



5. Export demand projections

5.1. LNG exports

Natural gas can be exported by pipeline or as liquefied natural gas (LNG), which is gas that has been liquefied by reducing its temperature to -161°C at atmospheric pressure. LNG's volume is less than 1/600 of gas at atmospheric pressure, and it is economic to transport by rail, road and ship in insulated and/or refrigerated containers. The economics and feasibility of transportation of natural gas favour LNG shipping over pipelines in long haul inter-continental trade, where pipelines may be required to transit extremely deep water or multiple political boundaries. LNG also provides opportunities for more flexible and secure sourcing of gas and markets than pipelines tied to single regions for supply and demand.

The LNG industry commenced commercial operations in 1965 with shipments from Algeria to the UK, followed in 1969 by the commencement of LNG supplies to Japan from Alaska. The LNG industry in Australia commenced operation in 1989, with supplies from the North West Shelf Project at Dampier, Western Australia, to Japan. This plant has been expanded to five trains⁵ and will be joined by the first train of Pluto LNG in 2011. Gorgon LNG, currently planned as three trains, has begun construction with scheduled operation in 2014. The single train Darwin LNG operation started up in 2006. In addition to further trains at Pluto and Gorgon, there are a number of other WA LNG projects in various stages of planning, including Wheatstone, Browse, Prelude and Scarborough and the Ichthys project in Commonwealth waters off WA which will be piped to Darwin and processed there.

The possibility of exporting LNG from the east coast of Australia has arisen as a result of significant growth in coal seam gas reserves, which now exceed domestic market requirements. The first CSG based LNG project was announced in May 2007 and since that time a further nine have followed. At present LNG is the most economic option for developing gas reserves that are surplus to domestic requirements – the principal alternative option is gas-to-liquids conversion (GTL), however GTL capital costs are higher and the returns lower than LNG, for as long as LNG pricing remains linked to oil (refer to section 8.1.1).

Two projects, Queensland Curtis LNG (QCLNG) operated by Queensland Gas Company, a subsidiary of BG Group, and Gladstone LNG (GNLNG), operated by Santos, recently reached final investment decisions and are committed to construct the first two trains of their respective projects. Their project schedules suggest that QCLNG's trains will start up in 2014 and 2015 and that GNLNG's trains will start up in 2015 and 2016. The gas volumes associated with these trains are

⁵ A train is one virtually stand-alone liquefaction unit. Typical trains produce between 3 and 5 million tonnes of LNG per annum, equivalent to 165 to 275 PJ net delivered gas per annum.



viewed as firmly committed to exports and will be included in all scenarios. A third project, Australia Pacific LNG (APLNG), has recently entered a firm supply agreement for one train and may reach FID for a single train in the near future. If so, the start-up is expected to be in 2015 or 2016.

The timing of other eastern states LNG projects and further trains at the committed projects will be determined by a combination of factors:

- ❖ Firming up of offtake agreements. This is partly determined by the global LNG demand-supply balance and partly by each project's competitiveness with other projects.
- ❖ Project progress in:
 - proving up sufficient reserves to support exports
 - obtaining environmental approvals
 - completing front-end engineering and design
 - obtaining finance

5.2. Eastern Australian LNG Projects

At the time of writing, there are two committed LNG projects and a further eight proposed projects at various stages of developments. The two committed projects and another two projects have been declared as 'significant projects'⁶ by the Queensland government and are larger in size (more than 3 Mtpa). These projects are to be located off the coast of Gladstone at Curtis Island, where construction of a total of 17 trains has been approved by the Queensland Government.

The remaining projects are smaller with individual train capacities of less than 3 Mtpa. These projects are less likely to be affected by global LNG demand-supply balance but rather by their own project financing and development.

⁶ Determined by the Coordinator General of Queensland state government following a submission of an Initial Advice Statement by the project proponent



5.2.1. Large projects (>3 Mtpa)

■ **Table 5-1 Queensland LNG major project structure**

Project	Trains No. x Mtpa	Date announced	Participants	Participation	
				Upstream (Production)	Downstream (Liquefaction)
Queensland Curtis LNG (QCLNG)	3x4.25	1 Feb 08	Queensland Gas Company (wholly owned by BG Group)	93.75%	87.5%
			Tokyo Gas	1.25%	2.5%
			China National Offshore Corporation	5%	10%
Gladstone LNG (GLNG)	3x3.6	18 Jul 07	Santos	30%	30%
			Petronas	27.5%	27.5%
			Total	27.5%	27.5%
			KOGAS	15%	15%
Australia Pacific LNG (APLNG)	4x4.5	8 Sep 08	Origin Energy	42.5%	42.5%
			Conoco Phillips	42.5%	42.5%
			China Petroleum Corporation	15%	15%
Arrow LNG Project (Arrow LNG)	4x4	16 Feb 09 ⁷	Shell	50%	50%
			PetroChina	50%	50%

⁷ This is the original date of a Shell proposal for a 4x3-4 Mtpa project on Curtis Island. The JV bid for Arrow was announced on 8 March 2010.



■ **Table 5-2 Queensland LNG major project key parameters**

Project	Committed Customers (HoA or MoU) (Mtpa)	Significant Project Declaration	Environmental Approval		FID	Train start-up schedule
			QLD	Federal		
QCLNG	CNOOC (3.6) Tokyo Gas (1.2) Singapore (up to 3) Chile (1.7) Chubu Electric (0.4)	4 July 2008	23 June 2010	22 October 2010	31 October 2010	2014 2015 3 rd later
GLNG	Petronas (3.5) KOGAS (3.5)	16 July 2007	28 May 2010	22 October 2010	13 January 2011	2015 2016 3 rd later
APLNG	Sinopec (4.3)	9 April 2009	8 November 2010	21 February 2011	2011 (target)	2015 2016 3 rd &4 th later
Arrow LNG	PetroChina (N/a)	12 June 2009	Pending IES	Pending IES	2012 (target)	2017? Others later



5.2.1.1. Queensland Curtis LNG Project (QCLNG)

QCLNG is the first project in Queensland to reach Final Investment Decision (FID), which was announced on 31 October 2010. The first phase of the project is expected to start exporting LNG in 2014 by building two trains with capacity of up to 8.5 Mtpa and a scope for expansion since the project received environmental approval for up to 12 Mtpa.

The project is underpinned by long term sales agreements with China, Chile, Singapore and Japan for total sales of LNG up to 9.5 Mtpa, which consists of a 20-year, 3.6 Mtpa agreement with the China National Offshore Oil Corporation (CNOOC); a 21-year, 1.7 Mtpa agreement with GNL Chile; a 20-year agreement to supply up to 3 Mtpa to customers in Singapore; a 20-year agreement to supply up to 1.2 Mtpa to Tokyo Gas; and a 21 year agreement to supply approximately 0.4 Mtpa to Chubu Electric.

Two of the agreements include an acquisition of equity interest in QCLNG by the parties involved. CNOOC is to acquire 10% equity interest in QCLNG Train 1, while Tokyo Gas acquires 2.5% equity interest in QCLNG Train 2. Additionally, CNOOC is to acquire 5% of QGC's reserves and resources in Surat Basin, while Tokyo Gas acquires 2.5% interest.

QCLNG is operated by Queensland Gas Company Pty Ltd (QGC), a wholly owned subsidiary of BG Group, a UK based company with global experience in LNG.

At a presentation on 10th May 2011, BG Group's chief executive indicated a target date of mid 2012 for FID on QCLNG train 3⁸.

5.2.1.2. Gladstone LNG Project (GLNG)

GLNG is the second project to reach FID, which was sanctioned on 13 January 2011 with exports expected to start in 2015. Initially, the project involves building two trains with capacity of up to 7.8 Mtpa with possible expansion to 10 Mtpa.

GLNG is a joint venture between Santos (30%), Petronas (27.5%), Total (27.5%) and Kogas (15%) and is underpinned by long term sales agreements with two of its proponents Petronas and Kogas. The agreement with Petronas is for 20 years of up to 3.5 Mtpa, while Kogas also agreed for volume of up to 3.5 Mtpa for 15 years with GLNG having the option to extend for another 5 years.

5.2.1.3. Australia Pacific LNG Project (APLNG)

APLNG received state environmental approval in November 2010 and subsequently a federal approval in March 2011 with FID expected in 2011 and first LNG export as early as 2015. The

⁸ Frank Chapman, *BG Group 2011 First Quarter Results*, 10 May 2011



project is proposed to initially build two trains of up to 4.5 Mtpa each with a further two trains of 4.5 Mtpa in the second stage.

The project's 50:50 joint venture partners, Origin Energy and ConocoPhillips, signed a binding agreement with China Petroleum & Chemical Corporation (Sinopec) on 21 April 2011. This agreement includes a long term sales of LNG to Sinopec for up to 4.3 Mtpa for 20 years and for SIPC (a wholly-owned subsidiary of Sinopec) to acquire 15% equity interest in APLNG, effectively reducing Origin Energy's and ConocoPhillips's ownerships to 42.5% each. Commitment to the first train, to service the Sinopec contract, was announced on 28th July 2011.

5.2.1.4. Arrow LNG Plant Project (Arrow LNG)

This project, previously known as Shell Australia LNG Project (SALNG), is a joint venture of Shell Australia and PetroChina. Arrow Energy was acquired by the partnership of Shell and PetroChina (CS CSG Pty Ltd) on 23 August 2010. The project is undergoing its FEED and environmental approval stages and an Environmental Impact Statement (EIS) is being prepared with expected release in 2011.

The project is planned to go ahead in two stages, initially by building two trains with capacity of around 4 Mtpa each and a possible expansion of two extra trains in the future with total combined capacity of around 16 Mtpa from four trains. First export is targeted for 2017. No firm sales contracts have been announced but it is assumed that PetroChina will take the output from at least one train. On 16th May 2011, Shell signed an HoA with CPC Corporation of Taiwan to supply 2 Mtpa of LNG for 20 years starting from 2016 from its portfolio of LNG supply, which potentially includes Arrow LNG project and Prelude floating LNG project offshore Western Australia.

5.2.2. Small Projects (<3Mtpa)

5.2.2.1. LNG Limited's LNG Project at Fishermans Landing (Gladstone LNG Project)

Gladstone LNG Project was one of the earliest projects proposed to convert CSG in Queensland to LNG for export. Originally, the gas was to be supplied by Arrow Energy, however since Arrow Energy's takeover by the joint partnership of Shell and PetroChina, the draft sales agreement has terminated and LNG Limited is still seeking alternative gas supply options. An HoA between LNG Limited and Golar LNG Ltd for the offtake of LNG has also terminated.

The project is to be developed using LNG Limited's OSMR technology, which LNG Ltd claims to be superior to alternative technologies. The project will be developed in two stages by building a train with capacity of 1.5 Mtpa in each stage at Fisherman's Landing in Gladstone.



The project is operated by Gladstone LNG Pty Ltd (Gladstone LNG), a subsidiary of LNG Limited. On 28 January 2011, LNG Limited announced an agreement with Huanqiu Contracting and Engineering Corporation (HQCEC) – a subsidiary of China National Petroleum Corporation (CNPC) – for it to acquire 19.9% stake in the company pending Government approvals. The proceeds will go to the development of Gladstone LNG Project and potential off-take agreements between LNG Limited and HQCEC.

The project has recently entered an agreement with Jemena to evaluate expansion of Jemena's Queensland Gas Pipeline to transport gas from the Wallumbilla Gas Hub to the Callide Gas Hub near Gladstone. The project is negotiating for gas supply to either hub.

Initial timing of export projection was targeted for 2012, however this is no longer achievable and the date is now conditional on the project securing alternative gas supply.

5.2.2.2. Abbot Point LNG Project

Energy World Corporation (EWC) proposes to develop an LNG export plant at Abbot Point and/or Hay Point in Queensland. The initial phase of the project will involve building four modular LNG trains of 0.5 Mtpa each with combined capacity of 2 Mtpa and potential expansion to 5 Mtpa. Modular trains are smaller than the typical LNG trains and incorporate standardized design. The project involves building a pipeline linking Abbot Point and Hay Point to the Bowen basin and eventually through to Cooper basin. The pipeline will enable other producers in the Bowen basin to feed the gas to the plant and export it as LNG. The connection to Cooper basin will utilise EWC's gas resources at Eromanga and Gilmore. The latest update on the project was incorporated in the company's half yearly report in February 2010, which targeted production in about 3 years.

5.2.2.3. Southern Cross LNG Project

Announced in 2008, the Southern Cross LNG Project was planned to be an open access service to export LNG on Curtis Island near Gladstone. It would enable gas producers of varying size to realise the potential of exporting their gas to international markets. The project was to be built in stages with a total of three trains with capacity of 0.7 – 1.3 Mtpa each. The first train was originally scheduled to start up in 2013. There do not appear to have been any further developments associated with this project since its announcement and at present there are insufficient gas reserves independent of the major LNG projects to support the project.

Southern Cross LNG Project is operated by Impel LNG, a wholly owned subsidiary of Galveston LNG. Galveston LNG was an independent Canada based company which is developing the Kitimat LNG Terminal, an import terminal that have been converted to an export terminal following shale gas developments in the US and Canada. As of February 2011, Galveston LNG operates as a subsidiary of EOG Resources Canada.



5.2.2.4. Metgasco Flex LNG

In September 2010, Metgasco announced its Memorandum of Understanding (MoU) with Flex LNG to launch a feasibility study into the possibility of exporting LNG offshore utilising a floating LNG plant. The gas would be supplied by Metgasco's tenements in the Clarence-Moreton basin in NSW - these resources are estimated to be sufficient to supply up to 3 Mtpa of LNG though certified 2P reserves are not yet at this level.

5.2.2.5. LNG Newcastle Project (LNGN)

The project was announced in June 2010 with a MoU between Eastern Star Gas (ESG), Hitachi Limited and Tokyo Engineering Corporation for feasibility study of LNG export project in Newcastle, NSW. As of February 2011, the project has entered the Front-End Engineering and Design phase (FEED) with completion expected mid 2011 and possibility of reaching FID in 2012 and first export by 2015.

The first phase of the project involves two trains of 0.5 Mtpa each using electric motor driven technology and a possible expansion up to 4 Mtpa. The plant will use gas from the Narrabri gas field in the Gunnedah basin.

5.2.2.6. SA LNG

A MoU between Beach Energy and Itochu Corporation to develop an LNG export facility in South Australia was announced in November 2010. The facility is proposed to have a capacity of 1 Mtpa of LNG and supply to come from Beach Energy's gas portfolio of conventional and unconventional gas resources. This may include shale gas resources from the Cooper basin that Beach Energy is currently pursuing.

5.3. Global LNG Demand

The LNG market represents approximately 9% of the global gas market. LNG is the primary source of gas supply in countries with no domestic gas, such as Japan, Korea and Taiwan and a supplementary source in other countries, including the US, many European countries, China and India. LNG has recently been the most rapidly growing fossil fuel sub-sector, averaging 6% between 2005 and 2009, compared to 3% for the gas market as a whole, and recovered quickly from the Global Financial Crisis (GFC) with continued growth through 2009 and 2010.

5.3.1. Global gas market

After the decrease in demand for natural gas of around 2% in 2009 due to the GFC, the global trend for demand has rebounded and is on the rise according to energy outlook projections by IEA and



several others⁹. In early June 2011, after the following analysis was complete and the draft report was issued, IEA published a gas scenario from the forthcoming World Energy Outlook 2011, entitled “Are We Entering A Golden Age of Gas?” This scenario envisages higher demand and supply growth, supported by government policies and by gas prices that are \$US1.50-2.50/mmbtu lower than in the World Energy Outlook 2010. IEA suggests the scenario would double world trade by 2035, an increase of 620 bcm. About 50% of this increase will go to LNG, equivalent to 310 bcm or 210 Mtpa, which is consistent with the High Scenario derived below, except possibly for the lower price assumption.

Non-OECD countries are the main drivers of growth in demand for natural gas, with China leading the way. Non-OECD countries tend to have higher economic growth attributed mainly to the growing industrial sector. Demand for gas in China is projected to have an average annual increase in the range of 6 to 7%. Other countries driving the growth in demand for natural gas include India, Brazil and the Middle East, each with projected average growth in demand to range between 4 and 5% per year. More broadly, the increased demand for natural gas around the world is driven mainly by the power sector, where natural gas is increasingly used for electricity generation in preference to coal. Natural gas is projected to continue displacing coal generation as countries aim to reduce their carbon emissions, albeit at a lower rate in mature OECD countries due to advancement of renewable technologies.

Globally, demand for natural gas can be met by domestic production, pipeline import or LNG import. In recent years, LNG has become more widely used as an alternative to oil and a cheaper alternative to pipeline gas over long distances.

5.3.2. Regional LNG markets

The LNG import markets are made up of three broad regions of Asia, Europe and the Americas. The growth region is in Asia with traditional LNG importers of North Asia recently joined by strong growth potential from China and India as well as emerging South East Asian countries. Imports of LNG in Europe are also increasing as more gas fields are being depleted and as a means of reducing dependence on gas supply from Russia, the reliability of which has been affected by disputes between Russia its former satellites such as Ukraine, through which the Russian gas is exported. North American markets including the US have been significantly impacted by shale gas developments, which are displacing LNG imports, while some South American countries have emerged as new LNG import markets.

⁹ *World Energy Outlook 2010*, International Energy Agency, 9 November 2010
BP Energy Outlook 2030, BP, January 2011
The Outlook for Energy a view to 2030, ExxonMobil, 27 January 2011
International Energy Outlook 2010, Energy Information Administration, 27 July 2010



This section will provide a more detailed breakdown of each of the regions including discussion of demand drivers and potential threats from the likes of pipeline gas and unconventional gas developments.

5.3.2.1. Asia

Within Asia, there are three broad groups of LNG importing countries:

- Traditional LNG importers (Japan, Korea, Taiwan);
- Growing LNG importers (China and India); and
- Emerging markets (predominantly South East Asian countries including Indonesia, Malaysia, Singapore, etc).

Japan is the world's largest LNG importer and after a decrease in imports in 2009 as a result of the GFC, import has rebounded strongly in 2010 to pre-GFC level and amounted to 70.0 Mtpa. This is mainly driven by economic recovery and government push to increase gas consumption in power generation in an effort to reduce emissions. Japanese LNG imports have traditionally been forecast to increase at a modest growth rate; however the recent earthquake and tsunami disaster which led to a nuclear meltdown is likely to have a significant impact on LNG in the short to medium term. Infrastructure damage was extensive including several explosions at Fukushima Dai-Ichi nuclear power plant, comparable in severity to the nuclear disaster of Chernobyl in the 1980s. This crisis has also led to other nuclear plants being shut down.

These unfortunate events are likely to increase LNG import into Japan by around 10 percent for the next four or five years to replace lost generation from nuclear. In the long term the boost in demand is likely to moderate because despite the looming crisis, Japan remains committed to nuclear power¹⁰.

Korea imported 32.6 Mtpa of LNG in 2010, a big gain even compared to the pre-GFC level of imports in 2008. Growth in LNG is forecast to continue especially in the short term to replace swapped cargoes with Japan following the earthquake. In the longer term, the government's push to increase nuclear generation, which has not been affected by the events in Japan, might impact LNG demand.

Taiwan is the other traditional North Asian LNG importer that has weathered the GFC and recovered strongly in 2010, with import totalling 11.2 Mtpa. On nuclear, the Japan crisis has led to a suspension of the country's plan to build additional nuclear reactors.

China began importing LNG in 2006 and has grown remarkably over the past few years. In 2010, LNG import amounted to 9.4 Mtpa, a 69.1% increase over 2009. LNG import is projected to

¹⁰ Statement from Hidehiko Nishiyama, a spokesman for Japan's Nuclear and Industrial Safety Agency



increase at an average annual rate of 12-17%. This is mainly driven by the increased demand for gas in industrial and power generation due to strong economic growth and efforts to reduce the country's emission intensity.

There are several factors that could impact the future growth rates of LNG import to China. Firstly, pipeline gas imports from Turkmenistan are also set to grow significantly and new capacities are being added from Myanmar and Russia. Over the longer term, domestic unconventional gas production could materially reduce the need to import. Additionally, the Japan nuclear crisis has caused a temporary suspension for approvals of nuclear power plants in China. This might have an effect on LNG demand in the short to medium term.

China is already producing tight gas and is currently seeking options to develop coal bed methane/coal seam gas and shale gas. Development of unconventional gas has been in the spotlight ever since the success of shale gas in the US and coal seam gas in Australia. According to the EIA¹¹, China has technically recoverable resources of shale gas in the order of 1275 Tcf (1,351,500 PJ), which is roughly 12 times the amount of proved natural gas reserves. This represents a huge potential for domestic gas production and could significantly impact LNG import in the future. Additionally, FACTS Global Energy (FGE)¹² reported around 385 Tcf (406,175 PJ) of recoverable resource of CSG available in China. Nonetheless, FGE believes that unconventional gas development in China is still in its infancy and the effect on LNG will be minimal in the short to medium term. In the long term, shale gas development in China is capable of substantially diminishing its need to import LNG, similar to the occurrence in the US.

Another factor impacting LNG demand is prices. China's domestic natural gas prices are regulated by the government while LNG imports are based on long term contracts often with oil indexed pricing. This creates a situation where high import costs are not reflective of the price paid by consumers in the domestic market causing substantial loss to LNG importers. Not surprisingly, LNG demand is highly sensitive to price movements and this has led to calls of action for price reform.

India's demand for LNG continues to grow rapidly, driven by increased industrial demand and growing use natural gas in electricity generation. Imports in 2010 amounted to 9.3 Mtpa and are forecasted to increase strongly.

¹¹ *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, Energy Information Administration, 5 April 2011

¹² *Unconventional Gas and Implications for the LNG Market*, FACTS Global Energy, 2011 Pacific Energy Summit February 2011



Similar to China, the growth potential of LNG in India may be affected by future developments in unconventional gas. Unconventional gas development in India is also at an early stage and potential is more limited - the EIA assessed India's recoverable shale gas resources only at 63 Tcf (66,465PJ). Additionally, India has less alternative options from pipeline gas. The implication of this is that growth potential of LNG in India is greater than that of China.

Domestic gas prices in India are regulated by the government which makes demand highly sensitive to oil-linked import prices.

South East Asian countries have had strong economic growth, which has led to a marked increase in demand for natural gas domestically. Consequently, countries have had to explore alternative options of meeting this demand, including LNG imports. Thailand and Singapore¹³ have already begun construction of LNG import terminals, while countries like Vietnam and the Philippines continue to explore and develop this option. Indonesia and Malaysia have traditionally been LNG exporters but will start importing LNG to meet surging domestic demand. Indonesia has proposed plans of constructing LNG receiving terminals as well as converting Arun LNG to an import terminal. Malaysia also plans on building an import terminal with gas supplied through a long term sales agreement with GLNG.

5.3.2.2. Europe

Countries around Europe have already started recovery from the GFC although at a much lesser rate than Asian countries. Economic growth will continue to drive up demand for LNG which will be used mainly in power generation in an effort to move away from coal. This move is supported by Europe's carbon mitigation policy¹⁴, in Europe is expected to decline as mature gas fields deplete. The gap in supply and demand is increasingly being met by LNG imports.

The nuclear crisis in Japan has also sent shockwaves around Europe with countries divided regarding the future of nuclear. Strong opposition against nuclear power expansion is present in Austria as well as Germany, where a moratorium has been introduced. Other countries like France and Britain are still in support of nuclear expansion citing geological differences between Europe and Japan as the main factor.

Another factor to consider is unconventional gas development in particular shale gas. The main issue that needs to be addressed in regards to shale gas development in Europe is land access and population density. Given the close proximity of shale gas resources to the population, concerns

¹³ Singapore is becoming a trading hub for LNG with global players trying to take advantage of the surging demand in China and India

¹⁴ Set out in Europe 2020: reduction in emissions 20% lower than 1990 level, renewable energy 20% of market share and 20% increase in energy efficiency



regarding environmental impacts of hydraulic fracturing used in extracting shale gas have caused suspensions and delays in development.

In the UK, LNG import has been on a sharp increase mainly due to it receiving spot cargoes from Qatar that has been redirected from the US. This is caused by the arbitrage opportunity between the hub based prices of NBP and Henry Hub of around \$US1-2/mmbtu.

5.3.2.3. Americas

In North America, increased production from shale gas has virtually eliminated the need to import LNG. Originally LNG importers, the US and Canada may soon be exporting shale gas in the form of LNG. Several LNG importing terminals planned for the US have been suspended or cancelled and Kitimat LNG in Canada, which was originally planned to be an import terminal, has been converted to an export terminal. This has also caused the US Henry Hub gas prices to drop to around \$US4/mmbtu. This low price has diverted LNG cargoes that were originally intended for the US away to other markets, mainly to the UK and other parts of Europe as well as Asia.

The development of shale gas in North America shows no sign of slowing down despite growing environmental concerns regarding hydraulic fracturing.

In other part of the Americas, Argentina, Brazil and Chile have emerged as LNG importers driven by economic growth and increased use of gas in power generation.

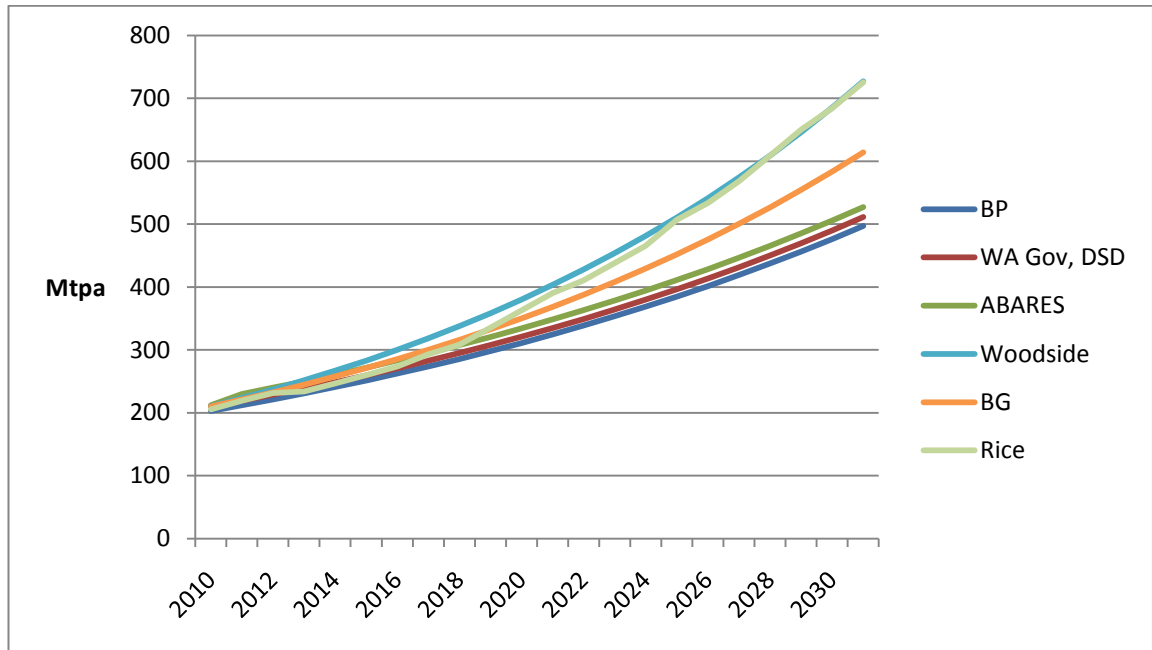
5.3.3. Global LNG Demand Projections

5.3.3.1. Public domain projections

Notwithstanding the threats posed by new domestic sources such as shale gas in the US, which has resulted in LNG contracted to US buyers being diverted to other markets, there is a broad consensus that global LNG demand will continue to enjoy growth rates of approximately 4.5% pa over the coming decades (Figure 5-1). Some forecasters project growth rates of approximately 6% and none project growth of less than 4%, in what we interpret as their most likely or medium projections.



■ **Figure 5-1 Global LNG Demand Projections – public sources**



Source: BP Energy Outlook 2030, WA DSD Northern Energy Arc, ABARES Australian Commodities March 2011, Woodside Annual Report 2010, BG Q4 2010 Full Year Results and Annual Strategy Update, Rice University Shale Gas and Emerging Market Dynamics

5.3.3.2. Scenario projections

For 2011 GMR, we have selected 4.5% as the base global LNG demand growth rate representing the Medium Scenario. Forecasts available in the public domain provide limited guidance on growth rates compatible with the High and Low GMR scenarios. However we believe that reasonable scenario estimates can be obtained by varying the base growth rate according to the scenario factors that impact global LNG growth as follows:

- Economic growth: High/Low = $\pm 1.0\%$
- Emissions targets : High/Low = $\pm 0.5\%$
- Energy prices: High/Low = $\pm 0.5\%$

Consequently the High Scenario growth rate is set at 6.5% and the Low Scenario growth rate is set at 2.5%.



5.4. Global LNG Supply

5.4.1. Current supply

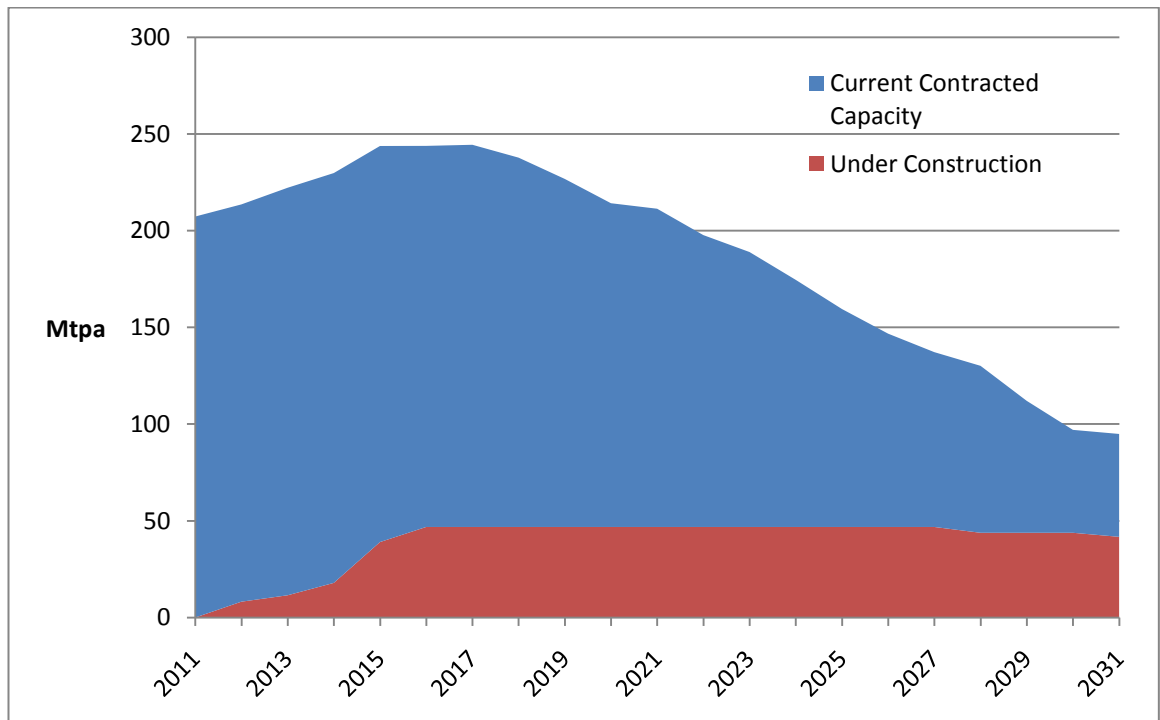
LNG capacity that is currently contracted is illustrated in Figure 5-2. This includes:

- Capacity contracted as at 2009 according to GIIGNL
- SKM MMA estimates of near-term contract extensions by Brunei and Libya
- SKM MMA estimates of capacity contracted by committed projects under construction (including the recent APLNG agreement with Sinopec)

It does not include:

- Recently refurbished Algerian capacity of approximately 9 Mtpa
- As yet uncontracted Qatari capacity, approximately 15 Mtpa
- As yet uncontracted Iranian capacity of 10 Mtpa, scheduled for start-up in 2013 but likely to be delayed beyond that date

■ **Figure 5-2 Contracted LNG capacity**



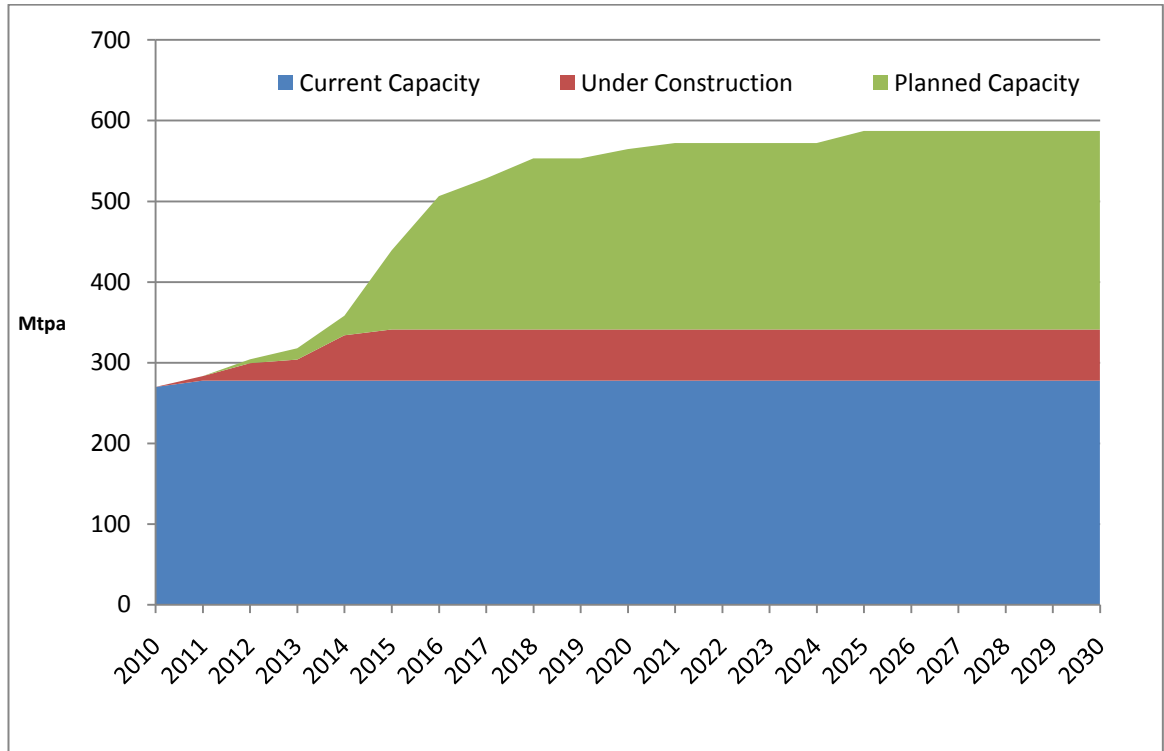
Source: The LNG Industry 2009, GIIGNL plus project websites

Total global liquefaction capacity currently operating, under construction and planned is shown in Figure 5-3 and detailed in Table 5-3. This is the total capacity available and not representative of



actual production and similarly not a forecast of future LNG trade. Additionally, it does not take into account the possibility of reducing current capacity in the future (due to plant shutdown or conversion of export terminal to import terminal).

■ **Figure 5-3 Global Liquefaction Capacity**



Source: IEA Gas Market 2008, GIIGNL LNG Industry 2009, Global LNG info plus project websites

■ **Table 5-3 Global LNG supply capacity end-2010 (Mtpa)**

Asia-Pacific	
Existing	99
Under Construction	43
In planning	93
Total	234
Australia (included in above)	
Existing	19
Under Construction	23
In planning	85
Total	127



Middle East Existing Under Construction In planning Total	 133 15 49 198
Other Existing Under Construction In planning Total	 45 5 104 154
Global Existing Under Construction In planning Total	 277 63 246 587

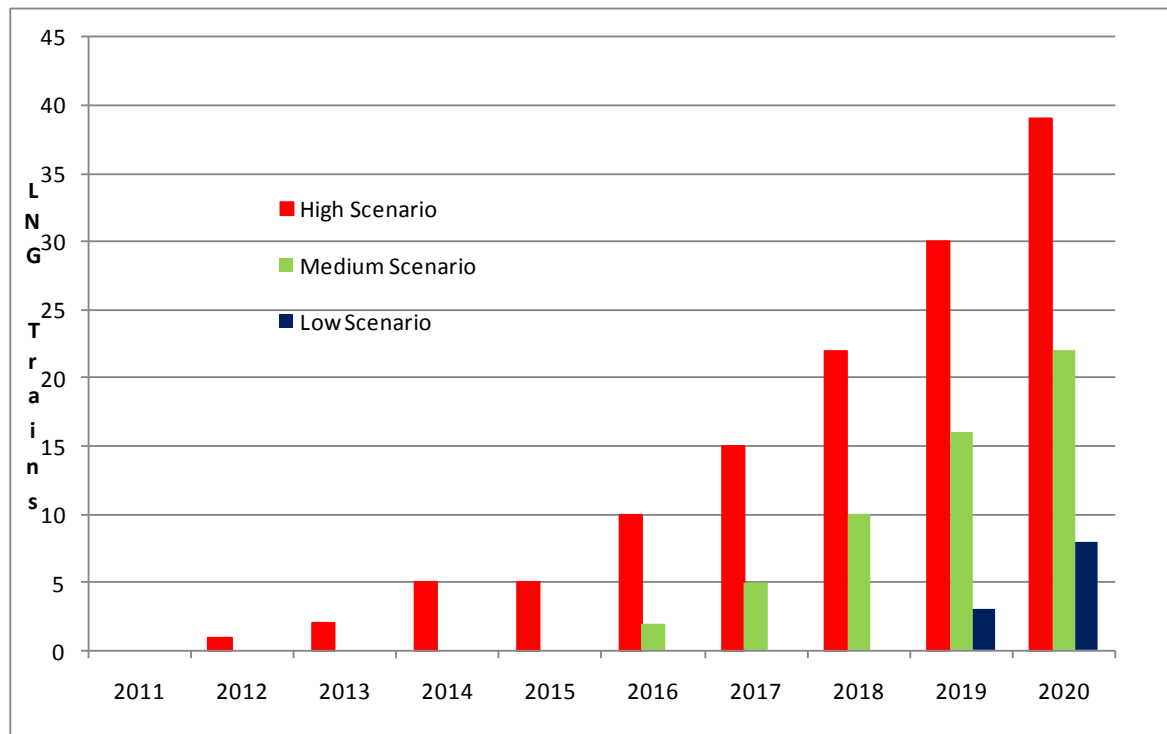
Source: IEA Gas Market 2008, GIIGNL LNG Industry 2009, Global LNG info plus project websites

5.4.2. New supply required

Comparing Figure 5-1 and Figure 5-2 it can be seen that currently contracted capacity will meet projected demand out to 2012 or a little beyond, depending on the utilisation of Algerian and Qatari capacity and when or whether Iranian capacity gets to the market. Further capacity is required to be constructed to meet projected demand beyond this. Figure 5-4 shows the number of new trains (of 4 Mtpa capacity, contracting 3.5 Mtpa on average) required to meet demand in each scenario, assuming that 20 Mtpa of Algerian and Qatari capacity is taken up.



■ **Figure 5-4 Cumulative global new LNG capacity requirement**



The first new supply requirement in each scenario is: High, 2012; Medium, 2016; and Low, 2019. First delivery in the period to 2015 is difficult for as yet uncommitted projects and this suggests some supply constraints in the short-term in the High Scenario. The first requirements in the Medium and Low scenarios can readily be achieved by projects yet to reach FID.

5.5. Eastern Australian LNG Projections

According to the IEA and other sources there is approximately 250 Mtpa of LNG capacity in planning that is capable of delivery between 2015 and 2020. Much of this capacity however is in projects that have been in planning for a prolonged period and do not seem able to reach commitment. There is widespread belief among analysts that capacity for 2015 to 2020 and beyond will come primarily from countries which combine resource access for major private sector oil and gas companies and limited country risk. Australia is one of the few countries that combines these attributes and is seen as a likely source of much of the new capacity. This position is strengthened by the discovery of large reserves of coal seam gas (CSG) in Queensland, which has led to the large number of proposals for CSG to LNG export projects.



Large-scale capacity expansion from the current top three exporters Qatar, Malaysia and Indonesia are not likely to come in before 2020. Qatar has kept in place its moratorium to further develop the North Field gas reservoir until at least 2014, which prevents commissioning of any new projects. The only form of capacity expansion in Qatar would be from debottlenecking existing plants. In Malaysia and Indonesia, growing demand for natural gas domestically and expiration of long term LNG supply contracts will likely weaken exports levels. Malaysia and Indonesia are also expected to start importing LNG; with Malaysia's Petronas already a committed off-taker as part of its joint venture interest in the Santos-led GLNG project and Indonesia is building its first LNG receiving terminal.

Nevertheless, the CSG to LNG projects in Queensland are not without risks. As with all capital intensive projects, they are susceptible to cost blow-outs and delays, which could threaten the projects' economics. Added to that is the growing skills and labour shortage in Australia in part caused by LNG projects in both Queensland and Western Australia.

Projects seeking to complete FID in 2011 and competing to be first in line include:

- PNG Train 3 – (3.15 Mtpa)
- Angola Train 2
- Pluto Train 2
- Gorgon Train 4 (5 Mtpa) FID aimed for 2013– trains 1,2,3 are 2014,2015 and 2016
- Ichthys (2 trains) (2x4.2 Mtpa) – economics supported by high liquids content
- Wheatstone (2 trains) (2x4.3 Mtpa) - Shell has recently become involved
- Prelude¹⁵ (1 train) (3.6 Mtpa) – a test for Shell's floating LNG technology, new HoA with CPC to supply 2 Mtpa over 20 years from 2017 from Shell's portfolio of gas supply
- Liquid Niugini LNG(1 train) (5 Mtpa) – high liquid content
- APLNG (2 trains) (2x4.5 Mtpa) – Train 1 is included in capacity under construction

Browse and Scarborough in WA are less advanced and Arrow LNG is targeting FID in 2012. GLNG and QCLNG will be targeting FID on third trains when their reserve positions are sufficiently mature, unlikely before 2012.

Economies of scale tend to favour 2nd and subsequent trains (2nd trains in particular) and Bernstein Research¹⁶ has suggested that APLNG will follow all the projects above it in the above list except

¹⁵ Prelude FID was announced on 20 May, after the analysis in this section was completed.

¹⁶ Australian LNG: Strong Demand, Rising Commodity Prices - But Will Cost Inflation Erode The Upside? Bernstein Research, February 16 2011.



Angola and Gorgon, making the two trains numbers 9 and 10 in line. Arrow LNG would be trains 11 and 12. Following the announcement of a binding agreement with Sinopec for 4.3 Mtpa of LNG over 20 years, equivalent to production from one train, APLNG is likely to commit to a single train, which is included in all the scenarios. (Note: this was announced on 28th July 2011). The second train will follow once a buyer is found.

The timing of the second train can be approximated to when the 10th train is required for each of the global demand projections (refer to Section 5.4.2). This is shown in Table 5-4.

■ **Table 5-4 APLNG second train start-up dates under Bernstein assumption**

	Start-up
High Scenario	2016
Medium Scenario	2018
Low Scenario	2021

Under the High Scenario, the timing of APLNG's second train in 2016 coincides with the expected start up date of the first train; therefore it would be delayed by one year.

The rate of LNG train build up in Eastern Australia will be impacted by the global requirement for new trains to meet global LNG demand (refer to Section 5.4.2). Globally, the average number of new trains per year after 2018 required to meet demand under each scenario are as follows:

- High Scenario A = 11
- Medium Scenario C = 6
- Low Scenario E = 4

As a starting point we assume that the total number of trains starting up in Eastern Australia beyond 2018 is proportional to the global requirement. For the High Scenario we assume that one train per year is constructed i.e. approximately 9% of world incremental capacity. This is lower than the two per annum rate that will be achieved between 2015 and 2017, because greater competition from other projects is assumed.

Based on 9% of global capacity, for the Medium Scenario the train construction rate would be approximately one every two years and in the Low Scenario one every three years, starting in 2021.

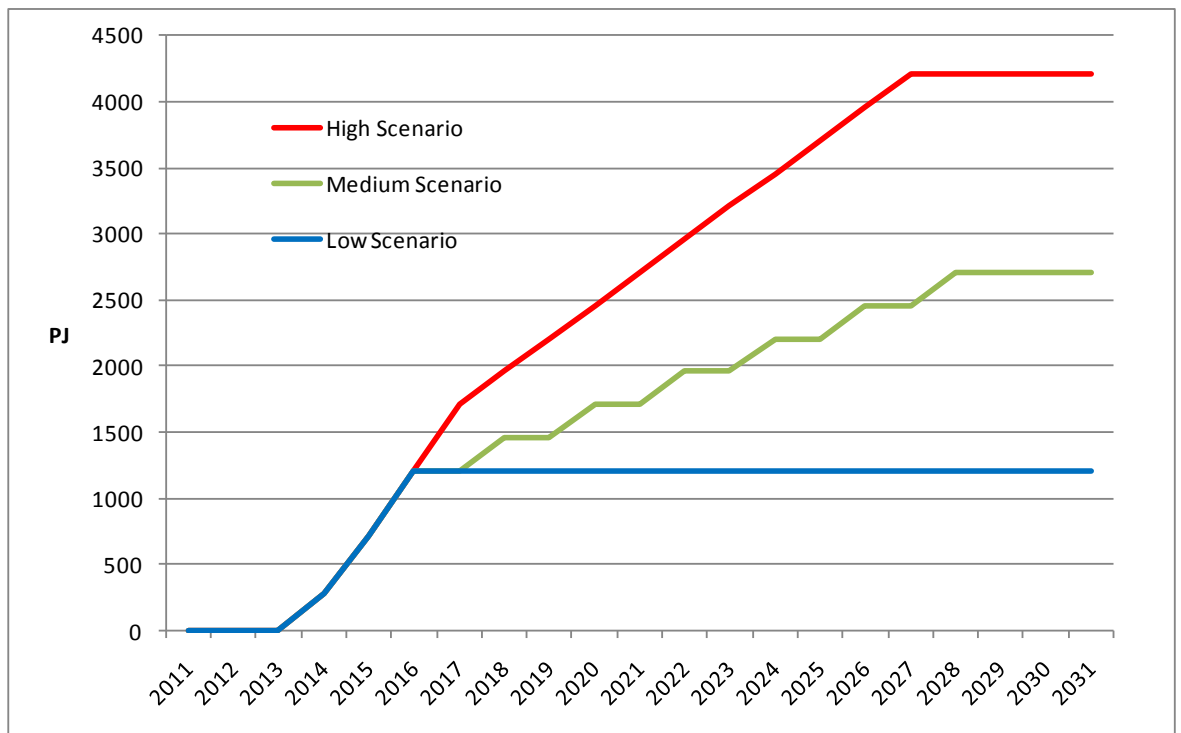


The above outcomes are further modified by:

- In the High Scenario, a cap of 17 trains on Curtis Island, the number currently approved
- In the Low Scenario, given the slow growth rate and further global competition, all growth is eliminated i.e. the number of trains is capped at 5
- In the Medium Scenario, for symmetry between the High and Low scenarios, the number of trains is capped at 11.

The volume of gas¹⁷ required for export is illustrated in Figure 5-5. For the first 5 trains, the actual contracted capacity has been used, while the remaining trains are assumed to be contracted at 4 Mtpa.

■ **Figure 5-5 Eastern Australia gas requirement for export (PJ)**

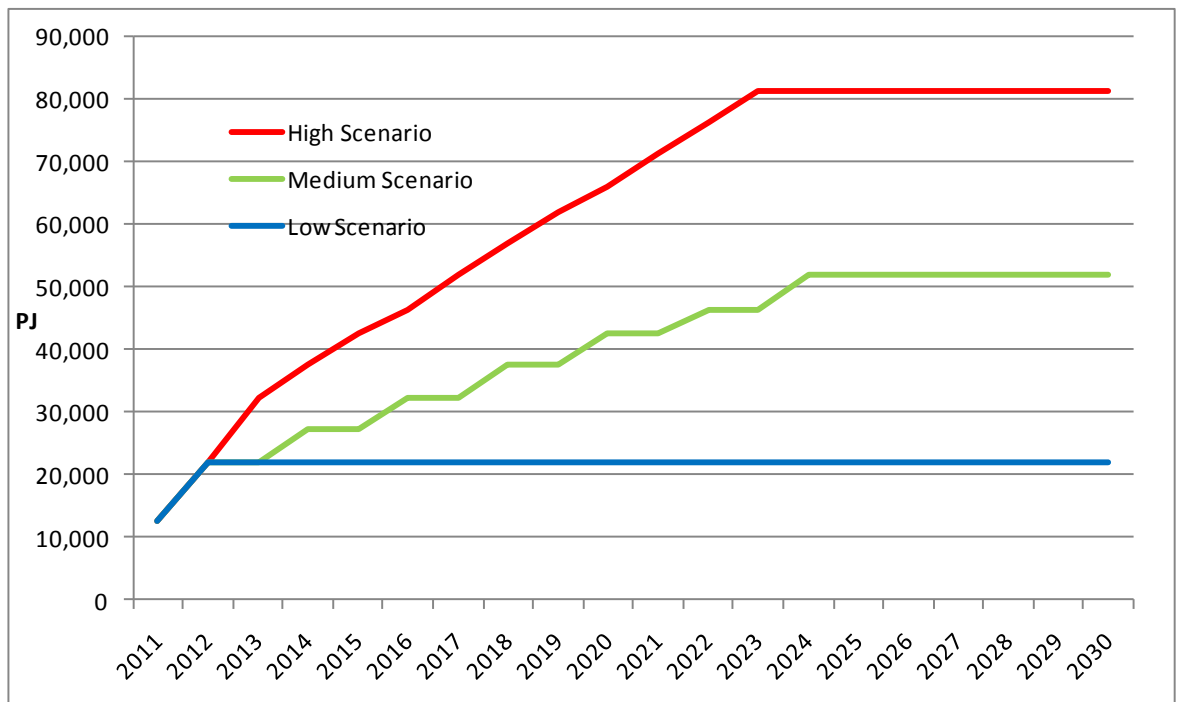


¹⁷ Assuming each million tonne of LNG requires 62.5 PJ of delivered gas



The 2P reserves commitments required to service the above export projections are presented in Figure 5-6. The commitments are calculated on the basis that reserves sufficient to meet export deliveries for the life of the sales contracts are committed to the contracts at the time of contracting, which is assumed to be four years prior to first gas sales. These requirements are compared with available reserves in section 7.

■ **Figure 5-6** **2P reserves commitments for export**





6. Gas Supply

6.1. Introduction

This section of the report describes the gas resources of Eastern Australia, their disposition, estimated costs of production and adequacy to meet the demand projections.

Natural gas is a blend of hydrocarbons, principally methane, and inert gases found in sandstone, carbonate and shale reservoirs and in coal seams, at depth in the earth's crust. Gas is frequently categorised as conventional (sandstone and carbonate reservoirs with good porosity and permeability) or unconventional (low permeability reservoirs or tight gas, shale gas and coal seam gas or CSG¹⁸).

In Australia CSG is currently the dominant unconventional gas and we maintain a distinction between conventional gas and CSG throughout this report. From a discovery and production perspective conventional gas and CSG are somewhat different¹⁹ however downstream of the processing plant gate, in transmission, distribution and end-use, there is little distinction other than small differences in heating value and the two are virtually interchangeable. Both tight gas and shale gas are regarded as highly prospective following drilling technology developments in the US that have enabled large resources to be exploited. Preliminary resource evaluations have begun with development likely over the second half of this decade.

Liquid hydrocarbons such as oil and condensates are found in the same types of reservoirs as conventional natural gas, sometimes in association in the same reservoir - the term petroleum is used to cover all naturally occurring mixtures of hydrocarbons in the gaseous, liquid, or solid phase. This has had a very material impact on gas discovery as much conventional gas has been discovered in the search for more valuable oil. In contrast there are no liquid hydrocarbons with CSG and all CSG is found by deliberately searching for coal seams from which it can be extracted economically.

¹⁸ Also known as coal seam methane (CSM) and coal bed methane (CBM). CSG, CSM and CBM are terms used for gas recovered by drilling into coal seams from the surface. The term coal mine methane (CMM) is generally used to refer to gas recovered from coal seams in association with coal mining.

¹⁹ The production of gas from conventional tight gas fields of low porosity/permeability has much in common with CSG production however.



6.2. Reserves and Resources

The gas reserves and resources estimates used in this study are updates of the estimates presented in the 2010 AGMR and those prepared in 2010 for the Australian Energy Market Operator (AEMO) by MMA with assistance from RLMS. The updates incorporate the most recent reserve estimates published by Geoscience Australia²⁰ and by the gas companies. MMA's report to AEMO, "Gas Reserves Development in Eastern Australia – Forecasts Prepared for the GSOO 2010", is available from the AEMO website²¹.

The GSOO 2010 report provides background material on the gas resource development process and the approaches used to classify gas resources into:

- Commercial reserves (demonstrated reserves that would yield a commercial return at expected prices):
 - Proved reserves (1P)
 - Proved and probable reserves (2P)
 - Proved, probable and possible reserves (3P)
- Sub-commercial contingent resources (demonstrated resources whose commerciality requires further assessment):
 - Low estimates (1C)
 - Best estimates (2C)
 - High estimates (3C)
- Prospective resources (inferred resources – low, medium and high estimates)

2P reserve estimates are the most widely quoted, as they form the basis of long-term contracts for gas sales and purchases - a producer's ability to deliver gas under the contract is usually underwritten by demonstrated gas reserves at the proved and probable (2P) level. Reserves equal to the total contract gas quantity are typically dedicated to contracts though in some cases where 2P reserves are initially less than the total contract gas quantity the producer may undertake to prove up sufficient reserves within a set period or on an annual basis, for example to maintain a minimum number of years of coverage at all times. In summary, 2P reserves form the basis of commercial contracting and the other estimates are not commonly used for this purpose.

²⁰ Oil and Gas Resources Australia 2009 (OGRA 2009)

²¹ <http://www.aemo.com.au/planning/1410-0008.pdf>

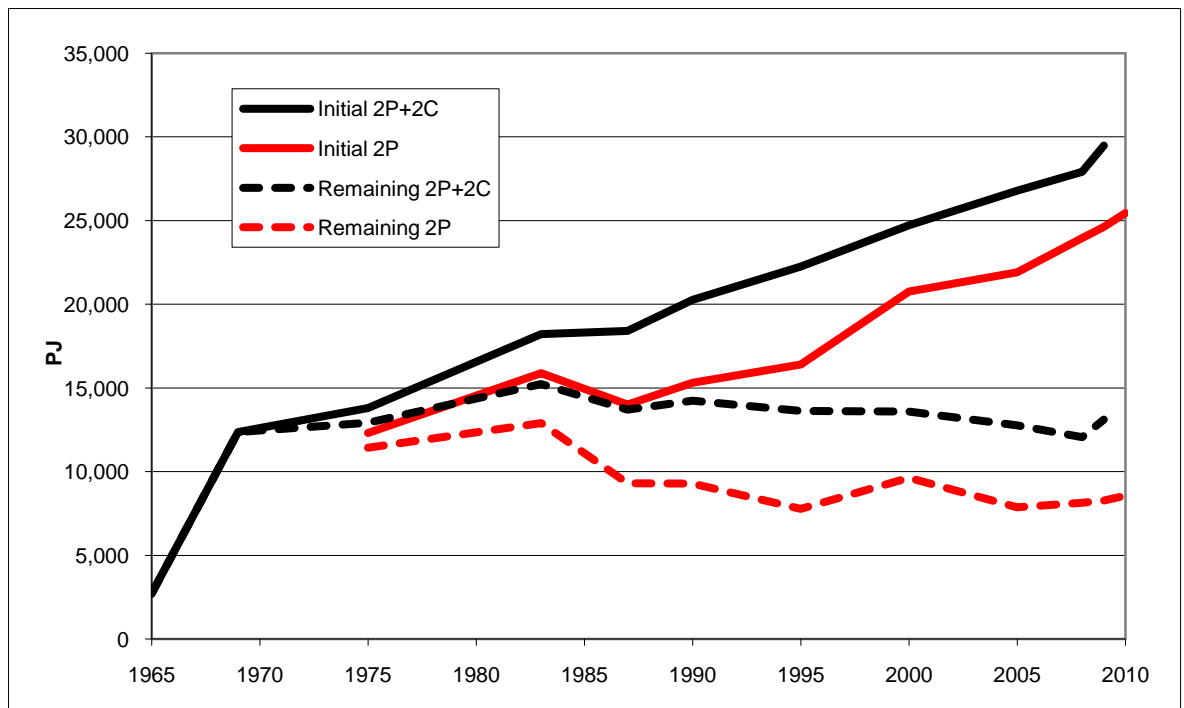


1P estimates may be used as an indication of the certainty of gas production in the short term and 3P and 2C estimates are used to indicate the potential for future 2P reserve development.

6.2.1. Historical growth

Historical reserve and resource trends are shown in Figure 6-1 and Figure 6-2. Whereas remaining reserves of conventional gas have been relatively static since the initial discoveries were made in the 1970s, CSG reserves have grown rapidly from a zero base in 1995 to overtake conventional reserves in 2008.

■ **Figure 6-1** Aggregate conventional gas resources and reserves, Eastern Australia (PJ)

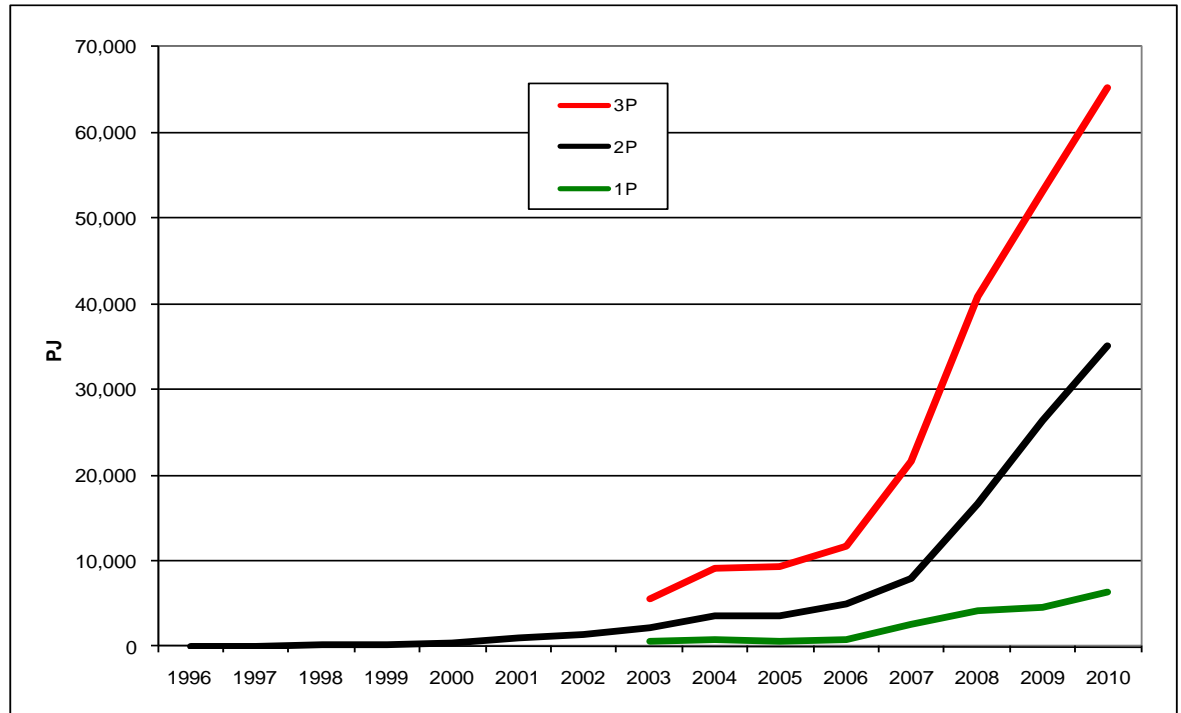


Estimates at 31 December

Sources: Geoscience Australia, APPEA



■ **Figure 6-2** Aggregate CSG reserves, Eastern Australia (PJ)



Estimates at 31 December

Sources: GSOO 2010, Producer websites

6.3. Conventional reserves and resources as at 31st December 2010

The reserve and resource estimates used for each of the major joint venture producers considered in the study are presented in Table 6-1. The 2P reserves are based on OGRA 2009 adjusted for gas produced in 2010, with the exception of Cooper Basin reserves which are based on Santos estimates²². The 2P reserves are lower than in the 2010 GMR, which was based on the 2009 GSOO.

The contingent and prospective resources are based on the values reported in the 2010 GSOO, adjusted for differences in 2P reserves (so that total resources are as in the 2010 GSOO) and gas produced in 2010. It is important to bear in mind that these contingent and prospective resources apply only to conventional resources and that unconventional resources such as tight gas and shale gas in the relevant basins may be considerably larger.

²² Santos Media Release 8 February 2011



Adavale Basin reserves and resources have been omitted on the grounds that the basin went out of production more than five years ago and on the basis of the very low OGRA 2009 reserves and resources estimates, production is unlikely ever to restart. Gunnedah Basin conventional reserves have also been omitted because they are very low.

■ **Table 6-1 Remaining conventional gas reserves and resources as at 31st December 2010 (PJ)**

Basin	Joint Venture	2P	2C + Prospective
Gippsland, Longford	BHPB, Exxon	5,210	6,184
Gippsland, Orbost	Nexus	392	465
Bass	Origin, AWE	313	517
Otways, Minerva	BHPB, Santos	142	183
Otways, Geographe	Origin, Others	638	822
Otways, Casino	Santos, Others	376	484
Cooper Eromanga	Santos, Beach, Origin	1,385	2,914
Cooper Eromanga	Others	29	61
Surat-Bowen	All producers	110	429
	Total	8,595	12,058

Sources: refer to text

6.4. CSG reserves and resources as at 31st December 2010

6.4.1. Reserves

Recent CSG 2P reserves growth for each of the major joint ventures considered in the study are presented in Table 6-2. The values from 2006 to 2009 are derived from the GSOO 2010, while the 2010 values are based on producer website information. We understand that GSOO 2010 data for Queensland has been reconciled with data published by DEEDI. Important points to note are:

- Eastern Star Gas, Metgasco and Arrow Energy have not reported any reserves updates since 31st December 2009. Metgasco has recently announced that it will release an update during the June quarter of 2011
- The APLNG figure for 2010 includes 18 months growth
- GLNG includes other Santos reserves in the Surat/Bowen basin. Since a recent transfer of Santos reserves to GLNG this figure is approximately 10% of the total.
- Gloucester Basin 2010 2P includes Hunter Basin 2P. Reserves in both basins are 100% owned by AGL

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- Second Tier includes: Bow Energy; Mitsui; Molopo; Toyota Tsusho; Victoria Petroleum; and Westside.
- The figures in the table are based on current acreage ownership, i.e. the figures in earlier years include reserves of all companies that were taken over by the JV in subsequent years, so that the growth relates to current acreage.
- The above are company estimates, most of which have been verified by independent assessors. We have not discounted reserves that have not been verified by independent assessors.
- Some of the Bowen/Surat Basin estimates are understood to include conventional gas reported separately in Table 6-1. To avoid double counting, these conventional gas reserves (110PJ) have been excluded from the total reserve estimates reported in Table 6-6.

■ **Table 6-2** Remaining CSG 2P reserves as at 31st December (PJ)

Basin	Joint Venture	2006	2007	2008	2009	2010
Sydney	AGL	82	82	82	126	151
Gloucester	AGL	0	175	175	423	811
Gunnedah	ESG/Santos	0	185	336	1,520	1,520
Clarence Morton	Metgasco	22	247	298	397	397
Bowen	AGL/Arrow Energy	500	500	947	1,510	1,810
Surat	APLNG	1,374	2,470	5,482	7,266	11,262
Surat	BG Group	695	1,786	3,694	5,200	8,200
Surat/Bowen	GLNG	1,357	1,573	3,648	4,625	5,638
Surat	Arrow Energy	581	700	1,744	4,648	4,602
Surat	Second Tier	326	293	343	597	664
	Total	4,936	8,011	16,749	26,312	35,055

Sources: refer to text.

6.4.2. Resources

Contingent and prospective resource values for 2010 have also been derived from producer reserves/resources statements (DEEDI does not publish resource estimates). Since the publication of the 2010 GMR there have been relatively few updates of contingent and prospective resources.



■ **Table 6-3** CSG 2C and prospective resources as at 31st December 2010 (PJ)

Basin	Joint Venture	2C	Prospective	Combined
Sydney	AGL			
Gloucester	AGL	370		370
Gunnedah	ESG/Santos	3,515	50,000	53,515
Clarence Morton	Metgasco	10,597	3,893	14,490
Bowen	AGL/Arrow Energy	14,613	18,492	33,105
Surat	APLNG	5,333	6,117	11,450
Surat	BG Group	8,400	4,400	12,800
Surat/Bowen	GLNG	4,201	21,000	25,201
Surat	Arrow Energy	10,783	4,326	15,108
Surat/Bowen	Second Tier	3,054	0	3,054
Galilee	All participants		21,840	21,840
	Total	60,866	130,067	190,933

It is noted that in comparison with the estimates presented in the 2010 GMR:

- 2C resources are approximately 2,400 PJ lower, implying that in net terms approximately 27% of the 8,700 PJ of 2P reserves growth from 2009 to 2010 was derived by conversion of 2C resources. Consistent with this, the fall in 2C resources is in the Surat/Bowen basin, where most of the reserve growth occurred.
- Prospective resources are approximately 10,000 PJ higher. This is entirely due to the addition of estimates for APLNG and BG Group. The APLNG estimate has been derived by equating Prospective resources with 3C less 2C, so that the sum equals 3C.

6.5. Reserves growth potential

6.5.1. Conventional

The derivation of conventional gas contingent and prospective resources is consistent with their discovery and proving up over a thirty year period (GSOO 2010). Consequently future conventional reserve additions are based on the assumption that the 2C and prospective resources in Table 6-1 are converted to 2P reserves at a steady rate over a thirty year period. Economic factors may lead to variations in the rate of conversion.



6.5.2. CSG

Future growth rates for CSG 2P reserves are constrained by industry capacity to convert resources into reserves and by the total quantum of resources. Recognising that since the first LNG projects were announced in 2007 the industry has had a strong incentive to expand CSG resources as fast as possible, recent reserve additions are taken to be indicative of the industry's maximum capacity to expand the CSG reserves base. Estimates of gross reserve additions in each year are presented in Table 6-4, these being the sum of the net growth reflected in Table 6-2 and gas produced in each year.

■ **Table 6-4** CSG 2P reserve growth rates in the year to 31st December (PJ)

Basin	Joint Venture	2007	2008	2009	2010	Future Maximum
Sydney	AGL	0	7	53	36	30
Gloucester	AGL	175	0	248	388	300
Gunnedah	ESG/Santos	185	151	1,184	0	500
Clarence Morton	Metgasco	225	51	99	0	50
Bowen	AGL/Arrow Energy	0	467	583	328	500
Surat	APLNG	1,096	3,048	1,829	4,072	2,500
Surat	BG Group	1,091	1,932	1,533	3,039	2,000
Surat/Bowen	GLNG	216	2,107	1,030	1,066	1,400
Surat	Arrow Energy	119	1,067	2,939	-3	1,400
Surat	Second Tier	-33	58	262	75	200
	Total	3,075	8,889	9,761	9,001	8,880

The maximum future annual 2P reserves growth rates used in our modelling are based on the average growth achieved over the last three years, which appear to reflect the incentives provided by LNG prospects, with the exception of: Gloucester, which has been adjusted upwards by approximately 100 PJ to reflect the inclusion of AGL's Hunter Valley reserves in the 2010 figures; and Second Tier Surat, where the 200 PJ reflects higher growth expectations but is still below the collective growth target of the group. It is also noted that:

- GLNG has indicated that it expects reserve growth of less than 1,000 PJ/yr from existing acreage. The 1,400 PJ figure above includes growth in other Santos Surat Basin acreage.
- Gunnedah Basin reserves have the potential to grow faster than 500 PJ/yr but until there is a commitment to large scale development higher growth is not assured.



In the 2010 GMR and both the 2009 GSOO and 2010 GSOO gas reserves projections the potential development of 2P reserves in the Galilee Basin was discounted. Notwithstanding continuing development work in the basin by AGL²³, Exoma and others, this practice is continued in the 2011 GMR. It appears that 2P reserves may be certified over the next 2-3 years, followed or accompanied by sales contracts, with production from 2017 at the earliest. On this basis Galilee developments will not materially affect market activity over the next one to two years and the potential impact can be evaluated in a future GMR when the scale of reserves becomes clearer.

In modelling future reserves growth the following factors are also taken into account.

6.5.2.1. Flood impacts

Recent floods in Queensland have restricted access to most drilling sites and both production and appraisal drilling has slowed down:

- In its December 2010 quarter production report Origin Energy reported that “all drilling, fracing and work-over activities ceased during December and are expected to be restricted through the March Quarter 2011”. Origin’s March 2011 quarter production report confirmed that “Australia Pacific LNG’s drilling program has continued to be disrupted due to adverse weather during the Quarter with only 22 wells drilled”.
- In a first quarter earnings conference call, BG Group chief executive Frank Chapman said while the company’s drilling program had suffered some impact from the Queensland floods it was working hard to make sure there was no delay to the project. “In common with pretty much every operator, we’ve been unable to access some areas because of very poor ground conditions still existing quite a long time after the floods have abated.

“So we’re having to in fact change the drilling sequence to some degree, we’ve got to prepare well sites in areas that we can access, we have to indeed think about accelerating the drilling program by using more rigs and so on.

“Bearing in mind we have about 700 wells already, we’ve got to get to about 2,000, we do have time to catch up.”

There seems little doubt that drilling programs will under achieve in 2011 and further flooding next summer would clearly extend this into 2012. In this regard it is noted that the Northern Bowen Basin experienced similar conditions in 2010. It is reasonable to assume that if production build up for LNG is delayed then LNG production will necessarily be delayed, with no consequences for contracted domestic supply. However if appraisal is delayed then availability of reserves for domestic contracting in 2012 and 2013 (for first supply in 2016 or 2017) will be set back. A

²³ Upstream Gas Strategy Overview, AGL October 2010.



scenario in which reserve growth is restricted to 50% of maximum levels in 2011 and 2012 will therefore be considered.

6.5.2.2. Ultimate constraints

Cumulative reserves growth is constrained to levels below current contingent plus prospective resources, consistent with the approach taken in the 2010 GMR and GSOO studies.

6.5.2.3. Declassification

No allowance is made for possible declassification of reserves declared 2P at 1st January 2010, because earlier declassifications have already affected historical growth and are therefore built into the growth estimates.

Declassification could nevertheless occur if the market price expectations built into the 2P commerciality assessments are not met in the future. We understand that many companies base their assessments on historic prices but that some estimates may be based on higher prices.

6.5.2.4. Market incentives

Unless LNG developments continue beyond those already announced (refer to section 5) we would expect CSG reserve growth to eventually taper off to levels below the maximum achievable. In our economic demand-supply modelling this is effected by setting a target band for reserves dedicated to the domestic market and using this to determine a rate of reserve growth between zero and the maximum that maintains this reserve component in the target band, where possible. If a growth rate greater than the maximum is required, the reserve component will fall below the lower limit of the band.

6.5.3. Other unconventional gas

Unconventional gas other than CSG, namely tight gas and shale gas, has made rapid progress in the US over the past decade and in 2010 made up over 50% of US production and reserves²⁴. In summary, a rise in US wholesale prices from \$US2.50/mmbtu in 2000 to approximately \$US8/mmbtu in 2008 made possible development of more expensive tight gas fields and application of tight gas technology to shale gas deposits. Rapid technology refinement has reduced the cost of shale gas to the point where the most productive areas are lower cost than much of the

²⁴ Energy Information Administration Annual Energy Outlook 2011



conventional gas base. The impact of this development on US LNG imports is described in more detail in section 5.3.

Over the past five years Australian gas producers have started to explore for unconventional gas, with a strong focus on shale²⁵. Extensive deposits have already been found in the Cooper Basin by Santos²⁶ and Beach, in the Perth Basin by AWE and in the Canning Basin by Buru Energy. The US Energy Information Administration has conducted a survey²⁷ of world shale resources and estimates that Australia has 396 Tcf (approximately 417,000 PJ) of risked recoverable resources, i.e. resources that should be recoverable given a market at the right price. Basin details are provided in Table 6-5. Shale resources that are relevant to this study, in the Cooper and Maryborough basins, total approximately 108 Tcf (114,000 PJ), the same order of magnitude as CSG contingent and prospective resources.

■ **Table 6-5 Estimated Australian risked recoverable shale gas resources (Tcf)**

Basin	Resource
Cooper	85
Maryborough	23
Perth	59
Canning	229
Total	396

By comparison with development timeframes for shale in the US and CSG in Australia, it is likely to be five years before 2P reserves are established and ten years before shale gas is in production. Shale developments will therefore not materially affect market activity over the next one to two years and we have not considered the availability of shale reserves - the potential impact can be evaluated in a future GMR when the scale of reserves becomes clearer.

6.5.4. Role of the PGPLR

The Gas Security Amendment Bill 2011 establishes the concept of “the Australian market supply condition” that may apply to gas produced from certain gas lease areas. The Australian market supply condition means that gas produced from within the lease must be sold and onsold only within Australia. The Australian market supply condition can be imposed on any or any part of a

^R Reserves of tight gas have been known for some time, notably the Warro field in the Perth Basin and in the onshore Gippsland Basin. Their development has been hindered by low prices, though recent higher prices in WA have led to renewed interest in Warro.

²⁶ Santos ref

²⁷ World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States. US Energy Information Administration, April 2011



new lease granted and any lease on which it is imposed becomes PGPLR (Prospective Gas Production Land Reserve) land.

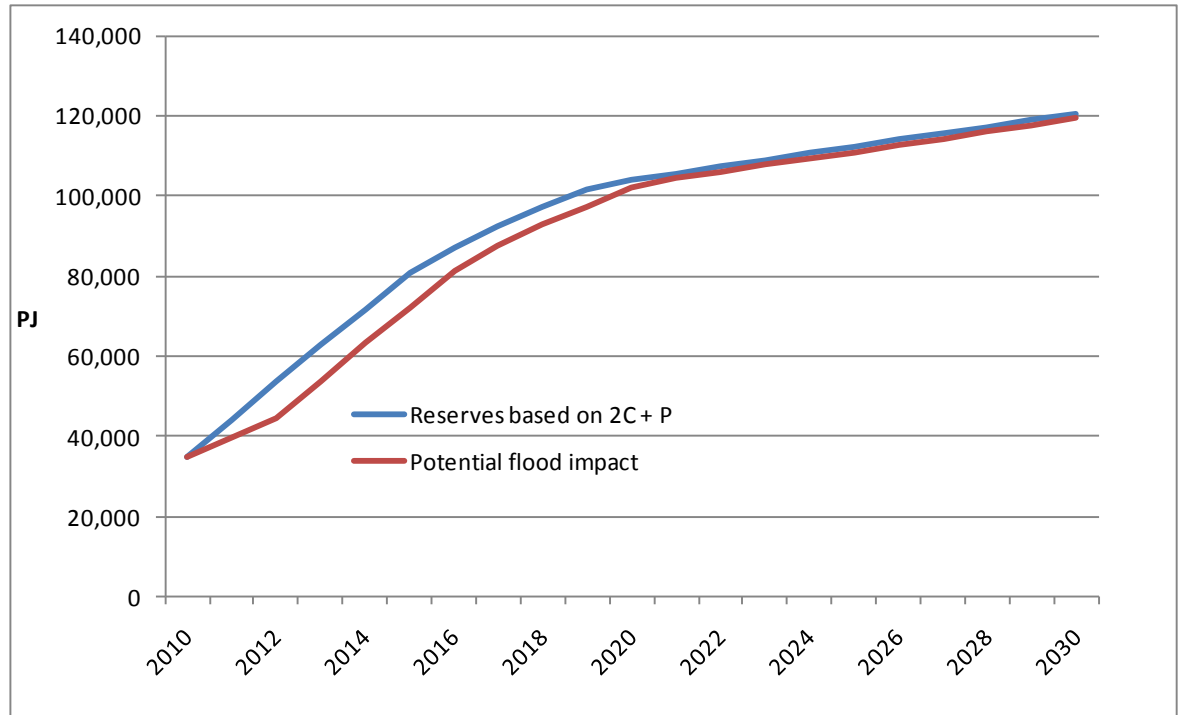
No land has been granted as PGPLR land to date. Resources in any, as yet, un-released acreage would be additional to those considered in the domestic reserve/resource figures presented in this study. The timeframe within which such reserves could be added are uncertain, but are likely to be 2-3 years before completion of appraisal and reserve declaration, followed by 3-4 years before first production, assuming that the reserves are contracted soon after they are declared due to strong demand. It is assumed therefore, that grant of PGPLR land needs to precede a forecast production shortfall by up to 7 years and reserves shortfalls (for contracting) by up to 3 years.

6.5.5. Total reserve growth projections

Figure 6-3 illustrates aggregate uncontracted gross (prior to production) 2P reserves growth at the maximum growth rates consistent with recent growth rates, and the potential impact of Queensland floods, with cumulative growth capped at current 2C plus prospective resources. The flood impact scenario assumes 50% growth in 2011 and 2012 with no subsequent catch up until the maximum growth case is constrained by ultimate resources. The initial growth rates will be maintained in the longer term only if there is continued growth of prospective resources feeding into contingent resources and reserves. The reserves projection based on 2C +P is very similar to the same-basis projection in the 2010 GMR, owing to the 2010 reserves growth being as projected in the 2010 GMR.



- **Figure 6-3** Projected aggregate uncontracted gross 2P reserves with maximum growth assumptions (PJ)



6.6. Reserves committed to GSAs

SKM MMA maintains a data base of Eastern states GSAs, derived largely from information published on buyer/seller websites supported by analysis of industry data provided via the AEMO Bulletin Board and in support of the Victorian gas market. While there are likely to be some GSAs missing from the data base, either because their existence is not on the public record or because we have failed to find it, SKM MMA believes that 95% of the gas volume contracted is accounted for. For many GSAs however only the term and total volume committed are known and annual volumes can only be estimated. The GSAs tabled below include volumes estimated for related party GSAs which can be inferred but have not been publicly revealed, such as between Origin Energy's production and generation divisions, but do not include any LNG related arrangements.

Table 6-6 shows the total domestic contracted and resulting uncontracted volumes, compared with 2P reserves as at 31st December 2010. The contracted volumes do not include LNG related contracts, of which two are known:

- Santos (and various JV partners) is to supply GLNG with 750 PJ primarily from the Cooper Basin, over 15 years. It is understood that the gas is additional to current 2P reserves and therefore does not affect the uncontracted figure in Table 6-6.

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- APLNG is to supply BG Group with 640 PJ from jointly owned tenements ATP 648P and 620P. This will reduce ALPNG's uncontracted figure in Table 6-6 by 640 PJ.

- **Table 6-6 Comparison of 2P reserves and gas contracted as at 31st December 2010 (PJ)**

Basin	Joint Venture	2P Reserves	Contracted	Uncontracted
Conventional				
Gippsland	BHPB, Exxon	5,210	1,914	3,296
Gippsland	Nexus	392	210	182
Bass	Origin, AWE	313	118	195
Otways	BHPB, Santos	142	110	32
Otways	Origin, Others	638	463	175
Otways	Santos, Others	376	348	28
Cooper Eromanga	Santos, Beach, Origin	1,385	359	1,026
Cooper Eromanga	Others	29	0	29
CSG				
Sydney	AGL	151	97	54
Gloucester	AGL	811	0	811
Gunnedah	ESG/Santos	1,520	0	1,520
Clarence Morton	Metgasco	397	0	397
Bowen	AGL/ Arrow Energy	1,810	279	1,531
Surat	APLNG	11,262	2,321	8,941
Surat	BG Group	8,200	851	7,349
Surat	GLNG	5,638	267	5,371
Surat	Arrow Energy	4,602	344	4,258
Surat	Second Tier	664	35	629
	Total	43,540	7,716	35,824

Source: MMA estimates.

Note: Surat/Bowen conventional reserves are omitted to avoid potential double counting.



6.7. Gas production costs

6.7.1. Costs implied in reserve declarations

Information regarding gas production costs is not widely disseminated in Australia. The production cost for declared reserves can be inferred from the fact that they are commercial, provided that the market price at which the reserves test for commerciality has been conducted is known. For the large majority of reserve estimates this market price is not stated however.

For gas in Eastern Australia, where the wellhead market price has always been low in world terms, in the range \$3/GJ to \$4/GJ in real 2011 dollar values, it has until recently been reasonable to assume that commerciality meant profitable at that price level or perhaps slightly above if a price rise was anticipated by the developer. For conventional reserves this remains a reasonable assumption but for CSG reserves being developed for LNG exports, which could sustain higher gas input prices, the possibility of higher price assumptions arises.

It is therefore of interest to note that Origin Energy has previously declared that its reserves estimates are still based on commerciality at the above price level²⁸, noting that its reserve estimates were based on “economic tests included capital and operating cost estimates based on Origin’s current and projected developments together with current market gas prices in eastern Australia (circa \$3 per GJ)”. Origin also provided a schematic illustration of the relationship between gas prices and economically viable gas reserves.

Santos²⁹ has indicated that for Cooper Basin conventional resources 55% of original gas in place (OGIP) is 2P at current prices but that at (unspecified) higher prices, a further 20% of OGIP could be classified 2P.

These statements support the concept that current reserves can be produced for \$3/GJ to \$4/GJ but that some resources will only be declared 2P if the market price supports a higher cost of production. The exact nature of the relationship between gas prices and reserves is likely to be unknown even to gas producers, given the preliminary nature of contingent and prospective resource data.

²⁸ Origin Energy. UBS Resources Conference June 2008.

²⁹ Santos Investor Seminar 3 June 2008.



6.7.2. Estimates based on project costs

At the time the GLNG project reached FID the component costs of the project were revealed³⁰:

- ❖ Capacity 7.8 Mtpa (sales 7 Mtpa)
- ❖ Costs in \$US:
 - upstream production and processing, \$3.5bn (Fluor)
 - pipeline, \$1bn (Saipem)
 - storage, \$0.5bn (SKM MMA estimate).
 - liquefaction plant cost is, \$9bn (total cost of \$14bn excluding contingencies, less other costs).

With the following further assumptions the cost of gas production for GLNG can be estimated:

- Drilling of further wells through the life of the project will cost another 50% to 80% of the initial upstream capex
- Upstream operating costs are approximately \$1.50/GJ, including allowance for a \$40/t carbon price and royalties
- 12% is a reasonable breakeven IRR (GLNG's base case project return is 11% to 14%)

The estimated costs of production under these assumptions range from \$3.53/GJ to \$3.69/GJ depending on the cost of further wells.

6.7.3. Gas production cost escalation

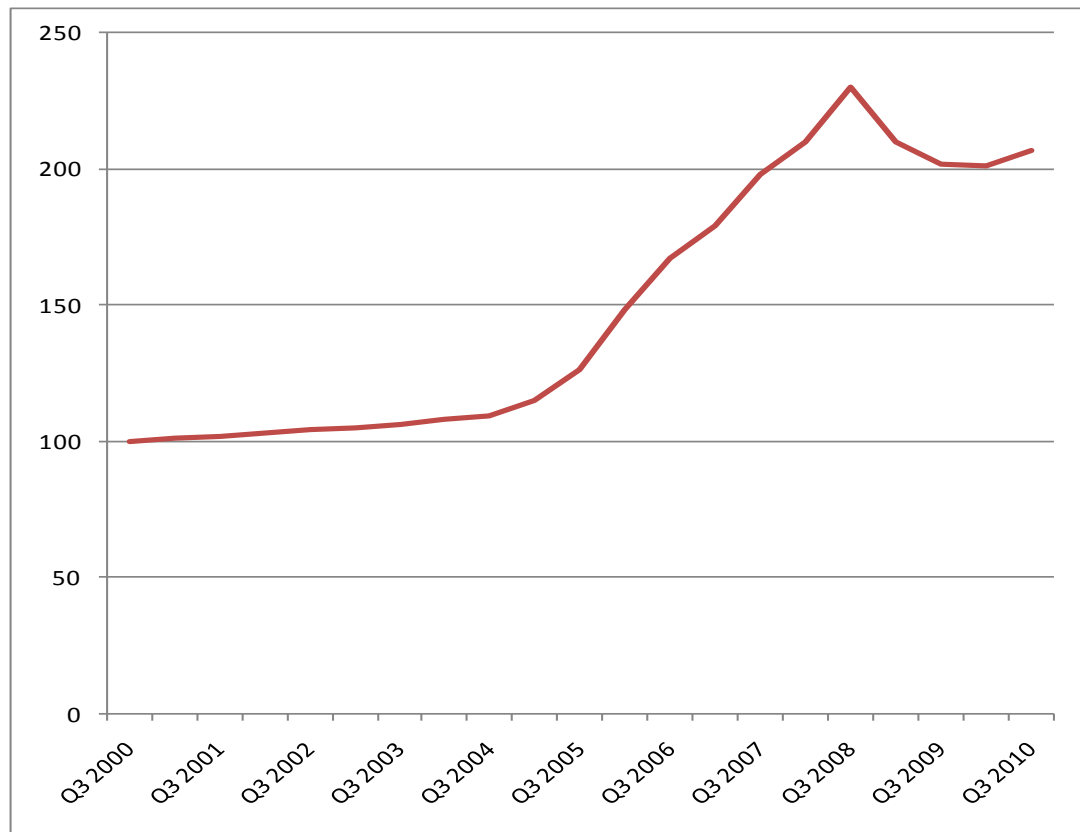
The Upstream Capital Cost Index (UCCI) published by IHS/CERA tracks the costs of equipment, facilities, materials, and personnel used in the construction of a geographically diversified portfolio of twenty eight onshore, offshore, pipeline and LNG projects in the US. Owing to the large import component in most Australian capital projects, it is highly relevant to the costs of Australian gas production.

Starting at a value of 100 in 2000 the UCCI tracked inflation until 2005 and then escalated rapidly to a peak of 230 in Q3 2008 owing to a combination of increases in the cost of materials (steel and cement) and skilled labour. Having retreated to a value of 200 in the wake of the global financial crisis, the UCCI has recently resumed its upward movement.

³⁰ GLNG Project FID, 13 January 2011, and Santos Investor Presentation, March 2011, both available at www.Santos.com



■ **Figure 6-4** UCCI



Source: www.ihsindexes.com

The intensive development of LNG projects in Gladstone and Western Australia is putting additional local pressure on Australian project costs. It is noted that the cost of construction of the Kipper Tuna Turrum project in the Gippsland Basin, which will provide replacement capacity for declining fields in that basin, has recently escalated by 60%³¹ owing to a combination of design changes and labour cost escalation.

6.7.4. Assumptions for the 2011 GMR

For the purposes of this study we have assumed gas production costs excluding carbon costs as follows:

- CSG and Gippsland Basin conventional gas - \$3.50/GJ
- Other conventional gas - \$4.00/GJ

³¹ <http://www.theaustralian.com.au/business/blowouts-delays-hit-projects/story-e6frg8zx-1225991941368>



These costs are assumed to be constant in real terms and across all scenarios. Carbon costs are added on a scenario basis, based on the scenario carbon costs and producer specific estimates of CO₂ content and gas used in production.

In the 2010 GMR the starting costs were similar but a real cost decline of 1% pa was assumed and carbon costs were not scenario specific.

In response to comments from stakeholders on the draft report, it is noted that SKM MMA believes that CSG production costs do and will vary between producers and over time. The above assumptions of uniform costs reflect the absence of any data differentiating between producers rather than a constraint imposed by our modeling tools, which are able to use fully differentiated cost inputs. SKM MMA would support any initiatives to improve production cost data availability.

6.8. Gas transmission assumptions

The existing network of transmission pipelines depicted in Figure 2-1 in principle enables gas to be transported from any production centre to any major market centre, with the exception of Townsville. Of course in practice there are capacity constraints and difficulties in arranging backhaul but these can generally be overcome where there is sufficient commercial incentive.

As the cost of gas delivered to the city gate or transmission customer meter is made up of approximately 75% wellhead price and 25% transmission price, when matching demand and supply, our focus is more on the wellhead component of supply than transmission and our assumptions regarding pipelines are as follows:

- Existing pipelines are “unconstrained”, that is, capacity can be added by further compression or duplication
- Pipeline tariffs continue at current levels/escalation rates
- Uncommitted new pipelines can be added but their projected throughput must be tested to ensure commercial viability.

In the scenarios analysed for this study uncommitted new pipelines have been included as follows:

- Pipelines to convey CSG from the Southern Bowen/Surat basins and from the Northern Surat Basin (Moranbah) to Gladstone for the LNG projects. Pipeline start-up timing is aligned with LNG project timing. Pipeline tariffs are estimated to be \$0.70/GJ with CPI escalation.
- A modified version of the proposed Queensland-Hunter pipeline, to convey CSG from the Gunnedah and Gloucester Basins north to Wallumbilla and south to Wilton to compete in the broader NSW market. Pipeline start-up is assumed to be 2015 in all scenarios. At throughput rates of 50PJ/yr the tariffs for both the north and south sections are estimated at \$1.00/GJ



escalating at CPI. At these tariffs the cost of shipping Queensland CSG from Wallumbilla to Wilton through this pipeline is comparable to the cost of shipping through the existing pipelines: SWQP-QSNLink-MSP.

- The Lions Way pipeline linking Clarence-Morton CSG production in northern NSW with Brisbane. Pipeline start-up is assumed to be 2015 in all scenarios. The pipeline tariff is estimated to be \$0.50/GJ with CPI escalation.

6.9. Ramp-up gas

Ramp-up gas is the unavoidable gas produced from LNG project CSG wells prior to LNG plant start-up, owing to the difficulty of shutting-in CSG production. Ramp-up gas management could be achieved by placing it in underground storage or disposing of it cheaply to electricity generators or other users who can take more than their current contracts.

Net quantities likely to be available from each LNG project remain largely unknown but SKM MMA has estimated that for the first train, 100 to 200 PJ of gas would need to be managed. However for the second train most ramp-up gas could be absorbed by turning down the wells supplying the first train and we therefore view ramp-up gas as a short term phenomenon likely to result in cheaper gas being available to some domestic users mainly one and two years prior to first train start up, i.e. in the period 2012, 2013 and possibly 2014.

Users able to take advantage of the lower prices will undoubtedly be willing to enter the shorter-term contracts associated with it but we do not see this on its own leading permanently to shorter term contracting and ramp-up gas is unlikely to greatly influence long-term contract prices negotiated now or in the future.



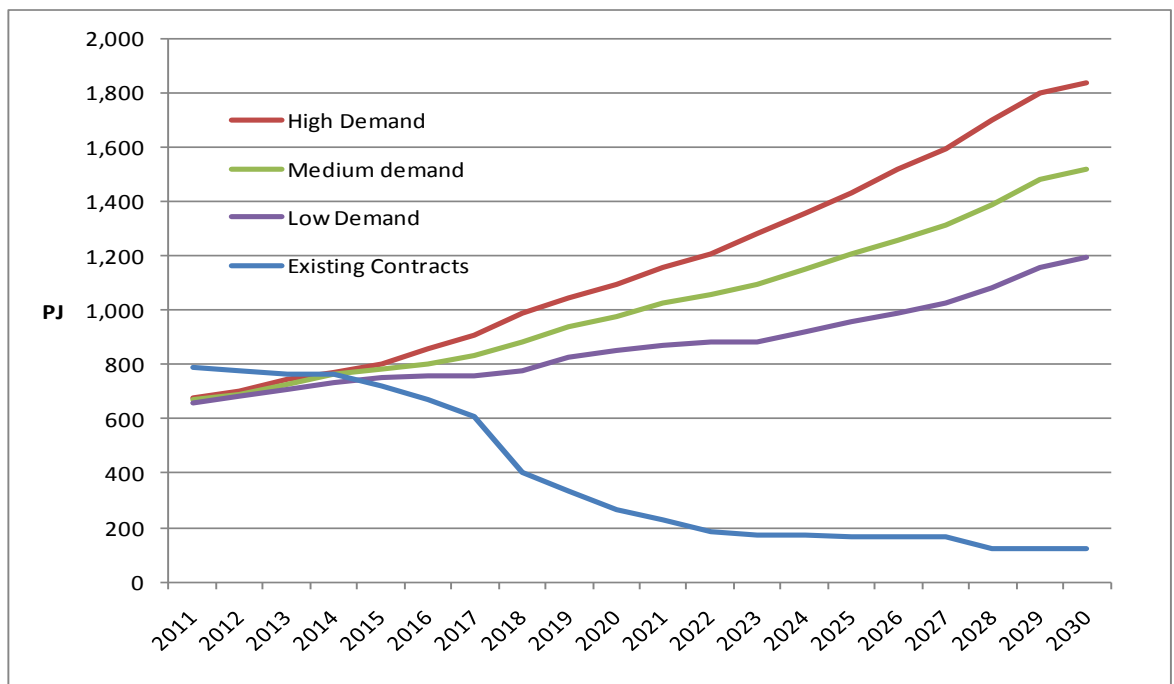
7. Physical demand-supply balance

7.1. Domestic market new contract requirements

The time structure of gas volumes committed under existing domestic contracts is compared with domestic demand projections in Figure 7-1. In aggregate across Eastern Australia contracted volumes are adequate up to 2013 but additional contracts may be required in specific zones or by specific gas buyers before that. Annual new contract requirements for existing and new loads (load growth) are shown in Figure 7-2 (Eastern Australia as a whole), Figure 7-3 (Queensland Total) and Figure 7-4 (Queensland Total, first ten years). The contract requirements pictured are based on the assumption that new contracts have a term of ten years, hence the high requirement in 2018 in Figure 7-2 is repeated in 2028.

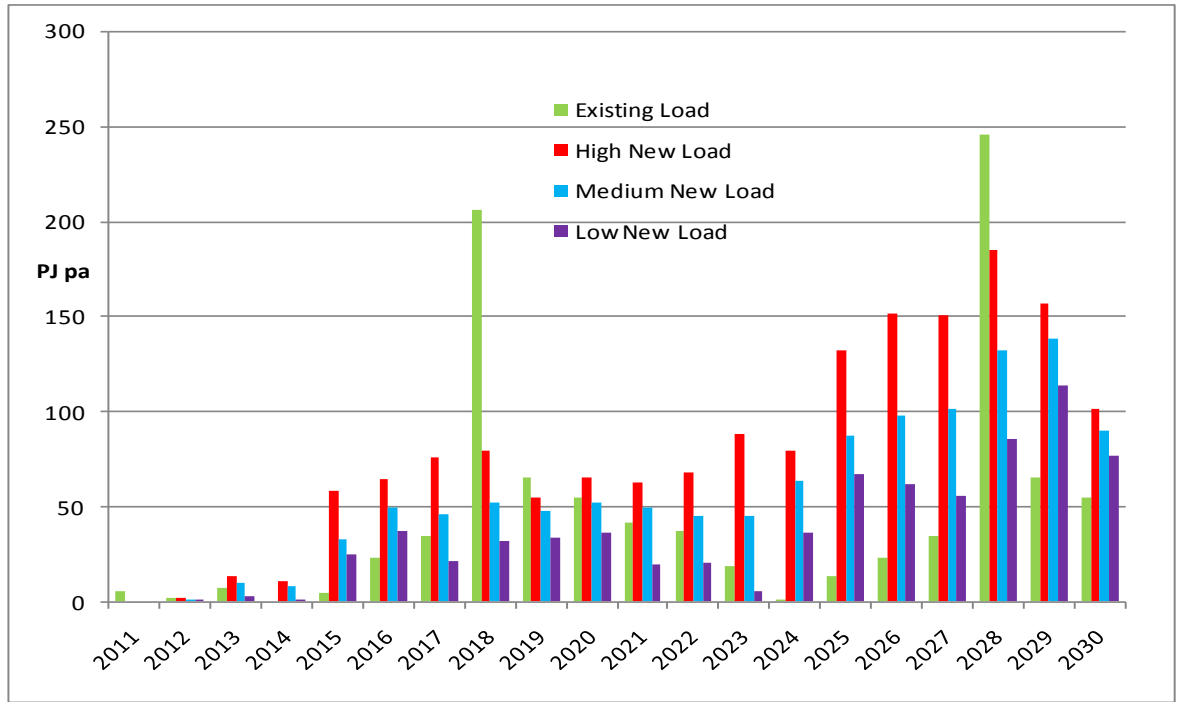
In Eastern Australia as a whole there is a very high contract replacement requirement in 2018 due to the termination of contracts in Victoria. Cumulatively the requirement for contracts for new loads exceeds the requirement for existing loads in the high and medium scenarios and the requirements are approximately equal in the low scenario. In Queensland the requirement for contracts for new loads exceeds the requirement for existing loads in all three scenarios.

■ Figure 7-1 Eastern Australian Domestic Forecast Volumes vs Existing Contract Volume Commitments (PJ)

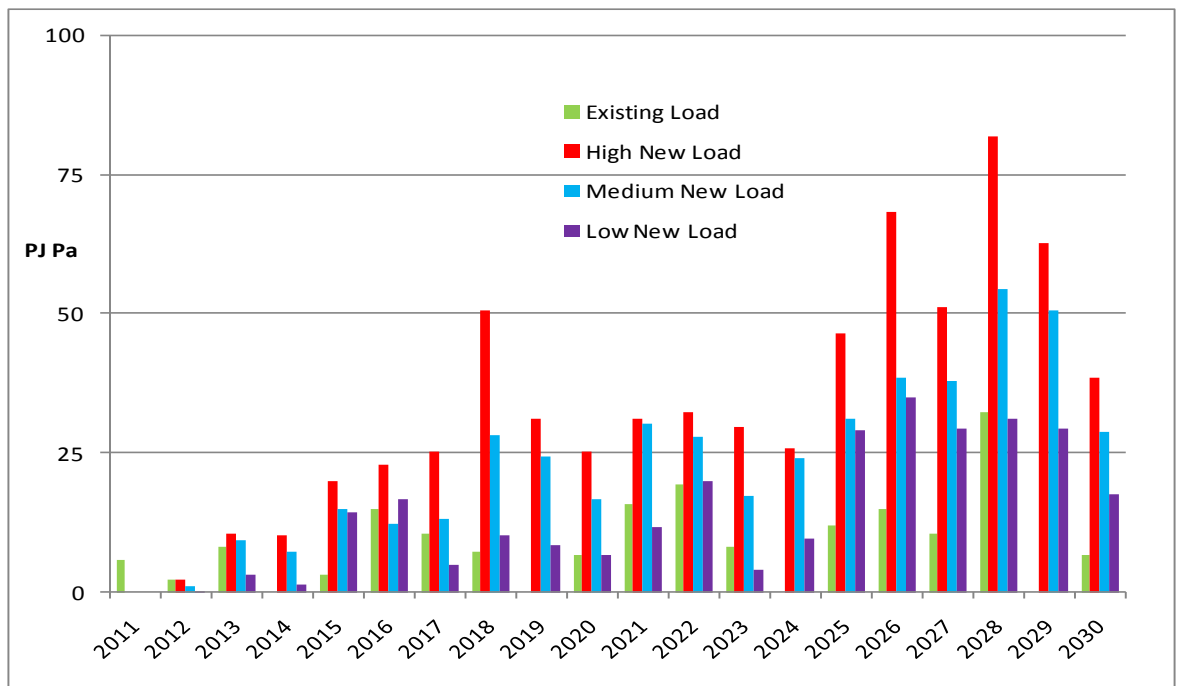




■ **Figure 7-2 Annual New Contract Requirements for Existing and New Loads, Eastern Australia (PJ)**

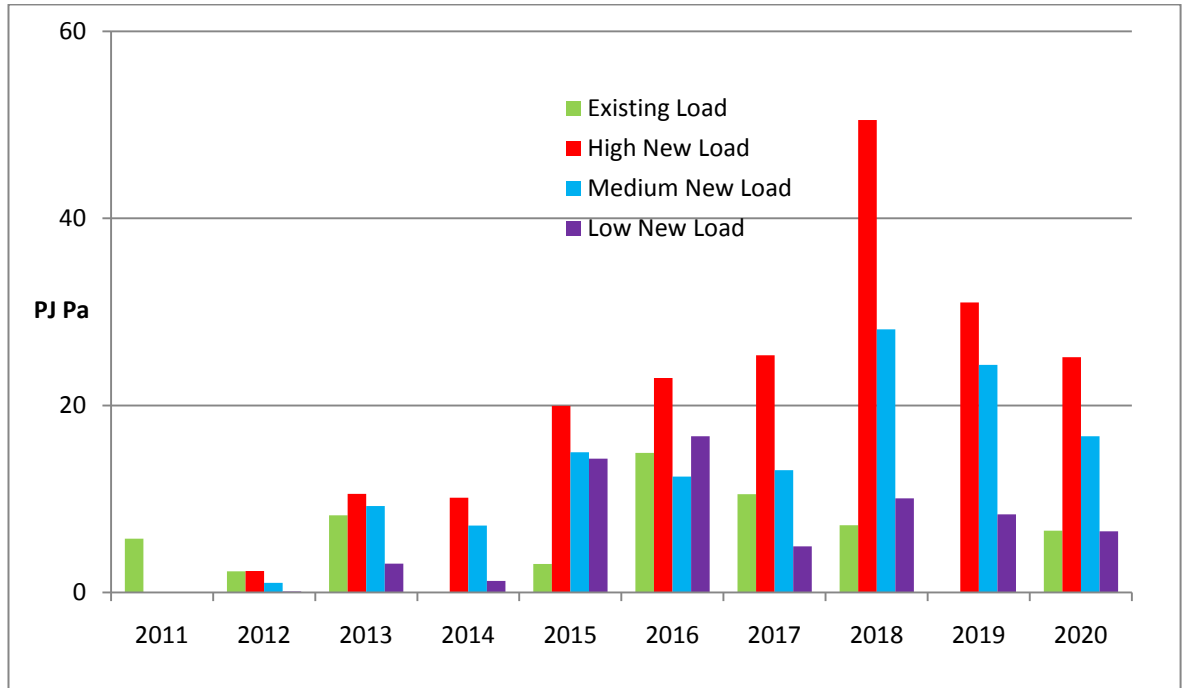


■ **Figure 7-3 Annual New Contract Requirements for Existing and New Loads, Queensland (PJ)**





■ **Figure 7-4 Annual New Contract Requirements for Existing and New Loads, Queensland (PJ)**



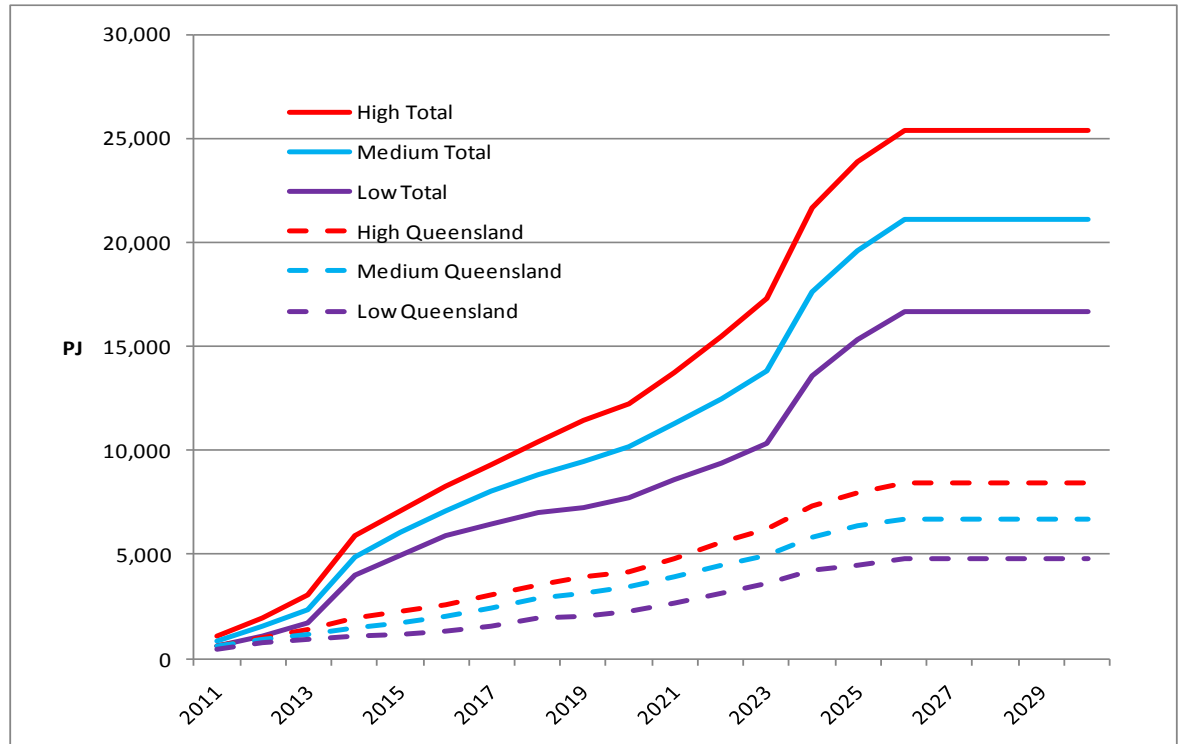
7.2. Domestic gas reserves requirements

As discussed in section 6, gas contracts are generally supported by 2P reserves. The above contract requirements can therefore be translated directly into requirements for gas reserves to be available at the time contracts are entered, which for any contract is of course some time prior to the commencement of supply under the contract, to allow for construction of production capacity and, in some cases, transmission capacity. Contract entry is generally two to four years before supply commencement.

The following chart illustrates the cumulative domestic gas reserves requirements, assuming contract entry four years before first delivery. The projections are flat after 2026 because the underlying demand projections extend only to 2030.



■ **Figure 7-5 Cumulative domestic gas reserves requirements (PJ)**



7.3. Reserve availability for the domestic market

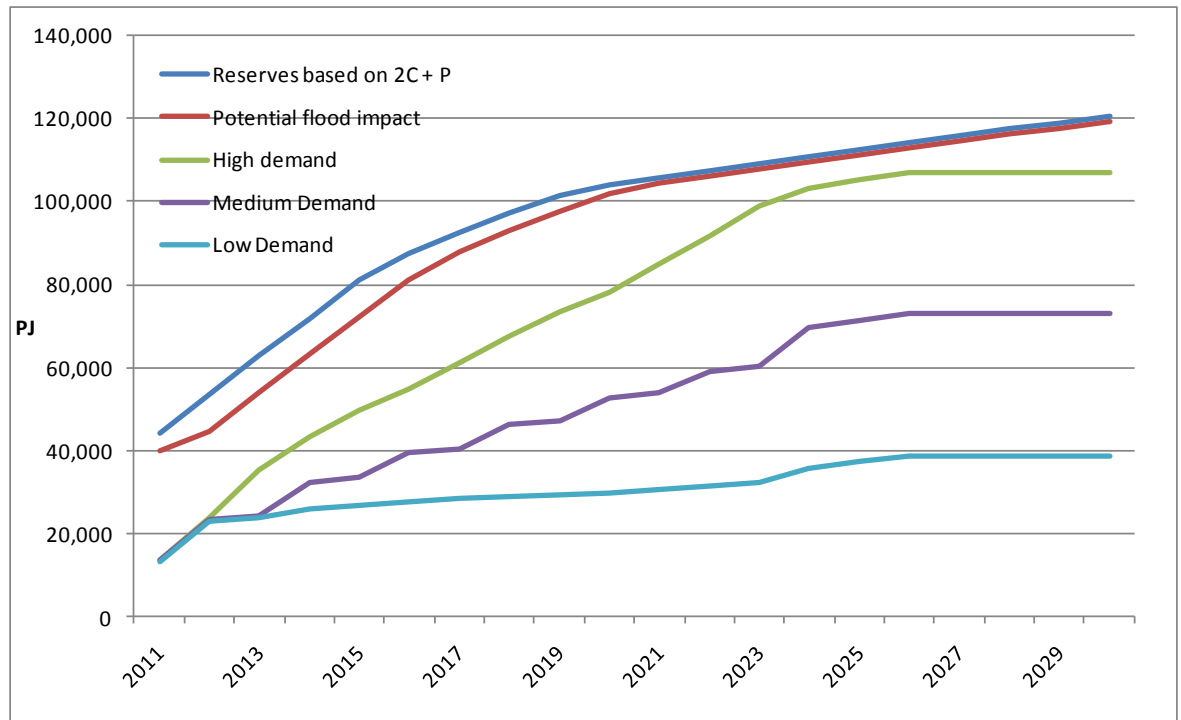
Combined domestic and LNG reserves requirements from Figure 7-5 and Figure 5-6 are compared with uncontracted 2P gross reserves projections from Figure 6-3 in Figure 7-6 below.

The aggregate reserve requirements in the High Demand Scenario result in 2P reserve margins of approximately 30,000 PJ being maintained until 2020 if reserve development is not affected by Queensland floods and margins of at least 20,000 PJ in the potential flood impact scenario. These margins will be maintained after 2020 only if there is continued growth of prospective resources feeding into contingent resources and reserves.

The aggregate reserve requirements in the Medium and Low Demand Scenarios can also be met readily, with much larger margins extending into the long term, to the extent that reserve development at the maximum rate is unlikely to be required.



■ **Figure 7-6 Combined domestic + LNG reserve requirements vs 2P uncontracted gross reserve projections (PJ)**

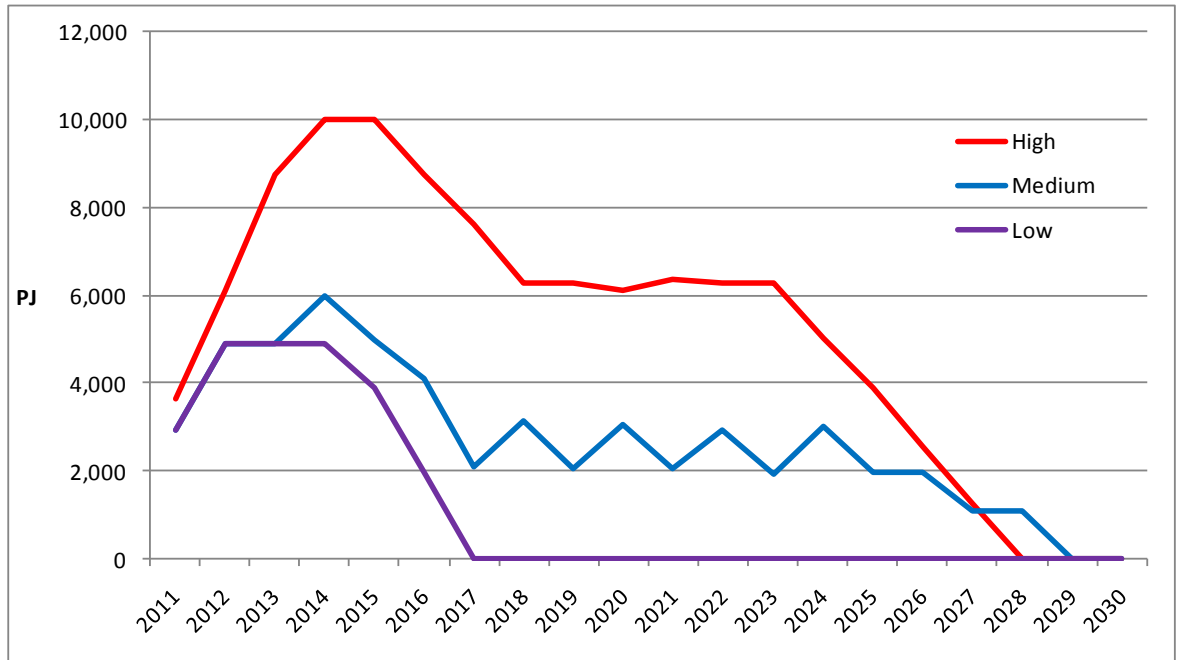


The adequacy of margins between 2P reserves and the demand for reserves to meet new contracts, even though it takes into account contracting four years ahead of first gas delivery, does not however imply that the amounts of reserves will be made available to the domestic market. Two factors act to considerably reduce the amounts of reserves that will be made available to the domestic market:

1. The LNG project proponents are planning multi-train developments and are building up reserves for multiple trains, which offer economies of scale plus construction cost savings if the trains are built within certain time windows. To avoid jeopardising these advantages, LNG project proponents are unlikely to commit reserves to new domestic contracts until their reserves meet their multi-train LNG requirements
2. Until gas production starts, the annual volumes of gas that each PJ of reserves can produce are uncertain. If production wells are less productive than anticipated, greater acreage, i.e. reserves, may be required to support each train. We understand that LNG proponents take the view that up to 1,500 PJ of reserves are required to support each Mtpa of LNG contracted, compared to approximately 1,250 PJ based on 20 years at 55 GJ per tonne plus allowance for gas used in liquefaction.



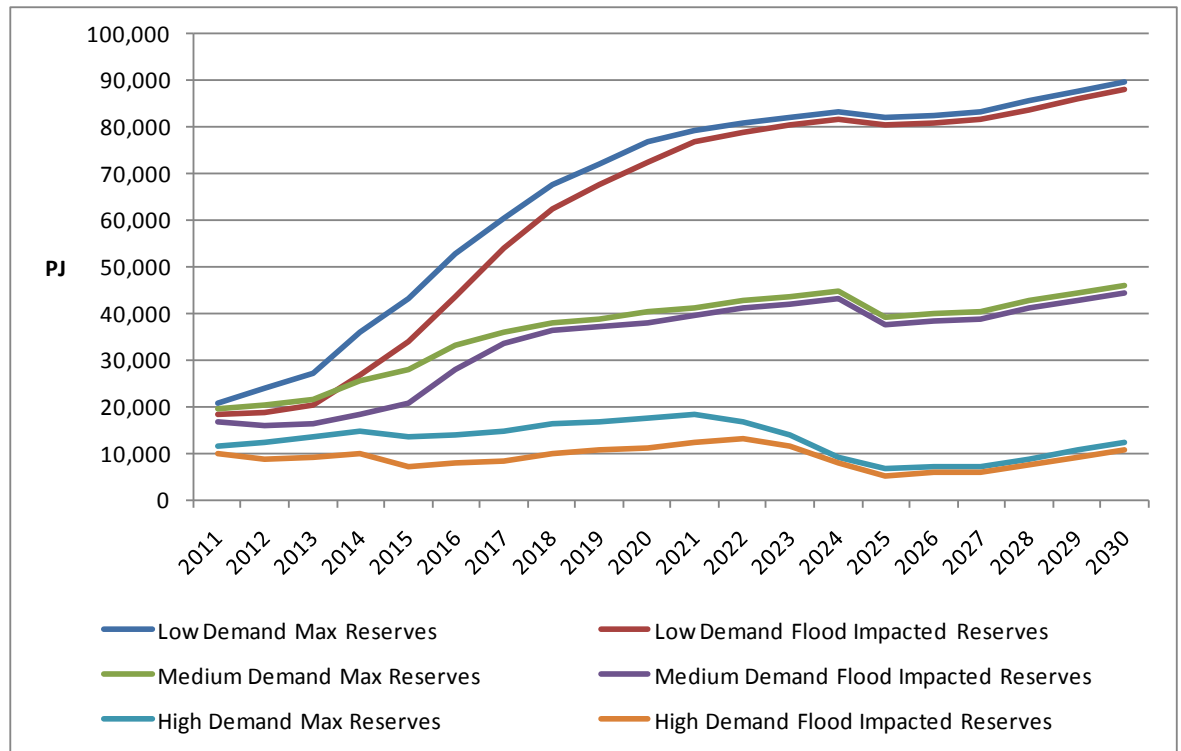
■ **Figure 7-8 Reserves margins to cover CSG production uncertainty**



Gas reserves available for new domestic and third party LNG contracts (uncontracted and not pre-committed to future LNG) have been estimated taking these factors into account (Figure 7-9). In the High Demand scenario with maximum reserves development the reserves available grow steadily from approximately 11,000 PJ in 2011 to 17,000 PJ in 2020 but in the High Demand scenario with flood impacted reserves the reserves available remain at approximately 10,000 PJ from 2011 to 2017.



■ **Figure 7-9 Gas reserves available for new domestic and third party LNG contracts, Eastern Australia**



7.3.1. High demand, flood impacted reserves scenario

In 2011 the reserves available across Eastern Australia as a whole in this scenario include:

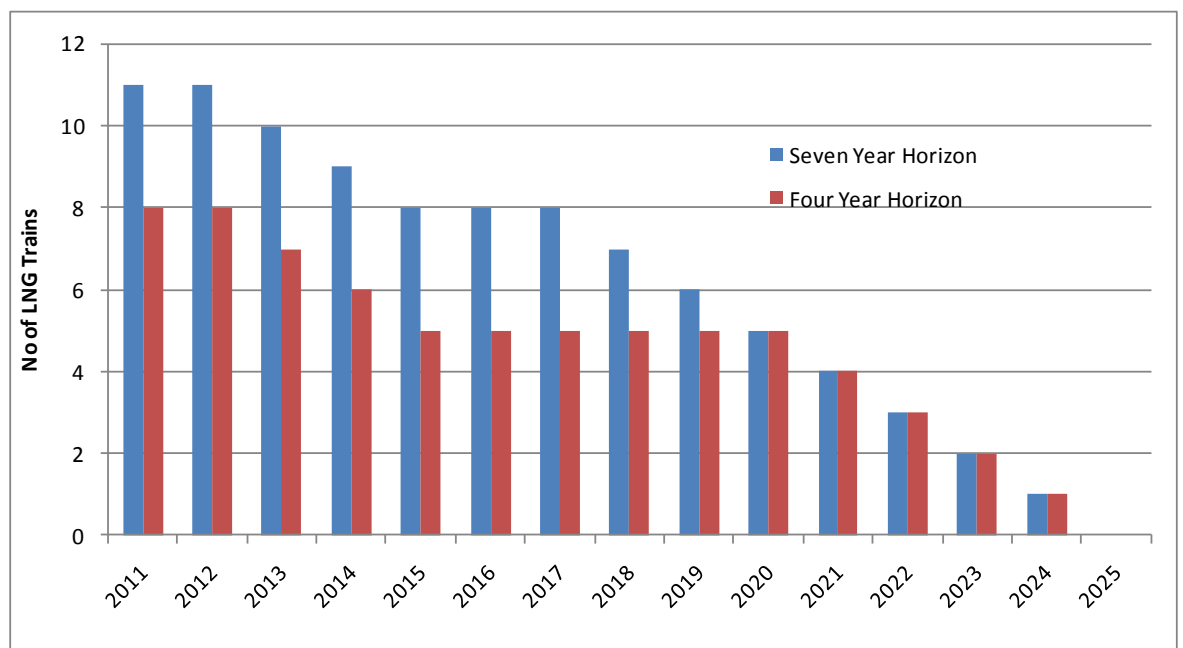
- 4,000 PJ in Victoria, which could be swapped into Queensland but otherwise cannot be transported economically to Queensland other than at high volumes.
- 2,700 PJ in NSW in the Clarence Morton, Gunnedah, Gloucester, Hunter and Sydney basins, none of which are currently connected by transmission pipeline to Queensland. Although transmission could be planned and constructed by 2015, when the majority of new contract deliveries are required, the economies of scale in transmission would make this difficult for domestic buyers acting individually to execute. Moreover, key reserve holders ESG and Metgasco are contemplating their own LNG projects and may not wish to release sufficient reserves available.
- 1,500 PJ in the Bowen Basin at Moranbah which is not currently connected to markets other than Townsville. It seems unlikely that a Moranbah-Gladstone pipeline will be built until the reserves are required by the Arrow Energy LNG project, which is likely to start up in 2017 as



These factors have been incorporated into reserves adequacy calculations as follows:

1. It is assumed that LNG proponents consider the adequacy of their reserves to meet LNG demand several years into the future – this is a more flexible assumption than assuming a fixed number of trains. In the High LNG demand scenario a seven year horizon is approximately the same as considering three trains initially and a four year horizon is approximately the same as considering two trains. Figure 7-7 the time variation of the number of LNG trains for which reserves are being built up, for seven- and four-year look-ahead assumptions, in the High LNG Demand scenario. The numbers decline because of the fall in the rate of CSG LNG development over time. In the following analyses a seven year look-ahead time frame has been used.
2. To cover uncertainty in the reserves-production relationship it has been assumed that there is a temporary additional reserves margin of 20% imposed at the time the LNG is contracted and released when it comes into production four years later, i.e. the reserves prove to be adequate for production and the uncertainty is eliminated at that time. Figure 7-8 illustrates the reserves margins added to the multi-train build up requirements in each LNG demand scenario.

■ **Figure 7-7** Number of LNG trains for which reserves are being built up, High LNG demand scenario





Arrow controls approximately 50% of Moranbah reserves. This makes the reserves unavailable for new contracts (other than in Townsville) negotiated before 2013.

- 1,123 PJ in the Cooper Basin, historically a source of gas for Queensland markets
- 628 PJ of CSG in the Surat and Bowen basins controlled by parties with no direct LNG interests (2nd tier producers). This figure excludes about 20% of total 2nd tier reserves that are not within reasonable distance of existing pipelines.

Under the assumptions in this scenario no reserves are made available by LNG proponents to the domestic market for new contracts until 2014 or later.

Queensland domestic reserve requirements in this scenario are:

- In 2011, 622 PJ for domestic contracts and 1,139 PJ for third party LNG contracts (reflecting a projected deficit in the LNG proponents' reserves owing to the flood impact on reserves development).
- In 2012, 379 PJ for domestic contracts and 233 PJ for third party LNG contracts.

If the reserves that are difficult for Queensland buyers to access (Victoria, NSW and Moranbah) are taken out of consideration, then the total reserves available in 2011 are 1,751 PJ and the total reserve requirement is 1,761 PJ, leaving a small shortfall of 10PJ.

In 2012 the only reserves available would 197 PJ due to reserve increases, assumed to be 97 PJ in the Cooper Basin and 100 PJ for the 2nd tier Surat-Bowen producers, against 612 PJ of reserve requirements, leaving a substantial shortfall of 415 PJ or 425 PJ if the 2011 shortfall is accumulated. Regardless of the allocation of available reserves, both the domestic market and the third party LNG purchasers will bear some of the shortfall.

From 2013 it would be expected that wider access to Bowen Basin reserves may alleviate the shortfall.

This scenario shows that a physical shortfall of gas, i.e. inability to source gas for contracts, is possible under circumstances that are plausible. The domestic shortfall can be avoided only by deferral of third party LNG contracts or satisfaction of the LNG contracts by reserves that have been excluded, such as Gunnedah Clarence Morton Basin reserves.

It is noted that physical shortfalls do not occur in any of the other scenarios depicted in Figure 7-9.



7.3.2. Long-term reserves adequacy

The charts above do not show any long-term reserves shortfall. However, this is only because they do not extend to the period in the 2030s when the initial LNG contracts will end and, with the LNG plants likely to be operational for a further 20 years, the contracts will be renewed for further periods. Figure 7-10 shows that in the High Scenario the reserves/production ratio falls to 10 years by 2030, which, while sustainable in a dynamic market, means that reserves will not support LNG recontracting for another 20 years at that time.

■ **Figure 7-10 Gas reserve/production ratio**

