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Gas Market Report

2015

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Foreword

The gas industry had a challenging year in 2015, with LNG prices at their lowest since 2009. Large additions to LNG supply will continue to put downward pressure on prices, and the outlook for both oil and spot LNG suggest that prices may remain subdued to 2020 and potentially beyond. However, it is not all doom and gloom for Australian LNG exports. Although supply conditions are becoming increasingly competitive, LNG demand is forecast to grow strongly. Medium term growth will be led by Asia, particularly China and India, and Australia remains very well placed to help meet this growing need for LNG.

2015 saw the completion of Queensland Curtis LNG's second train, the first cargoes from Gladstone LNG, and the commencement of production from Australia Pacific LNG. This will be followed by the first cargoes from Gorgon in early 2016, and Wheatstone, Prelude and Ichthys in 2017, together adding more than 60 million tonnes to Australia's annual LNG export capacity once all projects are fully developed. Australia remains on track to become the world's largest LNG exporter by 2020.

Of course, this achievement will not be without challenges. Operating in a low price environment after many years of high prices will place constraints on investment and necessitate increases in productivity and competitiveness. Low prices are not the only challenge, as global LNG markets are experiencing a range of other changes. The number of importers and exporters has increased rapidly over recent years, and there has been significant growth in the number of shorter term trades. These trends are expected to continue, with the growth in the number of smaller and potentially intermittent buyers, increasing the fragmentation, liquidity and volatility of the market.

This will also have an impact on domestic markets. The eastern Australian gas market is now exposed to the increasingly volatile global LNG markets. Uncertainties around the volumes of LNG which will be exported from the Queensland LNG plants will impact on decisions by producers to invest in additional gas production capacity, even during a time of tight domestic supply and relatively high domestic prices. Unfortunately, the most likely outcome of increased uncertainty is that decisions to invest in production will be constrained.

Transitions in global and domestic gas markets remain a fascinating and important issue, and the *Gas Market Report 2015* provides invaluable insights into the current circumstances and the outlooks for the future.

Mark Cully
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March 2016

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Acronyms and abbreviations

2C	contingent resources
2P	proved and probable reserves
ABARE	Australian Bureau of Agricultural and Resource Economics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
APPEA	Australian Petroleum Production and Exploration Association
ASEAN	Association of Southeast Asian Nations
bcm	billion cubic metres
CSG	coal seam gas
DES	delivered ex-ship
EIA	Energy Information Administration (US)
EU	European Union
FID	final investment decision
FOB	free on board
FSRU	floating storage and regasification units
GAMS	General Algebraic Modelling System
GBJV	Gippsland Basin Joint Venture
GDP	Gross Domestic Product
GIIGNL	International Group of Liquefied Natural Gas Importers
GJ	gigajoule
GLNG	Gladstone LNG
GPG	gas-powered generation
HHI	Herfindahl-Hirschman Index
IEA	International Energy Agency
IPI	Iran-Pakistan-India pipeline
LNG	liquefied natural gas
MCP	mixed complementarity programming
MMBtu	million British thermal units
Mt	million tonnes
Mtpa	million tonnes per annum
NBP	National Balancing Point (United Kingdom)
NEGI	North East Gas Interconnector
OECD	Organisation for Economic Cooperation and Development
OIL	Oil India Limited
ONGC	Oil and Natural Gas Corporation Limited
PJ	petajoule
QCLNG	Queensland Curtis LNG
TAPI	Turkmenistan-Afghanistan-Pakistan-India pipeline
US	United States
WGM	World Gas Model (Nexant)

Conversion rates

From	To	mmcm	bcm	tcm	mmcf	bcf	Mt LNG	GJ	TJ	MMBtu	PJ
mmcm	Multiply by:	1	0.001	1.00 x10^{-6}	35.31	3.53 x10^{-2}	7.35 x10^{-4}	38,800	38.80	3.88 x10^{-2}	36775
bcm		1000	1	1.00 x10^{-3}	35,313	35.31	0.735	3.88 x10^{7}	38,800	38.80	3.68 x10^{7}
tcm		1.00 x10^{6}	1000	1	3.53 x10^{7}	35,313	735	3.88 x10^{10}	3.88 x10^{7}	38,800	3.68 x10^{10}
mmcf		0.028	2.83 x10^{-5}	2.83 x10^{-8}	1	1.00 x10^{-3}	2.08 x10^{-5}	1099	1	1.10 x10^{-3}	1,041
bcf		28.32	0.028	2.83 x10^{-5}	1000	1	0.021	1.10 x10^{6}	1.099	1.099	1.04 x10^{6}
Mt LNG		1361	1.361	1.36 x10^{-3}	48,045	48.04	1	5.28 x10^{7}	52787	52.79	5.00 x10^{7}
GJ		2.58 x10^{-5}	2.58 x10^{-8}	2.58 x10^{-11}	9.10 x10^{-4}	9.10 x10^{-7}	1.89 x10^{-8}	1	1.00 x10^{-3}	1.00 x10^{-6}	0.948
TJ		0.026	2.58 x10^{-5}	2.58 x10^{-8}	0.910	9.10 x10^{-4}	1.89 x10^{-5}	1.000	1	1.00 x10^{-3}	948
PJ		25.77	0.026	2.58 x10^{-5}	910	0.910	0.019	1.00 x10^{6}	1.000	1	9.48 x10^{5}
MMBtu		2.72 x10_{-5}	2.72 x10^{-8}	2.72 x10^{-11}	9.60 x10^{-4}	9.60 x10^{-7}	2.00 x10^{-8}	1.055	1.06 x10^{-3}	1.06 x10^{-6}	1

Notes:

1. To convert 10 million tonnes of LNG into million cubic metres, multiply by 1361—10 million tonnes LNG = 13 610million cubic metres of gas
2. 1 million cubic metres = 10^{6} x 1.0 cubic metre (m^3)
3. 1 billion cubic metres = 10^{9} x 1.0 cubic metre (m^3)
4. 1 trillion cubic metres = 10^{12} x 1.0 cubic metre (m^3)
5. 1 gigajoule = 10^{9} x 1.0 joule (J)
6. 1 terajoule = 10^{12} x 1.0 joule (J)
7. 1 petajoule = 10^{15} x 1.0 joule (J)
8. 1 British thermal unit = 1055 joules (J)
9. 1 tonne = 10^{3} x 1.0 kilogram (kg) = 2205 pounds (lbs)

Executive summary

The *Gas Market Report 2015* considers both domestic and international gas market issues. On the domestic side, it provides detailed analysis of the state of the eastern Australian gas market, and how the exposure to international liquefied natural gas (LNG) markets is likely to impact on gas demand and gas prices going forward. Internationally, it provides an assessment of the transitions underway in LNG markets, outlooks for LNG supply and demand, and some more detailed analyses of supply diversification by major LNG buyers, and of India's prospects for natural gas and LNG demand.

The transitions in gas markets are occurring in the context of broader changes in global economies and commodity markets. Chapter 1 considers the economic context and the implications of slowing growth in the Chinese economy for the Australian resources sector. While economic outlooks are currently subdued, longer term prospects are still quite positive. There remain near-term challenges for the Australian resources sector given the current low prices and excess supply capacity in commodity markets. However, future demand growth for energy commodities is likely to be driven by the emerging economies in the Asian region, and Australia remains well placed to meet this demand.

The eastern Australian gas market

The transition to LNG exporting from Australia's eastern market is well underway, as set out in Chapter 2. The increased volumes of gas demanded by the LNG projects, combined with the higher costs of extracting coal seam gas (CSG), has led to an increase in gas prices, and contributed to the subsequent reduction of domestic gas demand. Domestic demand is forecast by the Australian Energy Market Operator (AEMO) to continue to decline, particularly in the gas powered electricity generation (GPG) and industrial sectors.

Modelling the market

Analysis of a range of key issues which may impact on the eastern Australian gas market over the coming years is presented in Chapter 3.

The nexus between international gas prices and east coast LNG production, domestic demand and domestic gas prices is increasingly complex. In theory there are sufficient proved and probable (2P) reserves in eastern Australia to supply both the domestic and export markets for the next 20 years. However, if the market is divided into the North (Queensland and Cooper Basin) and the South (Victorian and New South Wales reserves), there are insufficient 2P reserves in the South to meet its forecast demand, which will require the development of contingent resources (2C), new gas discoveries and/or imports from the North.

This situation could be exacerbated if international gas prices and demand are high enough to support east coast LNG production beyond contracted volumes (i.e. into the international spot market). In this circumstance, additional gas to take advantage of LNG spot market opportunities will be required from either increased production capacity in the Queensland CSG fields (which may take time and capital to develop) or from the domestic gas market and southern gas production.

Conversely, if LNG demand is lower, there will be fewer spot market opportunities, and even contracted volumes could be under pressure. In this circumstance, there is the potential for excess production capacity, which could boost the GPG market in Queensland and offer opportunities to supply gas into the southern domestic market.

In short, the international gas spot price, rather than the long-run netback price, is likely to be the main influence on domestic gas demand and prices, mediated by the short-run marginal costs of LNG production.

Oligopolistic competition in the eastern gas market gives rise to the potential for higher impacts on price in the South, given there are a small number of suppliers and the Victorian market is dominated by residential and commercial demand, which is relatively insensitive to wholesale prices. The impact of oligopolistic competition is smaller in the North, as demand is more price sensitive and there are a larger number of suppliers. In the North, higher prices are likely to be a result of production constraints, particularly if LNG demand is high.

A case study considering a number of scenarios for supply from the Northern Territory into the eastern Australian gas market has found that it could help to meet domestic demand. However, the benefits of this supply depend strongly on the cost of this gas supply compared to costs of supply from the Cooper Basin and new CSG production from Queensland.

International LNG markets

LNG outlooks

Chapter 4 provides an update on global LNG markets and the outlooks to 2020 and 2030. Following on from an extended period of market tightness accompanied by very high LNG prices, recent supply additions have led to an excess of LNG supply capacity and a reduction in spot prices, coinciding with the fall in oil-linked LNG contract prices.

Global LNG demand is expected to grow strongly to 2020, although the current excess capacity in the market is likely to continue into the medium term as the LNG export projects currently under construction, primarily in Australia and the United States (US), come online. As a result, LNG prices are likely to remain subdued for some time.

The Asia Pacific gas market is expected to be the driver of growth in global LNG demand, despite plateauing or falling demand in the main markets of Japan and South Korea. Future growth will be predominantly from China and India, as well as a recovery in demand from Europe, but also from the smaller markets of Indonesia, Singapore, Malaysia, Chinese Taipei, and Pakistan. The growing numbers of LNG importers, each with a relatively small market share, will accelerate market fragmentation and at the same time support increasing competition and liquidity in global LNG markets.

There is a growing desire for more flexible contracting arrangements, and the global LNG trading environment has become increasingly more complex. The growing flexibility in long term LNG contracts over the past decade is illustrated by the relaxation of destination clauses in contracts, an increase in the use of free-on-board (FOB) sales contracts rather than delivered-ex-ship (DES), and less onerous take or pay commitments.

This has also led to increases in shorter term LNG trades. The LNG spot market is likely to continue to grow, given uncertainties in long term gas demand as a result of environmental policies and the price competitiveness of other fuels. Buyers will be reluctant to enter into long term contracts when they are unsure of the future supply and demand for gas, and they are likely to rely on the shorter term market to secure their immediate needs.

These uncertainties will be heightened by the fact that the main expansion of LNG demand will be in countries which can access alternative sources of gas supply. These countries have the opportunity to use LNG as the balancing item in overall gas supply, and hence LNG demand has the potential to be more variable over time.

Another driver of spot trading in the medium term is the excess supply capacity anticipated over the next five years, driven by the large export projects in Australia and the US. Over the long term, however, long-term contracts will still be required to lock in investment in new sources of supply.

Both buyers and sellers are seeking more options for pricing, which until recently has been dominated by oil-linked pricing. These options include linkages to hub-based prices and hybrids involving a mix of indexes. Recent developments are likely to diminish the trend away from oil-linked pricing, in particular the drop in international oil prices and the convergence of LNG and regional natural gas prices since late 2014. At current oil prices, there is no significant advantage to Henry Hub-linked prices over oil-linked pricing. For the foreseeable future, oil-linked pricing is expected to remain the standard paradigm for LNG contracts in Asia.

Whilst LNG demand is expected to grow strongly to 2020, the outlook beyond 2020 is unclear. This is, to some extent, the result of the highly competitive market that will prevail between gas and alternative energy sources such as nuclear, renewables and coal, and the difficulties in predicting the likely direction of global environmental and economic policies. Therefore the cost competitiveness of gas will be a key determinant of the outlook beyond 2020. The price needs to be low enough to sustain and improve the share of natural gas in total primary energy consumption, but high enough to encourage investment in new gas supply. In the case of either low or high prices, there may be constraints on investment, and excess capacity would be expected to decline between 2020 and 2030.

Diversity of LNG supply

Competition for future supply into global LNG markets will be tight. Buyers will consider a range of issues in making purchasing decisions, including the cost of supply, the reliability of their suppliers, and the diversity of their gas supply portfolio. Chapter 5 assesses the diversification of LNG supply to some of the major and growing LNG consumers, using the Herfindahl-Hirschman Index (HHI).

The analysis finds that as the LNG market itself has become more diverse over recent years, most importers have managed to substantially diversify their supply portfolios. Considering the expected evolution of supply diversity over the forecast period (based on cost minimisation principles and known contractual positions), the HHI is held within or at the boundaries of moderate concentration until 2020 for most LNG buyers.

A number of the major LNG importers in the Asian region have supported the current wave of Australian LNG supply through long term contracts, and have a large and growing proportion of Australian imports in their LNG supply mix over the medium term. The results of the analysis suggest that concentration of supply may become an issue for some of these buyers, and further growth in LNG exports from Australia is more likely to come from emerging importers. Counter to these concerns, however, is Australia’s reputation as a stable and reliable supplier of LNG.

India is an exception to the trend of increased LNG supply diversification, as based on least cost supply forecasts it is expected to take little LNG supply from Australia beyond contracted volumes from the Gorgon project, and its supply mix remains concentrated out to 2020. However, India’s forecast should be interpreted with some caution, as its contracted imports are small, and the forecast least cost supply mix will be balanced against the value of diversification in increasing energy security and spreading financial risks. Hence, future Indian LNG supply decisions could take a significantly different path to current projections.

Prospects for India

The Gas Market Report 2015 includes a detailed assessment of India's natural gas and LNG outlooks, and the implications for Australian supply, in Chapter 6. India's natural gas and LNG demand is forecast to grow strongly over the medium term, but there are significant uncertainties as to the extent and the rate of that growth. India's price sensitivity and infrastructure limitations are potential constraints on the growth of natural gas consumption, with much of the projected future demand disappearing at higher gas prices, or if planned import and pipeline infrastructure is delayed.

The extent to which India can increase its own domestic production will also play a large role in determining how much of India's gas demand is met by LNG. Government policies and continued low domestic prices could deter the expansion of indigenous supply, as policies will need to be sufficiently supportive to attract participation in the sector, and prices will need to be high enough to encourage ongoing investment.

Australia is potentially well placed as a proximal and reliable supplier to India, despite current limited Indian interest in Australian LNG. Forecasts vary as to the extent of Australia's role in meeting India's potential future growth in LNG demand. The next wave of Australian projects will need to ensure they can provide competitively priced LNG if they want to participate in the Indian market. However, in Australia's favour is its proximity to the east coast regasification terminals currently under construction in India, and the need for greater diversity in India's LNG supply mix.

Seri Bakti arrives at Santos GLNG site, Curtis Island

CHAPTER 1

Global economic growth: the outlook for the Australian resources sector[1]

1.1 Economic outlook

The Australian economy has grown year-on-year since 1992, and may yet surpass the Netherlands record of almost 27 years without a technical recession.[2] To be sure, that growth has been uneven and slowing over time, averaging 4.0 per cent a year between 1992 and 1999, 3.4 per cent a year between 2000 and the advent of the global financial crisis in 2008, and 2.4 per cent a year since then.

The slower growth in real Gross Domestic Product (GDP) in the period leading up to the global financial crisis was a result of falling rates of productivity growth (relative to those seen in the 1990s), but this was masked by the positive income effect arising from the largest and most sustained boost ever experienced in Australia's terms of trade. The sluggish growth of more recent years and the unwinding of some of the terms of trade gains have resulted in living standards falling since 2011. These are now back to 2008 levels.

[1] This chapter is based upon a speech by Mark Cully at the APPEA Tax and Commercial Conference on 29 October 2015. The address was prepared jointly with Nicole Thomas and Kate Penney in the Office of the Chief Economist, with thanks also to Stephen Wilson from Cape Otway Associates for his many insights.

[2] By convention, rather than economic theory, defined as two successive quarters of a fall in real GDP. Since 1992, there have been four quarters of declining economic activity: Q3 1997, Q4 2000, Q4 2008 and Q1 2011.

This remarkable period in Australia's economic history is inextricably tied to the largely unforeseen and astonishing emergence of China as the world's largest economy. Back in 1997 the Organisation for Economic Cooperation and Development (OECD) projected that world economic growth between 1995 and 2013 would average around 3.1 per cent a year.[3] While they were quite close to the mark, they did not anticipate the speed or the extent of the eastward shift in the world's economic centre of gravity. China was projected to grow between 5.0 and 6.6 per cent a year over this period. Its actual growth was closer to 10 per cent. In contrast, growth in OECD countries fell short of expectations.

Since 2013, growth in the Chinese economy has slowed as it makes the transition from investment-led growth to a stronger role for consumption. Official figures report growth of 7.4 per cent for the year ended 2014, and a range of unofficial estimates (based on factors such as electricity use and bank loans) have come in lower.

The world economy is forecast to grow by 3.4 per cent in 2015 increasing steadily to a solid 4.0 per cent by the end of the decade.[4] China's growth rate is forecast to taper off to 6.5 per cent a year, India's growth to remain high at around 7.0 per cent a year, and the OECD as a whole to nudge up to 2.6 per cent a year.

Lant Pritchett and Larry Summers have argued that we should be careful not to be seduced by "Asiaphoria", a belief that historically high growth rates of recent times can persist over the long-term; rather there will be what economists call reversion to the mean.[5] This is a sensible approach, noting though that much depends on how long the reversion process takes. China still has a lot of room for growth if one accepts its trajectory is moving towards GDP per capita levels of OECD countries; for India this is even more so.[6] Given the size of their respective populations, the economic performance of these two countries will increasingly come to dominate global economic activity.

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[3] OECD (1997) The World in 2020: Towards a New Global Age

[4] Department of Industry, Innovation and Science (2015) Resources and Energy Quarterly: September Quarter 2015

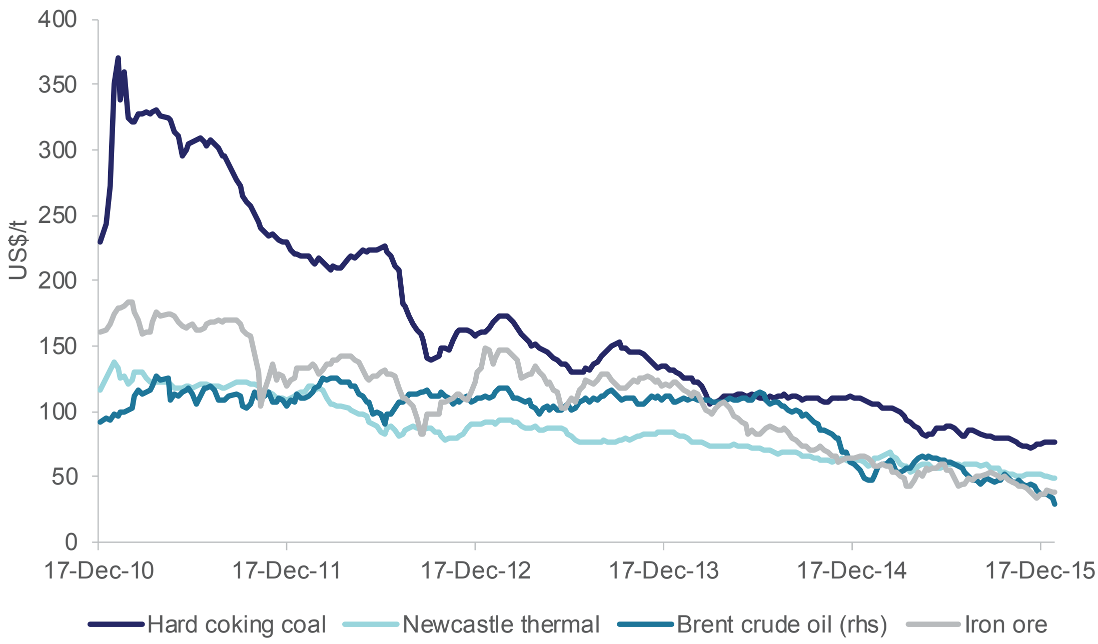
[5] Pritchett & Summers (October 2014) Asiaphoria Meets Regression to the Mean

[6] In 2013, China's GDP per capita (on a purchasing power parity basis) was 23 per cent of the US while India's was 10 per cent. Source: IMF World Economic Outlook Database, October 2015.

1.2 Implications for resources and energy commodities

After a decade-long increase in commodity prices, driven by a combination of economic growth in China, a slow global supply response and the depreciation of the US dollar, each of these underpinning factors of the 'super cycle' are in reverse. The result has been a sea of red ink, in commodity prices and in stock market values for commodity companies. From their peak, iron ore prices have fallen by 74 per cent, metallurgical coal by 79 per cent, thermal coal by 62 per cent and Brent oil by 61 per cent.

Figure 1.1: Commodity prices have come down substantially from their peaks

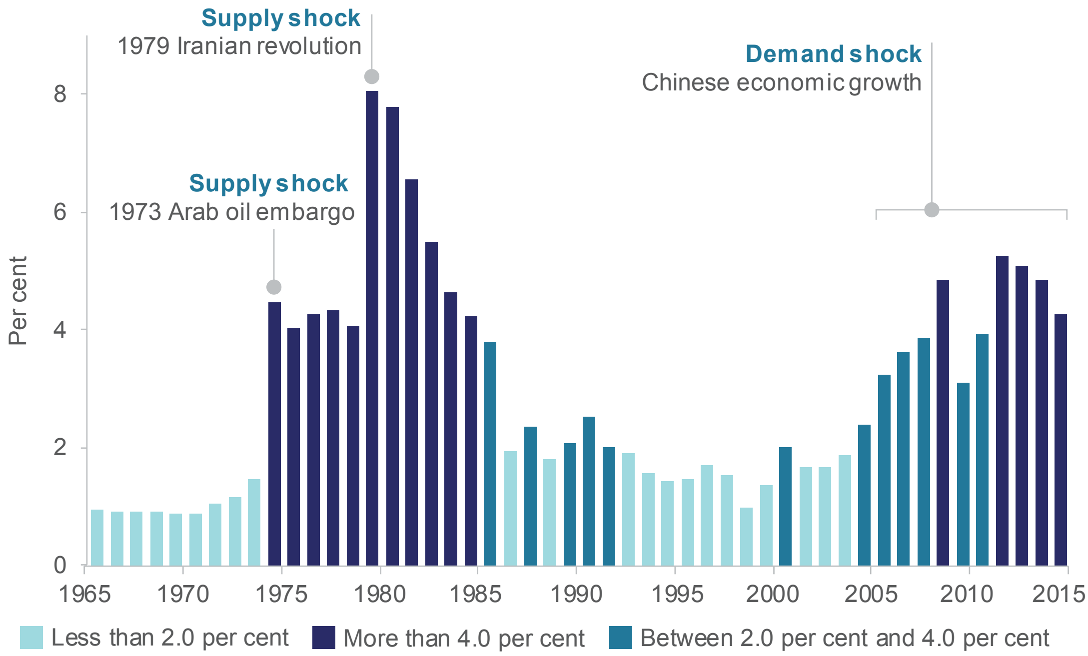


Source: IHS (2015); Platts (2015); Bloomberg (2015)

In the short term, prices for most commodities are forecast to remain below their peaks as markets adjust to a period of growing output but lower demand growth. Given the significant addition to supply capacity over recent years, even the stronger world economic growth we forecast is unlikely to stimulate a demand-driven recovery in commodity prices. Any price increases over the next few years are likely to be a result of a cut in supply as higher cost producers exit the market or curtail production.

We see this in general across the commodities, with oil an illustrative example.

Figure 1.2: High oil prices have tended to coincide with global economic and financial stresses



Source: IMF (2015) World GDP; world crude oil expenditure estimated from world consumption at annual average market prices from BP Energy Statistics

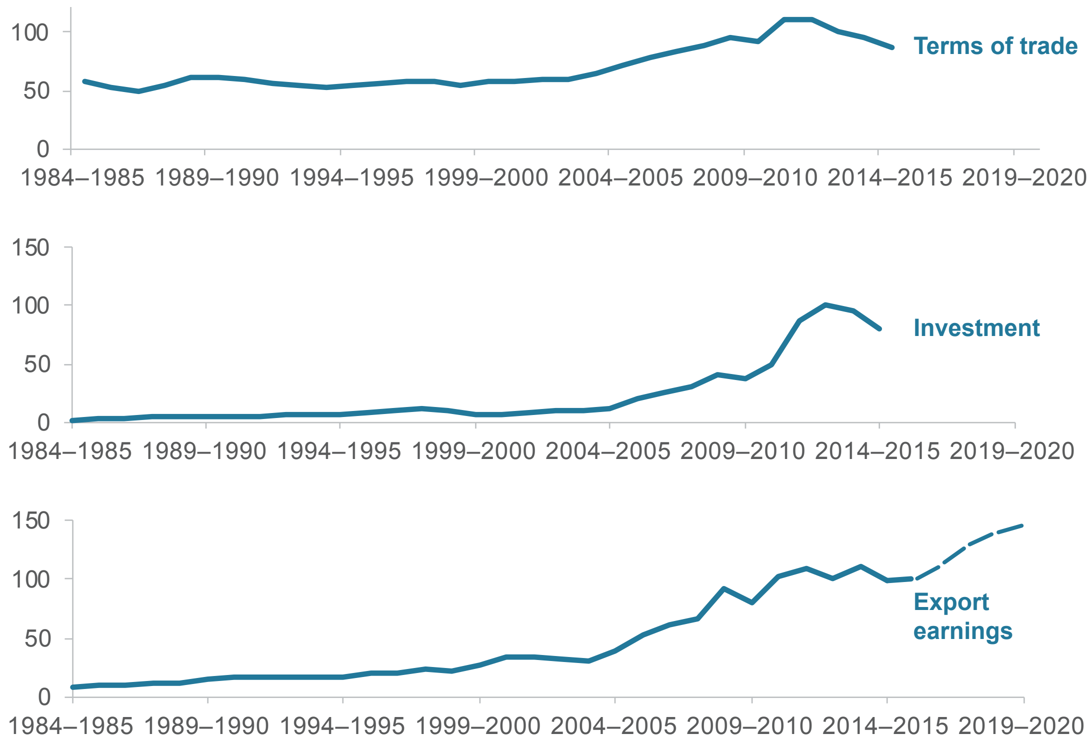
The oil price is a bit like the blood pressure of the global economy, with higher prices inducing economic stress. In the 1970s, sudden supply reductions led to extreme price shocks. World crude oil expenditure jumped from about 1 per cent of global GDP to 4 per cent. The market rebalanced by reducing demand by radical means as oil was substituted out of power and new cars became more efficient. This took time, and it was more than a decade before oil expenditure was back under 2 per cent of global GDP following the 1973 Arab oil embargo.

The blood pressure has been high again lately, although it crept up more gradually this time. We are now emerging from a demand shock in which China has become an oil importer on the scale of the US and the European Union (EU). It is now more than a decade since oil expenditure was less than 2 per cent of GDP, back in 2004. For five of those years global oil expenditure has exceeded 4 per cent of world GDP. This time the market has rebalanced by unlocking new supply, especially US tight oil. Again, the effect on price was not instantaneous, but prices have now fallen and investment is being curtailed.

Over the medium term, the outlook for the Australian resources sector is largely positive. Production volumes will increase from a number of projects that are nearing completion or have recently started operations, with export earnings projected to reach $235 billion (in 2015–16 dollars) by 2019–20.

The strongest growth in export earnings will be in LNG, which is projected to increase from 23.2 million tonnes (Mt) in 2013–14 to about 80 Mt in 2019–20. By the end of this decade Australia is likely to be the world's largest LNG exporter, generating estimated export earnings of almost $45 billion in 2019–20 compared to just over $17 billion last financial year.

Figure 1.3: The resources boom is transitioning through to the production phase



Notes: Index 2012–13=100

Source: ABS (2015) cat. 5206; ABS (2015) cat. 5625; ABS (2015) cat. 5368

1.3 Energy futures

Turning now specifically to energy markets, in the World Energy Outlook 2015, the International Energy Agency (IEA) projected world energy consumption out to 2040 to increase by 32 per cent under its New Policies Scenario. Almost all of this growth is expected to occur in non-OECD countries. China accounts for around one-third of this growth while India, with over 300 million people lacking adequate access to electricity, will be the driving force in consumption growth beyond 2025.

Figure 1.4: Emerging economies to drive electricity consumption growth

Source: World Bank (2015) World Development Indicators; IEA (2015) World Energy Balances

Electricity is projected to be the fastest growing final form of energy worldwide. Around 82 per cent of the world's population resides in non-OECD countries, yet they account for only 54 per cent of world electricity consumption — roughly 2100 kilowatt hours a person compared with 8600 kilowatt hours a person in the OECD.[7] As these economies develop, living standards and electricity consumption will rise in tandem. Given the size of the population in these economies, even small increases in electricity use per person will translate into large absolute increases in total electricity consumption.

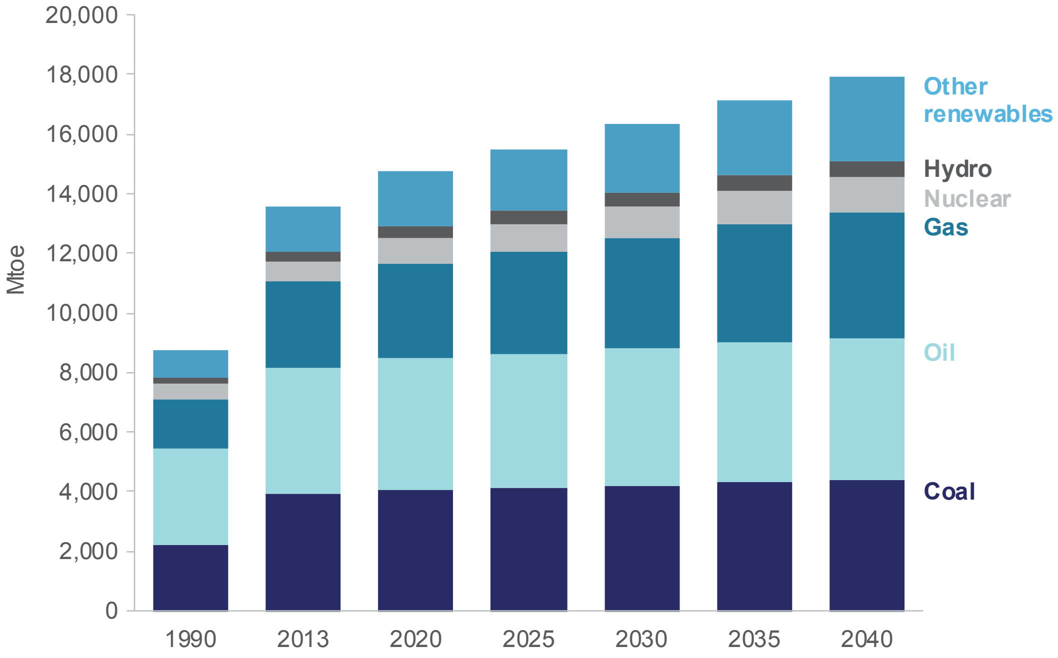
How emerging economies meet their growing electricity needs is a major challenge which should not be underestimated. In addition to China and India, six of the eight next largest countries by population are emerging economies — Indonesia, Brazil, Pakistan, Nigeria, Bangladesh and Russia. These countries combined have around 270 million people without adequate access to electricity.[8]

There is no single energy option that will allow a country to meet all of its growth and environmental objectives. Under its New Policies Scenario, the IEA forecasts that demand for every primary energy source will increase between now and 2040. The share of fossil fuels is expected to fall gradually, though still remain dominant in 2040.

[7] IEA World Energy Balances (2015)

[8] IEA Energy access database (2014)

Figure 1.5: Demand for every primary energy source is forecast to grow

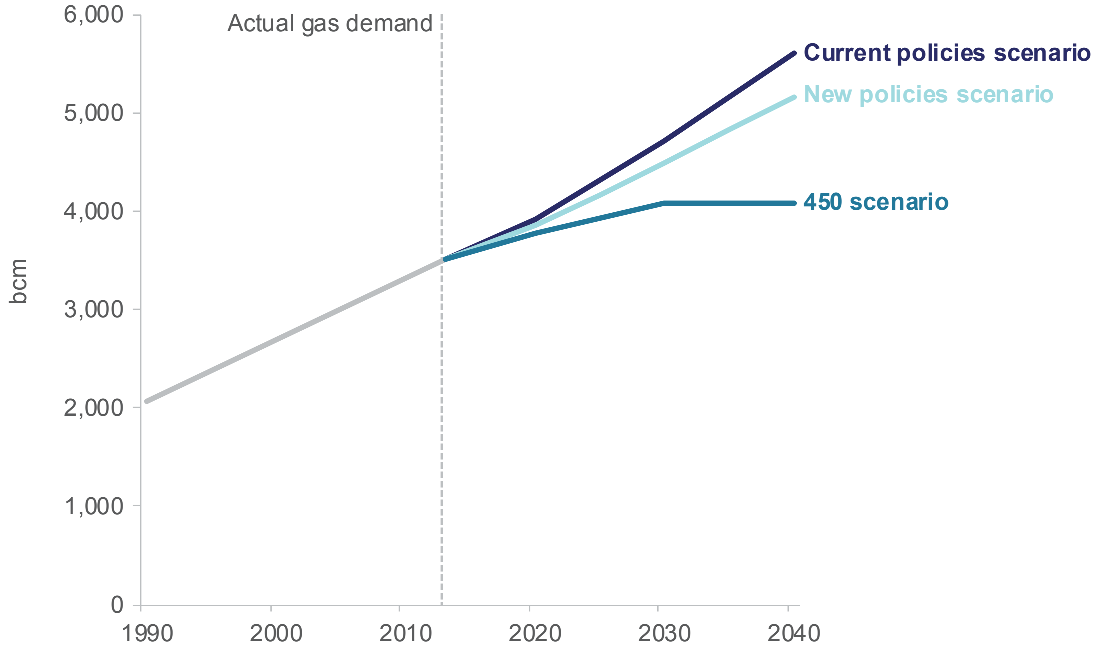


Source: IEA (2015) World Energy Outlook

It is only under the 450 Scenario — so named to indicate the level of carbon emissions that might constrain global warming to a 2°C increase — that fossil fuel use falls, with coal and oil falling while gas use plateaus. The world's fuel mix in 2040 will ultimately be determined by changes in relative prices, the composition of economic growth, energy policies and technological advances.

While natural gas is likely to play a significant role in meeting the world's future energy needs, it is unclear quite how large a role it will be. The IEA, in its 2011 World Energy Outlook, asked whether we were entering a golden age of gas. Natural gas was expected to be a transition fuel, replacing other fossil fuels as the world moved into a low carbon future. In the golden age of gas, consumption was expected to increase by almost 50 per cent by 2035, overtaking coal's share of the global energy mix by 2030.

Figure 1.6: The 'golden age of gas' will depend on future policies and prices



Source: IEA (2015) World Energy Outlook

For Australia, this golden age looked truly promising. In 2011, Pluto LNG was nearing completion, and final investment decisions (FIDs) were taken on an additional four projects that year. We would become the first country in the world to export LNG from three different types of projects – conventional offshore gas, floating LNG, and CSG to LNG.

Four years later, is the outlook for gas still as optimistic for Australia? The short answer from an economist's perspective is 'it depends'. Globally, supply is now coming online in response to the recent tight market conditions, but capacity is expected to grow at a faster rate than demand over the next five years.

At the same time, there has also been significant overcapacity in the world's oil supply, primarily as a result of the growth in US shale oil production. Oil prices are expected to remain low over the medium term, as a result of potential supply from Iran and weakening economic conditions in China. As the bulk of long-term LNG contracts are linked to oil prices, this means that the low LNG spot prices, which have emerged as a result of the excess liquefaction capacity, are coinciding with low contract LNG prices. Australia's new LNG projects are delivering their first gas cargoes into a market characterised by growing excess capacity and low prices.

For there to be a ‘golden age of gas’, it will be important that the price settles into a ‘Goldilocks zone’, a ‘just right’ price that encourages growth in demand and the supply required to meet it. If prices are too high, customers will turn to other energy sources and moderate their gas demand. If prices are too low, investors will not see attractive returns to motivate investment in future capacity. We are currently experiencing prices in the latter category.

The ‘Goldilocks zone’ will be dynamic as it depends on a range of factors including the relative prices of other energy types, which makes determining the zone with any precision difficult. Falls in LNG prices have been matched by similar falls in prices for oil and coal, as part of a cyclical downturn in commodity markets, and therefore do not necessarily provide the price incentive for consumers to switch from oil and coal. And in electricity generation markets, gas is finding increasing competition with renewables, supercritical coal, and nuclear energy.

LNG must also compete with other sources of gas. LNG effectively balances many gas markets, since local supply, if available at a reasonable cost, will be preferred to imports. International pipelines are another source of competition for LNG in some markets, particularly China. Conversely LNG is being used in some European markets to offset reliance on pipeline gas out of Russia.

On the supply side, we expect an excess of LNG capacity over the next five years, and the level of LNG exports from the US to be an important factor for Asian LNG pricing. On the demand side, there is significant uncertainty. In Japan the key uncertainties are the timing and number of nuclear restarts in the medium term, and the fuel mix policy over the longer term. In China, the key uncertainties are the level of indigenous gas production and the extent of pipeline imports from Russia, Central Asia and Myanmar.

As noted earlier, it depends. Extended periods of low prices have the potential to impact on the long-term viability of LNG projects as well as on the likelihood of investment into additional projects. However, the Office of the Chief Economist’s bottom-line forecast is a very large increase in export earnings from now through to the end of the decade, with volume increases outweighing the impact of lower prices.

1.4 Impacts on Australia's eastern gas market

The relatively rapid expansion of Australia's LNG sector brings with it substantial economic benefits in the form of added employment and incomes, investment in infrastructure and community assets, royalties and taxes. It can also present challenges, as is being experienced in the eastern gas market. The linking of the eastern Australian domestic gas market to international LNG markets, has resulted in a major transition.

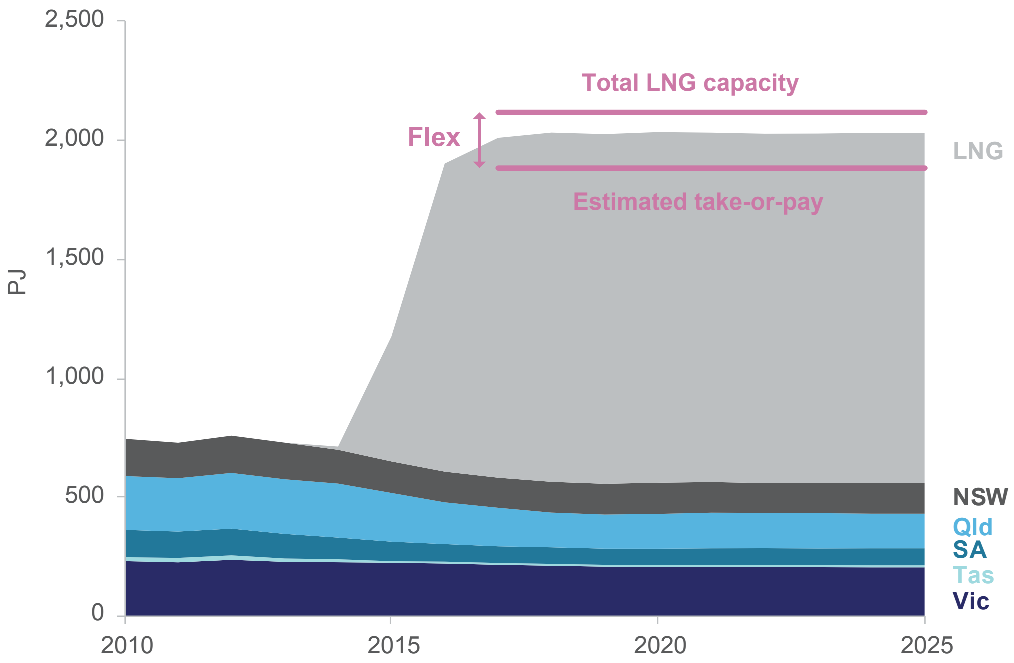
While there has been significant investment in supply, transport and storage infrastructure over recent years, the eastern Australian gas market requires more gas supply. This is because some domestic production has been diverted to LNG production, and because the existing conventional gas fields are facing depletion over the medium to long term.

Why has supply not yet responded to bring domestic prices down? One factor may be the financial stress on the Australian producers who are exposed to the current low oil price and low LNG returns. However, the main factor is likely to be the significant increase in uncertainty as a result of the interconnection to international LNG markets. This issue is explored further in Chapter 3.

There are uncertainties about the cost to develop the CSG reserves which underpin the Queensland LNG projects. These projects are the first in the world to use CSG as an input into LNG production, and these reserves have distinctly different characteristics to conventional gas reserves.

By their nature, there is more uncertainty about CSG reserves compared to conventional gas reserves. Despite the fact that the LNG projects have access to substantial proven and probable reserves, the reality is that the productivity and the cost of production for these reserves will become more uncertain over time.

Figure 1.7: The potential volatility of LNG supply exceeds total Victorian demand



Source: AEMO (2014); Department of Industry, Innovation and Science (2015)

Adding to this uncertainty is the need to maintain an ongoing social licence to operate these fields. In October, the Office of the Chief Economist published the *Review of the socioeconomic impacts of coal seam gas in Queensland*, which found that trust and social licence are essential for CSG projects. Earning this licence is based on early and genuine community engagement, and this takes time and money.

There is little doubt that sufficient conventional and CSG resources exist to support both export growth and to meet domestic demand well into the future. In addition, much of Australia's unconventional gas sector, particularly shale gas and tight gas, is still in its infancy, but holds significant promise.

The challenge is to create an investment and regulatory environment which has the confidence of investors, which also means having the confidence of the broader community. The Australian Government sees addressing issues of supply certainty and the efficiency of the market as being of paramount importance and is working on a range of reform measures to improve the way the market works and boost competition.

1.5 Conclusion

In conclusion, the global economic outlook is presently subdued but quite positive looking ahead. There is some re-balancing as the global economy adjusts to slowing growth in China and current excess supply in commodities and energy markets. Despite these near-term challenges, the overall prospects for Australia's resources and energy sector are broadly positive. Future demand growth for commodities, particularly energy, will be driven by the emerging economies, and Australia is well placed in the Asian region to help meet this demand.

View across Train 1 at Santos GLNG site, Curtis Island

CHAPTER 2

State of the eastern Australian gas market

2.1 Role of gas in the eastern Australian energy market

Natural gas has assumed an increasingly important role in the energy industry in eastern Australia since production first commenced 45 years ago from Bass Strait in Victoria, the Cooper Basin in South Australia, and the Surat Basin in Queensland. The relatively low cost supplies from these basins led to the rapid penetration of gas into the residential, commercial and industrial markets. More recently, gas consumption has expanded into the power generation market with the growth of both peaking and base load generation capacity.

This rapid growth in the exploitation of natural gas resources was part of a world-wide phenomenon, which was sufficiently widespread that in 2011 the IEA asked if it was the beginning of a 'golden age of gas'.

However, the consumption of natural gas has always been a discretionary decision, unlike the utilisation of electricity. Natural gas is valued for its premium, clean-burning properties which make it particularly suitable for domestic space and water heating, and for process heating in the industrial sector. Its rapid responsiveness makes it ideal as a fuel for the provision of peaking electricity generation, and in combined cycle mode it provides unmatched levels of efficiency in base load electricity generation.

Whilst its premium properties are highly valued, gas must compete against a wide range of alternatives, and it is fair to say that the rapid growth in natural gas consumption has been predicated on its availability at relatively low prices. These low prices arose initially from the association of gas production as a by product of the production of oil, and later from the economies of scale associated with the rapid expansion of gas transmission and distribution assets.

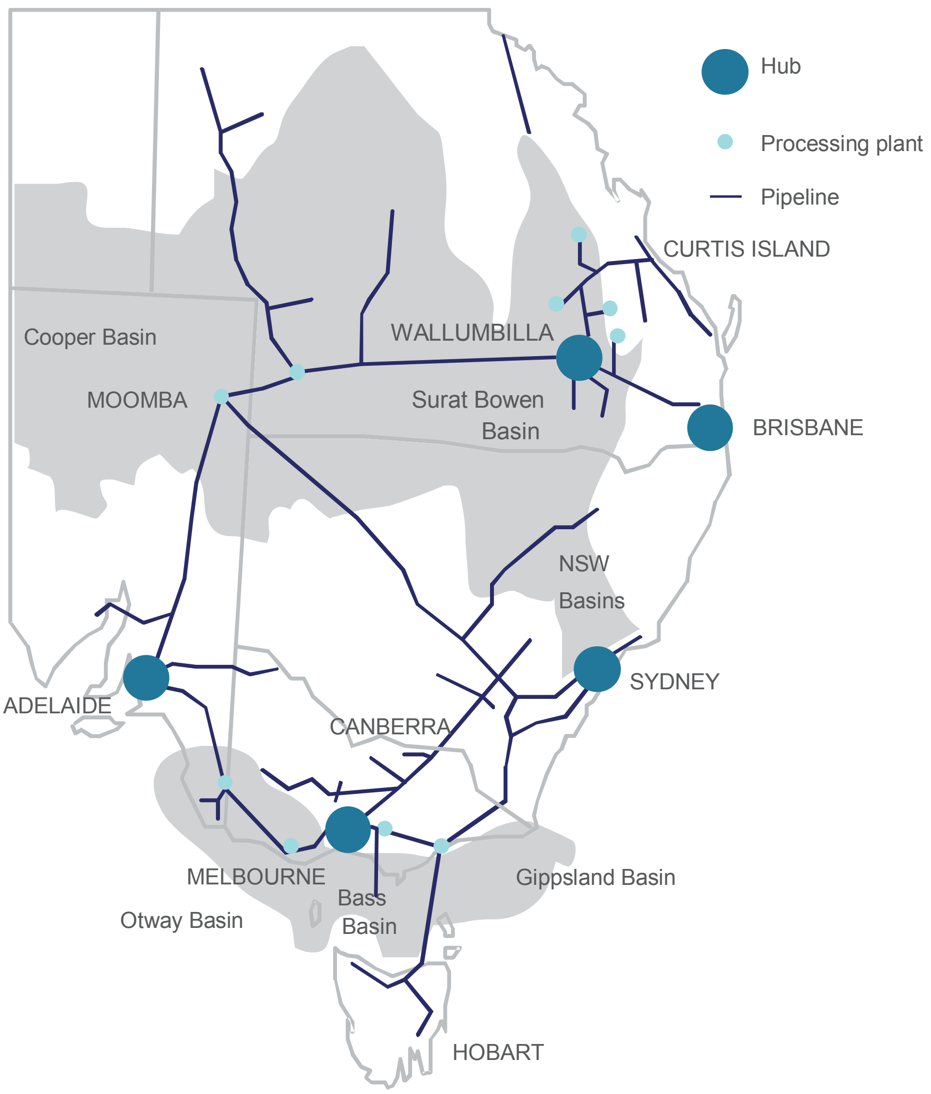
With the maturing of the gas industry, the price of gas has become the key determinant of its future viability. The 'golden age of gas' has been transformed into a highly competitive market where gas utilisation must contend with increasingly efficient alternative technologies. For example, in both the domestic and the world-wide electricity generation markets, gas is being squeezed between low cost coal and the growth of renewables (and in the international market with nuclear power).

With the expansion of LNG exports from Australia, and the connection of the export and domestic markets in eastern Australia, international factors will play an increasing role in the evolution of the eastern Australian gas market.

2.2 Structure of the gas market

The physical layout of the eastern Australian gas market is shown in Figure 2.1. It is clear that the market is highly interconnected and, with the exception of Brisbane, each capital city has direct access to two or more sources of supply. The level of interconnection allows for potentially sophisticated gas swap arrangements, although in reality this will depend on the strength of upstream competition.

Figure 2.1: Eastern Australian interconnected gas network



Source: Department of Industry, Innovation and Science (2015)

Figure 2.1 also shows the four spot markets that currently operate in eastern Australia, and the gas trading market that operates at Wallumbilla in Queensland. The Victorian market has been operating since 1999, the Adelaide and Sydney markets from 2010, and the Brisbane market from 2011. The markets allow for trading of imbalances and set a daily or intra-day market price, but there are concerns that the level of liquidity is not yet sufficient to create a viable transactional spot market.[9]

Eastern Australia gas demand

Domestic gas penetration into the eastern Australian market was 18 per cent of total primary energy consumption in 2013–14. This varies between a low of 10 per cent in NSW to a high of 35 per cent in South Australia. Figure 2.2 shows the gas penetration in each state in 2013–14.

[9] AEMC (2015) East Coast Wholesale Gas Market and Pipelines Framework Review: Stage 2 draft report

Figure 2.2: Gas share of Total Primary Energy Consumption 2013–14

Source: Department of Industry, Innovation and Science (2015) Australian Energy Statistics, Table C

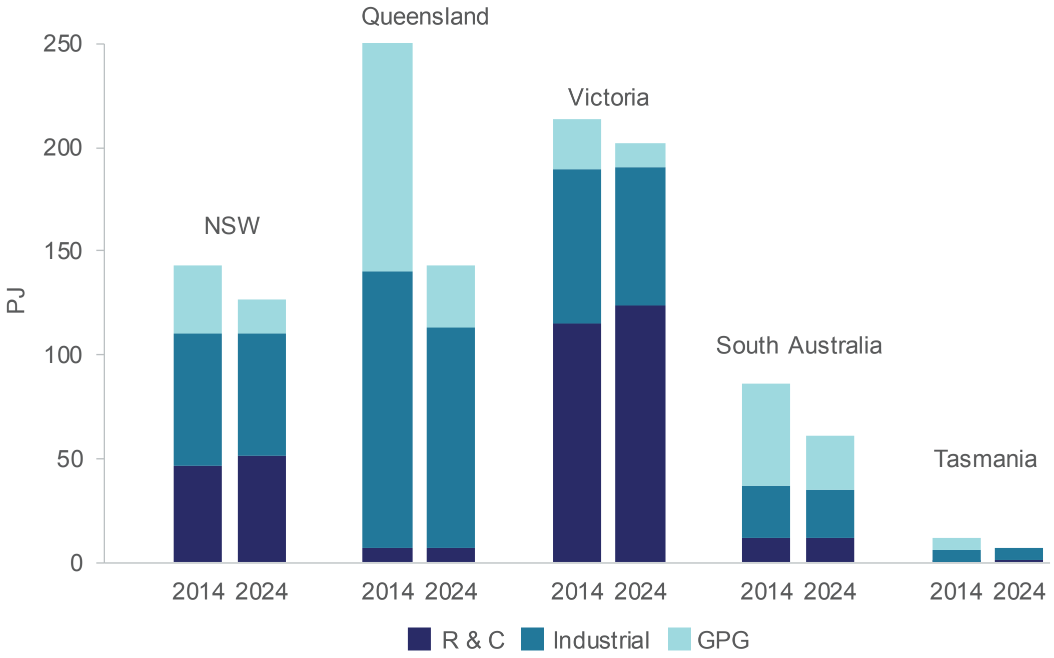
The high penetration in South Australia is due to the relatively high share of gas in the electricity generation mix in that state. The gas share of fuels used in electricity generation in 2013–14 was between 6 and 8 per cent in NSW, Victoria and Tasmania, 25 per cent in Queensland, and 45 per cent in South Australia.[10]

In the domestic market gas is used in the residential and commercial sector (26 per cent of total gas demand), the industrial sector (44 per cent) and the GPG sector (30 per cent). There is a wide variation in the consumption of gas in these sectors between each state, reflecting both the overall size of the sectors in each state, and the level of competition between gas and alternative fuels. Figure 1.3 shows the gas demand in each sector and in each state for the year 2014 and the base case projection for the year 2024 from AEMO.[11] The state with the highest gas consumption is currently Queensland, which has the largest industrial and GPG sectors in the east coast, followed by Victoria, where gas has a dominant role in the residential and commercial sector.

[10] Department of Industry, Innovation and Science (2015) Australian Energy Statistics, Table O

[11] AEMO (2015) National Gas Forecasting Report

Figure 2.3: Gas demand by sector, by state, 2014 and 2024



Source: AEMO (2015) National Gas Forecasting Report

Gas demand is expected to decline significantly by 2024, in response to rising wholesale gas prices and declines in the energy intensive manufacturing sectors. AEMO projects an overall decline of 23 per cent by 2024, principally in the GPG sector (a 62 per cent decline), with a smaller decline in the industrial sector (13 per cent). The residential and commercial sector is projected to grow by 7 per cent, despite the increase in wholesale prices, since the wholesale price is only a small proportion of the final selling price due to the presence of high retail and distribution margins.[12]

In summary, natural gas utilisation varies significantly by sector across each state in eastern Australia, which justifies the description of gas as a discretionary fuel. Natural gas demand is also quite volatile, with significant declines anticipated in the GPG and industrial sectors in the coming years. This volatility and sensitivity to price makes it very difficult to determine the long-run equilibrium between supply and demand and the long-term outlook for gas in the energy supply mix.

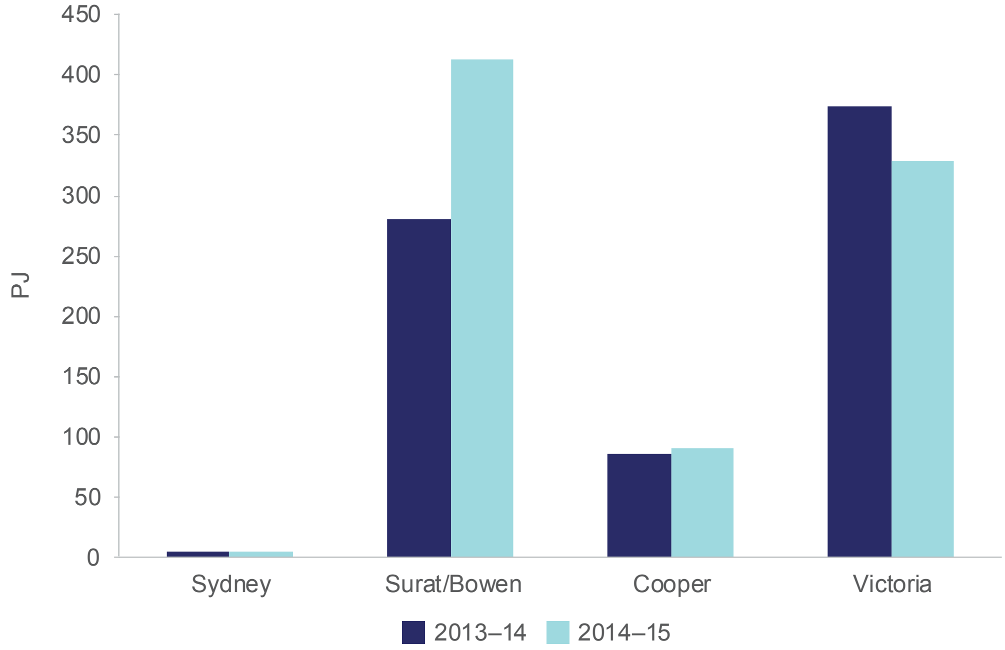
[12] This forecast assumes that gas remains competitive against electricity in the large space heating market in Victoria. However if price relativities move against gas, then residential and commercial demand could decline significantly.

Eastern Australian gas supply

Natural gas is produced from four main regions in eastern Australia. In 2013–14 the Victorian offshore basins (Otway, Bass and Gippsland) supplied the greatest volumes, followed by the Queensland Surat and Bowen basins (predominantly CSG) and the South Australian Cooper Basin. A small quantity of CSG was also produced from the Sydney Basin.

Figure 2.4 shows the gas production from these main gas basins for the years 2013–14 and 2014–15. [13]Gas production declined marginally in Victoria (mainly in the Otway Basin), but increased substantially from the CSG fields in Queensland. This large growth in Queensland production was associated with ramp gas and the start-up of LNG production at QCLNG. Some of the ramp gas was used in a surge of GPG demand in 2014.

Figure 2.4: Sources of gas production for 2013–14 and 2014–15



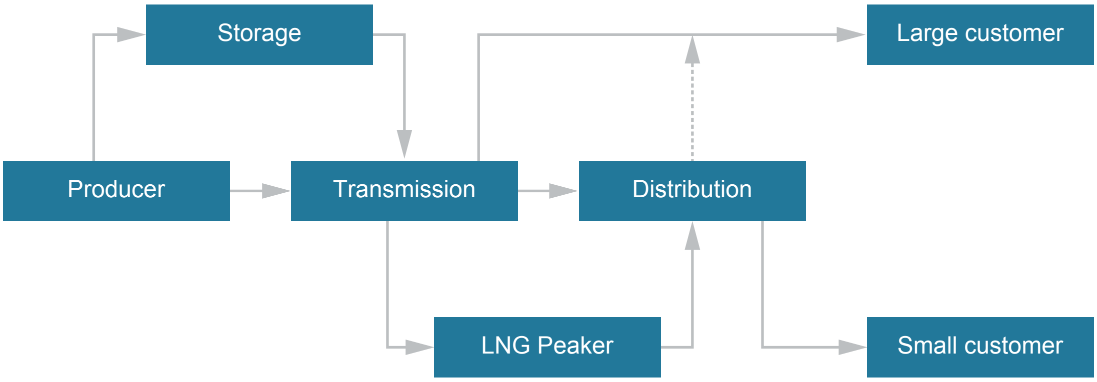
Source: EnergyQuest (2015) EnergyQuarterly, August 2015

Domestic gas value chain

The physical delivery of natural gas extends from the gas wells and processing facilities located near the main production fields, through the long-distance transmission pipelines to the local distribution networks, and finally to the customer's premises (Figure 2.5). It is convenient to distinguish the end-use customers as small (or retail) customers who are supplied off the distribution networks, and large customers who are mainly supplied from the transmission pipelines (because they usually require high supply pressures). These customers are also generally large enough to negotiate their own supply arrangements.

[13] EnergyQuest (2015) EnergyQuarterly, August 2015

Figure 2.5: Domestic market physical value chain

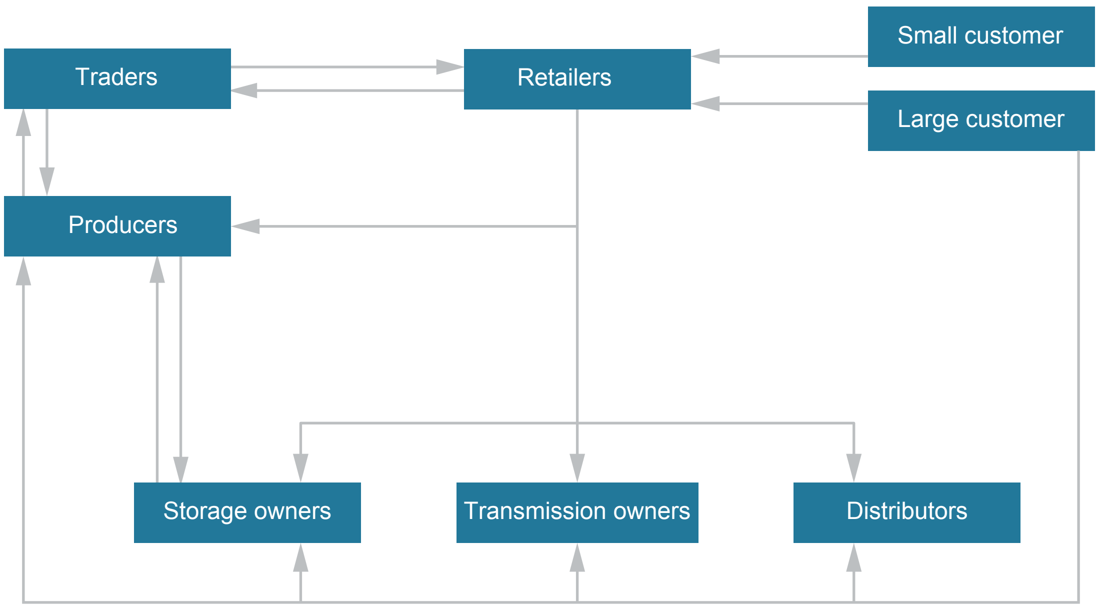


Source: Lewis Grey Advisory (2015) Gas Market Model Review

Gas storage is becoming increasingly important to the operation of the market. It ranges from large underground storages located near the production centres (such as the Iona and Moomba facilities), to small LNG peaking plants located near the demand centres (Dandenong and Newcastle).[14] Storage is used to balance supply and demand over the course of the year, and for gas supply security. By storing gas during the off-peak season, and sending it out during the peak season, it makes the best possible use of daily gas production and transmission capacity, and optimises investment in these facilities.

Figure 2.6 shows the financial flows associated with the gas value chain.

Figure 2.6: Domestic market financial value chain



Source: Lewis Grey Advisory (2015) Gas Market Model Review

[14] LNG peaking plants hold relatively small amounts of gas for use on a few days a year when demand spikes above the maximum daily supply or transmission capacity of the system.

Table 2.1 shows the key players and their relationships to the gas value chain within the current structure of the eastern Australian gas market.

Table 2.1: Gas market structure

Sector	*Price Regulation*	*Major Participants*	*Linkages*
Exploration and production	Competitive	AGL BHPB Exxon Mobil Origin Energy QGC Santos	Oil production LNG export Storage
Transmission	Pipelines with market power are regulated New pipelines typically not regulated	APA Jemena	Storage Distribution Barred from trading gas
Storage	Competitive	AGL QIC Ltd Santos	Production Transmission
Distribution	Regulated due to strong monopoly characteristics	Envestra Jemena SP Ausnet	Transmission Barred from trading gas
Retail	Competitive except NSW with price controls on some small users	AGL Energy Australia ERM Lumo Origin Energy	Electricity retail and generation Gas production
End users	N/A	Alcoa Incitec Verve QAL RioTinto Aluminium Australian Paper Burrup Fertiliser	Some vertically integrated with retail and production (e.g. generators)
LNG	Competitive on world market	APLNG Shell GLNG INPEX QCLNG Woodside Chevron	Exploration and production

Source: Lewis Grey Advisory (2015), Gas Market Model Review; Department of Industry, Innovation and Science (2015)

Three key points to note are:

1. The large customers (including GPG plants) can negotiate directly with gas producers without going through a retailer – nevertheless around 70 per cent of all demand has been supplied through the three large retailers who procure their supply under contracts with the gas producers. As a consequence the downstream market has strong oligopsony characteristics.

2. With few exceptions, both independent large customers and retailers must deal with the gas transmission companies to obtain delivery of their contracted gas supplies. This industry sector is heavily concentrated, but restrictions on gas trading by pipeline owners, and regulatory limitations on cross-ownership of competitive pipelines, can mitigate this ‘bottleneck’ effect.

3. The industry operates with minimal economic regulation. Only those elements with strong

monopoly characteristics are regulated under the National Gas Law and Rules. This comprises distribution networks, those transmission lines with no direct competitors, and retail prices in a limited number of jurisdictions. Historically the upstream gas industry has successfully relied on unregulated transactions between private sector producers and public or private utilities.

Price setting in the wholesale market

Historically the gas market in Australia has been built upon bilateral, long-term trades between substantial gas producers and large, financially sound users, such as private and government-owned utilities, retailers, large industrials, and power generators. This has underpinned the penetration of gas into the energy market by giving users the confidence to invest in long-life gas using equipment, and for suppliers to develop or underwrite capital intensive gas production and transmission facilities.

A similar evolution has occurred overseas, but in some places, most notably the US, this structure has given way to a diverse, highly liquid spot market. An example of such a market is the Henry Hub exchange in Louisiana, where gas can be traded under spot sales, and under a range of futures and financial derivatives. The distinguishing feature of this market is that buyers can be confident that gas is readily available to any buyer, that long-term risks can be hedged, and that the prevailing gas price is truly representative of the market dynamics.

The Australian market lacks the number of active market participants required to support such a deep, highly liquid market structure. The four balancing markets in Victoria, Sydney, Adelaide and Brisbane, and the gas trading exchange at Wallumbilla, are an attempt to facilitate such a dynamic market structure, but to date the general view is that there is insufficient engagement with these markets by participants to generate the required degree of confidence to manage the long and short term price risks involved.

This may be due to the limited number of participants in the east coast market, but it may also be a consequence of the complexity of trading across five different platforms (soon to be six with the creation of the Moomba hub), which can hamper the development of liquidity. Until this liquidity develops, the markets will lack the financial risk management tools that are required to enable all participants to hedge spot market risks and trade without physical gas contracts.

The prevalence of bilateral trading and long-term contracts has the following consequences: [15]

- For both buyers and sellers, limited opportunities to adjust prices and volumes in existing arrangements. This particularly affects buyers already in competitive markets for their output, who find it difficult to manage the risks in the absence of short-term market liquidity.
- Lack of price transparency and infrequent price discovery (to the extent prices are even known).
- Potential for contracts to terminate at a time when no replacement supply is available. This results in long lead times for contract replacement, to ensure availability of capacity in developed and undeveloped resources. Three or four year lead times are typical. This has particularly been a problem since around 2010 when domestic supply availability has been constrained by LNG project developments.

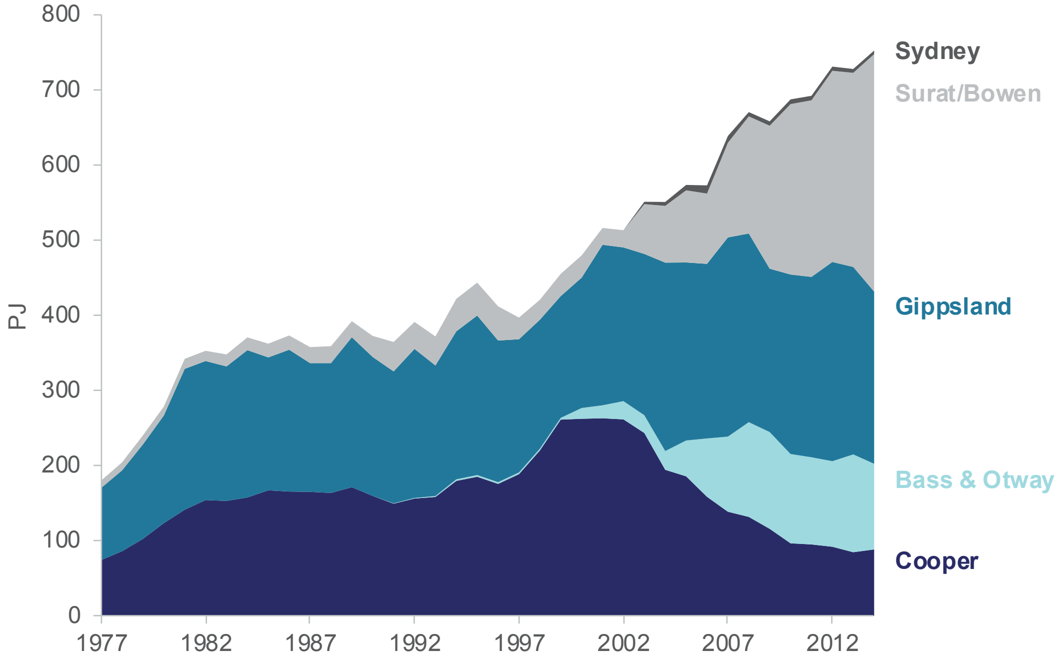
[15] Lewis Grey Advisory (2015) Gas Market Model Review

The absence of a well-functioning and liquid spot market effectively forces participants into long-term, rigid commercial arrangements in order to minimise long-term supply and demand risks. This favours concentration and vertical integration and means that new entrants find it difficult to enter the market. As a consequence the lack of liquidity tends to perpetuate itself.

Market structure

Despite the absence of a deep, liquid market, there has been a measure of diversification of supply, particularly since the development of the Otway Basin in Victoria and the CSG reserves in the Surat and Bowen basins in Queensland from around 2000 (Figure 2.7). The diversification of supply has been accompanied by significant growth in the number of upstream market players (Figure 2.8). Furthermore, between 1998 and 2003 there was a significant expansion of gas transmission pipelines which has facilitated gas-on-gas competition and increased supply security.

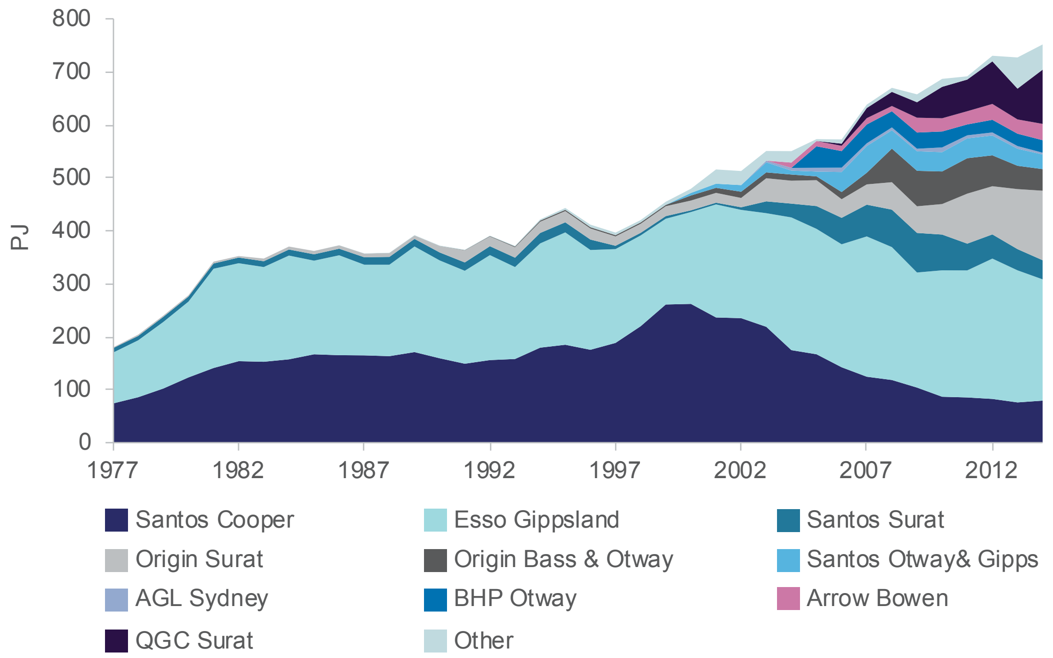
Figure 2.7: Eastern Australia sources of gas supply



Source: SKM (2013) Gas Market Modelling; EnergyQuest (2015) EnergyQuarterly

These developments have occurred concurrently with (and possibly as a result of) the introduction of competition reforms and third-party access to pipelines. However, to a large extent these developments have still relied on long-term bilateral arrangements between large suppliers and buyers (in some cases the same entities) in order to secure the large capital investments required.

Figure 2.8: Eastern Australian gas producers



Source: SKM (2013) Gas Market Modelling; EnergyQuest (2015) EnergyQuarterly

Oligopoly replaces monopoly

As a consequence of these historical reforms, the eastern Australian gas market is no longer dominated by long-term, state-based monopoly/ monopsony arrangements. At present the best characterisation of the market is as an oligopoly/oligopsony market, supplemented by a limited number of smaller players.

2.3 The current state of the market

Factors affecting the current market

The eastern Australian gas market is currently undergoing a major transition. This has been initiated by the rapid expansion of CSG production required to supply the three LNG plants operating or under construction at Gladstone, Queensland.

These huge export projects are having a major impact on the domestic market, leading to fears of gas shortages and significant price rises. Compounding these concerns is the fact that many of the long-term (and low priced) legacy contracts which have underpinned the market have recently come up for renewal, which has exposed users to prevailing gas prices, and to the uncertainties of shorter term, less flexible contracts, and in some cases the risks of oil price linkage.

LNG exports from Queensland

The LNG export projects operating or under construction at Gladstone, Queensland are set out in Table 2.2.

Table 2.2: Queensland LNG export projects

	Equity Investors	*Nameplate Capacity Mtpa*	*First LNG*
Queensland Curtis LNG (QCLNG)	BG Group (73.8 per cent) CNOOC (25 per cent), Tokyo Gas (1.3 per cent)	8.5	Q4 2014
Gladstone LNG (GLNG)	Santos (30 per cent) Petronas (27.5 per cent) Kogas (15 per cent)	7.8	Q3 2015
Asia Pacific LNG (APLNG)	Origin (37.5 per cent) ConocoPhillips (37.5 per cent) Sinopec (25 per cent)	9	Q4 2015

Source: Department of Industry, Innovation and Science (2015)

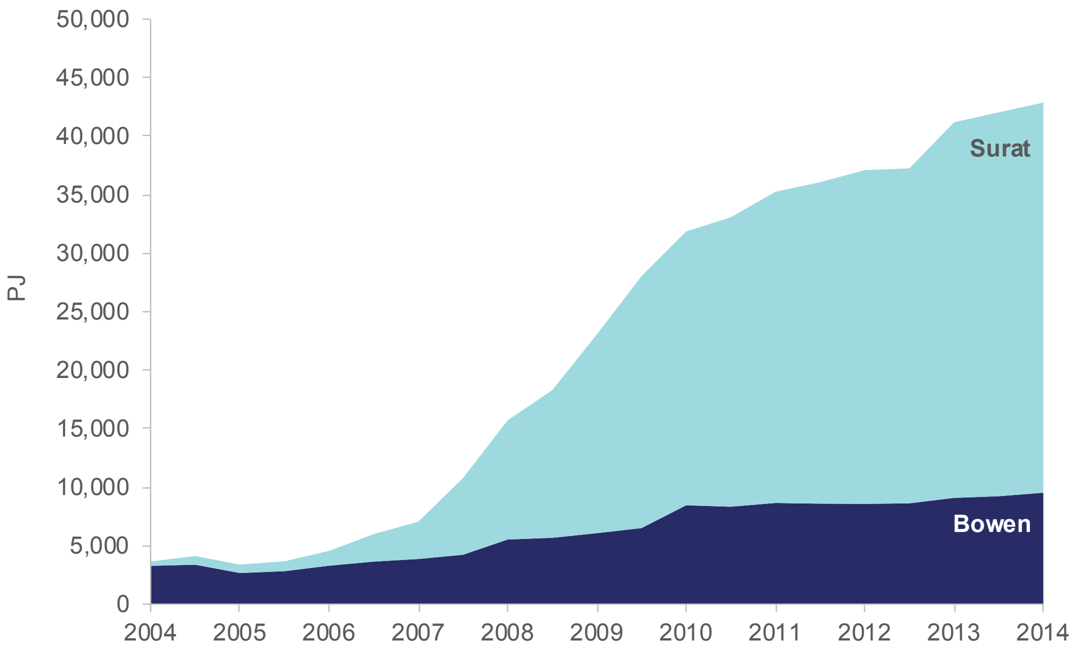
These projects have all entered into long-term (~20 years) contractual obligations with overseas LNG buyers. The LNG producers have hedged their supply risks by finding and developing substantial 2P CSG reserves in the Surat and Bowen basins. Figure 2.9 shows the scale of the rapid build-up of 2P CSG reserves in Queensland over the last 10 years. FIDs were made on the three Queensland LNG projects between 2010 and 2012.

However, the LNG projects can also access gas supplies from other producers in the domestic market, as for example when the GLNG project contracted for 750 PJ of gas over 15 years from the Cooper Basin. This and similar trades have established a clear linkage between the domestic and global LNG markets. Future trading activity should be facilitated by the developing gas trading hub at Wallumbilla.

The consequences of this rapid build-up in exports are:

- Gas supply to the domestic market is now in a competitive market with supply to the LNG producers (and any shortfall or delays in building production capacity for the LNG plants will impact on supply to the domestic market)
- Domestic gas markets will be increasingly exposed to the prices and volatility in the global LNG market.

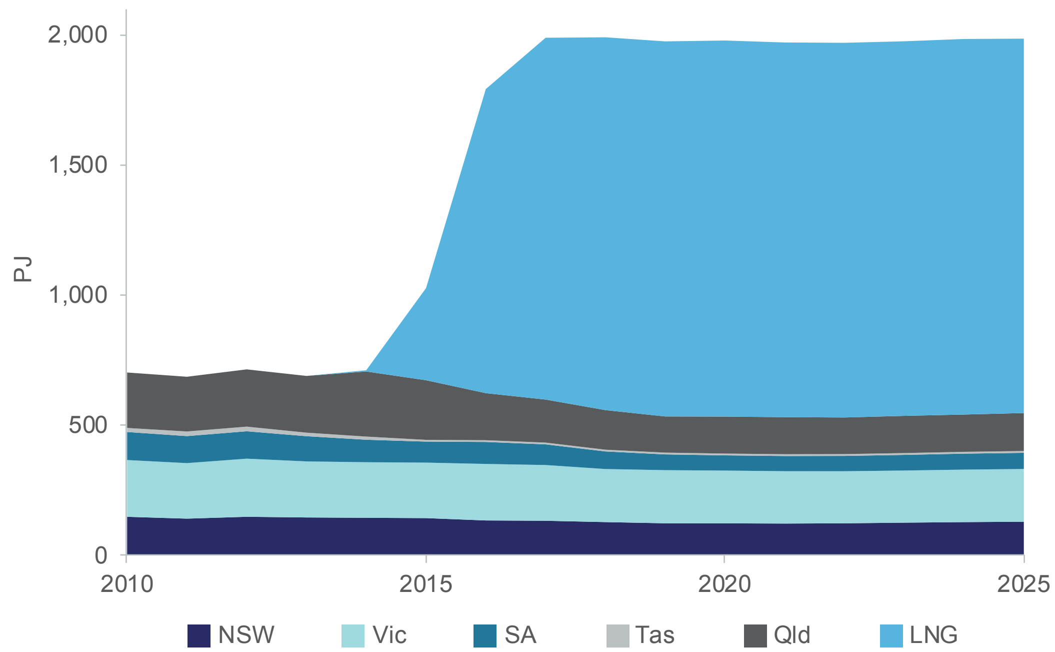
Figure 2.9: Queensland proved and probable CSG reserves



Source: Queensland Department of Mines (2015)

Figure 2.10 shows AEMO's forecast of gas demand in the eastern Australian gas market, and demonstrates the large scale of LNG exports relative to the domestic market. LNG exports have already commenced from all plants, with two trains operational at QCLNG.

Figure 2.10: Eastern Australia gas demand forecast



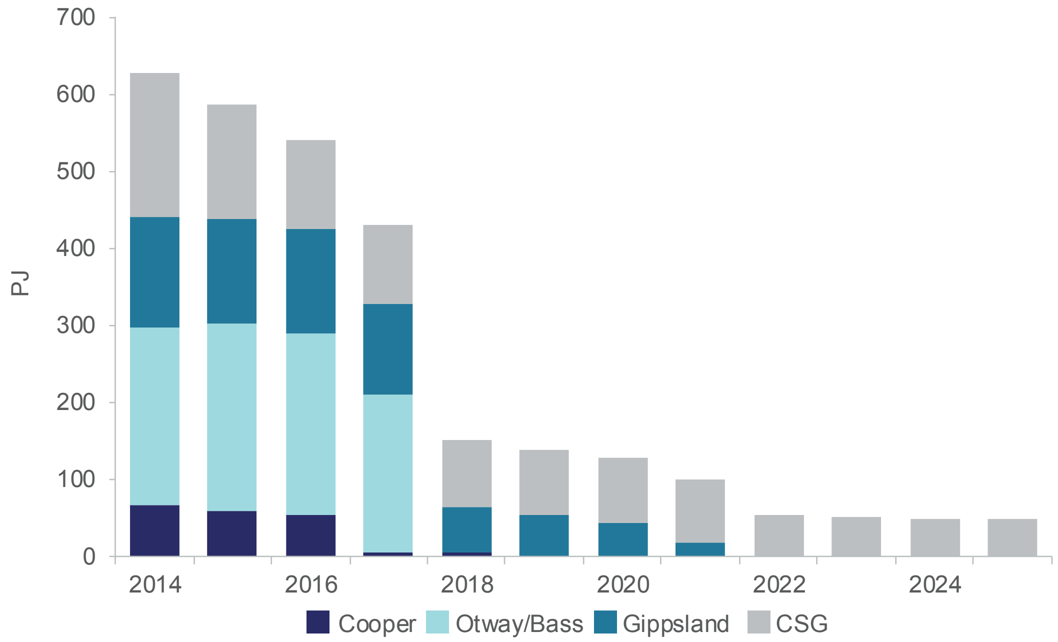
Source: AEMO (2015) National Gas Forecasting Report

Legacy contracts unwind

Figure 2.11 shows the estimated roll-off of older (pre-2012) gas supply contracts by basin. Users and suppliers are renegotiating supply and price arrangements, which is exposing a growing number of users to the consequences of the LNG export ramp-up.

It should be noted that the existence of a supply contract to a given domestic customer does not imply that the customer will consume that gas, as the domestic contracts can be on-sold to higher-value users elsewhere. For example, there are reports of this happening with supply contracts to some Queensland GPG plants.

Figure 2.11: Roll-off of older gas contracts by basin



Notes: Contracts in place prior to 2012

Source: Core Energy (2015) Eastern gas contracts database

Eastern Australian gas market outlook

The rapid growth of CSG production in Queensland to supply the ramp-up of the three LNG export plants has led to a number of concerns about the outlook for gas demand in the eastern Australian gas market:

1. Diversion of gas from the domestic market

   Domestic gas reserves (not associated with the new CSG reserves booked by the LNG proponents) have been contracted to LNG projects. For example, Santos has contracted 750 PJ of Cooper basin gas to the GLNG project. This removes a substantial proportion of the remaining 2P gas reserves in the Cooper Basin, and puts pressure on future supply to NSW and South Australia.

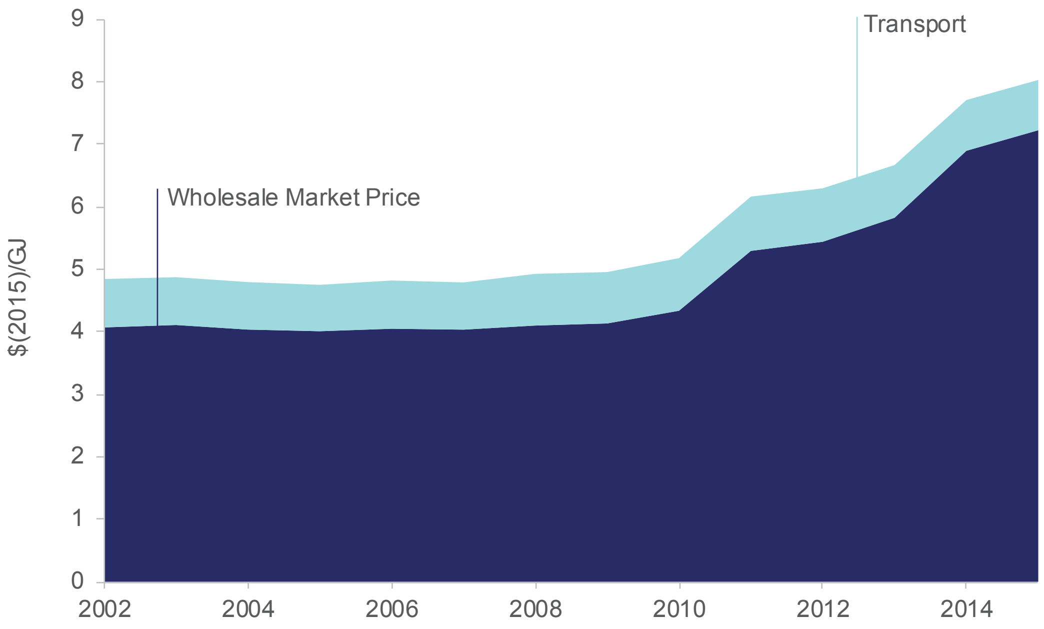
2. Escalation of wholesale gas prices

Industrial users have reported difficulty in getting offers of gas supply, and of significant price rises in those offers being made. These concerns have been verified by the ACCC in its current enquiry into upstream competition, which has reported that there was a marked change in the gas market after the FIDs by the LNG projects in 2010–11, and that between 2012 and 2014 it was hard to find signs of an effective market for domestic gas.[16]

It is difficult to assess the level of prevailing prices at the wholesale level given the small number of contracts being renegotiated each year, and the lack of liquidity in the market. Figure 2.12 shows the recent history of industrial market wholesale prices in eastern Australia. These estimates represent the price of the small number of new gas contracts negotiated each year, rather than the average price, which will be somewhat lower due to the persistence of low-priced legacy contracts in the market. There is no consensus on how these gas prices will evolve into the future, although it is generally accepted that prices will not fall back to the levels of the older legacy contracts.

The factors affecting gas prices into the future are discussed at greater length in Chapter 3 on modelling results.

Figure 2.12: Eastern Australian industrial market wholesale gas prices



Source: Oakley Greenwood (2015) Gas Price Trends Review

3. Reductions in gas market share

The increase in domestic gas prices in the eastern Australian gas market is expected to cause significant falls in demand in all states. Figure 2.10 shows the extent of the possible declines in demand as projected by AEMO.[17] The main declines are expected to occur in the GPG sector, which is very sensitive to price relativities with coal and the penetration of renewables. As a consequence, gas demand will show significant falls in Queensland and

[16] Rod Sims, Chairman ACCC, speech to the Eastern Australia Energy Market Outlook 2015 Conference, 17 September 2015.

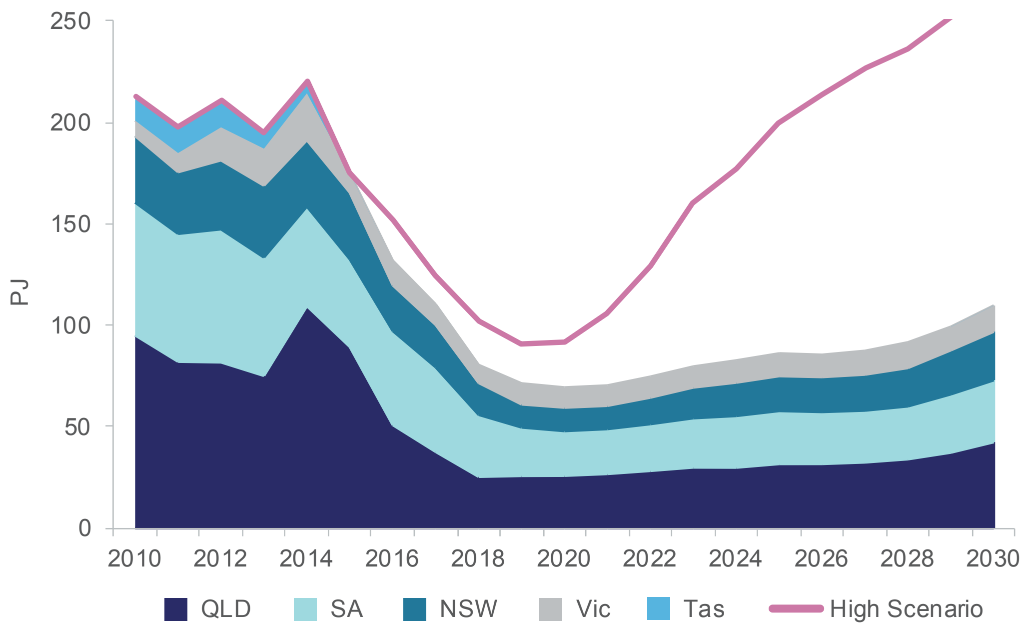
[17] AEMO (2015) National Gas Forecasting Report

South Australia, where GPG is a large component of total gas demand.

Figure 2.13 shows the AEMO forecast for GPG demand in eastern Australia.[18] There was a small spike in demand in 2014 in Queensland associated with the surplus ramp gas made available during the start-up of the QCLNG project, but it is expected that demand will fall rapidly from 2015 to 2018. It is understood that GPG plants have already been withdrawn and mothballed at Torrens Island (South Australia) and Swanbank E (Queensland).

This scenario is very sensitive to gas prices, and even small changes in the price outlook could have a significant impact on the level of GPG. The figure also shows the high scenario from AEMO, based on assumptions of higher electricity demand and reduced competition from coal-fired generation. This demonstrates the extreme volatility of the GPG sector.

Figure 2.13: Eastern Australian GPG gas demand forecast



Source: AEMO (2015) National Gas Forecasting Report

Gas demand is also expected to soften in the industrial sector, although whether this is due to gas price increases or to general economic conditions for the manufacturing sector is difficult to determine.

Global LNG market outlook

There are currently seven LNG export projects under construction or recently commenced in Australia,[19] which will create an additional 62.3 million tonnes per annum (Mtpa) of nameplate liquefaction capacity and lead to Australia becoming the world's largest LNG exporter by 2019. This additional capacity will add around 25 per cent to global liquefaction capacity, and will help to supply the rapid growth in demand expected after the tight market conditions that have prevailed between 2011 and 2014.

These projects are all substantially underwritten by long-term contracts with mainly

[18] AEMO (2015) National Gas Forecasting Report

[19] Department of Industry, Innovation and Science (2015) Resources and Energy Quarterly, September Quarter 2015

Asian customers at oil-linked prices. However a number of these contracts, particularly in Queensland, are with customers who are portfolio players, and also equity investors in the projects (for example BG/Shell and Petronas), where there is not necessarily an identified end-use consumer.

These projects were all initiated in an environment where LNG prices were very high. However, two events have occurred which have significantly changed the outlook for LNG exports, and hence the potential impact on the eastern Australian gas market. These are an excess of LNG supply capacity, and the recent fall in LNG prices.

Excess LNG production capacity

The global LNG market has been tight from 2012 to 2014 after the 'first wave' of new supply from Qatar was absorbed by unexpected demand growth in Japan after the Fukushima disaster, and after a number of failures at African LNG export plants.[20] It was expected that new production from Australia would assist to meet the pent-up demand particularly in the growing market of China.

However the supply and demand situation has changed significantly due to two recent trends:

1. The US 'shale gas revolution'

   The rapid expansion of shale gas production in the US will transform the country from a net importer of gas to a net exporter. Approximately 63 Mtpa of LNG capacity is currently under construction (Table 2.3) and will enter the market by 2020, and even more capacity is under consideration.

2. Russian 'pivot east'

   The Russian strategy appears to be to diversify its customer base by developing new markets for both LNG and pipeline gas in Asia. The 38 billion cubic metre (bcm) Power of Siberia pipeline is currently under construction (equivalent to 28 Mtpa of LNG), and combined with an expansion of Central Asian pipelines to about 85 bcm (62 Mtpa of LNG equivalent), will place severe competitive pressure on LNG imports into China.

Table 2.3: US LNG capacity currently under construction

Project	*First LNG*	*Capacity Mtpa*
Sabine Pass	2016	22.5
Cove Point	2017	5.3
Cameron	2018	12.0
Freeport	2018	13.9
Corpus Christi	2019	9.0
Total		62.7

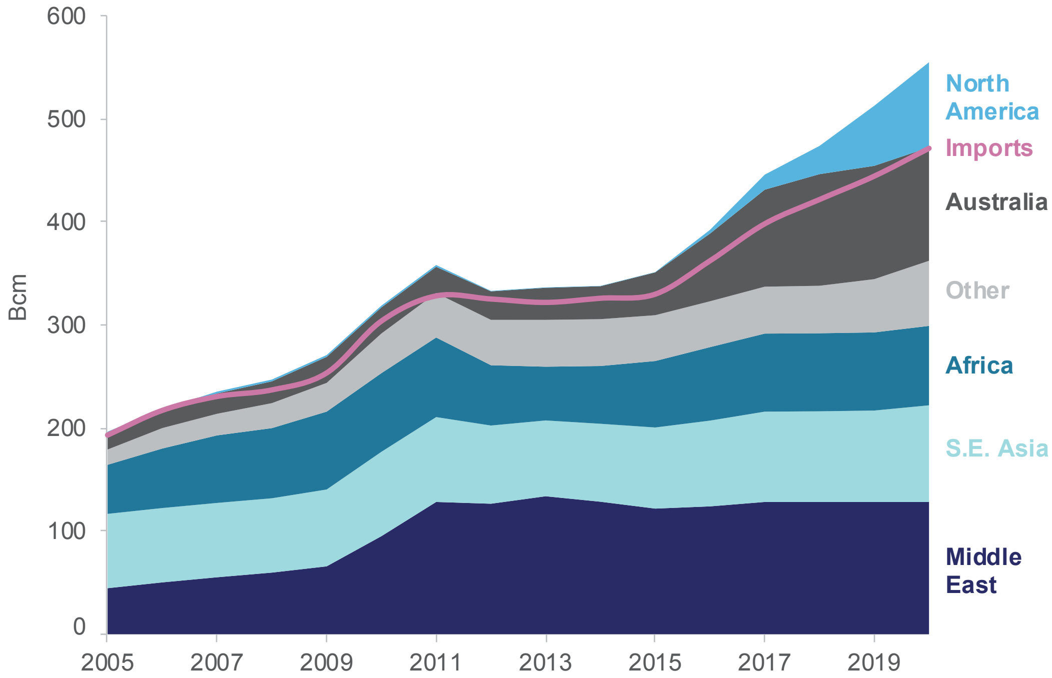
Notes: A sixth train at Sabine Pass and a third train at Corpus Christi are planned and would take the total to 71.7 Mtpa

Source:Department of Industry, Innovation and Science (2015)

[20] Bureau of Resources and Energy Economics (2014) Gas Market Report 2014

Figure 2.14 shows the forecast of the supply and demand balance in the global LNG market (as described in Chapter 4). The graphic shows that despite the rapid increase in demand to 2020, the rapid expansion of LNG capacity over the same period will add to excess supply in the market. A consequence of the excess supply will be downward pressure on spot prices, which could lead to reductions of LNG exports towards take-or-pay levels (or downward quantity tolerances) in LNG supply contracts.

Figure 2.14: Global LNG liquefaction capacity and imports



Notes: Liquefaction capacity at nameplate less allowance for plant downtime and maintenance

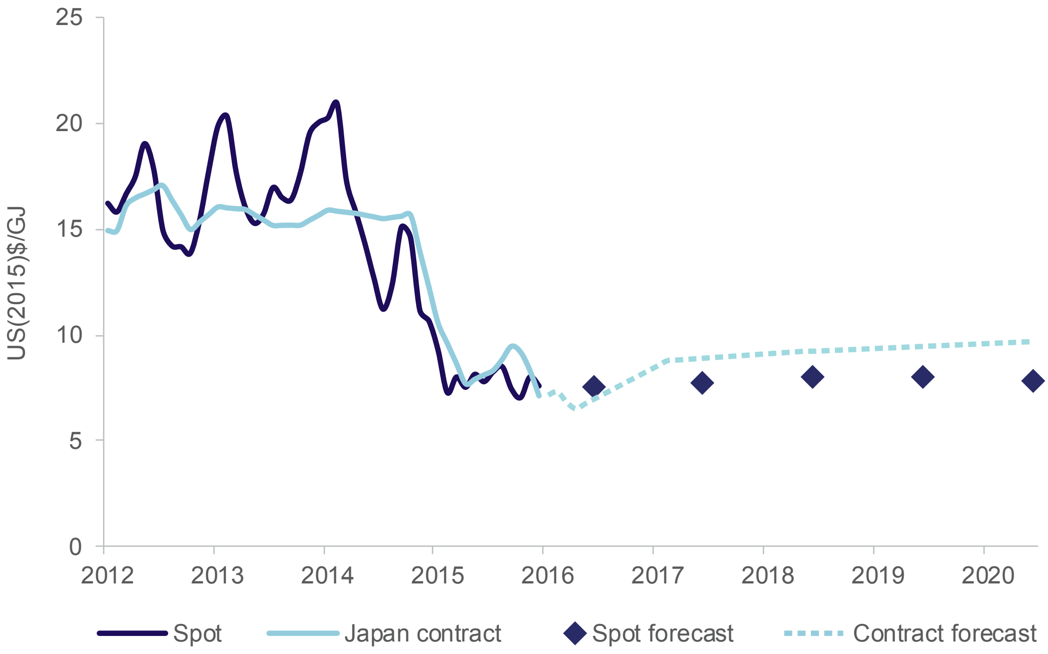
Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

There is no certainty that this excess capacity will evaporate after 2020 (which is explored further in Chapter 4). The countries with the greatest potential for long-term demand growth in the LNG market can also access pipeline supplies and/or indigenous production, which could depress LNG demand. In addition, the demand for natural gas will be sensitive to the price relativity of gas versus other fuels, and the recent falls in gas and alternative fuel prices may impact on end-use demand in unexpected ways.

LNG prices have fallen

Since the oil price began to fall in August 2014, the Asian LNG contract price has fallen at a similar rate with only a short lag. This is because most contracts are linked to the oil price. At the same time, the LNG spot price has also collapsed in line with contract prices, and as a result of the emerging excess supply capacity.

Figure 2.15: Asian LNG prices



Notes: Argus ANEA Spot Index, Japan Contract price from Nexant WGM

Source: Argus (2015) Argus Direct; Nexant (2015) WGM; Department of Industry, Innovation and Science (2015); FGE (2015)

Figure 2.15 shows the historical trends and a forecast of prices to 2020. The spot price is the Argus North East Asian index, and the contract price is an indicative Japan contract at a slope factor of 13.8 per cent, utilising an oil price forecast of US$67/barrel by 2020.

Given recent events in the LNG market, these forecasts should be treated with caution. However they do suggest that prices in the LNG market will remain subdued over the next five years and beyond.

One of Santos GLNG's major gas processing hubs, Surat Basin

CHAPTER 3

Modelling the eastern Australian gas market

Chapter 2 sets out the current state of the eastern Australian gas market and the concerns that have been raised for the future development of the market as LNG exports commence from Gladstone.

In response to these concerns, a Gas Market Model has been built to explore the physical, economic and market-related issues raised by this market transition. This chapter describes the approach taken to modelling this market, the design of the model, and some of the results obtained to date.

The modelling has demonstrated that wholesale prices in the eastern Australian gas market are likely to rise significantly as LNG production commences from Gladstone and as legacy contracts are renegotiated. This will lead to substantial falls in demand, predominantly in the GPG sector. The fall in demand means that gas supply capacity will be adequate to meet demand, although the market will be very tight, and will become tighter as gas reserves are depleted over time.

The analysis finds that gas reserves on the east coast are sufficient, provided no additional LNG trains are constructed, but that gas production capacity is the key constraint. As gas production in the Cooper Basin and Queensland is directed to the LNG plants, the southern markets will have to rely almost completely on production from the Otway, Bass and Gippsland basins. The analysis points to a potential shortfall in supply over time as these reserves deplete and production capacity declines, which will require supplementary supplies from the north.

In Queensland, the market must rely on additional production capacity to satisfy both LNG demand and the Queensland domestic market. A potential issue will be incentives to expand capacity to meet Queensland domestic demand and to supplement demand in the southern States. Both volumes and prices in the Queensland market will become more volatile as gas production moves between the domestic market and the flexible part of LNG production. A key determinant of this volatility is expected to be the price of LNG in the Asian spot market.

3.1 Key issues for further analysis

Based on the overview in Chapter 2 of the main factors at work in the eastern Australian gas market, the following key issues have been identified for further analysis by the eastern Australian Gas Market Model.

1. Are there sufficient gas reserves to supply the market over the long term?
2. Is there sufficient production capacity to meet projected domestic and export demand?
3. How will events in the global LNG market affect the domestic gas market?
4. Given the concentration of upstream ownership, what is the impact of a potential supplier oligopoly on gas prices and levels of production?
5. Case study – impact of Northern Territory supply.

3.2 Modelling overview

Focus on upstream competition and wholesale prices

The main issue facing the gas market for the foreseeable future is the impact of LNG exports on gas production, and the effect this will have on the price and availability of gas to the domestic market. Therefore the focus of any analysis must be on the upstream sector and the processes that determine production volumes and the level of wholesale prices. This is closely tied to the adequacy of gas reserves, and the rate at which these reserves will decline over time.

The Gas Market Model aims to explore the way that wholesale prices are formed, and how this impacts on both the level of demand, and the level and source of gas supply.

As discussed in Chapter 2, the gas market can best be characterised by an oligopoly/oligopsony structure. This means that gas production (and hence the wholesale gas price) is strongly influenced by the limited degree of competition between suppliers and amongst buyers. There has been little research or analysis on the effects of this market structure on gas markets in the past. For the purposes of the Gas Market Model, the focus is on the oligopoly elements of the market, and the potential oligopsony element is ignored.[21]

The aim of modelling the market as an oligopoly is to throw some light on the adequacy of upstream competition to constrain prices, and how this might be affected by the rapid growth in LNG exports.

Key elements of the Gas Market Model

The gas market can be modelled by finding the gas price that leads to a balance between demand and supply, and tracking the evolution of that balance over time.

In the case of the eastern Australian market, the supply and demand centres are geographically dispersed, with some demand centres over 1000 km from the main source of supply. Furthermore, the market is connected in such a way that purchases and sales of gas can be transacted over multiple paths. Therefore the market must be modelled as a network, taking into account:

[21] A key issue would be whether the presence of oligopsony increases the margin created by an oligopoly, or whether the margin is split between the producer and the retailer.

- the limited capacity of the transmission connections and the applicable transmission tariffs
- the option to use alternative transmission paths to match demand to supply.

The wholesale price determines the volumes of gas consumed at each location and the quantity of gas supplied from each source. Demand is determined by price in the sense that higher prices lead to lower demand, and vice versa (also known as demand elasticity). Similarly, supply is determined by the price offered for gas supplies, in the sense that higher prices bring on more supply.

Under this approach there is no concept of a 'supply shortage'. Instead, if production is inadequate, then the price will rise to:

- clear the market (reduce demand to the available supply), and/or
- bring on more supplies, possibly from more distant locations.

Therefore the indicator of a supply shortfall is a sharp rise in the price of gas.

The approach taken by the Gas Market Model is to treat the upstream suppliers as the active participants, competing with each other to maximise their individual profits. The consumers are treated as passive players who simply respond to the offered prices by varying their level of demand. In reality the gas market is more complicated, as the limited number of large buyers in the market can also exercise market power, and there are many instances of vertical integration.

The meaning of price in the Gas Market Model

The eastern Australian gas market lacks the liquidity that would allow wholesale prices to settle to a single market price at any given location. Some buyers will pay legacy prices under long-term contracts, and others will be able to negotiate better prices than their neighbours.

The four eastern Australian spot markets and the trading hub at Wallumbilla operated by AEMO are an attempt to establish a single daily market price at each location, but to date this has been only partially successful. The Australian Energy Market Commission (AEMC) is currently considering an eastern Australian gas market price index in liaison with the ABS, but this is still in the early stages.[22]

The Gas Market Model calculates a single price at each demand centre. This represents the opportunity value of gas at that location. To the extent that a retailer has been able to negotiate a low priced supply contract with a gas supplier, or has a legacy contract, they have the opportunity to increase the price to the end-use customer, up to the opportunity value, and claim the potential profits. The model assumes that demand will respond to this opportunity price rather than to legacy prices.

3.3 Eastern Australian Gas Market Model – model design

A full description of the design of the model is provided in Appendices A to C.

Structure

The Gas Market Model consists of 33 demand and/or supply nodes across the east coast of

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[22] AEMC (2015) East Coast Wholesale Gas Market and Pipelines Framework Review

Australia, connected by gas transmission pipelines. The current model structure is shown in Figure B1 of Appendix B.

The demand nodes represent the main demand centres in each state, based on there being a sufficient geographical separation between centres to warrant a separate node. Hence South Australia is represented as one node at Adelaide, whereas Queensland has five nodes at Brisbane, Gladstone, Curtis Island, Mount Isa and Wallumbilla.

The supply nodes represent the main gas producers. The goal is to represent enough producers to capture the competitive dynamics in an oligopoly. A joint venture is defined as a single producer, for example the Gippsland Basin Joint Venture (GBJV). Too few producers will exaggerate the effects of market power, and will generate prices which are higher than would be expected in the real world, and vice versa.

The existing transmission pipelines are represented as links between the nodes. Each pipeline has a maximum daily capacity, a load factor of supply, and a fixed transmission tariff. Future additions to capacity are included where projects have been announced, such as the NSW-Victoria Interconnect expansion. In order to model gas swaps, the pipelines can accommodate reverse flows, but net flows are limited by the known transmission capacity.

Modelling methodology

The model balances supply and demand each year over the nodal network, using the supply and demand curves at each node. As gas is produced from each gas field, the reserves decline and the costs of production will increase.

The market is modelled as an oligopoly, which means that the model solves to maximise the profit to the suppliers. A supplier can set the selling price, but is constrained by competition from other suppliers. The outcome of this limited competition is that prices are set somewhat lower than would apply under a monopoly, but higher than would apply in a perfectly competitive market.

In a perfectly competitive market the optimal price will be equal to the marginal cost of supply.

In an oligopoly the price includes a mark-up over the marginal cost. The ability to command a mark-up over marginal cost is an indicator of market power.[23] The Gas Market Model models the oligopoly under Cournot competition, in which the producers independently choose their output levels to maximise profit.

The model also takes into account constraints on production and transmission capacities. These constraints can cause prices to exceed marginal cost even in a competitive market (as discussed in Appendix A.7).

Modelling outputs

The model balances supply and demand and calculates:

- the wholesale delivered gas price at each node
- the annual demand (in each of the three market sectors) at demand nodes
- the annual production of gas at supply nodes
- the annual flows on each transmission pipeline.

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[23] The mark-up is expressed by the Lerner index which is the divergence of price from marginal cost, relative to the price. An index of zero indicates the absence of market power.

The production and transmission flows are constrained by the known capacities of these assets, but these can be changed exogenously.

The model also tracks the remaining gas reserves at each supply node, and adjusts the gas supply cost and the maximum annual production capacity appropriately.

3.4 Domestic gas market analysis

Issue One – is there enough gas?

There are 49,000 PJ of 2P reserves in the eastern Australian gas market located in four main producing areas, as shown in Figure 3.1 and Table 3.1.[24]

Figure 3.1: Proved and probable gas reserves by region

Did you know?

- The vast majority of the reserves are in the Surat/Bowen basins of Queensland and the bulk of these reserves were discovered only since about 2005.
- The Victorian offshore reserves are the next largest, and cover the Gippsland, Bass and Otway basins.
- Third in magnitude is the Cooper basin reserves centred on Moomba.
- Finally there are the largely undeveloped CSG reserves in NSW, based around Sydney, Gloucester and Narrabri.

Source: Department of Industry, Innovation and Science (2015)

In addition to the 2P reserves there are substantial 2C reserves, which are reserves where the commerciality has not been established due to lack of information and uncertainties about the cost of development.

[24] EnergyQuest (2015) EnergyQuarterly: August 2015 Report

We have found it convenient to separate the eastern Australian gas market into the North (Queensland and Cooper Basin reserves) and the South (Victorian offshore and NSW CSG reserves). This is because it is anticipated that the Surat/Bowen and Cooper production will predominantly support demand in the North (the Queensland and LNG export demand), leaving the reserves in the South to support local demand in Victoria, NSW, South Australia and Tasmania. A mismatch between reserves and demand in the North or in the South therefore indicates a lack of self-sufficiency (that is, the necessity for gas to flow from the North to the South over time).

Table 3.1: Proved and probable gas reserves

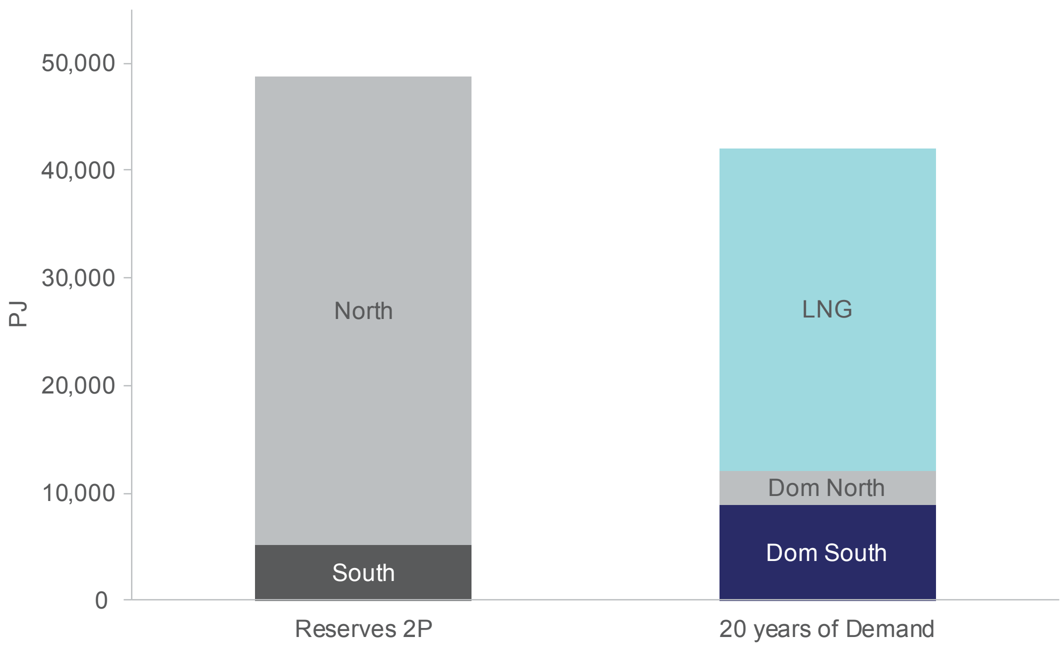
Basin	*Reserves (PJ)*
Surat and Bowen basins	45,513
Victorian offshore basins (Gippsland, Otway and Bass)	4,469
Cooper basin	1,797
NSW CSG basins (Sydney, Gloucester, Gunnedah)	1,364

Source: EnergyQuest (2015) EnergyQuarterly: August 2015 Report

A large proportion of the Queensland reserves is dedicated to the three LNG export projects, and underpins their long-term contractual obligations. The Queensland reserves also include the Arrow reserves (Shell and PetroChina) which were intended to cover an additional LNG project at Gladstone (an additional two trains on top of the six trains of the three existing projects), which was deferred in early 2015.

The Gas Market Model has been built on the assumption that no additional trains are developed at Gladstone. If this assumption holds true, there is a large surplus of gas available to the domestic market.

Figure 3.2: Reserves (2P) versus production



Source: Department of Industry, Innovation and Science (2015)

Figure 3.2 compares the known 2P reserves with the domestic and export demand over a 20 year period. A 20 year reserves to production ratio has generally been considered as an adequate coverage ratio in the gas industry.[25]

Figure 3.2 demonstrates that there are sufficient 2P reserves to supply the domestic and export markets for the next 20 years. However, the reserves in the South are not sufficient for the demand in the South and will require development of the 2C reserves, or imports from the North (Cooper, Queensland or the Northern Territory).

It should be noted that the overall adequacy of reserves does not necessarily imply that demand can be supplied at viable prices. For example, the gas may require expensive transportation to reach the market. In addition, although Arrow has deferred additional LNG trains at Gladstone, they may decide to hold their reserves till the LNG market improves. If this happens there will be greater pressure on the remaining proved and probable reserve,s which may require development of contingent resources. However, the analysis does indicate that the main issue facing the market is not the availability of gas, but rather the cost, competitiveness and deliverability of that gas.

Issue Two – is there enough production capacity?

A gas field or basin produces gas through a system of connected producing wells, and one or more processing plants which clean-up, regulate and pressurise the gas from the wells. The maximum daily production capacity is defined by the size of these facilities, including the number of wells and the design capacity of the processing facilities. In practice the actual capacity of the field is limited by the productivity of the gas wells servicing the field and this productivity will decline over time as the gas is produced.

Investment in production capacity is the main expense associated with developing a gas field. Hence, irrespective of the size of a field, the level of production will depend on the willingness of a producer to make substantial capital investments in production and processing facilities. As an example of these significant costs, the GBJV is spending over $1 billion to build a gas conditioning plant at Longford to process new gas production from the Tuna/Turrum/Kipper fields, without adding to the total production capacity from Gippsland.

The production capacity in the eastern Australian gas market has not been an issue until recently, because the system has grown on an incremental basis over time to meet a growing market. However, with the growth of LNG exports, it is expected that gas production capacity will come under pressure.

To analyse the adequacy of gas production capacity, the eastern Australian market has been conceptually separated into a northern market and a southern market (as discussed above). The South is currently supplied from Victorian offshore gas with additional supplies from the Cooper Basin and the Queensland CSG fields. However with the expansion of LNG exports, it is expected that gas flows will reverse on the South West Queensland Pipeline, diverting gas from the Cooper Basin to Queensland, and leaving the Southern market exposed.

[25] Too high a reserves ratio requires uneconomic exploration expenditure. Too low a ratio does not give users confidence to invest in gas-consuming assets.

Production capacity in the South

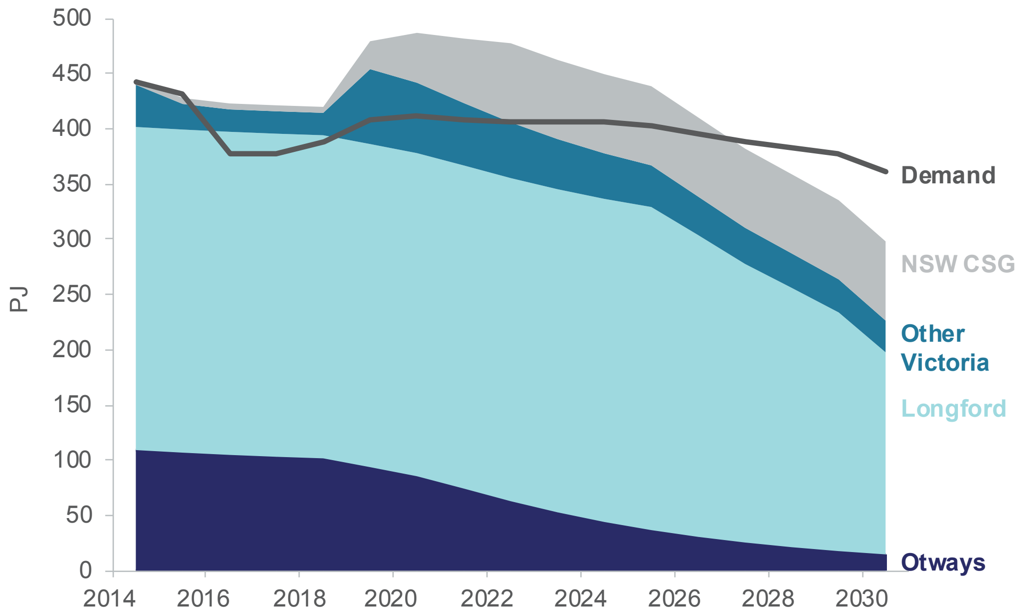
Figure 3.3 shows the annual production capacity of the Victorian offshore and NSW CSG fields over time, compared to a forecast of demand in the South.

The Victorian production forecast is based on exploitation of both 2P and 2C reserves. This can be considered a 'best case' scenario, since there is no guarantee that the 2C reserves can be developed at a reasonable cost. Therefore there is a possibility that shortfalls will occur earlier than suggested by this analysis.

Production capacity is made to decline as the combined 2P and 2C reserves approach depletion.[26] This models both the physical run-down in well deliverability, and also the lack of incentives on gas producers to invest in maintaining gas production when there is limited production life left in the gas fields.[27]

Figure 3.3 includes the potential production from the NSW CSG fields at Camden, Gloucester and Narrabri.[28] This production assumption is based on the known 2P reserves, since there are doubts about the commerciality of developing the 2C reserves. However, the development of the NSW 2C reserves is an option to extend the life of gas production in the South.

Figure 3.3: Maximum gas production capacity available in the South



Source: Department of Industry, Innovation and Science (2015)

[26] Maximum production capacity declines so that the reserves-to-production ratio never falls below six years.

[27] Maximum production Longford is assumed to be 295 PJ based on installed processing capacity and estimated load factors of deliveries to Victoria, Tasmania and NSW.

[28] AGL has recently announced that it is abandoning the development of the Gloucester reserves due to higher costs than originally anticipated.

We can draw the following conclusions from this analysis:

1. The anticipated fall in demand takes some of the pressure off supply in the short term.

2. Production in the South is adequate in the short to medium term, without requiring supplementary supply from the North (Cooper or Queensland). The current expansion of the Interconnect and the Eastern Gas Pipeline from Victoria to NSW suggests that the market is responding to the potential loss of supply from the North.

3. However, in the longer term, the run-down in production from the Otway, Bass and Gippsland basins becomes a problem.

4. The exploitation of NSW CSG can extend the life of Southern production, but it is clearly not a panacea.

Therefore the options available to maintain supply to the South are:

- exploitation of the 2C resources in the NSW CSG fields (approximately 1390 PJ,[29] although it is not clear that these will be commercial)
- further discoveries in Victoria (although these will have to be in the order of at least 3000 to 4000 PJ in order to provide a comfortable 20 year reserve-to-production ratio)
- imports from new production in Queensland, the Cooper, or from the Northern Territory.

Production capacity in the North

Production capacity in the North consists of the production out of the Cooper Basin (almost all of which is at Moomba) and the production capacity in the Surat and Bowen basins in Queensland. Production capacity at Moomba has declined recently, but it is assumed that this will be increased to approximately 135 PJ a year in the medium to long term.

Production capacity in Queensland is growing rapidly as the three LNG projects ramp-up production to supply exports. This production is based on the development of new CSG reserves in the Surat and Bowen basins.

The rate of growth of this capacity depends on the number of wells drilled, the time to dewater these wells, and the productivity of each well over time. The installed CSG processing capacity is another limiting factor.

The ultimate deliverability of these CSG fields is the main factor which will determine outcomes in the eastern Australian gas market. This is because even a small shortfall in production capacity (relative to the size of the LNG export market) will lead to substantial competitive tensions between the LNG export market and the domestic market.

CSG production capacity in the Gas Market Model is based on the forecast of gas production for LNG exports undertaken by Jacobs for AEMO's Gas Statement of Opportunities.[30] Almost all of this is new production capacity currently being constructed in Queensland specifically for the LNG projects, but it is assumed that over 100 PJ a year of existing CSG production capacity in Queensland is diverted to the LNG projects to meet contracted levels of LNG demand.

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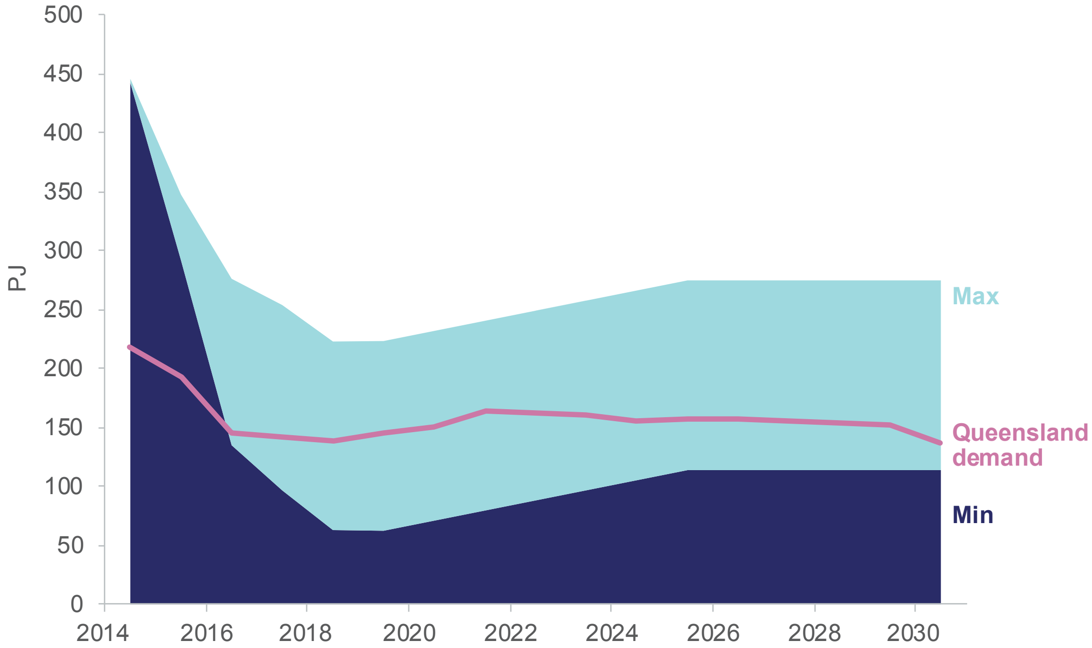
[29] Includes 2P and 2C reserves, but excludes Metgasco resources in north east NSW.

[30] AEMO (2015) Gas Statement of Opportunities

Figure 3.4 shows the Queensland gas demand forecast compared to the maximum gas production capacity (Cooper plus Surat and Bowen basins) which is not allocated to LNG exports.

Note that the amount of capacity which is allocated to the LNG market is itself a variable. It will depend on the demand for LNG in the international market. Figure 3.4 shows a reasonable range for this demand which varies between full nameplate capacity (maximum LNG production) and the contracted take-or-pay level (minimum LNG production).[31]

Figure 3.4: Gas production capacity available in the North



Notes: The Min (Max) capacity is the total Queensland production capacity after deducting the requirements of the LNG plants operating at their maximum (minimum) capacity. The range between Min and Max represents the swing in the capacity available to the domestic market.

Source: Department of Industry, Innovation and Science (2015)

The chart shows that production capacity is severely constrained in the North after a spike of excess capacity as the CSG fields ramp up. The large reduction of demand in Queensland is a result of the very tight market that is expected to prevail in the near future as GPG demand declines.

Unless additional production for the domestic market is added in Queensland, there is little capacity available to supply the South.

Nevertheless, there is sufficient capacity to supply the Queensland market, albeit at a reduced level of demand. However, this is only true if the LNG demand is at contracted levels (about midway between the maximum and minimum levels in the chart). If LNG demand approaches nameplate capacity, then either Queensland demand must fall further, or imports will be required from the South.

On the other hand, if LNG demand is lower (due to low international spot prices or unscheduled downtime) then there will be a surfeit of gas production. The modelling suggests that this production would be available to boost the GPG market in Queensland.

[31] The take-or-pay level is not publically available. It is assumed to be 95 per cent of the contracted quantities.

The main issues facing the North are:

- whether the expected CSG production level will be sufficient to meet the forecast gas requirements (given the uncertainty in well productivity as new wells are drilled to maintain production over time)
- the level of LNG demand, which can vary by a large amount compared to domestic demand.

As such, the main issue facing the North is the adequacy of production capacity, in a market where demand can vary significantly due to events in the international LNG spot market.

A key issue is whether gas producers have an incentive to invest in additional CSG production capacity which can supply both the domestic market and the LNG export market, in an environment where demand can vary significantly due to events in the global LNG market. The most likely outcome is that capacity will remain constrained, and volatility in the global LNG market will be transferred to the domestic market.

In the event that LNG demand is at the lower end of the range, the excess gas production can be shut-in, transferred to underground storage, or sold into the domestic market. The main sector in the domestic market which can absorb the swing in supply is the GPG market. This is largest in Queensland and South Australia, where some gas powered generators are currently being mothballed, but these generators could be brought back online at short notice.

Issue Three – how will events in the LNG market affect the domestic market?

When the three LNG projects at Gladstone were initiated, LNG prices were at record highs. It was widely thought that the domestic market would have to adjust to the higher opportunity value of gas in the export market by paying very high 'netback prices' of up to $10 a gigajoule (GJ) at the wholesale level, compared to legacy prices of around $4/GJ.

The potential for LNG exports from Queensland inspired the rapid increase in exploration, development and production of Queensland CSG, and also the diversion of some domestic gas production to the LNG projects.

However, LNG prices, and hence netback prices, have collapsed over the last year. Figure 2.15 shows how LNG contract prices have fallen since August 2014, in line with falls in the oil price. It also shows the dramatic fall in spot prices, which are expected to fall even more than oil-linked contract prices as new supply from Australia and the US floods the global market.

The eastern Australian gas market is now connected to the global LNG market, which means that global volatility will translate through to the domestic market. The Gas Market Model makes the following assumptions in order to model this connection:

1. There will be no new LNG plants at Gladstone.[32]
2. If LNG spot prices are low:
    - International buyers could profit by reducing their take from the Australian plants to the take-or-pay level in their contracts, and buying in the spot market, if spot prices are less than contract prices.
    - If the spot price is less than their short-run marginal cost of production, LNG producers could profit by supplying gas purchased in the spot market to their customers instead of domestically produced LNG
3. If LNG spot prices are high:
    - Buyers would purchase LNG from the Australian plants up to their contracted levels.
    - LNG producers would seek to maximise their profit by selling up to their nameplate capacity through the spot market.

The LNG demand function is described in Appendix C. The key factors affecting LNG production will be:

- the ‘flex’ in the contracts, which is the difference between the minimum take-or-pay quantity in LNG contracts and the nameplate capacity
- the Asian LNG spot price
- the short-run marginal cost of LNG production.

For an LNG producer with firm contracts with LNG consumers, the decision to produce more or less LNG will be based solely on short-run costs and prices. It follows that when LNG spot prices are low (as now) there is likely to be less production of LNG.

The Gas Market Model treats the LNG gas producers as independent entities who can sell to the LNG plants or the domestic market to maximise their own profits. Therefore, less LNG demand means more gas is available to the domestic market, but the actual level of production will be reduced to the profit-maximising level. The Gas Market Model does not model the fact that some CSG wells are difficult to turn down. However, this assumption is likely to be acceptable at the margin.

Figure 3.5 shows an estimate of how LNG production responds to LNG spot prices. There is lower production of LNG at low spot prices, and an increase in demand in the domestic market, although there is an overall reduction in production.

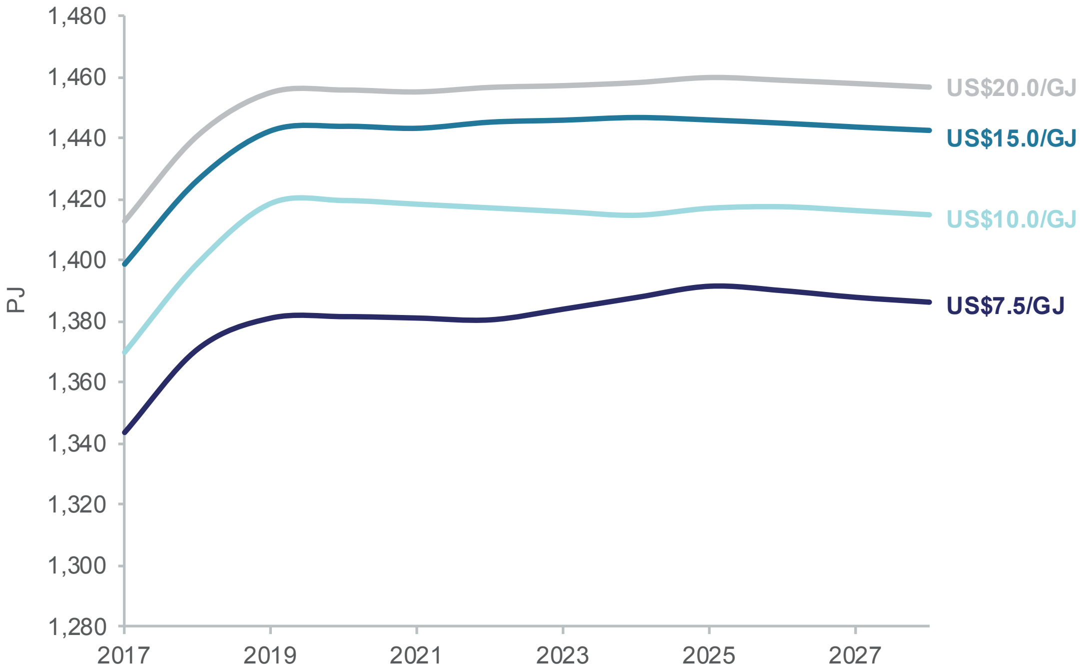
In summary, the domestic market will be strongly influenced by events in the global LNG market. The main influence is expected to be through LNG spot prices (including short to medium term trades) and will be mediated by the short run marginal costs of LNG production, rather than through long-run netback prices.

[32] New capacity at Gladstone is not expected for the foreseeable future, but if global conditions change it would introduce the same transitional issues created by the three existing plants.

The global short-term and spot markets are currently about 30 per cent of the total LNG market (as explored further in Chapter 4.2). In addition, the LNG market is expected to become more liquid as destination clauses are renegotiated in contracts.

This creates the potential for significant volatility in the domestic market. It is assumed that the GPG market in Queensland (and possibly South Australia) could absorb any additional production on relatively short time scales.

Figure 3.5: LNG production at various Asian LNG spot prices

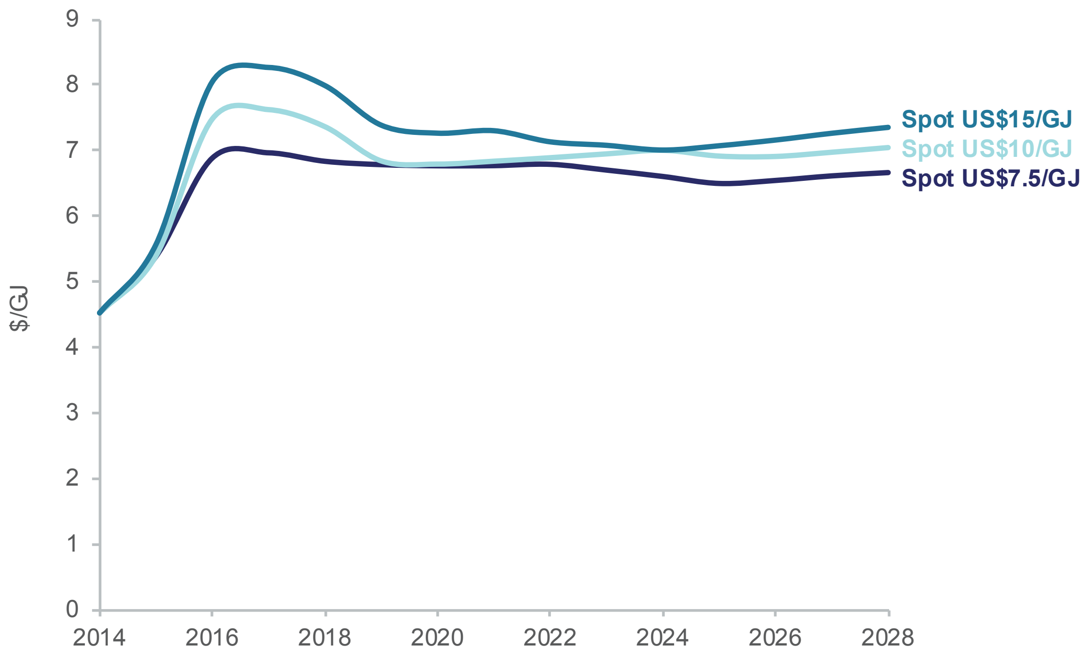


Source: Department of Industry, Innovation and Science (2015)

Figure 3.6 shows the impact of LNG spot prices on the gas price in Queensland (on the assumption the spot price is constant over time). The reason that prices spike between 2016 and 2018 is due to the lack of sufficient production capacity as the LNG plants ramp up. As production grows, the prices fall back. Note that it has been assumed that additional production from non-LNG producers has been brought on after 2018.[33] In the absence of this assumed growth, the prices would not fall back.

[33] New capacity at Gladstone is not expected for the foreseeable future, but if global conditions change it would introduce the same transitional issues created by the three existing plants.

Figure 3.6: Queensland prices at various Asian LNG spot prices



Source: Department of Industry, Innovation and Science (2015)

Issue Four – what is the impact of oligopolistic supply?

An oligopoly creates the ability to set prices higher than marginal cost.

In a perfectly competitive market price is set at marginal cost, and this price will maximise social welfare (the sum of the producer and consumer surpluses).

In an oligopolistic market, price is set above marginal cost by a limited number of producers whose aim is to maximise individual profits. This leads to higher prices and lower production than would otherwise be the case. The potential market power of the producers is limited by competition from competing suppliers, and by competition from alternative energy sources (manifested as high price elasticities in the demand sectors).

The Gas Market Model is designed to represent the profit maximising behaviour in an oligopoly. It can therefore provide an estimate of the extent to which market power could potentially be exercised in various parts of the eastern Australian gas market.

The impact of limited competition on gas prices and demand has been estimated using different levels of the Market Power Index (described in Appendix A). A value of zero models a perfectly competitive market where price is equal to marginal cost, whereas a value of unity represents a pure oligopoly where prices are set to maximise producer profits in the presence of a limited number of competitors. The difference in prices between these extremes will signify the potential extent of market power. At a value of 0.5, the price mark-up over marginal cost is half what would be expected in an oligopoly, and represents a situation where there may be countervailing oligopsony power.

The following results show the impact of the concentration of ownership in the northern and the southern markets of the eastern Australian gas market. The price is the weighted average wholesale delivered price over the main demand centres in each market.

Oligpolistic competition in the South

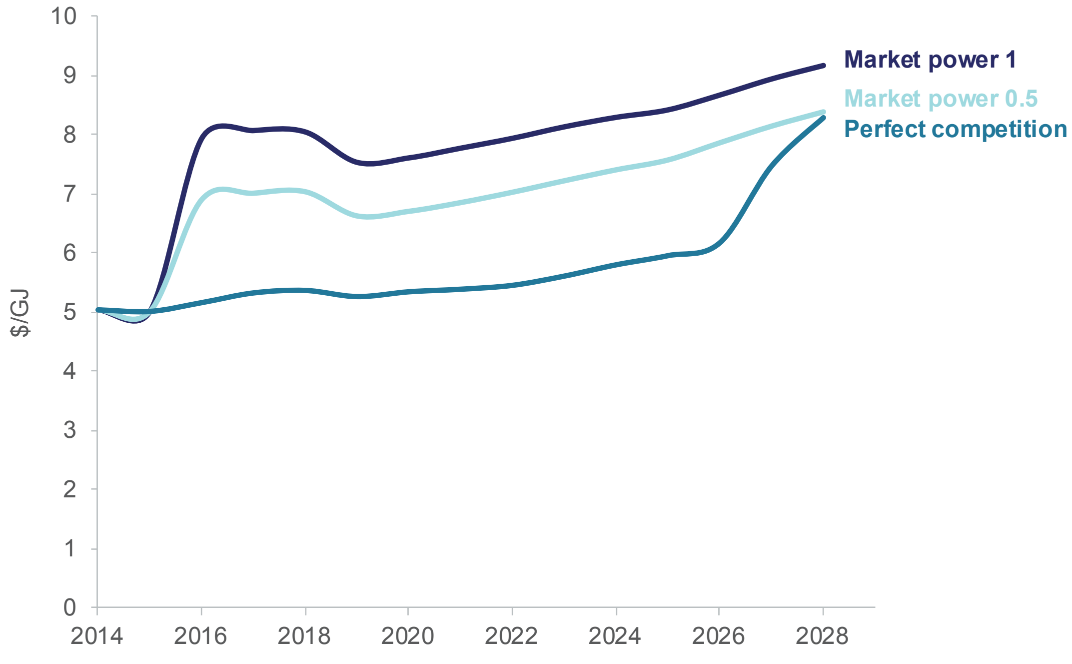
Figure 3.7 and Figure 3.8 show the impact of limited competition in the southern market on gas prices and gas demand. This market is dominated by the Victorian offshore producers, and by the large, relatively price inelastic Victorian demand.

These results show that prices under oligopolistic competition are much higher than they would be in a perfectly competitive market. This is due to the fact that gas production is dominated by the GBJV, and that the concentration of supply in this market will increase over time as the Otway Basin declines.

The wholesale gas price in the perfectly competitive scenario rises gradually towards the end of the outlook period. This is because with higher consumption, the fields are depleted more quickly, which causes the cost of production to increase.

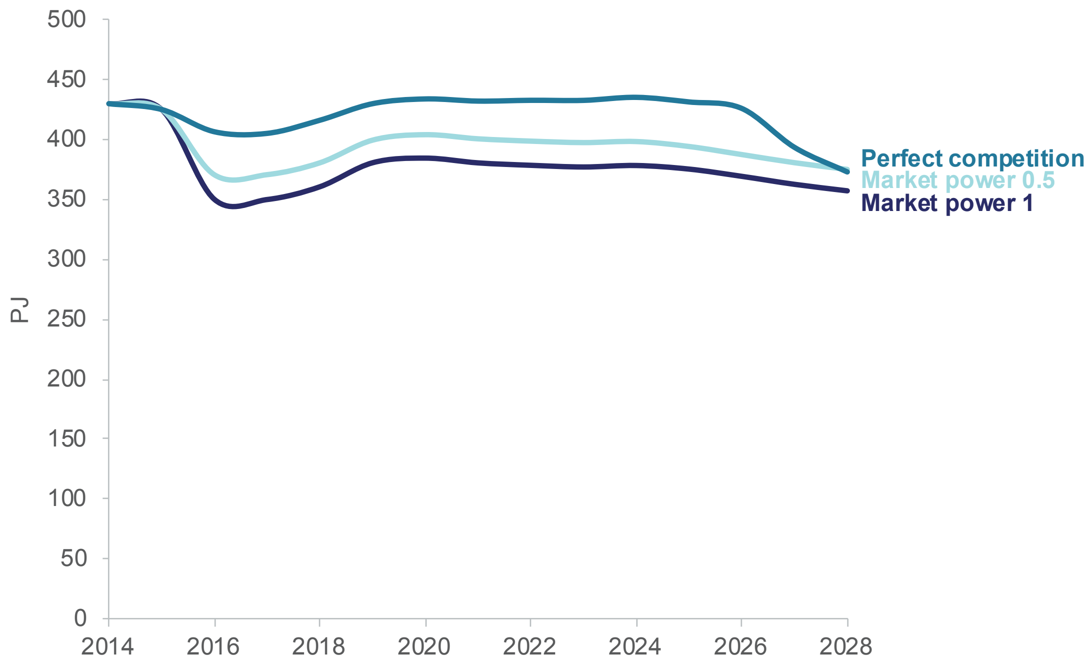
The extent of price mark-ups in the South is also enhanced by the fact that the Victorian market is dominated by the residential-commercial demand, which is relatively insensitive to wholesale prices. The end-user price paid in the residential commercial market includes a large distribution charge and retail margin, which insulates the consumer from changes in the wholesale price. The resulting low price elasticity leads to a larger mark-up under oligopolistic competition but, as shown in Figure 3.8, it also means that demand is not greatly affected by the wholesale price mark-ups.

Figure 3.7: Gas prices in the South



Source: Department of Industry, Innovation and Science (2015)

Figure 3.8: Gas demand in the South



Source: Department of Industry, Innovation and Science (2015)

Oligopolistic competition in the North

Figure 3.9 and Figure 3.10 show the impact of limited competition in the northern market on gas prices and gas demand. This market is dominated by production from the CSG fields of the Surat and Bowen basins, and to a lesser extent from the Cooper Basin. The demand in Queensland is based mainly on industrial consumers and GPG.[34]

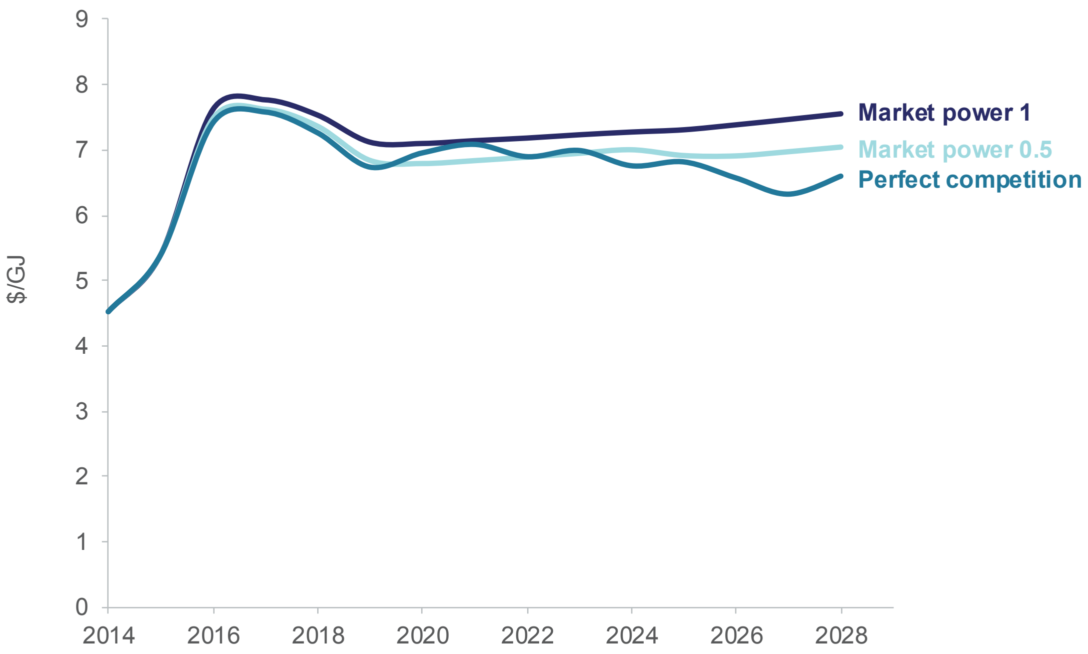
The results show that oligopolistic competition has less impact on gas prices in the North than in the South. However, prices are still relatively high overall. This is related to the fact that production is highly constrained, as the optimal level of production is higher than the physical capacity of the production facilities. Even in the case of perfect competition, the presence of production constraints can cause prices to significantly exceed marginal costs, leading to congestion rents (as discussed in Appendix A.7).

The scope to exercise market power in the North is not as strong as in the South, which is most likely related to the fact that there are many more competing suppliers, and also because the market is more price sensitive. Both of these factors mitigate market power in an oligopoly.

These results are based on an intermediate level of LNG production. As discussed earlier, LNG production is likely to be volatile. For a given level of installed gas production capacity, we would expect that if LNG demand is higher, then production constraints (the lack of sufficient production) would dominate, leading to higher prices. If LNG demand falls, then we would expect a relaxation of the production constraints, and lower prices.

[34] Modelled at an LNG spot price of $10/GJ.

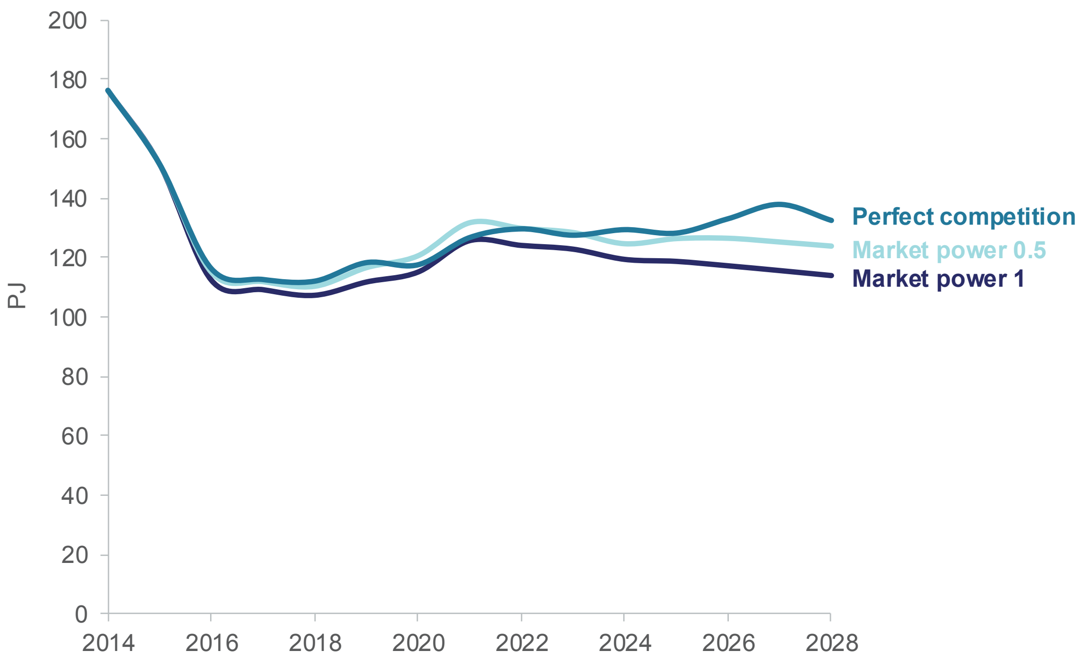
Figure 3.9: Gas prices in the North



Source: Department of Industry, Innovation and Science (2015)

These results suggest that an increase in production capacity would lead to a more competitive market in the North. However, for production capacity to increase, the producers would require strong incentives to make the required investments. It is difficult for a producer to make these investments when the future demand is uncertain and potentially volatile.

Figure 3.10: Gas demand in the North



Source: Department of Industry, Innovation and Science (2015)

In summary, the market prices in the North appear to be dominated by the potential shortfalls in production capacity. Prices are higher when LNG demand is higher than average, since this will place pressure on the available production capacity. The effect of oligopolistic competition appears to be less important than the impact of production constraints.

3.5 Case study – impact of Northern Territory supply

Background

The Northern Territory Government has undertaken a competitive process seeking commercial proposals to construct a North East Gas Interconnector (NEGI) from the Northern Territory to the east coast of Australia. The successful proposal is a 622 km, $800 million pipeline from Tennant Creek on the Amadeus Darwin Pipeline to Mount Isa in Queensland, where it connects to the east coast via the Carpentaria Gas Pipeline.

The NEGI is expected to assist in relieving the tight supply situation in the eastern Australian gas market, to increase competition in the market, and to stimulate new gas exploration and production in the Northern Territory. There is about 25-35 PJ a year of contracted but unused gas supply from ENI's contract with the Northern Territory Government's Power and Water Corporation that will be shipped on the NEGI. While it is understood that there are some other smaller additional volumes from proven reserves that could be shipped on the NEGI, greater volumes that would more fully utilise NEGI's planned capacity will require expanded exploration and development of the potentially large onshore gas resources in the Northern Territory, particularly the shale gas resources.

At the present time there are too many uncertainties about the proposal to conduct a proper evaluation. These uncertainties include the profile of volume growth over time, the price of the gas delivered to Mount Isa or beyond, and the tariffs that will be charged for backhaul down the Carpentaria pipeline. In addition, other pipelines may require expansion in order to accommodate the changed flows. Therefore a range of assumptions have been made to define a case study.

Gas Market Model assumptions

Preliminary evaluation shows that volumes of 25-35 PJ a year are not sufficient to make a material difference to the overall supply/demand dynamic (being only 5-6 per cent of the total domestic market). Therefore it is assumed that volumes will expand over time as new gas supplies are developed in the Northern Territory. It is also assumed that additional production is forthcoming from the Surat and Bowen basins, as this is a potential source of competition for the NEGI. This additional production could come from the Arrow reserves, or from other Queensland reserves not currently dedicated to the LNG producers.

The following assumptions are made to define the case study:

- new production at Wallumbilla is 25 PJ a year from 2018, growing to 55 PJ a year by 2024
- Gloucester is assumed to produce 25 PJ a year from 2019
- Northern Territory supply starts in 2019 at 25 PJ a year, growing to 50 PJ a year by 2024, and increasing to 100 PJ a year from 2025 (the Carpentaria Pipeline will require additional capacity after deliveries at Mount Isa exceed about 70-80 PJ a year).
- two scenarios are explored for the cost of gas delivered to Mount Isa:
- the Carpentaria Pipeline back-haul tariff is discounted to $0.30/GJ to encourage flows from the Northern Territory
- the Moomba to Adelaide pipeline is expanded to 90 PJ a year (load-factor adjusted) from 2025 to accommodate greater flows into Adelaide and on to Victoria, as Victorian reserves deplete
- LNG demand at Gladstone is at the higher end of the range to test the impact on NEGI flows.

Gas Market Model results

The results are strongly dependent on the assumptions regarding other supply sources, and the cost of competitive supplies at other nodes. However, the main factor affecting market outcomes is the cost of the gas delivered from the Northern Territory to Mount Isa. The following supply scenarios have been modelled:

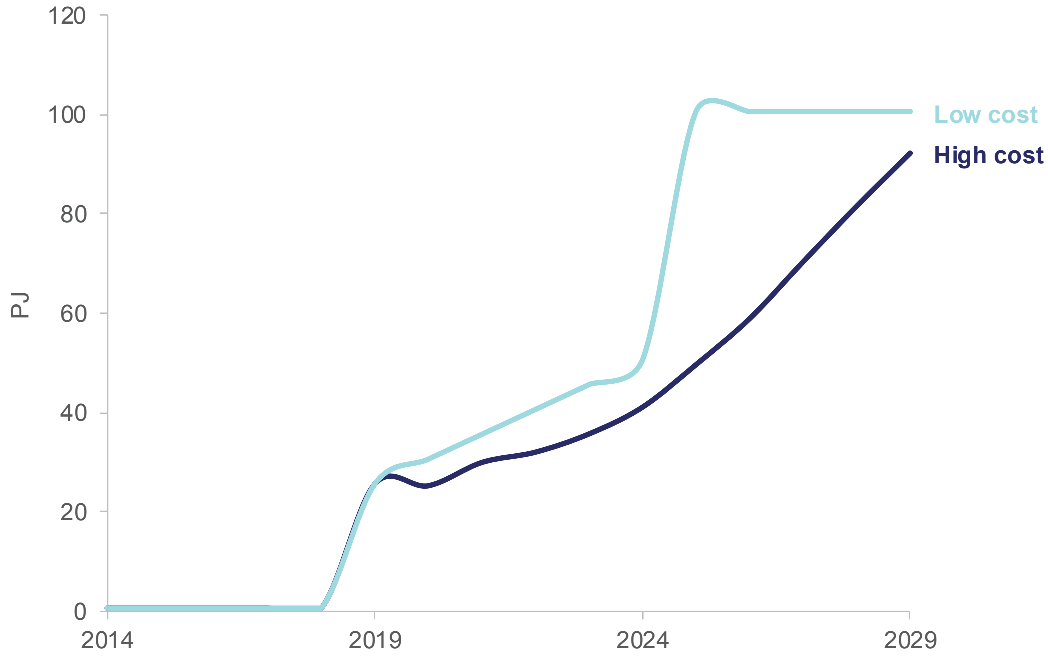
	Supply assumptions
Scenario 1	Comparison base case — No Northern Territory supply
Scenario 2	Low cost scenario — Northern Territory gas at Moomba matches Moomba cost
Scenario 3	High cost scenario — Northern Territory gas $1.00/GJ higher than Moomba cost

Note that these scenarios refer to the cost of gas supply. The price negotiated by customers is likely to be significantly higher than cost.

In summary, the modelling shows the following results:

- The profit-maximising level of supply at Mount Isa depends strongly on the delivered cost of Northern Territory gas. Figure 3.11 shows the production levels for each of the three scenarios.
- Delivered prices are only marginally lower in both Queensland and the South.
- Flows from Moomba or Ballera to Wallumbilla are only marginally higher under both NEGI supply scenarios.
- Flows from Moomba to Adelaide are higher as a result of the NEGI (as shown in Figure 3.12), and some gas is carried to Victoria, associated with a reduction in Gippsland basin production.
- Whilst the Northern Territory increases the overall level of supply, the model shows that the Cooper Basin reduces production by up to 40 PJ a year when faced with competitive supplies from the Northern Territory. Figure 3.13 shows the combined production from the Cooper Basin and Mount Isa.

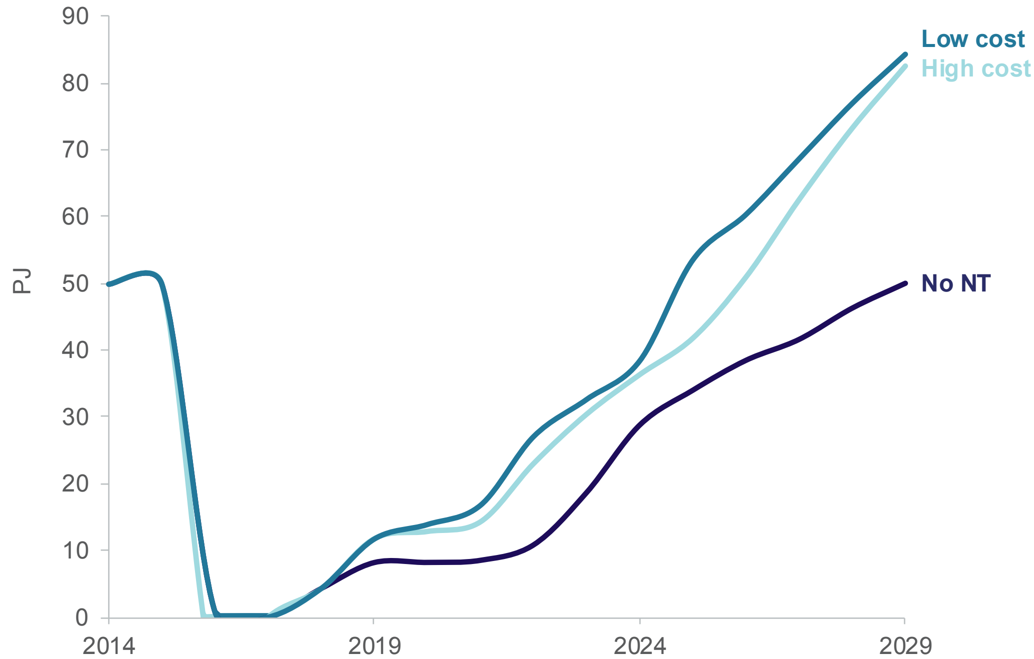
Figure 3.11: Production levels at Mount Isa



Notes: Lost cost production matches assumed maximum production at Mount Isa

Source: Department of Industry, Innovation and Science (2015)

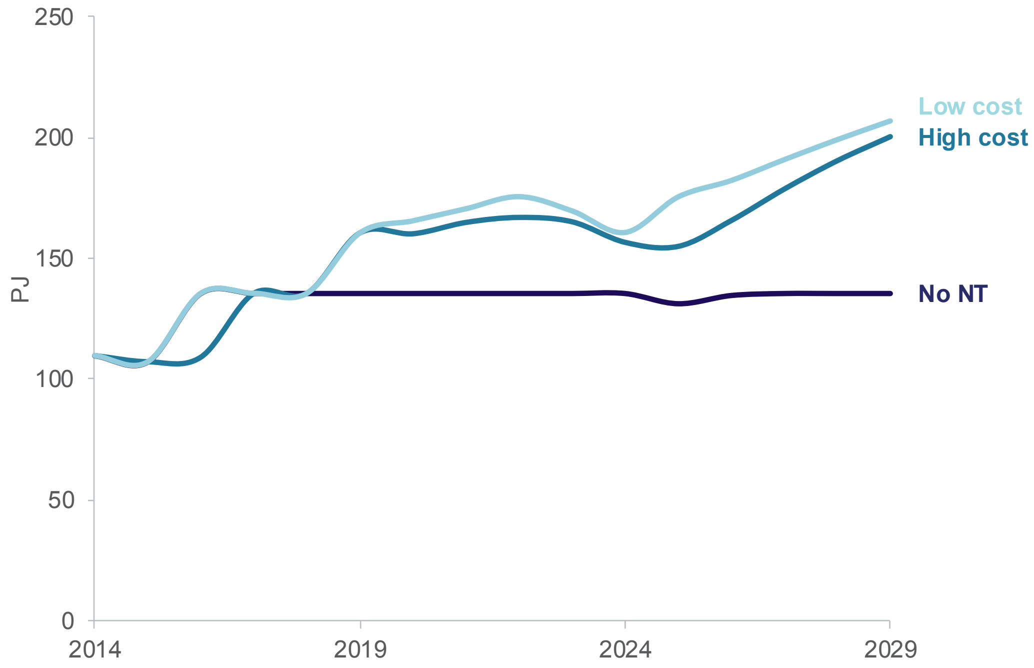
Figure 3.12: Pipeline flows Moomba to Adelaide



Notes: Results exclude contracted flows after 2015

Source: Department of Industry, Innovation and Science (2015)

Figure 3.13: Combined output Moomba and Mount Isa



Source: Department of Industry, Innovation and Science (2015)

Northern Territory supply conclusions

The modelling results show that additional supply from the Northern Territory could help to support domestic demand. However the benefits of this supply depend strongly on the competitiveness of this gas supply compared to Cooper Basin supply costs and the costs of new production in Queensland.

The most surprising result is that the addition of new supply could cause competing producers to reduce production. This is likely to be a result of the profit-maximising behaviour of the individual producers in a situation where there is limited competition. This suggests that market power is potentially an issue even in the face of new supply.

It should be borne in mind that the model assumes that production by the LNG producers can be maintained at forecast levels, and that the production costs do not escalate significantly over the next 15 years. If either of these assumptions is incorrect, then the demand for new gas supplies in Queensland to back-fill the LNG demand will benefit greatly from new sources of supply such as the Northern Territory. However the new supplies will have to be price competitive in order to satisfy this potential demand.

Oil and gas plant at night

CHAPTER 4

Global LNG market outlook

This chapter provides an overview of the global LNG market and the long-term outlook. It places LNG trade within the context of overall natural gas consumption and production patterns, and then considers the changing dynamics within the LNG market. These dynamics include the increasing diversification of LNG supply (which is explored further in Chapter 5), the rise and fall of LNG prices, and the growing importance of short and medium term LNG trades. It presents outlooks for LNG markets out to 2020 and 2030, noting that longer term projections are by their nature indicative.

The global LNG demand outlook to 2020 is projected to grow strongly, although the outlook to 2030 is less certain. The current market environment, which is characterised by excess capacity and low LNG prices, is likely to continue into the medium term. LNG demand is driven by growth in Asia and a strong recovery in Europe, but it will become increasingly fragmented. Aggregate demand in the traditional markets of Japan and South Korea is expected to plateau, whilst China and India, together with many smaller buyers such as Indonesia, Malaysia, Pakistan and Singapore, will become increasingly important markets for further expansion of the LNG trade. The fragmentation and diversification of the market is being supported by the increasing use of floating storage and regasification units (FSRUs) which currently supply almost 40 per cent of the LNG importing markets.

As the number of importing countries increases, the market will become less predictable, and sellers will be operating in a more challenging environment. This is compounded by the fact that many of the new importing countries have access to alternative sources of gas supply, such as indigenous production or pipeline imports. This is likely to accelerate the volume of LNG traded in the spot and short term markets, but it will also make it more difficult to underwrite new LNG supply projects. The fragmentation in the market will be exacerbated by growing uncertainties around future global environmental and energy policies.

4.1 Natural gas and LNG

Natural gas is becoming an increasingly important global energy source. Consumption grew at an average rate of 2.6 per cent a year between 2000 and 2014, and natural gas currently makes up around a quarter of the global energy mix.

Table 4.1 presents a snapshot of the role of natural gas in Australia compared to the top three natural gas producing, consuming, importing and exporting countries in the world. Across these countries in 2013, the share of natural gas in the energy mix varied significantly, even within countries with large natural gas reserves.

Russia and the US are the top two producers and the top two consumers of natural gas in the world, but the majority of indigenous production is consumed domestically. Russia exports only around 30 per cent of its natural gas production, but is nevertheless the largest exporter in the world.

Qatar and Norway are the second and third largest exporters respectively. In these countries, natural gas production is oriented to exports. Over 80 per cent of Qatar's natural gas is exported; more than triple its level of consumption. In Norway exports make up 95 per cent of its natural gas production in 2013 — over 18 times the quantity of gas consumed.

Table 4.1: Natural gas statistics for key countries, 2013

	TPE	*Consumption*			*Production*			*Exports*		
Net exporters	*Mtoe*	*Mtoe*	*Share (per cent)*	*Rank*	*Mtoe*	*Share (per cent)*	*Rank*	*Mtoe*	*Share (per cent)*	*Rank*
Russia	731	395	54	2	548	139	2	174	32	1
Qatar	40	39	98	18	131	333	3	106	81	2
Norway	33	5	15	55	92	1,840	7	87	95	3
Australia	129	30	23	27	49	166	14	28	57	11
Net importers										
Japan	455	106	23	5	2	2	55	104	98	1
Germany	318	73	23	7	10	13	39	82	112	2
United States	2,188	610	28	1	551	90	1	67	11	3
China	3,036	142	5	3	97	68	6	44	31	6

Notes: TPE is total primary energy. Consumption share is percentage of TPE, production share is percentage of consumption, export share is percentage of production, and import share is percentage of consumption.

Source: IEA data (2015)

In China, natural gas plays only a small role in the energy mix, providing just 5 per cent of its total primary energy requirements. Despite this fact, China is still the sixth largest producer, the third largest gas consumer, and the sixth largest importer of natural gas in the world, demonstrating the magnitude of its overall energy needs.

Japan, the world's largest natural gas importer, obtains all of its import requirements via LNG, and currently around 20 per cent is sourced from Australia. Australia was the third largest LNG exporter in the world in 2014, and the 14th largest gas producer globally.

The majority (70 per cent) of global gas demand is currently supplied by indigenous production. Of the gas which is traded between countries, around two thirds is carried through pipelines, which can be relatively cost effective even over long distances, and the rest (10 per cent of global demand) is supplied through LNG imports.[35] Figure 4.1 shows the global balance of production and consumption of natural gas and the sources and destination of pipeline and LNG trades.

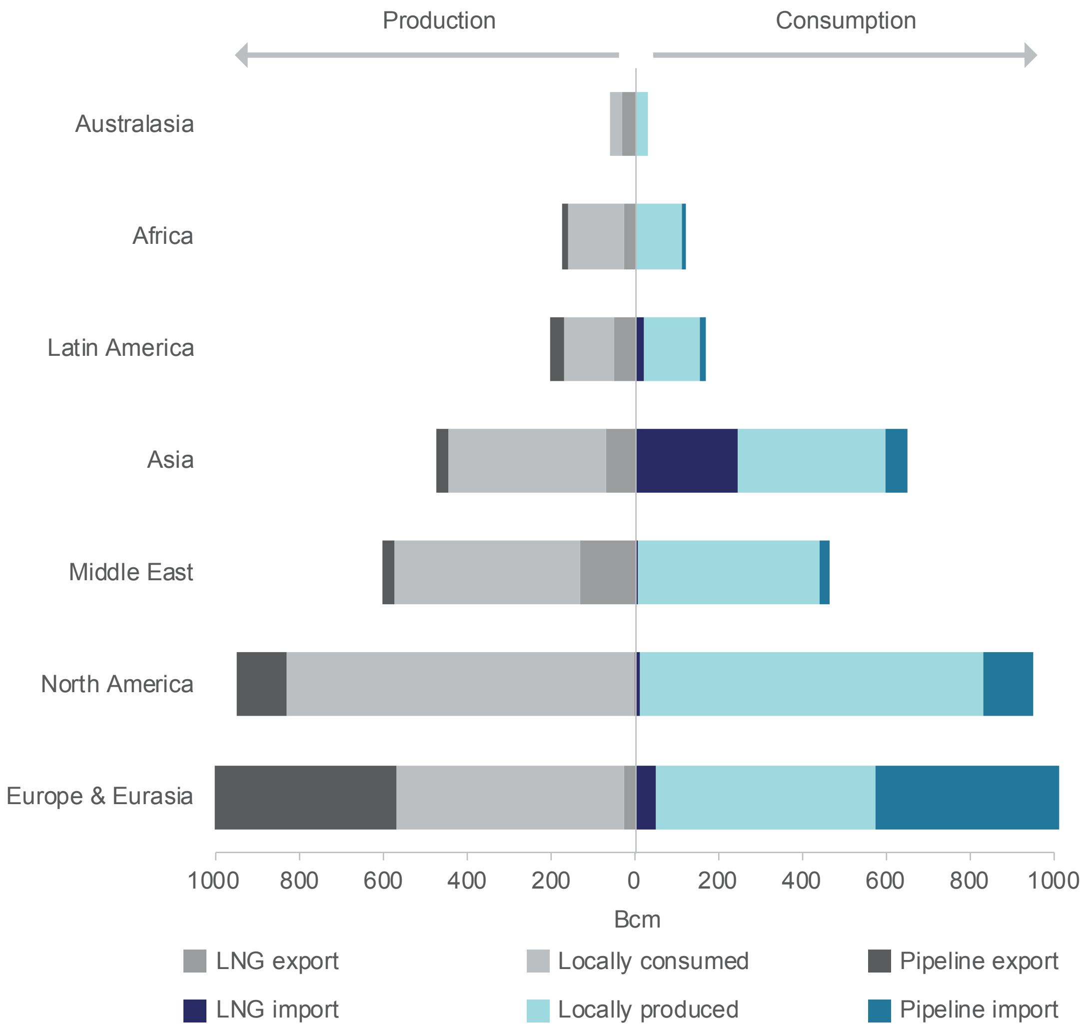
LNG requires complex and capital intensive infrastructure in both source and destination

[35] International Gas Union (2015) IGU World LNG Report

countries, covering the functions of liquefaction, storage, regasification and shipping. Because of these high costs, LNG supply has traditionally been the preserve of countries with no indigenous gas resources or access to commercially viable pipeline supply. On the supply side, LNG trade has been one of the principal options available to monetise otherwise stranded gas reserves.

Nevertheless, global LNG trade has been growing faster than both indigenous production and pipeline supply, at an annual rate of six per cent since 2000. This growth in market share is expected to continue at least until 2020. Furthermore, the liquidity of the LNG market has increased substantially in recent years, reflected in strong growth in both LNG contracted volumes and spot trades, and facilitated by growing numbers of importers and exporters and their greater geographical spread.

Figure 4.1: Natural gas: global production and consumption in 2014



Source: BP (2015), Statistical Review of World Energy; Department of Industry, Innovation and Science (2015)

The next section will examine how the global LNG market has evolved over time, with a focus on its changing dynamics, and covering trends in supply and demand, global LNG prices and spot trading.

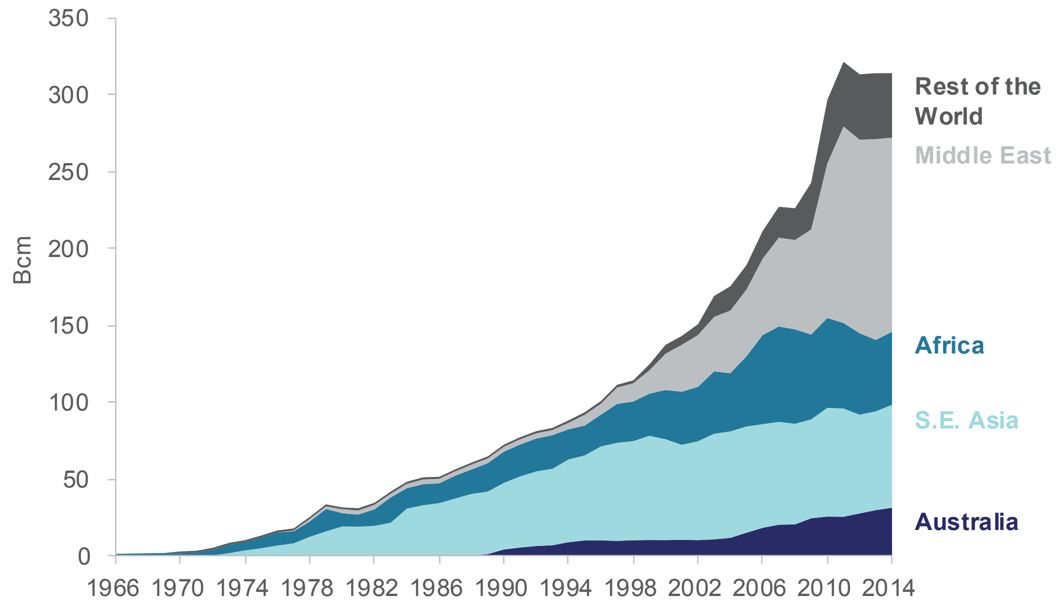
4.2 The changing dynamics of the LNG market

Global LNG trade expanded rapidly between 1964 and 2011, increasing at an annual rate of 18.5 per cent a year. Growth declined marginally from 2011 to 2014, associated with a decline in European gas demand as coal imports displaced gas, and with a tight supply market. This tight market was the result of a number of LNG plant failures in Africa and a domestic gas reservation policy in Egypt, and was exacerbated by the peak in Japanese demand following the Fukushima disaster. The market has only recently eased with the commencement of a number of new LNG projects, including in Australia and Papua New Guinea.

Increasingly diversified global LNG trade to 2014

The LNG industry has become increasingly globalised over the past fifty years. The majority of global LNG was traditionally supplied by South East Asia (Brunei, Indonesia and Malaysia) and Africa (mainly Algeria, Nigeria and Egypt). However, the Middle East became the principal supplier around 2010, after a rapid expansion in Qatari liquefaction capacity. Qatar, currently the world's largest LNG exporter, supplied around one third of global LNG trade volumes (77 Mtpa) in 2014.[36] Australia's LNG supply has grown since exports commenced from the North West Shelf project in 1989, and by 2014 supplied around 10 per cent of global LNG imports. The growth and diversification of LNG supply is shown in Figure 4.2.

Figure 4.2: Global LNG production 1966 to 2014

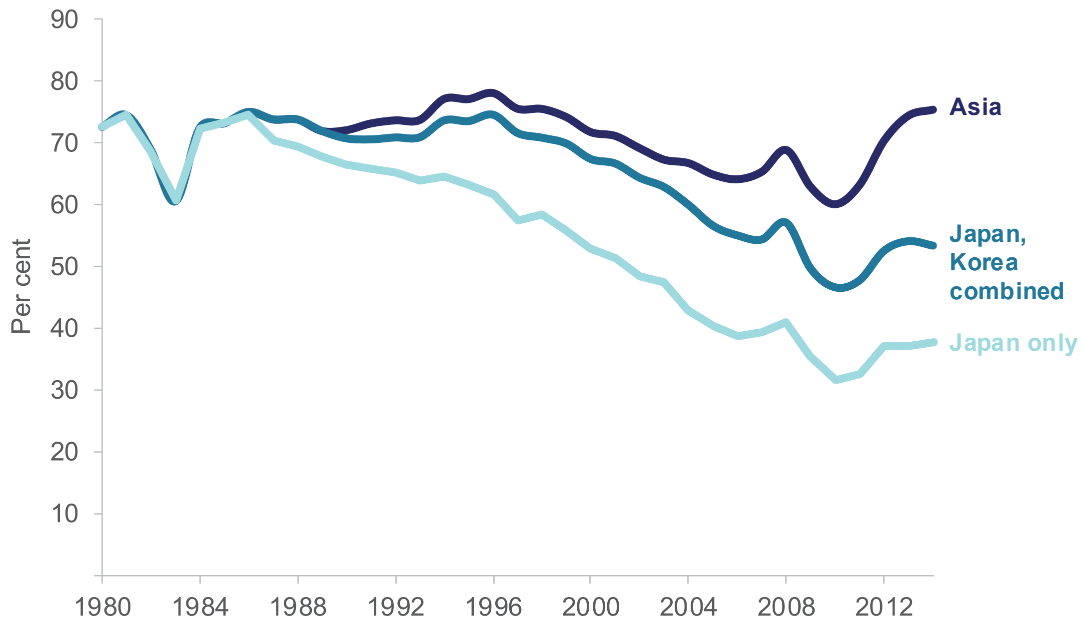


Source: Petroleum Economist (2015) LNG data master; Department of Industry, Innovation and Science (2015)

Asia has been the primary destination of LNG supply since the late 1970s, with Japan and South Korea alone absorbing approximately 70 per cent of global production between 1980 and 2000, as shown in Figure 4.3. The strong growth in LNG demand in these countries arose mainly from substantial increases in the share of gas in the total energy supply mix, and a lack of alternative sources of gas supply, such as indigenous production or pipeline imports.

[36] International Gas Union (2015) IGU World LNG Report

Figure 4.3: Asian share of global LNG consumption 1980 to 2014



Source: Petroleum Economist (2015) LNG data master; Department of Industry, Innovation and Science (2015)

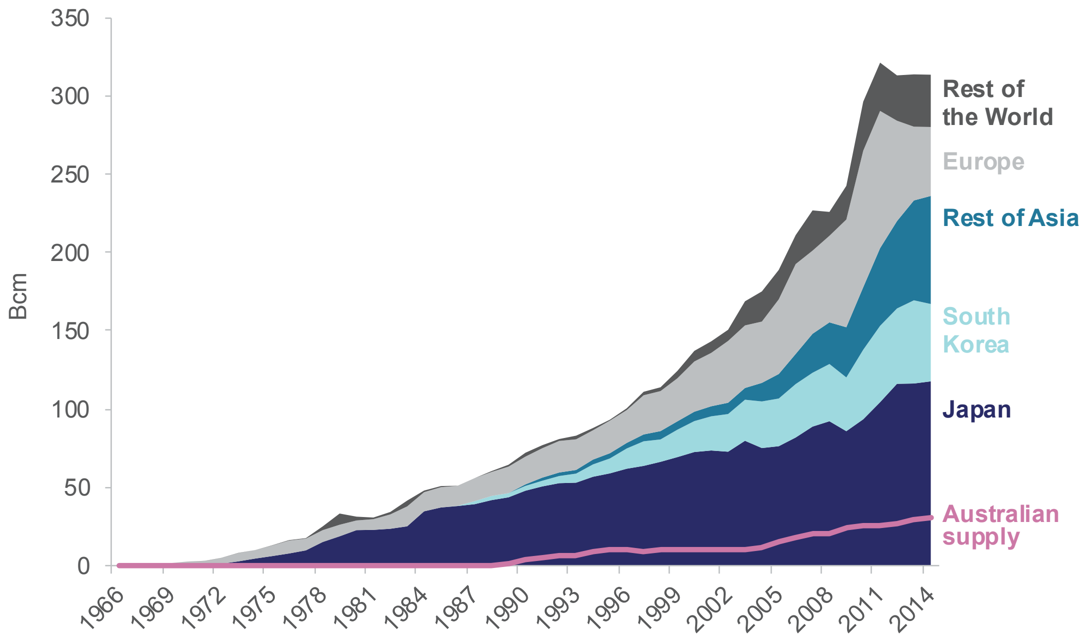
Since 2000, the share of global LNG demand going to Japan and South Korea has fallen to 50 per cent, as demand has grown strongly in the rest of Asia. A rapid increase in Chinese LNG demand from just 1 bcm in 1996 to 26.4 bcm by 2014 is the key driver for the substantial growth in the rest of Asia over this period, and has held Asia's share of global LNG consumption at around 70 per cent.

The other main destination for LNG supply has been Europe, as shown in Figure 4.4. There was steady growth in demand until 2011, mainly in the UK, Spain and France, despite the fact that Europe has access to substantial indigenous production and pipeline imports. However, since 2011 LNG imports have declined significantly as a result of weak economic conditions, tight supply and intense competition from price-competitive substitutes, such as coal and renewables.

The rapid growth of LNG imports has been associated with substantial growth in the numbers of importing and exporting countries, which have grown from 17 in 1990 to 48 in 2014, as shown in Table 4.2. In 2014, four countries became LNG importers (Israel, Lithuania, Malaysia and Singapore), and four more countries (Jordan, Egypt, Pakistan and Poland) commenced imports in 2015.[37]

[37] International Gas Union (2015) IGU World LNG Report

Figure 4.4: Global LNG demand 1966 to 2014



Source: Petroleum Economist (2015) LNG data master; Department of Industry, Innovation and Science (2015)

The growth in the number of LNG importing nations is being facilitated by the expansion of FSRUs which allow small volumes of LNG to be received economically in less mature import markets. Floating terminals provide import capacity in 11 importing nations, and this number will grow to 13 when Uruguay and Columbia commence import with FSRU terminals from 2016. The greater number of importers and exporters increases not only LNG penetration and globalisation, but also the liquidity and flexibility of the LNG market.

Table 4.2: LNG importers and exporters in 1990, 2000 and 2014

	1990	*2000*	*2014*
LNG importers	9	13	29
LNG exporters	8	12	19

Source: Petroleum Economist (2015), LNG data master

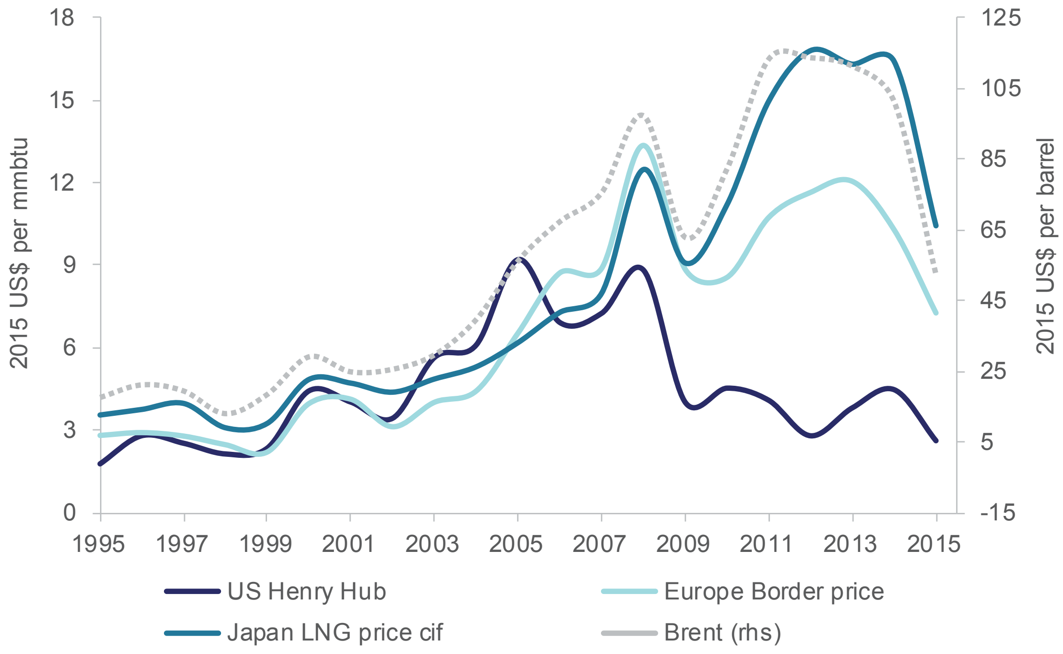
Rise and fall of global LNG prices

LNG markets have traditionally been based on long-term contracts, which mitigate the significant capital investment risks involved in constructing liquefaction and regasification facilities. This has led to both a lack of liquidity in LNG markets and the need for a pricing reference in contracts to lock in capital. Oil-linked contracting has been and remains the primary form of LNG contract pricing, given the role of oil as an international benchmark and as a substitute for gas. This contrasts with the use of hub-based pricing in US and European natural gas markets. Hub based pricing can emerge when a market is sufficiently liquid to allow price discovery, such as at the Henry Hub in the US or the UK's National Balancing Point (NBP).

There was a growing divergence in gas prices between Europe, the US and Asia between 2009 and 2014, as shown in Figure 4.5. Japanese LNG prices continued to track oil prices and became significantly higher than hub-based natural gas prices in Europe, resulting in the 'Asian premium' of around (US)$4 to $6 per MMBtu. The Asian premium was driven primarily by high oil prices, but it was exacerbated by the very high LNG demand growth in Japan, following from the Fukushima disaster, and strong LNG demand growth in China, associated with rapid economic growth.

European gas prices diverged substantially from oil prices during this period. Weaker gas demand in Europe since 2011, resulting from intense competition from coal and renewable energy and stagnant economic conditions, contributed to these significantly lower European gas prices.

Figure 4.5: Global natural gas prices, benchmarked against oil price (2015US$) 1995 to 2015



Source: World Bank (2016) Commodity price data; Department of Industry, Innovation and Science (2015)

In a similar way, US natural gas prices also diverged markedly from international oil-linked prices. The high prices prior to 2009 stimulated greater investment in exploration and production. This, in combination with the 'shale gas revolution', led to a substantial increase in gas production and a decline in gas prices, to such an extent that the US will shortly transition from a net gas importer to a net gas exporter.

One response to the Asian price premium was growing support for Henry Hub-linked pricing in LNG contracts to Asia in association with the new US export projects coming online from 2016. Whilst oil-linked pricing can be very volatile, the alternative of Henry Hub pricing can also be equally volatile, and it has the disadvantage that an Asian customer's LNG imports become linked to the supply and demand dynamics in a region unrelated to the market in which they operate.

However, since late 2014, LNG contract prices have fallen significantly in line with the fall in oil prices. This has led to a convergence of Asian LNG prices with the regional hub-based natural gas prices in the Atlantic and Pacific basins. At the same time, spot prices have also declined, as new LNG supply capacity has come online to relieve the previous tight market conditions.

At current oil prices, there is no significant advantage to Henry Hub-linked prices over oil-linked pricing. For the foreseeable future, oil-linked pricing is expected to remain the standard paradigm in LNG contracts in Asia.

In response to the volatility in LNG contract prices into Asia, there has been growing interest in a regional pricing hub in Asia. There are suggestions for a pricing hub at Singapore or Shanghai, but as yet there is no firm candidate. A regional hub would set prices based on the dynamics of regional supply and demand, but it requires a deep, liquid market before users can be confident executing contracts around regional hub prices.

The IEA has set out a range of institutional and structural requirements for a viable trading hub, and for a competitive regional natural gas market. These requirements include expanded shipping availability, third-party access to regasification facilities and a relaxation of destination clauses in contracts.[38] However, despite the strong growth in the spot market since 2010, there is no consensus that hub-based pricing will replace the traditional pricing models in the near future.

Rapid growth of spot trading

LNG trades have historically been based on long-term bilateral contracts between buyers and sellers with strict source-destination clauses. This is, to a large extent, a consequence of the capital intensive nature of LNG trade, which requires the long-term security of a reliable revenue stream in order to underwrite the necessary investments.

There is a growing desire for more flexible contracting arrangements, and the global LNG trading environment has become increasingly more complex. The growing flexibility in long term LNG contracts over the past decade is illustrated by the relaxation of destination clauses in contracts, an increase in the use of FOB sales contracts rather than DES, and less onerous take or pay commitments. Both buyers and sellers are seeking more options for pricing, which until recently has been dominated by oil-linked pricing. These options include linkages to hub-based prices, such as the Henry Hub in Louisiana, and hybrids involving a mix of indexes including power generation prices.

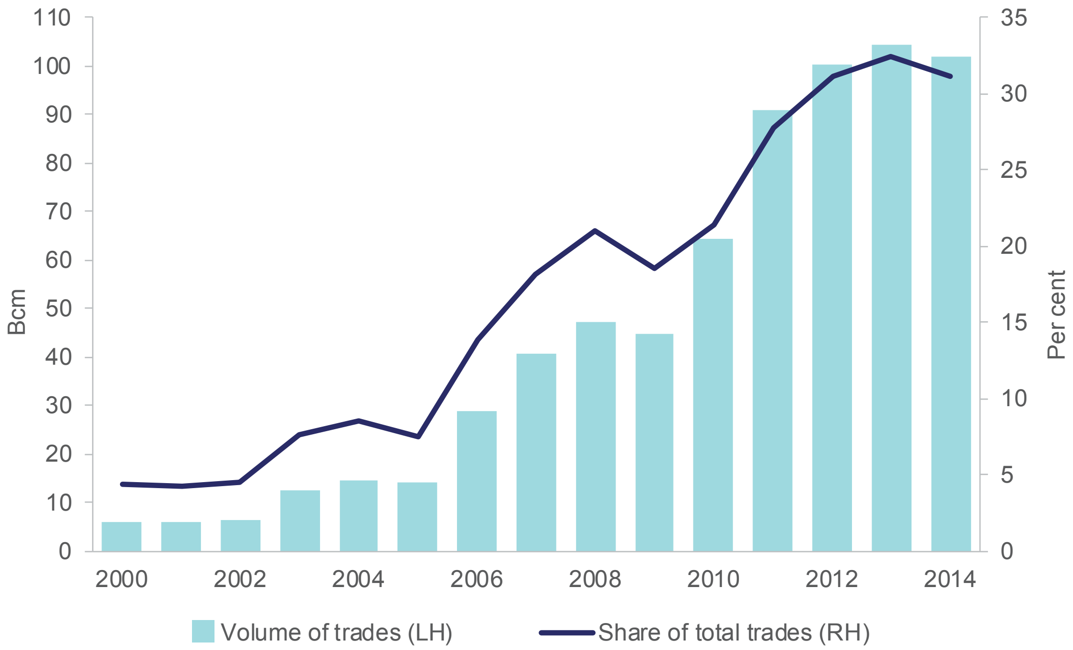
The need for more flexible supply arrangements between buyers and sellers is also demonstrated by the growing importance of reloads, which have expanded rapidly since 2000 to reach 6.6 Mtpa in 2014. Reloads have helped to manage the growing volatility in the LNG trade, as shown for example by the fall in European imports since 2011 and the rapidly growing demand in Asia.

[38] IEA (2013) Developing a natural gas trading hub in Asia

These trends have coincided with an increase in shorter term LNG trades. In 2000, 95 per cent of global LNG trades were transacted on long-term contracts, but this share declined to around 70 per cent by 2014. The shorter term LNG trades can be classified into the following two groups:

- The spot and short term market, where LNG is contracted for periods of two years or less. This market has grown at 22.3 per cent a year from around 4.5 Mtpa in 2000 to 65 Mtpa by 2014. Spot and short term trades currently constitute around 85 per cent of all shorter term trades.
- The medium-term market, where LNG is contracted for periods of two to five years. Medium-term trade volumes have grown over the last decade to around 10 Mtpa by 2014, from under 1 Mtpa in 2000.

Figure 4.6: Shorter term LNG trades 2000 to 2014



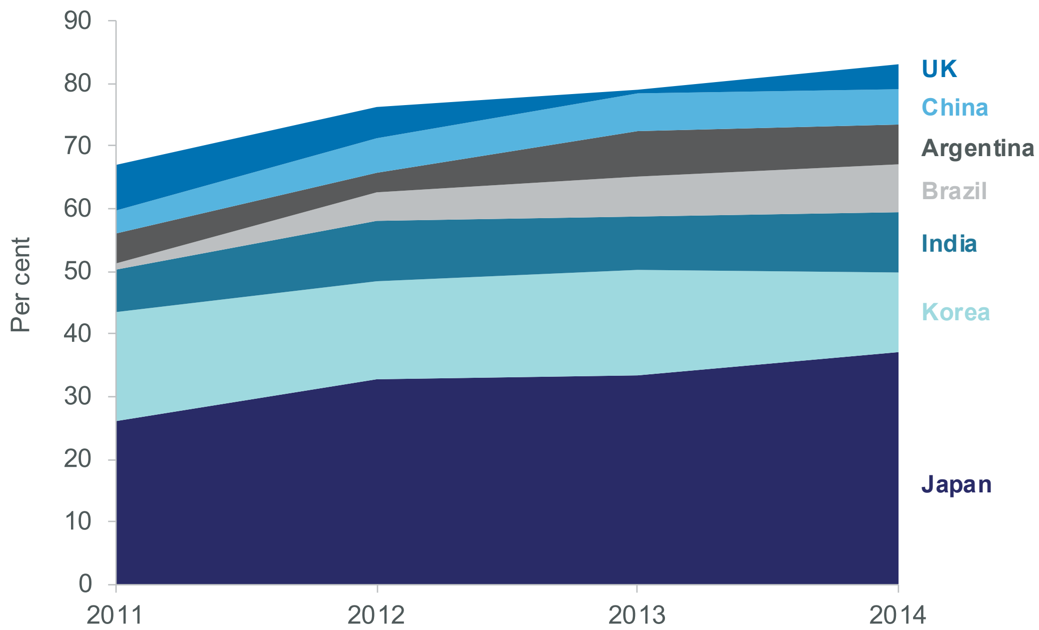
Notes: Includes spot and short term trades (contracted for two years or less) and medium term trades (two up to five years).

Source: International Gas Union (2015), World LNG Report; Petroleum Economist (2015), LNG data master

The main suppliers of shorter term trades were Qatar, Nigeria, Trinidad and Tobago, and Indonesia. These four countries collectively supplied around two thirds of total short and medium term trades in 2014, while Qatar, currently the world's largest supplier, provided approximately 35 per cent of total trades.

Japan and South Korea were the key buyers of short term trades, and made up nearly 50 per cent of this market in 2014 (37 per cent for Japan and 13 per cent for South Korea). India, Brazil, Argentina and China collectively accounted for an additional 30 per cent in 2014. The smaller importers of Argentina, Brazil and India have sourced a large part of their LNG imports through short and medium term trades, but the major LNG importing countries Japan, South Korea and China still source the majority of their imports from long term contracts.

Figure 4.7: Top buyers of shorter term LNG trades 2011 to 2014



Source: GIIGNL (2015) The LNG Industry in 2014

Consistent with recent analysis by the International Gas Union,[39] the main drivers of the growth in spot trading have been:

- the expiration of long-term contracts as the LNG liquefaction plants have aged, increasing the volume of uncontracted gas available on the market
- unexpected swings in demand, such as the post-Fukushima surge in Japan from 2011
- the rapid fall in demand into Europe, which freed up volumes for other destinations
- the opportunity to arbitrage between prices in the Atlantic and Pacific basins, which until recently showed a wide divergence.

Qatar is well located to benefit from trade to both the Atlantic and Pacific basin LNG markets and may become a driver of the increasing integration of these markets. When exports commence from the US in 2016 there will be further alignment of these markets, as the US can export to Europe or to Asia via the newly widened Panama Canal.

[39] International Gas Union (2015) World LNG report

In addition to these drivers, the growth of spot trades has been facilitated by a range of other developments occurring simultaneously in LNG markets:

- An increasingly globalised LNG trade environment, reflected in the large increase in the number of trading countries, and growing overall demand, with the consequence that a growing web of interconnections is being created between buyers and sellers.
- The growth of portfolio players such as BG and Petronas, who own a number of LNG facilities across the globe, and who can use spot trading to better manage supply and demand fluctuations.
- The growth of the LNG shipping fleet to 373 carriers by 2014, which has created more opportunities for tendering spot sales over longer distances such as the trade from the Atlantic to Asia.

4.3 Outlook to 2020

The projections for the medium term outlook to 2020 and the long term outlook to 2030 have been derived from the Nexant World Gas Model (WGM), adjusted in line with assumptions by the Office of the Chief Economist where relevant. The model calculates the mix of indigenous production, pipeline imports and LNG imports that minimises the cost of supply to each country, taking into account existing LNG and pipeline contracts.

In contrast to the very tight market conditions over the past four years, it is expected that there will be excess supply capacity in the global LNG market until at least 2020. This is a result of the completion of a number of new liquefaction and regasification plants currently under construction, which outweighs strong LNG demand growth.

Growth in production and continuing overcapacity

LNG supply capacity is expected to grow rapidly over the next five years to 2020, with global LNG liquefaction capacity expected to reach around 550 bcm (400 Mtpa) by 2020, an increase of 64 per cent from 2014 (see Figure 4.8). Approximately 230 bcm (170 Mtpa) of new capacity will be introduced into the global LNG market between 2014 and 2020, with the bulk of that from Australia and the US.[40]

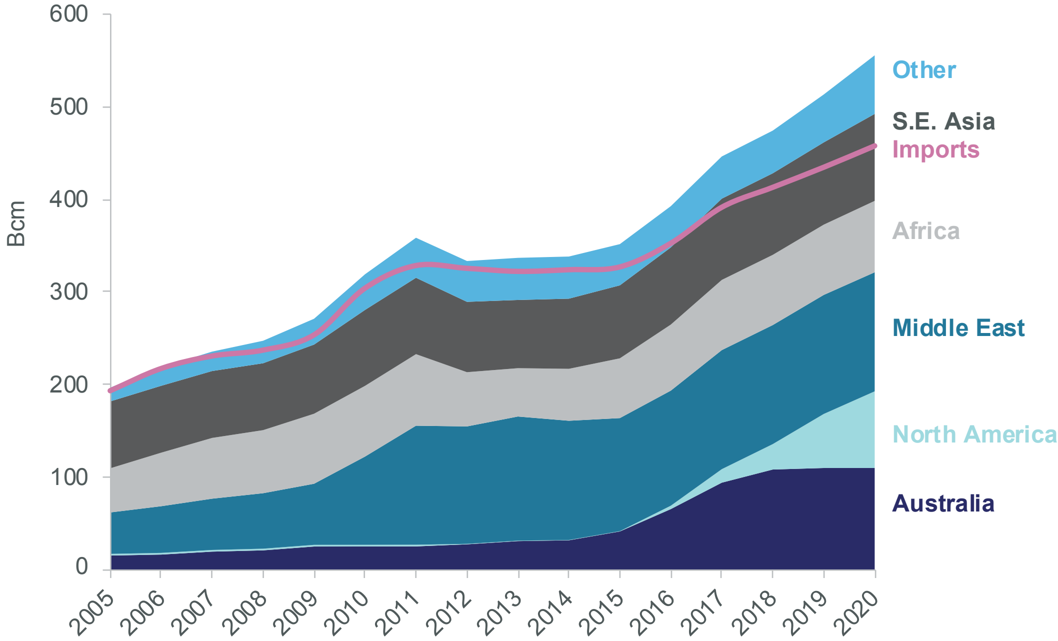
In Australia, there are seven liquefaction plants which have either recently started exporting or are currently under construction, providing a total capacity of 62.3 Mt:

- APLNG, GLNG, and QCLNG in Queensland, with a total combined capacity of 25.3 Mt
- the Gorgon, Prelude Floating LNG, and Wheatstone projects in the west, with a total combined capacity of 28.1 Mt
- the Ichthys project in the Northern Territory, with a total capacity of 8.9 Mt.

By 2019-20, Australia is expected to become the world's largest LNG exporter.

[40] Department of Industry, Innovation and Science (2015) Resources and Energy Quarterly, September Quarter 2015

Figure 4.8: Global LNG supply capacity by country 2005 to 2020



Notes: Nameplate supply capacity less allowances for plant downtime and maintenance

Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

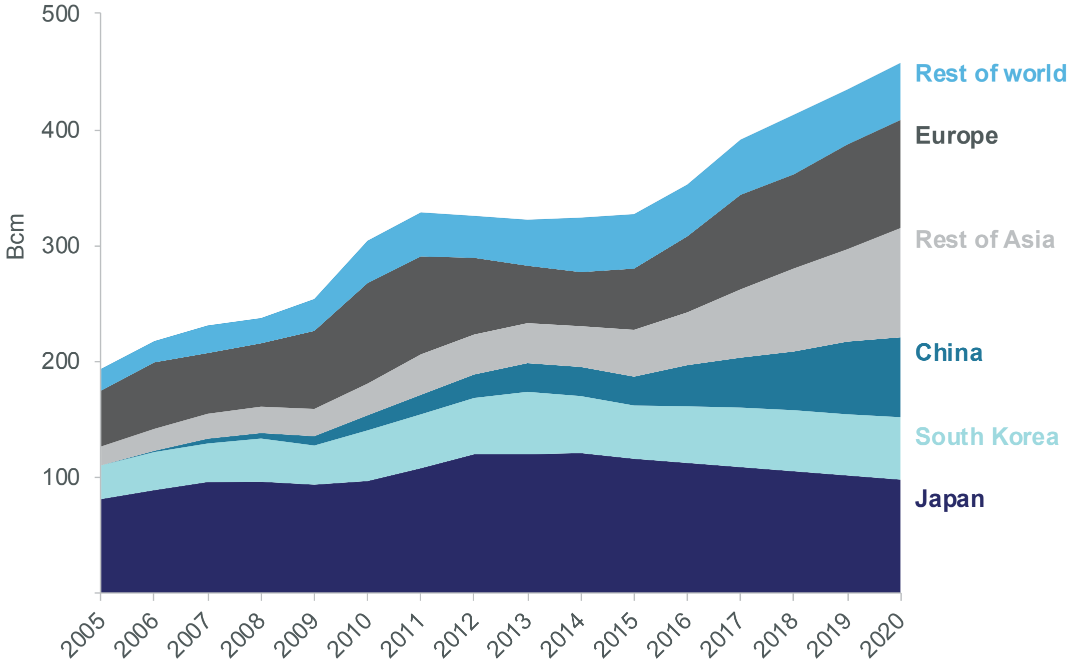
Similarly, there are five liquefaction plants under construction in the US which will be completed before 2020, with a total capacity of 62.7 Mt. They include Sabine Pass (22.5 Mt), Cove Point (5.3 Mt), Cameron (12 Mt), Freeport (13.9 Mt), and Corpus Christi (9.0 Mt). There are plans to add additional trains to these project with a capacity of 9.0 Mt, and prospects for even greater capacity to be constructed in the US.

Demand growth led by China, the rest of Asia and Europe

Global LNG demand is expected to grow strongly to 2020 to approximately 457 bcm (336 Mt), an annual increase of 5.9 per cent from 2014, as shown in Figure 4.9. This growth is led by China, the rest of Asia and Europe, offset by falling demand in Japan. Demand growth has softened recently but the prospects remain positive overall.

Demand in Japan has reached its peak and is expected to decline over the medium term, due to the restart of nuclear power plants and strong competition from alternative energy sources in electricity generation. Nevertheless, Japan is still expected to remain the largest single importer of LNG, accounting for over 20 per cent of global LNG demand by 2020 (100 bcm or 73.5 Mtpa) as illustrated in Figure 4.10. This is broadly consistent with the IEA perspective on the future trend of natural gas demand in Japan. South Korea, currently the second largest importer, is expected to be overtaken by China, and will become the third largest single importer by 2020.

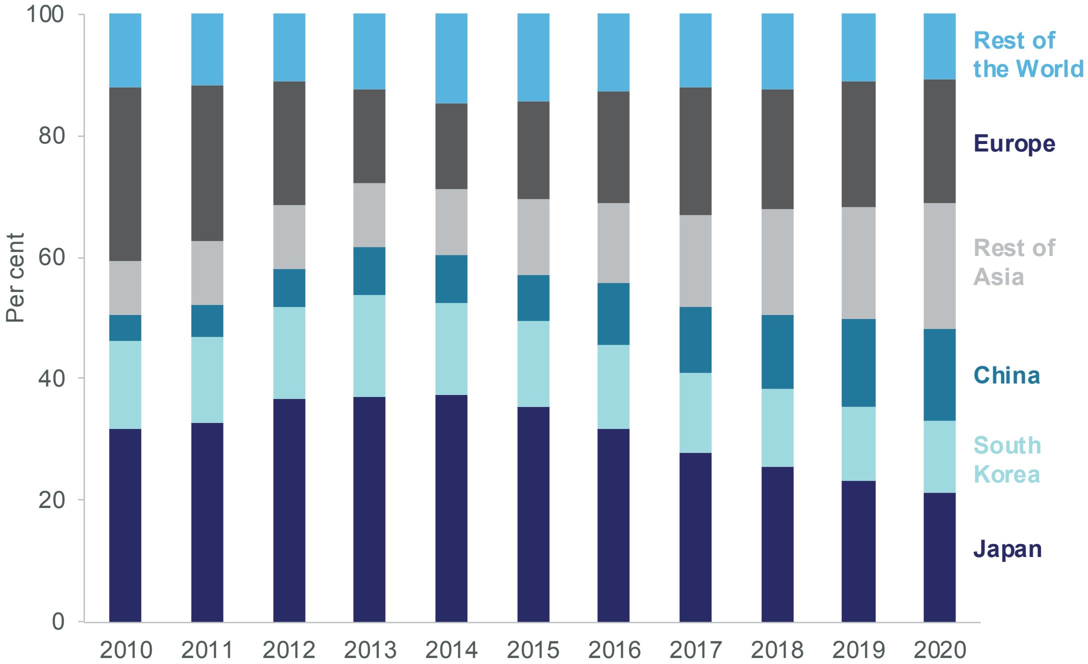
Figure 4.9: Global LNG demand by country 2005 to 2020



Notes: Rest of Asia includes Bangladesh, Chinese Taipei, India, Indonesia, Malaysia, Pakistan, Philippines, Singapore, Thailand, and Vietnam.

Source: Department of Industry, Innovation, and Science (2015); Nexant (2015) WGM

Figure 4.10: Global share of LNG demand 2010 to 2020



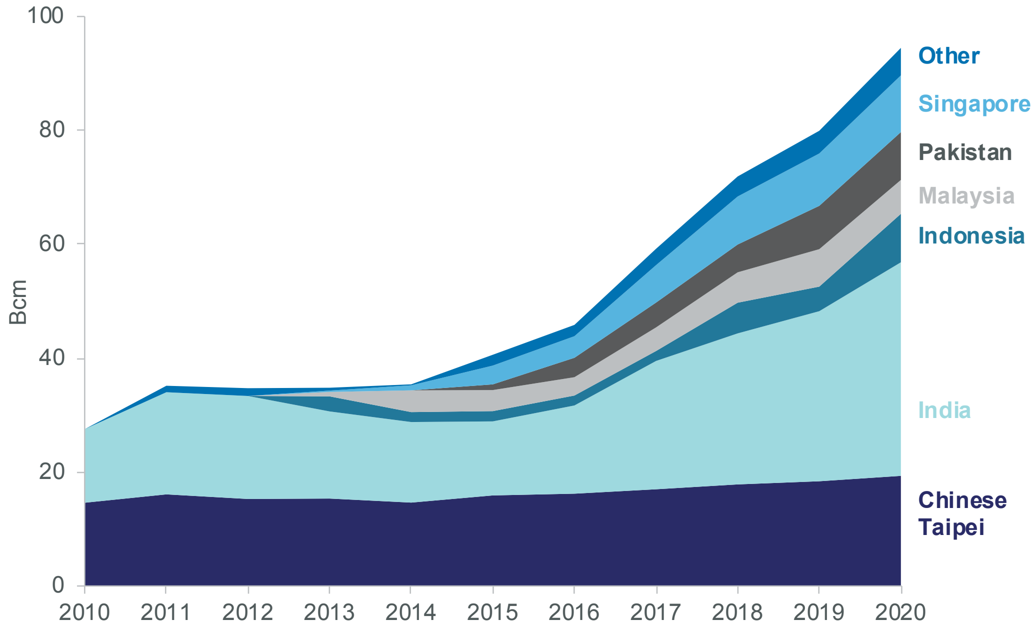
Notes: Rest of Asia includes Bangladesh, Chinese Taipei, India, Indonesia, Malaysia, Pakistan, Philippines, Singapore, Thailand, and Vietnam.

Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

Gas has an important role in the energy mix in China, and will continue to grow given the Chinese government's aim to increase the share of gas from 5 to 10 per cent of total energy consumption by 2020. The Chinese government is promoting gas to improve urban air quality, and as a means to increase energy security. In line with the projections from the IEA's World Energy Outlook 2015, total gas demand in China is expected to increase to 310 bcm by 2020, from 178 bcm in 2014, a growth rate of 9.7 per cent a year. As a consequence, Chinese LNG demand is projected to triple to 69 bcm by 2020, although this is lower than previous estimates because of increasing competition from pipeline supplies from Russia and Central Asia.

Europe is expected to make a strong recovery in LNG demand by 2020, growing at 12.3 per cent a year from 2014, which is effectively returning to earlier demand levels. This strong growth occurs despite the poor prospects for growth in overall gas demand in Europe, a consequence of a poor economic outlook, and continued penetration of renewables in the energy mix. The growth in LNG imports is primarily the result of falling indigenous production (particularly in the Netherlands) and a desire to diversify from dominant Russian pipeline supply.

Figure 4.11: LNG import outlook in the rest of Asia 2010 to 2020



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

LNG demand is also expected to grow strongly in the rest of Asia to 95 bcm by 2020, and will exceed imports into China by this date. Imports are spread across a large number of countries, as shown in Figure 4.11. India is expected to be the engine of demand growth, with LNG demand likely to triple by 2020 to reach 37.5 bcm, from 13 bcm in 2010. Nearly half of India's total gas demand is expected to be supplied by LNG. This is a result of the poor outlook for indigenous production, and limited prospects for international pipeline imports due to geopolitical and economic factors.

Whilst the outlook for India is positive, forecasts for both LNG and overall gas demand in India vary greatly. There are many barriers to greater gas penetration in the Indian market. For example, the domestic market is very sensitive to price and competition from alternative energy sources, and gas distribution infrastructure must be expanded significantly, issues which are explored further in Chapter 6. The forecasts in this report are for larger volumes of gas and LNG consumption in India by 2020 than projected by the IEA in its 2015 World Energy Outlook, however the forecasts converge again by 2030.

Amongst the other countries in the rest of Asia, the main growth in LNG demand is expected in Chinese Taipei, Indonesia, Malaysia, Pakistan, and Singapore. This growth is driven by a range of county-specific factors. In Indonesia and Malaysia, gas demand in the eastern provinces is distant from the offshore gas reserves in the west, which increases their reliance on LNG imports. This in turn makes less gas available via pipeline to Singapore and increases its reliance on LNG. Pakistan's gas demand is expected to increase rapidly as a result of the expansion of gas-fired electricity generation, and LNG imports will fill the gap between overall gas demand and falling indigenous production.

A key observation from this forecast of LNG demand is that it relies on growth in a large number of smaller importers. The growing numbers of LNG importers, each with a relatively small market share in the rest of Asia will accelerate market fragmentation and at the same time support increasing competition and liquidity in global LNG markets.

Uncertainties and implications

Demand growth going forward is subject to many uncertain influences. One of the key uncertainties is Japan's nuclear restart schedule and ongoing energy diversification policy. Two nuclear power plants — Sendai 1 and 2 — have resumed commercial operations in 2015, in line with the Japanese government's aims to supply 20 to 22 per cent of total electricity generation from nuclear power by 2030. However the scope and timing of restarts for the remaining nuclear power plants is uncertain. This, together with strong support for renewables and further improvements in energy efficiency, creates a downside risk for LNG demand in Japan.

As outlined above, Chinese and Indian LNG demand growth is also uncertain, and will depend on the relevant energy policies in each country and the extent to which growth in domestic production growth can be achieved, in particular the prospects for shale gas in China.

In spite of China's large recoverable shale gas resources and supportive government policies, there are significant barriers to a rapid expansion of shale gas production. These include the regulatory structure of the gas sector in relation to pricing and pipeline access, as well as geological aspects such as difficult terrain for intensive drilling, high drilling costs as a result of longer drilling times, and water availability.

In late 2014, the Chinese government revised down its 2020 target for shale gas output from 60 to 100 bcm to 30 bcm. There are concerns, noted in the IEA's World Energy Outlook 2015, that even this revised 2020 target is ambitious. This report projects unconventional gas production of only 18 bcm in 2020, growing to 50 bcm by 2030. If these reduced targets are not achieved, there are prospects for higher LNG imports than forecast in this report.

The extent of shale gas production in Europe is also unclear, as is their ability to diversify away from Russian pipeline imports, and the future positioning of gas in relation to alternative energy sources. Environmental policies including greenhouse gas mitigation will have important implications for the future energy mix.

These uncertainties are likely to result in continued growth in the LNG spot market. Buyers will be reluctant to enter into long term contracts if they are unsure of the future supply and demand for gas, and they are likely to rely on the shorter term market to secure their immediate needs. These uncertainties will be heightened by the fact that the main expansion of LNG demand will be in countries which can access alternative sources of gas supply. These countries have the opportunity to use LNG as the balancing item in overall gas supply, and hence LNG demand will be more variable over time.

4.4 Outlook to 2030

Whilst LNG demand is expected to grow strongly to 2020, the outlook beyond 2020 is less certain This is, to some extent, the result of the highly competitive market that will prevail between gas and alternative energy sources such as nuclear, renewables and coal, and the difficulties in predicting the likely direction of global environmental and economic policies. The cost competitiveness of gas is likely to be a key determinant of the outlook beyond 2020. The price needs to be low enough to sustain and improve the share of natural gas in primary energy consumption, but high enough to encourage investment in new gas supply.

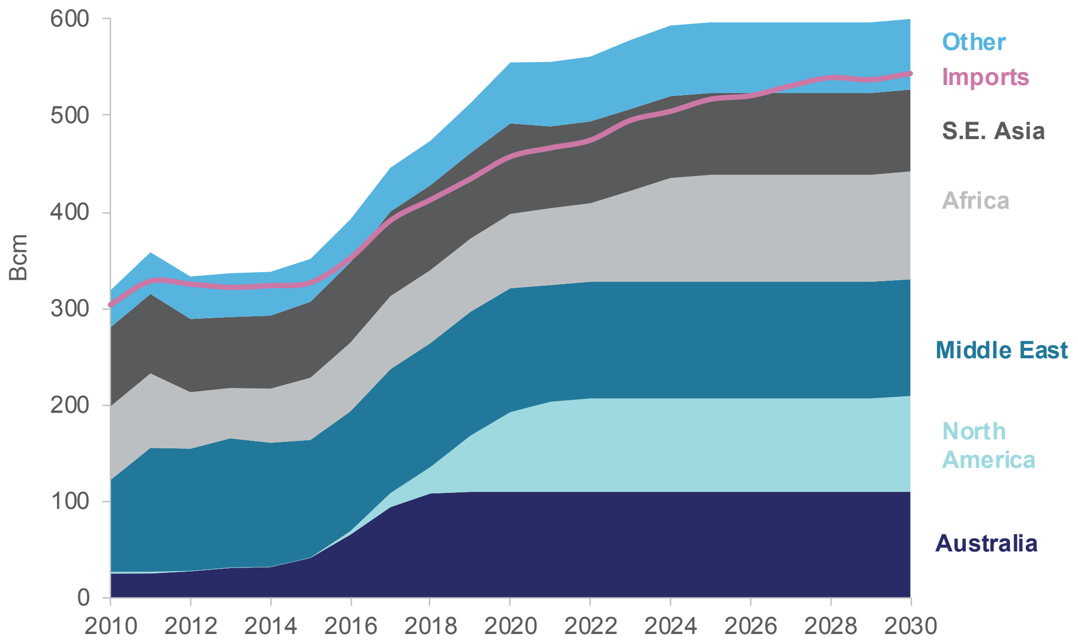
There is a need to make many assumptions to inform medium and long term forecasts, including about the costs of field production, the expected tariffs for competitive pipeline supply and the terms and conditions of the LNG contracts covering existing and proposed projects. As a result, the modelling results should be considered as a tool to identify and assess the key drivers of future LNG demand. The results reflect a possible future for the evolution of LNG demand and supply, but given the many uncertainties noted above, it should be treated as indicative of future directions.

Continuing excess supply capacity to 2030

Global LNG demand is projected to slow after 2020, as discussed in the next section. In response to this slowdown and given the overhang of excess supply capacity in 2020, growth in capacity after 2020 is projected to decline to only 0.8 per cent a year, to reach 600 bcm by 2030 (see Figure 4.12).

This amounts to the addition of 50 bcm of new capacity over the period between 2020 and 2030, principally sourced from East Africa (Mozambique and Tanzania). There is also a small expansion from existing projects in Russia. If demand growth proves to be stronger than currently forecast, there are a number of untapped LNG projects which could also go ahead, based in Australia, the US and Russia.

Figure 4.12: Global LNG supply by country 2010 to 2030



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

Slow demand growth, led by Asia

Global LNG demand growth is projected to slow between 2020 to 2030, growing at 1.7 per cent a year to around 540 bcm by 2030. Higher indigenous production (including shale and other unconventional gases) in most regions and increases in pipeline imports are two important factors which contribute to this slowdown in growth.

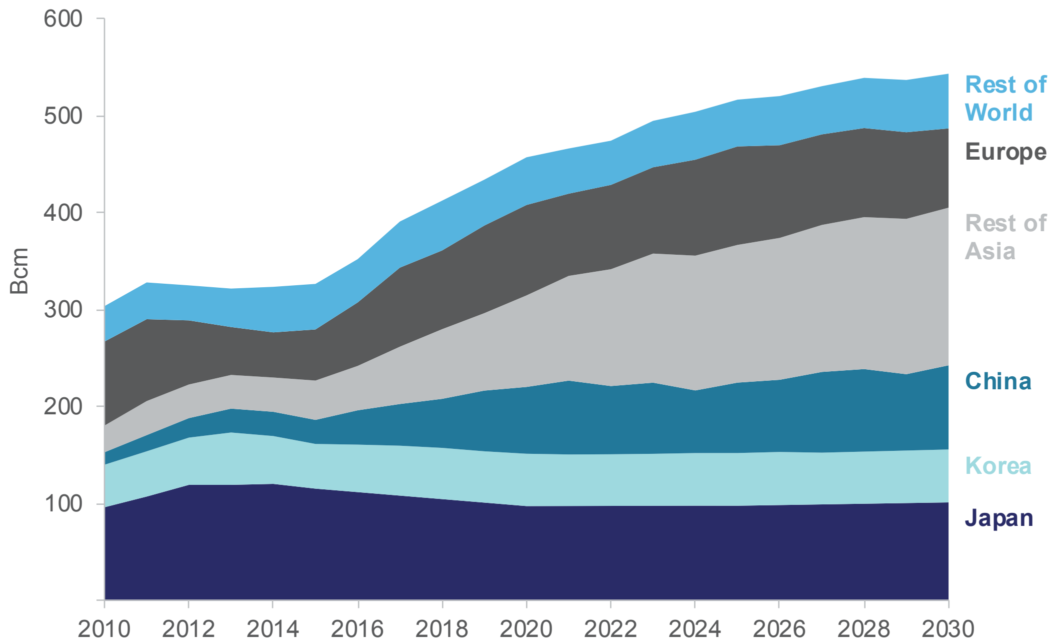
As shown in Figure 4.13, the main LNG importers of Japan, South Korea, China and Europe are expected to show the lowest growth after 2020, for the reasons discussed below. The rest of Asia shows the greatest growth potential, albeit at a slower rate than during the decade to 2020.

Slowing growth in Japan, South Korea, and Europe post-2020

Negligible demand growth is projected for Japan and South Korea after 2020, as shown in Figure 4.13. This is mainly a result of strong competition from alternative energy sources. Despite a decline in market share, Japan is still expected to be the largest single importer by 2030 (110 bcm). South Korea, however, is expected to be overtaken by India by 2030 (67 bcm) and drop to fourth position (55 bcm).

There are significant uncertainties in projecting long term LNG demand for Japan, as it will depend on the scope of nuclear restarts and government policies on Japan's future energy mix. If the operational life of existing nuclear plants is extended, there is potential for a further reduction in LNG demand after 2020.

Figure 4.13: LNG demand by country 2010 to 2030



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

LNG demand in Europe is projected to fall slowly after rapid growth to 2020. This is the result of limited growth in gas demand in an environment of expanding renewables energy. The continuing fall in indigenous production is balanced by substantial increases in pipeline supplies, anticipated to come from Central Asia and Africa. Russian pipeline imports are expected to moderate slightly.

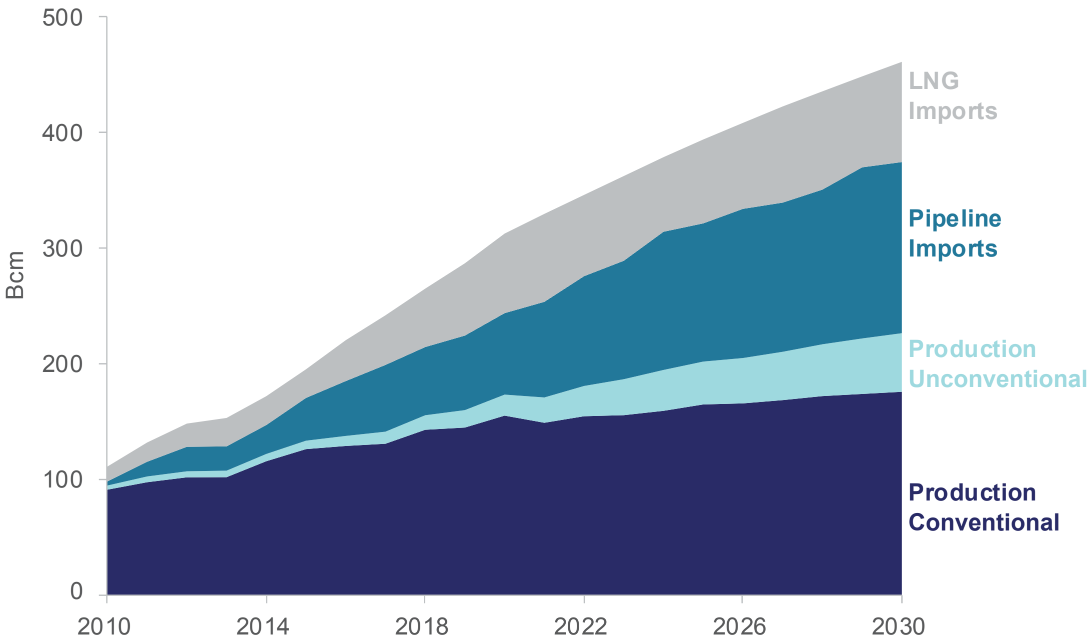
Slower growth in China

Long-term LNG demand for China is also projected to grow slowly after 2020, at an annual rate of 2.3 per cent between 2020 and 2030. LNG imports are projected to reach 87 bcm by 2030.

This slower growth in LNG imports occurs despite the expectation that Chinese total gas consumption will more than double between 2015 and 2030. There is the potential for substantial increases in pipeline imports from Russia and Central Asia and increases in indigenous gas production, primarily shale gas (as illustrated in Figure 4.14). However, the economic viability of expanded shale gas production is unclear owing to the limited development to date, and the more difficult geology and water availability. The Fuling project in Sichuan is the only gas field producing commercial quantities of shale gas (1.3 bcm a year in early 2015).[41] If shale gas costs are on the high side then the LNG demand outlook would improve substantially.

With increasing competition between LNG and various alternative energy sources, the price competitiveness of LNG is the crucial factor in China's long term LNG demand projection.

Figure 4.14: Chinese LNG supply and demand balance 2010 to 2030



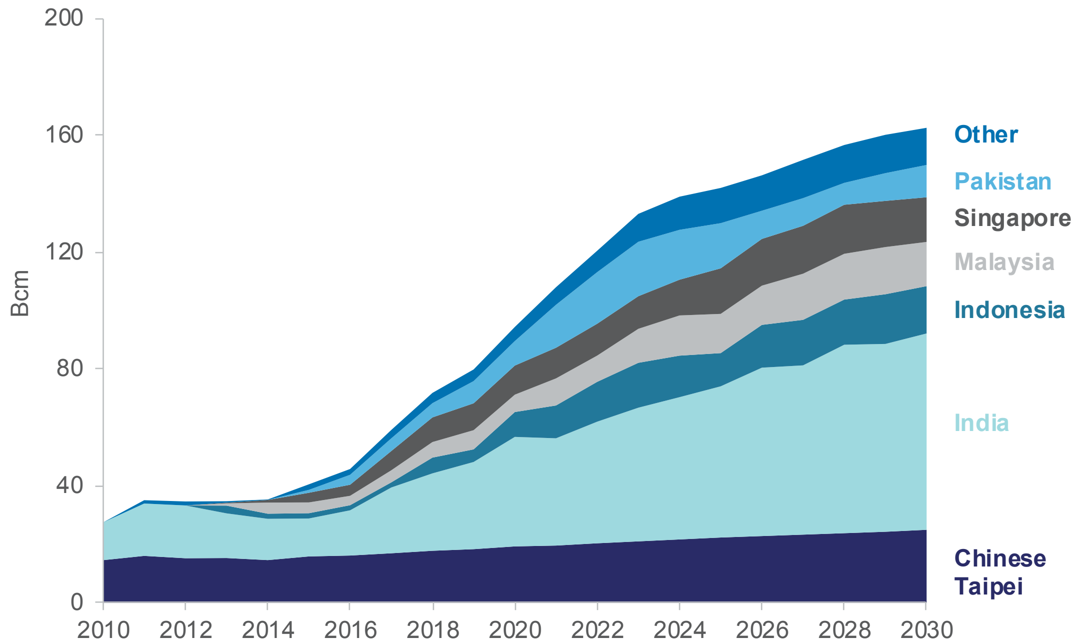
Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

[41] IEA (2015) World Energy Outlook 2015

Strong demand growth in the rest of Asia

LNG demand in the rest of Asia is projected to continue to increase strongly beyond 2020, growing at an annual rate of 5.6 per cent to 163 bcm by 2030, from 95 bcm in 2020, as shown in Figure 4.15. This is primarily led by strong and steady growth in India, followed by Indonesia and Malaysia.

Figure 4.15: LNG demand outlook by country in the rest of Asia 2010 to 2030



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

India is expected to emerge as the third largest LNG importer by 2030, accounting for around 12 per cent of global LNG demand. Poor prospects for indigenous gas production and limited possibilities for pipeline imports remain the primary causes of the projected strong LNG demand growth.

After 2020, indigenous gas production in India relies increasingly on unconventional gas, in particular CSG in the medium term and shale gas in the longer term. There are substantial uncertainties in the growth potential of these resources, due to high development costs and the very limited geological information available to date, especially for shale gas.

In Indonesia and Malaysia the long term demand for LNG is expected to increase as a result of falling or flat indigenous production in these countries after 2020, as epitomised by the depletion of the fields supplying the Bontang LNG plant in western Indonesia. In both countries, the increase in LNG imports is due to the separation of the gas producing regions in the east from the centres of demand in the west. However, as is the case with China, expanded pipeline networks throughout the Association of Southeast Asian Nations (ASEAN) region could provide a downside risk to higher LNG demand in these countries.

LNG demand growth is expected to be moderate for Chinese Taipei, Singapore, and Pakistan post-2020. In Singapore, the share of LNG in gas imports will continue to increase, as pipeline supply from Indonesia and Malaysia continues to decline. The opposite is expected to happen in Pakistan with the commencement of pipeline imports from Iran, which will compete strongly with LNG imports. In the case of Chinese Taipei, which has negligible indigenous production, the moderation of LNG demand is driven by slowing growth in total gas demand.

4.5 Implications

Global LNG trade volumes have grown strongly over the last 50 years, facilitated by the diversification of both import and export markets. The LNG market has become increasingly interconnected and flexible, reflected in the increasing significance of LNG spot trading.

The global LNG market is experiencing rapid and dynamic changes in market conditions, as the high prices and tight supply conditions prior to 2014 have given way to sharply lower spot and contract prices, as new supply from Australia and the US enters the market.

The LNG market will continue to become more dynamic and fragmented in the medium term. In spite of the ongoing importance of the traditional importing nations of Japan and South Korea, that the market share of these countries will gradually decline over time. This is a result of strong growth in China, India and emerging buyers in the rest of Asia, as well as a return to higher levels of demand in Europe.

However, the strong growth in capacity, primarily from Australia and the US, will more than offset the projected demand growth over the period. We expect that the global LNG market will have excess LNG supply capacity at least to 2020 and likely beyond, leading to a prolonged period of lower gas prices. LNG suppliers will therefore face a challenging environment over the medium to longer term to 2030.

Firstly, there will be increasing competition between LNG suppliers, given the expansion of supply capacity from Australia and the US, and the potential for significant new capacity from a range of existing and emerging suppliers.

Secondly, the demand for LNG will become more fragmented and uncertain. The majority of emerging countries with strong growth prospects in LNG demand have access to alternative sources of supply, from indigenous production and/or pipeline imports. This includes China, India, Pakistan and a number of other countries within Asia, albeit with varying degrees of current and future prospects of alternative gas supplies.

Small LNG importers will constitute a growing share of the global market, leading to greater diversity within the LNG demand market. The marketing of LNG will therefore require a more balanced approach between the traditional high volume markets and the diverse emerging markets in terms of developing and improving market shares.

It is also noted that LNG is, at the same time, competing against alternative sources of energy within these countries, mainly coal, nuclear and renewable energy. In light of these developments, price competitiveness will be an increasingly important determinant for future growth, both in terms of relative price against other commodities, and competitiveness between LNG suppliers. Future energy and climate change policies will also have a large impact on the role of gas in the energy mix.

Australian LNG suppliers have established solid business relationships with the major LNG trading countries of Japan, South Korea and China. If Australian suppliers are to expand their markets, they will need to ensure the ongoing competitiveness of Australian supply, and focus sales on the many smaller but rapidly growing market opportunities in Asia. Although there is increasing supply competition, Australia remains well placed to take up these opportunities, owing to its close proximity to the Asian markets and to its strong reputation as a stable and reliable LNG supplier.

Methane Spirit, carrying the first export cargo ship for Australia Pacific LNG.

CHAPTER 5

LNG market diversification

As set out in Chapter 4, global LNG markets are growing strongly, with growth of 6.1 per cent a year between 2000 and 2014 compared to total natural gas demand growth of 2.4 per cent a year. This has been associated with an even greater growth in the numbers of both buyers and suppliers, from 25 in 2000 to 48 in 2014. LNG buyers, who previously had only a limited number of options for sourcing LNG, now have a growing range of countries across many regions from which to choose.

With the deepening of the market, there has been an increase in the diversification of LNG supply to consuming nations, although the extent of this diversification varies.

A diversified portfolio of LNG supply is in the interests of consumers for a number of reasons. Firstly, it increases energy security by mitigating the impact of supply disruptions due to political, market or environmental issues. Many LNG exporters are located in areas associated with high levels of geopolitical risk, and a heavy reliance on a single country or region could leave an importer exposed if LNG production or transport is constrained. Recent events in a number of LNG producing countries have led to serious impacts on LNG supply, such as the diversion of Egyptian gas to satisfy domestic market shortfalls, and delays in production from Angolan plants as a result of accidents and technical failures.[42]

Diversification also spreads the financial risk arising from potentially significant price differentials between LNG supply regions. Natural gas supply is less fungible than other commodities such as oil, and prices can vary significantly between regions, as shown in Figure 4.5. An example of inter-regional financial risk is the 'Asian premium', which emerged between 2010 and 2014 largely as a result of high oil prices and strong demand growth in Asia (a result of the demand surge in Japan after the Fukushima disaster, and the rapid growth in gas demand in China). In order to mitigate financial risk, the buyer must diversify across regions, not necessarily just across countries. As with any diversification strategy, this may incur some additional costs (such as higher shipping charges), but this must be weighed against the benefits of diversification and the reduction of risk.

[42] Adel (2015) Idku plant LNG exportation collapses 2014: BG official; Gastech News (2014) Angola LNG shuts down until 2015 for major re-build

This chapter will examine the diversification of the LNG supplies of the major and growing consuming regions of Japan, China, South Korea, India and Europe between 1990 and 2014. It will also show the expected evolution of supply diversity over the forecast period to 2020, based on outlooks for LNG flows.

5.1 Methodology

The Herfindahl-Hirschmann Index (HHI) is used to quantify the degree of concentration in a market. It has been used extensively in the US to identify the presence of market power in anti-trust investigations. The HHI has also been employed in the evaluation of energy diversification strategies, mostly in the oil market and total energy supply, but has also been used previously to assess LNG diversification.[43]

The HHI is calculated by squaring the market share (expressed as a percentage) of LNG imports from the each LNG supplying country, and then summing the resulting numbers. The HHI can range from a low below 1,500, representing a highly diversified market, to a high of 10,000, representing a monopolistic market. Given the weighting process, the HHI is relatively sensitive to LNG importers with a large market share.

The HHI is expressed as:

$$HHI = s1^2 + s2^2 + s3^2 + \dots + sn^2$$

where sn is the percentage of LNG imports from the *n*th exporting country.

The following table is a guide to the interpretation of the HHI. This guide, developed by US Department of Justice and Trade Commission,[44] is traditionally used to analyse competition in antitrust law and industry regulation. In this chapter, it is used as an indicative guide to assist the interpretation of HHI results for LNG diversification.

Table 5.1: HHI Interpretation

Concentration	*HHI*
Unconcentrated	Below 1500
Moderately concentrated	1500 to 2500
Highly concentrated	Above 2500

Source: US Department of Justice and Federal Trade Commission (2010) Horizontal Merger Guidelines

The HHI levels of 1500 and 2500 are employed in the following figures to indicate the bounds of moderate diversification in the supply mix to a given country. An index above 2500 is considered to be exposed to a high level of supply risk. An index below 1500 would represent a high level of diversification, but it is important to keep in mind that lower scores would be difficult to achieve in practice, given the level of liquidity in the LNG market, and the fact that this analysis is based on exporting countries rather than individual suppliers. To achieve an index of 1500 or less would require LNG imports from at least seven different countries (assuming equal market shares).

It should be noted that the subsequent analysis is based purely on LNG supplies and not total natural gas imports. High levels of LNG import concentration may be more concerning for countries which do not have other supply options, such as Japan and South Korea. Countries with large reserves of domestic gas or pipeline imports may be less concerned about the

[43] See Vivoda (2014) LNG Import Diversification in Asia

[44] US Department of Justice and Federal Trade Commission (2010) Horizontal Merger Guidelines

concentration of LNG imports in the long run, given their total natural gas supply is more diversified.

In addition, the HHI does not distinguish between supplier countries according to their perceived reliability. In reality, countries such as Australia may have a good reputation as a reliable supplier, and importing countries may be willing to take a larger share from these countries than the HHI would suggest.

Historical import data in this analysis is based on the Natural Gas Information published by the IEA. Forecast LNG trades are based on projections from the Office of the Chief Economist using the Nexant WGM. This model uses known existing and future contracts to project the sourcing of LNG supplies. Where contracts do not cover the full demand forecast, the model provides a least cost optimisation of LNG trades as determined by the unit costs of production, liquefaction, shipping and regasification.

These forecasts, and the associated HHI, should therefore be interpreted with some caution, as the projected import volumes outside known contracts are based on the cost minimisation principle, and not on an attempt to minimise risk. As such, the results for the outlook period should be interpreted as the impacts on LNG supply concentration if countries make future decisions based predominantly on cost minimisation, without making a conscious effort to improve supply diversification.

5.2 HHI analysis

An analysis of the HHI has been undertaken for a range of LNG importing countries and regions. Japan and Korea are the two largest LNG importers globally, and China and India's imports are growing rapidly. The EU is also considered in this analysis as one of the traditional LNG buying regions, although its level of LNG import diversification may not have direct implications for Australian supply.

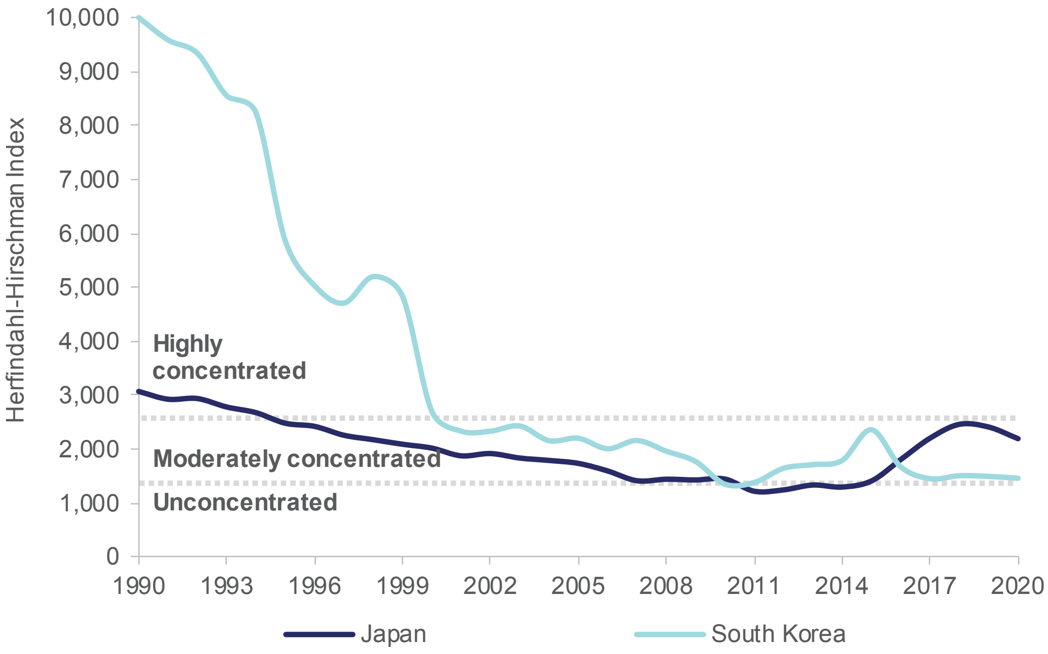
Japan and Korea are both mature LNG importers. As shown in Figure 5.1, both countries have increased their supply diversification over the last twenty years to achieve a low to moderate concentration of LNG imports.

Japan

Japan obtains almost all its gas supply from LNG imports, and has consistently been the world's largest importer. Whilst the volume of imports has continued to grow, the share of global trade has declined steadily from about 70 per cent in 1990 to the current level of 37 per cent. Figure 5.2 shows the increase in total supply and the diversity of Japan's import sources over time.

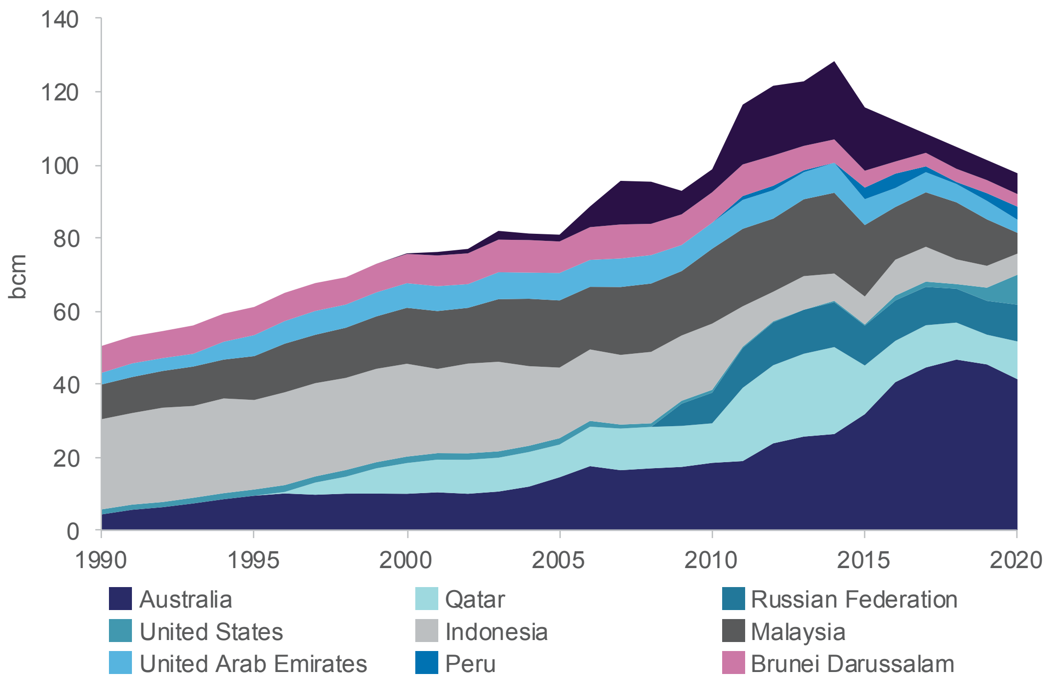
Since 1990, the level of diversification of LNG imports into Japan has gradually increased, as reflected in a downward trend in the HHI until 2015. Japan imported a minimum of 10 per cent of LNG from each of Australia, Malaysia and Qatar between 1990 and 2014. Japan's reliance on Indonesia has decreased substantially over the period, from almost 50 per cent of supply to less than 10 per cent, which has coincided with an increasing share from Russia since 2009.

Figure 5.1: Herfindahl-Hirschman Index – Japan and South Korea 1990 to 2020



Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

Figure 5.2: Japan's LNG supply sources 1990 to 2020



Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

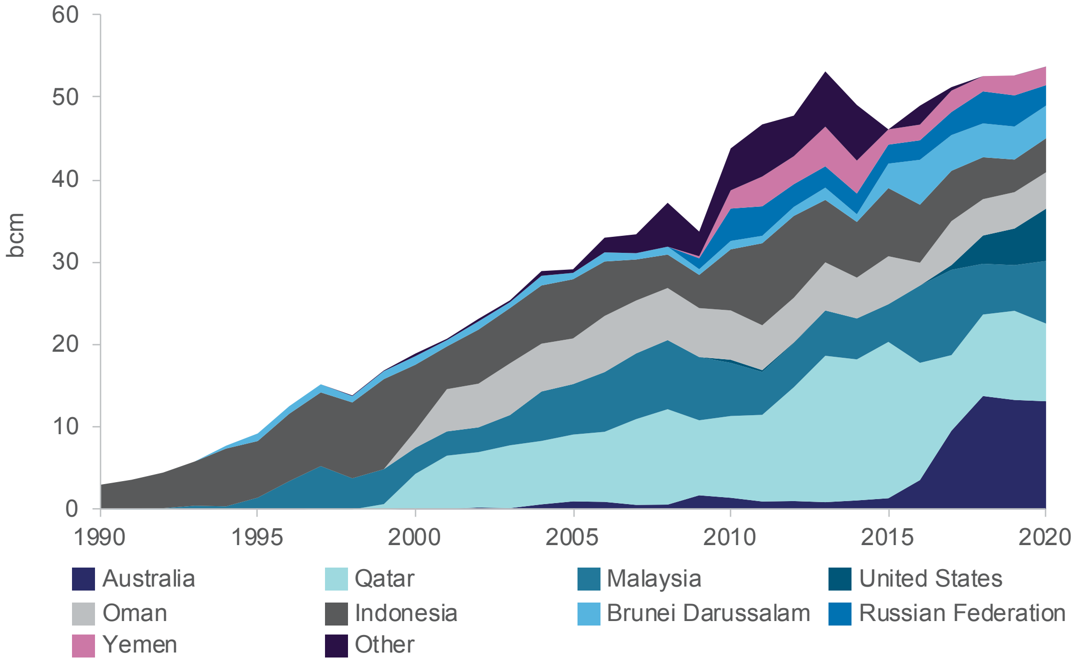
Japan's HHI, however, is expected to rise over the next five years to the boundary of a concentrated market. This is driven mainly by Japan's increasing reliance on Australian LNG, which is expected to account for an average of 40 per cent of total LNG imports by 2020. The US is also expected to be an important LNG supplier from 2020 onward, increasing to 10 per cent of supply.

Given that Japan is at the upper end of the HHI boundary for a moderately concentrated market, it is likely to attempt to develop a broader supply mix after 2020. Additional supplies from Australia would risk making Japan's gas supplies highly concentrated; particularly given Japan is so reliant on LNG for its gas needs.

South Korea

South Korea is another mature LNG importer, with imports commencing in 1987. It is currently the second largest LNG importer in the world. South Korea has, like Japan, shown a very high degree of supply diversification since 2001, as shown in Figure 5.3.

Figure 5.3: South Korea's LNG supply sources over time



Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

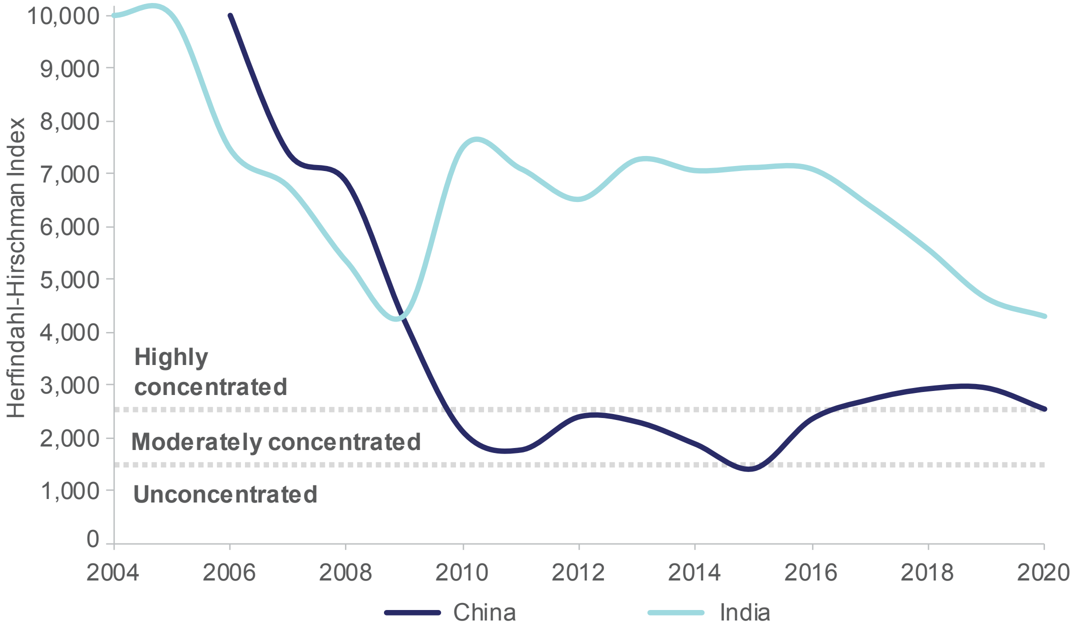
Prior to 2001, South Korea had a highly concentrated LNG market, initially relying on Indonesia and Malaysia for 100 per cent of its LNG supply. As South Korea's LNG consumption increased, the market became more diversified, although Indonesia, Malaysia, Oman and Qatar remained its four major LNG suppliers between 1990 and 2014. Over the period to 2020, Qatar's share is expected to decline substantially from around 35 per cent in 2014 to around 16 per cent in 2020 (after peaking at 42 per cent in 2015). South Korea's reliance on Indonesia and Oman is also expected to decrease to less than 10 per cent of overall imports.

It is expected that South Korea will make up for these declines by increasing LNG imports from Australia and the US over the next five years, growing to over 25 and 10 per cent of LNG supply respectively. Despite the significant changes in the supply mix, South Korea should maintain a highly diversified LNG import portfolio, reflected in a low HHI from 2016 once the reliance on Qatar has declined. On this basis, it would be possible for South Korea to increase Australian imports without risking a loss of diversity.

China

China and India both commenced LNG imports within the last decade, but have shown a significantly different path in LNG import diversity, as shown in Figure 5.4.

Figure 5.4: Herfindahl-Hirschman Index – China and India 2004 to 2020

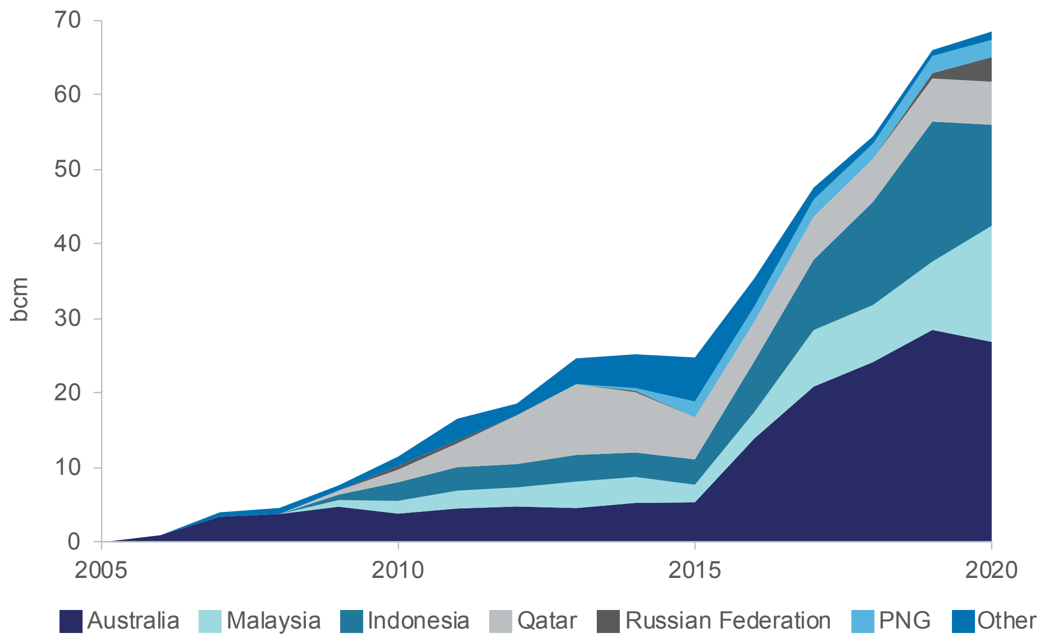


Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

China commenced its LNG imports in 2006 with LNG contracted from Australia's North West Shelf project. There has been a strong push to diversify LNG supplies since then, reflected in a sharp downward trend in the HHI as volumes rapidly expanded. Chinese buyers quickly expanded LNG imports from Indonesia, Malaysia and Qatar, taking more than 10 per cent of overall imports from each nation, while reducing Australia's share from 100 per cent in 2006 to around 20 per cent in 2014, as shown in Figure 5.5.

The prospects for Chinese gas demand remain strong. Nevertheless the weakened economic outlook and strong competition from indigenous production and pipeline imports are expected to put pressure on LNG imports. In light of this increased uncertainty, we would expect China to increase its take from the spot market, and avoid new longer term contracts.

Figure 5.5: China's LNG supply sources over time



Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

On current projections, China's HHI is starting to trend upwards. As is the case with Japan, the increasing share of Australian LNG to approximately 40 per cent is the key contributor for this result. Based on these results, Chinese LNG imports will be on the boundary of a highly concentrated market by 2020, and the Chinese importers may act to diversify their portfolios to reduce supply and financial risk.

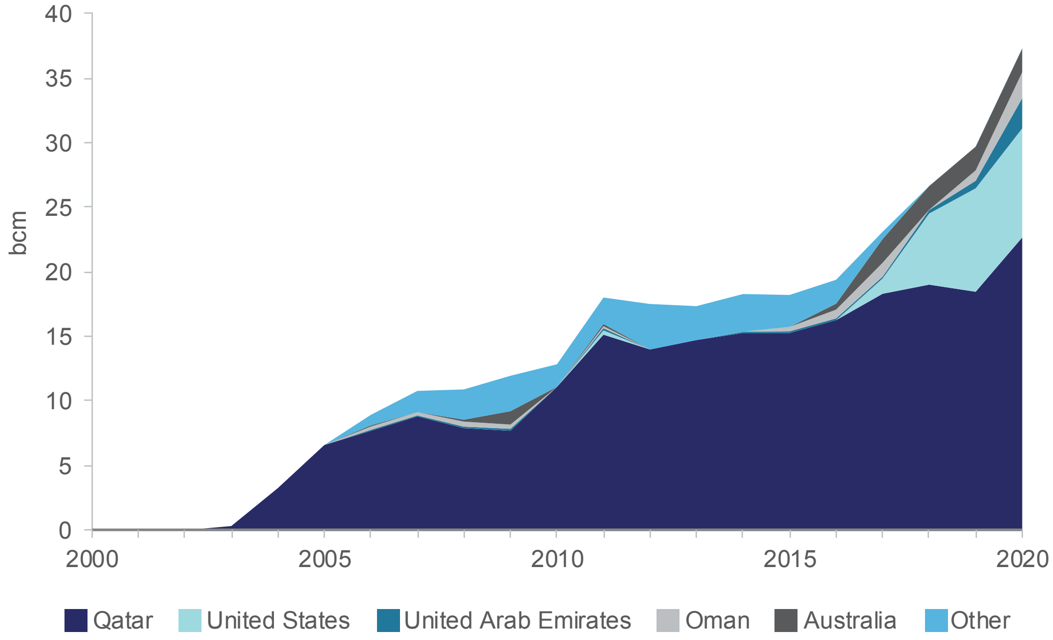
India

In contrast to China, India's LNG supply has remained highly concentrated since the commencement of imports in 2004. This is reflected in a high HHI, which dropped to almost 4000 in 2009, but has since increased to around 7000.

As shown in Figure 5.6, nearly all LNG imports to India are sourced from Qatar. Although the proportion shrank to less than 65 per cent in 2009, when spot cargoes from Australia reached almost 9 per cent, India's reliance on Qatar increased again since 2010 when spot supplies became too expensive for India's price sensitive market. Given India's small number of long term contracts, mainly with Australia and the US, increasing volumes of Qatari LNG has played a key role in supplying India's increasing LNG volumes over the period.

Over the period to 2020, India's reliance on Qatar is expected to decrease gradually to around 60 per cent of overall imports, reflected in a downward trend in the HHI out to 2020. It is also expected India will increase LNG imports from the US, Australia, Oman, and the United Arab Emirates. In particular, the share in India's overall imports from the US will increase rapidly to around 22 per cent by 2020, from just 5 per cent in 2017. Australia's share is projected to peak at 8 per cent in 2017, but shrink to 5 per cent in 2020.

Figure 5.6: India's LNG supply sources over time



Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

The current and projected market conditions — excess supply capacity and lower LNG prices — should facilitate strong increases in Indian LNG demand at least to 2020, but volumes will depend on a range of factors, including the level of domestic production, which are explored at greater length in Chapter 6.

Despite India's increasing diversity of supply, Indian LNG imports are likely to remain highly concentrated by 2020, unless there are conscious efforts to improve diversification. As Indian imports grow, it is likely that diversification and security of supply will become more important considerations to the Indian importers. The geographical advantage of the Middle East in supplying LNG to India will also be somewhat reduced by the new LNG regasification terminals under construction on India's east coast, further adding to the attractiveness of Australian supply.

EU

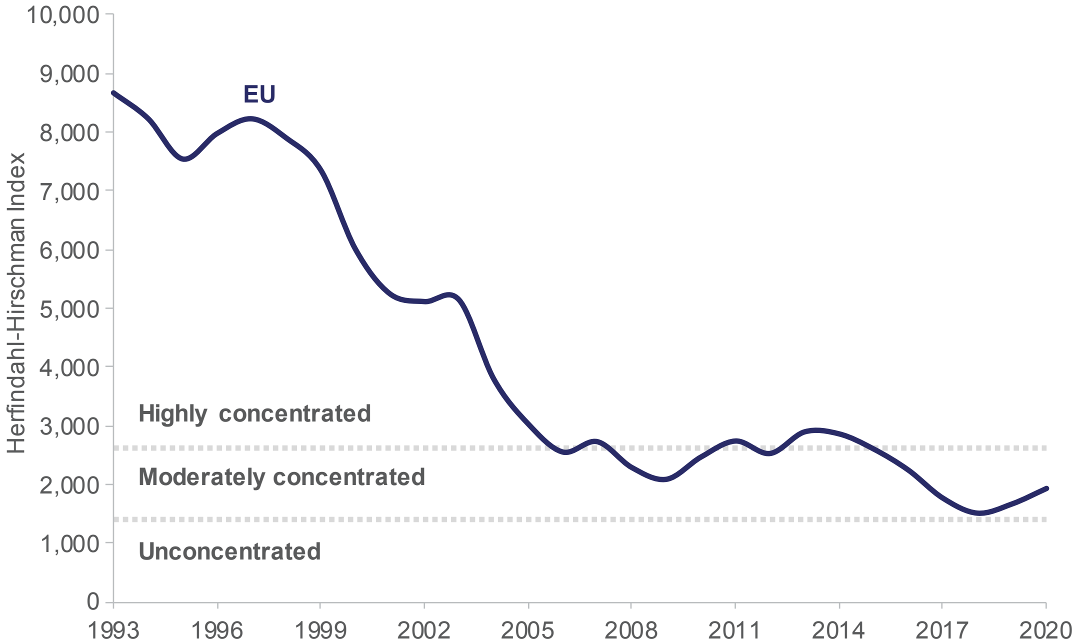
While the EU is not a single gas consuming country, it is treated as one entity in this analysis because of the internal interconnections between its constituent entities.[45] As with Japan and South Korea, the EU's LNG import portfolio has become substantially diversified, although this has only been the case since about 2006 (see Figures Figure 5.7 and Figure 5.8).

Early LNG supply to Europe was predominantly from Algeria, which supplied over 50 per cent of imports until 2005. This has been supplemented by gradually growing imports from Qatar since the late 90s. These countries remain the two major LNG suppliers to the EU, and together accounted for more than two thirds of overall EU imports in 2014.

45 There are some concerns that imports to the UK and France cannot easily be exported to the east, but new LNG import terminals in Lithuania and Poland will assist to balance the supply and demand for LNG throughout the EU. Inter-regional trade between countries within Europe has been included in the analysis in order to capture the total volume of supply.

EU imports of LNG fell steadily between 2010 and 2014, which led to a reduction in imports from a number of smaller suppliers such as Egypt, Trinidad and Nigeria. This loss of diversity contributed to the spike in the HHI in 2014.

Figure 5.7: Herfindahl-Hirschman Index – EU 1993 to 2020

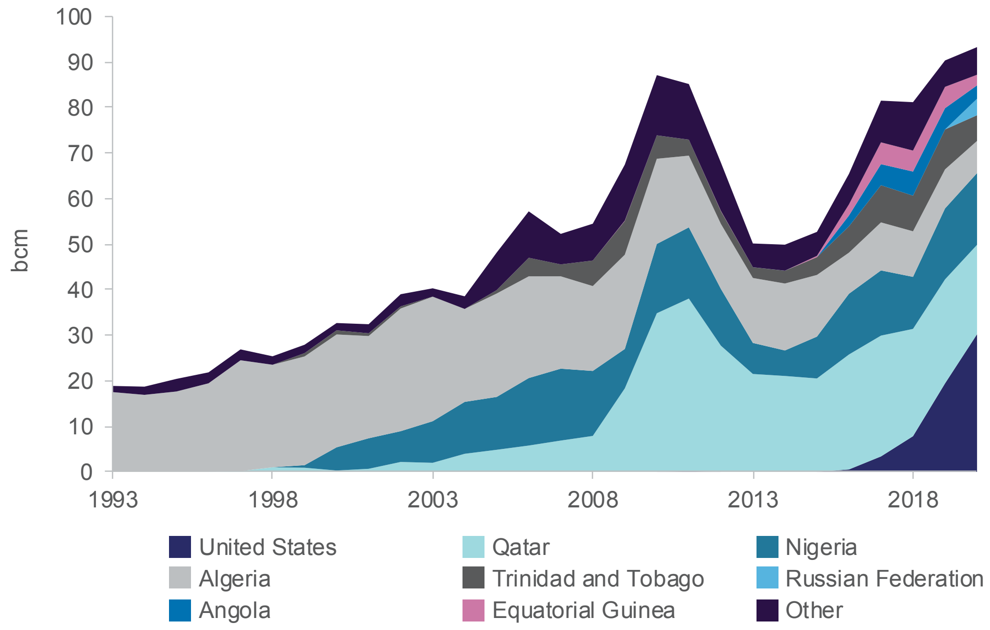


Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

However, over the next five years, LNG demand in the EU is projected to grow substantially, as a result of a decline in indigenous production and a desire to diversify from the dominant Russian pipeline imports. The current and projected favourable market conditions — the excess supply capacity and low priced LNG — would further contribute to this strong demand growth.

The portfolio of suppliers is also expected to expand, and the market share of Algeria and Qatar will fall to 30 per cent by 2020. This will all contribute to the downward trend in the HHI from 2015 to 2018. There is a small increase in the HHI forecast in 2019 and 2020, which is mainly due to the anticipated growth in US LNG exports to the EU to around 30 per cent. However on current projections, EU supply is expected to be reasonably diversified by 2020.

Figure 5.8: EU LNG supply sources over time



Source: Department of Industry, Innovation and Science (2015); IEA data (2015); Nexant (2015) WGM

5.3 Conclusions

The LNG importers considered in this analysis have all substantially diversified their supply portfolios over the last five to fifteen years, although India's supply concentration remains high. This trend towards diversification can be attributed to a number of factors in the global LNG market:

- the rapid growth in the volume of trades, and in the number of importing and exporting countries
- the growth in the spot market and the decline in destination restrictions, which means importers are less tied to specific suppliers under long term contracts
- a perception of less reliability from many traditional suppliers, based on a recent history of technical failures, depletion of gas supplies and political risks such as domestic gas reservation.

The results between 2010 and 2020 show that even without factoring in conscious decisions to increase LNG supply diversity, the HHI is held within the boundaries of moderate concentration for most LNG buyers. This move towards increased concentration appears to be a rational response to the perceived risks of LNG supply. With the continued growth in the size and depth of the market, and the growth in spot and short term contracts, there is greater scope for importers to maintain a reasonable level of diversity.

Implications for Australia

A number of the major LNG importers in the Asian region have supported the current wave of Australian LNG supply through long term contracts, and have a large proportion of Australian imports in their LNG mix over the medium term. The results of this analysis suggest that future growth in LNG exports from Australia is more likely to be from emerging importers rather than these foundation buyers, although Australia's reputation as a stable and reliable supplier of LNG may mean that buyers are content to have a larger share of Australian supply. With increasing supply competition as a result of excess supply capacity, price competitiveness will be an increasingly significant determinant of future growth. Australian LNG producers will need to be globally competitive to ensure further expansion of their markets, especially into emerging countries. Despite the increasing market share of Australian LNG in South Korea, the high level of diversification projected over the next five years would allow South Korean buyers to further increase the share of Australian LNG in their supply mix. India may also be a potential destination for increased Australian LNG exports in the future, as a result of its current low levels of supply and its need for further diversification in LNG imports. The proximity of Australia to the east coast regasification terminals under construction in India will favour greater Australian supply.

On the other hand, Australia is projected to significantly increase its share of the market in Japan and China to 40 per cent in each country by 2020. In both countries the level of supply diversification will be at the upper bound by this date, which militates against a higher market share from Australia. As a result, the prospects for market share in these countries will depend on other factors, such as Australia's perceived reliability as a long-term LNG supplier.

Kolkata, India

CHAPTER 6

India: prospects for natural gas

In the context of the current oversupply in global LNG markets, and where China's anticipated demand growth may be smaller than previously forecast, India is being flagged as an emerging demand destination with the potential to quickly increase its LNG imports and natural gas consumption. Forecasts for Indian gas consumption generally show rapid growth.

This chapter considers the economic and policy drivers of India's gas demand, to assess whether India is likely to meet these expectations. It presents an assessment of India's current natural gas usage and LNG reliance, as well as the economics of and outlooks for future LNG demand, in the context of India's broader energy challenges. It also considers the potential role of Australia as a major LNG supplier to India. Given one of the key constraints for India's gas consumption is its high level of price sensitivity, Australia will need to ensure it can provide competitively priced LNG if it is to play a large role in meeting India's growing demand.

The Australian Bureau of Agricultural and Resources Economics (ABARE) published a research report in 2007 on prospects for LNG imports into India, which found that there was a large potential for growth in Indian gas consumption, but that there were a number of policy challenges which created uncertainty about the prospects for LNG imports.[46] Much has changed since this report, including a number of policy changes and sustained growth in gas consumption. Yet challenges still remain for India's gas sector, including the deregulation of pricing of gas and its key outputs. This chapter reconsiders the prospects for Indian LNG imports, taking into account recent policy developments and updated outlooks for Indian gas consumption.

Section 6.1 sets out some of the challenges faced by the Indian gas sector and the energy sector more broadly. It assesses India's gas consumption and supply, including both domestic gas production as well as imports of natural gas. The outlook for India's gas demand going forward is set out in section 6.2, which also considers whether this demand can be met by

[46] Rumley et al (2007) Natural gas in India: prospects for LNG imports

each of the three supply options: increased domestic production, imports via natural gas pipelines, or imports of LNG. The relative merits and drivers for the various supply options are assessed, including the range of challenges that India faces in pursuing each of these options. Some of these challenges include domestic gas prospectivity; government regulation which is unattractive to international investors; the geopolitical challenges of pipeline imports; and the economics of LNG imports.

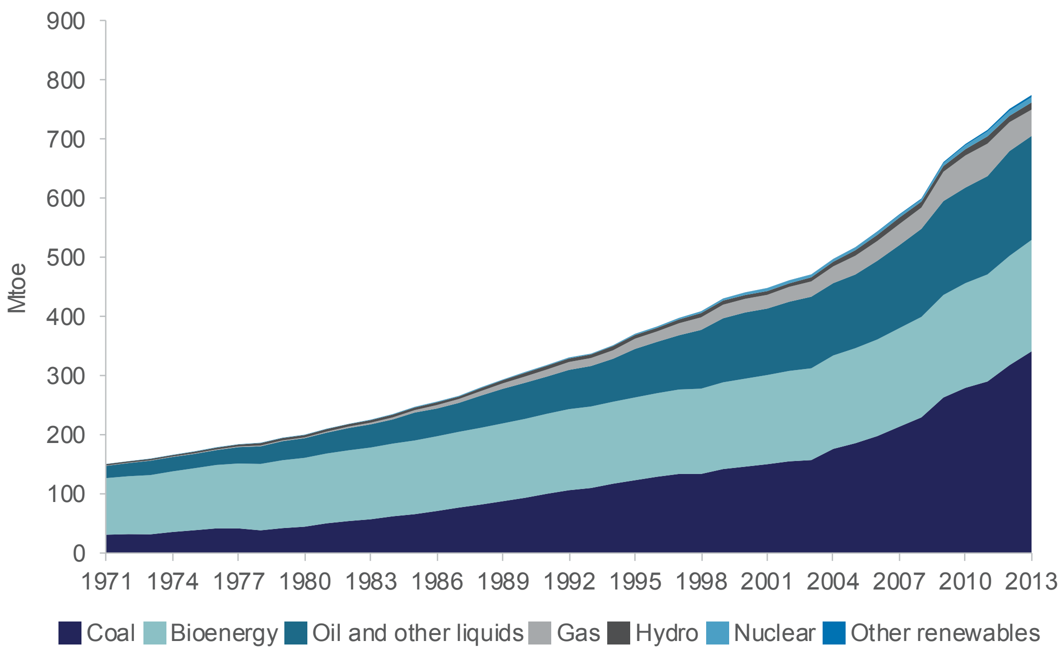
The third section assesses the implications of these outlooks for Australian LNG supply into India, as a proximal but high cost gas producer. Given India's price sensitivity, Australia will face challenges in securing a position as a high volume supplier to India.

6.1 Energy and natural gas in India

India's energy sector

As the second most populous country in the world, India has a large and growing need for energy. As shown in Figure 6.1, total primary energy supply is dominated by coal, at around 45 per cent in 2013, followed by bioenergy and oil. The proportion of natural gas in India's total energy mix has been increasing, albeit from a low base, increasing from three per cent in 1990 up to a peak of almost eight per cent in 2011. It dropped to six per cent in 2013 as a result of high LNG prices and lower than anticipated domestic production.

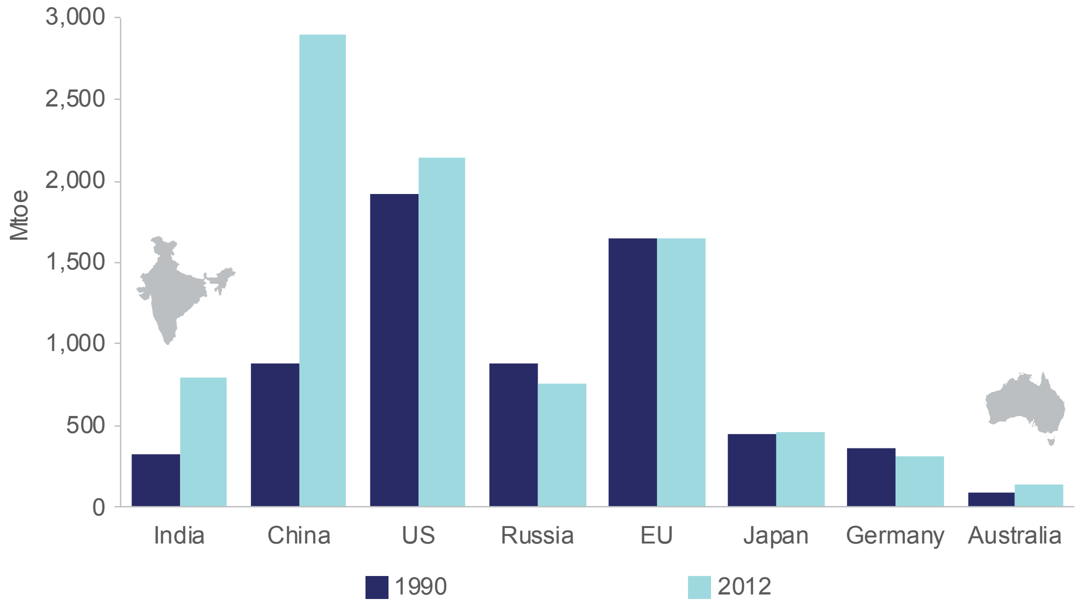
Figure 6.1: India's total primary energy consumption



Source: IEA data (2015)

Hydropower, nuclear and other renewables make up the remainder of India's energy mix. India's energy demand has more than doubled between 1990 and 2012, as shown in Figure 6.2, but is still very low in relative terms. India's energy growth is expected to ramp up significantly in the medium term, both to support economic growth, and also to meet the significant level of unmet demand. Outlooks for energy, electricity and gas demand will be considered in more detail in the following section.

Figure 6.2: India’s energy demand



Source: IEA data (2015)

Energy security and energy policy

Energy security is one of India’s main policy concerns, given the size of its energy sector and the increasing reliance on imports to satisfy its energy needs. Although India does have significant endowments of coal, oil, and gas, production of all three commodities is limited by inefficient regulation, and there is a growing gap between oil and gas demand and domestic supply.[47] This can place a considerable burden on India’s current account, particularly when commodity prices are high.

The Indian government has made commitments to reduce import dependence in the medium term. Although prices for fossil fuel imports are currently low, there remain incentives to ensure that domestic production is optimised and reliance on imports is minimised. This has been done through high levels of government involvement in the past, although there are moves to allow the market to operate more independently in some of these areas.

Although the availability and affordability of India’s energy supply is of utmost concern, the Government of India is also increasing its focus on limiting greenhouse gas emissions. The Government has committed to large increases in renewable energy supply in the coming years, and has goals to become a leader in solar energy in particular. Increased natural gas consumption is likely to play a part in the transition of India’s economy to a low carbon future.

[47] EIA (2014) India: International energy data and analysis

Electricity in India

India's per capita electricity usage remains lower than many other emerging economies, as shown in Figure 6.3. Almost a quarter of India's population, around 300 million people, is currently without access to electricity.[48] Around 250 million people get only between three to four hours of power per day from India's national grid,[49] and many more live with unreliable power, often relying on backup diesel generators for the frequent dropouts of electricity supply. These issues were highlighted by the blackouts in the summer of 2012 which left over 600 million people without power for several days.

Figure 6.3: Economic growth and electricity demand

Source: World Bank (2015) World Development Indicators; IEA (2015) World Energy Balances

The problem of insufficient electricity supply is partially a result of artificially low electricity prices in India, which reduces incentives for investment. Electricity pricing in India is politically sensitive, and energy often appears to be perceived as an entitlement rather than a commodity. Distribution companies are often heavily indebted as a result of pressure from various levels of government to maintain artificially low electricity prices, in addition to high levels of electricity theft.

Prime Minister Narendra Modi has committed to ensuring availability of electricity to every Indian home by 2019.[50] Reforms have commenced to overhaul the sector, but this will take some time. Large scale reform of electricity transmission and distribution is required, as well as retail pricing reforms to prevent excess consumption in sectors which are heavily subsidised. Significant investment in generation capacity and transmission infrastructure is also required.

48 IEA (2014b) Energy access database

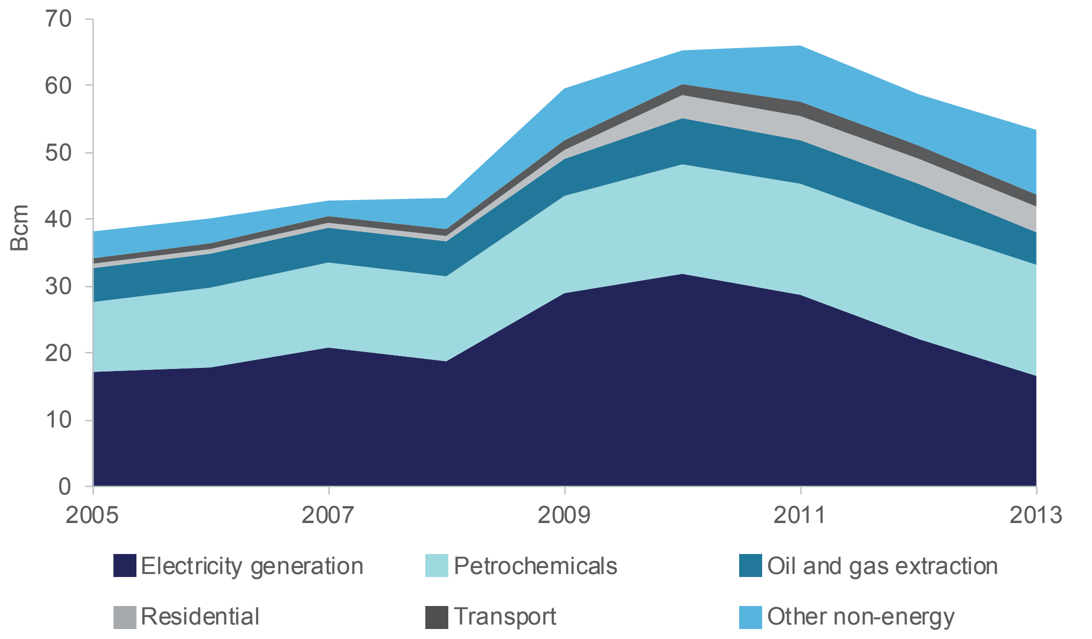
49 Martin (2015) India's Energy Crisis

50 *ibid*

India's gas consumption

Much of India's natural gas is used for the generation of electricity, as shown in Figure 6.4. Given the issues outlined above, natural gas usage for electricity is very price sensitive, and India has seen gas powered generation plants sitting idle as a result of a lack of gas availability at prices which can be absorbed downstream. Over 50 per cent of plants stood idle in 2014, with the balance operating at around 30 per cent of capacity.[51] Natural gas usage for power generation peaked in 2010–11 at 50 per cent, but this dropped to almost 30 per cent in 2013–14, as domestic production declined and regional LNG prices peaked in the region.

Figure 6.4: India's natural gas consumption per sector



Source: IEA data (2015)

A large proportion of the gas is also used for industry, with much of this as a feedstock for making fertiliser. Like the electricity sector, the fertiliser industry is very sensitive to price, as it is also unable able to pass through high input costs.

These sectors can consume large quantities of gas at the right price. The price of conventional domestic gas production is factored into the costs of electricity and fertiliser, while LNG, depending on the price, can be more challenging for these sectors to absorb. This is increasingly a concern as the quantity of domestic production is unable to keep up with demand.

[51] HDFC Bank Investment Advisory Group (2015) Power Sector

In addition to price sensitivity, another factor which constrains India's gas consumption is its infrastructure. India has a pipeline network of over 15,000km,[52] but it only reaches a small proportion of the population, as shown in Figure 6.5. There is a strong regional imbalance in gas infrastructure, where a few states are able to consume the majority of the gas, while a large number of states have no access as they lack gas infrastructure. Many of the planned expansions (totalling over 10,000km) have been delayed in obtaining regulatory approvals, for a number of reasons including issues related to land rights.[53] This is complicated by the fact that many pipelines would traverse multiple states, adding to the regulatory burden.

Figure 6.5: India's natural gas infrastructure

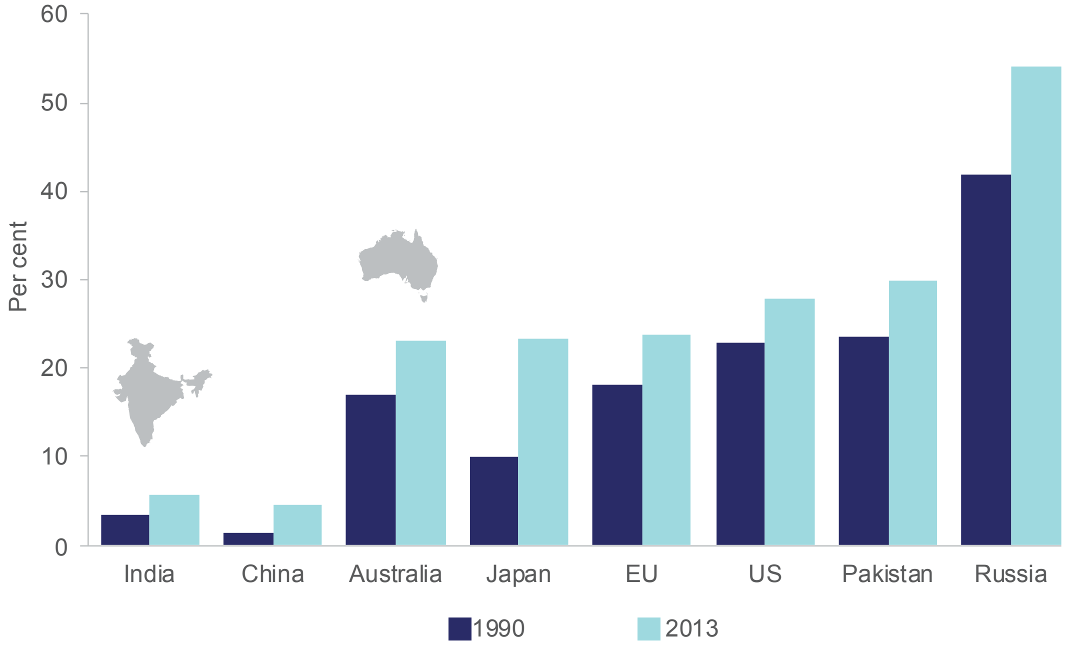
Source: McKinsey (2013) Asian gas: Partnerships for a growing industry

52 Petroleum Planning and Analysis Cell (2015) Gas Pipeline Networks in India

53 EIA (2014) India: International energy data and analysis

Because of these constraints, and as a result of a range of other factors, including the relative endowment of domestic gas reserves, India's current gas consumption is very low relative to other countries (as shown in Figure 6.6). For instance, natural gas in Qatar (not shown in the chart) makes up 98 per cent of primary energy supply. Although India's gas consumption is not likely to reach these levels, there is capacity to increase the proportion of gas in its energy mix.

Figure 6.6: Natural gas as a proportion of total primary energy



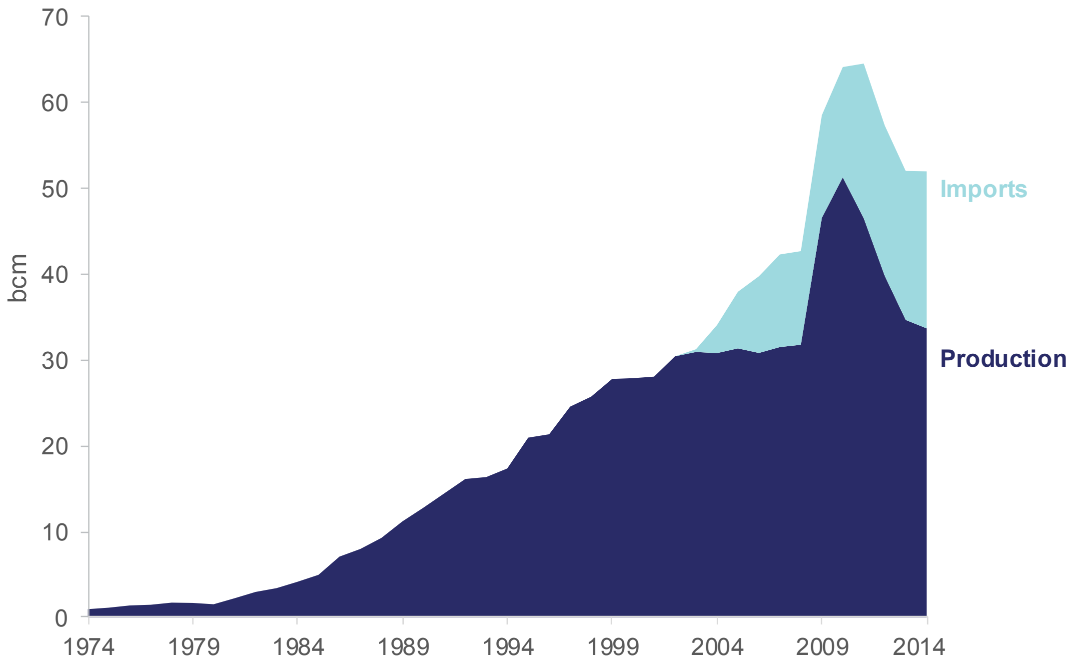
Source: IEA data (2015)

Domestic gas production

India has considerable reserves of natural gas, estimated at 1,427 bcm of proved and indicated recoverable reserves in 2013–14. This is almost 30 years of consumption at the 2014 level.

The majority of India's natural gas consumption has historically been met by domestic production. The sector is dominated by India's government owned oil and gas companies, predominantly Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL). Although energy security concerns have prompted the Indian Government to encourage foreign companies to enter the sector, only a small number have participated thus far, as a result of unattractive regulation, including downstream price setting and a large government role in exploration and development activities.

Figure 6.7: India's natural gas consumption by source



Source: IEA data (2015)

As shown in Figure 6.7, domestic gas production increased rapidly in 2009 as private companies entered the upstream gas sector, most notably in the Krishna Godavari Basin off India's eastern coast. However production from the basin has been much lower than anticipated, because of technical difficulties in extracting the gas. This was likely compounded by the low domestic gas prices, which were set at levels insufficient to encourage investment into more challenging gas fields. India's gas price has since been increased to a level which is indexed to a basket of international prices, but may be too high given the high expenses required for deepwater drilling, particularly given recent falls in LNG prices and the lag in updating the price.

India's gas imports

The proportion of India's gas consumption being met by domestic production is shrinking. There are no international pipelines into India, so all natural gas imports have been LNG. LNG imports commenced in 2004 with the completion of the Dabhol terminal, and have increased to around 37 per cent of gas consumption in 2014.[54]

India now has 25 Mtpa of LNG regasification capacity, from four plants on the west coast, as shown in Table 6.1. However, India's actual imports remain well below this, as two of the plants are operating well under capacity. The Dabhol terminal lacks a breakwater, so cannot import LNG during monsoon, for around six months of each year. The Kochi terminal is constrained by the limited gas pipeline infrastructure in south India, and is reported to be importing only 2 per cent of its nameplate capacity.[55]

[54] IEA data (2015)

[55] Das (2015) India LNG terminal project scrapped

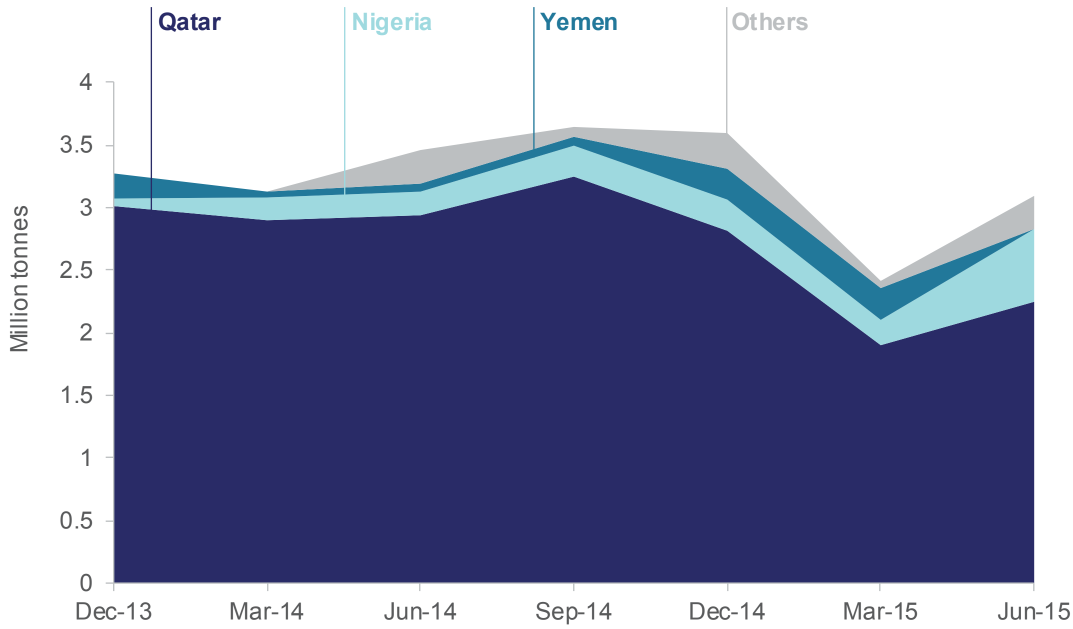
Table 6.1: India's LNG regasification capacity, existing

Terminal	*Capacity*	*State*	*Owner*	*Completion*
Dahej	10 Mtpa	Gujarat	Petronet LNG	5 Mtpa in 2004, 10 Mtpa in 2009
Hazira	5 Mtpa	Gujarat	Shell/Total	2005
Dabhol	5 Mtpa	Maharashtra	Ratnagiri Gas and Power/GAIL	2013
Kochi	5 Mtpa	Kerala	Petronet LNG	2013

Source: Company websites

In 2014, India imported 13.8 Mtpa of LNG, making it the fourth largest LNG importer in the world.[56] As shown in Figure 6.8, India imports the majority of its LNG from Qatar, much of which is under long-term contracts. In 2014, 86 per cent of India's LNG was imported from Qatar, 6 per cent from Nigeria, 3 per cent from Yemen, and small volumes from exporters including Spain, Oman, Algeria, and the United Arab Emirates.[57]

Figure 6.8: India's LNG imports, quarterly



Source: Argus (2015) Argus Direct

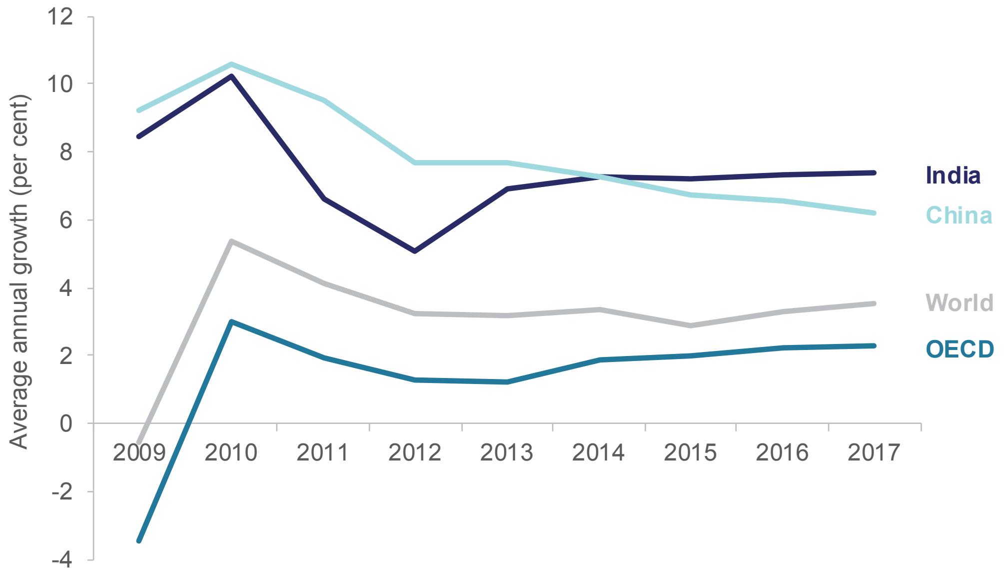
[56] Argus (2015) Argus Direct

[57] ibid

6.2 Outlook for gas demand

The key underlying driver of India's natural gas demand is its economic growth. The OECD has forecast that India's GDP growth will be maintained at over 7 per cent until 2017, much higher than average growth in the OECD of just over 2 per cent (Figure 6.9).

Figure 6.9: Outlooks for economic growth



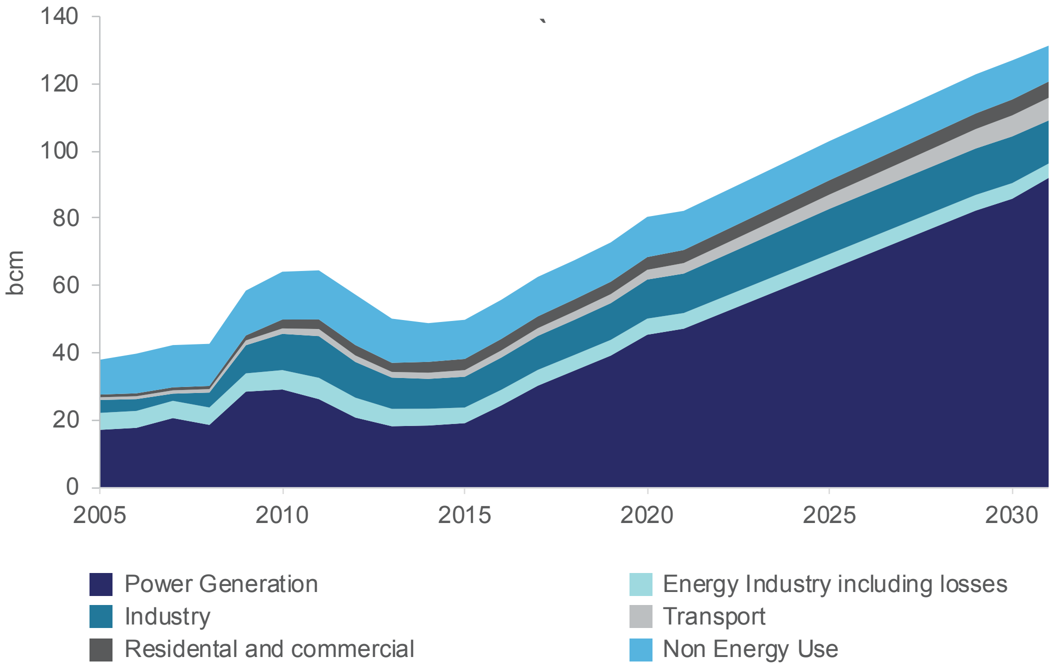
Source: OECD data (2016)

This forecast increase in GDP will need to be supported by large increases in energy and electricity consumption. Although the Indian government's commitment for all households to be electrified by 2019 may not be achieved, a substantial increase in electricity use and penetration is expected. Particularly given the size of India's population, even a gradual increase in electricity demand will mean a large increase in demand.

This prospective increase in electricity demand will need to be met using a variety of sources and fuels. There isn't a single fuel which could support India's energy growth and policy objectives, but increases in all options will be required. There are many policies in support of renewable energy, driving large increases in solar, wind and hydro power. However, the growth in renewable energy capacity is not expected to be at the expense of fossil fuel consumption. Coal use in India will continue to grow, with plans to double coal capacity by 2020. There is also huge potential growth in India's gas demand as a result of India's current low levels of energy, electricity, and natural gas consumption relative to other developed and developing nations.

As shown in Figure 6.10, India's natural gas demand is forecast to grow by over 6 per cent a year, from less than 50 bcm in 2015 to over 125 bcm in 2030. Consumption growth has been limited in recent years by high LNG prices, and lower than anticipated domestic production. Forecast low LNG prices in the medium term should help support increased consumption given current spare import and electricity generation capacity, and should provide a foundation for continued growth going forward.

Figure 6.10: Forecast Indian gas demand



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

This is consistent with a range of other forecasts expecting large increases in India's natural gas use. In its World Energy Outlook 2015, the IEA forecast India's total gas demand to reach 121 bcm by 2030, and 174 bcm by 2040.[58]

The IEA considers that Indian consumption and production dynamics will be one of the biggest uncertainties in global LNG markets going forwards.[59] As shown above, the main source of India's increasing gas demand is power generation, which will be vulnerable to a range of risks, including the rate of economic growth India is able to achieve.

Given the price sensitivity of Indian demand, the price of LNG in the context of other energy commodities will be a large factor in the dynamics of production. If India is unable to secure sufficient quantities of cheap gas, LNG imports could be reduced, but there is also an upside risk in the short term. Given India currently has significant underutilised capacity, both in terms of LNG regasification facilities and gas powered generation plants, the availability of cheap gas could rapidly increase India's consumption. However, resolving the price sensitivity in the long run will require broader reform of energy policies and other subsidies. These are very difficult policy issues, and although there are policies being put in place to address them, progress is likely to be slow.

In addition, infrastructure sufficiency is likely to continue to be a large limiting factor, and a downside risk to any forecast of substantial growth in Indian gas demand. Given the delays already in constructing pipelines throughout India, they could hamper the outlook for gas consumption. Although the Modi Government has made commitments to ease the difficulties of doing business in India, regulatory reform and ongoing approvals from the various levels of the Indian government are likely to remain slow, and India's population density and compensation laws make land access challenging.

[58] IEA (2015c) World Energy Outlook 2015

[59] IEA (2015b) Medium-term gas report

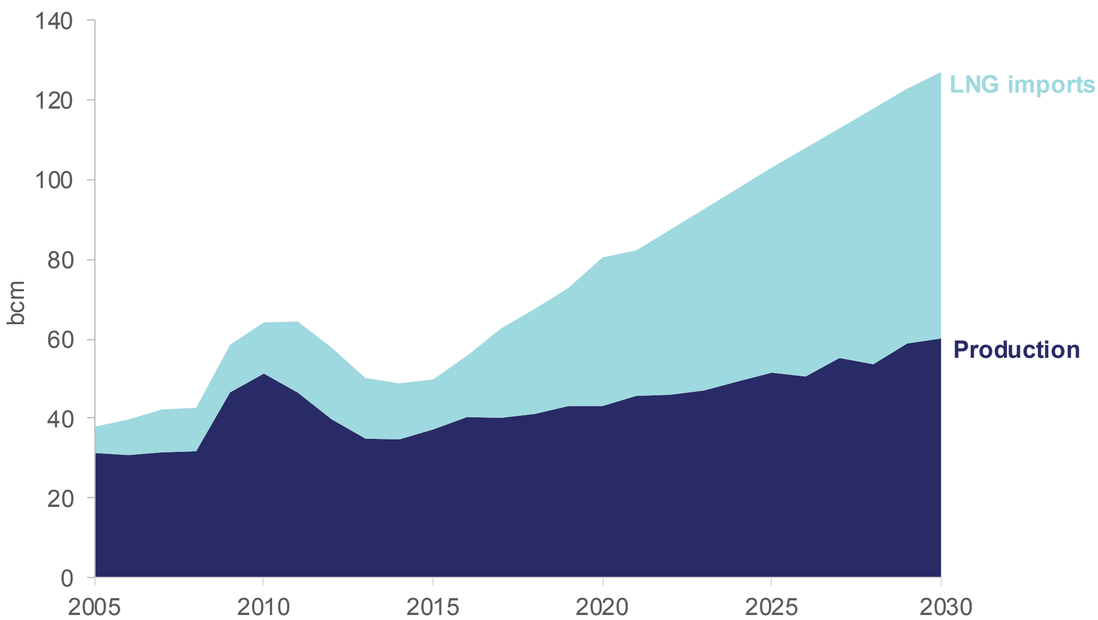
The gas demand outlook can also be impacted by climate and energy policies. A key assumption behind a growing role of gas in India and more broadly, is its role as a transition fuel to a less carbon intensive future. India has ambitious targets for large increases in solar, wind and hydro power technology. However, given the scale of India's forecast GDP and energy demand, rapid increases in renewables can coexist with equally large increases in other energy fuels, and is likely to do so. Although still a fossil fuel, gas use is associated with lower emissions than coal, and can also be used as a back-up for intermittent electricity generation from renewable energy. As such, if India is successful in reaching its renewable energy capacity targets, this could further support increased reliance on natural gas for peak power, as well as helping meet India's baseload electricity demand.

Although there are uncertainties regarding the scale and pace of India's growth in gas demand, it is clear that India's gas demand is growing, and will need to be met from a variety of sources. These sources include increased natural gas production, pipeline gas from proximal neighbours, or through increased imports of LNG. The next sections will consider outlooks for each source of gas for India, and some of the specific challenges for each in addition to the broader risks to the gas outlook outlined above.

Domestic natural gas production

Firstly, domestic production must play a key role in meeting this increased demand, but consistent with current trends, it is likely that domestic production will struggle to keep up with demand going forward. Although the volume of India's domestic gas production is forecast to increase substantially to 60 bcm by 2030, the share of domestic production in India's natural gas consumption is expected to shrink from around 75 per cent in 2015 to less than 50 per cent by 2030, as shown in Figure 6.11.

Figure 6.11: India's natural gas consumption outlook



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

Given India's energy security concerns and available reserves of natural gas, the Government of India is likely to maximise its domestic production in preference to more expensive gas imports. However, much of India's reserves are unconventional gases, including CSG and shale gas, so the extent to which India can increase its domestic natural gas production will depend on the quality of these reserves and how the costs of these technologies improve over time, relative to the imported gas price. A complicating factor is that there is limited pre-competitive geoscience information on sedimentary basins, which makes exploration more difficult, and a higher risk for companies. In addition, social licence and community support are likely to become significant issues for any onshore unconventional gas development.

Distortions in the upstream gas market continue to reduce incentives for investment, including allocations of specified quantities of gas to various sectors. Indian policy experts have been calling for further liberalisation of the Indian gas markets for a number of years,[60] but progress has thus far been slow.

A stable and attractive regulatory and fiscal regime will provide India with the best chance of optimising natural gas production; however, there is currently a lack of clarity about future policies. Debate is continuing regarding the appropriate fiscal regime for natural gas, with the government foreshadowing a future move from the current production sharing contract regime to a revenue sharing regime.

Domestic pricing of natural gas is another important aspect of the regulatory regime. The domestic price for natural gas needs to be high enough to encourage investment, but not so high that consumers are priced out of the market. India's domestic gas price is currently based on a formula providing a weighted average of a range of international gas prices, updated every six months. Although this price is higher than the very low prices previously set by government, the recent falls in global prices may have resulted in a domestic price which is too low to sustain a viable gas supply sector.

Based on analysis by the IEA, the gas price for India's domestic producers will need to increase, as the current pricing regime will not encourage sufficient investment in supply to meet projected domestic demand. The total volume required between now and 2040 is estimated to be around 2000 bcm, which is larger than India's current total proved and indicated recoverable reserves of natural gas.[61]

Another disincentive for investment is that a number of the areas which were issued by the government for exploration have since become mired in disputes over defence or international boundary issues. The latest acreage release round, announced in 2013, is still yet to be finalised, given delays in confirming that a successful applicant will have access to the permit areas. The Government of India will need to resolve these issues and makes its regulation of the sector more attractive if it wants to increase exploration and production.

Pipeline gas

Given the large potential gap between domestic supply and total demand, much of India's natural gas will need to be imported. Depending on distances, international pipelines are generally able to provide gas at a lower price than LNG. Although there is still a large upfront cost in building a pipeline, as in building liquefaction and regasification plants, the ongoing costs are much smaller.

As a result, India has been investigating a number of pipeline options for many years, including the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline and the Iran-Pakistan-India (IPI) pipeline, as shown in Figure 6.12. Both of these projects have been long delayed, largely as a result of geopolitical concerns. There are a number of other outstanding issues which would need to be resolved prior to either of these projects going ahead, including pipeline security, but also financing of the TAPI pipeline, given neither the Indian or Pakistani government can

[60] See Jain (2012) Natural Gas in India, and Kelkar (2009) Towards a new natural gas policy

[61] IEA (2015c) World Energy Outlook 2015

afford the sizable investment, and the involvement of international petroleum companies which are reluctant to invest as they are not able to take a share in the Turkmen gas.[62]

Figure 6.12: Proposed pipeline routes into India

Source: Cohen et al (2008) The proposed Iran-Pakistan-India Gas Pipeline

There still remain prospects that the geopolitical and economic hurdles of international piped gas may be overcome, but pipeline gas has not been factored into our forecasts of Indian gas supply to 2030. However, given the uncertainties around the potential timing of these pipelines, this is not a consensus view. In contrast to the projections in this report, the IEA in its World Energy Outlook 2015 considered it likely that at least one of these projects would be viable in the long term, and has forecast that pipelines will constitute 16 per cent of India's total gas imports by 2020.[63]

LNG

As a result of the challenges facing domestic production growth and pipeline imports, much of India's increasing demand will need to be met by LNG. India's LNG imports are forecast to increase to 67 bcm by 2030, or almost 50 Mtpa.

Table 6.2: India's LNG regasification capacity, proposed

Terminal	*Capacity*	*State*	*Owner*	*Completion*
Dahej expansion	+7.5 Mtpa	Gujarat	Petronet LNG	2016
Hazira expansion	+2.5 Mtpa	Gujarat	Shell/Total	2017
Kakinada	5 Mtpa	Andhra Pradesh	Andhra Pradesh Gas Distribution Corporation/GAIL	≈2017
Gangavaram	5 Mtpa	Andhra Pradesh	Petronet LNG	≈2017
Ennore	5 Mtpa	Tamil Nadu	Indian Oil Corporation	≈2019
Haldia	4 Mtpa	West Bengal	Hiranandani	≈2019

Source: Company websites

[62] Abdurasulov (2015) Is Turkmenistan's gas line a pipe dream?

[63] IEA (2015c) World Energy Outlook 2015

There is almost 30 Mtpa of import capacity under construction and soon to be completed, as shown in Table 6.2, which would bring India's total nameplate LNG import capacity to 55 Mtpa. Should all of these plants go ahead, India will be well placed to import the forecast level of LNG. There is a further 30 Mtpa of additional capacity proposed,[64] but further construction will depend on whether the current projects are successful and there is sufficient LNG demand.

LNG imports too are not without risks and challenges. Given LNG is effectively a balancing fuel for India, increases in India's LNG supply are dependent on the risks to the total consumption outlook, as well as to the extent that domestic production can be increased. Ongoing improvements in infrastructure, both in terms of committed regasification capacity and domestic pipelines, will be critical. India's LNG demand is likely to remain highly price elastic until there is broader market liberalisation across the power and fertiliser sectors. India has previously participated heavily in LNG spot markets when prices are low, but has purchased few cargoes when spot prices are high.[65] India's level of demand is likely to continue to vary according to LNG prices relative to other fuels.

6.3 Implications for Australia

Australia and India have very close strategic and economic ties, with strong growth in the economic relationship in recent years. India is now Australia's twelfth largest trading partner, and our seventh largest export market.[66] The majority of Australia's goods exports to India are energy and mineral commodities, dominated by coal, copper and gold. This trade relationship will continue to grow in the future, and Australia will play a vital role in fuelling India's growth. This will be supported by the Closer Economic Cooperation Agreement, which is currently being negotiated and is expected to be finalised soon.

This growth in demand from India will be very timely for Australia and other commodity exporters, as it is coinciding with the weakening of economic growth in China and consequent slowing of commodity demand growth. However, it is unclear whether LNG will play a significant part in Australia's growing commodity trade with India.

Australia has supplied very little LNG to India in the last two years, and these volumes have only been spot supplies.[67] Only one contract has been signed between Indian buyers and Australian sellers of LNG from Australia's current wave of LNG projects under construction. Government-owned Petronet LNG has entered into a 20 year contract for 1.5 Mtpa of LNG from ExxonMobil's share of the Gorgon LNG project offshore Western Australia, which is expected to commence production in early 2016.

This is in strong contrast to other regional buyers, which are heavily reliant on Australia for LNG supply, and will become more so as Australia's LNG production increases. In 2014–15, 20 per cent of Japan's LNG supply was from Australia, and this is expected to increase to almost 40 per cent by 2020. Australia is also expected to supply almost 40 per cent of China's LNG and 25 per cent of South Korea's LNG by the same date.

[64] Argus (2015) Argus Direct

[65] Balyan (2013) Meeting demand challenges of an emerging LNG market: India

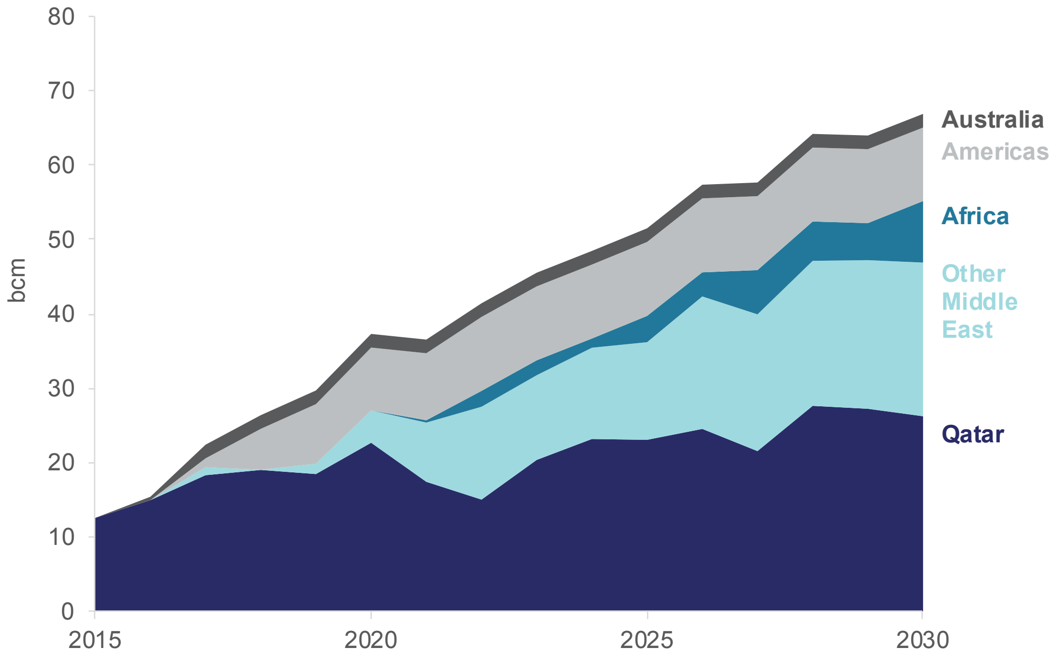
[66] Department of Foreign Affairs and Trade (2015) India country brief

[67] Argus (2015) Argus Direct

In contrast, forecasts using the Nexant WGM show Australia supplying only 5 per cent of India's LNG imports by 2030, unlikely to increase above the 1.5 Mtpa contracted from ExxonMobil (Figure 6.13). The WGM is based on a least cost optimisation of LNG trades on the basis of long run marginal costs, and this outcome is more pessimistic for Australian supply than other forecasts. The IEA, taking into account the need for India to diversify its LNG imports, expects a bigger role for Australian LNG, with over 10 Mtpa of Australian LNG supply by 2030, or almost 20 per cent of India's natural gas imports.[68]

The proportion of Australian LNG in India's future imports will depend on a large number of factors, as decisions on buying and selling LNG are based on more than just long run marginal costs. The current wave of LNG supply out of Australia is largely already contracted to long term buyers, but there remains some surplus capacity which could be sold to Indian buyers on a short or long term basis.

Figure 6.13: Sources of Indian LNG imports



Source: Department of Industry, Innovation and Science (2015); Nexant (2015) WGM

India is often considered to be undercontracted for LNG relative to its forecast growth in demand; however Indian buyers currently seem reluctant to enter into long term LNG contracts. The spot market is currently relatively cheap compared to contract prices, and may continue to be a more attractive and flexible option for India's price sensitive demand. Australia may be able to sell additional spot cargoes into India if they are offered at an appropriate price.

If Indian buyers were to consider long-term contracts, there is an increasing number of competing supply options. Given the current reliance on LNG from Qatar, Indian buyers are likely to be interested in diversifying the origin of their LNG supply, and consider other existing and emerging LNG suppliers.

Australia is one of these options, but there is also potential for further supply from other exporters in the Middle East, given their close proximity to India's west coast. There is also interest in India for emerging supply out of East Africa, given its close proximity, as well as supply from the US through the innovative tolling arrangements of the new projects under construction.

[68] IEA (2015c) World Energy Outlook 2015

Although Australia is also relatively close and has cost advantages over a number of other regions such as the US, transport cost advantages are shrinking while the oil price is low. Any transport advantage may potentially be offset by Australia's higher capital costs.

One of the key issues for Australia with respect to exporting LNG to India is this perception of Australia as a high-cost supplier. Although Australian suppliers can point out that a high cost of production does not necessarily equate to a high price for a buyer, particularly given Australia's relative proximity to Asia, this is a reputation which can be difficult to shake.

In the long term, substantial increases in supply to India from Australia would need to come from new projects, potentially brownfields expansions at existing export terminals. Proponents of these projects will be seeking long-term contracts in order to raise the required capital in order to proceed to FID. These projects will be entering into a much more crowded market than the current wave of LNG supply, with a larger range of potential buyers but also more supply competition from emerging LNG suppliers such as the US and East Africa.

Another factor which may hamper Australia's future supply to India is the very low level of foreign investment by Indian companies into Australian gas export projects, making Indian buyers less likely to be foundation buyers for any upcoming LNG projects. Indian companies have no investments in export plants and only limited investment in Australian oil and gas exploration and production, such as Prize Petroleum's investment in the Bass Basin in waters offshore Victoria, producing gas for Australia's domestic market.[69] In contrast, Indian companies have significant interests in LNG projects in East Africa, the US and Russia, supporting future supply agreements.

Australian projects will be competing against these nations to secure LNG supply contracts with India, and hence they will need to ensure they are competitively priced, and address the perception of Australia as a high cost supplier, if they wish to help India meet its growing gas needs.

6.4 Conclusion

India's natural gas demand and LNG demand is forecast to grow strongly over the medium term, but there are significant uncertainties as to the extent and the rate of that growth. Amongst a range of issues, India's price sensitivity and infrastructure limitations will be significant potential constraints on the growth of natural gas consumption, with much of the projected future demand disappearing at high prices. The extent to which India can increase its own domestic production will also play a large role in determining how much of India's gas demand is met by LNG. Government policies around exploration and development will need to be supportive to encourage participation in the sector. Continued low prices are also a risk to India increasing indigenous supply, as prices will need to be high enough to encourage ongoing investment.

Australia is potentially well placed as a proximal and reliable LNG supplier, but Indian interest in Australian LNG is currently very limited. Forecasts vary as to the extent of Australia's role in meeting India's potential future growth in LNG demand. The next wave of Australian projects will need to ensure they are able to provide competitively priced LNG if they want to participate in the Indian market.

[69] IEA (2014a) The Asian Quest for LNG in a Globalising Market

Santos GLNG feeding gas into the pipeline to Curtis Island

APPENDIX A

Gas Market Model design

A.1 Overview

The Gas Market Model calculates the demand, supply and price at each node of the eastern Australian gas network for each year of the forecast period. The model consists of a suite of data files and a central control program written in the General Algebraic Modelling System (GAMS) language. The control program solves an optimization model of the gas network, using the method of Mixed Complementarity Programming (MCP).

The model aims to find the optimal level of production from each supply source in the eastern Australian gas network. The market is modelled as an oligopoly, which means that the optimal solution is that which maximises the profits to the suppliers. Each supplier acts independently in determining their level of production, but they are constrained by competition from other suppliers. The outcome of this competition is that prices are set somewhat lower than would apply under a monopoly, but higher than would apply in a perfectly competitive market.

The model solution respects the network constraints, such as maximum production and transmission capacities, and the basic requirement that gas into a node must equal gas out of that node. A key feature of the model is that it accounts for the depletion of gas reserves over time as gas is produced from a given field each year.

A.2 Structure

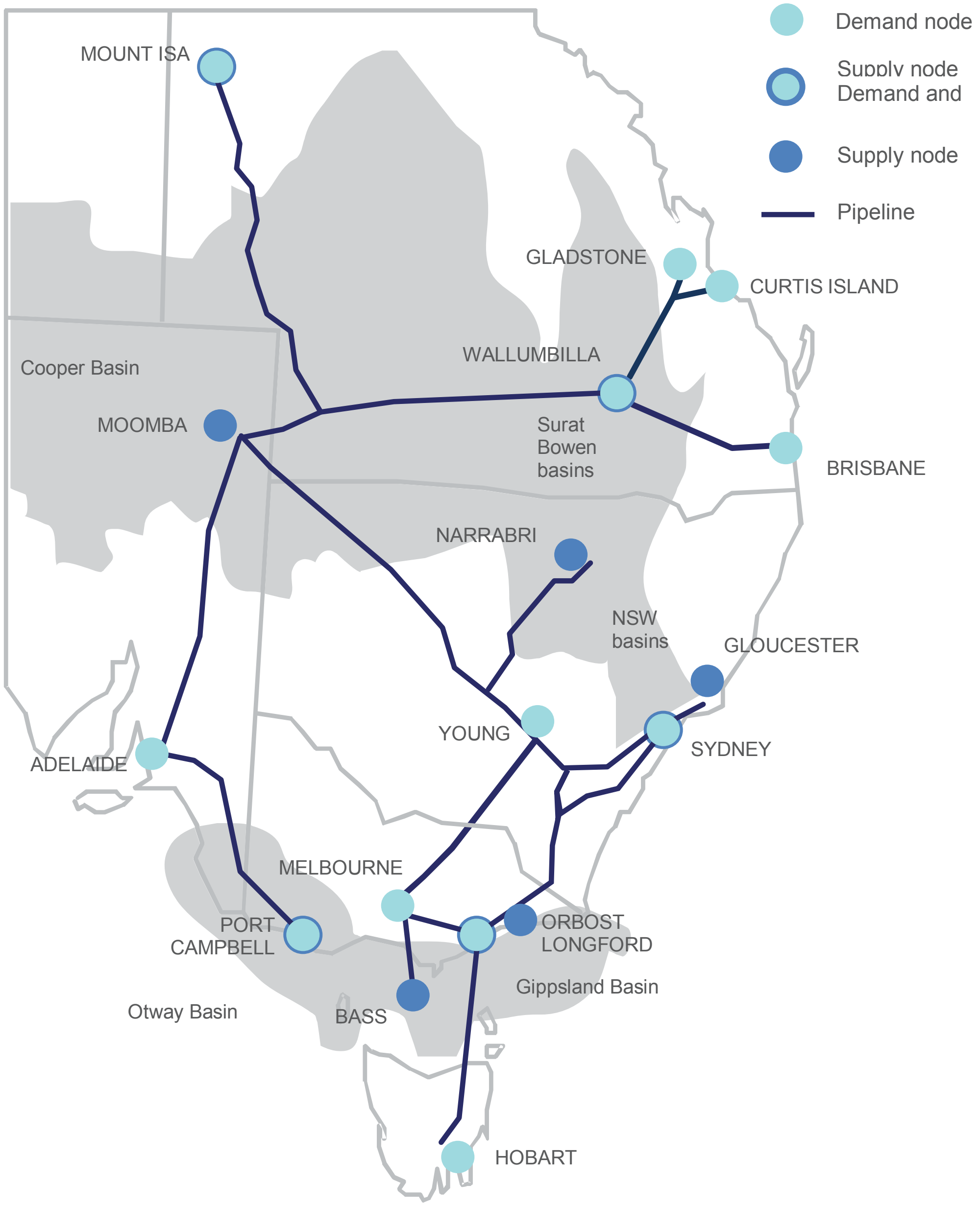
The eastern Australian gas network is represented as a network of supply and demand nodes, connected by a system of transmission lines. The current nodal structure is shown in Figure A1.

Each supply node represents an independent supplier, and has an associated maximum production limit, and a cost of production that varies with the cumulative production from the field.

Each demand node represents the consumption of gas in the residential-commercial sector, the industrial sector, and the GPG sector, each with a separate demand curve.

The existing transmission pipelines are represented by links between the nodes. They are characterised by each pipeline's maximum daily capacity, its load factor of supply, and the applicable fixed tariff. Known additions to capacity are included, such as on the NSW-Victoria Interconnect expansion. In order to model gas swaps, the pipelines can accommodate reverse flows, but net flows are limited by the known transmission capacity.

Figure A1: Gas Market Model nodal structure



Source: Department of Industry, Innovation and Science (2015)

A.3 Key design elements

1. Suppliers are the active participants. Each independent supplier chooses the level of production each year which maximises its profit, in the face of competition from other supply nodes.
2. Demand is modelled as a ‘passive’ responder to the prevailing marginal gas price (demand is a simple linear function of the gas price at each demand centre).
3. Production costs are based on estimates of the levelised cost of supply from each field.
4. The decline in gas reserves from each field is tracked each year as gas is produced from the field, with two consequences:
    - gas supply costs increase as the initial lower cost reserves are supplemented by more expensive contingent and speculative reserves
    - gas production capacity declines as the fields approach depletion.
5. Gas prices are determined by one of two methods:
    - the market is perfectly competitive, which is modelled by setting price equal to the marginal cost of supply
    - the market is an oligopoly, which means that price is set by modelling the competition between the limited numbers of suppliers, where each supplier seeks to maximise their profit.

A.4 Modelling outputs

The model balances supply and demand and calculates:

- the wholesale delivered gas price at each node
- the annual demand (in each of the three market sectors) at demand nodes
- the annual production of gas at supply nodes
- the annual flows on each transmission pipeline.

The production and transmission flows are constrained by the known capacities of these assets, but these can be changed exogenously.

The model also tracks the remaining gas reserves at each supply node, and adjusts the gas supply cost and the maximum annual production capacity appropriately.

A.5 Other assumptions

In order to achieve a workable model, the following additional assumptions are made:

1. The model matches demand and supply on an annual basis, but in reality the daily demand profile tends to peak in the winter, and supply must also match these peak days. Hence a pipeline which can carry the required annual load may have insufficient capacity during the winter. The model manages the impact of the annual profile by applying appropriate load factors to the production and transmission capacities, allowing for the use of storage facilities where appropriate.

2. The model ignores existing domestic contracts. Gas will go to where it is valued the most, or where profits can be maximised. A contract holder can always on-sell gas to a more valued location if this is profitable, which would come close to replicating the model outcomes.

3. The model takes into account the contractual arrangements between the LNG producers at Gladstone and the international customers. This is because the demand by the LNG producers is so great compared to domestic demand that these arrangements will dominate other considerations in the eastern Australian market. In practice this means that we must take into account the obligations to supply the average contractual quantities (ACQ), and the ability of the LNG buyers to reduce their orders to the take-or-pay levels in their contracts.

4. Demand responds directly to the gas price prevailing in each year. There is no allowance for a lagged price response over time, although this is likely to be the behaviour in the residential market as appliances are switched to alternative technologies over the course of time.

5. Gas production capacities are held fixed at their known daily capacities, unless gas reserves are low. New capacity can be added exogenously by means of scenarios. This avoids the situation where the model chooses capacity endogenously and 'solves' the supply shortfalls (as in a black box) in ways that may or may not be realistic.

6. Gas production capacity falls as reserves approach depletion. The model reduces capacity so that the reserves-to-production capacity ratio does not fall below six years. The reserves are the remaining 2P plus 2C reserves. This models both the natural decline of gas reservoirs, and the expectation that when reserves are this low, it would not be economic to invest capital to maintain production levels.

A.6 Gas Market Model methodology

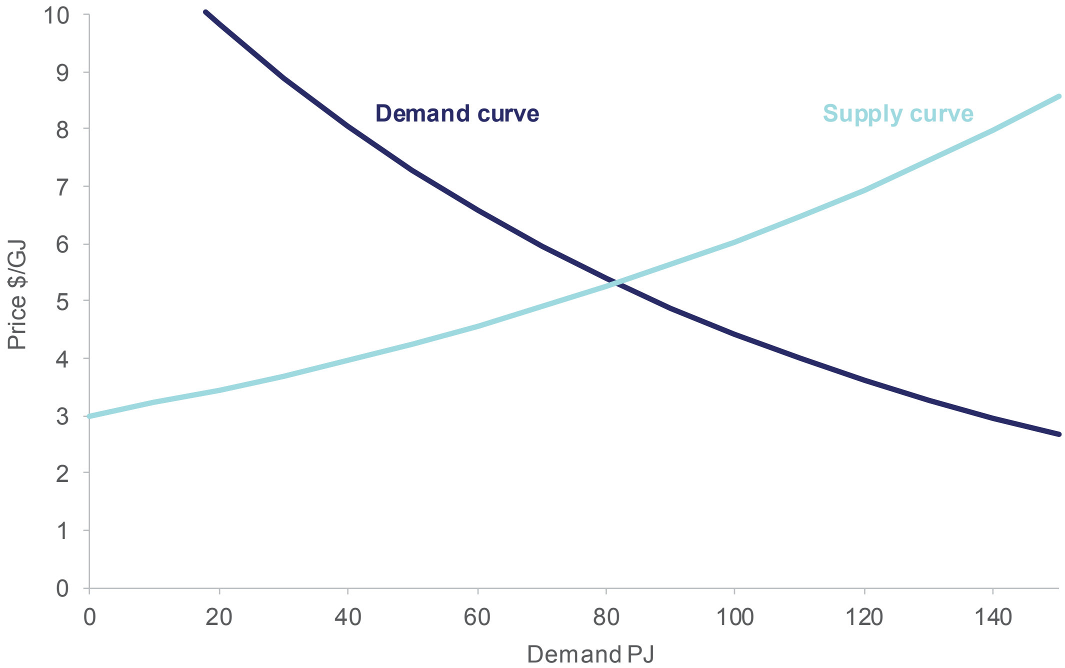
The model balances supply and demand each year over the nodal network, using the supply and demand curves at each node, and hence determines the price applying at each node. It does this by determining the optimal production level at each supply node, and the volume of production that is sold to each demand node.

The model sets prices so as to maximise supplier profit, which is the difference between the revenue from sales at each demand node and the cost of production (where the cost of production includes the cost of transmission). The methodology is a decentralised, profit-maximising algorithm based on the Cournot model.

This algorithm is considerably more complex than similar models that solve by minimising the cost of supply, since in a decentralised model the algorithm must calculate the optimal sales from each producer to every demand node on the network. However the pricing equation is a simple modification of the marginal pricing rule.

In the case of a perfectly competitive market the optimal price and quantity are determined where the supply and demand curves cross (Figure A2). At this point price is equal to the marginal cost. Theory says that when this rule applies, social welfare (represented as the sum of consumer and producer surpluses) is maximised.

Figure A2: Balancing supply and demand



Source: Department of Industry, Innovation and Science (2015)

However in an oligopoly, the pricing rule includes a mark-up over the marginal cost — that is, prices are always higher in an oligopoly. The ability to command a mark-up over marginal cost is a measure of market power. In the Cournot solution, the two factors which determine the level of market power, and hence the extent of the mark-up, are the extent of competition, and the price elasticity of demand.

$$\text{Price} = \text{marginal cost}^{i} * (1 - \text{market share}^{i} / \text{elasticity})$$

- the greater the number of competitors, the smaller the mark-up (in the limit the solution approaches perfect competition);
- the greater the elasticity, the smaller the mark-up (producer market power is mitigated if the customers can easily substitute gas with an alternative supply — that is, if demand is highly elastic).

If the mark-up term is set to zero, the optimisation algorithm will return the same solution as in a perfectly competitive market. Hence the Gas Market Model includes a multiplier on this term, called the Market Power Index, which represents the strength of market power present at a particular demand node. It can vary from zero (perfect competition) to one (oligopoly).

The index can be interpreted as:

- an increase in the perceived elasticity which influences the price setting process (for example, long run elasticities might be larger than the short-run elasticity used to calculate demand)
- a reflection that market power is limited by other factors.

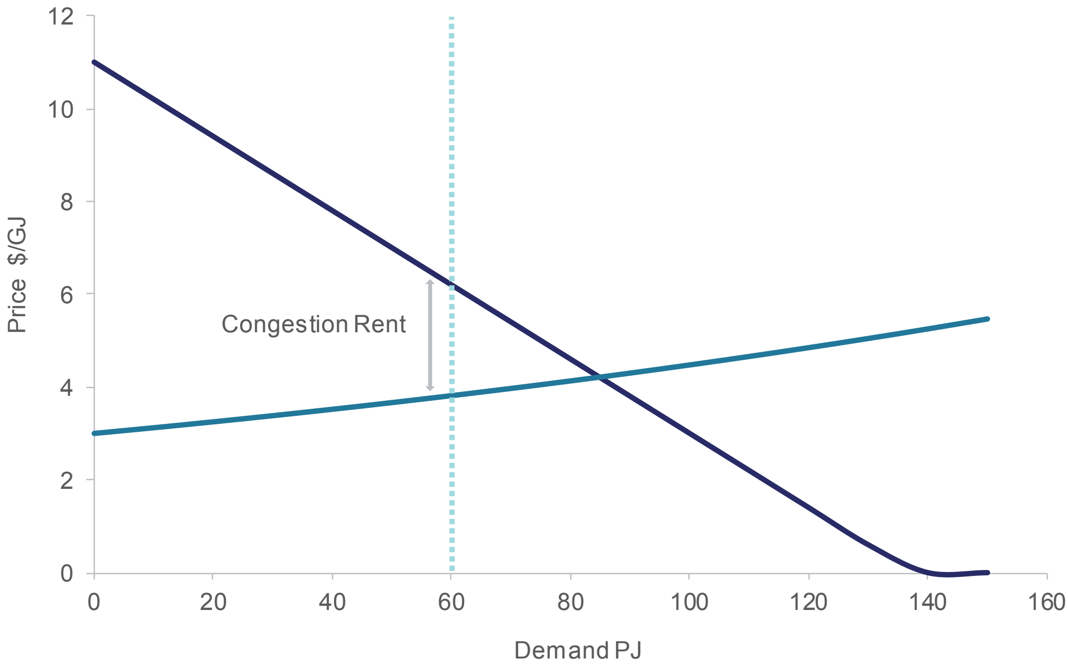
The base case for most modelling scenarios uses an index of 0.5, which appears to give the most reasonable results. For the first two years 2014 and 2015, the index was set to zero, giving perfect competition results. This was an approximation to reflect the wind down of legacy contracts, which are otherwise not modelled.

The model uses MCP to find the optimal solution each year. It is based on the modelling of Harker and further development of that work by Wagner (see Appendix B for a full description).

A.7 Impact of constraints

A constraint exists when the production from a field, or the flows along a pipeline, have an upper bound due to a physical capacity limitation. The presence of production or transmission constraints can cause prices to exceed marginal cost, even in a perfectly competitive market, as shown in Figure A3.

Figure A3: Constrained production



Source: Department of Industry, Innovation and Science (2015)

This leads to a separation of prices and costs, where the price required to clear the market, and the cost required to meet demand, are different by an amount called the congestion rent.

If a constraint binds (that is, if optimal flows would exceed the capacity constraint), then prices will increase to reduce demand to the level allowed by the constraint. In the case of a production constraint, the congestion rent is available to the producer, but it is difficult to separate this effect from market power.

In the case of a transmission constraint, the congestion rent can be claimed by a number of parties. In the case of electricity networks the rent can be claimed by an Independent System Operator (colloquially called ‘black hole money’). In the Gas Market Model, the rent is assumed to go to the transmission owner. It is calculated by the model and reported as an output, and serves as an indicator of where transmission capacity expansion may be desirable.

A.8 Demand functions

Demand at each node is modelled as a linear function of the wholesale price at that node. The nodal demand consists of a demand function for each of main market sectors:

- Residential-commercial load
- Industrial load
- GPG load.

The demand function (Figure A4) is:

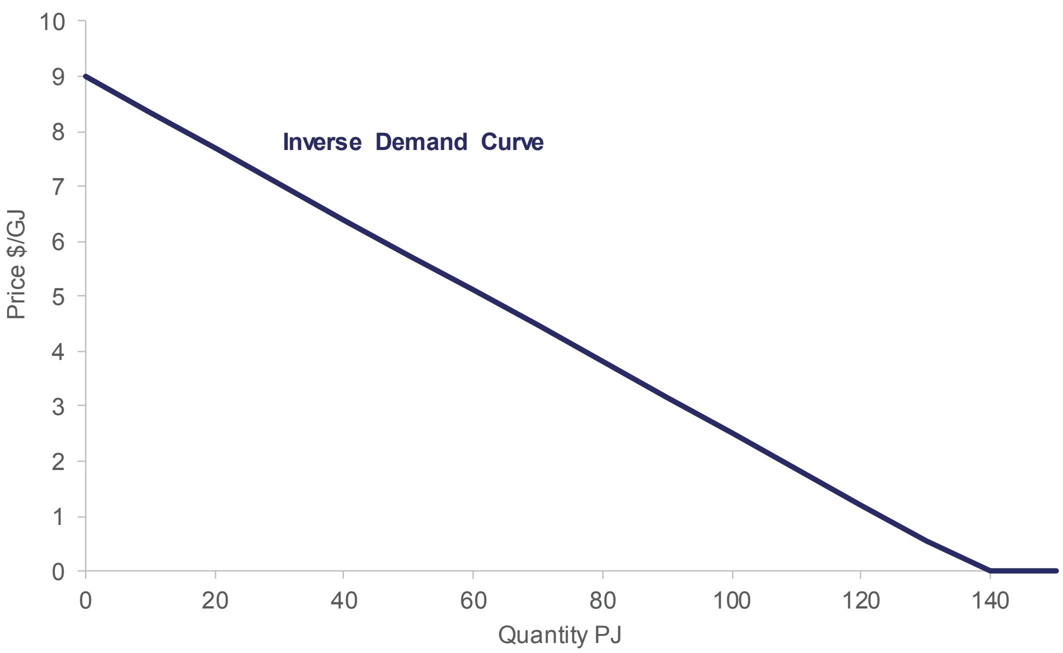
$$Q(t) = a(t) \left(1 - \beta P(t) \right)$$

The base parameter a(t) varies over time according to the range of non-price related factors at work at that demand node (such as economic growth and, industrial closures). The demand parameters are derived from projections in the AEMO National Gas Forecasting Report (2014). The parameter β determines the elasticity of demand, and is chosen to be consistent with these projections.

The demand elasticity is a key parameter in the model, as it is crucial to the way that market power can be exercised. Gas demand responds to the selling price of gas, where the selling price includes the wholesale delivered gas price, plus the distribution and retailer margins. These margins are only significant in the residential-commercial market, and act to reduce the wholesale price elasticity in this sector to a value estimated as about –0.1 (where a 10 per cent increase in wholesale prices results in only a 1 per cent decrease in demand).

The consumers in the industrial and GPG sectors pay a tariff at the burner tip which is much closer to the wholesale price. On average the wholesale price elasticity is assumed to be about -0.5 for the industrial market, and around –0.9 to –1.1 for the GPG market.

Figure A4: Indicative demand function



Source: Department of Industry, Innovation and Science (2015)

A.9 Supply functions

The cost of supply is the key parameter in setting the final wholesale price. At any given level of production, the cost of production will set the lower bound on the price charged in the market.

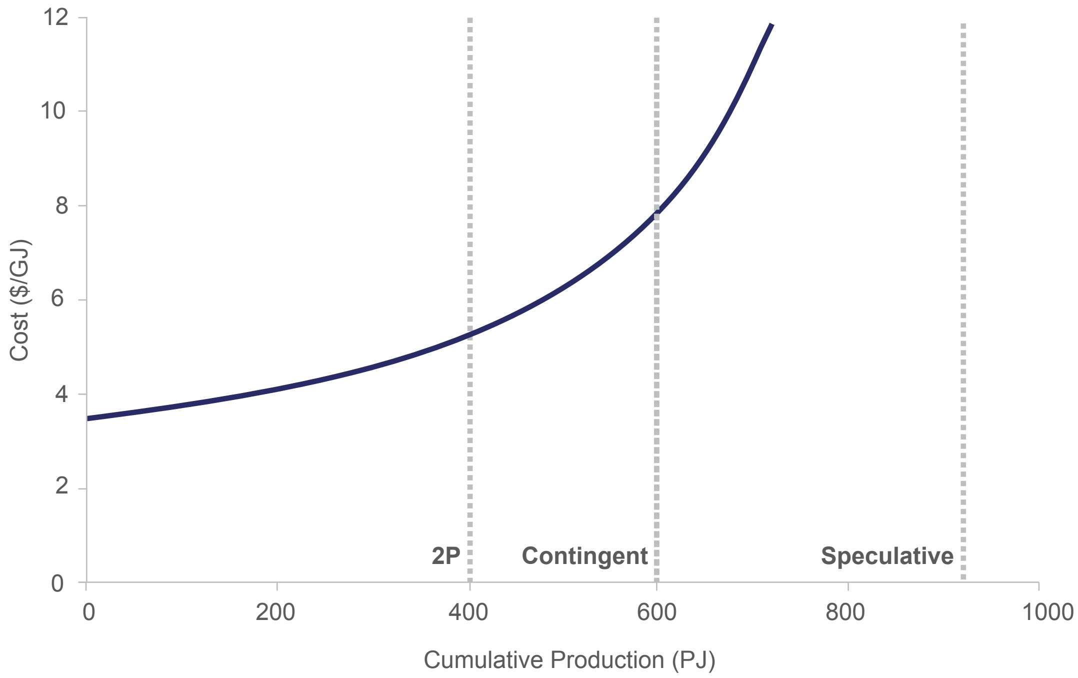
Unfortunately there is very little reliable and verifiable data on the costs of production from existing and prospective gas fields. This is partly because of commercial confidentiality, but also because of the diverse and field-specific nature of costs, and the inherent uncertainties of each potential development.

The Gas Market Model uses a levelised cost of production for each supply node, based on estimates published by SKM . These estimates provide the costs of production of the 2P reserves, and a cost for the (as yet undeveloped) 2C reserves. Based on recent anecdotal information, and to be conservative, the 2C reserves costs have been escalated by 20 per cent.

The impact of reserve depletion is modelled by allowing the cost of supply to increase as the reserves are consumed. Figure A5 shows how the cost of production increases for a typical gas field.

The cost curve is represented by a Golombek function, which is a simple mathematical representation of a complex underlying process. In reality, the 2P reserves will be produced at a known levelised price, but before they are completely depleted, new developments of the potentially more expensive 2C reserves will be undertaken to support production, and the average cost of production is therefore likely to increase (before the 2P reserves are depleted). Hence in the Gas Market Model, gas reserves do not so much deplete, as become too expensive to produce.

Figure A5: Supply cost function



Source: Department of Industry, Innovation and Science (2015)

APPENDIX B

Gas Market Model documentation

B.1 Model structure

The Gas Market Model is a suite of data files and a central control program written in the GAMS programming language. The GAMS program file reads all input data from an Excel file, and sets up the relevant model equations to solve the supply and demand balance on a network.

The GAMS file calls on an MCP solver program to calculate the optimal solution for the model. This solver is available within the proprietary PATH suite of solvers.

Output is written to an Excel file, or it can be read using the utility program GdxViewer if desired.

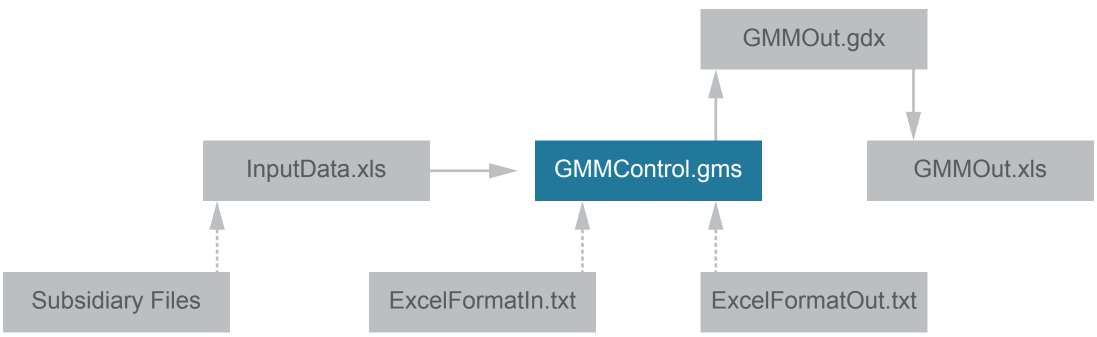
The GAMS program file GMMControl.gms is shown in Figure B1

The GAMS file reads in all the relevant data from an Excel file called InputData.xls, using formats in ExcelFormatIn.txt. This data includes the nodal structure, the demand and supply functions, the production limits and the capacity and tariffs for each of the transmission links which constitute the network.

The nodal structure is shown in Appendix A.

The logical structure of the suite of files making up the model is shown in Figure B1.

Figure B1: Logical model structure



Source: Department of Industry, Innovation and Science (2015)

After the GAMS file has been compiled and executed, an output file GMMOut.xls is created, based on formats specified in ExcelFormatOutp.txt. This summarises the output and presents it in graphical form. The Excel output file is created by conversion of a GDX file, which is also created by the program.

Nodes

Each node is named and is treated as both a supply and demand node. If there is no supply, a very high supply cost is assigned to prevent production. If there is no demand, a very low demand function is assigned to prevent any demand. In this way the same code in the GAMS file can be used for all nodes.

Production capacity can be capped by placing an upper bound on the nodal production.

Links

Links in the Gas Market Model represent the transmission lines between nodes. Each link has a transmission capacity constraint and an associated transmission tariff. Transmission constraints are not imposed by applying an upper bound on the transmission flow variable. Analysis showed that the MCP method breaks down if flows reach a transmission constraint within the oligopoly model.

Instead, a transmission constraint is applied by escalating the transmission tariff with an exponential function when flows exceed the maximum transmission capacity. This causes the transmission tariff for constrained pipelines to exceed the standard rate. The escalation represents the congestion rent accruing to the pipeline owner.

B.2 Modelling methodology

The GAMS control file is a development of the Harker Model which is available in the GAMS Model Directory. There are two models which can be run simultaneously within the same GAMS file:

Table B1: Harker models

	Model Name
Perfect Competition	harker
Oligopoly	harkoli

Source: GAMS Model Directory

The models consist of six (harker) or seven (harkoli) equations. Most equations ensure the model solves on the network correctly (for example, gas into a node equals gas out of a node). These equations are self-explanatory.

The key equation is the market clearing equation.

- In harker it is ***mrmc*** Set price to marginal cost
- In harkoli it is ***altmrmc*** Set price to marginal cost plus oligopoly mark up

The model loops through each year of the forecast period.

There is no relationship between the variables from one year to the next except for the remaining reserves at each node. This means that each year is solved independently of earlier years. However the remaining reserves at each node do determine the production cost at that node for that year (production costs increase as reserves decline). One consequence of this structure is that it is not possible to model a lagged demand response to prices.

B.3 Structure and Linkages

Main Program Files

harkmcpDev20.gms	GAMS file (opened in NotePad); run within GAMS IDE interface
InputData20.xls	Excel file containing all input data; called by .gms file
MCPOutput20.xls	Excel file where output of .gms file is written

GAMS utility files

(used by or created by GAMS after each run, for diagnostic purposes)

harkmcpDev20.lst	List file created by GAMS containing standard GAMS diagnostics, compilation errors, and output of any Display statement in .gms file
harkmcpDev20.log	Log file created by GAMS showing execution events and errors (only needed if program crashes on execution)
gmsproj.gpr	Project file which must be specified when GAMS is opened; shows in which directory all output will be filed.
MCPOutput20.gdx	An intermediate file used to create the MCPOutput.xls file. Can be viewed separately using GdxViewer; same output as in .xls file,

Support Files

(used by GAMS when .gms program is run to allow interface with Excel files)

ExcelInput20.txt	Text file (opened in NotePad) showing Excel format of all variables in InputData20.xls which are called by .gms program.
ExcelOutput20.txt	Text file (opened in NotePad) showing Excel format of all variables in MCPOutput20.xls which are written by .gms program.

Subsidiary Files

(data processing for subsequent use in InputData.xls)

SupplyCostsModel20.xls	Calculates supply cost curves for each supply node, for transcription into InputData20.xls
TransmCostModel20.xls	Compendium of transmission capacities, load factors and tariffs
Demand Forecast20.xls	Calculates demand functions for each demand node from AEMO forecasts, for transcription into InputData20.xls
Reserves/Production.xls	Reserves and production capacity data

The Subsidiary and input data files are available on application.

GAMS Code

```
$title Models of Spatial Competition in MCP Form (HARKMCP,SEQ=128)

$Ontext

        Adapted from Harker, P T, Alternative Models of Spatial Competition. Operations

        Research 34, 3 (1986), 410-425.

$Offtext

$eolcom  #

sets    n   nodes

        l(n)            supply and demand nodes

        coefslabel      labels for columns in coefs /alpha, beta, rho, eta, prodcap/

        pairslabel      labels for columns in pairs /kappa, nu, transcap/

        sdlabel         labels for suppdat       /URR, cost1, cost2, cost3, R2P, R2C/;

set   i year /2014*2030/;                   # index for each year over which model is run

*     linear demand function:

*          d(p) = (rho - p) / eta

*     linear marginal cost function:

*          c(y) = alpha + 2 * beta * y

alias (l,lp),(n,np);

parameter       coefss(l,coefslabel,i)

                coefs(l,coefslabel)         demand and supply data

                suppdat(l,sdlabel);

parameter       pairss(n,np,pairslabel,i)

                pairs(n,np,pairslabel)     transport costs and capacities;

parameters      QO(l)                      initial values of cumulative production

                RR(l), RemR2P2C(l)         remaining reserves

                ToP(l,i), LNGProd(l,i)     amounts associated with LNG production contracts

                MP(l,i), MPindex(l)        index of Market Power

                congest(n,np,i)            congestion costs on links

                pcost(l,i), zz(l)          calculated production cost in year i;

$call gdxxrw.exe I=InputDatav13.xlsx @ExcelInputv13.txt

$gdxIn InputDatav13.gdx

$load n,l,suppdat,coefss,pairss,ToP,LNGProd,MP
```

```
$gdxIn
display  l,n, coefss, suppdat, MP;
*          the market is structured on a network.  the total transport cost
*          on the ij link is given by:
*          tcij = kappaij  * xij  (Note change from original Harker)
*          “nu” will now apply a tramsmission constraint
set arc(n,np) active arcs;
parameter        elast(l)            price elasticity at demand node
                 balance(i)          indicator that supply equals demand;
QO(l) = 0;  RR(l)=suppdat(l,”URR”);
RemR2P2C(l) = suppdat(l,”R2P”) + suppdat(l,”R2C”);
positive variables
          d(l)               consumer demand,
          c(n)               marginal cost,
          y(n)               production,
          x(n)               total sales,
          p(l)               consumer price,
          t(n,np)            transport;
equations
*          equations for basic Perfect Competition model:
          demand(l)          inverse demand function (linear),
          supply(n)          node balance condition,
          mkt(l)             market clearance,
          mrmc(l)            pricing equation,
          tcost(n,np)        transport cost equation,
          cost(n)            marginal cost of supply;
*          market structure flags:
*          in these equations the associated variable is listed after
*          the description:
*           inverse demand functions (d):
demand(l)..       coefs(l,”eta”) * d(l) =g= coefs(l,”rho”) - p(l);
*          node balance (c):
```

```
supply(n)..         y(n)$l(n) + sum(np$arc(np,n), t(np,n)) =g=
                    x(n)$l(n) + sum(np$arc(n,np), t(n,np));
*       supply-demand balance (p):
                    mkt(l)..       x(l) =g= d(l);
*       pricing equation relating marginal cost to consumer price (x):
mrmc(l)..           c(l) =g= p(l);
*       transport activity zero profit condition
tcost(n,np)$arc(n,np)..
                    c(n) + pairs(n,np,"kappa") *
                    (1+pairs(n,np,"nu")*exp(min(15,250*(t(n,np)-t(np,n)-pairs(n,np,"transcap")))))
=g= c(np);
*                   marginal cost equations:
cost(l)..                     coefs(l,"alpha") + 2 * coefs(l,"beta") * y(l) =g= c(l);
*       define the model and the equation.variable associations:
*model harker /demand.d, supply.c, mkt.p, mrmc.x, tcost.t, cost.y/;
*       additional variables for oligopoly model:
positive
variables
        cc(l,n)             cost of supply to node n by producer l,
        xx(l,n)             supply from producer l to market lp,
        tt(l,n,np)          shipments by producer l from node n to np;
*       revised equations for oligopoly model:
equations
                    altsupply(l,n)          node balance equation,
                    altmkt(l)               demand balance,
                    altmrmc(lp,n)           pricing equations,
                    alttcost(l,n,np)        transport margins,
                    altcost(l)              supply price equation,
                    tdef(n,np)              total transport demand;
set  prd(l,n)       indicator set for producer type l operating at node n;
prd(l,n) = no;
prd(l,l) = yes;
*                   material balance:
```

```
altsupply(lp,n)..
            y(lp)$prd(lp,n) + sum(np$arc(np,n), tt(lp,np,n)) =g=
            xx(lp,n)$l(n) + sum(np$arc(n,np), tt(lp,n,np));
*                       demand balance:
altmkt(l)..                         sum(lp, xx(lp,l)) =g= d(l);
*                       pricing equation:
altmrmc(lp,l)..
            cc(lp,l) =g=
            p(l) - xx(lp,l) * coefs(l,"eta") * MPindex(l);
*           transport activity zero profit condition:
alttcost(l,n,np)$arc(n,np)..
            cc(l,n) + pairs(n,np,"kappa") *
            (1+pairs(n,np,"nu")*exp(min(15,250*(t(n,np)- t(np,n)- pairs(n,np,"transcap"))))) =g=
            cc(l,np);
*           total transport demand
tdef(n,np)$arc(n,np)..
            t(n,np) =e= sum(l, tt(l,n,np));
*           marginal cost of supply:
altcost(l)..
            coefs(l,"alpha") + 2 * coefs(l,"beta") * y(l) =g= cc(l,l);
model harkoli  /demand.d, altsupply.cc, altmkt.p,altmrmc.xx,
                        alttcost.tt, altcost.y, tdef.t/;


parameters      reptransp (n,np,i)                  transport summary,
                repsupply(l,i), repdemand(l,i),     # supply demand and price summary;
                repprice(l,i), repelast(l,i),
                represerves(l,i), repmaxprod(l,i);
t.l(n,np) = 0;
y.l(l) = 25;
x.l(n) = 1;
c.l(n) = 1;
d.l(l) = 1;
p.l(l) = 1;
```

```
Loop(i,

arc(n,np) = yes$pairss(n,np,"kappa",i);

t.fx(n,np)$(not arc(n,np)) = 0;

tt.fx(l,n,np)$(not arc(n,np)) = 0;

*   Impose production capacity constraints, allowing production to decline when reserves are low

y.up(l) = min( coefss(l,"prodcap",i), RemR2P2C(l)/6 );

coefs(l,coefslabel) = coefss(l,coefslabel,i);    # This is needed to avoid un-controlled set references in coefs outside of loop

pairs(n,np,pairslabel) = pairss(n,np,pairslabel,i);

*          solve two alternative models, all based on the same data:

$Ontext

*          1. classical spatial price equilibrium: perfectly competitive

*          producers and suppliers facing average cost pricing

*          of transportation:

           pcost(l,i)=100;  zz(l)=suppdat(l,"URR")/RR(l)/30;

           pcost(l,i)$(zz(l)<0.99)=suppdat(l,"cost1")-suppdat(l,"cost2")*log(1-zz(l));

           pcost(l,i)$(pcost(l,i)<suppdat(l,"cost3")) = suppdat(l,"cost3"); # Price floor

           coefs(l,"alpha")=pcost(l,i);          # set annual prod cost using cost function

           solve harker using mcp;

           QO(l) = QO(l) + y.l(l);  RR(l) = max(RR(l) - y.l(l),.01);  RemR2P2C(l)
           =max(RemR2P2C(l)-y.l(l),.01);

           reptransp(arc,i) = t.l(arc)+.001;

           repsupply(l,i) = y.l(l)+.001;

           repdemand(l,i) = d.l(l)+.001;

           repprice(l,i) = p.l(l)+.001;

           elast(l) = -p.l(l)/max(coefs(l,"rho")-p.l(l),0.0001);

           repelast(l,i) = elast(l);

           congest(n,np,i)$arc(n,np)= pairs(n,np,"kappa")*pairs(n,np,"nu")*exp(250*(t.l(n,np)-
           t.l(np,n)- pairs(n,np,"transcap")));

$Offtext

*          2. multi-producer oligopoly model with average cost pricing

*          of transportation links:

           pcost(l,i)=100;  zz(l)=suppdat(l,"URR")/RR(l)/30;
```

```
        pcost(l,i)$(zz(l)<0.99)=suppdat(l,"cost1")-suppdat(l,"cost2")*log(1-zz(l));

        pcost(l,i)$(pcost(l,i)<suppdat(l,"cost3")) = suppdat(l,"cost3"); # Price floor

        coefs(l,"alpha")=pcost(l,i);          # set annual prod cost using cost function

        MPindex(l) = MP(l,i);                 # set market power index for year i

        solve harkoli using mcp;

        QO(l) = QO(l) + y.l(l);   RR(l) = max(RR(l) - y.l(l),.01); RemR2P2C(l)
        =max(RemR2P2C(l)-y.l(l),.01);

        balance(i) = sum(l, y.l(l) - d.l(l) );

        reptransp(arc,i) = t.l(arc)+.001;

        repsupply(l,i) = y.l(l)+.001;

        repdemand(l,i) = d.l(l)+.001;

        repprice(l,i) = p.l(l)+.001;

        represerves(l,i) = RemR2P2C(l);

        repmaxprod(l,i) = y.up(l);

        elast(l) = -p.l(l)/max(coefs(l,"rho")-p.l(l),0.0001);

        repelast(l,i) = elast(l);

        congest(n,np,i)$arc(n,np)= pairs(n,np,"kappa")*pairs(n,np,"nu")*exp(250*(t.l(n,np)-
        t.l(np,n)- pairs(n,np,"transcap")));

*  Note the trick to add .001 to all reported variables so whole file is printed

);    #   End of loop over years i

        display i,coefss, RR,RemR2P2C, balance;

*       Write output variables from oligopoly model to a GDX file GMMOutputv13.gdx

Execute_Unload "GMMOutputv13", coefss, pairss, congest, repsupply, repdemand, repprice,
repelast, reptransp,

represerves, repmaxprod, pcost, d, c, y, p, t, cc, xx, tt, LNGProd, ToP, MP, balance;

Execute "gdxxrw.exe I=GMMOutputv13.gdx @ExcelOutputv13.txt";
```

APPENDIX C

LNG demand function

The three LNG plants at Gladstone are expected to consume more than twice the entire demand in the eastern Australian domestic market each year. As such, the relationship of this demand to the cost of gas supply is a key factor in determining domestic price levels.

The consumption of gas in the LNG plants is a derived demand. It depends on the demand for LNG in the international market, and this in turn is dominated by the contractual arrangements between the LNG producers and their customers. It is necessary to understand how the LNG contracts work in order to construct the LNG demand function.

In addition, the price obtained from LNG spot and contract sales is based on international benchmarks (including oil-linked prices) and is not related to the cost of gas supplied into the LNG plant.

In order to make this a manageable problem, the activities of the LNG producers has been conceptualised as a two part process:

1. Gas production by each LNG producer

   Each LNG producer possesses leases on a number of CSG fields and has installed gas production facilities in these fields. This capacity is treated as an independent supply node within the model. The supply node is a profit-maximising entity, and aims to sell to all potential buying entities, including its related LNG production plant, other LNG plants, or the domestic market. In practice, most gas will be supplied to its related LNG plant as this has the lowest transmission delivery cost amongst all potential buyers. However if the installed gas production capacity exceeds own-use requirements, the excess is available for sale on the open market, and vice versa.

2. Gas demand into the LNG plant

   The LNG plant is assumed to be a demand node, which takes more or less domestic gas production into the plant according the demand for LNG and the price of the gas supply into the plant. As with other demand nodes, it is a passive entity, such that demand is determined by the price of the gas on offer in the market at that location. However, the LNG demand must take account of the terms and conditions in the LNG sales contracts, since these dominate the LNG demand function.

The LNG contracts are incorporated within the LNG demand function by using two distinct linear functions:

1. Firm' demand up to take-or-pay levels

   It is assumed that the LNG sales contracts allow the LNG buyer to take less than the annual contract quantity at the buyer's discretion, but must pay for the LNG up to the take-or-pay level whether the LNG is taken or not. This sets a floor for gas demand into the LNG plant.

   Once an LNG sales contract is signed, this floor level of demand must be supplied to the buyer, irrespective of the cost of gas into the LNG plant. Therefore there is no concept of a long run netback price which sets a cap on how much an LNG producer would pay.

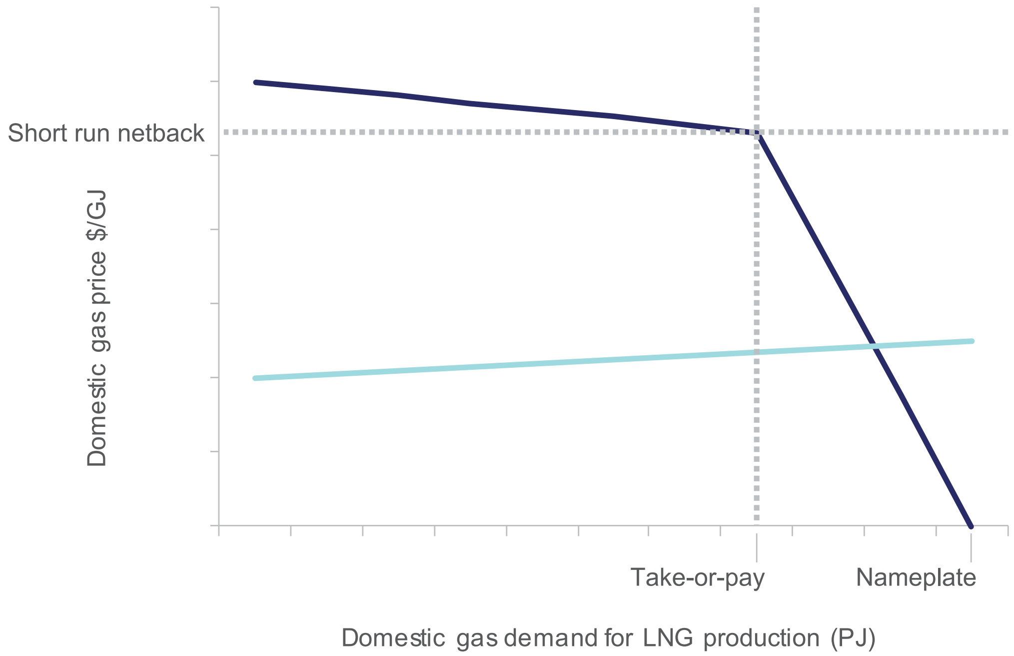
Long run LNG netback pricing is only relevant when an LNG producer is building up a portfolio of supplies to underwrite a prospective sales contract. During this period, the producer will primarily seek to develop their own gas reserves, as a hedge against future price escalations. They may also seek gas in the domestic market, and might be willing to pay up to the long-run netback. However, unless there is a severe shortage of supply capacity during this build-up period, competition between suppliers should keep prices below long-run netback levels, even in an oligopolistic supply market.

2. Flexible demand between take-or-pay levels and nameplate capacity

   LNG buyers have discretion on consumption above take-or-pay levels. It is assumed that if they can purchase spot LNG for less than contract prices, then they will reduce their take from the contract and buy on the spot market. The producer might also profit by substituting low cost spot LNG in place of purchases of domestic gas for LNG sales; or if spot LNG prices are high, by increasing production up to nameplate and selling spot cargoes above their contracted levels.

   This is modelled by a linear demand function expressing the level of gas demand into the LNG plant as a function of the price of domestic gas offered for sale at the LNG demand node. If suppliers in the domestic market (including the LNG supply nodes) can offer gas production to the LNG demand node at close to zero prices, the LNG demand node will take the absolute maximum of gas, and produce LNG at nameplate capacity (noting that the amount of gas purchased from suppliers is greater than the quantity of LNG produced by the amount of gas used in LNG production, which is approximately 9 per cent). As the gas supply price rises, demand in the LNG demand node will fall to the take-or-pay level, when the gas price is equal to the short-run netback (the LNG spot price, less shipping costs and short-run liquefaction costs).

Figure.C1: LNG demand function



Source: Department of Industry, Innovation and Science (2015)

This approach essentially assumes that (after contracts have been signed) LNG production decisions will be based on short-run costs and prices. Capital costs are sunk and must be recovered over the long-run by sales at oil-linked international prices.

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