand to grow at an annual compounded rate of approximately 9.5% to 3,380 PJ/annum for 2023, while ACIL Tasman's forecast in 2011 expects total gas demand to grow only at an annual compounded rate of 4.8%, to 3,000 PJ/annum. The difference in growth rates is the result of different starting points and assumptions regarding LNG projects[140] (NIEIR's starts from a demand level of approximately 1,590 PJ/annum, while ACIL Tasman starts at 1,968 PJ/annum).

Figure 40 – Comparison of Total Gas Demand Forecasts (excluding LNG and Petroleum Processing), 2014 – 2023



Source: NIEIR Forecasts 2013 – 2022 and 2014 – 2023 and ACIL Tasman (2011). **Note:** ACIL Tasman (2011) total demand figures were re-calculated by converting to calendar years.

[140] ACIL Tasman's LNG assumptions are as follows, NWSLNG – 16.3 Mtpa capacity from 2009 – declining from 2023, Pluto, one 4.3 Mtpa train commissioned in 2012, with full production from late 2013, Gorgon LNG – production commences in 2014 with full production of 15 Mtpa by 2017, Scarborough LNG – 6six Mtpa production with first gas 2018, Wheatstone LNG – 4.3 Mtpa from 2017, while NIEIR's total demand forecasts are similar for NWS and Pluto with Gorgon – 15.6 Mtpa from 2015, Wheatstone 4.45 Mtpa from 2016 and 4.45 Mtpa from 2017, Prelude 3.6 Mtpa from 2017 and Gorgon Expansion Train 4 from 2020. See ACIL Tasman (2011).

8. Liquefied Natural Gas Market

The influence of the LNG market on WA's domestic market is unquestionable[141]. Several existing and future gas producers have the opportunity of selling gas to either the international LNG market or to the domestic gas market. As such, changes to the international LNG market, especially in the Asia Pacific region, may influence the willingness of these producers to supply to the domestic gas market.

As discussed in Chapter 7, WA's LNG export market in 2012-2013 is already more than three times the size of the domestic market and the LNG export market is estimated to expand to seven times the size of the domestic market by the end of 2023.

This chapter reviews the existing and potential buyers of WA's LNG and also presents some commentary on various competitors and risks to the WA LNG export market for the 2014 to 2023 period. While WA also supplies LNG domestically, domestic LNG supplies are not considered in detail in this GSOO due to the relatively small size of this market. For more information regarding WA's domestic LNG market, please refer to Chapter 6 of the July 2013 GSOO.

Information provided in this chapter is for context only. It has not been incorporated into the potential supply model discussed in Chapter 6.

8.1. The International LNG Market

The positive outlook for the international gas market has not changed materially since the publication of the July 2013 GSOO. Demand for gas is expected to grow over the coming decades, steered by the continued industrialisation of China, India and south-east Asia, coinciding with policies in various countries attempting to curb environmental pollution and greenhouse emissions[142].

According to the International Energy Agency (IEA), international gas demand for electricity generation is expected grow at an average rate of 2% per annum from a share of 21% of the global energy mix to 25% by 2035, overtaking coal in 2030[143]. This promising outlook for international gas demand was referred to by the IEA as the 'Golden Age of Gas'[144].

International gas trade currently occurs via international gas pipelines or seaborne LNG ships. Although pipeline gas trade accounts for approximately 68.3% of the international gas trade in 2012, LNG is the faster growing segment. For a description and brief history of the international LNG market, please refer to the July 2013 GSOO.

LNG demand consists of two segments: the premium and remaining customers. The premium segment consists of mainstay LNG customers Japan, South Korea and Taiwan, which account for approximately 51.4% of the total LNG import market[145]. The premium segment encounters the highest wholesale gas prices, as these customers are entirely dependent on LNG to meet their gas consumption requirements. The remaining LNG customers in many cases have greater access to competing gas pipelines and/or energy options. These customers include rapidly developing countries such as China and India, and are expected to drive growth in the international gas market in the forecast period.

Australia is currently the third largest LNG exporter in the world, after Qatar and Malaysia[146]. Australia is capable of supplying 24 Mtpa, accounting for approximately 8% of the total LNG export market. With the upcoming completion of LNG projects in WA, Qld and the NT, 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% of

[141] EISC (2011) reports domestic gas prices have persistently reached or exceeded LNG netback prices.

[142] The United Nations treaty to limit the production of greenhouse gases, the Kyoto Protocol, applies to nearly 200 countries and was extended to 2020 in December 2012. The European Union (EU) introduced its emissions trading scheme in 2005 and Australia introduced a carbon price on 1 July 2012.

[143] This figure was updated in IEA (2012), *World Energy Outlook 2012*, to 1.6% growth per annum to 2035.

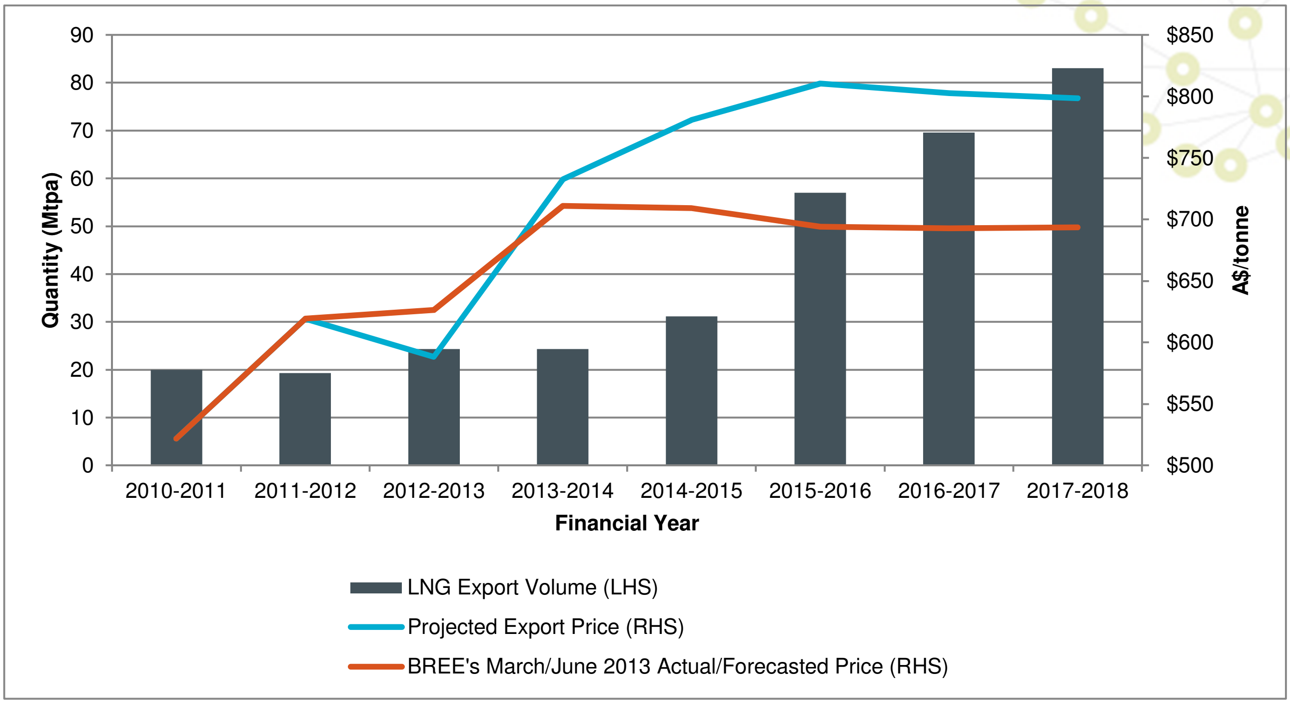
[144] The IEA (2011) *World Energy Outlook 2011* suggests the world has entered a Golden Age of Gas and forecasts continued growth of international gas demand for the period 2011 to 2035.

[145] Market shares for Japan, South Korea and Taiwan's LNG imports are from BP (2013), *Statistical Review of World Energy 2013*, June 2013, http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013.html, accessed 13 June 2013.

[146] According to IGU (2013), *World LNG Report – 2013 Edition*, http://www.igu.org/gas-knowhow/publications/igu-publications, accessed 20 November 2013, Qatar and Malaysia account for approximately 32.6% and 9.7%, respectively, of total international LNG exports in 2012.

international LNG export capacity)[147]. BREE projects that Australian LNG exports will grow at a rate of approximately 27.5% per annum from 19.3 to 83 Mtpa for the period 2011-2012 to 2017-2018 (see Figure 41), with a nominal export value of about $66.2 billion in 2017-2018[148].

Figure 41 – LNG Exports and Pricing (nominal), Historical and Projected (Australia), 2010-2011 to 2017-2018



Source: BREE (2013h), BREE (2013c) and BREE (2013), being the Resources and Energy Quarterly reports for the September, June and March quarters of 2013, Gas Outlook 2012-2018 sections, respectively. **Note:** These are solely BREE's forecasts and are not used in NIEIR's forecasts of LNG feedstock requirements. See http://bree.slicedlabs.com.au/sites/default/files/files/publications/req/req-2013-09.pdf, accessed 23 January 2014.

BREE's updated forecasts for September 2013, shown in Figure 41, are consistent with NIEIR's view that LNG prices are expected to rise in the upcoming 2013-2014 to 2017-2018 period.

8.2. The Australian LNG Market

Despite the current expansion of Australia's LNG export capacity, the NWS JVs' LNG facility in WA remains the largest operational LNG export facility in Australia, with almost four times the export capacity of the next largest facility (Pluto)[149].

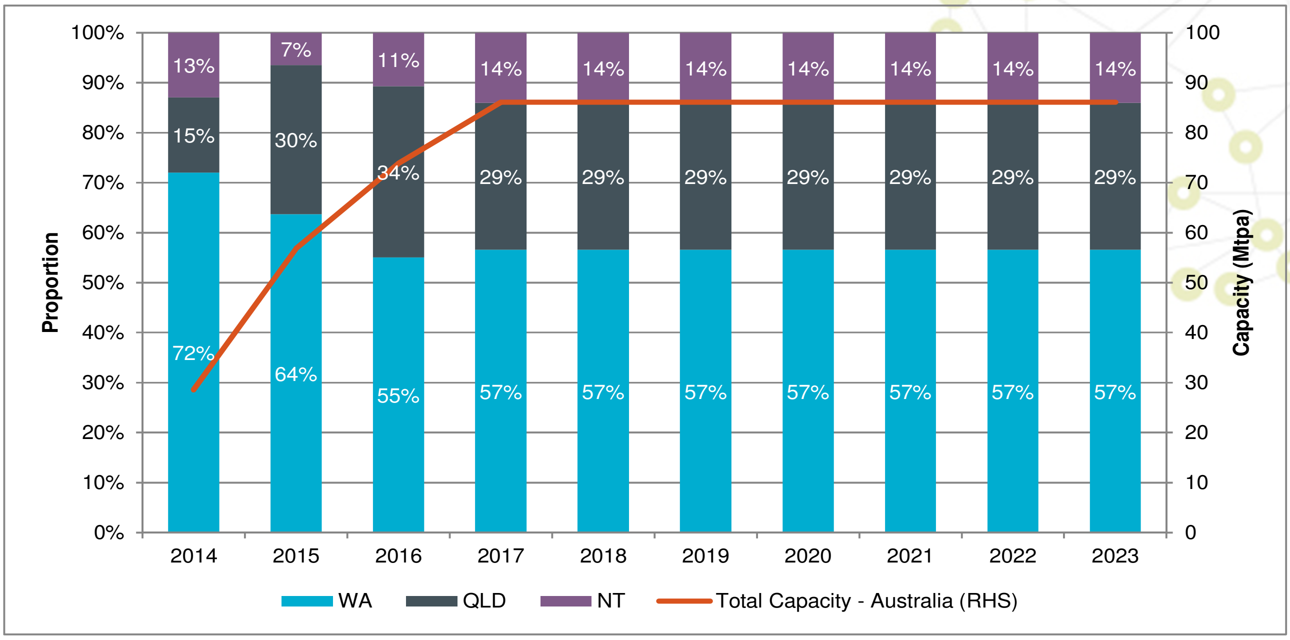
Currently, WA hosts approximately 72% of Australia's total LNG export capacity but this share is anticipated to fall from 2014 due to the expected commissioning of LNG facilities in Qld and the NT, as shown in Figure 42.

[147] Timeline is estimated by Innovative Energy Consulting (2012), *Australia Domestic Gas Policy Report – Prepared for The DomGas Alliance*, November 2012, http://www.domgas.com.au/pdf/Media_releases/2012/Australia%20Domestic%20Gas%20Policy%20Final%20Report.pdf, accessed 7 May 2013 assuming all existing LNG export capacity that has approvals remains unchanged. This sentiment is also outlined in Gas Today (2013). According to IGU (2012), by 2022, Malaysia and Indonesia are more likely to import gas and consume their gas reserves internally.

[148] See BREE (2013, 2013c, 2013h) for more information on LNG forecasts for the 2011 to 2018 period.

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

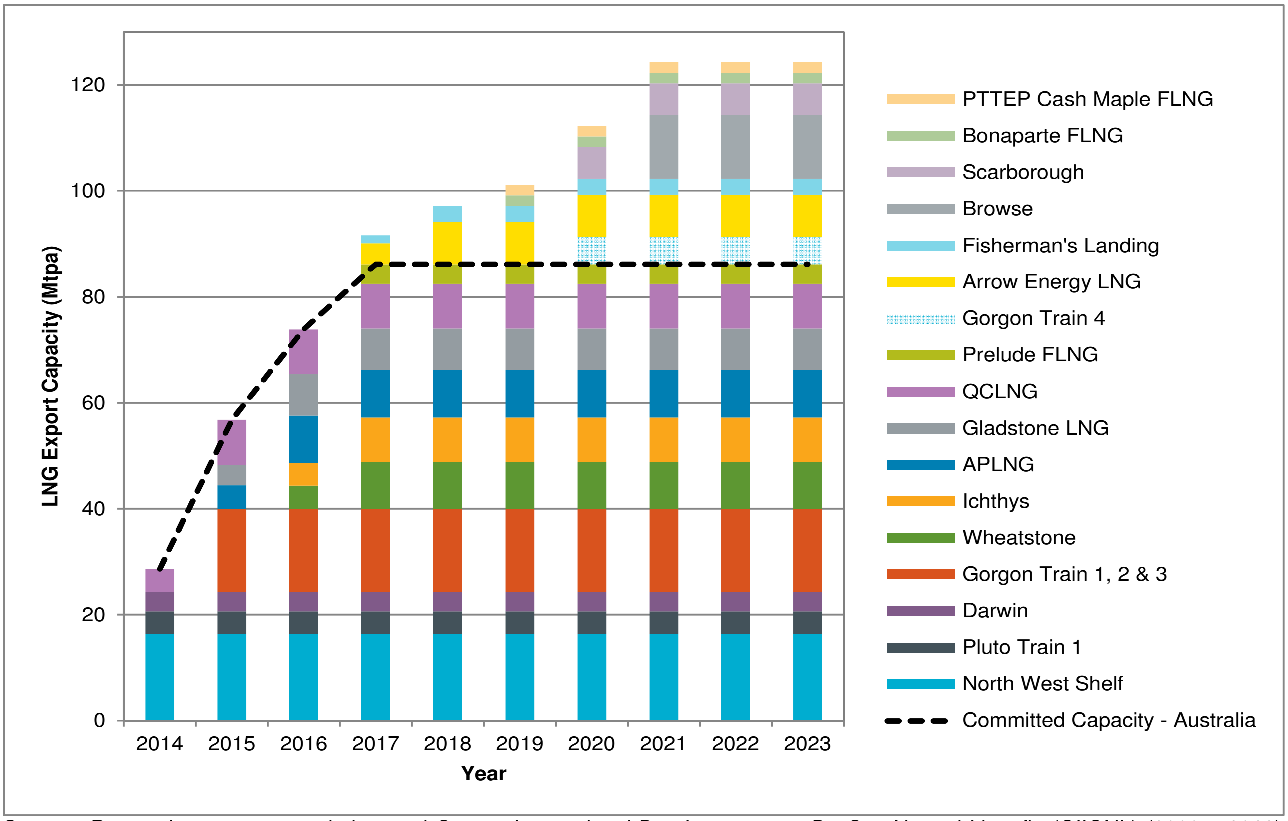
Figure 42 – Share of LNG Export Capacity by Australian States and Territories, 2014 – 2023



Source: Figure 43. **Note:** Shares include the Prelude FLNG project. Proposed LNG projects that have not attained Final Investment Decision (FID) approvals are excluded. The figure has been updated from the July 2013 GSOO and assumes the NWS LNG facility will remain at 16.3 Mtpa LNG export capacity for the entire period.

It is estimated that Australia will host 10 LNG facilities in 2023 shown in Figure 43; three in Qld (Australia Pacific, Gladstone and Qld Curtis LNG facilities), two in the NT (Darwin and Ichthys LNG facilities) and five (four onshore, one offshore) in WA (Gorgon, NWS JVs, Pluto, Prelude and Wheatstone LNG facilities).

Figure 43 – Total Estimated LNG Export Capacity in Australia, 2014 – 2023



Source: Respective corporate websites and Groupe International Des Importateurs De Gaz Naturel Liquefie (GIIGNL) (2009 – 2012). **Note:** Projects above the committed capacity line are speculative in nature (before FID) and may not be realised in the 2014 to 2023 period. Other potential LNG projects such as Caldita-Barossa, Crux, Equus, Poseidon, Thebe, Crown and others are not reflected in this figure as there are no known indicative dates and/or export capacities.

8.3. Western Australian LNG Market

WA's LNG production serves two distinct market segments, namely LNG exports and domestic LNG consumption. LNG exports are dominant with the NWS and Pluto LNG facilities consisting of six trains (as shown in Table 17) capable of exporting a total of 20.6 Mtpa of LNG, estimated to be worth $2.5 to $3 billion to the WA economy annually. Both facilities are operated by Woodside Energy.

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

LNG Facility	Capacity (Mtpa)	Commissioned	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
Total LNG Export Capacity	**20.6**		

Source: Woodside Energy corporate website, see http://www.woodside.com.au/Our-Business/North-West-Shelf/Pages/default.aspx and http://www.woodside.com.au/Our-Business/Pluto/Pages/default.aspx, accessed 5 November 2013. **Note:** LNG train capacities for the NWS LNG facility may increase, as some facilities are being upgraded. This was outlined in Woodside (2012).

Table 18 provides the ownership structure of the two LNG facilities in WA, showing that Woodside Energy Ltd holds the largest ownership share.

Table 18 – Ownership of Operational LNG Export Facilities in Western Australia, 2013

LNG Facility	NWS Ownership (%)	Pluto Ownership (%)
Woodside Energy Ltd (Operator of NWS and Pluto LNG)	16.7	90
BHP Billiton Petroleum (NWS) Pty Ltd	16.7	-
BP Developments Australia Pty Ltd	16.7	-
Chevron Australia Pty Ltd	16.7	-
Japan Australia LNG (MIMI) Pty Ltd	16.6*	-
Shell Development (Australia) Pty Ltd	16.7	-
Tokyo Gas	-	5
Kansai Electric	-	5
Total	**100%**	**100%**

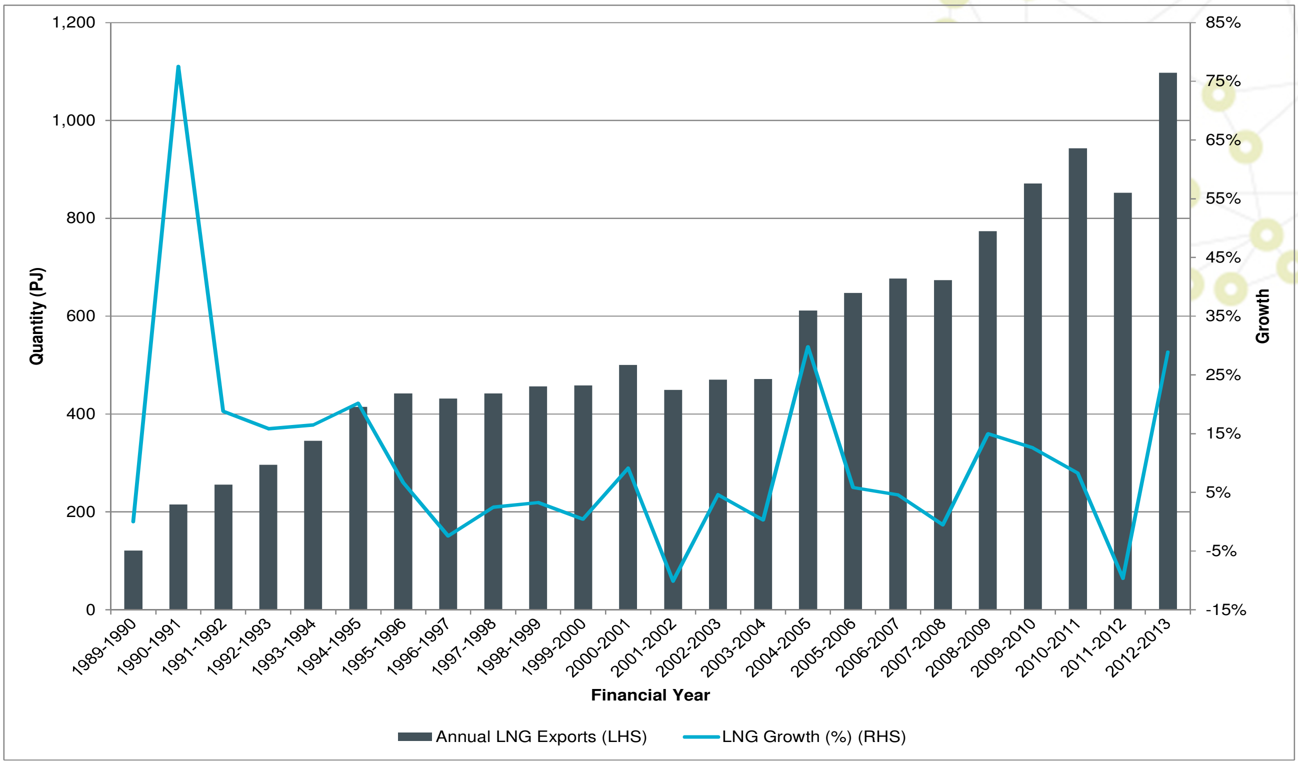
Source: Commonwealth National Electronic Approvals Tracking System and Woodside Australia corporate website, see https://neats.nopta.gov.au and http://www.woodside.com.au/Our-Business/Pluto/Pages/default.aspx, accessed 5 November 2013. **Note:** the ownership shares relate to the LNG facility, some NWS reserves include CNOCC NWS Private Limited. *See NBR (2013).

Since 1989, more than 50 million tonnes of LNG in total have been delivered to customers in China, India, Japan, Korea, Malaysia, Spain, Taiwan and the US under long-term 'take or pay' contracts, short-term contracts or spot cargoes. Figure 44 shows LNG exports from WA LNG facilities over the period from 1989-1990 to 2012-2013.

As shown in Figure 44, DMP reports that WA exported approximately 1098 PJ (19.8 megatonnes [Mt]) in 2012-2013 as LNG, a 29% increase from 2011-2012. This increase is primarily due to increasing gas demand from Japan, after the Japanese Government temporarily decommissioned all its nuclear facilities for safety inspections after the Fukushima nuclear incident in 2011, and the commencement of exports from Pluto[150].

[150] See DMP (1990-2013) for more information about LNG exports from WA.

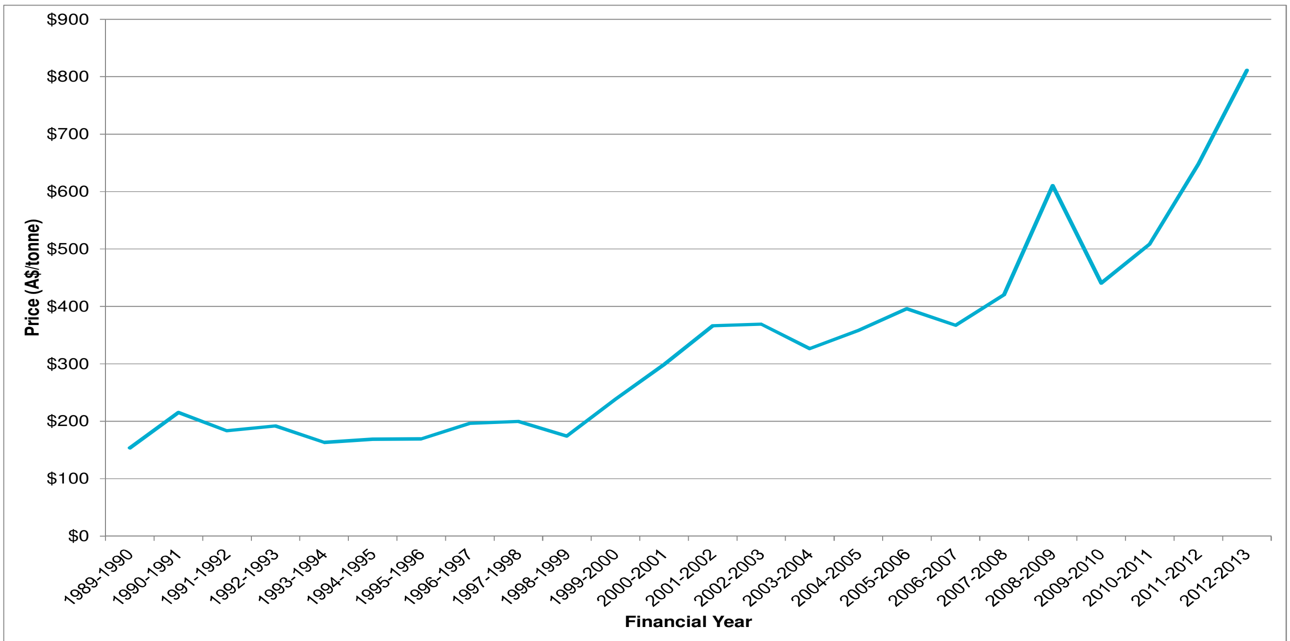
Figure 44 – WA LNG Exports, 1989-1990 to 2012-2013



Source: DMP (1989-1990 to 2012-2013) Annual LNG Exports. **Note:** This figure is different to that presented in the July 2013 GSOO as this figure covers financial years.

Reviewing LNG prices from 1989-1990 to 2012-2013, Figure 45 shows nominal LNG export prices remained relatively stable through to 1998-1999 before prices started to rise from 1999-2000 until 2012-2013. In 2009-2010, world LNG prices fell due to the impact of the GFC on major gas consuming countries[151].

Figure 45 – WA LNG Export Prices (nominal), 1989-1990 to 2012-2013



Source: DMP (1989-1990 to 2012-2013), Resources Data Files, Petroleum Statistics, LNG Exports. **Note:** This figure is different to that presented in the July 2013 GSOO as this figure covers financial years.

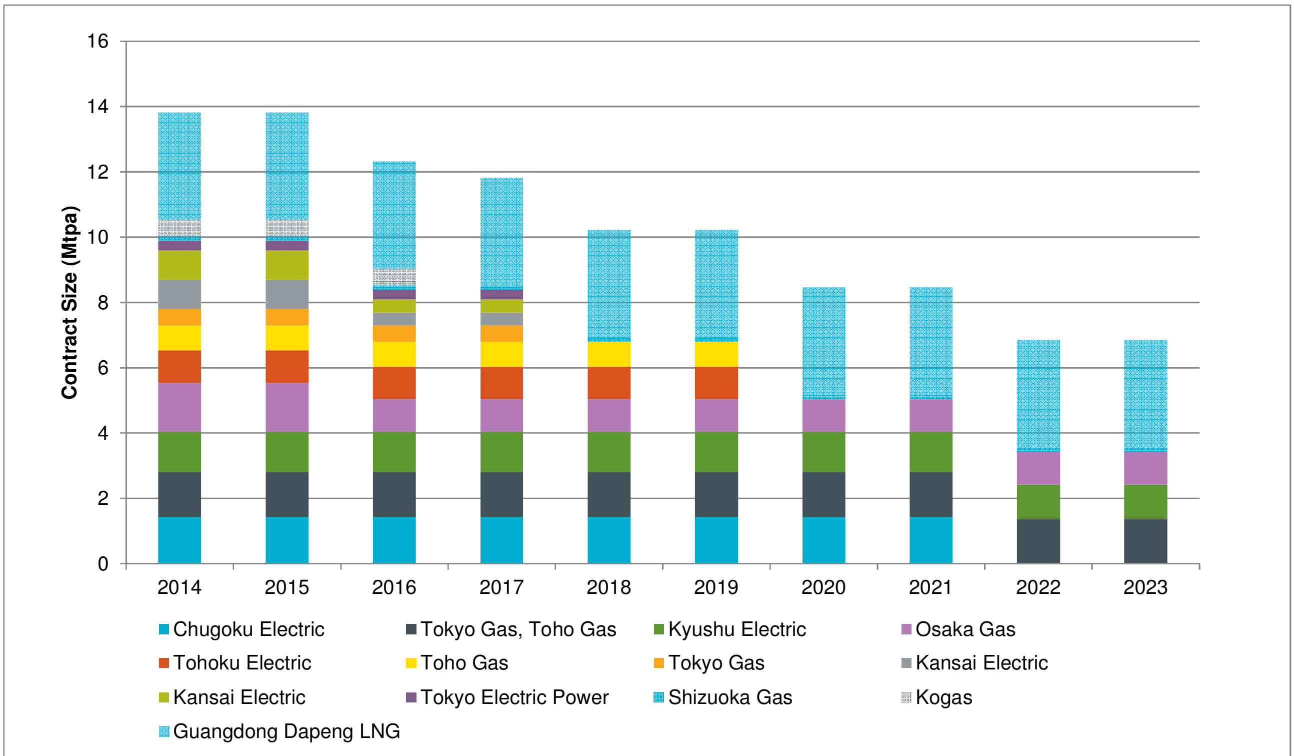
[151] BREE (2013d), *Westpac–BREE China Resources Quarterly, August 2013*, http://www.bree.gov.au/publications/westpac%E2%80%93bree-china-resources-quarterly, accessed 24 January 2014 reports there were price declines in 2009 for Japan (24%), US (54%) and the EU (32%).

8.3.1. Existing Western Australia LNG Contracts (Operational LNG Plants Only)

Despite rising LNG prices since 1999-2000 (shown in Figure 45), WA has succeeded in maintaining a long and close relationship with Japan as a source of stable supply of LNG. As a result, most long-term LNG contracts with Japan were renewed over the 2003 to 2008 period[152]. This section presents a view of existing LNG contracts of operational LNG facilities in WA.

Figures 46 and 47 present the average contracted quantity of the NWS and Pluto LNG facilities, respectively, as reported by the Groupe International Des Importateurs De Gaz Naturel Liquefie (GIIGNL) in 2012. Both figures show a significant portion of WA's LNG export capacity is contracted until 2016. Beyond 2016, a proportion of contracts for NWS LNG will start expiring. To the best of the IMO's knowledge, there have been no announcements regarding whether these existing supply contracts will be extended.

Figure 46 – Reported LNG Contracts for NWS, 2014 – 2023

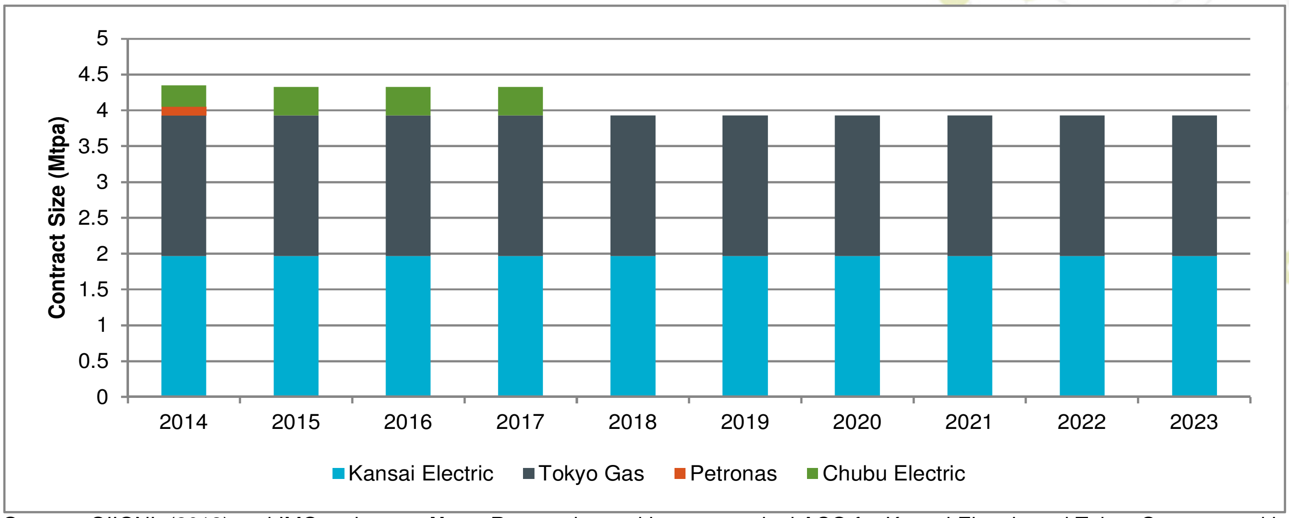


Source: GIIGNL (2013).**Note:** Reported quantities are nominal average contract quantities (ACQ) for all reported LNG contracts. Actual LNG production and LNG sold quantities may vary from contractual quantities shown in this figure as actual sales may deviate from these values due to contractual agreements, seasonality and LNG storage.

In contrast, Figure 47 shows the Pluto LNG export facility will remain almost fully contracted to supply LNG to its existing Japanese customers for the next 10 years.

[152] During this period, the renewed quantity of LNG exported to Japan increased and new customers such as China were also supplied.

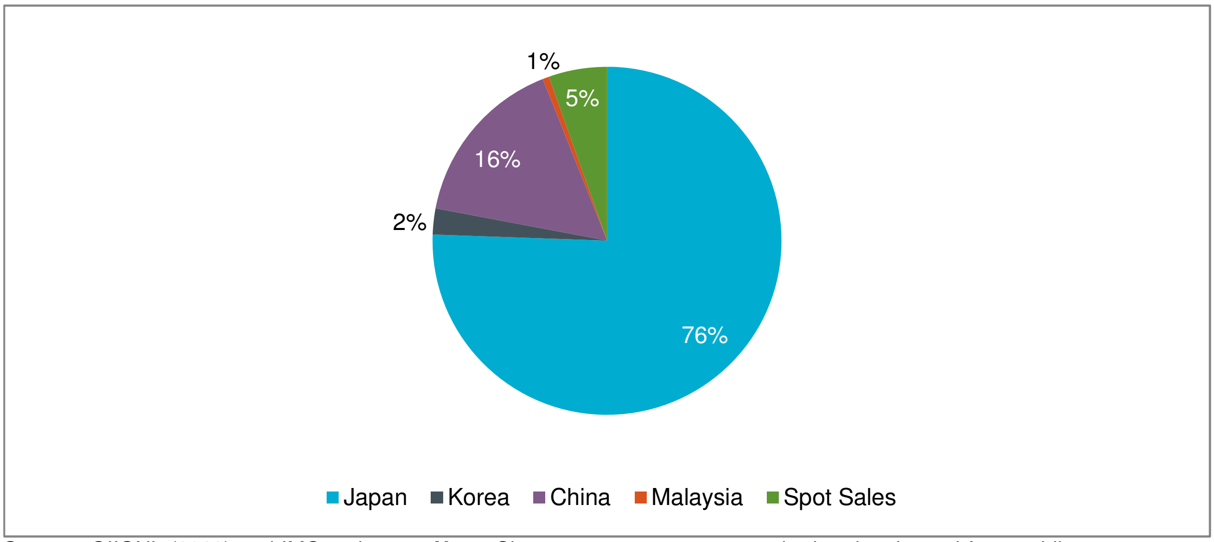
Figure 47 – Estimates of LNG Contracts for Pluto LNG, 2014 – 2023



Source: GIIGNL (2013) and IMO estimates. **Note:** Reported quantities are nominal ACQ for Kansai Electric and Tokyo Gas reported in GIIGNL's report. Contract quantities also include IMO estimates of equity gas for Kansai Electric and Tokyo Gas. It is understood Kansai Electric's LNG contract has a maximum contract quantity of two Mtpa. Petronas short-term LNG supply contract quantities are estimated by the IMO. Chubu Electric's three-year contract is also estimated from Woodside (2014).

Applying the reported contractual positions and estimates of equity gas outlined in GIIGNL, Figure 48 shows that approximately 76% of WA's LNG exports are supplied to Japan. This close relationship with Japan has led to Japanese companies and Japanese-linked JVs owning equity stakes in existing LNG facilities and upcoming LNG projects in WA[153].

Figure 48 – Estimates of WA LNG Exports by Country, 2013



Source: GIIGNL (2013) and IMO estimates. **Note:** Short-term contracts are acquired and estimated from public announcements. Spot sales are estimated from corporate announcements from Woodside (2012).

[153] Japan Australia LNG (MIMI) Ltd owns 16.6% of NWS JV; Tokyo Gas and Kansai Electric collectively own 10% of Pluto LNG; Osaka Gas, Tokyo Gas and Chubu Electric collectively own approximately 2.67% of Gorgon JV; Kyushu Electric and PE Wheatstone Pty Ltd (a special purpose company for Mitsubishi, Nippon Yusen Kabushiki Kaisha and Tokyo Electric) collectively own approximately 9.46% of Wheatstone JV; and Inpex owns 17.5% of the Prelude FLNG project. The ownership values for Wheatstone LNG have been updated from the July 2013 GSOO to include Japanese ownership via PE Wheatstone Pty Ltd. Ownership of LNG and FLNG projects are reported in North West Shelf Venture (2010), *North West Shelf Venture* fact sheet, http://www.nwsg.com.au/about/nwsg_venture_brochure_june_2010.pdf, accessed 28 February 2013, Woodside (2013), *Pluto LNG*, http://www.woodside.com.au/our-business/pluto/pages/default.aspx, accessed 28 February 2013, Chevron (2013), *Gorgon LNG Project*, http://www.chevronaustralia.com/ourbusinesses/gorgon.aspx, accessed 28 November 2013, Chevron (2013b), *Wheatstone LNG Project*, http://www.chevronaustralia.com/ourbusinesses/wheatstone.aspx, accessed 28 November 2013 and Royal Dutch Shell (2013), *Prelude FLNG – An overview*, http://www.shell.com/global/aboutshell/major-projects-2/prelude-flng/overview.html, accessed 20 November 2013.

8.3.2. Future Growth of WA LNG Capacity

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 2023 (Table 19)[154].

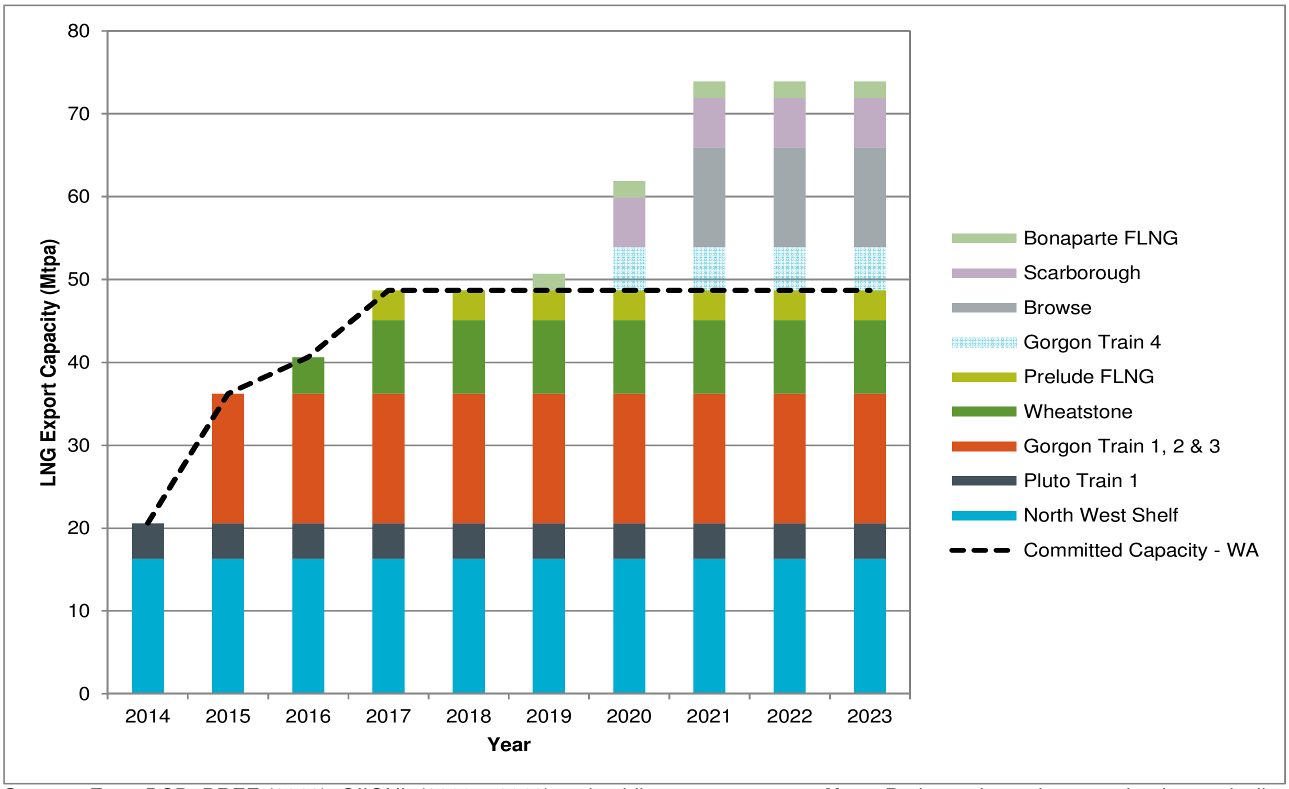
Table 19 – Committed LNG Facilities under Construction in WA, 2013

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

Source: Chevron Australia and APPEA website, http://www.chevronaustralia.com/ourbusiness and http://www.appea.com.au/oil-a-gas-in-australia/lng.html, accessed 23 January 2014. *See The Australian (2011).

As shown in Figure 49, DSD expects LNG production capacity in WA will continue to grow from 16.3 Mtpa in 2011-2012 (prior to the commissioning of Pluto) to almost 50 Mtpa in 2016-2017[155]. This will increase WA's share of international LNG export capacity from 6.3% in 2012 to approximately 13.7% by the end of 2017 (by which time Australia is expected to provide 23.6% of the world's LNG supply)[156].

Figure 49 – Committed and Speculative LNG Export Capacity in Western Australia, 2014 – 2023



Source: From DSD, BREE (2013), GIIGNL (2009 – 2013) and public announcements. **Note:** Projects above the committed capacity line are speculative in nature (before FID) and may not be realised in the 2014 to 2023 time period.

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[154] 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% to 97.6% of maximum capacity. See Woodside (2012), *2011 Full Year Results Briefing*, February 2012, http://www.woodside.com.au/Investors-Media/Announcements/Documents/22.02.2012%202011%20Full%20Year%20Results%20Presentation%20with%20Speaker%20Notes.pdf, accessed 21 May 2013.

[155] DSD (2013b), *Western Australia Economic Profile – April 2013*, http://www.dsd.wa.gov.au/documents/001022.mike.thomas.pdf, accessed 20 May 2013 reports that Gorgon, Wheatstone and other WA projects will increase LNG production capacity to almost 50 Mtpa.

[156] According to the Grattan Institute (2013), in 2012 WA's share of international LNG export capacity was 6.3%.

Other LNG export facilities for WA are being considered[157]. However, concerns relating to the cost of constructing LNG facilities in WA, highlighted by a further increase in construction costs for Chevron's Gorgon LNG facility from US$52 to US$54 billion[158], may affect investment decisions for some of these potential LNG projects.

Table 20 – 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	Unknown	Offshore/Onshore	Unknown
Gorgon Train 4	Chevron	5.2	Onshore	Anticipated to be 2014 or later#
Wheatstone Expansion	Chevron	8.6	Onshore	Anticipated to be 2014 or later
Browse	Woodside	12*	Anticipated to be Offshore^	Anticipated to be between mid-2015 or later%
Bonaparte	GDF Suez or Santos	2	Offshore	Anticipated to be 2014 or later
Scarborough	ExxonMobil	6 or 7**	Anticipated to be Offshore**	Anticipated to be 2014 or later**
WA LNG export capacity under consideration		**~38.1**		

Source: Respective corporate websites, DSD (2013), and Reuters (2013b). **Note:** Caldita-Barossa is not considered as Santos has announced it will to be used to backfill Darwin's LNG, see Australian Financial Review (AFR) (2011). At the time of this report, entities that own the Poseidon, Equus and Thebe gas fields located offshore have not publicly stated their intentions. *See the Woodside (2012d). **Although project proponents have indicated a FLNG development is highly likely, this is still being evaluated. See comments made by Mr. Luke Musgrave, to the WA Parliament inquiry into the economic implications of FLNG http://www.parliament.wa.gov.au/Parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/CC8120188033DB0548257C0F0017CF4B/$file/20131021+Exxon+Mobil+21+October+2013+Final+Transcript+WEB.pdf, accessed 20 December 2013. According to the West Australian (2013l), the Scarborough project has acquired environmental approval from the Commonwealth Government. ^According to the Woodside (2013), the Browse JV partners have selected FLNG as the basis for developing the Browse gas fields located in WA. #According to the West Australian (2013k), the fourth LNG train for the Gorgon project will not be decided until 2014 due to ongoing difficulties with the existing Gorgon project. %According to the Australian (2013c), it may be up to five years before a final investment decision on Browse.

8.4. International LNG Demand Outlook

The international outlook for gas consumption remains relatively unchanged for the 2014 to 2023 period from the July 2013 GSOO. LNG represents approximately one third of the total international gas market, and international LNG is expected to grow faster than pipeline gas during the same period. For a more detailed overview of the international LNG market, please refer to the July 2013 GSOO.

A summary of recently completed international studies provided in Table 21 suggests international gas consumption will increase by 1.6% to 2.6% per annum in the 2014 to 2023 period, while the LNG market is expected to grow by approximately 22.5% to 33.9% per annum in the same period.

Table 21 – Projected International Gas Growth – A Selection of Reports

Report	Time Period	Projected Annual International Gas Consumption (pipeline and LNG) Growth (%)	Projected Annual LNG Growth (%)
BP's Energy Outlook 2035 (2014)	2011 — 2035	2.0	3.9

[157] DSD (2012) lists potential LNG projects that are being considered.
[158] See the Australian (2013d), *Chevron lifts Gorgon cost to $59bn*, http://www.theaustralian.com.au/business/mining-energy/chevron-lifts-gorgon-cost-to-59bn/story-e6frg9df-1226781401181, 12 December 2013.

BREE (2013), Resources and Energy Quarterly, September 2013 (citing IEA's 2013 Medium-term Gas Market Report figures)	2012 – 2018	1.8	Not provided
Energy Information Administration's (2013b) International Energy Outlook	2009 – 2040	1.7	Not provided
ExxonMobil's (2013) The Outlook for Energy: A View to 2040	2010 – 2040	1.7	Not provided
International Energy Agency's (2013b) World Energy Outlook	2011 – 2035	1.6^	Not provided
Institute of Energy Economics Japan (IEEJ) (2013) Asia/World Energy Outlook 2013	2011 – 2040	1.9**	2.9**
OPEC's (2013) World Oil Outlook	2010 – 2035	2.4	Not provided
Royal Dutch Shell's (2013) New Lens Scenarios – A shift in Perspective for A World in Transition	2010 – 2040	2.6*	Not provided
Statoil's (2013) Energy Perspective	2012 – 2040	1.6^^	2.5%

Source: International gas growth projections are extracted or estimated from the identified reports. **Note:** All data on the table have been updated from the July 2013 GSOO except the shaded studies. *Although Shell's report provided gas projections to 2060, only figures for the period 2010 to 2040 were used. ^Data acquired from Interfax (2013) *Natural Gas Daily*, 13 November 2013. ^^StatOil's report forecasts international gas growth is expected to be 3% per annum in 2014-2018. %This is only an estimate inferred from the document.

Gas consumption growth in Asia is expected to be stronger, anticipated to almost triple over the period from 2011 to 2040 with China and India anticipated to grow at 4.5% and 2.7% per annum over the 2011 to 2040 period, respectively[159]. The projected growth prospects for Asia Pacific LNG demand are grounded on the view that:

- major LNG consumers, such as Japan, South Korea and Taiwan will remain the largest consumers of gas, but face slowing growth rates; while
- China and India will drive growth in gas demand, increasing their usage of gas in power generation, industrial and residential consumption due to the rapid urbanisation, motorisation, economic development, government reforms and energy policies of these countries.

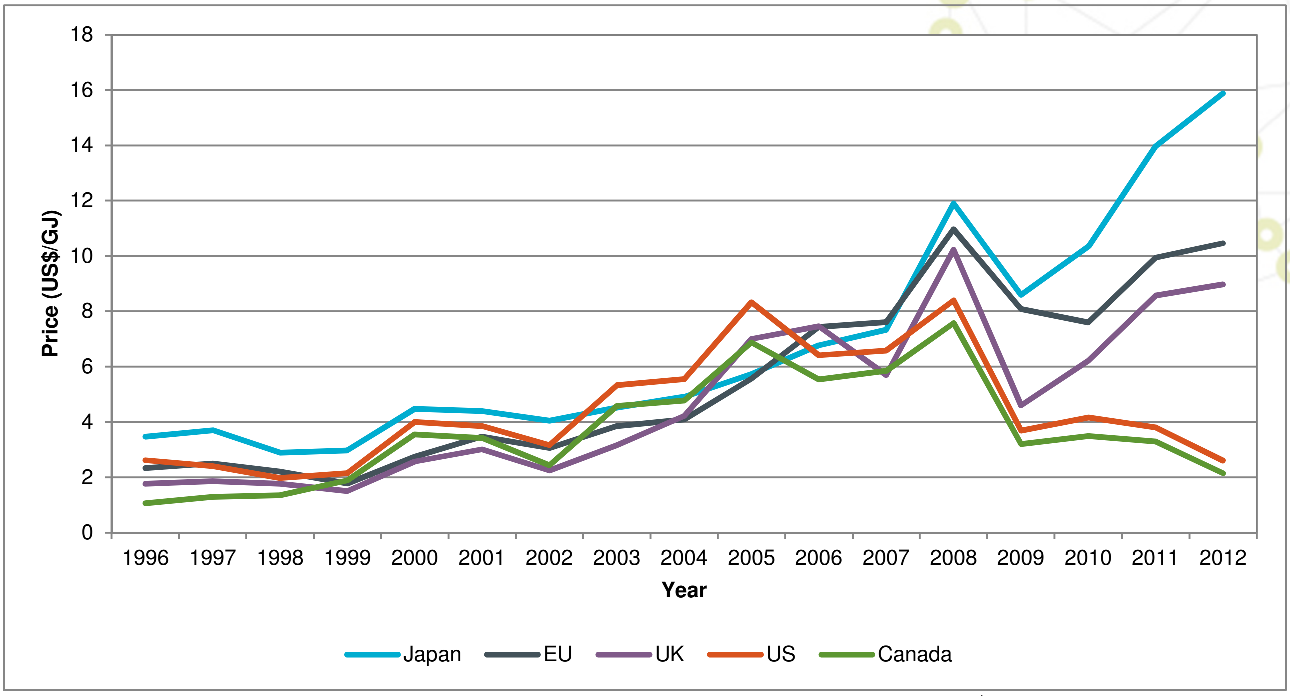
In addition, new international shipping standards and the potential development of LNG storage bunkers are anticipated to further increase demand for LNG exports. Potential European Union (EU) regulations and improved emission standards from the International Maritime Organisation[160] are anticipated to be in place by 2016. New marine emission control areas located in the Baltic Sea, North Sea, North America and the US Caribbean are also likely to hasten the adoption of LNG as a fuel for ships servicing these areas[161].

The 2012 Lloyd's Register report also identifies potential LNG bunkering locations internationally to encourage the use of LNG in international shipping[162].

Price differentials between Japanese LNG prices and gas prices for other LNG importing regions will also continue to drive the expansion of LNG supply to the Asia Pacific region[163]. Figure 50 shows international gas prices over the period from 1996 to 2012.

[159] See IEEJ (2013f), *Asia/World Energy Outlook 2013*, http://eneken.ieej.or.jp/data/5331.pdf, accessed 21 January 2013.
[160] The improved emission standards refer to Annex VI amendments (Tier II and III) to the International Maritime Organisation's International Convention on the Prevention of Pollution from Ships that outlines ship pollution rules internationally and other related regulations such as interim codes such as MSC-285(86) for ship fuels. In short, Tier II standards apply internationally, while Tier III standards apply in the new marine emission control areas.
[161] See Det Norske Veritas (DNV) (2010), LNG Update No 1. 2010, Baltic Sea, http://www.dnv.com/industry/maritime/publicationsanddownloads/publications/updates/lng/2010/01_2010/index.asp, accessed 28 January 2014.
[162] Lloyd's Register (2012), *LNG Bunkering Infrastructure Study*, http://www.lr.org/Images/LR_LNG%20bunkering%20infrastructure%20study_tcm155-237162.pdf, accessed 7 November 2013.
[163] As the largest international importer of LNG, Japanese LNG prices are a good benchmark for Asia Pacific LNG prices.

Figure 50 – International Gas Prices (nominal) by Region, 1996 – 2012



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

The following sections provide an update on countries that are likely to drive growth in international LNG demand, as well as consideration of the risks to LNG demand for the 2014 to 2023 period.

8.4.1. Japan

Since the Fukushima Daiichi nuclear accident in 2011, Japan has temporarily shut down most of its 50 nuclear power facilities in a bid to ensure the safety of all remaining facilities. Prior to the accident, nuclear energy in Japan provided approximately 30% of its power generation[164]. Following the accident, in September 2012 the Japanese Government pledged to increase nuclear safety by establishing the Nuclear Regulation Authority (of Japan) and promised to phase out all nuclear powered electricity generation by 2040[165]. The current Japanese government subsequently decided to reverse its total phase out decision in January 2013, however the fate of nuclear power in Japan remains unclear[166].

Since the July 2013 GSOO, Japan has halted operations at its last nuclear powered facility[167] and has become even more reliant on oil and gas-fired generation to power its economy. The Nuclear Regulation Authority released new safety regulations for nuclear powered electricity generators on 8 July 2013 and has proposed a nuclear safety review period shorter than six months[168]. According to the Institute of Energy Economics Japan (IEEJ), four power companies have applied to Japan's Nuclear Regulatory Authority to review 12 nuclear powered facilities under the new regulations, but it remains unclear when these Japanese nuclear powered electricity generators will be allowed to restart[169].

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[164] See World Nuclear Association (2013), *Nuclear Power in Japan*, http://www.world-nuclear.org/info/Country-Profiles/Countries-G-N/Japan/, accessed 7 March 2013 for a breakdown of Japan's nuclear sector.

[165] See ABC News (2012), *Japan to phase out nuclear power by 2040*, http://www.abc.net.au/news/2012-09-14/japan-to-phase-out-nuclear-power/4262744, accessed 20 February 2013. This is also outlined in Japan's Ministry of Economy, Trade and Industry's (METI) 2011 Annual Report on Energy (also known as the Energy White Paper 2011), see http://www.meti.go.jp/english/report/downloadfiles/2011_outline.pdf, accessed 20 November 2013, and following the announcement released in October 2012.

[166] The Guardian (2013), *Japan seeks to reverse its commitment to phase out nuclear power*, http://www.guardian.co.uk/environment/2013/jan/11/japan-reverse-nuclear-phase-out, accessed 20 February 2013. METI's Japan's Financial Year 2012 Annual Report on Energy suggests the zero-nuclear policy is being reviewed, see http://www.meti.go.jp/english/report/downloadfiles/2013_outline.pdf, accessed 20 November 2013. IEEJ (2013) and the Economist (2013), *Japan's Nuclear Future – Don't Look Now*, April 20th 2013 Issue suggest otherwise.

[167] See Bloomberg (2013h), *Shutdown of Japan's Last Nuclear Reactor Raises Power Concerns*, http://www.bloomberg.com/news/2013-09-16/shutdown-of-japan-s-last-nuclear-reactor-raises-power-concerns.html, accessed 22 October 2013.

[168] See IEEJ (2013c), *e-Newsletter No. 17*, http://eneken.ieej.or.jp/en/jeb/130712.pdf, accessed 22 October 2013.

[169] IEEJ (2013b), *e-Newsletter No 16*, August 16, 2013, http://eneken.ieej.or.jp/en/jeb/130816.pdf, accessed 5 November 2013. The power stations are

In a bid to reduce electricity generation costs, several Japanese regional power companies are anticipated to start up new gas-fired electricity generators by the end of 2014 to increase the reserve margin and reduce the reliance on oil-fired generators[170].

In a bid to reduce LNG prices paid by Japan and improve market transparency in the Asia Pacific LNG market Japan, through the IEEJ, has established a multilateral joint study group on LNG[171]. Japan recently hosted the second LNG Producer-Consumer Conference in September 2013 (with the third scheduled for 2014) with the aim of encouraging discussions between buyers and sellers of LNG to improve transparency and the sustainability of the LNG market in the Asia Pacific region. At the conference, Japan announced it had commenced bilateral studies into joint purchasing with commercial firms and joint studies with Europe and India into the pricing of LNG[172].

With the continued shutdown of nuclear-fired electricity generation, Japan is anticipated to remain more reliant on LNG imports for electricity generation. However, any changes to Japanese nuclear policy and the timing of nuclear facility restarts is likely to significantly impact the international LNG market and LNG exporting countries such as Australia, and especially WA that exports most of its LNG to Japan.

8.4.2. China

The outlook for Chinese gas demand remains bullish, with BREE forecasting growth of 12% per annum to 2018, more than doubling China's 2012 consumption[173]. The 12th Five Year Energy Development Plan and the 12th Five Year Plan for the Nationwide Development of City Gas for the period 2011 to 2015 remain the key energy policies of China.

These policies establish ambitious targets for the country's energy mix for 2015 that are biased towards increasing gas consumption[174]. In addition, China's growing concerns about the air quality in major cities have coincided with the signalling of the introduction of a new environmental taxation system (carbon tax) before the end of 2015[175]. China's official goal is to reduce carbon emissions by 40% to 45% from 2005 levels by 2020[176], suggesting the country will seek to reduce coal-fired generation.

Although Chinese gas demand is anticipated to be the primary driver for growth in international gas demand, China intends to supply some of this future gas demand indigenously. In 2012, China set itself ambitious targets of producing 6.5 Bcm of shale gas annually by 2015 and between 60 and 100 Bcm per annum by 2020. This was outlined in China's Shale Gas Development Plan for 2011 to 2015[177]. In addition, China is currently developing offshore gas fields in the South China Sea to meet this target[178]. While China is unlikely to meet this target[179], meeting a proportion of this target remains a distinct possibility[180].

Tomari, Takahama, Ohi, Ikata, Genkai and Sendai nuclear units, mostly located towards the west of the Japanese islands away from any potential tsunamis and earthquake faults.

170 Reuters (2013d), *Japan on gas, coal power building spree to fill nuclear void*, http://www.reuters.com/article/2013/10/16/us-japan-power-outlook-idUSBRE99F02A20131016, accessed 22 October 2013.

171 See IEEJ Press Release (2013), Multilateral Joint Study Group on LNG to be established, http://eneken.ieej.or.jp/en/press/press130910.pdf, accessed 5 November 2013.

172 See IEEJ (2013d), *e-Newsletter No 23*, http://eneken.ieej.or.jp/en/jeb/131015.pdf, accessed 2 December 2013.

173 See BREE (2013h*), Resources and Energy Quarterly*, September 2013, World Gas Consumption, http://www.bree.gov.au/publications/resources-and-energy-quarterly, accessed 30 November 2013.

174 British Chamber of Commerce in China (2011), *China's Twelfth Five Year Plan (2011 – 2015) - the Full English Version* http://www.britishchamber.cn/content/chinas-twelfth-five-year-plan-2011-2015-full-english-version, accessed 19 November 2013.

175 See the Australian (2013b), *China to tax carbon by 2015*, http://www.theaustralian.com.au/national-affairs/china-to-tax-carbon-by-2015/story-fn59niix-1226238633181, accessed 29 April 2013. Air pollution is a significant problem in China, according to Fortune (2013), *Fracking Comes to China*, Fortune Magazine, 29 April 2013, where air pollution in Beijing and Shanghai has reached several hundred times above the safe level.

176 Bloomberg (2013c), *China Sticks to Carbon-Intensity Target, Dismisses CO_2 Cap*, http://www.bloomberg.com/news/2013-06-04/china-sticks-to-carbon-intensity-target-while-dismissing-co2-cap.html, accessed 22 October 2013.

177 According to CSIS (2012), *Prospects for Shale Gas Development in Asia, Examining Potential and Challenges in China and India*, http://csis.org/files/publication/120824_Nakano_ProspectsShaleGas_Web.pdf, accessed 21 February 2013, China plans to scale up shale gas exploration during the period of the 13th Five Year Plan (2016-2020). Fortune (2013) reports the 12th Five Year Plan originally had a goal of 230 Bcm by 2015 and at least 2.2 Tcf by 2020.

178 See Wall Street Journal (2013b), *China Prepares to Open Its First Deep-Water Gas Project*, 14 November 2013, http://online.wsj.com/news/articles/SB10001424052702304672404579180991007342138, accessed 18 November 2013.

179 Reuters (2013e), *China back to drawing board as shale gas fails to flow*, http://www.reuters.com/article/2013/09/05/china-shale-idUSL4N0GY23420130905, accessed 22 October 2013.See Interfax (2014), *China losing sight of 2015 supply target*, Volume 4, Issue 12, accessed 21 January 2014. A presentation by the New Energy division of Bloomberg presented credible results on China's shale industry at the Singapore International Energy Week 2013 on 1 November 2013 suggesting China is very unlikely to meet its unconventional gas targets.

180 According to Bloomberg (2013), *China's Shale Gas No Revolution as Price Imperils Output: Energy*, 19 February 2013 http://www.bloomberg.com/news/2013-02-19/china-s-shale-gas-no-revolution-as-price-imperils-output-energy.html, accessed 19 November 2013.

Since the July 2013 GSOO, part of China's increasing gas demand has already been met by emerging gas producers such as Myanmar, Turkmenistan and Kazakhstan[181]. China's proximity to Russia and Tajikistan suggests some of China's growing gas demand could also be met by these neighbouring gas rich countries. The recent approval by a Russian parliamentary committee to allow the expansion of Russian LNG exports has increased the likelihood of China receiving more LNG from Russia. Heads of Agreement were recently reached between Yamal LNG, a JV between OAO Novatek and France's Total, and China National Petroleum Corporation (CNPC) for a 15-year supply contract of no less than three Mtpa of LNG. This agreement along with an additional agreement for CNPC to purchase a 20% equity share in Yamal LNG was concluded on 5 September 2013 and has been approved by the Russian Government[182].

Additional cross-country pipelines connecting Russian gas-producing fields located in eastern Europe, Siberia and the Russian Far East to China's gas transmission network located just across the border may also be a possibility.

China's gas consumption for the 2014 to 2023 period will also depend on its ability to receive seaborne LNG shipments. At the time of this report, China has nine operational LNG regasification facilities[183] with four new regasification facilities under construction; the Beihai (Guangxi), Diefu, Hainan and Qingdao LNG facilities. Two of the facilities under construction (Beihai and Qingdao) are scheduled to be completed in 2014 and the remaining two (Hainan and Diefu) in 2015[184].

Although China's demand is expected to grow significantly due to an increase in gas importation infrastructure, changes to tax incentives for gas infrastructure[185] and other Government projects[186], it is unclear whether the majority of gas consumption growth in China will be met by gas pipelines or LNG imports from countries such as Australia. BREE reports that Australia's share of total LNG imports to China shrank from approximately 31% in March 2011 to 18% in September 2013, despite China's LNG imports almost doubling from 2.3 Mt in March 2011 to 4.6 Mt in September 2013[187].

8.4.3. India

As the world's second most populous country, India is also anticipated to increase its gas consumption in the 2014 to 2023 period[188]. At the time of this report India is reliant on foreign imports for approximately 80% of its total energy requirements, with volumes from its declining domestic gas fields unable to satisfy domestic demand.

In a bid to improve gas allocation and encourage investment in meeting gas demand, the Indian Government reduced subsidies for domestic buyers, embarked on gas market reform, started gas exploration initiatives to open oil and gas exploration areas to private investment, approved LNG regasification facilities and

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According to EIA (2011), *World Shale Gas Resources - An Initial Assessment of 14 Regions outside the United States*, http://www.eia.gov/analysis/studies/worldshalegas/, accessed 26 February 2013, China also holds approximately 1,275 Tcf of shale resources, approximately 3.2 times the amount of shale resources estimated to be in Australia.

[181] Reuters (2013f), *Myanmar gas pipeline complete but cites China delays*, http://www.reuters.com/article/2013/06/12/myanmar-china-energy-idUSL3N0EO0M120130612, accessed 22 October 2013. Platts (2013), China, Kazakhstan complete first stage of new gas pipeline, http://www.platts.com/latest-news/natural-gas/singapore/china-kazakhstan-complete-first-stage-of-new-27386568, accessed 22 October 2013.

[182] See Reuters (2013g), *Russian government committee approves LNG exports liberalisation*, http://www.reuters.com/article/2013/10/29/russia-lng-exports-idUSL5N0IJ19U20131029, accessed 20 November 2013, See OAO Novatek (2013), *Conclusion of heads of agreement on LNG supply with CNPC*, http://www.novatek.ru/en/press/releases/index.php?id_4=793, accessed 12 November 2013 and Interfax (2013f), *Russia approves CNPC's Yamal stock purchase*, http://interfaxenergy.com/natural-gas-news-analysis/russia-and-the-caspian/russia-approves-cnpcs-yamal-stock-purchase/, accessed 17 December 2013.

[183] The operational LNG regasification facilities are Dalian LNG, Fujian LNG, Guangdong LNG, Jiangsu Rudong LNG, Tangshan (Caofeidian), Tianjin (Tangshan) LNG, Tianjin Floating Storage Regasification Unit, Zhejiang Ningbo LNG and Zhuhai LNG terminals. See http://www.globallnginfo.com/World%20LNG%20Plants%20&%20Terminals.pdf, accessed 21 January 2014 and Platts (2014), *China's CNOOC receives first LNG cargo at Tianjin FSRU*, http://www.platts.com/latest-news/natural-gas/singapore/chinas-cnooc-receives-first-lng-cargo-at-tianjin-27666510, accessed 21 January 2014.

[184] Hydrocarbon Asia (2012), *LNG Terminals in China and Related Developments*, Jan-Mar 2012, http://www.hcasia.safan.com/mag/hca0112/r06.pdf, accessed 7 March 2013 outlines the upcoming regasification facilities. The Zhejiang facility outlined in the article was already operational in 2012.

[185] See Interfax (2013d), *China broadens the scope for tax refund for gas import projects*, 3 December 2013.

[186] An example of such projects is Guangzhou's intention to build 126 LNG stations by 2020 on top of the existing seven stations, see http://interfaxenergy.com/natural-gas-news-analysis/asia-pacific/guangzhou-to-build-126-lng-stations-for-vehicles-by-2020/, accessed 4 December 2013.

[187] See BREE (2013d, 2013e), *Westpac–BREE China Resources Quarterly*, August and November 2013 editions, http://www.bree.gov.au/publications/crq/index.html, accessed 18 November 2013.

[188] BREE (2013 and 2013c) expects India's LNG demand to grow at 39% in 2013, then at an average of 4% per annum for the period 2014 to 2018.

permitted foreign investment and ownership of LNG facilities[189]. The Indian Government also permitted gas retail competition to industrial customers on a limited basis.

In September 2012, the Indian Government announced the immediate reduction of subsidies for diesel and liquefied petroleum gas for residential use, while signalling the intention to further reduce government subsidies for other fuels such as kerosene and petrol that are competing with gas[190]. The continued reduction in fuel subsidies for substitute fuels and the expansion of LNG import infrastructure will drive increases in gas demand in India.

The Oxford Institute for Energy Studies suggests India may face significant challenges in securing sufficient gas supply to meet future demand, despite expanding its LNG import infrastructure from 15 Mtpa to 25 Mtpa by the end of 2013[191]. There is currently a lack of cross-country gas pipelines supplying gas to India meaning the country relies almost exclusively on seaborne LNG to meet its growing gas demand[192]. Given the delays experienced in constructing previous LNG import infrastructure in India, future gas demand may be inhibited if similar delays to planned infrastructure are experienced.

8.4.4. South Korea

South Korea remains the second largest importer of international LNG, accounting for approximately 15.2% of the international LNG market in 2012[193]. As the third largest importer of Australian LNG, South Korea relies on LNG imports to satisfy approximately 98.7% of its total natural gas consumption[194]. Similar to Japan, South Korea is not connected to any international gas pipelines (due to a demilitarised zone with North Korea) and relies almost exclusively on seaborne shipments of LNG for its domestic consumption.

According to statistics from the Korea Energy Economics Institute, gas usage in South Korea is rapidly expanding due to increasing demand in the residential and commercial sectors (growing from 3.9 Mtpa in 1992-1993 to 39.2 Mtpa in 2012-2013)[195]. As a result, South Korea increased its LNG imports from 3.8 Mtpa in 1992-1993 to approximately 39.1 Mtpa in 2012-2013. BREE forecasts gas consumption in South Korea to grow from 38 Mtpa in 2013 to 49 Mtpa in 2018[196].

8.5. International LNG Supply Outlook

While section 8.4 outlines continuing rapid growth in international gas demand for the 2014 to 2023 period, there are risks to this positive outlook. The time required to construct gas supply infrastructure to service the international LNG market remains lengthy[197]. As such, most of the risks outlined in this section are perceived as longer-term LNG supply risks, with the exception of Singapore.

LNG export volumes from existing WA LNG facilities and those under construction are predominantly locked into long-term LNG supply contracts. Most of these contracts are understood to contain take or pay minimum and maximum quantity clauses, with some containing restrictive destination clauses that shift volume risks to the LNG importer. Although these contractual clauses significantly reduce the risks for facilities currently under construction in WA, these LNG supply contracts are not totally immune to potential market shifts in the 2014 to 2023 period, especially towards the end of the period[198].

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[189] These are called the New Exploration Licensing Policy 1998, see Directorate General of Hydrocarbons (of India), http://www.dghindia.org/EandPGovernanceInIndia.aspx, accessed 21 January 2014.

[190] See Financial Times (2010), *Indian fuel reform*, http://www.ft.com/intl/cms/s/0/44586cac-8930-11df-8ecd-00144feab49a.html#axzz2K6A3pXfy, accessed 20 February 2013.

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

[192] 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) 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 2014 to 2023 period.

[193] BP (2013). According to BREE (2013 and 2013c), South Korea is expected to grow at 6% for 2013 and 5% per annum for the period 2014 to 2018.

[194] The only known gas producing field in South Korea is the Donghae gas field located in the Ulleung Basin.

[195] KEEI (2013), *Korea Energy Statistics Information System*, http://www.keei.re.kr/main.nsf/index.html, accessed 6 October 2013.

[196] Although South Korean gas demand is forecasted to increase by BREE (2013 and 2013c), gas demand in South Korea is typically seasonal, peak demand requirements are driven by heating in winter.

[197] A presenter at the 2013 IHS Energy Insight Symposium on 13 May 2013 in Perth suggested the minimum timeframe required to build an onshore LNG liquefaction processing facility has increased from five years to approximately 5.5 years.

[198] LNG contracts typically contain renegotiation triggers when certain conditions are met.

Potential shifts in the coming years include increased volume in the short-term LNG market, a looming international glut from North American LNG facilities if LNG export applications are granted, the relative cost of constructing LNG terminals in Australia, potential changes to Asia Pacific LNG pricing and the emergence of unconventional gas.

These risks may compel existing LNG importers with WA LNG contracts to take only minimum contracted quantities, enforce price re-opener clauses (if LNG prices vary significantly) or seek dispensation on existing contracts. Some of these risks may have already delayed or cancelled planned Australian projects that have not obtained financial approvals[199]. Australian projects are considered to be more expensive when compared to similar projects in other regions[200].

The following sections provide updates since the July 2013 GSOO to the risks posed by other LNG exporting countries and changes to the Asia Pacific LNG market, the predominant export market for WA's LNG.

8.5.1. Qatar

Qatar is increasingly diversifying its customer base, which was previously weighted towards the European market[201]. Since the GFC, European gas consumption and LNG prices in the Atlantic region have weakened, which has led Qatar to sell LNG into the higher priced Asia Pacific region, focusing on Japan, India, South Korea, Thailand and Singapore[202]. It is understood that Qatar's flexible LNG supply contracts with European purchasers allowed Qatar to quickly shift its international focus to the Asia Pacific region increasing its LNG exports to the region from 40% (2010) to 70% (2013) of total Qatari LNG exports[203]. The change in focus towards Asia Pacific customers may affect WA's LNG exports to the region.

Qatar currently has a moratorium until 2015 on increasing LNG supply to the international market. It is currently considering how to optimise existing production of the northern gas field and estimate the adequacy of its gas reserves[204]. Any unexpected changes to the moratorium will change international LNG supply dynamics in the 2014 to 2023 period. Interfax suggests this moratorium may not be lifted until 2019, unless Iran rapidly expands it gas production[205].

In addition to the moratorium, Qatar has yet to eliminate the bottlenecks in its existing LNG export facilities. It is understood to be capable of increasing LNG export capacity by 15% through optimisation of its LNG export facility once the moratorium is lifted[206].

8.5.2. North America

The domestic North American gas market is currently oversupplied, due to a significant increase in supply stemming from shale gas discoveries in the US. This has led to a sharp reduction in gas prices at the Henry Hub in 2012 and 2013[207], although prices have begun to increase in recent months. In a bid to improve profitability, American and Canadian gas companies are seeking to export excess gas as LNG to Asia Pacific customers to realise the higher gas prices paid by Asia Pacific gas importers[208]. In addition, large

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[199] At the time of this report, potential LNG export projects in Australia in advanced stages that have not achieved final investment decision status include; LNG Limited's Fisherman's Landing LNG, Browse LNG, Bonaparte FLNG, PTTEP FLNG, Timor Sea LNG and planned expansions to the Pluto, Gorgon, Wheatstone projects.
[200] For a comparison of international LNG capital expenditure costs see Deutsche Bank (2012), McKinsey (2013) and Credit Suisse Global Equity Research (2012), *Global LNG Sector Update 7*, June 2012, https://research-and-analytics.csfb.com/docView?language=ENG&format=PDF&document_id=977153251&source_id=em&serialid=lLnIHOuVvGf%2BeB6YKN9IA%2Bot%2FumB3JhDoxYEUUEK08s%3D, accessed 7 November 2013.
[201] Bloomberg (2013i), *Qatar LNG Spot Sales to Fall 40% by 2014, QNB Says*, http://www.bloomberg.com/news/2012-12-08/qatar-lng-spot-sales-to-fall-40-by-2014-qnb-says.html, accessed 20 November 2013.
[202] This information was presented by QatarGas at the 2nd Gas Asia Summit, 30-31 October 2013, Singapore International Energy Week.
[203] This information was presented by QatarGas at the 2nd Gas Asia Summit, 30-31 October 2013, Singapore International Energy Week.
[204] This information was presented by QatarGas at the 2nd Gas Asia Summit, 30-31 October 2013, Singapore International Energy Week.
[205] See Interfax (2013c), *Time to blow the whistle on the North Field Moratorium?,* Natural Gas Daily, Volume 3, Issue 219, 12 November 2013. This is as Qatar's North Dome field and Iran's South Pars gas fields are essentially connected.
[206] Information was provided by a source from within QatarGas.
[207] The average Henry Hub price for gas ranged between US$1.95/MMBtu to US$5.83/MMBtu or approximately US$1.83/GJ to US$5.50/GJ between January 2010 to December 2013. See EIA (2014), *Henry Hub Natural Gas Spot Price*, http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm, accessed 21 January 2014.
[208] According to Deloitte (2013*), Exporting the American Renaissance: International Impacts of LNG Exports from the United States*, http://www.deloitte.com/view/en_US/us/Industries/oil-gas/50cb7218eee8b310VgnVCM1000003256f70aRCRD.htm, accessed 20 February 2013, estimated LNG shipping and liquefaction costs are approximately US$5.70/GJ, while HSBC Global Research (2013), *Shale Oil and Gas, US revolution, global evolution*, September 2013, https://www.research.hsbc.com/midas/Res/RDV?p=pdf&key=1Qfc27A6P0&n=386783.PDF, accessed 12 November 2013 and

LNG purchasers such as Tokyo Electric are also exploring the possibility of imports from North America as a means to lower their LNG import costs[209].

While the potential to export LNG is significant, Canada and the US have government policies that require export licences for gas sales to countries with which they do not have a Free Trade Agreement (FTA). This prevents direct exports of North American LNG to many gas consuming countries[210]. However, US Government legislation does not prevent the re-export of LNG imported from other countries[211].

This situation may quickly change as the US Department of Energy (DOE) is currently assessing LNG export applications. In December 2012, the DOE released the two studies commissioned to analyse the impact of LNG exports on the US economy[212]. NERA Consulting's report finds that, in each of the market scenarios tested, net economic benefits increased with the level of LNG exports, with a slight increase in US domestic gas prices being projected[213,214].

Analysis by the Energy Information Administration (EIA) also finds LNG exports from the US will lead to higher prices for the domestic US market[215]. At the time of this report, the studies have been released for public consultation and the responsible departments are considering the implications of allowing international LNG exports[216].

Table 22 indicates the quantity of LNG from the US that could become available post-2015 if all of the requested non-FTA export licenses are approved[217].

Table 22 – Applications to Export LNG in the United States, as at November 2013

US Company	Estimated Capacity (Bcf/d)	Estimated Capacity (Mtpa)	FTA Applications	Non-FTA Applications	Company Announced Commencement Date[&]	Off-take
Sabine Pass Liquefaction	2.2	17.3	Approved	Approved (May 2011)	2015	~20 Mtpa to BG Group, Gas Natural Fenosa, Kogas, GAIL, Total and Centrica*
Freeport LNG Expansion and FLNG Liquefaction	1.4	11.0	Approved	Approved (May 2013)	2017/2018	~ 13.2 Mtpa to Osaka Gas, Chubu Electric, BP Global, TBD*

IEA (2013), *World Energy Outlook 2013* reports this is approximately US$4.00/MMBtu to US$9.00/MMBtu (or US$3.77/GJ to US$8.50/GJ). With Asia Pacific LNG prices remaining high at around US$15-16/GJ, there is a significant profitable opportunity for the US to export LNG to Asia Pacific.

209 See the Australian (2013f), *Japan raises US shale gas intake*, http://www.theaustralian.com.au/business/mining-energy/japan-raises-us-shale-gas-intake/story-e6frg9df-1226748532992, accessed 26 November 2013.

210 According to Ratner et al. (2013), *U.S. Natural Gas Exports: New Opportunities, Uncertain Outcomes*, US Congressional Service, CRS Report for Congress, R42074, April 8 2013, http://www.fas.org/sgp/crs/misc/R42074.pdf, accessed 1 May 2013, gas exports from the US require federal approval under section 3 of the *Natural Gas Act* (15 U.S.C 717b) with the DOE and the Federal Energy Regulatory Commission. There are no known gas export restrictions to FTA countries. Three LNG export facilities in the US (Sabine Pass LNG, Kenai LNG and Freeport LNG) have been approved to export LNG to non-FTA countries.

211 According to Ratner et al. (2013), there are currently seven companies that have permission (four are pending) to re-export LNG cargoes from foreign countries. According to the DOE's Quarterly Gas Imports and Exports reports, http://energy.gov/fe/listings/natural-gas-imports-and-exports-quarterly-reports, accessed 20 November 2013, and GIIGNL (2013), *The LNG Industry 2012*, http://www.giignl.org/fr/home-page/publications/, accessed 9 May 2013, in 2012, US companies have already re-exported approximately 0.41 million tonnes of LNG (or 18.8 Bcf) to other countries in Q3 of 2013.

212 The US DOE studies on LNG exports, namely the EIA's analysis (2012) and NERA Consulting (2012) report, http://energy.gov/fe/services/natural-gas-regulation/lng-export-study, accessed 13 November 2013.

213 The NERA (2012) study for DOE referred to above also indicated large US consumers of gas may be hurt by LNG exports due to price rises. However, a report by the Bipartisan Policy Centre (2013) finds otherwise, stating that LNG exports are unlikely to lead to US domestic gas price rises.

214 A report by the Bipartisan Policy Centre (2013), *New Dynamics of the U.S. Natural Gas Market*, 20 May 2013, http://bipartisanpolicy.org/library/staff-paper/new-dynamics-us-natural-gas-market, accessed 30 November 2013, finds contrary results to NERA's (2012) study, that LNG exports are unlikely to lead to US domestic gas price rises.

215 The high export scenario examined in the EIA's (2012) analysis assumes exports are limited to 12 Bcf/day (approximately 80 Mtpa), which is significantly lower than all the projects under consideration.

216 The LNG export debate is active in the US capital. According to Ratner et al. (2013), several Bills have been introduced to the US House of Congress to consider expediting international LNG exports, S.192 and H.R. 580 – Expedited LNG for American Allies and H.R. 1189 and H.R. 1191 – American Natural Gas Security and Consumer Protection.

217 Despite the prospect of the US significantly contributing to international LNG supply, Credit Suisse Global Equity Research (2012) indicates US dry gas converted to LNG requires more processing as US gas is 'leaner' (lower heating or calorific value) than gas sourced from WA. Gas purchased from WA meets the Japanese city gas mandated calorific value. In addition, Moody's Investor Service (2013) US Energy Producers and Asian Buyers primary winners from potential US LNG exports, Press Release, 1 May 2013, suggests only four additional projects (in addition to Sabine Pass) are expected to be approved in the US. The projects that are likely to obtain approval are brownfield projects that already have infrastructure in place, do not require stringent environmental approvals and are backed by companies with at least investment grade balance sheets and experience in the international LNG business.

US Company	Estimated Capacity (Bcf/d)	Estimated Capacity (Mtpa)	FTA Applications	Non-FTA Applications	Company Announced Commencement Date[&]	Off-take
Freeport LNG Expansion and FLNG Liquefaction (2nd application)	1.8	14.2	Approved	Approved (November 2013)	Unknown	Contracts reported above
Lake Charles Exports	2.0	15.7	Approved	Approved (August 2013)	2018	~15 Mtpa to BG Group*
Carib Energy	0.04	0.3	Approved	Under Review	Unknown	None reported
Dominion Cove Point	1	7.9	Approved	Approved (September 2013)	2017	~4.6 Mtpa to Pacific Summit Energy (Sumitomo) and GAIL*
Jordan Cove Energy Project	2	15.7	Approved	Under Review	2018	~6 Mtpa Heads of Agreement with customers in Indonesia, India and an East Asian country[%%]
Cameron LNG	1.7	13.4	Approved	Under Review	2017/2018	~12 Mtpa tolling agreements with GDF Suez, Mitsubishi Corporation and Mitsui Co**
Gulf Coast LNG	2.8	22.0	Approval	Under Review	Unknown	None reported
Gulf LNG Liquefaction	1.5	11.8	Approved	Under Review	2018	None reported
LNG Development Company LLC (Oregon LNG)	1.25	9.8	Approved	Under Review	2017	None reported
SB Power Solutions	0.07	0.6	Approved	Not Applicable	Unknown	None reported
Southern LNG (Elba Island)	0.5	3.9	Approved	Under Review	2015	~2.5 Mtpa to Shell's International LNG portfolio
Excelerate Liquefaction Solutions	1.38	10.9	Approved	Not Applicable	2017	None reported
Golden Pass Products	2.6	20.5	Approved	Not Applicable	2018	~ 15.6 Mtpa commercial framework agreement with Qatar Petroleum International
Cheniere Marketing	2.1	16.5	Approved	Under Review	Unknown	Contracts reported in first row
Main Pass Energy Hub	3.22	25.3	Approved	Not Applicable	Unknown	~4 Mtpa conditional Agreement with Petronet LNG Limited^^
Cambridge Energy FLNG	1.07	8.4	Approved	Under Review	Unknown	None reported
Waller LNG Services	0.16	1.3	Approved	Not Applicable	2014	None reported
Pangea LNG	1.09	8.6	Approved	Under Review	2018	None reported
Magnolia LNG (ASX: LNG Limited)	0.54	4.3	Approved	Not Applicable	Unknown	~2 Mtpa tolling term sheet signed with Gunvor Group and ~2 Mtpa draft legally binding tolling agreement with Gas Natural Fenosa Group[%]
Trunkline LNG Export	2.0	15.7	Approved	Under Review	Unknown	None reported
Gasfin Development	0.2	1.6	Approved	Under Review	Unknown	None reported

US Company	Estimated Capacity (Bcf/d)	Estimated Capacity (Mtpa)	FTA Applications	Non-FTA Applications	Company Announced Commencement Date[&]	Off-take
USA						
Freeport-McMoRan Energy	3.22	25.3	Approved	Under Review	2017	None reported
Sabine Pass Liquefaction	0.28	2.2	Approved	Under Review	2018	Contracts reported in first row
Sabine Pass Liquefaction	0.24	1.9	Approved	Under Review	2018	Contracts reported in first row
Venture Global LNG	0.67	5.3	Approved	Under Review	Unknown	None reported
Advanced Energy Solutions	0.02	0.2	Approved	Not Applicable	Unknown	None reported
Argent Marine Management	0.003	0.0	Approved	Not Applicable	Unknown	None reported
Eos LNG	1.6	12.6	Approved	Under Review	Unknown	None reported
Barca LNG	1.6	12.6	Approved	Under Review	Unknown	None reported
Sabine Pass Liquefaction	0.86	6.8	Under Review	Under Review	Unknown	None reported
Delfin LNG LLC	1.8	14.2	Under Review	Under Review	Unknown	None reported
Magnolia LNG (ASX: LNG Limited)	1.62	12.8	Under Review	Under Review	2017	~2 Mtpa Tolling Term Sheet signed with LNG Holdings[%]
Annova LNG LLC	0.94	7.4	Under Review	Under Review	Unknown	None reported
Texas LNG LLC	0.27	2.1	Under Review	Under Review	2018	None reported
Total Applications Received	**45.74 Bcf/d non-FTA Applications**	**360.10 Mtpa**	**360.10 Mtpa FTA applications**	**215.29 Mtpa under review**		

Source: DOE, Applications received by the DOE/Fossil Energy to Export Domestically Produced LNG, http://energy.gov/sites/prod/files/2014/01/f6/Summary%20of%20LNG%20Export%20Applications.pdf, 31 December 2013, accessed 20 January 2014. LNG facilities that have applied for non-FTA exports are assumed to seek 'blanket' approvals from the DOE. *Approximately 2.2 Bcf/day of the liquefaction capacity of Sabine Pass Liquefaction facility has been committed to 20-year contracts for supply to BG Group, Gas Natural Fenosa, GAIL Limited, Kogas, Total and Centrica. See http://www.cheniereenergypartners.com/liquefaction_project/liquefaction_project.shtml, accessed 23 January 2014. Freeport LNG's capacity has also been committed to a 20-year tolling agreement with Osaka Gas and Chubu Electric. See http://www.freeportlng.com/PDFs/20120731_pr.pdf. Dominion Cove has 20-year service agreements with Pacific Summit Energy LLC, a US affiliate of Sumitomo Corp., and GAIL Global (USA) LNG LLC, a US affiliate of GAIL (India) Ltd. See http://www.ogj.com/articles/print/volume-111/issue-9c/general-interest/doe-approves-dominion-cove-point-lng.html.
**See Bloomberg (2013e), Sempra Energy, GDF SUEZ, Mitsubishi, Mitsui Sign Tolling Capacity, Joint-Venture Agreements for Louisiana Liquefaction Export, http://www.bloomberg.com/article/2013-05-16/avRpCHdJ4xa0.html, accessed 19 November 2013. Tepco has agreed to purchase 0.8 Mtpa from Mitsui, as noted in Tepco (2013) press release, ^See PRWeb (2013), United LNG and India's Petronet Sign Major LNG Supply Agreement, http://www.prweb.com/releases/2013/4/prweb10664141.htm, accessed 19 November 2013. See Bloomberg (2013f), *Exxon to Build $10B US LNG Export Plant with Qatar*, http://www.bloomberg.com/article/2013-05-09/a8xI1avmICuQ.html, accessed 19 November 2013.
[%]See LNG Limited Corporate Update, 9 December 2013, http://www.lnglimited.com.au/IRM/Company/ShowPage.aspx/PDFs/1958-74630114/CompanyUpdatePresentationDecember2013, accessed 10 December 2013.
[%%] Yahoo Finance (2013), http://finance.yahoo.com/news/veresen-provides-commercial-activity-jordan-205000876.html, accessed 19 November 2013. [&]Information from International Gas Union (IGU) (2013). [&&] See LNG Limited Corporate Update, 9 December 2013, http://www.lnglimited.com.au/IRM/Company/ShowPage.aspx/PDFs/1958-74630114/CompanyUpdatePresentationDecember2013, accessed 10 December 2013.

Since the July 2013 GSOO, three additional LNG export facilities have been conditionally approved (Lake Charles, Dominion Cove Point and Freeport Expansion) taking the total potential non-FTA LNG export capacity of the US to approximately 69.12 Mtpa by the end of 2023. In addition, LNG exports to the countries that already have FTAs with the US could commence in the near-term, once infrastructure is completed, until non-FTA export approvals are granted[218].

Canada is also considering several LNG projects, summarised in Table 23, which would facilitate the export of gas. In February 2013, Canada's National Energy Board (CNEB) granted an LNG export licence to

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

LNG Canada to export up to 24 Mtpa. This is the third approval granted for projects located on the west coast of Canada, totalling approximately 20 Mtpa, potentially increasing export capacity up to 36 Mtpa by the end of the 2014 to 2023 period[219]. While these projects have been granted licenses by the CNEB, uncertainty regarding the tax on LNG exports from the province of British Columbia is delaying these projects[220].

Table 23 – Approved and Potential Canadian LNG Projects, 2013

Facility	Estimated Capacity (Bcf/d)	Estimated Capacity (Mtpa)	Estimated/Target Start-up*	Status
Douglas Channel Energy	0.1	0.98	2015/2016	CNEB Approved
Kitimat LNG	0.7	5.51	2017	CNEB Approved
Goldboro LNG	1.3	10.23	2018	Unknown
LNG Canada	1.7	13.38	2019/2020	CNEB Approved
Pacific Northwest LNG	1.6	12.59	2018	Application Under Review
Prince Rupert LNG	3.9	30.70	2019/2020	Application Under Review
Woodfibre LNG	0.29	2.10	2017	Application Under Review
Jordan Cove LNG (Oregon, US)	1.55	12.20	2018	Application Under Review
Triton LNG	0.3	2.30	2017	Application Under Review
WCC LNG	3.81	30.00	2021/2022	Application Under Review
Aurora LNG	3.05	24.00	2018	Application Under Review
Kitsault LNG	2.6	20.00	2018	Application Under Review
Discovery LNG	Unknown	Unknown	2019	Proposed
Unnamed LNG project at Grassy Point (Woodside)	Unknown	Unknown	Unknown	Proposed
Total		**151.80 Mtpa** applied for approval (excluding Jordan Cove)		~**19.88 Mtpa** Approved

Source: Canadian National Energy Board (CNEB), http://www.neb-one.gc.ca/clf-nsi/rcmmn/hm-eng.html, accessed 20 November 2013. For all approved and pending applications see, http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/lngxprtlcncpplctns/lngxprtlcncpplctns-eng.html, accessed 20 January 2014. *Start-up dates are reported by IGU (2013) and Reuters (2013k).

While under the *US Natural Gas Act of 1938*, the US Government can decide whether US LNG exports are in US interests, this law may be contrary to Article XI of the World Trade Organisation's General Agreement of Trade and Tariffs[221]. If US regulators approve all existing gas export applications, up to an additional of 215.3 Mtpa[222] (on top of the 69.1 Mtpa that has already been approved in the US) may be supplied to the international LNG market towards the end of the 2014 to 2023 period, potentially creating a glut in international LNG supply[223]. This situation should be monitored as it has the potential to influence the pricing of existing and future LNG contracts for WA suppliers[224].

8.5.3. Russia

Russia remains the country with the greatest potential to significantly change the dynamics of Asia Pacific's LNG supply, due to its proximity to the three largest LNG consumers in the region. Since the July 2013 GSOO, Russian company OAO Novatek has concluded an equity share agreement with CNPC for the Yamal LNG project[225]. This suggests China has started diversifying its LNG sources on the international market.

[219] According to IEEJ (2013) and Reuters (2013) *Canada approves export license for Shell-led LNG facility*, http://www.reuters.com/article/2013/02/25/canada-lng-idUSL1N0BPB4E20130225, accessed 23 April 2013, the three projects that have been granted approval are LNG Canada (February 2013 – Project Partners - Shell, Kogas, Mitsubishi and PetroChina), Kitimat LNG (October 2011 – Chevron and Apache Corporation) and privately owned BC LNG Export Co-operative's project.
[220] See Interfax (2013), *Natural Gas Daily,* 13 November 2013. **Note:** 36 Mtpa capacity is for all three projects including expansions, initial construction commitments only approximately 19.9 Mtpa.
[221] See Reuters (2013h), *US ban on LNG exports would violate WTO rules – experts*, http://www.reuters.com/article/2013/01/31/usa-trade-lng-idUSL1N0AZMTU20130131, accessed 12 November 2013.
[222] Some gas export facilities may not be commercially viable if they do not obtain non-FTA export approvals and others may withdraw their applications.
[223] Note the total LNG export figures do not include speculative LNG projects in Canada.
[224] For a priority list of all proposed US LNG export applications, see http://energy.gov/fe/downloads/order-precedence-non-fta-lng-export-applications, accessed 6 November 2013.
[225] See Bloomberg (2013b), *Russia Hastens China Energy Pivot with Oil, LNG Supply Deals*, http://www.bloomberg.com/news/2013-06-21/russia-hastens-china-energy-pivot-with-crude-lng-supply-deals.html, accessed 12 November 2013.

Although Russia has only issued a single export license to date, to its government-owned entity Gazprom, and only exports approximately 14.8 Mtpa of LNG internationally, according to Reuters the Russian government has approved an LNG export law allowing other potential LNG projects to export internationally[226]. Reuters also states Russia intends to more than double its market share of international LNG by 2020, increasing from approximately 4.5% to at least 10%[227].

Bloomberg reports the Russian President has ordered the Russian Energy Ministry to fast-track the LNG export licenses[228]. This suggests that the potential Yamal project and OAO Rosneft's JV with ExxonMobil (Far East LNG) in Russia are likely to be awarded LNG export licenses in 2014 and may be capable of exporting LNG from Russia to the Asia Pacific region by the end of the 2014 to 2023 period.

8.5.4. Singapore

Singapore further progressed into a potential LNG hub for the Asia Pacific region with the commencement of the Singapore LNG (SLNG) terminal on 7 May 2013[229]. Although the new SLNG terminal currently only receives LNG imports to meet Singapore's electricity and gas needs, the expected completion of the expanded SLNG terminal to six Mtpa by the end of 2013[230] and the expected completion of the secondary shipping berth for the SLNG terminal in early 2014[231] will support regional LNG redistribution, LNG bunkering and the expansion of the LNG spot market in the Asia Pacific region.

The Energy Market Authority of Singapore (EMAS) also recently undertook consultation[232] on the utilisation of the LNG terminal for LNG re-exports to secure Singapore's position as a future LNG hub, by considering an LNG import framework, a multi-user terminal access code for the SLNG terminal and international LNG re-exports. EMAS has proposed LNG storage capacity for imports into Singapore above Singapore's gas requirements of three Mtpa may be used for re-exports of LNG cargoes internationally, by two or more approved LNG importers. However, this proposal is still open for public comments[233]. The desire to develop Singapore as an international LNG hub was reiterated in a speech from the Minister, Prime Minister's Office, Mr S. Iswaran at the 2nd Asia Gas Summit 2013.

Singapore's intention to develop its LNG expertise, coupled with its fuel bunkering and shipping expertise in the Asia Pacific region, is expected to cement Singapore's unique LNG position in the Asia Pacific market[234]. Its intention to develop as an LNG hub will be further strengthened given its FTAs with potential key LNG producers, suppliers and logistics countries such as Australia, China, the EU, India, Japan, Panama, South Korea, the US, the Association of South East Asian Nations, countries under the Trans-Pacific Strategic Economic Partnership (including Brunei Darussalam, Chile, New Zealand and Peru) and other countries under the Singapore-European Free Trade Association (Iceland and Norway).

At the time of this report, Singapore is negotiating further FTAs with Canada, Ukraine, Pakistan, Mexico and other countries, many of which are large gas producing and gas consuming countries[235]. It is also anticipated to complete FTAs with other European countries by the end of 2014[236] and Canada by the end of 2020[237,238].

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[226] Reuters (2013i), *Russia's Putin approves LNG exports for Gazprom's rivals*, http://www.reuters.com/article/2013/12/02/russia-lng-idUSL5N0JH0W420131202, accessed 3 December 2013.
[227] Reuters (2013j), *Russian government passes law to open up LNG exports*, http://www.reuters.com/article/2013/10/30/russia-lng-market-idUSL5N0IK1DI20131030, accessed 5 November 2013.
[228] Bloomberg (2013g), *Russia Liberalized LNG Exports Move Closer after Putin Orders*, http://www.bloomberg.com/news/2013-10-21/russia-liberalized-lng-exports-move-closer-after-putin-orders.html, accessed 5 November 2013.
[229] EMAS (2013), *Singapore's LNG terminal starts commercial operations*, http://www.ema.gov.sg/media/news_pdfs/5188a8c3e0169Singapore_s_LNG_Terminal_Starts_Commercial_Operations_-_7_May_2013.pdf, accessed 5 November 2013.
[230] SLNG Press Release (2011b), *Samsung C&T Corporation awarded contract for the Third LNG Storage Tank at Singapore's LNG Terminal*, http://www.slng.com.sg/UserFiles/Press/PressRelease_SamsungawardedcontractforthirdLNGstoragetankatS'poreLNGTerminal_21012011.pdf, accessed 6 November 2013.
[231] SLNG Press Release (2011), *SLNG awards EPC Contract for Secondary Berth Project*, http://www.slng.com.sg/UserFiles/Press/SLNGawardsEPCcontractforSecondaryBerthBerthProject_PressRelease_04Aug11.pdf, accessed 5 November 2013.
[232] See EMAS (2013b), *Post-3 Mtpa LNG Import Framework*, https://www.ema.gov.sg/media/com_consultations/attachments/51ac3a2514e6c-Post-3Mtpa_Consultation_2_Final_3_June_2013.pdf, accessed 22 October 2013.
[233] EMAS (2013c), *Post-3 Mtpa LNG Import Framework, Draft Determination Paper*, Issued on 6 December 2013, http://www.ema.gov.sg/media/com_consultations/attachments/52a12d9b9631f-Post-3Mtpa_Framework_-_Draft_Determination_Paper_Final_launched_on_6_Dec_2013.pdf, accessed 7 December 2013.
[234] According to Lloyd's Register (2012), Singapore is already the largest fuel bunkering location internationally and already commands 17% of the total bunkering market share in 2010.
[235] See http://www.fta.gov.sg/fta_ongoingneg.asp for more details.
[236] Information provided kindly by the Singapore High Commission to the IMO.

These FTAs may provide Singapore with a comparative advantage allowing it to access and acquire LNG supplies that are currently abundant in the European Union (EU) and US for storage or for redirecting or re-exporting to either Asia Pacific or other international LNG customers[239].

8.6. Other Issues in the International LNG Market

8.6.1. The Potential End of Premium LNG Pricing in the Asia Pacific Region

Since the July 2013 GSOO, the average imported price of LNG in the Asia Pacific region has ranged between A$10.90 and A$15.87 per GJ, significantly higher than gas prices quoted at the Henry Hub (approximately A$2.06 to $5.53 per GJ between January 2010 and October 2013) in the US[240]. The persistent high price of LNG in the Asia Pacific region results from the reliance of Japan, South Korea and Taiwan on LNG imports. These major LNG consumers lack indigenous gas production and access to infrastructure connecting these countries to major sources of gas supply, relying almost exclusively on LNG as the source of gas[241]. Asia Pacific LNG demand remains more than double the size of Asia Pacific LNG export capacity, supporting comparatively higher prices in the region.

The persistence of high Asia Pacific LNG prices has led Japan, the largest LNG consumer in the region, to release a strategy document aimed at lowering gas prices domestically. In September 2012, Japan's Energy and Environment Council's Innovative Strategy for Energy and the Environment outlined how Japan intends to increase its LNG imports from North America to stabilise the cost of its LNG supply[242]. Japan has also publicly stated it does not favour oil-linked pricing in its LNG import contracts[243]. This stance may jeopardise potential LNG projects in WA that have yet to secure LNG off-take agreements from the world's largest LNG importer.

The misalignment in LNG pricing across regions has also encouraged the unabated interest in developing LNG liquefaction projects (in North America and Russia) to meet Asia Pacific LNG demand. Recently reported estimates by HSBC[244] and IEA[245] suggest the cost of shipping and liquefaction from North America to Asia is US$4 to US$9 per million British Thermal Unit (MMBtu) (US$3.79/GJ to US$8.53/GJ), meaning North American LNG may become a competitive source of gas supply in Asia Pacific[246].

With an average break-even cost estimated to be approximately US$14/MMBtu for new LNG projects[247], a significant fall in LNG contract prices is unlikely at this point[248]. However, the threat of abundant LNG supply to the Asia Pacific region may result in Asia Pacific LNG prices being gradually de-linked from oil-indexed

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

238 International Times (2013), *China's Taiwan, Singapore expect to complete FTA before June: Report*, http://www.globaltimes.cn/content/759308.shtml, accessed 5 November 2013.

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

240 Data from BP (2013) and EIA (2014), converted using A$1 = US$0.90 and converting one MMBtu = 1.055 PJ.

241 The exception is China that has access to international supplies of gas from cross country pipelines.

242 This is outlined in the Innovative Strategy for Energy and Environment policy document, http://www.cnic.jp/english/newsletter/nit151/nit151articles/02_strategy.html, accessed 6 November 2013.

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

244 HSBC Global Research (2013)

245 See HSBC Global Research (2013b).

246 According to Interfax (2013), IEA's Chief Economist states liquefaction and shipping costs of gas from North America is approximately US$6.00/MMBtu (or US$5.66/GJ). IES (2013), *Study on the Australian Domestic Market*, 28 November 2013, http://www.industry.gov.au/Energy/EnergyMarkets/Documents/IESStudyontheAustralianDomesticGasMarket.pdf, accessed 3 January 2014, also estimates the break-even landed cost of LNG from Canadian and Mozambique LNG projects to be approximately US$9.20 to $US9.50/MMBtu (or US$ 8.68/GJ to US$8.96/GJ) for Canada and US$9.00 to US$10.00/MMBtu (or US$ 8.49/GJ to US$ 9.43/GJ) for Mozambique.

247 This is revealed by a panel of experts at the CWC World LNG summit in Paris, 18-21 November 2013 that was reported by Interfax (2013b), *The LNG Market is set to grow, but at what cost?*, Natural Gas Daily, Volume 3, Issue 224, http://interfaxenergy.com/natural-gas-news-analysis/energy-news-analysis/the-lng-market-is-set-to-grow-but-at-what-cost/, accessed 19 November 2013. 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).

248 This is consistent with the view outlined by National Bureau of Asian Research (NBR) (2013), *Asia's Uncertain LNG Future*, NBR Special Report 44, November 2013, http://www.nbr.org/publications/issue.aspx?id=296, accessed 18 November 2013, views presented in IEA (2013) and by presentations at the Gas Asia Summit 2013 in Singapore, November 2013.

pricing over the long-term[249]. Another potential, more likely, outcome is the further relaxation of the oil-linkage formulas within existing LNG supply contracts to the Asia Pacific region and restructuring of risk management practices in the international LNG market[250].

Some long-term LNG contracts signed between US LNG exporters and other countries have already delinked from oil indexes, including links to the Henry Hub price[251]. Others are considering different LNG pricing structures such as tolling agreements between Freeport LNG and its Japanese customers (Chubu Electric and Osaka Gas) and BP Energy; and between Cameron LNG and Mitsubishi Corporation and Mitsui Co Ltd and Tepco[252], BP's supply deal with Kansai Electric[253], Shell and Gazprom's intention to index LNG to diesel[254].

This is anticipated to remain limited to certain brownfield LNG redevelopment projects in the US and less established LNG sellers looking to establish a foothold in the international LNG market. It is more likely restrictive clauses within LNG sales contracts will be dropped, allowing greater flexibility in LNG international trade, and new LNG pricing formulas introduced[255]. Greenfield LNG developments internationally still require stable long-term contracts to facilitate access to limited financial capital[256].

8.6.2. High Relative Cost of LNG Production in Western Australia

As a high cost producer of LNG internationally, WA is at risk of displacement in the LNG supply chain when some long-term LNG contracts for WA exporters start to expire from 2016 (see section 8.3.1)[257]. Deutsche Bank and Credit Suisse estimate that most WA projects (completed and under construction), with the exception of the NWS, are sitting towards the higher end of the LNG cost curve[258].

A study by McKinsey suggests the cost of development of LNG export facilities in Australia is now 20% to 30% higher than that in North America and East Africa[259]. The report highlights the following factors that may explain the cost differential:

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

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

[250] This is the more likely outcome as existing LNG suppliers would not want the pricing of new LNG supply contracts to be compared against legacy LNG contracts. The realignment of risk management for LNG suppliers also refers to the move towards managing LNG supply risk internationally like a portfolio (similar to the crude oil business). Rather than managing LNG exports with the single destination distribution model, this reduces cost for existing LNG suppliers in an international market. A presentation by Credit Suisse at the Singapore International Energy Week 2013 is consistent with this view.

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

[252] Tolling agreements are agreements that essentially separate liquefaction from the acquisition of gas. The LNG liquefaction operator and customers only agree to the rights of liquefaction and loading of gas onto LNG ships ('toll'). The LNG customer is responsible for acquiring its own gas and shipping to the liquefaction facility for processing. See Freeport LNG Press Release (2012) for information on Chubu Electric and Osaka Gas and Freeport Press Release (2013) for more information. See Bloomberg (2013e), *Sempra Energy, GDF SUEZ, Mitsubishi, Mitsui Sign Tolling Capacity, Joint-Venture Agreements for Louisiana Liquefaction Export*, http://www.bloomberg.com/article/2013-05-16/avRpCHdJ4xa0.html, accessed 19 November 2013 and See Tepco (2013) , *Purchase of LNG from the U.S. Cameron Project Basic Agreement on the First Project to Secure 10 Million Lean LNG Annually*, Press Release, http://www.tepco.co.jp/en/press/corp-com/release/2013/1224596_5130.html, accessed 20 November 2013.

[253] ICIS (2012), *BP, Kansai Electric deal sets Asian LNG pricing paradigm*, http://www.icis.com/resources/news/2012/11/23/9617683/bp-kansai-electric-deal-sets-asian-lng-pricing-paradigm/, accessed 20, November 2013.

[254] See Interfax (2013e), *Shell and Gazprom to index LNG to diesel*, http://interfaxenergy.com/natural-gas-news-analysis/european/shell-gazprom-to-index-lng-to-diesel/, accessed 28 November 2013.

[255] 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. This view is supported by Risk (2013), *Onset of hub-based Asian LNG pricing likely to be slow*, http://www.risk.net/energy-risk/news/2297409/onset-of-hub-based-asian-lng-pricing-likely-to-be-slow, accessed 6 November 2013 and views from IEA's Chief Economist reported in Interfax (2013b).

[256] A presentation by Standard Chartered Bank at the Singapore International Energy Week 2013 is consistent with this view.

[257] See Macquarie Equity Research (2012), *Global LNG Outlook*, 10 September 2012, Credit Suisse Global Equity Research (2012), Deutsche Bank (2012) and Deloitte (2013b) for international comparisons of LNG production costs, McKinsey (2013) also provides a breakdown of cost estimates for LNG projects in Australia.

[258] See Deutsche Bank (2012) and Credit Suisse (2012) reports.

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

Despite facing high costs of developing LNG projects, the establishment of FLNG projects, such as Prelude, puts downward pressure on LNG development costs planned for WA, while HSBC reports wage inflation has moderated in the resources sector[260]. The easing of costs may lead to a reassessment of potential WA LNG projects that were previously shelved.

8.6.3. Availability of Unconventional Gas to International Gas Supply

The timing and availability of unconventional gas, in the form of shale gas, tight gas, coal bed methane (coal seam gas [CSG]) and methane hydrates has the potential to significantly alter international gas supply. The best example of this effect is the US domestic gas market over the 2000 to 2012 period. During this period, the US shifted from being a major importer to become potentially the largest supplier of international gas due to increasing unconventional gas supplies entering the US domestic market.

International resources of gas have increased primarily due to the rapid exploration for and extraction of unconventional gas. Previously, it was estimated there was approximately 50 to 60 years of gas remaining for the entire international gas market, however unconventional gas resources have significantly improved this estimate to more than 200 years[261].

According to the EIA's assessment of shale gas resources in 40 countries, China holds the largest estimated reserve of shale gas followed by Argentina, Algeria, Canada, the US and Mexico[262]. With China exploring for unconventional resources intensively, exports of CSG as LNG about to commence from the eastern states of Australia 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[263]. However, the availability of unconventional gas is still small relative to conventional gas.

At the time of this report, uncertainty regarding the proportion of US gas available as exports (a potentially cheaper alternative to existing LNG supplies) is causing some uncertainty in the international gas market. According to the Financial Times, international LNG developments are being delayed as LNG purchasers and producers cannot agree on pricing terms[264]. The article also notes that only nine Mtpa of LNG liquefaction reached a positive final investment decision in 2013, all for US projects, contrasting with 14.1 Mtpa in 2012 and 26.8 Mtpa in 2011.

The impact of unconventional gas on the international gas market is still unclear and should be monitored closely by WA LNG exporters, market regulators and governments.

8.6.4. Potential Changes in LNG Contracting Behaviour in the Asia Pacific Region

According to the EMAS, LNG is increasingly being sold in smaller parcels, with shorter contracts and spot cargoes for quantities of LNG of 0.5 Mtpa or less[265]. If this practice leads to erosion of any price advantage associated with purchasing LNG in larger quantities, this could eventually impact on WA's LNG exports to large LNG consumers.

In addition, LNG purchasers have started to consider different purchasing arrangements from international LNG sellers. In January 2013, Chubu Electric and Kogas signed and the first international joint LNG purchase agreement in Asia with ENI, allowing Chubu Electric and Kogas to share quantities of LNG[266].

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[260] See HSBC Global Research (2013).

[261] This is outlined in Ernst and Young (2013), *International LNG: Will New Demand and New Supply mean New Pricing?*, http://www.ey.com/Publication/vwLUAssets/Global_LNG_New_pricing_ahead/$FILE/Global_LNG_New_pricing_ahead_DW0240.pdf, accessed 30 April 2013.

[262] EIA (2013), *Technically Recoverable Shale Oil and Shale as Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=85447655, accessed 23 July 2013 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. These figures have been updated from EIA (2011) *World Shale Gas Resources - An Initial Assessment of 14 Regions outside the United States*, http://www.eia.gov/analysis/studies/worldshalegas/, accessed 26 February 2013.

[263] While the timing of gas supply is important, the composition of unconventional gas (typically less dense than conventional gas) is also a consideration for gas exports.

[264] See Financial Times (2013), *US shale boom causing slowdown in LNG industry*, http://www.ft.com/intl/cms/s/0/ae32d7b6-51ff-11e3-8c42-00144feabdc0.html#slide0, accessed 26 November 2013.

[265] See EMAS (2013), *Post-3 Mtpa LNG Import Framework 2nd Consultation Paper*, https://www.ema.gov.sg/media/com_consultations/attachments/51ac3a2514e6c-Post-3Mtpa_Consultation_2_Final_3_June_2013.pdf, accessed 6 November 2013.

[266] See Chubu Electric Press Release (2013), *Chubu Electric and KOGAS execute Tripartite LNG Sales and Purchase Agreement with ENI~ The Very First*

According to Interfax, since 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, leading to Tokyo Electric considering an alliance of LNG purchasers in 2014 to source approximately 35 to 40 Mt from the international LNG market[267].

International Joint Purchase in Asia, http://www.chuden.co.jp/english/corporate/ecor_releases/erel_pressreleases/3207188_11098.html, accessed 20 November 2013.

[267] See Interfax (2014b), *Tepco looks to build LNG coalition as imports hit record*, Natural Gas Daily, Volume 4 Issue 12, http://interfaxenergy.com/natural-gas-news-analysis/asia-pacific/tepco-looks-to-build-lng-coalition-as-imports-hit-record/ accessed 20 January 2014.

9. Gas Supply and Capacity Forecasts

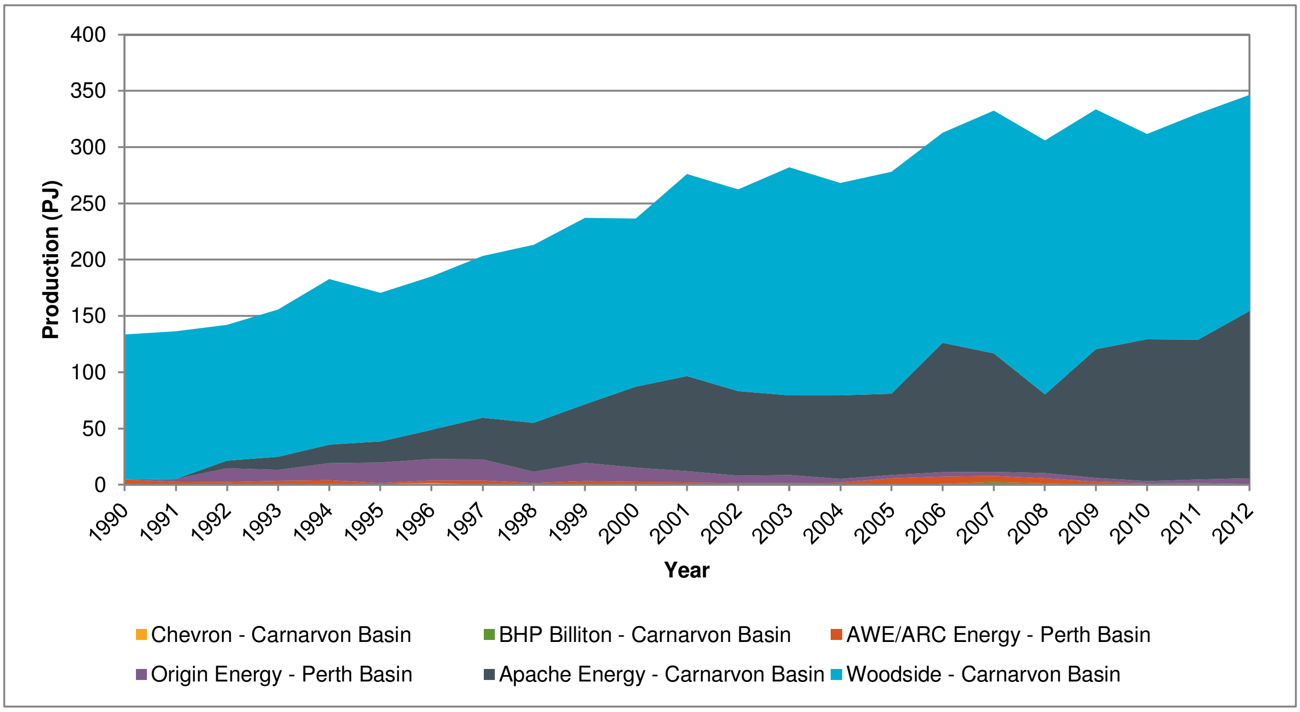
This section provides a snapshot of gas supply in the WA domestic gas market, including an outline of major domestic gas suppliers, and presents annual forecasts of potential supply for the 2014 to 2023 period[268].

9.1. Current Western Australia Domestic Gas Supply

At the time of this report, gas supply to the domestic market is provided directly by eight domestic gas production plants owned by various JVs (see section 4.3.1) and also through the secondary gas market. Although trade in the secondary gas market appears to be increasing it remains a small part of the WA domestic gas market, with estimated trade volumes of six to 30 TJ/day[269].

Figure 51 presents annual production (sales) data by operator for 1990 to 2012 as reported by APPEA. It shows that prior to 2013 gas supply originated predominantly from the NWS (Woodside) or Varanus Island (Apache) gas production facilities.

Figure 51 – Western Australia Domestic Gas Sales by Operator, 1990 – 2012



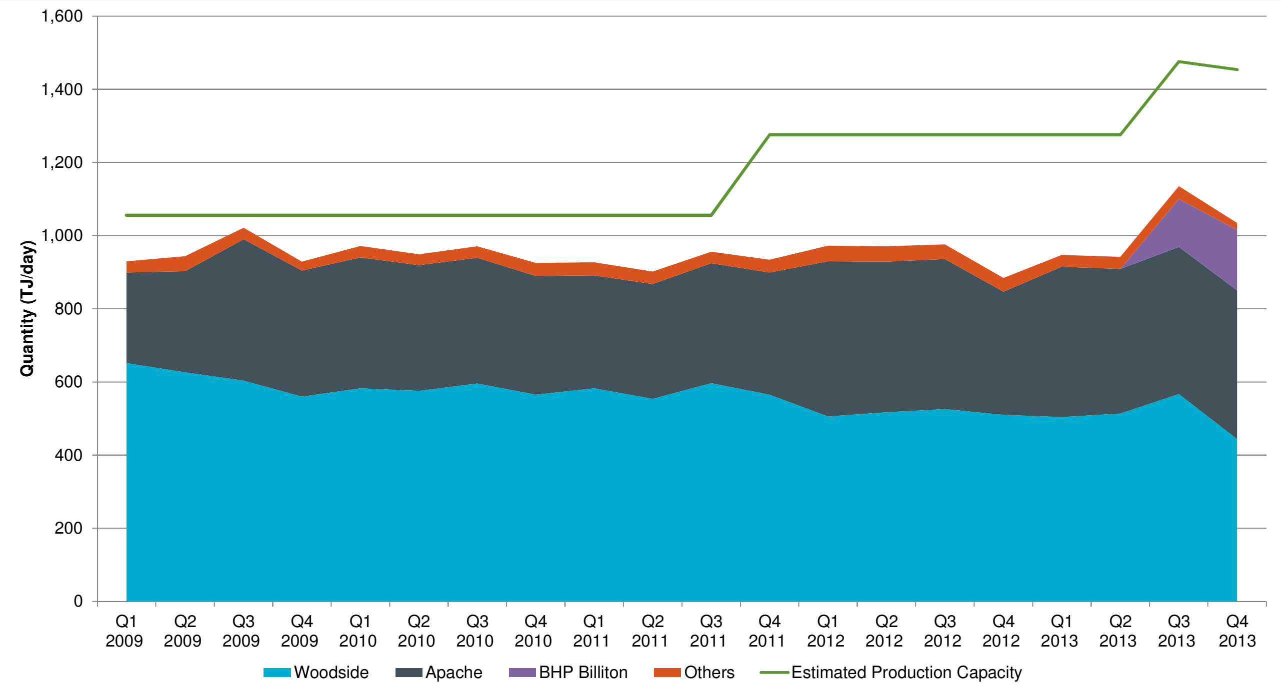
Source: APPEA Quarterly Production Data (1990 to 2012).

Figure 52 presents the estimated domestic gas production of all production facilities in WA between Q1 of 2009 and Q4 of 2013. Figure 52 shows that gas production in Q4 of 2011 remained largely unchanged, despite the introduction of the Devil Creek domestic gas facility. In the third quarter (Q3) of 2013, the increase in gas production is related to the injection of gas into the recently expanded Mondarra gas storage facility. Production in subsequent quarters is likely to decline once the initial 'cushion gas' volume has been injected into Mondarra. Recent data from the GBB indicates that the decline will be from a reduction in production by the NWS JVs.

[268] For a brief history of WA's domestic gas supply, please refer to Chapter 3 of the July 2013 GSOO.

[269] Based on data reported by Gas Trading Australia Pty Ltd, short-term trades via Gas Trading Australia increased from an average of approximately five TJ/day to about 15 TJ/day over the January 2012 to October 2013 period. See graphs at http://www.gastrading.com.au/spot-market/historical-prices-and-volume.html, accessed 7 November 2013. 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 is not aware of the volume of trades on Energy Access Services Pty Ltd's platform or by Apache's short-term trading arrangements.

Figure 52 – Reported and Estimated Domestic Gas Production by Operator, Q1 of 2009 to Q4 of 2013



Source: Quarterly Production reports for Q1 of 2009 to Q3 of 2013; Q4 of 2013 production and capacity is the average estimated from GBB data. Domestic gas production data is from quarterly production reports of Woodside Energy, Apache Corporation, Santos, Origin Energy, AWE Limited and Tap Oil to the ASX and the US Securities Exchange Commission between Q1 of 2009 to Q3 of 2013. All production is estimated for each operator. Others category includes Red Gully production estimates. **Note:** The shift in estimated domestic production capacity in Q4 of 2011 is due to the commencement of the Devil Creek gas production facility. The increase in capacity in Q3 of 2013 is due to the commencement of Macedon and Red Gully production facilities. Actual production varies from maximum production capacity due to varying contractual commitments and clauses within gas sales contracts (such as take or pay clauses, or maximum contracted quantities), gas nominations, seasonal gas demand, facility outages, maintenance and spare capacity.

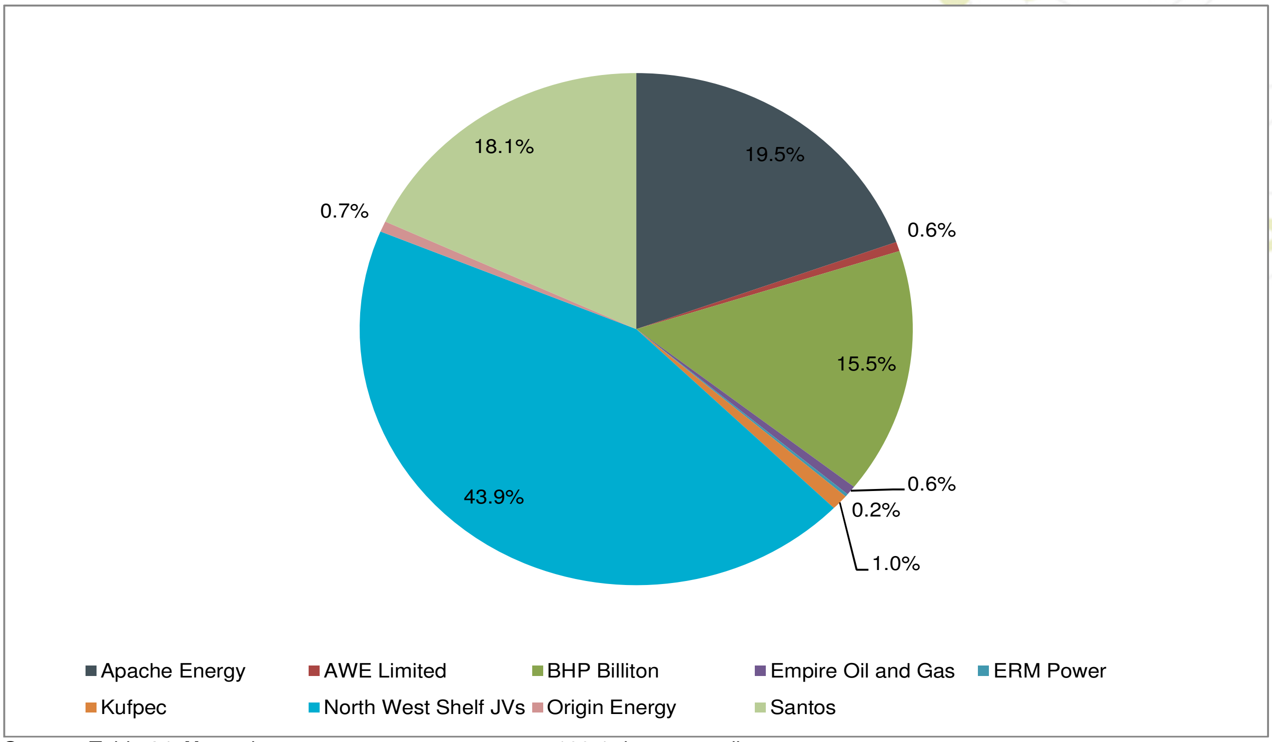
Based on quarterly production statistics for 2013 and data from the GBB, gas to the WA market is currently supplied by nine market participants. Table 24 and Figure 53 provide estimated production for Q4 of 2013.

Table 24 – Domestic Gas Suppliers, Q4 of 2013

Company	Estimated Average Supply to WA domestic market (TJ/day) – GBB Data
Apache Energy	197
AWE Limited	5.8
BHP Billiton	156.9
Empire Oil and Gas*^	5.8
ERM Power*^	1.8
Kufpec*	10.1
NWS JVs	443.6
Origin Energy	6.8
Santos	183.1

Source: IMO GBB data and IMO estimates. **Note:** *BHP Billiton and Kufpec production shares are estimated. Market shares are based on GBB data for Q4 of 2013. ^Data for the Red Gully gas production facility is not publicly available. ^ Shares reported by Empire Oil and Gas. Actual production for the entire 2013 calendar year may differ due to variation in gas demand from users, contractual variations, strategy and seasonality.

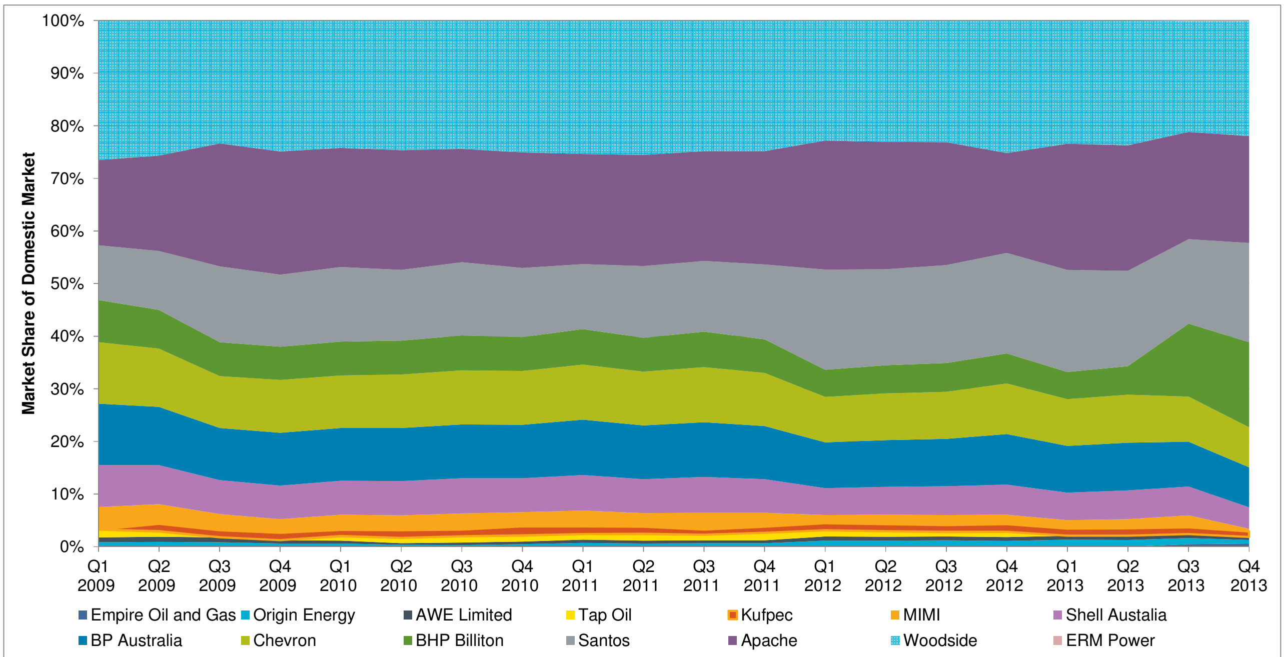
Figure 53 – Estimated Market Shares of WA Domestic Gas Suppliers, Q4 of 2013



Source: Table 24. **Note:** the percentages may not sum to 100% due to rounding.

Figure 54 presents estimates of the historical market shares of gas production by company supplying to the WA domestic gas market, covering the period from the Q1 of 2009 to Q3 of 2013. The NWS JV partners are shown separately.

Figure 54 – Estimated Market Shares of All WA Domestic Gas Suppliers, Q1 of 2009 to Q4 of 2013



Source: IMO estimates and GBB data. **Note:** Respective shares of the domestic market are estimated using gas production from quarterly reports and applying some assumptions. NWS JVs partners supplying the domestic market are estimated using NWS JVs (Domestic Gas JV (DGJV) and Incremental Pipeline Gas JV) shares outlined in Woodside (2012b) and assuming the DGJV retains all legacy contracts outlined in Table 1 of this GSOO.

Table 25 reports the average production and utilisation of each gas production facility supplying to the domestic market, based on GBB data, and indicates there is spare production capacity in the domestic market.

Table 25 – Domestic Gas Production Facilities Average Production and Utilisation, 1 August to 31 December 2013

Facility/Facilities	Ownership	Average Production 1 August – 30 December 2013 (TJ/day)	Average Utilisation (%) – based on nameplate and GBB data 1 August – 31 December2013
Beharra Springs	AWE Limited (33%) and Origin Energy (67%)	13.9	55%
Dongara	AWE Limited (100%)	2.1	30%
Devil Creek	Apache (55%) and Santos (45%)	109.5	50%
KGP	DGJV – Woodside (50%), and BHP Billiton (8.33%), BP (16.67%), Chevron (16.67%) and Shell (8.33%) Incremental Pipeline JV – Woodside (16.67%), BHP Billiton (16.67%), BP (16.67%) Chevron (16.67%), Japan Australia LNG (16.67%) and Shell (16.67%)	491.8	78%
Macedon	Apache (28.57%) and BHP Billiton (71.43%)	135.9	68%
Red Gully	Empire Oil and Gas (76.39%) and ERM Power (23.61%)	5.9	59%
Varanus Island	Harriet JV – Apache (80.7%), Kufpec (19.3%) East Spar JV - Apache (55%), Santos (45%)	293.8	75%

Source: IMO GBB data. **Note:** Production figures are estimates constructed from GBB data for the 1 August to 31 December 2013 period. Actual production for the entire 2013 calendar year may differ due to variation in gas demand from users, contractual variations, strategy and seasonality. NWS JVs partners supplying the domestic market are estimated using NWS JVs (Domestic Gas JV and Incremental Pipeline Gas JV) shares outlined in Woodside (2012b).

Figure 55 shows the spare gas production capacity by operator in the WA domestic gas market for the Q1 of 2009 to Q4 of 2013 period. This figure suggests the tight gas market experienced from 2009 to 2011 eased with the start of operations at the Devil Creek gas production facility in Q4 of 2011. Since that time, the majority of spare capacity in the domestic market relates to Apache's gas production facilities, in particular at the Devil Creek facility, which is understood to not be fully contracted at the time of this report.

Domestic gas production capacity increased again in Q3 of 2013 with the commencement of the Macedon and Red Gully facilities. Despite the increases to domestic gas production capacity that are backed by sufficient gas reserves (see section 10.4.2), actual domestic gas production remains largely unchanged.

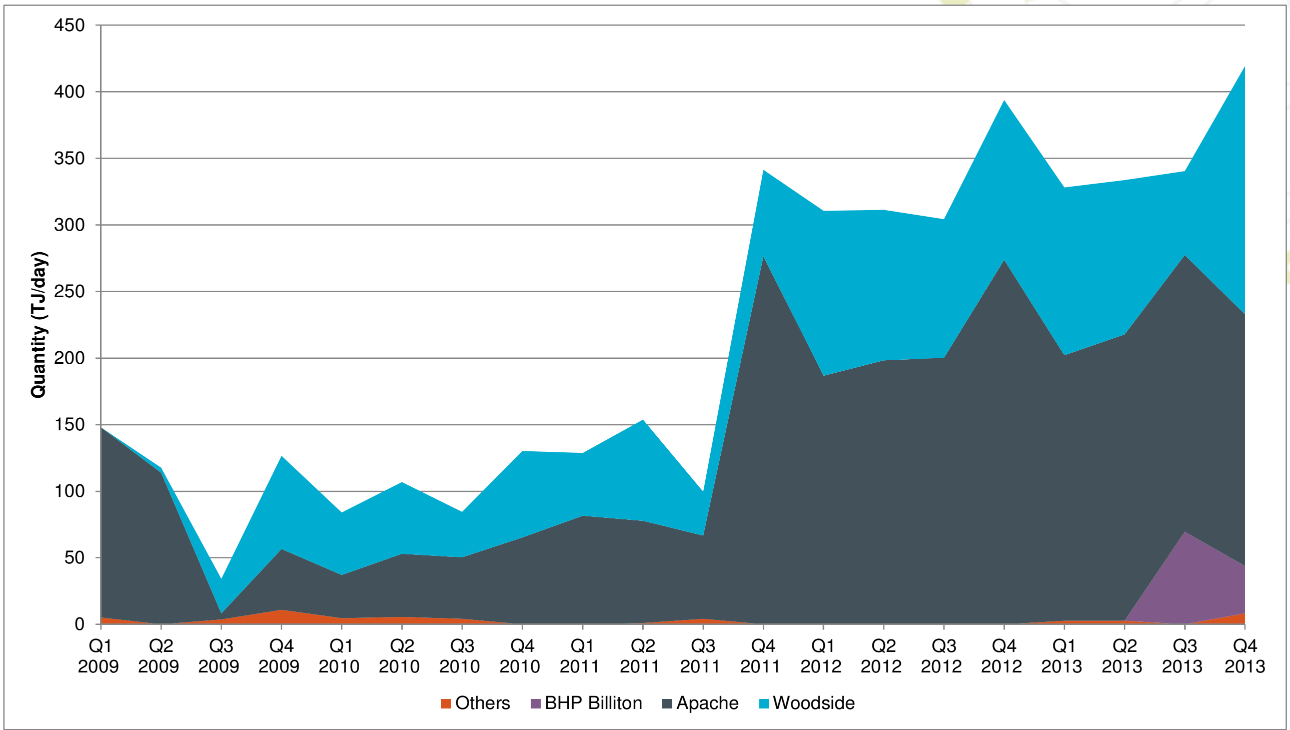
Since Q1 of 2012, spare capacity has represented between 25% and 32% of the total domestic gas production capacity (between 312 TJ/day to 419 TJ/day). A proportion of the persistent gap between total nameplate production capacity and actual production is accounted for, to varying degrees, by facility outages, utilisation rate and contractual mismatches.

Figure 55 also indicates as NWS domestic gas contracts expire, the majority of this spare capacity is not replaced by new gas supply contracts. It is estimated the average spare capacity of the NWS in Q4 of 2013 increased to approximately 186 TJ/day in Q4 of 2013 almost equivalent to the spare production capacity of Apache.

This spare capacity gap is projected to widen further over the forecast period with the commencement of the Gorgon and Wheatstone domestic gas production facilities. This data suggests that recent concerns by gas consumers relating to tightness of securing gas supply from existing gas producers may be somewhat allayed[270].

[270] There are instances where appropriate commercial terms cannot be agreed to leading to the perception of gas shortage in the WA domestic market.

Figure 55 – Estimated Available Gas Production Capacity (by Operator), Q1 of 2009 to Q4 of 2013

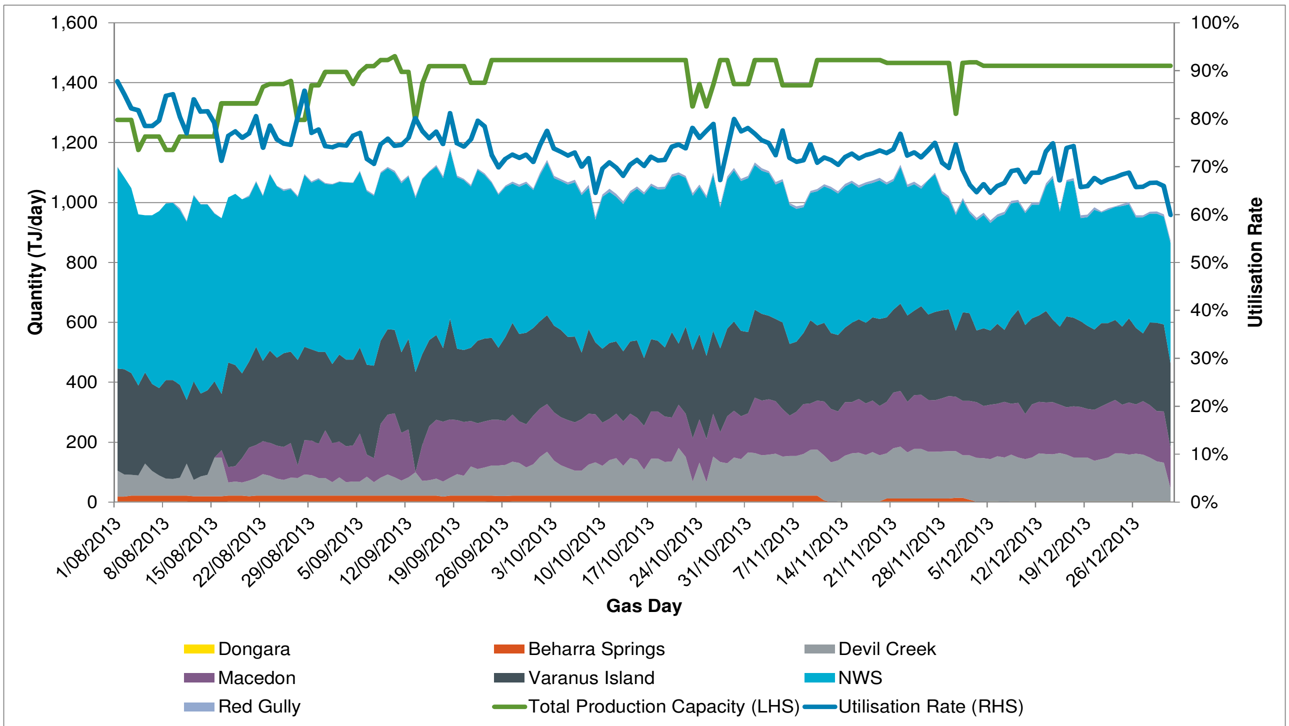


Source: IMO estimates using quarterly production reports and GBB data for Q4 of 2013. **Note:** Spare capacity is calculated by taking the difference between nameplate capacity and actual and estimated production for each quarter up to Q3 of 2013. Spare capacity for Q4 of 2013 is estimated by taking the difference between average capacity and average production calculated using GBB data.

9.1.1. Domestic Gas Production – Daily GBB Data

Figure 56 provides a view of gas delivered into the pipeline by production facilities on a daily basis for the 1 August 2013 to 31 December 2013 period, sourced from the IMO's GBB.

Figure 56 – Domestic Gas Delivered to Pipeline by Production Facility, 1 August 2013 to 31 December 2013



Source: IMO GBB data. Domestic gas production data is inferred from delivered quantities to respective pipelines. **Note:** Red Gully's production figures are only estimates as the GBB does not publish actual Red Gully production..

The daily production volumes outlined in Figure 56 present a similar picture to the previous section, showing gas delivered into the pipelines remains well below the total gas production capacity servicing the WA domestic market for the August to November 2013 period.

Actual production will vary from maximum production capacity due to varying contractual commitments and clauses within gas sales contracts (such as take or pay clauses, or maximum contracted quantities), gas nominations, seasonal gas demand, facility outages, maintenance and spare capacity. However, the spare capacity shown in Figure 56 suggests that there is sufficient gas supply capacity available for gas consumers to increase their consumption at the wholesale level to purchase gas for their operations, trade gas and/or manage their gas portfolios[271], assuming that gas producers and purchases can agree to commercial terms and that pipeline shipping capacity can be obtained.

Excess production capacity, coupled with the expanded gas storage capacity at Mondarra, may present opportunities for gas market participants to 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 supply, the underwriting of gas supply[272] or purchasing of gas for future use (utilising gas storage), potentially deepening the WA domestic gas market.

9.1.2.Potential Domestic Gas Production Facilities, 2014 – 2023

In the 2014 to 2023 period, gas production capacity is expected to increase with the development of two additional domestic production facilities, Gorgon and Wheatstone, as shown in Table 26. Other proposed facilities such as Buru Energy's Yulleroo, Transerv Energy's Warro and Woodside's Pluto have yet to reach final investment decision and it remains unclear whether these facilities will commence within the 2014 to 2023 period.

Table 26 – Domestic Gas Production Facilities That May be Operational by 2023

Production facility	Operator	Basin	Proposed Pipeline Connection	Anticipated Completion
Gorgon Domestic	Chevron	Carnarvon	DBNGP	2016 (Phase 1) and 2020 (Phase 2)
Wheatstone Domestic	Chevron	Carnarvon	DBNGP	2018
Warro	Transerv Energy	Perth	Parmelia/DBNGP	Currently under evaluation; subject to commercial viability
Pluto Domestic*	Woodside	Carnarvon	DBNGP	Currently under evaluation; subject to commercial viability*
Yulleroo / Valhalla	Buru Energy	Canning	Proposed Great Northern Pipeline	Currently under evaluation; subject to commercial viability

Source: Respective corporate websites. **Note:** *The status of Pluto domestic is unclear; according to Energy-pedia (2013b), Woodside recommenced exploration in 2013 in an attempt to expand Pluto's LNG plant, but this decision may have been reversed in July 2013, see the West Australian (2013e) article. Pluto's domestic gas facility may be dependent on the results of this exploration or whether it can negotiate a commercially acceptable agreement with other producing entities. Woodside has entered into an arrangement with the WA Government that commits to the supply of domestic gas, which is anticipated to begin five years after the first LNG is exported, providing it is commercially viable to do so.

9.2. Gas Supply Forecasts

9.2.1. Domestic Gas Supply

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

- potential gas supply;
- gas production capacity; and
- the adequacy of gas reserves (see Chapter 10).

[271] It is understood there are four market participants that already purchase gas on a monthly basis.
[272] 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).

Figure 57 presents NIEIR's gas supply forecasts for the 2014 to 2023 period. These forecasts are highly dependent on:

- the timing of upcoming domestic gas production facilities (Gorgon Phases 1 and 2 and Wheatstone);
- the estimated contracted level for each production facility;
- the estimated cost of production (and growth of costs) for each production facility;
- required rates of return on investment;
- NIEIR's forecast new contract prices (Base scenario);
- the continued willingness of the NWS to supply to the WA domestic market;
- the influence of alternative gas markets (LNG); and
- the assumptions surrounding NWS JV's production.

Due to the uncertainty surrounding future supply to the domestic gas market from the NWS JVs, including the outcome of the discussions between the WA Government and the NWS JVs (outlined in section 3.1), this GSOO presents two gas supply forecasts; Upper and Lower potential supply forecasts. Both the Upper and Lower potential supply forecasts assume that all other gas production facilities will continue to operate and contribute to the WA market and have sufficient reserves to supply to the WA market for the entire 2014 to 2023 period (see section 10.4.2).

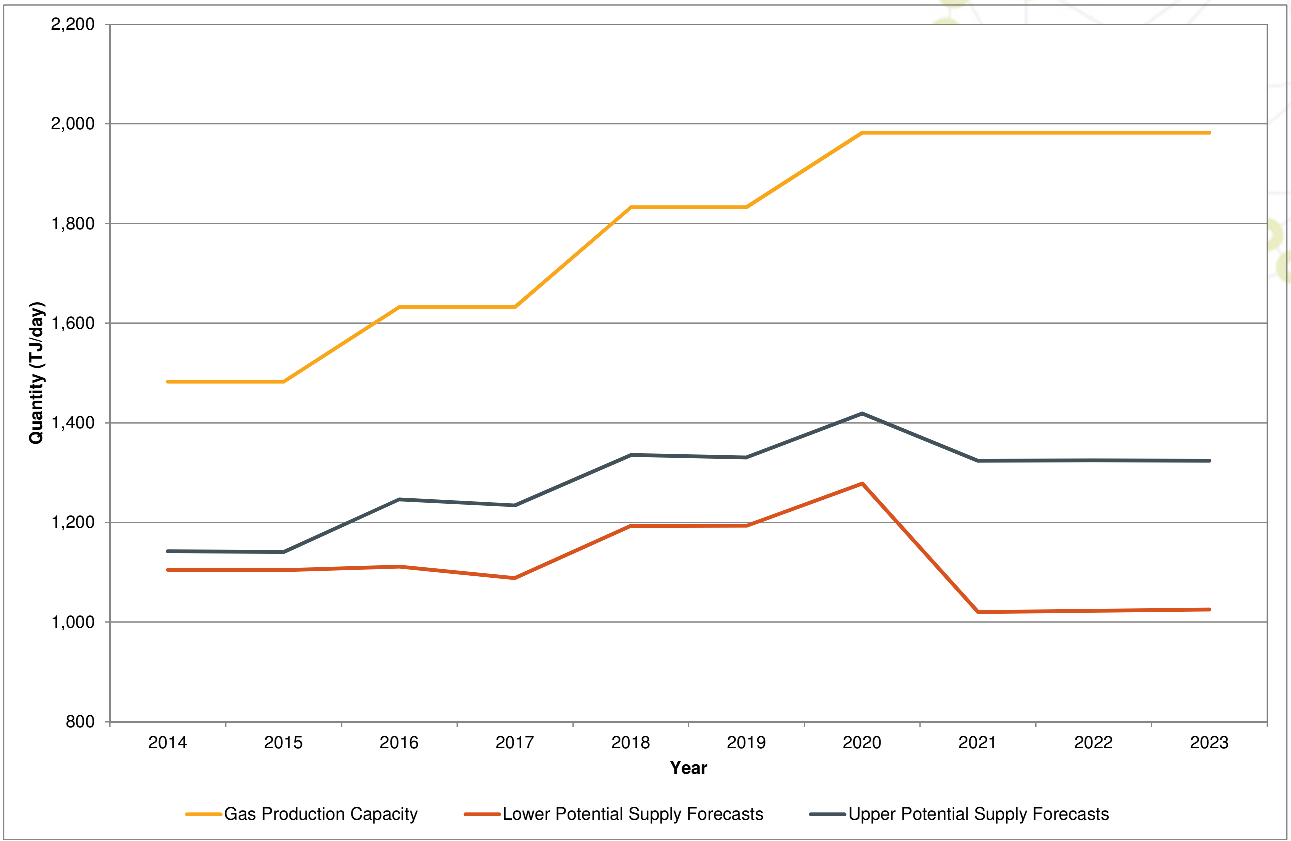
The Upper potential supply forecasts assume the NWS will continue to supply to the domestic gas market up to a maximum of 470 TJ/day until 2020 (inclusive) and 450 TJ/day until 2023. The maximum potential supply for 2014 is consistent with NWS average production observed for the 1 October 2013 to 30 November 2013 period using GBB data. Applying this assumption, the Upper potential supply forecasts indicate that the NWS will reduce gas supply to the WA domestic market from 459 TJ/day in 2014 to about 299 TJ/day in 2023[273].

The Lower potential supply forecasts assume the NWS only supplies domestic gas under its remaining domestic gas contracts outlined in Table 1 in section 3.1. Applying this assumption, gas supply from the NWS will decline over the period to 2020 and then drop to zero from 2021 to 2023. The forecasts are provided in Appendix 6.

Figure 57 shows that potential supply to the WA domestic is anticipated to grow in the 2014 to 2020 period. The growth for both the Upper and Lower potential supply forecasts is largely driven by the anticipated start-up of the Gorgon and the Wheatstone domestic facilities in 2016 and 2018, respectively. The difference between the Upper and Lower potential supply forecasts represents the price-sensitive supply that may be available from the NWS, based on the assumptions described above.

[273] This assumes none of the NWS's maximum 450 TJ/day supply capacity is recontracted between 2021 and 2023.

Figure 57 – Potential Domestic Supply Forecasts, 2014 – 2023



Source: NIEIR's Forecasts 2014 – 2023 and IMO estimates. **Note:** Upper and Lower potential supply forecasts should be used with caution as they rely on assumptions applied and projected prices for the Base scenario for the 2014 to 2023 period.

Over the 2014 to 2023 period, the Upper potential supply forecasts predict growth of, on average, 1.6% per annum from approximately 1,142 TJ/day (417 PJ/annum) peaking at 1,419 TJ/day (518 PJ/annum) in 2020 before declining to 1,324 TJ/day (483 PJ/annum) by the end of 2023. If the NWS only supplies to the remaining domestic gas contracts, the Lower potential supply forecasts predict domestic gas supply will grow on average by 2.5% per annum between 2014 to 2020 from approximately 1,105 TJ/day (417 PJ/annum) peaking at 1,278 TJ/day (466 PJ/annum) in 2020 before contracting to 1,026 TJ/day (483 PJ/annum) between 2021 and 2023.

The willingness of gas producers to supply the domestic market over the 2014 to 2023 period is likely to fall within the Upper and Lower potential supply forecasts. As noted in section 3.1, the IMO understands that, at the time of this report, the domestic gas and LNG production facilities at the KGP are integrated, with a quantity of gas exiting the LNG process and being diverted into the domestic gas production process. However, the IMO understands that this may change in the future.

9.2.2.Comparing Potential Supply Forecasts, July 2013 GSOO and January 2014 GSOO

This section compares the forecasts of potential supply with those presented in the July 2013 GSOO. This comparison, provided in Figure 58, shows the impact of the improvements to NIEIR's potential gas supply model. These changes include:

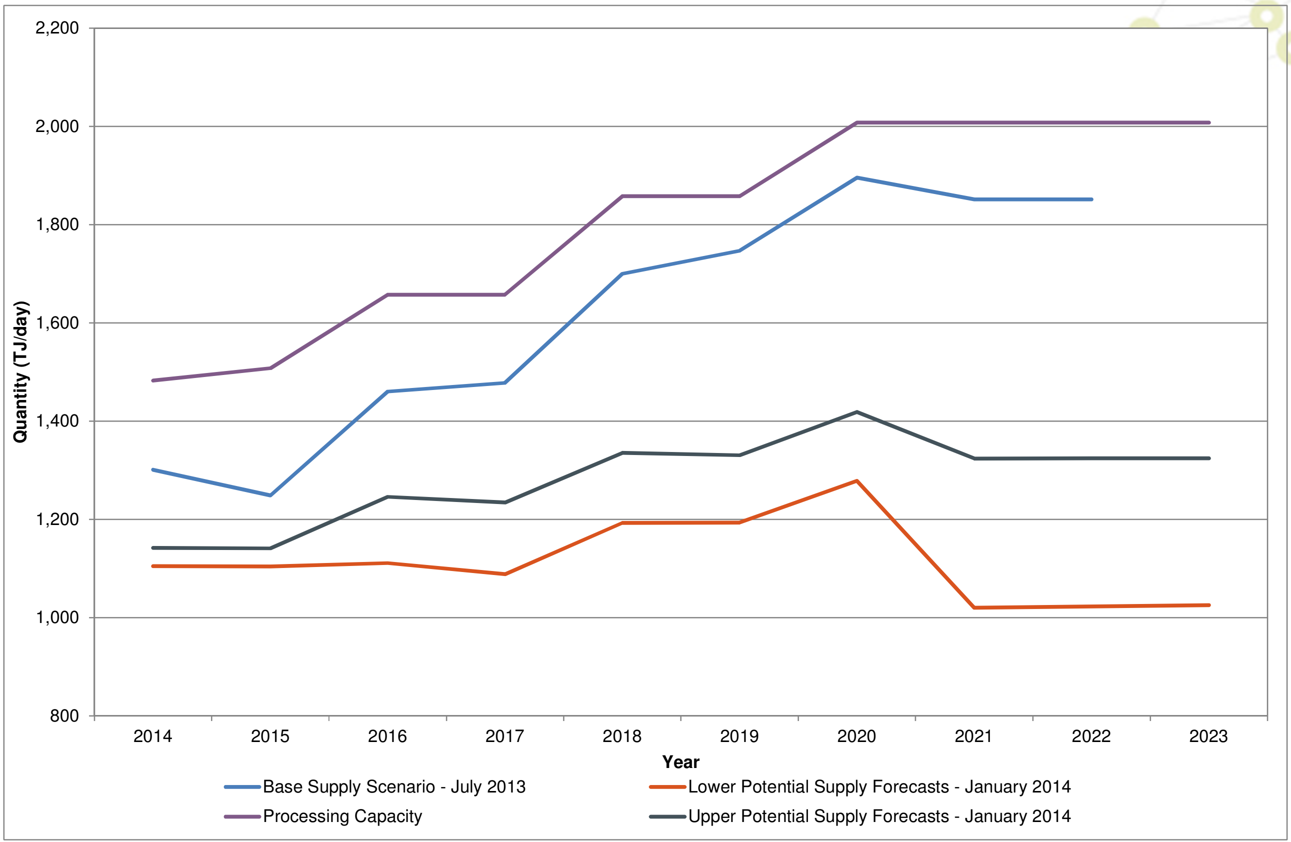
- improved application of exchange rates in the estimation of LNG netback prices, leading to different forecast average new contract gas prices;
- a reduction in the adjustment lag of average new contract gas prices to LNG prices[274];
- the separation of potential supply into contracted and price-sensitive portions, incorporating estimates of production costs and contracted supply quantities for each facility[275]; and

[274] From seven years to five years as suggested by the NWS at the 7 October 2013 GSOO Stakeholder presentation, see http://www.imowa.com.au/gsoo.
[275] The assumptions applied to estimate contracted supply quantities for each facility are not reported in full in this GSOO as some information is commercially sensitive.

- an assumed reduction in the NWS JVs' willingness to supply to the WA domestic market for the 2014 to 2023 period, from 530 TJ/day (for the 2013 to 2022 period) to the assumptions underpinning the Upper and Lower potential supply forecasts.

These changes to the forecasting model have resulted in a reduction of the potential supply forecasts as shown in Figure 58 and Table 27 below.

Figure 58 – Comparison of Potential Domestic Supply Forecasts between the July 2013 GSOO and January 2014 GSOO



Source: NIEIR Forecasts 2013 – 2022 and 2014 – 2023.

Table 27 – Comparison of Projected Supply Growth Rates, July 2013 and January 2014

Growth Rates	**Low/Lower**	**Base**	**High/Upper**
July 2013 GSOO	2.5	3.7	4.0
January 2014 GSOO	**NWS only supplies remaining domestic contracts** -0.8	Not Applicable	**NWS continues to supply to the domestic market** 1.7
	Low/Lower (TJ/day)	**Base (TJ/day)**	**High/Upper (TJ/day)**
July 2013 GSOO (2022)	1,626.3	1,826.3	1,882.2
January 2014 GSOO (2023)	1,025.6	Not Applicable	1,324.1

Source: NIEIR Forecasts 2013 – 2022 and 2014 – 2023.

While the improvements to the forecasting model have lowered NIEIR's potential supply forecasts for the 2014 to 2023 period, potential supply is still anticipated to remain higher than projected gas demand for the forecast period, as shown in Chapter 3.

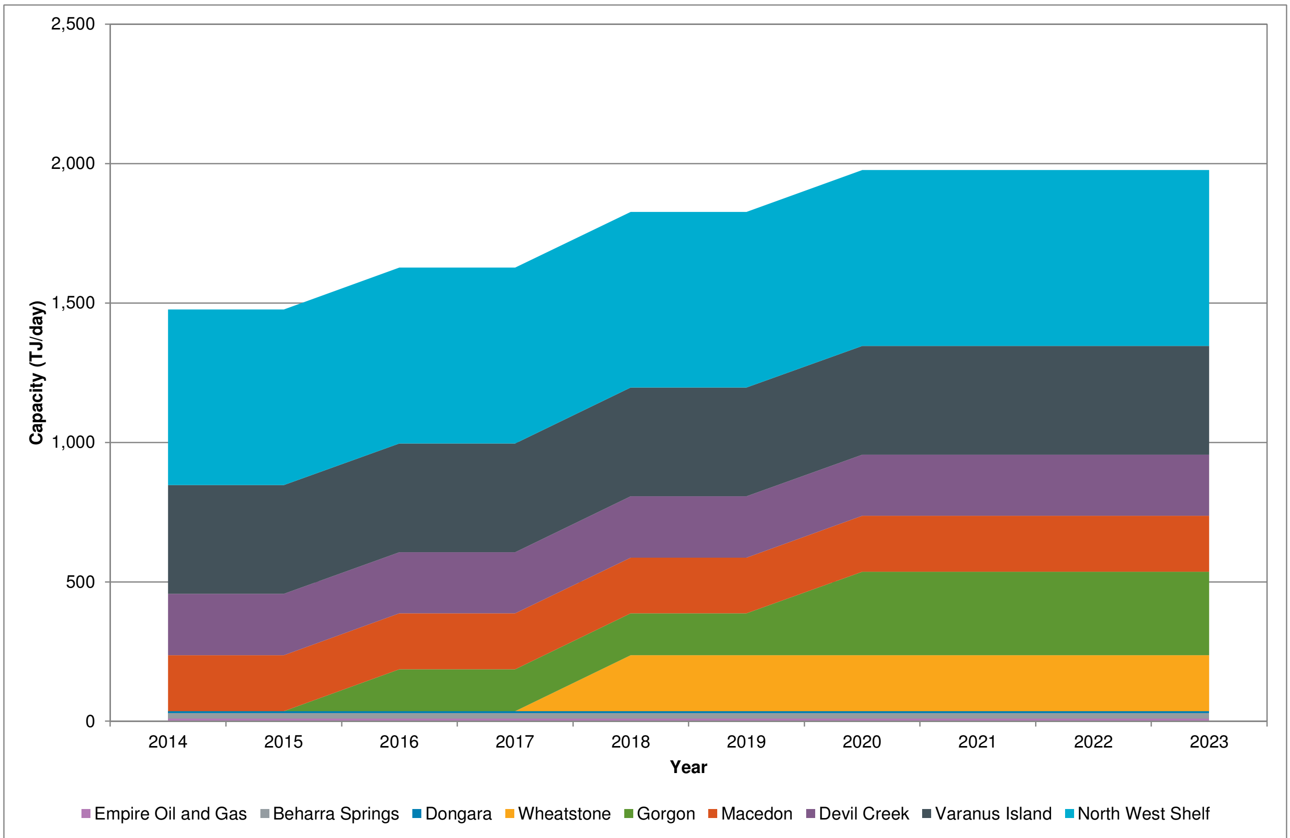
9.2.3. Gas Production Capacity

This section reviews the gas production capacity for the 2014 to 2023 period. Past reports[276] have presented gas production capacity as gas supply. Gas production capacity is simply the maximum amount of gas that producers can supply to the domestic market. This is estimated by aggregating the output capacities of all gas production facilities in WA that are existing and operational, under construction or committed for the 2014 to 2023 period[277].

Figure 59 presents a view of domestic gas production capacity based on the expected availability and commencement times of all existing and upcoming gas production facilities. Domestic gas production capacity will increase from approximately 1,477 TJ/day to 1,977 TJ/day by the end of 2023.

While gas production capacity is paramount to gas supply, it is not in and of itself an appropriate representation of gas supply to the domestic market. This view assumes each processing plant intends to operate close to or near maximum capacity, which is inconsistent with the actual operation of existing gas producers operating in the domestic gas market (see section 9.1).

Figure 59 – Estimated Gas Production Capacity of the WA Domestic Gas Market, 2014 – 2023



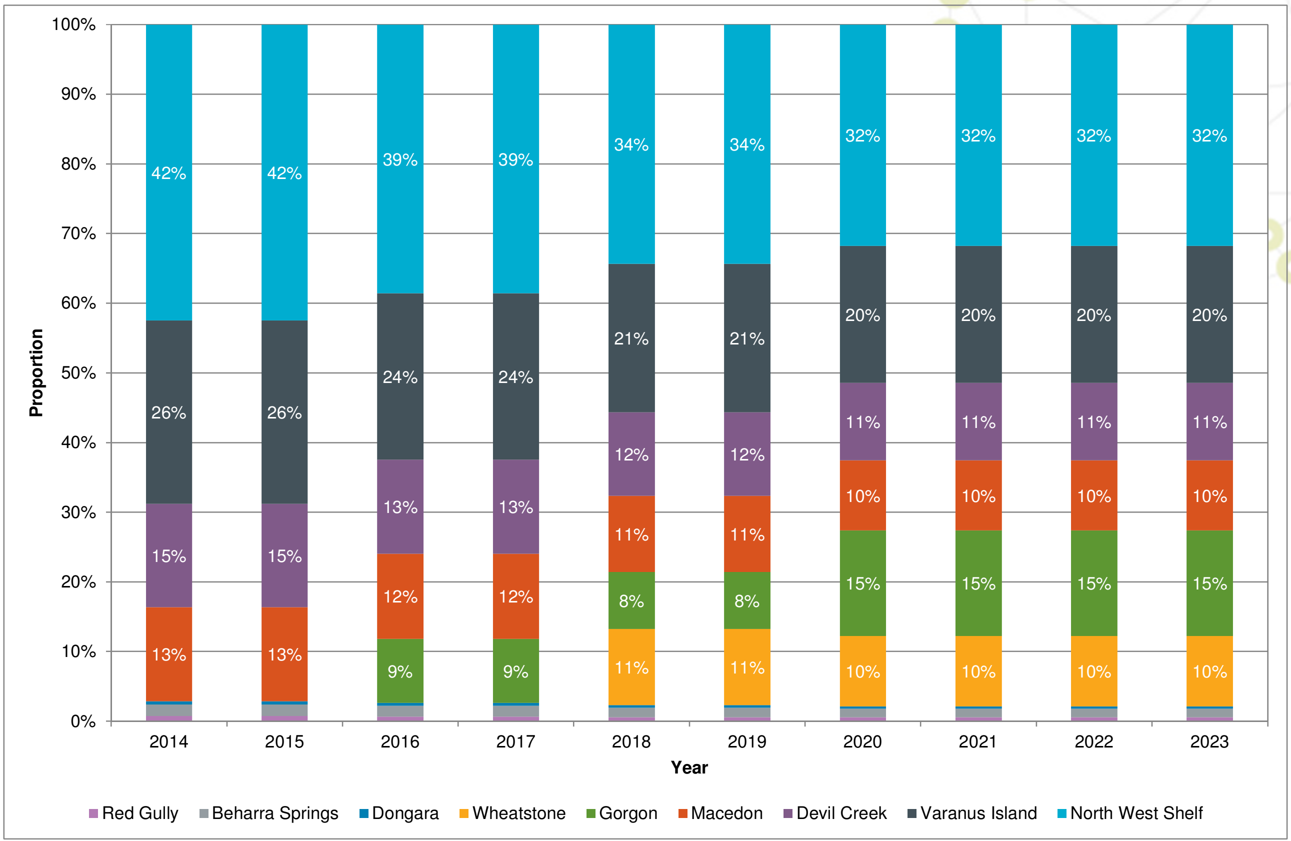
Source: IMO and various corporate websites. Gas production capacity for facilities is outlined in section 4.3.1. Start-up dates represented in this figure are Gorgon Phases 1 and 2 (2016 and 2020), Wheatstone (2018). **Note:** Proposed gas production facilities such as Woodside's Pluto, Buru Energy's Yulleroo and Transerv Energy's Warro are not included as these facilities are still being evaluated.

Figure 60 outlines the share of total WA capacity of each gas production facility for the 2014 to 2023 period. Despite an anticipated increase in domestic gas production capacity for WA, Figure 60 shows that the KGP is anticipated to remain the largest domestic gas production facility in WA in the 2014 to 2023 period if no additional domestic gas production facilities are constructed. It is forecast to provide almost one-third of the total gas production capacity by the end of 2023.

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

[277] 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 60 – Share of Total Gas Production Capacity of the WA Domestic Gas Market, 2014 – 2023



Source: Shares are calculated from Figure 59.

10. Gas Resources and Reserves

WA is the most gas endowed state in Australia. It is estimated that there is an abundance of undeveloped gas resources in WA relative to eastern Australia. Despite this, WA domestic gas prices remain relatively high when compared to eastern Australia.

Since the publication of the July 2013 GSOO, WA remains a destination for hydrocarbon exploration companies and the IMO estimates there are still in excess of 100 exploration entities owning interests in various partnerships, JVs, tenements and special prospecting permits in WA.

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

10.1. Key Basins in Western Australia

There are currently 10 basins within WA[278], of which five basins are known to contain hydrocarbon resources. These are shown in Table 28 and include the Bonaparte, Browse, Canning, Carnarvon and Perth Basins (see Table 28). For a brief description of these basins, please refer to the July 2013 GSOO.

Table 28 – 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 2012-2013 (PJ)
Bonaparte^^	250,000	20,000	1,054	22,000	1,032
Browse	140,000	0	17,384	35,300	0
Canning	76,000	430,000	Not available	<10	0
Carnarvon	535,000	115,000	71,885	101,500	17,153
Perth	122,500	50,000	40	200	722
Total	**1,123,500**	**615,000**	**90,363**	**159,000**	**18,907**

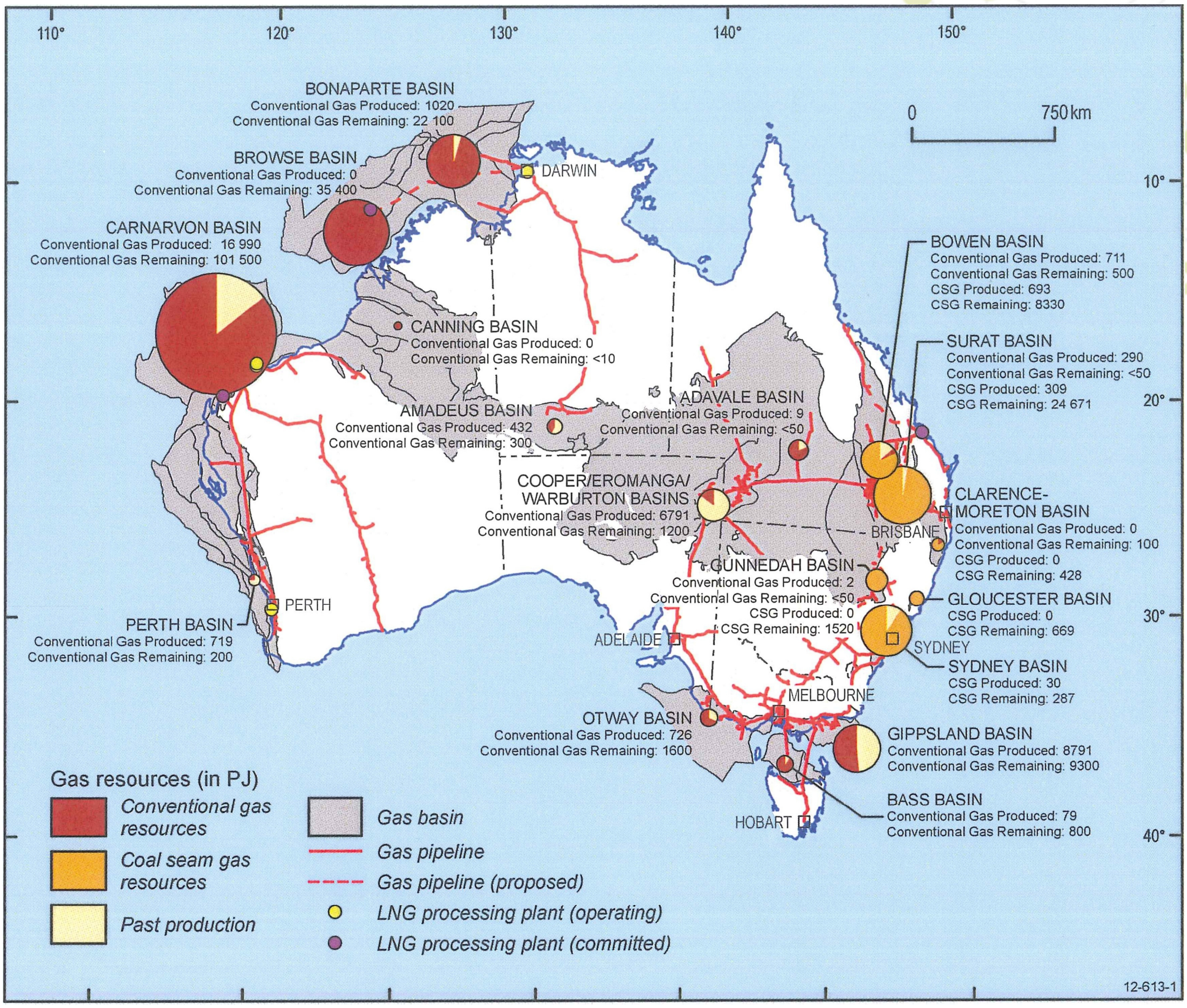
Source: Geoscience Australia (2012), Geoscience Australia (2012b), DMP (2012), EnergyQuest (2013), Australian Energy Regulator (2012) and BREE (2013i). **Note:** The table only highlights conventional gas resources and does not include estimates of unconventional resources such as CSG, shale gas or tight gas. While the onshore Canning Basin is not well assessed, geologists expect it to be a good prospect for gas resources. ^^Part of the Bonaparte Basin resources falls within the Joint Development Petroleum Area.

According to Geoscience Australia and shown in Figure 61, it is estimated approximately 92% of Australia's total conventional gas resources are located in WA, most of which are in the Bonaparte, Browse and Carnarvon Basins, while unconventional gas resources (specifically tight and shale gas) have been discovered in the Canning and Perth Basins[279].

[278] Note that the Amadeus, Bremer, Officer, Ord and Eucla Basins are not outlined in this GSOO as there are currently no official or known estimates of gas reserves in these basins within WA. Some geological information about these basins is outlined in brief in the Government of South Australia's *Roadmap for Unconventional Gas Projects in South Australia*, report of December 2012, http://www.petroleum.dmitre.sa.gov.au/__data/assets/pdf_file/0008/179621/Roadmap_Unconventional_Gas_Projects_SA_12-12-12_web.pdf, accessed 4 July 2013. At the time of this report, only Rodinia Oil Corp (Canadian company) and Ahava Energy (Australia) are known to be exploring the Officer Basin. DMP has also released new areas in the Officer Basin in June 2013, for petroleum exploration, http://www.dmp.wa.gov.au/7105_17803.aspx.

[279] See Geoscience Australia (2012) for more details.

Figure 61 – Key Australian Gas Basins



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

10.2. Conventional Gas Resources and Reserves

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

Currently only the Bonaparte, Carnarvon and Perth Basins are producing gas in WA. Of these, the Carnarvon and Perth Basins produce gas for the WA domestic market and LNG exports, while the Bonaparte Basin produces gas for the NT domestic market and LNG exports[280].

Domestic WA gas will continue to be supplied exclusively from the Carnarvon and Perth Basins until gas transmission infrastructure is constructed to connect to other basins[281]. Despite the size and scale of WA's undeveloped 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 challenge.

[280] Eni's Blacktip gas field is producing gas from the Bonaparte Basin which is processed at Wadeye for NT's Power Water Corporation. See Eni's Press Release (2009) for more information. LNG exports from the Bonaparte Basin are produced from the Bayu-Undan gas field.
[281] Gas extracted from the Browse and Canning Basins may be made available to the domestic market indirectly through swap deals with existing operators operating within the vicinity of gas transmission infrastructure.

10.2.1. Carnarvon Basin

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

Reliance on the Carnarvon Basin is expected to continue in the 2014 to 2023 period, with gas from this basin supplying the majority of the domestic and LNG export markets[282]. Before the end of 2023, the number of domestic gas production facilities that are expected to extract gas from the Carnarvon Basin will increase from five to seven; including the anticipated Gorgon and Wheatstone domestic gas production facilities (see section 4.3.1 for details). The number of facilities processing and liquefying gas into LNG is also anticipated to increase from two to four, with the inclusion of the Gorgon and Wheatstone LNG facilities (see section 8.3 for details).

10.2.2. Perth Basin

Due to the quantum of estimated reserves located in this basin and its proximity to existing and potential gas consumers, almost all gas projects in the Perth Basin are onshore projects and supply gas solely to the domestic market[283].

The Perth Basin is located in close proximity to two gas transmission pipelines, the DBNGP and the Parmelia Pipeline. Despite these advantages, the Perth Basin's less than ideal geological characteristics and relatively small estimated resources mean it is substantially less significant to WA's gas supply than the Carnarvon Basin[284]. In 2012, it is estimated the Perth Basin supplied approximately 1.7% of the total domestic market (see section 9.1 for details).

10.2.3. Browse Basin

The WA Government is actively encouraging the development of the Browse Basin and is in the process of developing the Browse LNG Precinct in the Kimberley region[285].

At the time of this report, only INPEX's Ichthys (to Darwin) and Shell's FLNG Prelude projects are confirmed projects for the Browse Basin[286]. Other potential gas projects under consideration include Woodside's Browse, ConocoPhilips' Poseidon and Santos' Crown projects. While there is a lot of activity within this basin, most of the significant gas discoveries are intended as potential LNG export projects, and so it is very unlikely that any gas supply from this basin will be available to the domestic market before 2023[287].

10.2.4. 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. Although these projects are extracting gas from the basin, they are processing the extracted gas for LNG export and domestic consumption within the NT and are not supplying gas to the WA domestic market. The GDF Suez and Santos Bonaparte FLNG project is also planned for this basin.

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[282] According to Energy-pedia (2013), since mid-2009 Chevron alone has made 21 hydrocarbon discoveries adding a total of 10 Tcf of gas to reserves in the Carnarvon Basin.

[283] The only offshore project in the Perth Basin is AWE Limited and Roc Oil's Cliff Head project. While this project mainly focuses on crude oil production, gas is known to be produced from this field and part of this gas is consumed by the power station located at the production facility with the remainder understood to be sold directly to a single consumer through a direct pipeline connection.

[284] According to Bell Potter Securities (2011), *Australian Shale Overview*, 9 December 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.

[285] According the Premier of WA (2013), the WA Government has secured land for the Kimberley gas precinct located at James Price Point.

[286] 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.

[287] The Ichthys (NT) and Prelude (FLNG) projects are not supplying the WA market. Other potential projects such as Woodside's Browse, for which a FLNG development is proposed and ConocoPhilips' Poseidon projects may not be constructed by 2023. Although Santos' Press Releases (2013 and 2013b), Gas discovery at Crown in the Browse Basin, 19 November 2013, http://www.santos.com/Archive/NewsDetail.aspx?p=121&id=1353, accessed 10 June 2013 and Gas Discovery in the Browse Basin, 7 June 2013, http://www.santos.com/Archive/NewsDetail.aspx?p=121&id=1379 , accessed 10 June 2013 report gas discovered at the Crown-1 and Basset West gas fields, the commercial value of these fields is yet to be determined and the IMO considers them unlikely to be available by 2023.

Despite the existence of these projects and a large volume of undeveloped gas resources located in the Bonaparte Basin, there is no gas production and transmission infrastructure located onshore in the Kimberley region to commercially extract, process and ship gas to domestic customers in the WA market[288]. The lack of infrastructure and facilities suggests it is highly unlikely that any gas reserves from the Bonaparte Basin will be extracted and processed for the WA domestic gas market in the forecast period.

There is a possibility that a proportion of the Bonaparte Basin's gas resources may be developed to supply domestic gas to eastern Australia, as the NT Government may be willing underwrite a gas pipeline to connect the NT domestic market to the eastern Australian domestic gas markets[289].

10.2.5. Canning Basin

There is currently no permanent gas-related infrastructure known to be located in the Canning Basin[290]. As such, any Canning Basin gas development project would be reliant on the construction of new infrastructure.

At the time of this report, several exploration and production companies, including Apache Energy[291], Buru Energy, ConocoPhillips, Hess, Key Petroleum, Mitsubishi, New Standard Energy, Oilex Limited, Oil Basins Limited and PetroChina[292] have either farmed into existing exploration efforts or are exploring the Canning Basin for hydrocarbons with an intention to supply gas to the domestic gas market. Buru Energy appears to be the most advanced explorer with one of its oil operations within the Ungani field moving towards production[293], while continuing to appraise its gas estimates within the Laurel formation[294].

10.3. Unconventional Gas Resources and Reserves

The quantum of WA unconventional gas resources, specifically tight and shale gas is largely unverified, but estimates from various sources are collated in this GSOO[295]. Currently, all shale and tight gas exploration activities have been confined to onshore exploration due to the depth of the potential resource[296].

The size and relatively lower risk of conventional resources in WA may indirectly impede the extensive exploration of unconventional gas. Due to the higher risks associated with unconventional gas exploration, such exploration is primarily focused on considerably well explored areas for conventional hydrocarbons within WA; namely within the onshore Bonaparte, Canning, Carnarvon and Perth 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, only Rusa Resources and Tap Oil are known to be exploring for unconventional resources after the WA Government awarded two special prospecting licenses covering a total of 38,000 square km[297].

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

[289] AFR (2013), *Government will underwrite NT pipeline*, http://www.afr.com/p/government_will_underwrite_nt_pipeline_sN59wpVdDxLRu3GmI4egMM, accessed 29 November 2013. However, it is unclear at this juncture as Rio Tinto's Gove refinery in NT has since been earmarked for closure in 2014, see AFR (2013b), *It's all over for Gove refinery*, 27 November 2013, http://www.afr.com/p/business/companies/it_all_over_for_gove_refinery_QNwcRslab4oGTMAlroYmzN, accessed 29 November 2013.

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

[291] See WA Energy Minister Media Statement (2013), *Progress for Canning Basin exploration*, 4 November 2013, http://www.mediastatements.wa.gov.au/Pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7917, accessed 4 November 2013.

[292] See ConocoPhilips Media Statement (2013), http://www.conocophillips.com.cn/EN/newsroom/news-releases/Pages/Articles/conocophillips-announces-three-agreements-with-petrochina.aspx, accessed 4 November 2013.

[293] See Buru Energy's Operations Update, 15 October 2013, http://www.buruenergy.com/download/asx-releases/2013/48.Operations%20Update.pdf, accessed 7 November 2013.

[294] See Buru Energy's Corporate Update, 1 October 2013, http://www.buruenergy.com/download/asx-releases/2013/44.Corporate%20presentation.pdf, accessed 7 November 2013.

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

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

[297] 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.

In the Perth Basin, companies such as AWE Limited, Caracal Exploration, Empire Oil and Gas, ERM Power (ERM Gas), Key Petroleum, Transerv Energy, Norwest Energy and Whicher Range Energy are actively exploring for shale and/or tight gas. AWE Limited and Transerv Energy are considered to be the most advanced unconventional gas explorers operating in this basin[298].

In the onshore Bonaparte Basin, only Advent Energy is known to be exploring for shale resources and is currently exploring shale gas at its Waggon Creek field[299].

In the Canning Basin, several exploration companies, JV partners and entities including Buru Energy, ConocoPhilips, FAR Limited (First Australian Resources), Green Rock Energy, Hess[300], Key Petroleum (via Gulliver Productions Pty Ltd), Mitsubishi Corporation, New Standard Energy, Oil Basins Limited, Oilex Ltd, Pancontinental Oil and Gas and Rey Resources have permits or JV interests in this basin[301]. 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)[302].

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

10.3.1. Shale Gas Resources

At the time of this report, Australia has not assessed its resources of shale gas. Despite this, at the end of 2011, Geoscience Australia estimated there are approximately 435,600 PJ (396 trillion cubic feet [Tcf]) of technically recoverable shale gas resources located within Australia[303].

The EIA estimates there are 268 Tcf of undeveloped shale gas resources within the onshore Canning and Perth Basins, more than twice the amount of WA's conventional gas resources[304]. A 2013 report by the Australian Council of Learned Academies (ACOLA) provides a higher estimate for shale resources located in WA and suggests there may be more shale resources (475 Tcf) than previously estimated.

Table 29 – Estimated Shale Gas Resources in Western Australia, 2012

Basin	EIA (Tcf)	EIA (PJ)	ACOLA (Tcf)	ACOLA (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 resources. Similar estimates are also reported in Gas Today (2013). ACOLA's (2013) figures are dry gas estimates in the respective basins. **Note:** Estimated shale resources are similar to estimates reported in Santos (2012). *EIA (2011) reports a lower estimate of 229 Tcf for the Canning Basin. **EIA (2011) and Bell Potter Securities (2011) report a higher estimate of 59 Tcf for the Perth Basin. Conversion factors are outlined in Appendix 11. ^Sum of Goldwyer and Laurel dry gas estimates.

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298 According to AWE Limited (2013), *Senecio feasibility study underway*, ASX announcement, 6 February 2013, http://www.awexplore.com/IRM/Company/ShowPage.aspx/PDFs/2779-67683348/Seneciofeasibilitystudyunderway, accessed 29 January 2014, AWE Limited managed to demonstrate a commercial gas flow capacity at its Senecio tight gas field. According Transerv Energy (2012), *Alcoa confirms it commitment to Warro Gas Project*, 5 November 2012, ASX Announcement, http://www.latentpet.com/images/stories/2012-11-05_Warro_Final_Commitment.pdf, accessed 23 April 2013, Transerv Energy's Warro gas field is estimated to contain three to four Tcf of recoverable gas.

299 See DMP (2013b), *Onshore Petroleum Successes*, http://www.dmp.wa.gov.au/documents/Onshore_Petroleum_Successes.pdf, accessed 15 October 2013. According to Advent Energy's website, it estimates that its Waggon Creek field potentially contains between 19 and 141 Tcf of shale gas, see http://www.adventenergy.com.au/projects/bonaparte/index.html, accessed 15 October 2013.

300 Hess acquired Kingsway Oil in 2012.

301 This represents an increase in interest in the Canning Basin. In May 2012, WA Business News (2012), Explorers Line Up to Unlock Onshore, 2 May 2012 reported only six entities were exploring unconventional gas in the Canning Basin; Buru Energy, ConocoPhilips, Mitsubishi Corporation, New Standard Energy, Hess and Kingsway Oil.

302 According to The Australian (2013), *PetroChina takes stakes in gas projects in deal with ConocoPhillips*, http://www.theaustralian.com.au/business/mining-energy/petrochina-takes-stakes-in-gas-projects-in-deal-with-conocophillips/story-e6frg9df-1226583068606, accessed 27 February 2013, in February 2013, PetroChina joined ConocoPhilips and New Standard Energy in its Goldwyer JV.

303 See Geoscience Australia (2012) for details.

304 See EIA (2013).

As shown in Table 29, the vast majority of the estimated shale gas reserves in WA are located in the Canning Basin. However, the remote location of this basin and lack of existing infrastructure make development of these reserves challenging. Other prospective basins for shale gas in WA include the Amadeus, Officer and onshore Bonaparte Basins, which are similarly remote[305].

Shale gas exploration activities are currently occurring within the Canning and Perth Basins. The most advanced shale explorer is believed to be AWE Limited, with the company exploring shale gas in its Woodada Deep and Arrowsmith fields located in the Perth Basin. The company reports it may be able to access approximately 13 to 20 Tcf of shale gas within its Perth Basin acreage[306].

10.3.2. Tight Gas Resources

Similar to shale gas, Australia has not ascertained its reserves of tight gas resources. As such, there are no accurate published estimates of WA tight gas reserves. Geoscience Australia estimates there are approximately 22,052 PJ (20 Tcf) of tight gas reserves in Australia. DMP considers that most of WA's tight gas reserves are located in the Perth Basin. The latest report from DMP estimates the Perth Basin contains approximately 12 Tcf of tight gas[307].

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 estimates reported by Geoscience Australia and DMP are conservative[308]. In addition to the Perth Basin, ASX announcements from Buru Energy suggest the Canning Basin may contain more tight gas than previously estimated. Table 30 provides estimates of tight gas reserves in WA.

Table 30 – Estimates of Tight Gas Reserves in Western Australia, 2012

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

Source: DMP (2013c), Buru Energy (2013b). **Note:** This table of tight gas estimates assumes a simple recoverability factor of 30% (EIA (2011) used a factor of 20-30%). It is acknowledged that the recovery factor is affected by formation and gas characteristics. *This is the sum of a proportion (30%) of the low estimate of AWE Limited's (2010) estimate (13 Tcf) for its Perth Basin tenements, a proportion (30%) of Norwest Energy (2013) unrisked estimate of North Erregulla (32 Tcf), and the low estimate of recoverable tight gas (three Tcf) for Transerv Energy's Warro Gas field, Transerv Energy (2012). The tight gas estimate does not include potential shale/tight gas estimates for Empire Oil and Gas within EP440 (36 Tcf) and EP368/EP426 (32 Tcf) reported to the ASX in May 2013, or Origin Energy's or Bharat Petroleum's estimates. **This is a proportion (30%) of the reported figure of Buru Energy's independent Review of Laurel Formation tight gas resources outlined in Buru Energy (2013b).

10.3.3. Other Unconventional Gas Resources

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

[305] According to the Commonwealth Scientific and Industrial Research Organisation (2012), *Australia's Shale Gas Resources*, http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/Shale-gas-potential.aspx, accessed 20 November 2013, these other basins may also contain shale gas.

[306] See AWE Limited (2010), *AWE announces 13-20 Tcf Gas in Place in its Perth Basin Shale Gas Acreage*, ASX announcement, 9 November 2010, http://www.asx.com.au/asxpdf/20101109/pdf/31trm8km18td7r.pdf, accessed 1 November 2013. The figures reported represent gas-in-place and ultimate recoverability is still unknown.

[307] This is an increase from the previous estimate outlined in DMP (2007), *Tight-gas Resources in Western Australia*, Petroleum in Western Australia, September 2007, http://www.dmp.wa.gov.au/documents/PWA_Sept_2007.pdf, accessed 28 February 2013 and DMP (2008), *Tight-gas Resources in the Northern Perth Basin, Petroleum in Western Australia*, April 2008, http://www.dmp.wa.gov.au/documents/071413_PWA-G.pdf, accessed 28 February 2013 (seven Tcf of tight gas) and PESA (2009) (10 Tcf of tight gas) and is broadly consistent with estimates reported in EISC (2011). Estimates of Buru Energy's unconventional gas are acquired from Buru Energy's March 2013 Corporate Update, http://www.buruenergy.com/download/recent-presentations/Buru%20Group%20Presn%20March%202013v1(2).pdf, accessed 16 April 2013. The latest report is DMP (2013c), *Western Australia Mineral and Petroleum Statistics Digest 2011-12*, http://www.dmp.wa.gov.au/documents/Statistics_Digest_2011-12.pdf, accessed 5 April 2013.

[308] See Geoscience Australia (2012) and DMP (2013c) reports.

According to SKM-MMA's report[309], Westralian Gas and Power is investigating the potential of CSG in the Perth Basin, while Eneabba Gas Limited is investigating the prospect of developing syngas as a feedstock for gas-fired power stations[310]. However, according to IES[311], the CSG exploration results to date in WA have been commercially disappointing, predominantly due to the low gas content of the coals in WA.

10.4. Remaining Resources and Reserves

Based on the total estimates of conventional and unconventional resources, Table 31 provides estimates of how long the remaining resources are expected to last based on existing and future expected production of domestic gas and LNG sales.

The results are reported in several ways; remaining resource years based on the most recent 2012-2013 gas production figures reported by DMP and Wood Mackenzie (for comparison), and remaining resource years based on total gas production forecasts for 2023. Both calculations assume production of gas is maintained at the same level *ad infinitum*.

Table 31 – Estimated Remaining Resource Years Based on Production for Western Australia, 2012 and 2023

Reserves and Resources	Resources and Reserves - 2012 (PJ)	2012-2013 Processing (PJ)	Estimated Production – Wood Mackenzie 2013**	Remaining Years beyond 2012 (based on 2012-2013 Processing)	Remaining Years beyond 2012 (based on Wood Mackenzie 2013 Production)	2023 Total Gas Demand Forecasts – Base Scenario (PJ)	Remaining Years beyond 2023 (based on 2023 Forecasts)
2P Reserves (see Table 34)	90,363	1,424	1190.63	72.1	75.9	3,768.5	24.0
McKelvey's Economic Resources only	102,700	1,424	1190.63	111.6	86.3	3,768.5	27.3
McKelvey's Economic and Sub-Economic Resources	159,000	1,424	1190.63	311.1	133.5	3,768.5	42.2
McKelvey's Economic and Sub-Economic Resources + EIA (2013) Shale Resources (PJ)	443,080*	1,424	1190.63	311.1	372.1	3,768.5	117.6
McKelvey's Economic and Sub-Economic Resources + EIA (2013) Shale Resources (PJ) & Official Tight Gas Estimates (12 PJ)	443,102	1,424	1190.63	311.1	372.2	3,768.5	117.6

Source: EnergyQuest (2013), Geoscience Australia (2012), BREE (2013), WA Business News (2013), DMP (2013) and NIEIR forecasts. **Estimated Production by Wood MacKenzie for 2013 was reported in WA Business News (2013). **Note:** Reserves by Company include gas fields that are not connect to any particular production facility.

Table 31 estimates the remaining years of WA gas production based on various classifications of resources reported by the Commonwealth Government. If sub-economic resources become economic in the future and unconventional gas resources can be developed in WA, Table 31 suggests there are sufficient resources in WA to last for approximately another 118 years at forecast 2023 demand levels. However, this estimate is highly reliant on the development of unconventional gas resources in WA, which represent nearly two-thirds of the estimate. If no unconventional resources are developed, remaining resource years based on

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309 See SKM-MMA (2011).
310 See Eneabba Gas Limited (2012), *The Future of Energy*, Company Presentation, August 2012, http://www.openbriefing.com/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20120803%2F01320135.pdf, accessed 5 July 2013.
311 See IES (2013).

conventional gas resources are estimated to be between approximately 27 years (excluding sub-economic resources) to 42 years (including sub-economic resources) from 2023, assuming gas production remained unchanged at the 2023 total gas demand forecast level outlined in this GSOO.

This GSOO is adopting a more conservative estimate than the July 2013 GSOO as, 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[312].

While existing gas resources are forecast to be sufficient to meet forecast domestic, LNG and FLNG demand levels for a considerable period beyond 2023, Table 31 suggests that the development of unconventional gas resources will be increasingly important in order to maintain WA gas production in future decades.

10.4.1. Resources and Reserves by Basin

As noted previously, WA is highly reliant on the Carnarvon Basin for its gas requirements (both domestic gas and LNG exports). The Carnarvon Basin, along with the Bonaparte and Browse Basins, where most of WA's gas resources are located, are offshore resources and within the Commonwealth's jurisdiction.

Table 32 shows conventional resources from the Carnarvon Basin are expected to last for another 27 years from 2012, assuming no additional exploration takes place and total gas production remains unchanged at the 2023 total gas demand forecast level outlined in this GSOO.

There is a risk that Carnarvon Basin resources may be depleted more quickly, considering additional LNG export projects are being considered for the Carnarvon.

Table 32 also indicates WA may be too reliant on a single basin for its domestic gas needs and LNG exports. This suggests gas exploration and production in other WA basins should be encouraged, such as in the Canning and Perth Basins, to diversify WA's sources of gas supply in order to secure the continued supply of gas to WA.

Table 32 – Estimated Remaining Resource Years Based on Production for Western Australia, 2012 and 2023

	Bonaparte	Browse	Canning	Carnarvon	Perth
Remaining Resource Estimate (McKelvey's EDR + SDR) – Conventional only	22,000	35,300	<10	101,500	200
Remaining Resource Estimate (McKelvey's EDR + SDR) including EIA (2013) Unconventional Estimates	-	-	249,100	-	3,980
Estimated 2P Gas Reserves – EnergyQuest (2013)	1,054	17,384	-	71,855	54
Estimated Production (2013) – Wood Mackenzie	Not Provided	Not Provided	Not Provided	1,706.9	11
2023 Total Gas Demand Forecasts (PJ)	-	-	-	3,768.5	23*
Remaining Resource Years beyond 2013 (based on Wood Mackenzie 2013 Forecasts) – Conventional Only	Not Provided	Not Provided	Not Provided	59.5	18.2
Remaining Resource Years beyond 2013 (based on Wood Mackenzie 2013 Forecasts) – Conventional and Unconventional	Not Estimated	Not Estimated	Not Estimated	59.5	3,198.2
Remaining Resource Years beyond 2013 (based on 2023 total gas demand forecasts) – Conventional Only	Not Estimated	Not Estimated	Not Estimated	26.9	11

Source: Geoscience Australia (2012), Business News (2013), EnergyQuest (2013) and NIEIR forecasts. **Note:** Gas production figures are Wood Mackenzie's estimates reported in Business News (2013), which are converted from million cubic feet (Mcf)/day to PJ/annum. These estimates do not represent full 2013 actual production; actual production values may vary significantly from estimated figures due to seasonality. Estimates reported in this table also include estimates of NWS and Pluto LNG production. *This figure is not modelled, it is simply estimated using the same proportions estimated by Wood MacKenzie in the Business News (2013).

10.4.2. 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, this section reviews the quantum of 2P reserves connected to each domestic

[312] At the time of this report, there is no known commercial production of unconventional gas in WA, although Santos has successfully commenced commercial production of shale gas in the Cooper Basin in South Australia, October 2012. See Santos (2012b), *Santos announces start of Australia's first commercial shale gas production*, 19 October 2012, see http://www.santos.com/Archive/NewsDetail.aspx?id=1347, accessed 18 November 2013.

production facility and estimates the remaining production years using estimates of domestic production for 2013 reported by Wood Mackenzie against reserves reported by EnergyQuest.

Table 33 suggests there are likely to be sufficient gas reserves supporting all domestic gas production facilities supplying to the domestic market, assuming 2013 production rates estimated by Wood MacKenzie are maintained for the entire 2014 to 2023 period, except for Dongara or Beharra Springs. While there is a possibility that the gas supply from either these facilities may cease in the 2014 to 2023 period, the disruption to domestic gas supply is minimal as their contribution to the domestic market is small and can easily be replaced by other providers that have spare capacity (see section 9.1).

Table 33 – Estimated Gas Reserves Linked to Domestic Production Facilities, November 2013

<table>
<tr><th>Production facilities</th><th>Gas Field</th><th>Operator</th><th>Basin</th><th>Estimated 2P Reserves (PJ)</th><th>Estimated Total Production – 2013 – Wood Mackenzie (PJ)</th><th>Years Remaining (Implied) from 2013 – Wood Mackenzie</th></tr>
<tr><td>Operational</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Karratha Gas Plant</td><td>NWS JVs fields</td><td>Woodside</td><td>Carnarvon</td><td>15,173</td><td>1190.7 (including LNG production)</td><td>12.7</td></tr>
<tr><td>Varanus Island</td><td>John Brookes, Harriet gas fields and Spar/Halyard</td><td>Apache Energy</td><td>Carnarvon</td><td>1,451</td><td>228.9</td><td>13.3</td></tr>
<tr><td>Devil Creek</td><td>Reindeer</td><td>Apache Energy</td><td>Carnarvon</td><td>451[#]</td><td>39.8</td><td>11.3</td></tr>
<tr><td>Dongara</td><td>Dongara, Yardarino and Elegans</td><td>AWE Limited</td><td>Perth</td><td rowspan="2">38.6^</td><td rowspan="2">9.2</td><td rowspan="2">4.2[%%]</td></tr>
<tr><td>Beharra Springs</td><td>Beharra Springs, Beharra Springs North and Tarantula</td><td>Origin Energy</td><td>Perth</td></tr>
<tr><td>Red Gully</td><td>Red Gully and Gingin</td><td>Empire Oil and Gas</td><td>Perth</td><td>228**</td><td>1.8^</td><td>126.7</td></tr>
<tr><td>Macedon</td><td>Macedon</td><td>BHP Billiton</td><td>Carnarvon</td><td>570[%]</td><td>65.7^^</td><td>>10[##]</td></tr>
<tr><td>Under Construction/ Consideration</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Gorgon Domestic*</td><td>Gorgon, Jansz, Io, Chrysaor, Dionysius and Eurytion</td><td>Chevron</td><td>Carnarvon</td><td>40,969</td><td>N.A</td><td>N.A</td></tr>
<tr><td>Wheatstone Domestic*</td><td>Wheatstone and Julimar Brunello</td><td>Chevron</td><td>Carnarvon</td><td>7,490</td><td>N.A</td><td>N.A</td></tr>
<tr><td>Pluto Domestic</td><td>Pluto</td><td>Woodside</td><td>Carnarvon</td><td>5,719</td><td>N.A</td><td>N.A</td></tr>
<tr><td>Total</td><td></td><td></td><td></td><td>72,089.6</td><td></td><td></td></tr>
</table>

Source: EnergyQuest (2013), AWE Limited Annual Report, Original Energy Annual Reserves Report and Business News (2013). **Note:** Gas production figures are estimates by Wood MacKenzie for 2013, reported in Business News (2013) and converted from Mcf/day to PJ per annum. These estimates do not represent full 2013 actual production; actual production values may vary significantly from estimated figures due to seasonality. *At the time of this report, these facilities are not operational. Deutsche Bank (2012) estimates there are approximately 18,028 PJ (17 Tcf) remaining in the NWS JVs fields. **Estimates include Gingin gas fields and do not take into account Empire's potential reserves in unconventional gas. [#]Does not include reserves from the Caribou field. ^Summation of Reserves reported in AWE Limited (2013b) Annual Report and Origin's (2013) Annual Reserves Report for Perth Basin. [%]Reserves for Macedon may be significantly higher than figures suggest as DMP (2013c) reports that gas extracted from the BHP Billiton operated Pyrenees Floating Production Storage and Offloading (FSPO) project is re-injected at 60 Mcf/day into the nearby Macedon field for future recovery. The Macedon JV and the WA Government have a 25-year agreement that formalises key commitments for the Macedon facility. BHP Billiton (2013) has also publicly announced that Macedon will produce gas until at least 2033. ^^Not estimated by Wood MacKenzie, estimated using 80% utilisation rate (reported in Empire Oil and Gas (2013b) Quarterly report, for the period ended 30 September 2013, http://empireoil.com.au/sites/empireoil.com.au/files/financial_information/ego-financials-quarterly-report-30-September-2013.pdf, accessed 20 November 2013) for Red Gully and 90% utilisation rate for Macedon. [##]The Macedon gas production facility is supported by additional reinjection of gas from the Pyrenees FSPO. [%%]While this figure is low, the IMO has been made aware of existing activities to increase the life of the production facility. This table does not consider LPG production that may be extracted from the same gas stream from the gas field. Note: 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.

10.4.3. Estimated Reserves by Company

Table 34 includes reserves estimates by company as reported by EnergyQuest and shows that as at the end of November 2013, 10 companies own approximately 91.9% of WA's known 2P gas reserves. It is estimated that approximately 99.9% of all discovered 2P reserves are located offshore[313]. Offshore gas, being more capital intensive to extract, is likely to face a higher cost of production and thus may influence the cost of gas in WA.

Table 34 – Natural Gas Reserves by Company (Western Australia and Northern Territory), November 2013

Company	2P Reserves (PJ)	Share (%)
Chevron	26,101	28.8%
Shell	14,995	16.6%
ExxonMobil	10,242	11.3%
Inpex	9,294	10.3%
Woodside	7,950	8.8%
TOTAL	4,070	4.5%
BP	2,960	3.3%
BHP Billiton	2,708	3.0%
Apache	2,624	2.9%
MIMI	2,204	2.4%
Santos	972	1.1%
Eni	914	1.0%
Tokyo Gas Co	909	1.0%
Kufpec	764	0.8%
CNOOC	752	0.8%
Osaka Gas	675	0.7%
Tokyo EP	551	0.6%
CPC	547	0.6%
Kogas	382	0.4%
Kansai Electric	286	0.3%
Chubu Electric Power	271	0.3%
Kyushu Electric Power	98	0.1%
ConocoPhillips	90	0.1%
Toho Gas	57	0.1%
Magellan	55	0.1%
Origin Energy	27	0.0%
AWE Limited	12	0.0%
Empire Oil and Gas	11	0.0%
ERM Power	4	0.0%
Total	**90,525**	**100.00%**

Source: EnergyQuest (2013). Although the table includes 2P reserves from NT, as these only represent 178 PJ (<1% of the total), the market shares of the companies are largely unaffected. **Note:** 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.

According to EnergyQuest's November 2013 report, there is a slight increase in the quantity of 2P reserves for WA from the July 2013 GSOO, increasing from approximately 90,334 PJ in total at the end of May 2013 to 90,347 PJ in November 2013.

313 Although this is not shown, EnergyQuest (2013) reports approximately 90,471 PJ of total 2P reserves are located offshore.

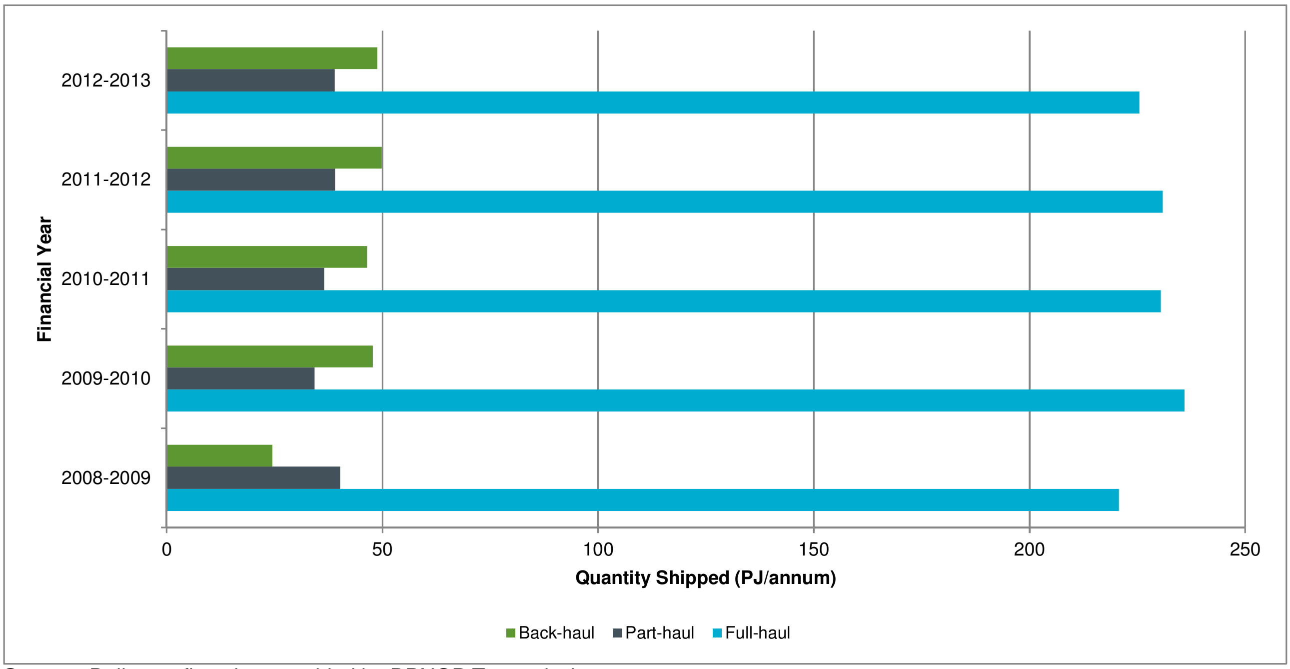
11. Gas Transmission

This chapter focuses on the gas transmission segment of the domestic market to understand the capacity for shipping of gas supplies to nominated delivery points on the pipeline network. It includes a review of the transmission capability and the utilisation of the main transmission pipelines (the DBNGP and the GGP).

11.1. Utilisation of the DBNGP and GGP

Figure 62 shows the quantity of gas shipped on the DBNGP on a full-haul[314], part-haul[315] and back-haul[316] basis over the 2008-2009 to 2012-2013 period. In 2012-2013, the DBNGP shipped approximately 225 PJ of gas from inlet points mostly located in the Carnarvon Basin to the south of Compressor Station Nine.

Figure 62 – Quantity of Gas Shipped by DBNGP (Full-Haul, Part-Haul and Back-Haul), 2008-2009 to 2012-2013



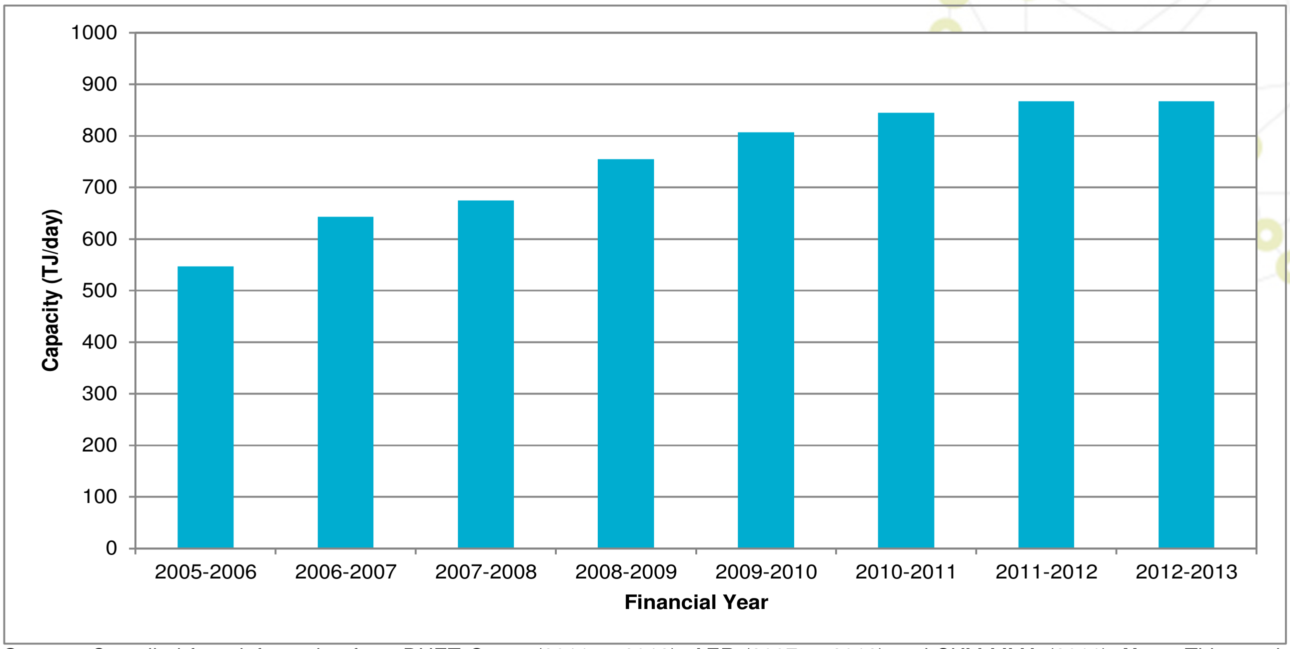
Source: Daily gas flow data provided by DBNGP Transmission.

Figure 63 shows the estimated annual full-haul capacity of the DBNGP from 2006-2007 to 2012-2013. The figure shows the DBNGP's average annual capacity increased through three major expansion projects that commenced between 2005 and 2010.

Figure 63 shows a current full-haul capacity of the DBNGP of 867 TJ/day, consistent with the information published in the DBNGP Capacity Register, published in September 2013[317]. DBNGP Transmission describes the value as representing "*the amount of Gas Transmission Capacity at which the probability of supply for the next GJ of Gas to be transported in the DBNGP is less than 98% for each Period of a Gas Year*". However, this value differs from the nameplate capacity of 845 TJ/day that has been provided as Standing Data for the GBB[318].

[314] Full-haul means the shipping of gas on the DBNGP to any gas outlet beyond Compressor Station Nine.
[315] Part-haul means the shipping of gas on the DBNGP to any gas outlet before Compressor Station Nine.
[316] Back-haul means the shipping of gas on the DBNGP to any gas outlet upstream of the inlet point.
[317] DBNGP Transmission (2013), *DBNGP Capacity Register*, http://www.dbp.net.au/access.aspx, accessed 16 November 2013.
[318] The GSI Rules define the Nameplate Capacity for a Transmission Pipeline as "*the maximum quantity of natural gas that, under normal operating conditions, can be delivered through the pipeline on a Gas Day*", see Appendix 1 of the GSI Rules.

Figure 63 – Estimated Full-Haul Capacity of DBNGP, 2006-2007 to 2012-2013



Source: Compiled from information from DUET Group (2011 to 2013), AER (2007 to 2012) and SKM-MMA (2011). **Note:** This graph has been revised from the July 2013 GSOO by applying the 867 TJ/day contracted capacity forecast for 2012-2013 and 2013-2014 reported in DBNGP Transmission (2012) and (2013).

DBNGP Transmission reports there is currently capacity available to support up to 10.5 TJ/day of full-haul transmission service on the pipeline with the remainder of full-haul services contracted. Table 35 shows the contracted capacity for the DBNGP at the end of the 2012 calendar year and 2013-2014 financial year[319].

Table 35 – Comparison of Forecast against Actual of Demand for DBNGP Services, December 2012 and June 2014

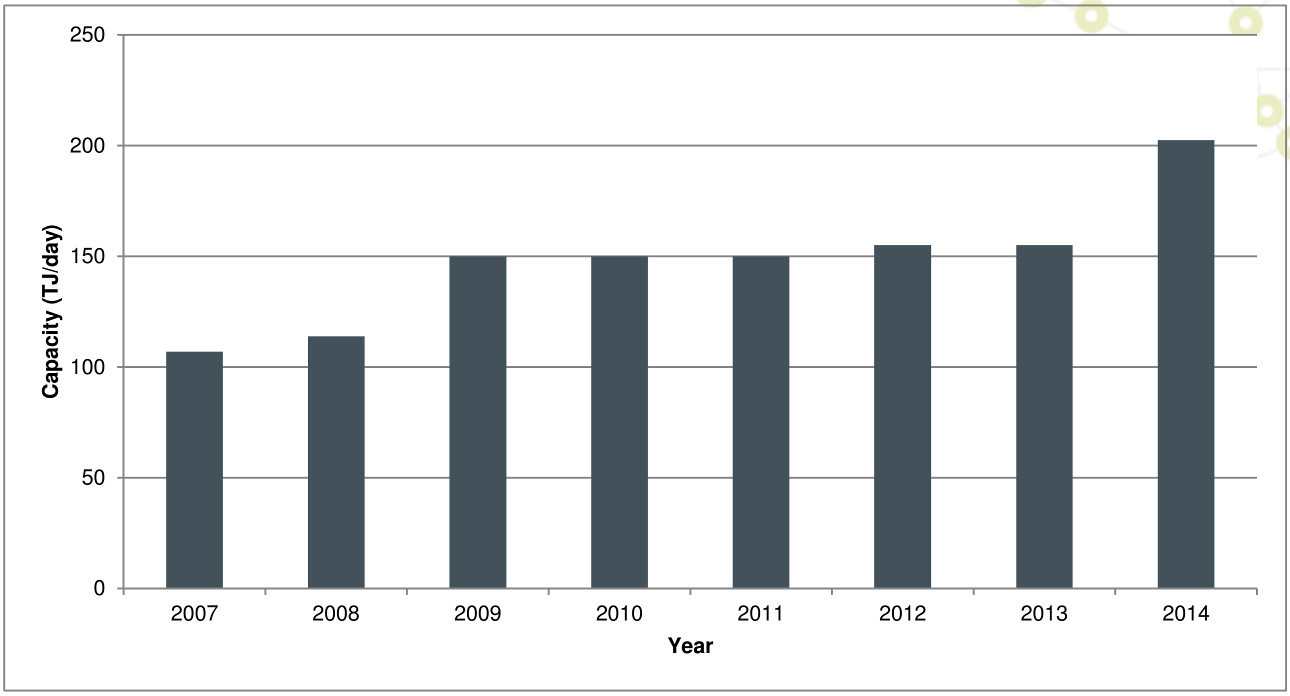
DBNGP – Full-Haul	December 2012 (TJ/day)	June 2014 (TJ/day)
Available Capacity	867.0	867.0
Contracted Capacity	867.0	856.5
Contracted Capacity (%)	**100%***	**98.8%***
Forecasted Full-Haul Throughput	651.0	630.0
Actual Full-Haul Throughput (2012)	630.2	N.A
Forecasted Expected Full-Haul Utilisation (%)	75%	72.7%
Actual Full-haul Utilisation (%)	**72.7%**	**N.A**
DBNGP – Part-Haul	**December 2012 (TJ/day)**	**June 2014 (TJ/day)**
Available Capacity	**N.R**	**N.R**
Contracted Capacity	242.2	242.9
Forecasted Part-Haul Throughput	135.7	130.5
Actual Part-Haul Throughput (2012)	103.3	N.A
Forecasted Part-Haul Utilisation (%)	56.0%	53.7%
Actual Part-haul Utilisation (%)	**42.7%**	**N.A**
DBNGP – Back-Haul	**December 2012 (TJ/day)**	**June 2014 (TJ/day)**
Available Capacity	N.R	N.R
Contracted Capacity	174.0	174.0
Forecasted Back-Haul Throughput	137.5	137.5
Actual Back-Haul Throughput (2012)	133.8	N.A
Forecasted Back-Haul Utilisation (%)	79.0%	79.0%
Actual Back-haul Utilisation (%)	**76.9%**	**N.A**

Source: DBNGP Transmission (2012) and (2013). **Note:** N.A – Not Available, N.R – Not Reported. Utilisation rates are calculated on capacity.

[319] This GSOO focuses on the main shipping services of DBNGP Transmission. The IMO has been advised that the company 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.

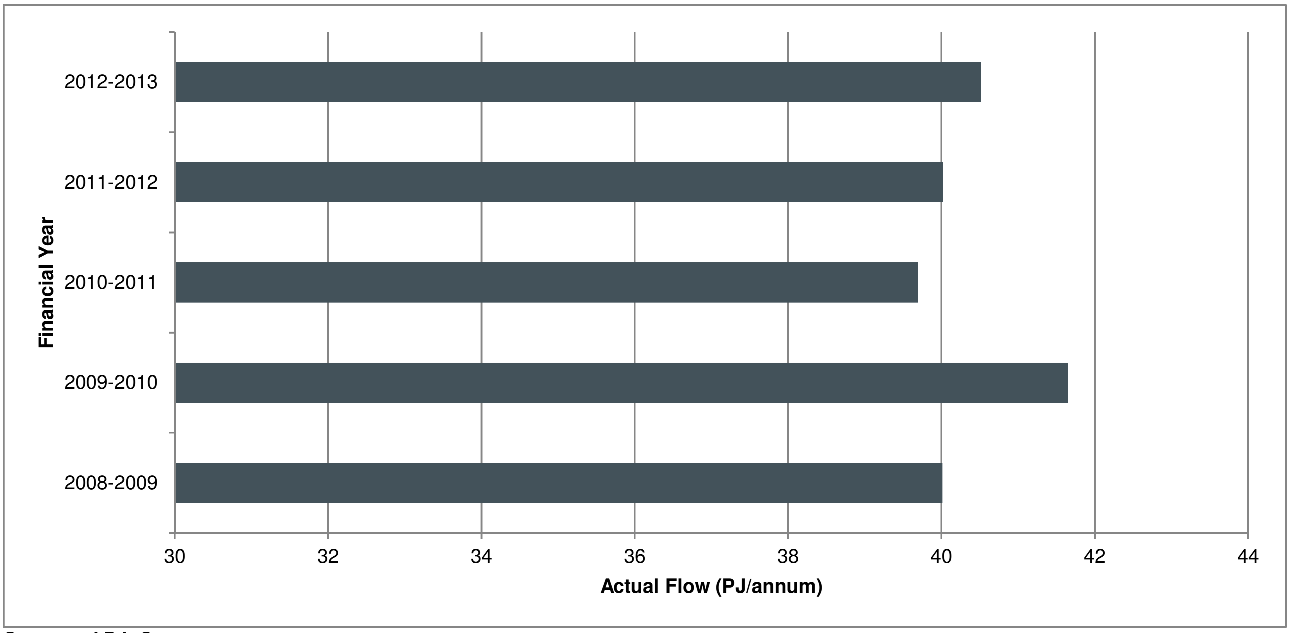
Figures 64 and 65 present the estimated annual capacity and the quantity of gas shipped, respectively, for the GGP over the 2008 to 2013 period. In 2012-2013, the GGP shipped approximately 41 PJ of gas. The APA Group reports there is currently spare firm transmission capacity, amounting to 3.5 TJ/day at Wiluna[320].

Figure 64 – Estimated Annual Capacity of GGP, 2007 – 2014



Source: GGP's pipeline capacity is estimated from AER (2007-2012), APA Group's public announcements, APA Group's submissions to the ERA and information provided directly by APA Group. **Note:** The GGP's pipeline capacity is expected to increase to approximately 202.4 TJ/day in 2014, see APA (2012).

Figure 65 – Quantity of Gas Shipped by GGP, 2008-2009 to 2012-2013



Source: APA Group.

[320] See APA (2012), *GGP Capacity Register*, http://www.apa.com.au/media/213106/ggp%20capacity%20register%2011-jul-2013.pdf, accessed 15 November 2013.

APA Group is currently increasing the capacity of the GGP and the majority of the expanded nameplate capacity of 47.4 TJ/day has been secured through 15 and 20-year contracts with BHP Billiton (24 TJ/day) and Rio Tinto (20 TJ/day), respectively[321].

Table 36 – Comparison of Forecasts against Actual of Demand for GGP Services, 2013 and 2014

GGP	2013 (TJ/day)	2014 (TJ/day)
Available Firm Capacity	108.9	Unknown (estimated to be more than 152.9 TJ/day after expansion)*
Contracted Capacity	105.4	149.4**
Contracted Capacity (%)	**96.8%**	**N.A**
Forecasted Throughput	89.7	N.A
Actual Throughput	111.1 (until 31 December 2013)	N.A
Forecasted Expected Utilisation (%)	75.9%	N.A
Actual Utilisation (%)	**100%**	**N.A**

Source: APA Group website, see http://www.apa.com.au/our-business/economic-regulation/wa.aspx, accessed 27 November 2013. **Note:** N.A – Not Available. Utilisation rates are calculated on capacity. *44 TJ/day of additional firm capacity is estimated to be added through the GGP expansion. **Estimated to include Rio Tinto and BHP's long-term contracts with APA Group.

Since the July 2013 GSOO, a small quantity of spare shipping capacity has emerged on both the DBNGP and the GGP[322]. This is due to the expiry of shipping contracts that are replaced or extended at different contracted quantities[323]. However, the low availability of firm shipping capacity continues to represent a challenge for medium to large gas consuming projects.

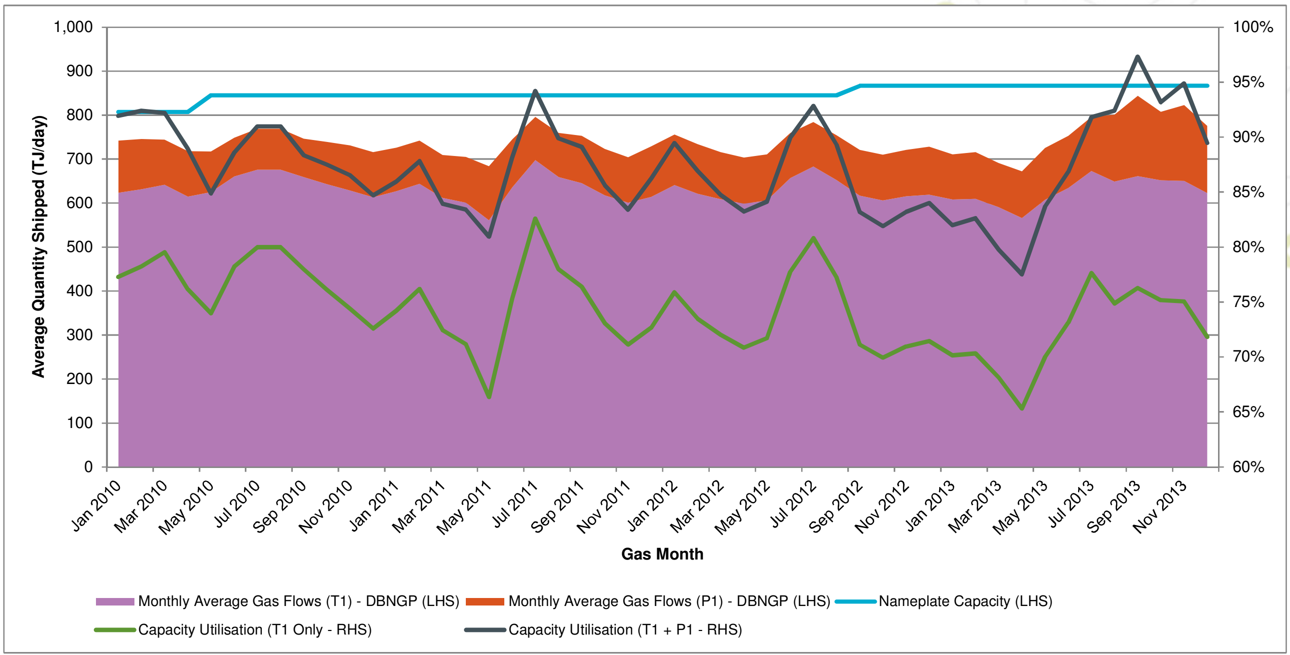
Recent expansions of both the DBNGP and the GGP demonstrate that additional firm capacity can be constructed to meet the project timeframes of shippers. However, continued development of firm gas transmission capacity will depend upon customers' ability to secure long-term gas supplies to underpin investment in new gas pipelines or significant expansion of existing pipelines.

In contrast to the small amounts of firm capacity on both transmission pipelines currently available, it is understood there are readily available quantities of interruptible non-firm capacity as the pipelines' maximum capacities are rarely reached[324]. This is indicated by the utilisation rates for the DBNGP and GGP which are shown in Figure 66 and Figure 67 respectively, and summarised in Table 37.

During winter months, the non-firm capacity of both pipelines is understood to be higher when lower atmospheric temperatures allow gas-powered compressors along the pipeline to run more efficiently. The higher availability of non-firm capacity during the winter, combined with the recently completed Mondarra gas storage facility will now offer an additional option of shipping and storing gas during off-peak periods for delivery in peak periods, allowing customers connected to the Parmelia Pipeline and DBNGP to more efficiently meet their gas consumption requirements. This may allow some gas shippers to reconsider their gas shipping capacity requirements.

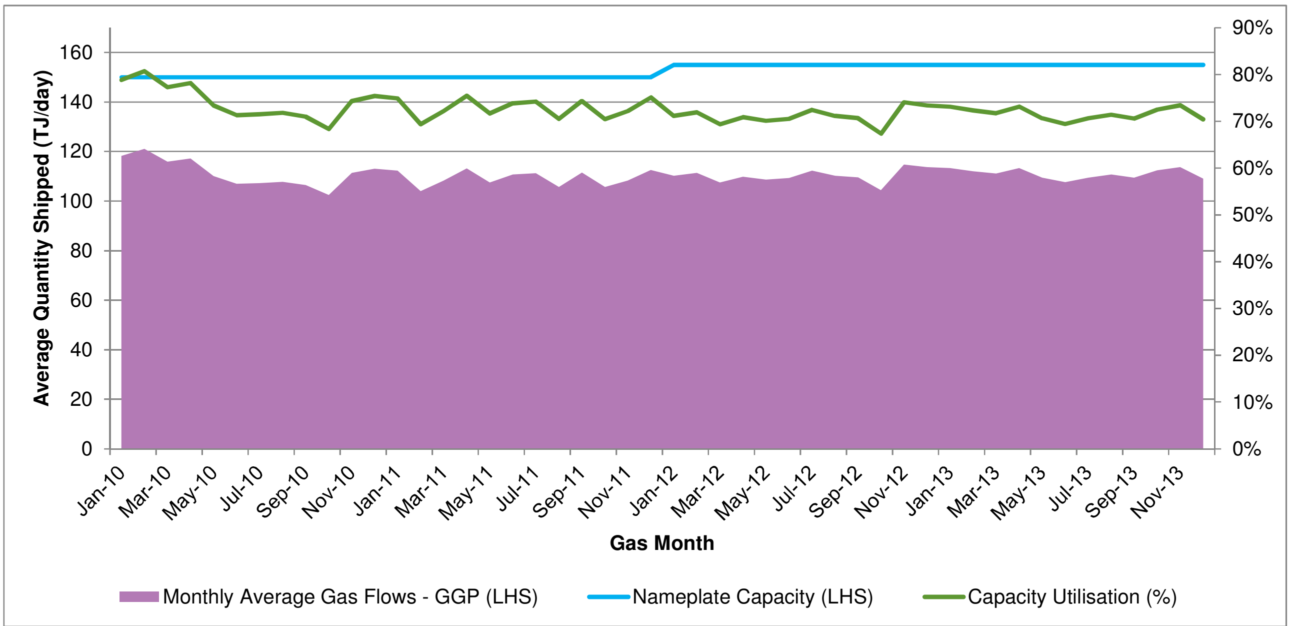
[321] See APA Group (2011, 2012), announcements on the planned expansion of the GGP and long-term contracts with Rio Tinto and BHP Billiton.
[322] See DBNGP Transmission (2013) and APA Group (2013), respectively.
[323] At this point in time, the IMO is not aware of the correlation between the end dates for existing gas and pipeline capacity contracts, although this may be explored in future GSOOs.
[324] Ambient operating temperature is a factor in the actual capacity of a pipeline for a particular gas day. Other known factors include pipeline diameter and length, gravity, density, compressibility, flowing temperature and viscosity of gas, pressure and friction.

Figure 66 – Estimated Utilisation Rates of DBNGP (Full-Haul and Part-Haul only), January 2010 to December 2013



Source: DBNGP Transmission, full-haul and part-haul monthly averages. **Note:** Nameplate capacity is as per Figure 63. Actual gas flows are monthly average gas flows.

Figure 67 – Estimated Utilisation Rates of GGP, January 2010 to December 2013



Source: APA Group. **Note:** A nameplate capacity of 150 TJ/day was used for the January 2010 to December 2011 period, as reported by AER (2011) and (2012). A constant nameplate capacity of 155 TJ/day is used for the January 2012 to August 2013 period. For the August to December 2013 period, the average GGP pipeline capacity reported to the GBB (155 TJ/day) is applied. Actual gas flows are monthly average gas flows.

To analyse the shipping utilisation rates of the DBNGP and the GGP, the utilisation is measured by comparing the average monthly gas flows against the nameplate capacity[325]. This is shown in Table 37.

[325] Capacity utilisation may be measured using three methods; as a measure of the average-natural gas throughput relative to estimates of system capacity at pipeline boundaries; as a system peak-day usage rate, which generally reflects peak system deliveries relative to estimated system capacity, or by measuring a system-wide pipeline flow rate, which highlights variations in system usage relative to an estimated system peak throughput level.

Table 37 – Main Transmission Pipelines, Estimated Capacity Utilisation, January 2010 to December 2013

Key Transmission Pipelines	Estimated Utilisation Rate (Min-Max) (%)*
Dampier to Bunbury Natural Gas Pipeline	65% - 83% (Full-haul only) 78% - 97% (Full-haul and Part-haul)
Goldfields Gas Pipeline	67% - 81%

Source: DBNGP Transmission and APA Group. **Note:** Utilisation rates are calculated based on the capacity values outlined in Figures 66 and 67. Capacity of a pipeline may vary over the course of a year due to weather conditions. *Due to the sensitive nature of the pipeline data, only a range of minimum and maximum utilisation rates are reported, representing the minimum and maximum utilisation rate of the pipeline's monthly average gas flow.

Two utilisation rates for the DBNGP are shown in Figure 66 as some part-haul customers only require the shipping of gas from the Pilbara to the Mid West. Part-haul transmission represents approximately 12%[326] of the total shipped volume of the DBNGP.

Figures 66 and 67 suggest the capacity of the DBNGP and GGP may not be fully utilised. This is expected, to some extent, given market demand for gas fluctuates day-to-day and gas buyers need to contract their maximum daily requirement to ensure delivery for peak demand.

This is also likely to be affected by economic conditions, and in particular, the significant increase in gas prices over the past few years which have seen gas demand plateau. It is likely that some customers who contracted pipeline capacity may not require the full contracted capacity due to falling demand.

It is understood that while some gas shippers utilise their firm capacity to ship gas on behalf of other shippers on a regular basis, firm pipeline capacity is not directly traded. Further research may be warranted into understanding the utilisation of transmission capacity by shippers in WA.

In a recent report, the Grattan Institute suggested the implementation of a transparent platform for trading short-term access to pipeline capacity[327]. The IMO's GAB has also indicated interest in investigating potential gas and capacity trading markets for WA.

11.2. Utilisation of Other Pipelines, 1 August 2013 to 31 December 2013

This section presents the utilisation rates of other WA pipelines for the 1 August 2013 to 31 December 2013 period as reported to the GBB. Table 38 presents the average quantities of gas shipped and the average utilisation of each pipeline. GBB data suggests other gas transmission pipelines in WA are similarly utilised in that parties contract for maximum demand, but seldom use this capacity on a continuous basis.

Table 38 – Estimated Utilisation Rate of Pipelines, GBB Data, 1 August 2013 – 31 December 2013

Pipeline	Nameplate capacity (TJ/day)	Average Utilisation (TJ/day)	Average Utilisation (%)
Pilbara Energy Pipeline*	166.0	59.6	35.9%
Telfer Gas Pipeline	29.0	24.2	83.5%
Mid West Pipeline	10.6	5.0	47.0%
Parmelia Pipeline	65.4	19.2	29.4%
Kalgoorlie to Kambalda Pipeline	29.3	Not reported	Not reported
Kambalda to Esperance Pipeline	6	Not reported	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 that pipeline entirely. * Excludes the Burrup Extension Pipeline.

11.3. Peak Gas Days, 2009-2013

[326] This is calculated by the IMO using the average of daily actual part-haul gas flow for each month for the 1 January 2010 to 31 December 2013 period provided by DBNGP Transmission.
[327] Grattan Institute (2013).

This section presents the peak gas days for 2009 to 2013 (up to 31 December 2013). Table 39 presents the quantities of gas transported on the DBNGP (full-haul only) on the top 10 days for the pipeline in each year, with Table 40 listing the respective dates. Tables 41 and 42 present similar information for the GGP over the same period.

The data presented in Tables 39 and 40 for the DBNGP (full-haul only) suggest that peak gas days on the pipeline occur more frequently during winter, and thus do not necessarily align with the summer electricity demand peaks experienced on the SWIS.

The exceptions are 2012 and 2013, in which peak gas demand was more closely aligned with summer days of highest electricity demand in the SWIS, when the use of gas turbine generators increases. The highest recorded gas flows on the DBNGP (full-haul) for these years occurred on 27 January 2012 and 12 February 2013, respectively. The seventh and ninth highest gas flow for 2013 also occurred other days identified within the 12 peak trading intervals for SWIS electricity demand[328].

The peak gas day data suggests gas consumption peaks may be becoming more coincident with the use of gas turbine generators in peak electricity demand periods within the SWIS.

Table 39 – Top 10 Peak Gas Days (Full-Haul), DBNGP, 2009 – 2013

Top 10 Peak Days (TJ/day) - DBNGP	2009	2010	2011	2012	2013
Highest reported gas flow	745.78	747.56	792.24	764.04	739.89
Second highest reported gas flow	743.62	744.87	782.33	737.58	727.00
Third highest reported gas flow	740.59	744.53	775.73	730.58	723.49
Fourth highest reported gas flow	735.68	730.95	761.78	728.09	711.02
Fifth highest reported gas flow	734.12	722.16	753.91	724.25	710.43
Sixth highest reported gas flow	731.09	719.48	744.56	722.19	710.43
Seventh highest reported gas flow	728.49	718.77	742.23	719.76	704.45
Eighth highest reported gas flow	726.82	717.87	735.75	716.34	701.72
Ninth highest reported gas flow	725.58	716.36	721.48	714.26	701.40
Tenth highest reported gas flow	723.83	715.28	719.89	714.05	699.91

Source: DBNGP Transmission and IMO GBB data. **Note:** Peak Days are based on total gas delivered for the pipeline.

Table 40 – Dates for Top 10 Peak Gas Days (Full-Haul), DBNGP, 2009 – 2013

Top 10 Peak Days (TJ/day) - DBNGP	2009	2010	2011	2012	2013
Highest reported gas flow	3/10/2009	9/07/2010	7/07/2011	27/01/2012	12/02/2013
Second highest reported gas flow	6/09/2009	26/02/2010	5/07/2011	10/07/2012	16/12/2013
Third highest reported gas flow	24/07/2009	25/02/2010	6/07/2011	24/07/2012	31/07/2013
Fourth highest reported gas flow	26/07/2009	12/07/2010	11/07/2011	9/07/2012	29/07/2013
Fifth highest reported gas flow	24/08/2009	6/07/2010	4/07/2011	4/12/2012	11/02/2013
Sixth highest reported gas flow	7/09/2009	19/07/2010	1/07/2011	28/01/2012	30/07/2013
Seventh highest reported gas flow	5/09/2009	8/07/2010	8/07/2011	13/08/2012	13/02/2013
Eighth highest reported gas flow	4/10/2009	11/03/2010	30/06/2011	12/07/2012	27/08/2013
Ninth highest reported gas flow	31/08/2009	12/03/2010	29/06/2011	21/06/2012	12/12/2013
Tenth highest reported gas flow	1/09/2009	18/08/2010	12/07/2011	25/07/2012	22/11/2013

Source: DBNGP Transmission and IMO GBB data. **Note:** Peak Days are based on total gas delivered for the pipeline.

The data presented in Tables 41 and 42 for the GGP shows different peak gas days that do not appear to follow any seasonal patterns. Gas consumption on the GGP may be more strongly correlated to seasonal demand for commodities extracted by mining operations consuming gas along the GGP[329].

[328] The 12 peak trading intervals are key components of determining an electricity customer's obligation to pay for capacity in the SWIS.
[329] While this is suggested, it was not fully analysed to determine if there is a link between seasonal demand for commodities and gas demand along the GGP.

Table 41 – Top 10 Peak Gas Days, GGP, 2009 – 2013

Top 10 Peak Days (TJ/day) - GGP	2009	2010	2011	2012	2013
Highest reported gas flow	130.12	130.97	126.45	123.79	122.60
Second highest reported gas flow	127.23	129.24	126.20	123.79	122.60
Third highest reported gas flow	127.11	126.90	125.23	123.03	122.40
Fourth highest reported gas flow	127.09	126.89	124.57	122.63	122.22
Fifth highest reported gas flow	125.83	126.22	124.03	122.45	121.99
Sixth highest reported gas flow	125.75	125.87	122.80	121.88	121.60
Seventh highest reported gas flow	125.59	125.73	122.01	120.75	121.40
Eighth highest reported gas flow	124.66	124.95	121.63	120.66	121.20
Ninth highest reported gas flow	124.39	124.76	121.57	120.43	120.90
Tenth highest reported gas flow	124.12	124.33	120.11	120.23	120.90

Source: APA Group and IMO GBB data. **Note:** Peak Days are based on total gas delivered for the pipeline.

Table 42 – Dates for Top 10 Peak Gas Days, GGP, 2009 – 2013

Top 10 Peak Days (TJ/day) - GGP	2009	2010	2011	2012	2013
Highest reported gas flow	6/03/2009	21/02/2010	8/04/2011	30/10/2012	9/10/2013
Second highest reported gas flow	11/12/2009	12/02/2010	7/04/2011	31/10/2012	11/10/2013
Third highest reported gas flow	26/10/2009	18/02/2010	6/04/2011	13/02/2012	9/02/2013
Fourth highest reported gas flow	7/03/2009	11/02/2010	9/04/2011	6/11/2012	27/01/2013
Fifth highest reported gas flow	4/03/2009	13/02/2010	2/07/2011	29/07/2012	3/02/2013
Sixth highest reported gas flow	19/10/2009	7/02/2010	5/04/2011	13/12/2012	22/11/2013
Seventh highest reported gas flow	12/02/2009	17/04/2010	3/07/2011	25/12/2012	7/10/2013
Eighth highest reported gas flow	17/04/2009	4/02/2010	27/06/2011	27/07/2012	1/11/2013
Ninth highest reported gas flow	9/01/2009	4/04/2010	26/06/2011	30/07/2012	13/10/2013
Tenth highest reported gas flow	5/03/2009	19/02/2010	17/12/2011	5/11/2012	23/05/2013

Source: APA Group and IMO GBB data. **Note:** Peak Days are based on total gas delivered for the pipeline.

11.4. Gas Shipping between GBB Zones, 1 August 2013 to 31 December 2013

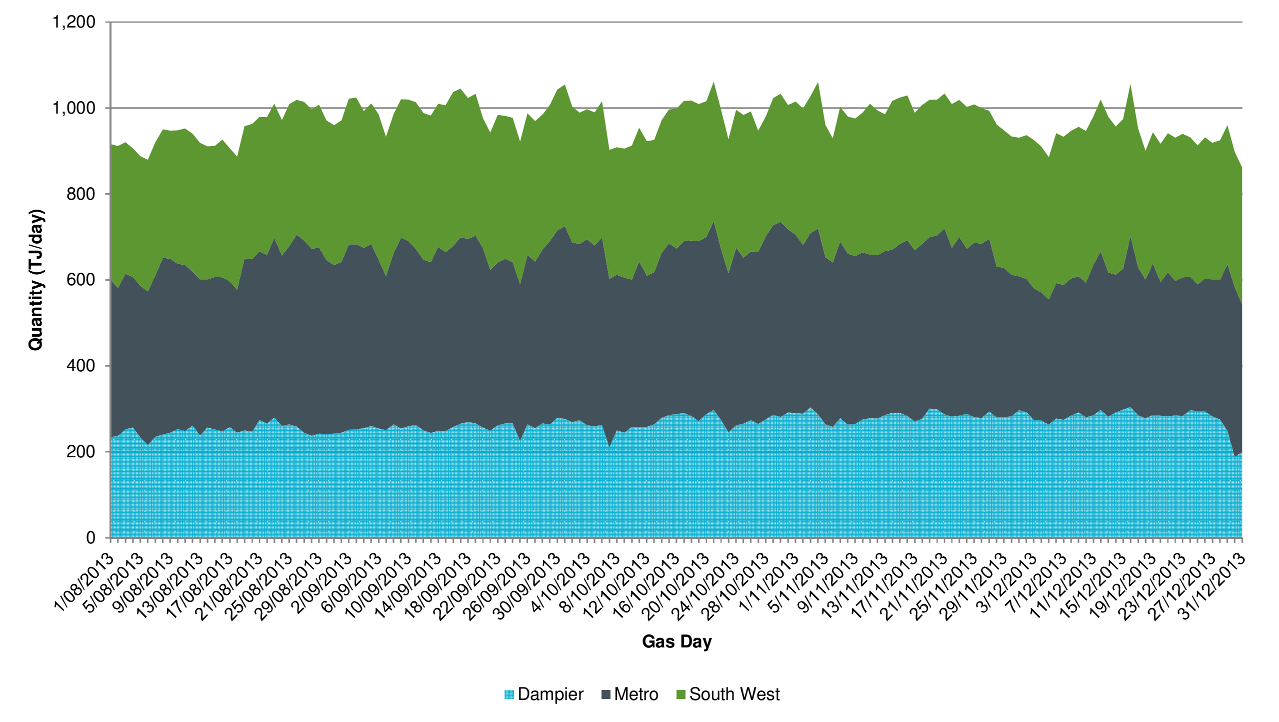
This section presents the shipping of gas by zones for the 1 August 2013 to 31 December 2013 period as reported to the GBB. Figure 68 presents the daily quantity of gas shipped on the DBNGP to each zone during the period while Figure 69 displays the shares of total gas delivered to each zone supplied by the DBNGP over this period.

These figures show that a large proportion (approximately 72%) of gas shipped on the DBNGP is delivered to customers located within the Metro and South West zones, which are located south of Compressor Station Seven. It is understood that the DBNGP has been shipping more than 900 TJ/day over the period, due to Synergy (formerly Verve Energy) injecting gas into the Mondarra storage facility (see section 4.3.6).

Figure 68 indicates a relatively constant gas consumption profile in the Dampier[330] and South West zones, which mainly consists of large mining and manufacturing customers. However, gas customers located in the Metro zone show more variability in their gas consumption. It is understood this variability is mostly driven by electricity generators located within the SWIS.

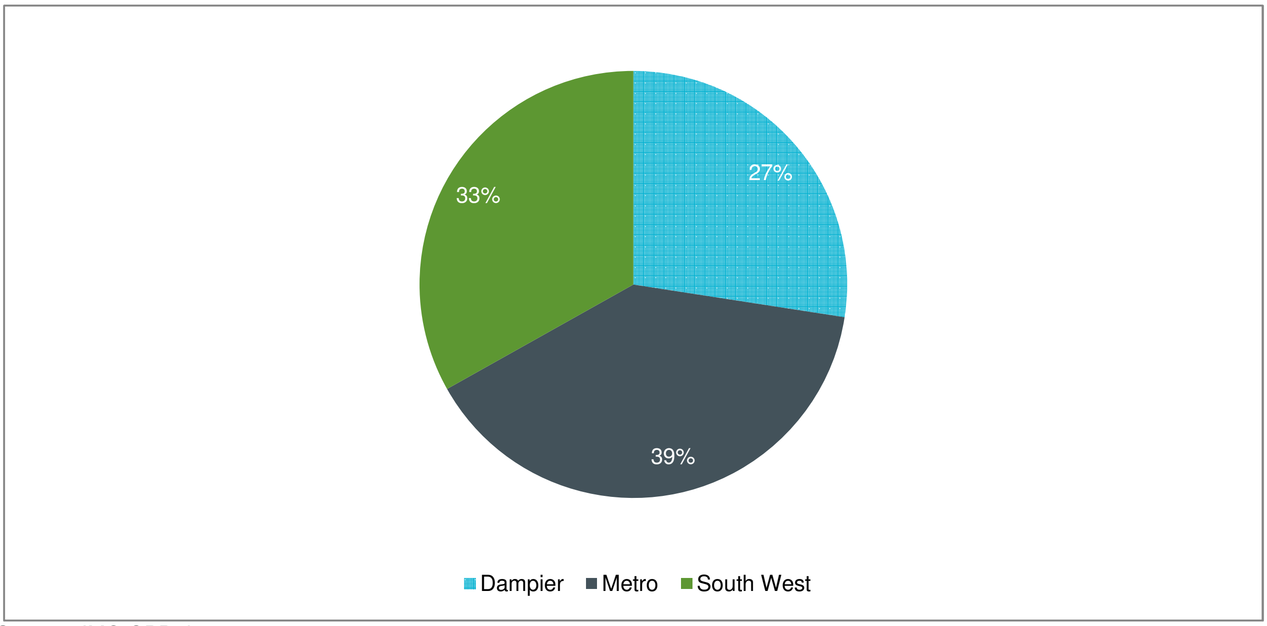
[330] The lower delivery of gas to the Dampier zone for the final days of 2013 coincided with Tropical Cyclone Christine, which crossed the Pilbara coast during the night of 30 December 2013.

Figure 68 – Delivery of Domestic Gas by Zone, DBNGP, 1 August 2013 – 31 December 2013



Source: IMO GBB data.

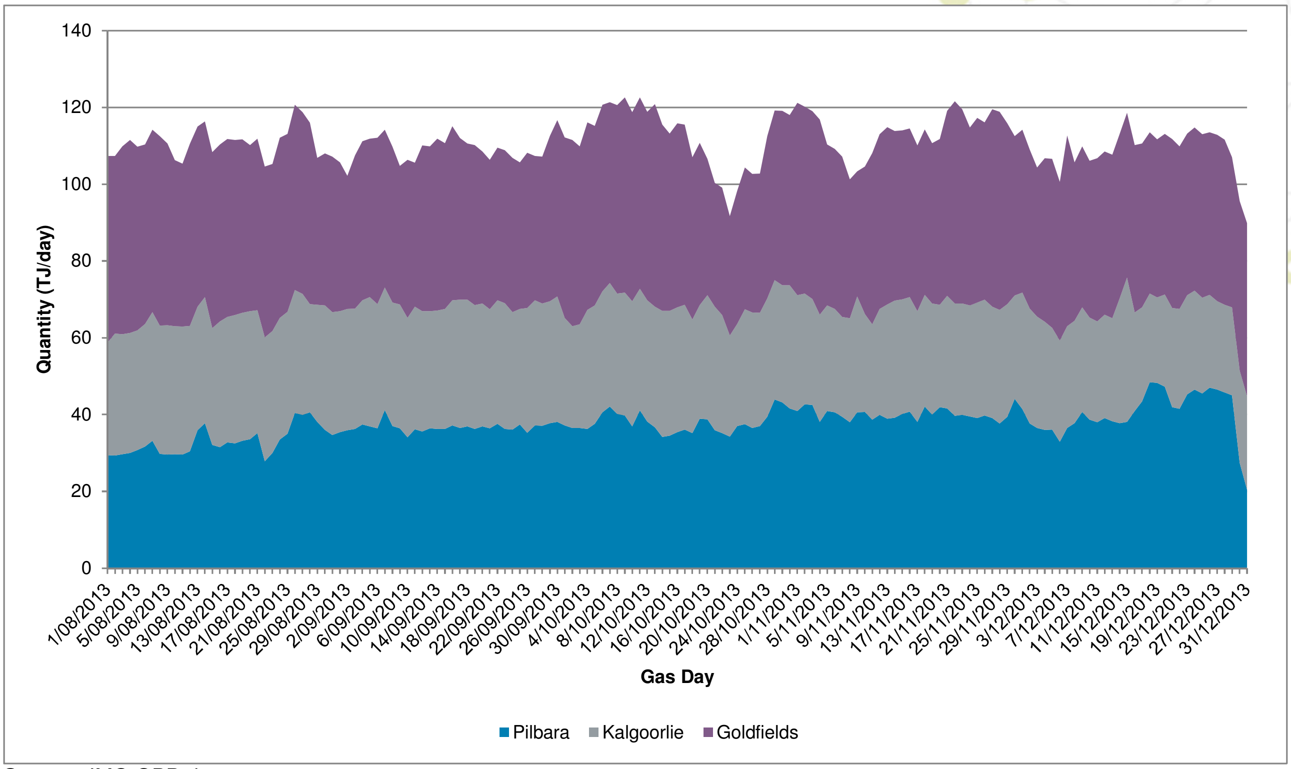
Figure 69 – Share of Gas Delivered by Zone, DBNGP, 1 August 2013 – 31 December 2013



Source: IMO GBB data.

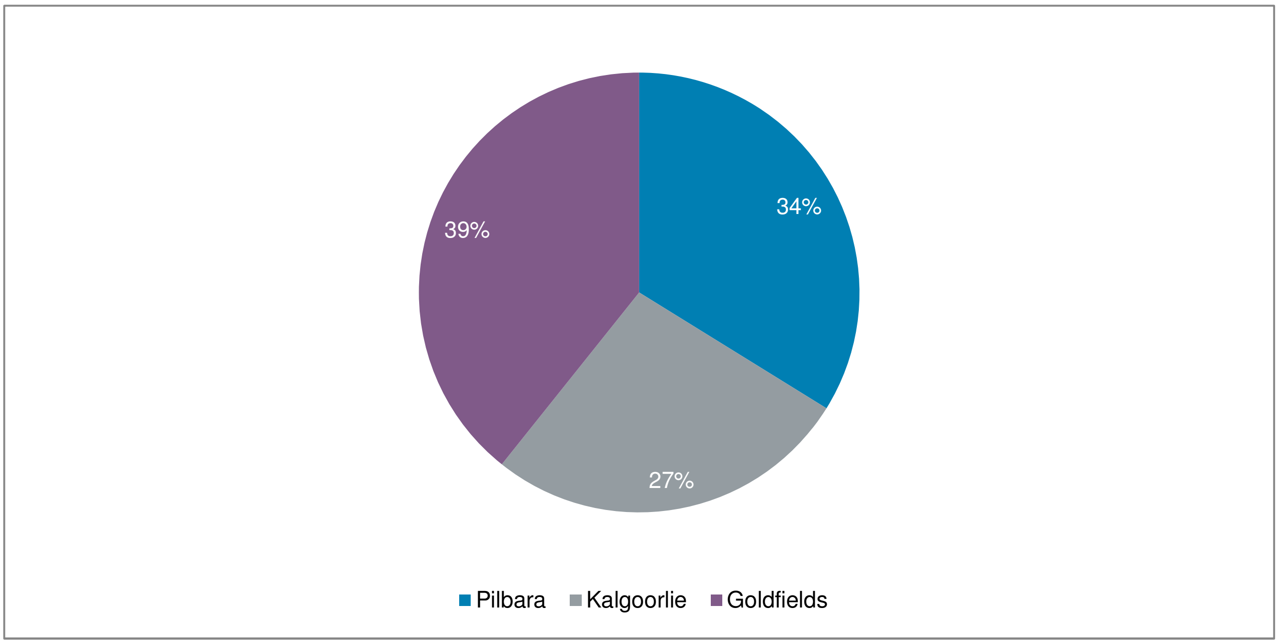
Figures 70 and 71 present similar data for the GGP. In particular, Figure 70 shows that gas deliveries to both the Pilbara and Kalgoorlie zones, which predominantly consist of mining customers, have a relatively constant gas consuming profile. Consumption in the Goldfields zone, which contains a diverse mix of customers, is more variable from day to day.

Figure 70 – Delivery of Domestic Gas by Zone, GGP, 1 August 2013 – 31 December 2013



Source: IMO GBB data.

Figure 71 – Share of Gas Delivered by Zone, GGP, 1 August 2013 – 31 December 2013



Source: IMO GBB data.

12. Other Issues

This chapter highlights other issues that may potentially influence and impact the medium to long-term demand and supply of gas in WA. In this GSOO, the Commonwealth's Study into the Eastern Australian Domestic Market is considered, along with the WA Government's inquiry into FLNG and the ERA's Inquiry into Microeconomic Reform in Western Australia.

12.1. Commonwealth Eastern Australian Domestic Gas Market Study and Energy White Paper

On 27 May 2013, the Commonwealth Government announced a study into the domestic gas market in eastern Australia, due to stakeholder concerns regarding the availability and cost of gas for the domestic market and the allocation of gas supplies to LNG exports[331].

The objective of the study is to produce a comprehensive report on the status of Australia's gas markets and the barriers to domestic gas supply, focusing on eastern Australia but including some analysis of the WA gas market.

The Eastern Australian Domestic Gas Market Study published in January 2014[332], recommends that a certain and predictable investment environment for domestic gas markets be developed. It suggests that information asymmetry in the Australian domestic gas markets is a major impediment to the further development of domestic gas markets and this inhibits the transition towards a more dynamic and efficient domestic gas market that underpins the price discovery and supply and demand response.

The study includes a number of recommendations that may be of relevance to the WA gas market, including the development of a gas market reform agenda, a targeted review of gas market competition, improvements to title administration and management, consideration of secondary trading mechanisms for pipeline capacity and a review of the suitability of alternative pipeline carriage models.

It is intended that the study will inform the Commonwealth Government's proposed Eastern Australian Gas Supply Strategy to 2020[333] and the upcoming Energy White Paper, expected to be published in September 2014[334], which will consider policy and regulatory reforms to improve the security, transparency, delivery, consumption and the competition for domestic gas and LNG export markets.

12.2. Floating LNG Inquiry by the Western Australia Government

The WA Government has instructed the Legislative Assembly's Economics and Industry Standing Committee (EISC) to conduct an inquiry into the economic implications of FLNG operations that are expected to commence in 2017 with Shell's Prelude project in the Browse Basin. At the time of this report, the EISC is conducting public hearings with stakeholders, which are expected to continue into 2014[335].

The WA Government's concerns are related to the economic impact on the state, as FLNG facilities for existing and potential WA projects are currently constructed or intended to be constructed in South Korea. The inquiry is examining the potential reduction of economic benefits to WA from the construction and ongoing maintenance of the FLNG facilities compared with land-based production facilities. In addition, the operation of FLNG facilities can avoid the WA Government's Domestic Gas Reservation Policy, potentially reducing the availability of gas reserves to the WA domestic market in the future.

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[331] Sydney Morning Herald (2013), *Canberra to probe domestic gas market*, http://www.smh.com.au/business/canberra-to-probe-domestic-gas-market-20130527-2n696.html, accessed 28 January 2014.
[332] See Department of Industry (2014),.
[333] For the terms of reference for this study, see box one of the Department of Industry (2013), *Issues Paper to inform preparation of a White Paper*, http://ewp.industry.gov.au/sites/ewp.industry.gov.au/files/energy-white-paper-issues-paper_0.pdf, accessed 30 December 2013.
[334] See http://ewp.industry.gov.au.
[335] EISC (2013), *Inquiry into the Economic Implications of Floating Liquefied Natural Gas Operations*, http://www.parliament.wa.gov.au/Parliament/commit.nsf/(EvidenceOnly)/12E97F0B529389C648257B7400157A93?opendocument,accessed 23 October 2013.

FLNG has become more attractive to gas producers, as relative costs for onshore gas production facilities have significantly increased (see section 8.3.2). From the perspective of a gas producer, the development cost of FLNG facilities is lower and allows these companies to access and develop offshore gas assets that were previously perceived to be uneconomic and stranded. In addition, deploying FLNG facilities may reduce environmental approval requirements and concerns commonly associated with onshore LNG facilities. At the time of this report, it is anticipated there may be at least seven FLNG facilities (the potential Browse project is considered as three facilities) operating off the coast of WA by the end of 2023[336].

However, it is understood that while the initial costs of FLNG are lower, the ongoing costs of operating an FLNG facility are higher than onshore production[337]. Further, FLNG facilities face unique technical challenges such as weather conditions, operational conditions, plant maintenance and compressed facility size, with the facility required to fit into an area roughly one quarter the size of a similar onshore facility[338].

The EISC is scheduled to table its report in Parliament in May 2014.

12.3. Microeconomic Reform Inquiry by the Economic Regulation Authority

The ERA is currently undertaking an inquiry into microeconomic reform in WA to provide recommendations to Parliament on reform measures that the WA Government could implement to improve the efficiency and performance of the WA economy.

As part of the inquiry, the ERA will consider the costs and benefits of WA's Domestic Gas Reservation Policy as part of its recommendations. From the 57 comments to its Issues Paper[339], Alinta Gas, APPEA, the Chamber of Commerce and Industry WA, Domgas Alliance, CMEWA, ESAA and others have provided differing comments backing as well as opposing the Domestic Gas Reservation Policy in its current form.

The WA Government is anticipated to review the Domestic Gas Reservation policy in 2014-2015[340].

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[336] As well as the three potential Browse FLNG facilities (for Woodside, Shell, MIMI, BP and PetroChina), the remaining projects are expected to be Shell's Prelude, ExxonMobil and BHP Billiton's Scarborough, Shell, Nexus and Osaka Gas' Crux and GDF Suez's and Santos Bonaparte. Only Shell's Prelude FLNG project has been sanctioned.

[337] This was articulated by Mr Andrew Smith, Country Chair of Shell Australia on 23 October 2013 to the Inquiry into the Economic Implications of Floating Liquefied Natural Gas Operations hearing conducted by the WA Parliament's EISC, http://www.parliament.wa.gov.au/Parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/A5C7361D59478CA048257C1200113FE5/$file/20131023+EISC+Transcript+Shell+eco131023+2.pdf, accessed 12 November 2013. This is also reported by ABC News (2013b), Shell says floating LNG technology up to 50 per cent cheaper than onshore development, http://www.abc.net.au/news/2013-10-23/shell-planning-to-source-browse-staff-locally/5041286, accessed 12 November 2013.

[338] This is articulated by Mr Roy Krzywosinski, Managing Director of Chevron Australia on 24 October 2013 to the Inquiry into the Economic Implications of Floating Liquefied Natural Gas Operations hearing conducted by the WA Parliament's EISC http://www.parliament.wa.gov.au/Parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/B9E5E2351682CE6148257C1200264A83/$file/20131023+EISC+Transcript+Chevron+eco131024+2.pdf, accessed 12 November 2013. This is also reported by ABC News (2013b), Shell says floating LNG technology up to 50 per cent cheaper than onshore development, http://www.abc.net.au/news/2013-10-24/chevron-dismisses-floating-lng-technology/5044504, accessed 12 November 2013.

[339] Submissions may be downloaded from, http://www.erawa.com.au/economic-inquiries/west-australian-microeconomic-reform/public-submissions, accessed 28 January 2014.

[340] See, Department of State Development website, *Domestic Gas Reservation Policy*, http://www.dsd.wa.gov.au/8482.aspx, accessed 13 January 2014.

13. Appendices

Appendix 1 – Abbreviations Used

- 2P – Proven and probable gas reserves
- ABS – Australian Bureau of Statistics
- ACOLA – Australian Council of Learned Academies
- APPEA – Australian Petroleum Production and Exploration Association
- ASX – Australian Stock Exchange
- BAP – Bunbury to Albany Pipeline
- Bcf – Billions of cubic feet
- Bcm – Billions of cubic metres
- BREE – Bureau of Resources and Energy Economics
- CCIWA – Chamber of Commerce and Industry (WA)
- CMEWA – The Chamber of Minerals and Energy (WA)
- CNEB – Canadian National Energy Board
- CSG – Coal seam gas
- DBNGP – Dampier to Bunbury Natural Gas Pipeline
- DBNGP Transmission – DBNGP (WA) Transmission Pty Ltd
- DMP – Department of Mines and Petroleum (WA)
- DOE – Department of Energy (US)
- Domgas – Domestic Gas
- DSD – Department of State Development (WA)
- EIA – Energy Information Administration (US)
- EISC – Economics and Industry Standing Committee
- EMAS – Energy Market Authority of Singapore
- ERA – Economic Regulation Authority (WA)
- ESAA – Energy Supply Association of Australia
- ESOO – Electricity Statement of Opportunities Report (WA)
- EU – European Union
- FLNG – Floating LNG
- FRGP – Fortescue River Gas Pipeline
- FTA – Free Trade Agreement
- GAB – Gas Advisory Board
- GBB – Gas Bulletin Board (WA)
- GDP – Gross Domestic Product (Australia)
- GFC – Global Financial Crisis
- GGP – Goldfields Gas Pipeline
- GIIGNL – Groupe International Des Importateurs De Gaz Naturel Liquefie
- GJ – Gigajoule
- GNP – Great Northern Pipeline
- GSOO – Gas Statement of Opportunities (WA)
- GSP – Gross State Product (WA)
- GWh – Gigawatt-hour
- IEA – International Energy Agency
- IEEJ – Institute of Energy Economics Japan
- IGU – International Gas Union
- IMO – Independent Market Operator
- JV – Joint Venture
- KEP – Kambalda to Esperance Pipeline
- KGP – Karratha Gas Plant
- KKP – Kalgoorlie to Kambalda Pipeline
- Km – Kilometre
- LNG – Liquefied Natural Gas
- LPG – Liquefied petroleum gas
- Mcf – Million cubic feet

- MMBtu – Million British Thermal Unit
- Mt – Million tonnes (megatonne)
- Mtpa – Million tonnes per annum
- MW – Megawatt
- MWP – Mid West Pipeline
- NBR – National Bureau of Asian Research
- NGERS – National Greenhouse and Energy Reporting Scheme
- NIEIR – National Institute of Economic and Industry Research
- NSW – State of New South Wales
- NT – Northern Territory
- NWIS – North West Interconnected System
- NWS – North West Shelf
- NWS JVs – North West Shelf JVs (includes DomGas JV, Incremental Pipeline JV and Extended Interest JV)
- OPEC – Organisation of Petroleum Exporting Countries
- PJ – Petajoule
- PPS – Pilbara Pipeline System
- PUO – Public Utilities Office
- QLD – State of Queensland
- SA – State of South Australia
- SWIS – South West interconnected system
- TAS – State of Tasmania
- Tcf – Trillion cubic feet
- TGP – Telfer Gas Pipeline
- TJ – Terajoule
- US – United States
- VIC – State of Victoria
- WA – State of Western Australia
- WA Treasury – Department of Treasury (WA)
- WEM – Wholesale Electricity Market

Appendix 2 – Forecasts of Economic Growth

Table I – Growth in Australian Gross Domestic Product (% year on year growth)

Year	Actual	Base	High	Low
2006-2007	3.8			
2007-2008	3.8			
2008-2009	1.6			
2009-2010	2.1			
2010-2011	2.4			
2011-2012	3.4			
2012-2013	2.8			
2013-2014		3.3	4.3	2.3
2014-2015		3.5	4.7	2.6
2015-2016		3.5	4.8	2.5
2016-2017		3.5	4.6	2.7
2017-2018		3.0	3.7	2.4
2018-2019		2.4	2.7	1.4
2019-2020		2.2	2.9	1.5
2020-2021		2.1	3.2	1.3
2021-2023		1.4	2.6	0.5
2023-2024		1.8	2.7	0.7
Average Growth %		**2.5**	**3.3**	**1.4**

Source: NIEIR Forecasts 2014 – 2023.

Table II – Growth in Western Australian Gross State Product (% year on year growth)

Year	Actual	Base	High	Low
2006-2007	6.2			
2007-2008	3.9			
2008-2009	4.3			
2009-2010	4.3			
2010-2011	4.0			
2011-2012	6.7			
2012-2013	5.1			
2013-2014		1.6	2.6	0.6
2014-2015		4.0	4.9	3.1
2015-2016		3.5	4.8	3.0
2016-2017		6.6	7.7	5.8
2017-2018		4.1	6.0	3.2
2018-2019		3.7	4.0	1.8
2019-2020		2.6	3.7	1.2
2020-2021		1.7	4.5	0.9
2021-2023		2.1	4.7	1.3
2023-2024		2.4	4.1	2.0
Average Growth %		**2.5**	**3.3**	**1.4**

Source: NIEIR Forecasts 2014 – 2023.

Appendix 3 – List of Upcoming Gas Related Projects

Table III – Projects Included in Gas Supply Forecasts

Project	Operator	Capacity of Gas-fired Generator (MW)	Anticipated Start-up	Capital Expenditure ($ million	Mtpa
Rio Tinto's Mine Expansions – Pilbara 290 Iron Ore Expansion (near Paraburdoo and West Angelas)	Rio Tinto	Unknown	2013	$10,200	53
Yarnima Power Station	BHP Billiton	190	2014	$597	N.A.
Rio Tinto's Cape Lambert Power Facility Replacement at Port Hedland	Rio Tinto	120	2015	$287	N.A.
Roy Hill Iron Ore Mine and Infrastructure	Hancock Prospecting	Unknown	2015	$9,500	55
Rio Tinto – Pilbara 360 Iron Ore Expansion	Rio Tinto	Unknown	2015	$6,100	70
Karratha Temporary Power Station	Horizon Power	20	2012	$30-40	N.A.
Mungullah Power Station	Horizon Power	18	2013	$73	N.A.
South Hedland Power Station	Horizon Power	67	2014	$125	N.A.

Source: APA Group (2011, 2012), BREE (2013f) and other respective corporate websites. **Note**: N.A. – Not Applicable

Table IV – Projects Not Included in Gas Supply Forecasts

Potential Project	Project Value (A$ millions)
API Management - West Pilbara Iron Ore Project	7,000
Asia Iron - Extension Hill Magnetite Mine*	2,900
BHP Iron Ore – Inner Harbour Expansion	2,000
BHP Iron Ore – Jimblebar Mine Expansion	3,200
BHP Iron Ore – Blending and Yard Facilities	1,500
Citic Pacific – Cape Preston Mine and Processing	5,200
Crosslands Resources – Jack Hills Stage 2	2,000
FMG – Chichester and Solomon Mines expansions	9,000
FMG – Anketell Point Port*	5000
FMG – Rail and Port expansion	4,600
FMG – Nyidinghu Rail Spur	3,500
FMG (with Baosteel) – Ironbridge	1,658
DBP Development Group/TEC Pilbara (TransAlta) – Fortescue River Gas Pipeline	178
Grange Resources/SRT Australia JV – Southdown Magnetite Mine	2,880
Gindalbie Metals/AnSteel – Karara Iron Ore Mine*	1,975
MCC – Cape Lambert Iron Ore Project	3,700
Rio Tinto Iron Ore – Hope Downs 4 Iron Ore Mine	1,556
Sinosteel Midwest Corporation – Weld Range Mine	1,000
AngloGold Ashanti/Independence Group – Tropicana Gold Project	700
CSBP – Kwinana Ammonia Nitrate Expansion	550
Perdaman Chemicals and Fertilisers – Coal to Urea Plant	3,500
Doray Minerals – Andy Well Project	55
Aphrodite Gold – Aphrodite Gold Project	244
Bauxite Resources – Fortuna Project*	250
Bauxite Resources/Yankuan Corporation – BAJV Aluminia Refinery*	1,500
Rutila Resources/Todd Capital – Balla Balla Project*	2,086
Australasian Resources – Balmoral South Magnetite Project*	8,300
Reed Resources – Barrambie Vanadium Project*	500
Hazelwood Resources – Big Hill Tungsten Project	112
Iron Ore Holdings – Buckland Project*	1,000
Bullabulling Gold Project	346
Montezuma Mining – Butcherbird Project	250
Rio Tinto – Koodaideri Project	3,500

Potential Project	Project Value (A$ millions)
Rio Tinto – Marandoo Project	1,070
Rio Tinto – Nammuldi Expansion	2,140
Rio Tinto/Hancock Prospecting – Cape Lambert Port and Rail expansion*	8,266
Phoenix Gold – Castle Hill Gold Project	110
Iluka Resources – Cataby Mineral Sands	200
Metals X – Central Murchison Project	117
Gunson Resources – Coburn Project	192
Diatreme Resources – Cyclone Project	223
Western Areas – Daybreak Project*	250
Western Areas – Diggers South Project	100
Potash West – Dinner Hill Project	650
Tronox – Dongara Project	300
Rey Resources – Duchess Paradise	200
Ferrowest – Eradu Iron Project	605
Ferrowest – Yogi Mine and Railway	1,066
Esperance Port Authority – Port Expansion*	250
Silver Lake Resources – Great Southern Project*	250
Panoramic Resources – Gidgee Gold Project	70
Mutiny Gold – Gullewa Project	62
Aquila Resources – Hardey*	2,500
Norlisk Nickel – Honeymoon Well	1,500
Atlas Iron – Horizon 1 and 2 Projects*	2,752
Atlas Iron – Ridley Magnetite	5,000
Atlas Iron – Utah Point Expansion	60
Atlas Iron/Aurizon/Brockman Resources – Pilbara Rail*	5,000
Iron Ore Holdings – Iron Valley Project*	500
Pluton Resources – Irvine Island	700
Newmont – Jundee Extension	220
Heron Resources – Kalgoorlie Nickel*	2,500
MZI Resources – Keysbrook Project	70
Southern Cross Goldfields – Marda Project	25
Brockman Resources – Marillana	1,900
Macarthur Minerals – Moonshine Magnetite*	5,000
Macarthur Minerals – Ularring Hematite	263
Jupiter Mines – Mount Ida and Mount Mason Projects*	2,573
Mindax – Mount Forrest	177
Panoramic Resources – Mount Henry	195
Panoramic Resources – Panton PGM	167
Reed Resources/Mineral Resources – Mount Marion Lithium Project	97
Atlas Mining/Altura Mining – Mount Webber 1 and 2	219
Altura Mining – Pilgangoora	96
Lynas Corp – Mount Weld Phase 2	170
Energy and Minerals Australia – Mulga Rock	260
GME Resources – NiWest Nickel Laterite Heap Leach Project	1,100
Image Resources – North Perth Basin Project	64
Sirius Resources – Nova Bollinger Nickel Project	471
Carzaly Resources – Parker Range Iron	164
Venturex Resources – Pilbara Copper-Zinc	279
Flinders Mines – Pilbara	1,100
Magnetic Resources – Ragged Rock	314
Australasian Resources/ Metals Australia*	250
Kimberley Metals – Sorby Hills	70
Grange Resources/Sojitz – Southdown Magnetite Iron	5,000
Ventnor Resources – Thaduna/Green Dragon Copper Project	70
AngloGold Ashanti/Independence Group – Tropicana JV Project	845
Toro Energy – Wiluna Uranium Project	269
Golden West Resources – Wiluna West*	2,500
Poseidon Nickel – Windarra Project	197

Potential Project	Project Value (A$ millions)
Gold Road – Yamarna Gold	40
Cameco – Yeelirrie Project	1,000
Total	**143,538**

Source: DSD (2013) and BREE (2013). *Denotes the highest estimate is used. **Note:** This is not an exhaustive list of projects.

Appendix 4 – Gas Demand Forecasts, 2014 – 2023

Table V – Demand Forecasts – Domestic – Considers Forecast Gas Prices (TJ/day)

Year	Low	Base	High
2014	956.9	976.2	983.8
2015	983.7	1005.0	1014.5
2016	968.6	992.0	1004.4
2017	959.7	991.4	1005.4
2018	957.3	998.4	1014.5
2019	962.5	1011.9	1030.2
2020	958.3	1011.9	1030.7
2021	955.4	1008.8	1030.8
2022	953.4	1007.6	1036.3
2023	957.5	1012.0	1041.6

Source: NIEIR Forecasts 2014 – 2023.

Table VI – Demand Forecasts – Domestic – Constant Prices (TJ/day)

Year	Low	Base	High
2014	966.1	986.5	995.7
2015	999.7	1023.0	1035.6
2016	991.7	1018.3	1035.3
2017	991.2	1027.8	1048.1
2018	999.0	1047.4	1071.8
2019	1015.9	1075.3	1104.8
2020	1018.5	1084.4	1116.2
2021	1022.6	1090.7	1128.2
2022	1027.1	1098.0	1144.8
2023	1038.2	1111.4	1161.1

Source: NIEIR Forecasts 2014 – 2023.

Table VII – Demand Forecasts – SWIS (PJ/annum)

Year	Low	Base	High
2014	253.0	254.0	254.5
2015	261.8	264.2	264.8
2016	258.2	260.9	261.8
2017	255.3	261.4	262.3
2018	255.3	263.4	264.5
2019	256.3	264.7	265.6
2020	254.5	265.1	266.1
2021	254.4	265.6	266.5
2022	255.4	266.7	267.7
2023	257.3	268.8	268.8

Source: NIEIR Forecasts 2014 – 2023

Table VIII – Demand Forecasts – Outside of SWIS (PJ/annum)

Year	Low	Base	High
2014	96.3	102.3	104.6
2015	97.3	102.6	105.5
2016	95.3	101.2	104.8
2017	95.0	100.4	104.7
2018	94.1	101.0	105.8
2019	95.0	104.7	110.4
2020	95.3	104.2	110.1
2021	94.3	102.6	109.8
2022	92.6	101.1	110.6
2023	92.2	100.6	111.4

Source: NIEIR Forecasts 2014 – 2023.

Appendix 5 – List of Production Facilities Included in Potential Supply, 2014 – 2023

Table IX – Production Facilities included in Potential Supply Forecasts

Production facility	Operator/Expected Operator	Basin	Estimated Gas production capacity (TJ/day)	Estimated Start-Up	Comments
Karratha Gas Plant (NWS)	NWSJVs	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	2016 (150 TJ/day only)	Capacity is anticipated to be 150 TJ/day until 2020
Wheatstone Domestic	Chevron	Carnarvon	200	2018	
Dongara	AWE Limited	Perth	7	N.A.	Facility may be expanded due to Senicio and Corybas 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 (~20 Mcf/day)
Total Gas production capacity			**1,976.6 TJ/day**		

Source: Public announcements and respective corporate websites. **Note**: N.A. – Not Applicable.

Appendix 6 – Potential Supply Forecasts, 2014 – 2023

Table X – Lower and Upper Potential Supply Forecasts (TJ/day)

Year	Lower	Upper
2014	1104.8	1142.1
2015	1104.5	1140.9
2016	1111.2	1246.0
2017	1088.3	1234.4
2018	1193.0	1335.2
2019	1193.5	1330.8
2020	1278.2	1419.0
2021	1020.0	1323.8
2022	1022.4	1324.7
2023	1025.6	1324.1

Source: NIEIR Forecasts 2014 – 2023.

Appendix 7 – Non-exhaustive List of Committed and Prospective Gas Projects in Western Australia

Table XI – Committed and Prospective Gas Projects, Western Australia (Non-exhaustive)

Project	Location	Type	Anticipated Start-Up	Estimated New Capacity	Indicative Cost ($ millions)
Gorgon LNG	Barrow Island, Carnarvon Basin	New Project	2015	15.6 Mt	$52,000
NWS - Greater Western Flank – Phase 1*	Carnarvon Basin	Expansion	2016	N.A	$2,300
Julimar Development Project^	180 km north-west of Dampier	New Project	2016	2.1 Tcf	$1,200
NWS - Greater Western Flank – Phase 2	Carnarvon Basin	Expansion	2016 or later	1.7 Tcf	Unknown
NWS – Persephone	Carnarvon Basin	Expansion	2016 or later	Unknown	Unknown
Pluto - Xena	Carnarvon Basin	Expansion	2016	Unknown	$370
NWS - Lambert Deep West	Carnarvon Basin	Expansion	2016 or later	0.2 Tcf	Unknown
Prelude FLNG	Offshore	New Project	2017	3.6 Mt	$12,600
Spar 2#	120 km west of Onslow	New Project	2015	18 PJ/annum	$117^
Wheatstone LNG	145 km north-west of Dampier	New Project	2016	8.9 Mt	$29,000
Browse	Browse Basin	New Project	2018 or later	15.9 Tcf	Unknown
Gorgon LNG (train 4)	Barrow Island, Carnarvon Basin	New Project	2018 or later	N.A.	$12,000
Bonaparte FLNG	Bonaparte Basin	New Project	2018 or later	2.4 Mt	$13,000
Equus	Carnarvon Basin	New Project	2018 or later	N.A.	$1,500-$2,000
Scarborough FLNG	Carnarvon Basin	New Project	2018 or later	6 Mt	$14,000
Total					**$144,840**

Source: BREE (2013c) and Woodside (2013b). **Note:** N.A. – Not Applicable. *The Greater Western Flank Phase 1 project is an extension of the NWS project, connecting the Goodwyn GH and Tidepole fields to the offshore Goodwyn A platform. ^The Julimar Development Project is linked with Wheatstone's LNG and domestic gas facility. #Santos' Spar 2 project is an extension to East Spar that is linked with the Varanus Island production facility. Browse is likely to be a FLNG project.

Appendix 8 – Medium to Long-Term Average (Ex-Plant) New Gas Contract Prices, 2014 – 2023

Table XII – Average Medium to Long-Term Average (ex-plant) Gas Prices Forecasts (real, $/GJ)

Year	Low	Base	High
2014	$6.12	$6.19	$6.31
2015	$6.30	$6.41	$6.60
2016	$6.44	$6.58	$6.79
2017	$6.63	$6.82	$7.05
2018	$6.89	$7.12	$7.39
2019	$7.06	$7.31	$7.69
2020	$7.01	$7.35	$7.72
2021	$7.23	$7.62	$8.08
2022	$7.33	$7.72	$8.20
2023	$7.49	$7.90	$8.41

Source: NIEIR Forecasts 2014 – 2013.

Appendix 9 – LNG Requirement Forecasts, 2014 – 2023

Table XIII – LNG Feedstock Estimates (PJ/annum)

Year	Low	Base	High
2014	1141.9	1141.9	1141.9
2015	1141.9	2006.6	2006.6
2016	2006.6	2253.2	2253.2
2017	2253.2	2699.4	2699.4
2018	2699.4	2699.4	2699.4
2019	2699.4	2699.4	3120.7
2020	2699.4	2987.7	3367.4
2021	2699.4	2987.7	3489.3
2022	2699.4	2987.7	3489.3
2023	2699.4	2987.7	3489.3

Source: NIEIR Forecasts 2014 – 2023.

Table XIV – LNG Processing Estimates – 8% of Feedstock (PJ/annum)

Year	Low	Base	High
2014	91.3	91.3	91.3
2015	91.3	160.5	160.5
2016	160.5	180.3	180.3
2017	180.3	216.0	216.0
2018	216.0	216.0	216.0
2019	216.0	216.0	249.7
2020	216.0	239.0	269.4
2021	216.0	239.0	279.1
2022	216.0	239.0	279.1
2023	216.0	239.0	279.1

Source: NIEIR Forecasts 2014 – 2023.

Table XV – Total LNG Requirement Estimates (PJ/annum)

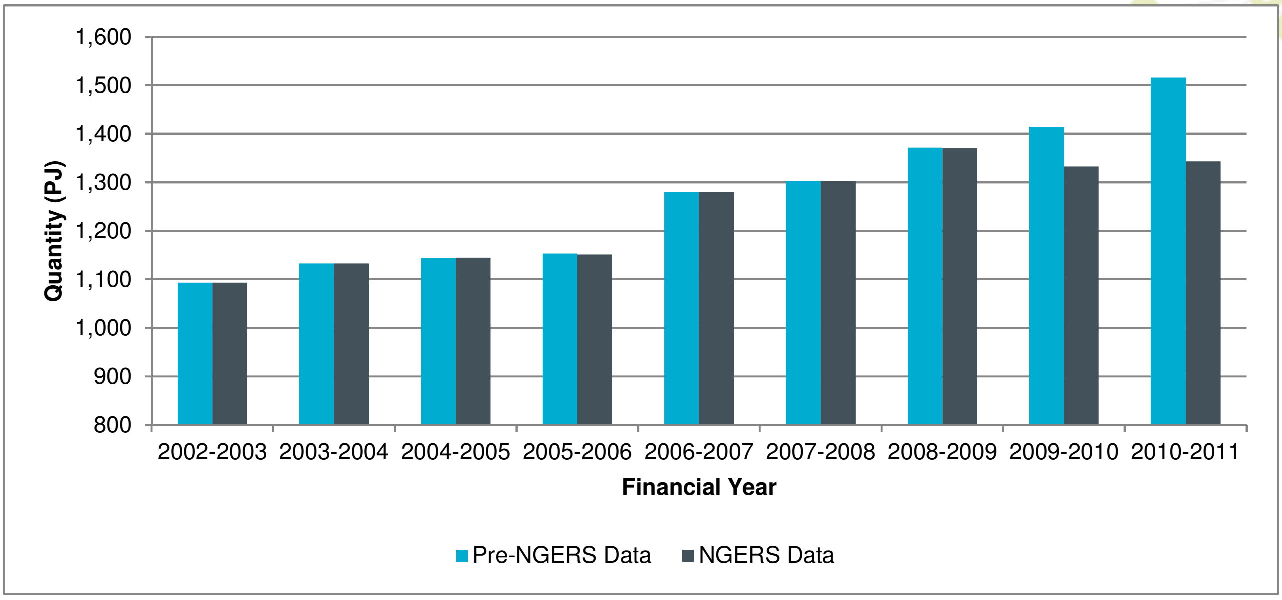
Year	Low	Base	High
2014	1582.5	1589.5	1592.3
2015	1592.3	2533.9	2537.4
2016	2520.6	2795.6	2800.1
2017	2783.8	3277.3	3282.4
2018	3264.8	3279.8	3285.7
2019	3266.7	3284.7	3746.4
2020	3265.2	3596.0	4013.0
2021	3264.1	3594.9	4144.7
2022	3263.4	3594.5	4146.7
2023	3264.9	3596.1	4148.7

Source: NIEIR Forecasts 2014 – 2023.

Appendix 10 – Difference in Bureau of Resources and Energy Economics Consumption Data

Figure I presents the difference between the WA gas consumption data estimated using the Fuel and Electricity Survey and NGERS data. This suggests the survey provided a fairly accurate estimation of WA gas consumption until 2008-2009.

Figure I – Differences between Pre-NGER and NGER data for WA's Gas Consumption, 2002-2003 to 2010-2011



Source: BREE (2012 and 2013), Australian Energy Statistics, 2012 and Australian Statistics, Update 2013, Table C.

Appendix 11 – Conversion Factors Applied

The following conversion factors have been applied to this GSOO.

Table XVI – Conversion Factors

	To						
Natural Gas and LNG	Billion cubic meters NG	Billion cubic feet NG	Million tonnes oil equivalent	Million tonnes LNG	Trillion British Thermal Units	Million barrels oil equivalent	Petajoules
From	**Multiply by**						
Billion cubic meters NG	1	35.3	0.9	0.74	35.7	6.6	37.45
Billion cubic feet NG	0.028	1	0.025	0.0216	1.01	0.19	1.06
Million tonnes oil equivalent	1.11	39.2	1	0.82	39.7	7.33	-
Million tonnes LNG	1.36	48	1.22	1	48.6	8.97	55.43
Trillion British Thermal Units	0.028	0.99	0.025	0.021	1	0.18	1.06
Million barrels oil equivalent	0.15	5.35	0.14	0.11	5.41	1	5.82
Petajoules	0.027	0.943	-	0.018	0.943	0.172	1

Note: NG = Natural gas

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