Recent Australian Natural Gas Pricing Dynamics and Implications for the U.S. LNG Export Debate

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Key Findings

- Critics of U.S. LNG exports have cited events in eastern Australian gas markets as a cautionary tale for U.S. policy toward LNG. Their claims are (1) that demand by eastern Australian liquefaction facilities for natural gas feedstock has driven up long-term natural gas contract prices and made it difficult for industrial gas customers, gas-fired power plants, and local gas distribution companies to procure long-term gas supplies and (2) that a similar fate awaits U.S. gas consumers if a substantial number of U.S. LNG projects are approved and enter operation.

- The first key finding of this report is that the demand for natural gas feedstock by eastern Australian liquefaction plants has indeed been large (in absolute terms and as a percentage of the non-LNG market) and has affected long-term natural gas pricing, the availability of long-term natural gas contracts, and non-LNG gas consumption plans in eastern Australia.

- However, the second finding of this report is that market characteristics of eastern Australia are much different from those in the United States and that the large movements seen in eastern Australian long-term contract prices are not expected to occur in this country. Instead, it is expected that U.S. gas supplies will grow along with new demands from U.S. liquefaction plants and that the U.S. gas market is expected to experience only modest price increases and losses of non-LNG loads.

- The first and most important factor that points to a different expectation for the U.S. market is that the domestic market in eastern Australia is small compared to the size of any one LNG project and to all projects in aggregate. In contrast, the U.S. LNG projects individually and in total are a much smaller part of the U.S. natural gas market.

- The second and closely related factor is that regional markets in Australia are not adequately interconnected to each other by pipeline and so demand increases can have big price effects. In the United States, the markets are strongly interconnected through the extensive gas pipeline network and the impacts of demand increases can be spread out over a much larger market area. Moreover, the U.S. trades gas through pipelines with Canada and Mexico making the effective market size even larger.

- A third important consideration is that the supply sources in eastern Australia for the LNG projects are new coalbed methane (CBM) development projects, which have not all performed as well as expected.[1] More wells and higher capital costs will be needed to achieve target production rates at CBM sites. The United States has a much more

[1] The Australian, 2013, "Triple whammy sparks $5bn blowout for BG's Gladstone project," http://www.theaustralian.com.au/business/companies/triple-whammy-sparks-5bn-blowout-for-bgs-gladstone-project/story-fn91v9q3-1226346265187#.

diverse set of supply options and recent well productivity tends to be at or above expectations.[2]

- There are challenges to developing CBM in eastern Australia due to environmental rules related to water disposal and drilling, and fracking moratoria that are in place in some areas.

- Australia has a relatively small population base with low levels of unemployment, especially in construction and high skilled sectors. This has led to cost increases in LNG export projects (both upstream and downstream segments and in both western and eastern Australia) and has slowed development of new gas supplies.[3] The United States has a much larger labor market and greater ability to meet incremental demands for labor, equipment, and materials with manageable cost increases.

- The natural gas contracting structure in Australia is very different from that in the United States. Australian long-term contracts are a large part of the overall market; they typically have relatively long terms of 10 to 20 years and rely on nontransparent prices determined through confidential negotiations. In contrast, most gas sales in the United States are monthly and daily spot sales or medium-term sales of 90 days to five years, which are typically indexed to reported/published monthly and daily gas price indices.

  Increases in long-term contract prices that affect large numbers of customers—similar to what has happened in eastern Australia—is unlikely to happen in the United States because such long-term contracts with fixed or oil-linked prices are very rare. In addition, price increases related to increased U.S. LNG exports would impact the market gradually through greater production and lower non-LNG consumption of gas as each U.S. LNG project comes online.[4] Although there is a loss in industrial and power sector gas use, there is a partially offsetting increase in U.S. domestic consumption in lease and plant gas use in the mining sector, pipeline fuel use in the transportation sector, and liquefaction plant fuel consumption in the manufacturing sector. The U.S. market is large and regionally interconnected and thus can rapidly adjust to incremental new market demands.

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[2] The Energy Information Agency of the U.S. DOE reports new-well production per rig is growing in most plays. See http://www.eia.gov/petroleum/drilling/.

[3] ABC, 2013, "Chevron reveals second Gorgon gas project cost blowout," http://www.abc.net.au/news/2013-12-12/gorgon-gas-project-cost-blowout/5151982.

[4] ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy." The American Petroleum Institute (API), March 2013: Washington, D.C. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf.

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Executive Summary

Critics of U.S. LNG exports have cited recent events in Australian natural gas markets, particularly those in eastern Australia, as a basis for a policy of restricting U.S. exports of LNG. The critics argue that liquefaction facilities now under construction in eastern Australia have driven up the demand for long-term natural gas contracts, thus forcing up prices and making it difficult for industrial gas customers, gas-fired power plants, and local gas distribution companies to procure long-term gas supplies. The critics further assert that U.S. gas consumers will see the same sharp increases in prices if a substantial number of U.S. LNG projects are approved and enter operation.

This study was requested by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) to provide policymakers and other interested parties with information on the Australian natural gas market and the extent to which the Australian experience could inform the debate on how LNG exports might affect future U.S. gas markets and prices. The Australian gas market differs from the U.S. gas market in important ways that are relevant to how developments there can be understood.

Our report provides information on the structure of the Australian natural gas market and gives an overview of the Australian gas supply, demand, and infrastructure. The report then explores recent trends in the Australian natural gas markets including pricing on new long-term gas contracts and spot market prices. In the final section, this report compares the U.S. and Australia markets and details the fundamental differences between the two markets in terms of overall market size, interregional and international pipeline interconnectivity, diversified resource base, gas supply industry size and capability, market structure, contracting practices, and price transparency. Some of those differences are shown in Exhibit 1 below.

In a previous report for API, ICF concluded that U.S. LNG exports will deliver positive job and GDP impacts, with moderate gas price increases and loses of non-LNG gas loads. This report confirms these conclusions and demonstrates that the Australian experience is very unlikely to be replicated in the U.S. context. Although average Australian gas prices under long-term contracts are expected to appreciate significantly in the coming years—due to price increases stemming from higher LNG export demand for feedstock supplies—the prediction of a similar phenomenon of sharp price increases in the U.S. gas market fails to consider the major differences between the two gas markets.

The most obvious major difference is **the overall economy and population of the United States is much bigger than that of Australia**. The U.S. Gross Domestic Product is 10.8 times that of Australia and the U.S. population is 13.8 times as large. Australia has a relatively small population base with low levels of unemployment, especially in construction and high-skilled sectors. This has led to cost increases in LNG export projects (both upstream and downstream segments and in both western and eastern Australia) and has slowed the development of new gas supplies. The U.S. has a much larger labor market and a greater ability to meet incremental demands for labor, equipment, and materials.

Because U.S. economy, population, and labor market are bigger, the **U.S. gas market is also much larger than that of Australia**. In terms of domestic gas production, the United States is 12.7 times as large as Australia (24.06 Tcf vs. 1.90 Tcf per year) and in terms of the domestic gas consumption, it is about 24 times as large as Australia (25.53 Tcf vs. 1.045 Tcf per year). The larger North American gas market (i.e., adding Canada and Mexico) is about 31 Tcf.

Regional markets in Australia are not well interconnected to each other by pipeline. This means the Australian gas market is really several smaller gas markets, so a large demand increase or a supply disruption in any one of them can have big price effects. In the United States, the markets are strongly interconnected and the impacts of demand increases and supply developments can be spread out over a much larger market area. The United States has approximately 305,000 miles of gas pipelines compared to 15,000 in Australia. The U.S. pipeline network is 20.3 times larger than Australia's. Moreover, the country trades gas through pipelines with Canada and Mexico making the effective market size even larger.

Another major difference is that **the United States has a much more diversified natural gas resource base and upstream infrastructure to supply gas for liquefaction**. The supply sources in eastern Australia for the new LNG projects are newly developed coalbed methane (CBM) plays, which provide the only foundation for export projects. The performance of these resources in Australia has been disappointing, which means that more gas wells and higher capital expenditures will be needed to achieve target production rates for LNG export commitments. By contrast, the United States has a much more diverse set of supply options—including shale, conventional, gas produced with oil, deep tight formation, offshore and onshore from about 483,000 wells. The resource base is geographically dispersed. And the country has a much larger drilling and well services infrastructure. For example, the Hughes rig count for the United States for a recent week stood at 1,860 while in Australia it was just 20—a difference of a factor of 93.0. Moreover, the U.S. gas industry has an extensive and highly developed base of knowledge in unconventional gas extraction.

Another difference is that CBM **development in eastern Australia has also been affected by environmental concerns** related to water disposal and drilling, and fracking moratoria that are in place in some areas. These concerns highlight Australia's lack of supply diversity and a technological knowledge base that is not yet mature. By contrast, U.S. production has consistently increased in part due to better established and understood regulations and practices, primarily at the state level.

A final major difference lies in how the gas markets of the two countries operate in **contracting practices, regulation, price formation, price discovery, and operational transparency**. The United States has a highly developed market operating under a robust regulatory regime with a vigorous spot market, locational price discovery, a well-developed futures market, multiple supply and pipeline contracting practices that together support a well-functioning market where prices are known. Australia lacks most of these mechanisms, and only recently has initiated a form of spot market trading. Contracts in Australia are long term and pricing is confidential. This has a major effect on the efficiencies of the market.

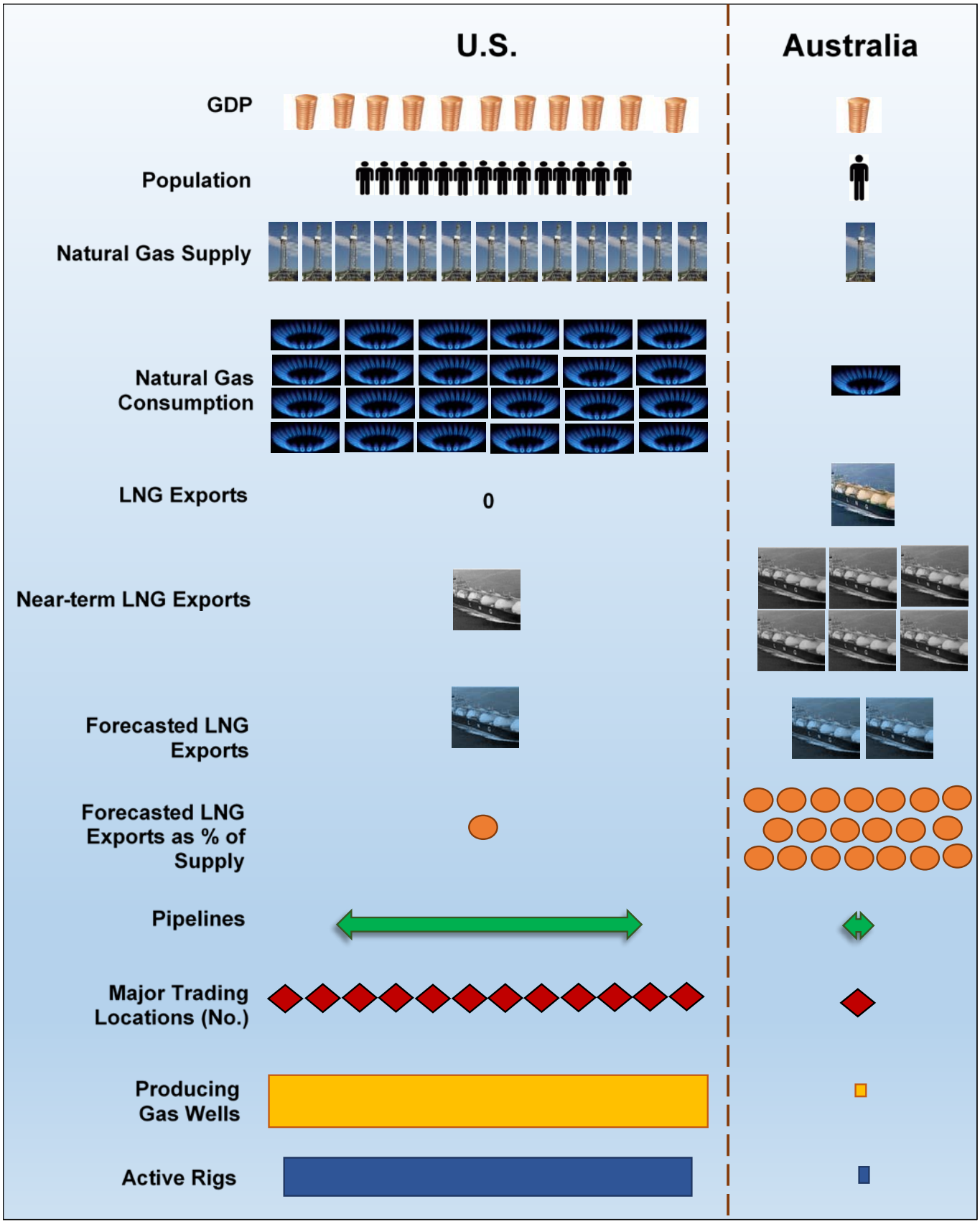
The differences in gas market characteristics between Australia, and eastern Australia in particular, and the United States, means that the large price increases arising from demand for LNG exports that have been reported for eastern Australia has little applicability to the United States. Instead, U.S. gas supplies are expected to grow along with new demands from U.S. liquefaction plants, largely obviating the need to reduce demand in other sectors through higher prices.

Exhibit 1: Summary Comparison of U.S. and Australian Natural Gas Markets

Criteria	Unit	U.S.	Australia
2012 GDP	Trillion current US$	$16.2	$1.5
2012 Population	Million people	313.9	22.7
2012 Total Supply (Dry Production + Imports)	Bcf	27,195	2,096
2012 Domestic Consumption	Bcf	25,533	1.045
2013 LNG Export	Bcf	0	1,050
Near-term LNG Export (2013 LNG export + LNG capacity under construction)	Bcf per year	803 (Sabine Pass, 2.2 Bcfd)	4,680
Forecasted LNG Export	Bcf per year	2,570 (per EIA AEO for 2025), 3,840 (assuming all 10.52 Bcfd of non-FTA DOE conditionally approved projects are in place)	4,680 (excluding Arrow LNG), 4,911 (including Arrow LNG)
Forecasted LNG Export as % of 2012 Total Supply	%	9.5%-12.4%	223%-236%
Pipelines	Miles	305,000	15,000
Number of Major Trading Locations	No.	58	5
Producing Gas Wells (2013)	No.	483,000	3,900 (CBM only)
Currently Active Rigs (2014)	No.	1,860	20
Market Structure		Highly integrated, price discovery and transparency, close regulation of pipelines; multiple contract options,	Unconnected markets ,loose pipeline regulation, no price discovery or transparency, long-term contracts

Source: EIA, World Bank, Baker Hughes, BREE Energy Statistics.

Exhibit 2: Relative Economic Comparisons



1 Introduction

With the advent of the shale gas revolution, U.S. gas production increased by over 20 percent over the 2008–2013 period.[5] The new abundance of natural gas has led to major transformations in the domestic gas market, with U.S. gas net imports declining sharply and multiple LNG export projects being announced. As of June 2014, the U.S. Department of Energy has conditionally approved seven LNG export applications for a total export volume of 10.52 billion cubic feet per day (Bcfd) to non-Free Trade Agreement (non-FTA) countries, equivalent to nearly 15 percent of U.S. domestic gas consumption in 2013.[6, 7] Please note that seven of the approvals are conditional. Only one of these seven projects, Cameron LNG, has secured authorization of its facility by the Federal Energy Regulatory Commission (FERC). The total conditionally approved LNG exports for FTA countries total more than 38 Bcfd. By comparison, Australia's exports in 2013 equaled 100 percent of its domestic market. LNG is a much more important element of the Australian gas sector than it is or will be in the United States.

The recent DOE conditional approval of applications for LNG export permits has led some parties to express concerns about possible negative implications of LNG exports for U.S. gas consumers. Some of the recent arguments these parties made drew on the experience of the Australian natural gas market, where the recent wave of investments in LNG export terminals is alleged to be controversial due to what some believe is evidence of soaring costs of natural gas to Australian industrial consumers and higher energy prices, presumably due to the LNG developments. [8, 9]

Critics of LNG exports have claimed that domestic gas shortages in Australia, due to LNG export, may cost more than 100,000 jobs in the manufacturing sector.[10] Further, they argue increases in electricity prices and significant increase of gas prices since 2007–2008 are affecting household welfare, particularly for lower-income families.[11] Manufacturers are allegedly concerned about gas price spikes and are finding it difficult to secure competitive gas supply contracts. Lastly, critics assert that the situation is expected to get worse if all LNG projects in Australia are completed.[12, 13]

In this context, the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) requested ICF International (ICF) to undertake a study of the Australian natural gas market and discuss

[5] U.S. Department of Energy (DOE). "U.S. Dry Natural Gas Production." DOE, 28 May 2014: Washington, DC. Available at: http://www.eia.gov/dnav/ng/hist/n9070us2a.htm.

[6] DOE. "Long Term Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of June 11, 2014)." U.S. DOE: Washington, DC. Available at: http://energy.gov/sites/prod/files/2014/06/f16/Summary%20of%20LNG%20Export%20Applications.pdf.

[7] U.S. Energy Information Administration (EIA). "Natural Gas Consumption by End Use." U.S. EIA, June 17, 2014: Washington, DC. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

[8] Fazzino, James. "Australian nitrogen fertilizer CEO confirms unfettered LNG exports have tripled natural gas prices." Industrial Energy Consumers of America, 15 April 2014: Washington, DC. Available at: http://www.ieca-us.com/wp-content/uploads/04.15.14_Australia-Congressional-Communication_Incitec-Pivot.pdf.

[9] Industrial Energy Consumers of America (IECA). "The Australia LNG export story should sound as a warning to U.S. policymakers." IECA, 15 April 2014: Washington, DC. Available at: http://www.ieca-us.com/wp-content/uploads/03.28.14_Australia-Congressional-Communication-2.pdf.

[10] Hoy, Greg. "Gas exports, price boom threaten 100,000 Australian jobs: manufacturers." ABC News, 27 March 2014. Available at: http://www.abc.net.au/news/2014-03-27/gas-boom-threatens-australian-manufacturing-jobs/5349822.

[11] Wells, Rachel. "Families going without food and medicine to pay the bills." The Sydney Morning Herald, 26 March 2013. Available at: http://www.smh.com.au/national/families-going-without-food-and-medicine-to-pay-the-bills-20130325-2gq2e.html.

[12] Chambers, Matt. "LNG demand to force spike in gas prices." The Australian, 07 March 2014. Available at: http://www.metgasco.com.au/industry-news/lng-demand-force-spike-gas-prices-2.

[13] Howes, Paul. "High costs due to energy, not labor." Financial Review, 04 March 2014. Available at: http://www.afr.com/p/opinion/high_costs_due_to_energy_not_labour_fNuuZKaA8DXgSt4ZE9Y69N.

the extent to which the Australian experience could inform the debate on how LNG exports might affect future U.S. gas prices. Our report addresses a number of issues.

- It is important to understand the developments in Australia and whether these developments offer a cautionary tale for the United States given the major differences between the U.S. and Australian gas markets. Most important from a market standpoint is that Australia is a resource-rich country where gas exports as LNG will exceed the size of the domestic market.
- The Australian market operates in ways very different from the U.S. market. The Australian domestic markets in the west, north, and east are not interconnected and the trading market is thin. Most gas moves under long-term contracts (10 to 20 years) at prices that are confidential. Pipelines are lightly regulated and there is considerable vertical integration of the industry. The small spot market deals in daily balancing volumes and is, at present, not reflective of underlying long-term trends.
- The timing of gas resource development to meet the anticipated LNG demand in eastern Australia—the locus of the controversy—has been complicated by unforeseen technical difficulties in developing the coalbed methane (CBM)[14] which is the source of new supply in eastern Australia. Adapting operations to environmental regulations and bans also has been a challenge. Production costs have been higher than expected. Producers are challenged to meet their obligations to exporters as well as to local markets.
- At the same time, liquefaction plant owners are developing and purchasing gas resources to supply their facilities. Many domestic supply contracts appear to be expiring and are up for renewal. With the stresses on production and attendant uncertainties, producers appear to be reluctant to commit to new long-term contracts at less than the full opportunity cost of meeting their long-term LNG contract requirements. Thus, it does appear that long-term gas prices supporting power generation and industrial customers have risen from around $3 to $4 per MMBtu to perhaps between $7 and $9 per MMBtu.[15] This may very well be a near term phenomenon until production grows to meet new demands and a new gas supply/demand balance reasserts itself.
- Australia is seeing a large expansion of LNG export facilities in both the traditional export region of the northwestern part of the country, where offshore-based production for LNG has been established for 20 years, as well as the new projects drawing on the CBM developments in the east. The demand for labor, materials, and resources has been large for an economy the size of Australia. This has contributed to increases in the cost of LNG plant construction and other construction around the country.
- The Australian and U.S. gas markets are profoundly different in size, structure, market rules, pipeline interconnectivity, regulation, price formation, contracting, and price transparency. These differences suggest that using Australian experiences to make predictions for U.S. gas price impacts from LNG exports is not advised.

This report expands on these themes and compares the Australian and U.S. markets, and points out key differences in the U.S. energy markets, which would lead to different outcomes for U.S. consumers. ICF has quantified various energy market outcomes of LNG exports for the U.S. market in a previous

[14] In Australia the term is coal seam gas (CSG). Throughout this report we use the term CBM, which is more common in the United States.

[15] All dollar figures are in U.S. dollars, unless otherwise stated.

analysis for the API.[16] This analysis concluded that U.S. LNG exports would increase GDP, increase employment, and promote manufacturing, while inducing only a modest increase in natural gas prices. Nevertheless, the assertions about Australia's experience deserve to be addressed and understood in the appropriate context.

This report is divided in three parts. The first part (Section 2) of the report discusses the structure of the Australian natural gas market and gives an overview of the Australian gas supply. Section 3 then explores recent trends in the Australian natural gas market. Although Australian gas prices are expected by various analysts to appreciate significantly in the coming years due to much higher LNG export demand from new terminals,[17] the comparison to the U.S. gas market situation fails to consider the major differences between the two gas markets. This comparison between the U.S. and Australia is detailed in Section 4. There are fundamental differences between the U.S. and Australian markets in terms of resource base, market structure, and demand patterns. This report reiterates the conclusions ICF found in its previous analysis for the API, and argues that the Australian experience is very unlikely to be replicated in the U.S. context.

[16] ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy." ICF, 15 May 2013: Fairfax, VA. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf.

[17] Wood, Tony and Carter, Lucy. "Getting gas right: Australia's energy challenge." IGU. Available at: http://grattan.edu.au/static/files/assets/ba24a4e0/189_getting_gas_right_report.pdf.

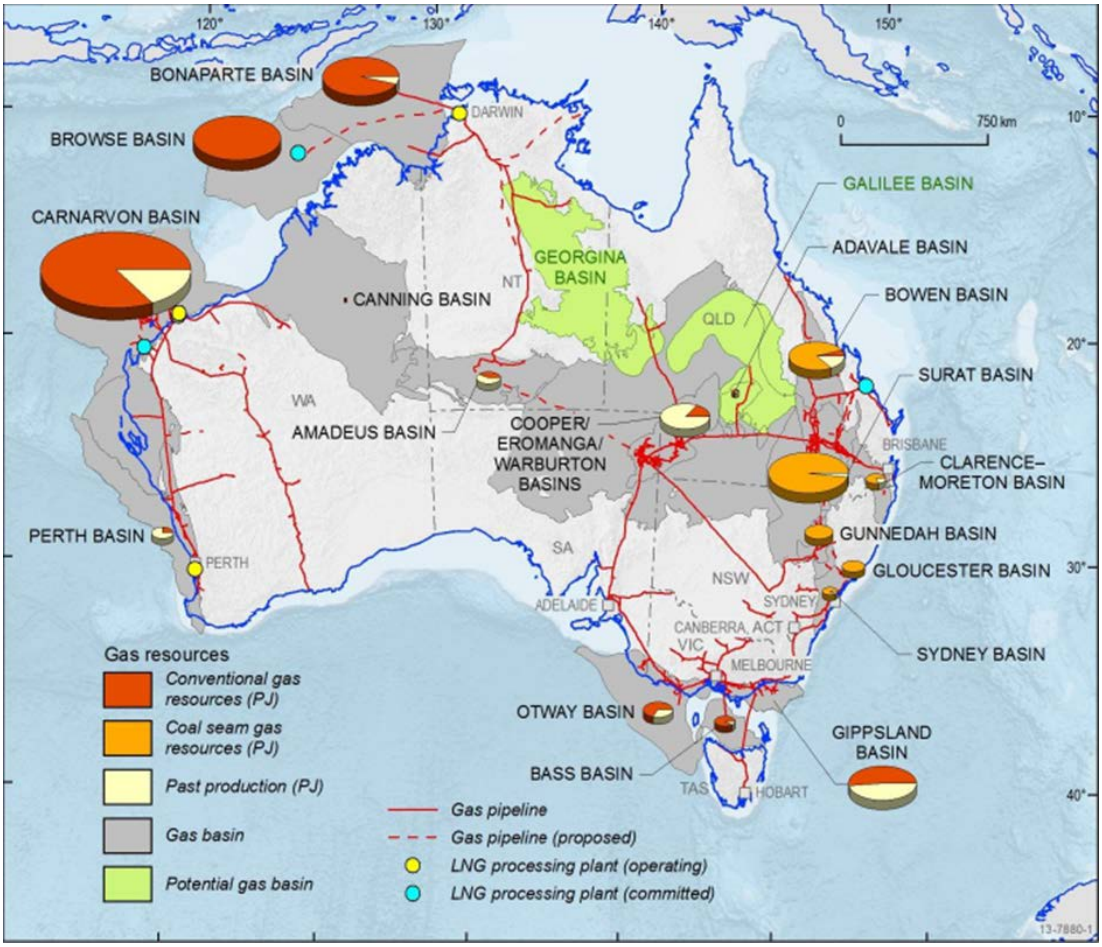
2 Australian Gas Market Structure

2.1 Overview

Australia is a major natural gas producer and exporter, but is not a large natural gas consumer. Australia produced about 2,096 Bcf, and exported 1,050 Bcf in 2012–2013. Most of the exported gas has historically come from offshore production in Western Australia and the Northern Territory. Total domestic consumption is about half that of total production (1,045 Bcf in 2012–2013[18]) where the bulk of the consumption is in the population centers in the east and south (New South Wales, Victoria, South Australia, and southeastern Queensland—eastern Australia). Putting this in perspective, total Australian domestic consumption is less than gas consumption in New York State alone (1,226 Bcf in 2012).

Australia's gas market is divided into three physically unconnected geographic gas markets (eastern Australia, northern Australia, and Western Australia). This is in contrast to that of the North American gas market, which has a large, highly integrated, continental domestic gas market. There is no national market in Australia.

Exhibit 3: Australia Natural Gas Infrastructure



Source: "Eastern Australia Domestic Gas Market Study," (p. 20). Available at: http://www.industry.gov.au/Energy/EnergyMarkets/Pages/GasMarketDevelopment.aspx.

[18] Australian Energy Regulator, 2014, "State of the energy market." Available at: http://www.aer.gov.au/node/23147.

The main gas basins in eastern Australia are connected to demand centers by long distance gas transmission pipelines. Conventional gas from the Cooper-Eromanga Basin in central Australia and the southeastern offshore Gippsland Basin has historically supplied the majority of demand in eastern Australia. The production of CBM in Queensland has expanded rapidly over the past decade. The development of a link between Queensland and South Australia in 2010 allowed CBM from Queensland to be supplied to markets in South Australia and New South Wales.

Conventional gas from offshore gas fields in the Carnarvon Basin supply the majority of demand in Western Australia and have supplied LNG exports since 1989. Gas consumers, almost entirely made up of mining, manufacturing, and electricity generation, are supplied under long-term bilateral contracts.

In northern Australia, gas demand is comparatively low with most of the gas consumed by a small number of gas power plants. Gas fields in the Amadeus Basin have historically supplied most of the gas demand in the Northern Territory. Gas is transported to Darwin from offshore gas fields in the Timor Sea where it is processed into LNG and exported to Japan.

The country has three operating LNG terminals, namely the North West Shelf, Darwin, and Pluto. Seven new projects are being developed to take advantage of the country's large conventional gas and CBM resources. Australia is the third largest exporter of LNG, behind only Qatar and Malaysia.[19] Three of the new projects are based on CBM production from the Surat and Bowen Basins, and the other four are based on conventional gas production from the offshore Carnarvon and Browse Basins. The growth in production in recent years from CBM in eastern Australia has contributed to increased domestic consumption in the east, and is providing the basis for the LNG exports planned from Queensland.

Most of the gas traded in Australia's domestic gas market is done so under long-term bilateral contracts between producers on the sell side and power generators, industry, and distribution companies on the buy side. These contracts keep pricing confidential among the parties. Regulators have no review authority over these prices. There are few publicly reported gas price indices to assist in price discovery. Eastern Australia has facilitated spot markets under two different pricing regimes one in Victoria and a second in eastern Australia for the distribution networks in Sydney, Adelaide, and Brisbane. A recent development has been a spot market centered on the Wallumbilla gas supply hub in central Australia. The spot markets provide wholesale participants with a mechanism for trading their short-term imbalance positions and have enhanced short-term price transparency and efficiency. Unlike the United States, however, these short-term prices do not inform pricing for longer-term contracts. They only address imbalances in the system. In addition, there is a lack of transparency and liquidity in the long-term contract market that has contributed to considerable price uncertainty for gas consumers. Most of what is known about this market comes from occasional press releases and other public statements made by market participants.

In terms of pipeline infrastructure, the main pipeline inter-connections currently operating in Australia are:

- Wallumbilla to Moomba: Relatively recent connection allowing 365 million cubic feet per day (MMcfd) western flow on the South West Queensland Pipeline (SWQP) to Moomba.
- Flows from Moomba: Conventional gas from the Cooper-Eromanga basin has been an important supply source for Sydney—via Moomba Sydney Pipeline(MSP)—which has an east flow capacity

[19] International Gas Union. "World LNG Report – 2014 Edition." IGU, 2014. Available at: http://www.igu.org/sites/default/files/node-page-field_file/IGU%20-%20World%20LNG%20Report%20-%202014%20Edition.pdf

of 416 MMcfd) and Adelaide—via Moomba to Adelaide Pipeline System (MAPS)—which has a south flow capacity of 240 MMcfd) demand centers.

- Flows from Victoria: Conventional gas from Victorian offshore gas fields is becoming increasingly important for supply to Sydney—via Eastern Gas Pipeline (EGP)—which has a north flow capacity of 274 MMcfd) and Adelaide—via SEA Gas Pipeline (SEAGas)—which has a western flow capacity of 284 MMcfd) demand centers.
- The Dampier to Bunbury Natural Gas Pipeline (DBNGP) transports gas from gas fields in the Carnarvon Basin off the north-west coast of the state to customers in the south west.
- The Amadeus gas pipeline is the main gas transmission pipeline in the Northern Territory running from the Amadeus gas fields in the south to the main demand center of Darwin. The Bonaparte pipeline, which connects to the Amadeus pipeline, was commissioned in 2008 to bring gas from the Bonaparte Basin to the Northern Territory.

The interconnection of the east coast markets is a relatively recent development that occurred with the construction of the Queensland to South Australia/New South Wales Link (QSN Link) between Moomba and Ballera. The QSN Link has connected the gas market in Queensland to markets in the south and east of Australia.

The Australian natural gas industry is organized into production, transmission, marketing, and distribution, with private companies owning and operating the various components of the system. There are nine distribution companies that provide distribution services in eastern Australian cities. These systems operate as “pipes” companies; they do not own gas or provide merchant gas services. They charge tariffs and are regulated by the individual states. Distribution tariffs are largely fixed cost recovery. Retailers buy gas at wholesale from the producers under long-term contracts, and contract for capacity on the pipelines and distribution networks in order to sell gas to individual customers. Retailers are who the customer deals with; the retailer manages all of the supply and transportation requirements to get the gas to the customers. There are approximately 20 retailers in eastern Australia. The large retailers operate across multiple states, in multiple markets, and they will sometimes have upstream positions in production and in power generation.

2.2 Australian Natural Gas Demand

Coal and petroleum products have historically supplied much of Australia’s energy needs, but natural gas has grown in importance as an energy source in the last two decades as resources have been developed in offshore Victoria and in the central part of the country around Wallumbilla. Like the United States and other developed countries, natural gas replaced manufactured town gas in the major cities of Melbourne, Adelaide, and Sydney.

<u>Eastern Australia</u>

Exhibit 4 shows the recent history and outlook for gas demand in eastern Australia and highlights the significance of LNG exports. Non-power consumption has grown slightly from about 450 Bcf per year to almost 500 Bcf per year since 2010. Most of the residential demand is centered in the state of Victoria because of highly developed distribution networks. Most of the manufacturing and mining demand are in the other eastern states and have historically accounted for the majority of gas demand. Over the past decade, demand for gas for power generation grew faster than other segments of the market and now accounts for a third of gas demand in eastern Australia.

Domestic gas demand is forecasted to fall over the next decade. Most of the decline is expected to be from power plants, while demand across the other market segments is forecasted to remain the same or grow slowly. Factors contributing to the expected decline in power demand for gas include higher gas prices, likely removal of the carbon tax (by removing the disincentives for coal), falling electricity demand, and growing levels of renewable generation.[20]

A number of gas-fired power generators have contracted, or plan to contract, for the sale of their gas back into the gas market to adjust to the prevailing gas and electricity market conditions. For example, in February 2014 Stanwell Corporation, the Queensland Government-owned energy company, announced its plan to mothball the Swanbank E Power Station near Brisbane in October 2014 for a three year period. Stanwell will sell its gas supplies into the gas market, rather than use these supplies to generate electricity. This will enable Stanwell to take advantage of recent high gas prices in the face of relatively weak electricity demand and low prices. Stanwell will restart some of its mothballed coal fired generation to replace Swanbank.

Redirecting long-term gas supplies from power generation is occurring elsewhere in eastern Australia. Origin Energy, which has a portfolio of power generation assets, including a gas-fired power plant, in eastern Australia, reportedly has entered into gas sales agreements with Gladstone LNG (GLNG)[21] and Queensland Curtis LNG (QCLNG).[22] These sales arrangements will allow Origin to divert supply from power generation to the LNG facilities when gas is not economic in the power sector.

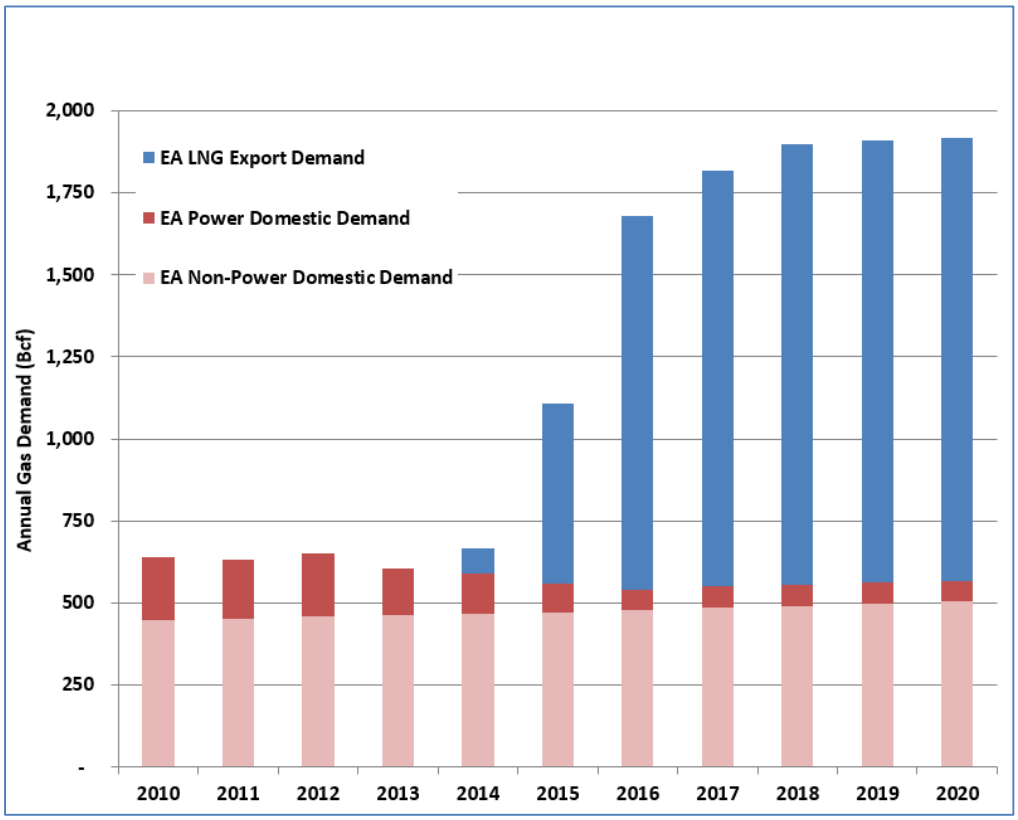
LNG exports from eastern Australia will begin in 2014 with the commissioning of QCLNG's first LNG train. LNG production will ramp up over the course of the following three years. By 2018, gas demand in eastern Australia is expected to be more than three times the current demand.

[20] See ABC News July 10, 2014: "More than a million Australians have already installed solar panels on their roofs, causing demand for electricity from the grid to plummet. Australia's household solar revolution has caught the energy sector by surprise, and may leave NSW and Queensland taxpayers footing the bill for billions of dollars' worth of "stranded assets." Retrieved July 11, 2014 from http://www.abc.net.au/news/2014-07-09/solar-panels-leads-to-less-demand-for-electricity/5586036.

[21] Origin Energy, 2013, "Origin announces new agreement to sell gas to GLNG." Available at: http://www.originenergy.com.au/news/article/asxmedia-releases/1539.

[22] Origin Energy, 2013, "Origin announces gas supply agreement with QGC." Available at: http://www.originenergy.com.au/news/article/asxmedia-releases/1535.

Exhibit 4: Gas Demand – Eastern Australia

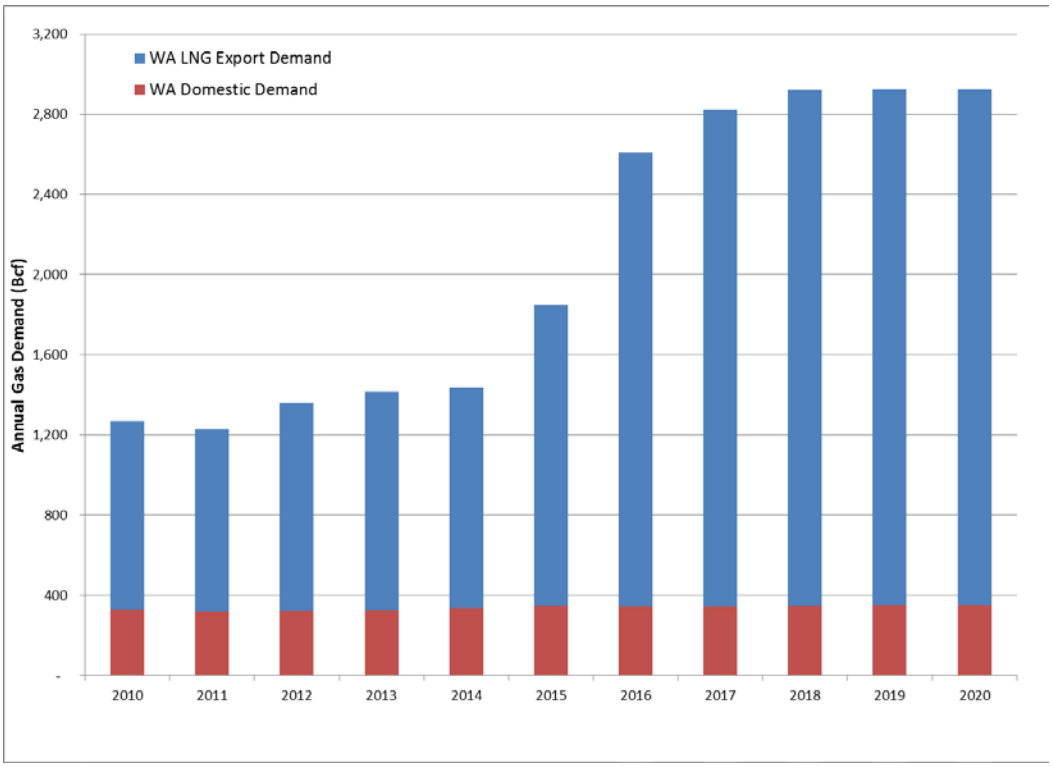


Source: AEMO 2013 national gas forecast, AEMO GSOO May 2014 Update.

Western Australia

Manufacturing, mining, and electricity generation have historically accounted for the majority of domestic gas demand in the state of Western Australia (WA). Demand from the residential sector is relatively small (around 1 percent) as households are more reliant on energy for cooling rather than for heating. WA has been exporting LNG since 1989 and the industry has continued to grow with the expansion of the NWS and Pluto projects. WA is entering a period of LNG export growth with the completion of the Gorgon, Wheatstone, and Prelude projects by 2018. Gas supplying LNG export demand is currently triple the size of domestic gas consumption. As shown in Exhibit 5, gas supplied to LNG exports will be more than seven times the size of domestic gas demand by 2018.

Exhibit 5: Gas Demand – Western Australia



Source: WA IMO GSOO 2014, LNG export demand is a function of liquefaction capacity.

Northern Territory

Northern Territory domestic gas consumption, estimated to be 30 Bcf in 2013–14,[23] is relatively small compared to other Australian states and territories. Gas power plants, which supply Darwin and the remote power grids, account for the majority of gas demand.[24]

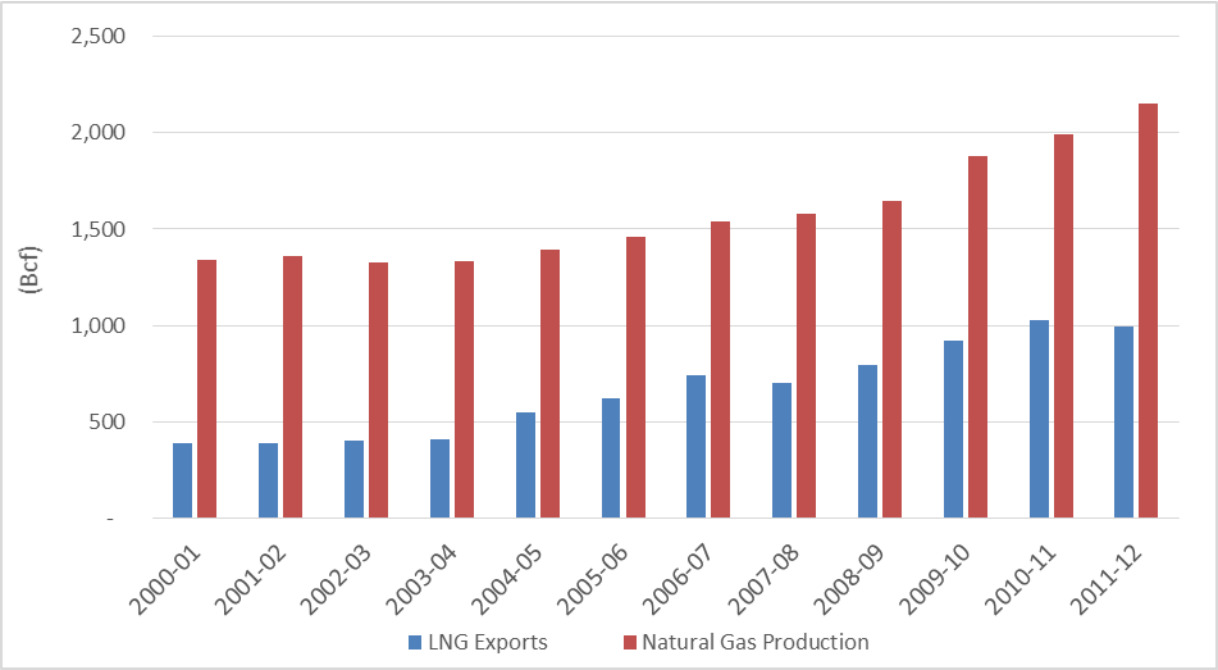
2.3 Natural Gas Production

Australia's natural gas production in recent years has averaged about 2,000 Bcf per year or 5.5 Bcf per day. Exhibit 6 shows historical Australia gas production, consumption, and net exports starting from 1990. The LNG component is sourced from production in the Carnarvon Basin, which is the location of current LNG export-related production. In recent years, CBM has increased to a level of 233 Bcf per year or 638 MMcfd. Operators are ramping up coal seam production in eastern Australia in anticipation of supplying LNG export facilities.

[23] APA Group, 2011, "Amadeus Gas Pipeline Access Arrangement Information." Available at: http://www.aer.gov.au/node/4760.

[24] AER, 2011, "N.T. Gas Access arrangement proposal for the Amadeus Gas Pipeline." Available at: http://www.aer.gov.au/node/4760.

Exhibit 6: Recent Historical Australia Natural Gas Production



Note: The LNG data series presented represents gas production that directly supplies an LNG export facility.
Source: BREE Energy Statistics.

Eastern Australia

Historically the majority of gas supplied to the eastern gas markets has been sourced from conventional gas reserves in the Cooper-Eromanga Basin (via the Moomba processing facility) and offshore gas fields in the Gippsland Basin (via the Longford processing plant).

Exploration for CBM in Australia began in Queensland's Bowen Basin in the 1970s, and the first CBM extraction in Australia began at the Dawson Valley project in central Queensland in 1996. The Queensland Gas Scheme, commencing in 2005, helped the development of the CBM industry by requiring 15 percent of electricity in the state to be sourced from gas-fired generation (GFG).

The prospect of selling LNG into the higher priced Asian markets sparked interest from large domestic and international gas producers and triggered a wave of investments and merger and acquisition activity culminating in the development of three CBM-to-LNG export projects on Curtis Island near Gladstone, Queensland.

Western Australia

Offshore gas fields in the Carnarvon Basin supply the LNG export projects and the majority of the Western Australian (WA) domestic market. Gas supplied to LNG export facilities does not enter the domestic gas transmission network.

WA has been exporting LNG from the Carnarvon Basin since 1989 when the North West Shelf (NWS) joint venture made its first shipment to Japan. The NWS project expanded over the next 20 years with the fifth LNG train, taking the total capacity to 794 Bcf per year, commencing production in 2008.

The Pluto project (209 Bcf) commenced in 2012. There will be a significant expansion of LNG exports with the Gorgon (760 Bcf), Wheatstone (433 Bcf), and Prelude (175 Bcf) projects currently under construction.

The WA government introduced a domestic gas reservation policy in 2006 that requires LNG export projects to reserve 15 percent of the gas from each LNG project and develop processing facilities for the domestic market.[25]

Northern Territory

Since the commissioning of the Bonaparte Pipeline in 2008, gas from the Bonaparte Basin has supplied the majority of domestic consumption in the Northern Territory.[26] The Amadeus Basin, near Alice Springs, historically supplied the majority of domestic consumption.

2.4 Australian Gas Resource Base

The U.S. Energy Information Administration (EIA) maintains a data series for Australia's proved gas reserves. The BP Statistical Review of World Energy also reports reserves (see Exhibit 7). The BP publication reserves figure is 133 Tcf as of year-end 2012. EIA reports only 43 Tcf of reserves as of year-end 2013.[27]

The assessment of conventional and unconventional gas recoverable resource by the Australian government totals to 820 Tcf as shown in Exhibit 8.[28] The Bureau of Resources and Energy Economics (BREE)'s 2012 analysis indicates the 820 Tcf of assessed gas resource to consist of 167 Tcf of conventional gas (new fields and reserve appreciation) including inferred resources, 204 Tcf of CBM, 20 Tcf of tight gas, and 398 Tcf of shale gas. The assessments of tight gas and shale gas are preliminary and ongoing. In its report on shale gas in Australia, the Australian Council of Learned Academies (ACOLA) concluded that there is uncertainty around the resources in Australia due to the limited appraisal of unconventional resources.[29] There is no commercial production of tight gas or shale gas. Current CBM production is 0.64 Bcf per day or about 12 percent of the total production.

In comparison to the 820 Tcf of Australian resources, North American resources total to over 4,000 Tcf, which include about 2,000 Tcf of shale gas.[30] The U.S. gas resource base quantities are considered much less uncertain than those of Australia, especially for shale gas. This is because almost all of the plays included in the 2,000 Tcf US estimate have been proven to be productive and economic on a large scale. The Australia recoverable shale gas resource base is still speculative.

[25] Government of Western Australia, Department of State Development, retrieved on July 11, 2014 from http://www.dsd.wa.gov.au/8482.aspx.

[26] Australian Energy Regulator, 2014, "State of the energy market 2013," http://www.aer.gov.au/node/23147.

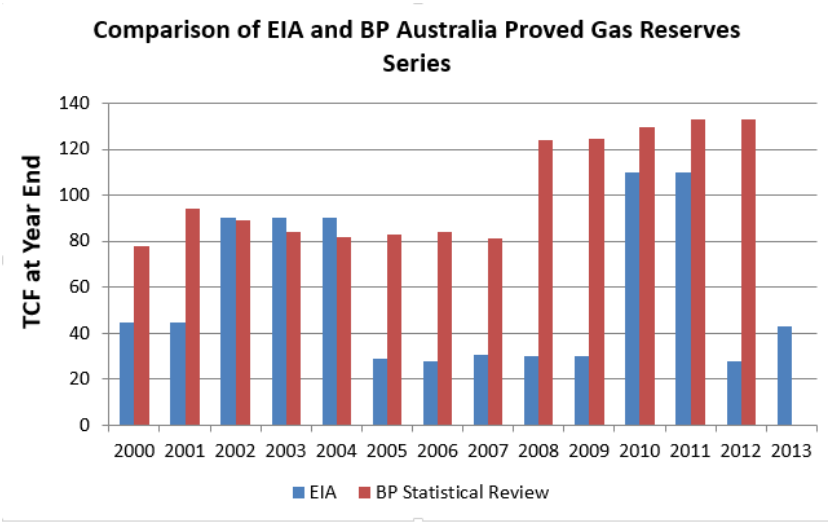
[27] U.S. EIA International Statistics page for Australia. Available at: http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=3&pid=3&aid=6&cid=AS,&syid=2010&eyid=2014&unit=TCF.

[28] Australian Bureau of Resources and Energy Economics, 2012, "Australian Gas Resource Assessment 2012." Available at: http://www.ga.gov.au/webtemp/image_cache/GA21116.pdf.

[29] Australian Council of Learned Academies, 2013, "Engineering Energy: Unconventional Gas Production, A study of shale gas in Australia." http://www.acola.org.au/index.php/projects/securing-australia-s-future/project-6.

[30] Source of U.S. shale is ICF International, resource assessment.

Exhibit 7: Australia Proved Gas Reserves



Source: EIA and BP Statistical Review of World Energy 2014.

Exhibit 8: Australia Gas Resource Assessment Summary

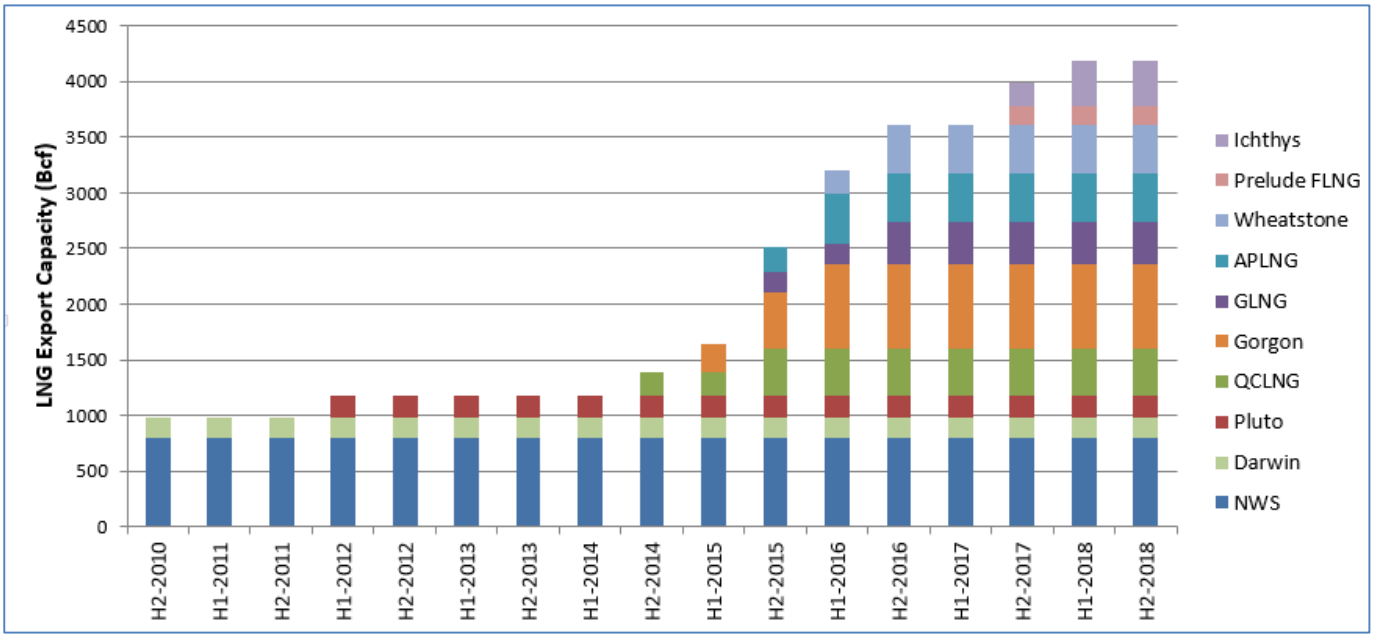
Category	Recoverable Resource (Tcf)				
	Conventional	CBM	Tight	Shale	Total
Economically Demonstrated (EDR)	103	33	0	0	136
Sub-economic Demonstrated (SDR)	54	60	0	2	116
Inferred	10	111	20	0	141
Sum of Identified Resources	***167***	***204***	***20***	***2***	***393***
Potential Additional Resources	0	31	0	396	427
Identified, Potential, Undiscovered Total	**167**	**235**	**20**	**398**	**820**

Note: this is the latest assessment as referenced in the October, 2013 BREE Market Report.
Source: Australian Gas Resource Assessment - 2012", BREE, 2012.

2.5 LNG Export Projects

Over $150 billion USD is being invested in LNG export projects across Australia. As shown below in Exhibit 9, once projects currently under construction have been completed Australia will have more than 3,896 Bcf of LNG export capacity making it one of the largest exporters of LNG in the world. More details about the LNG projects are in Appendix B.

Exhibit 9: LNG Export Capacity in Australia by First and Second Half of Each Year (Existing and Under Construction)



Source: BREE, project / company websites.

Eastern Australia

Three liquefied natural gas (LNG) export projects are currently under construction in Queensland. These projects will triple the gas demand in eastern Australia and drive a rapid increase in the production of CBM in the Surat and Bowen basins in Queensland. Each project is constructing a pipeline to transport gas from their gas processing facilities to their liquefaction facilities in Gladstone. The liquefaction facilities, each consisting of two LNG trains, are located side-by-side on Curtis Island in the Gladstone Harbor where LNG will be loaded onto LNG carriers for transport to Asia.

Modeling performed by AEMO for the May 2014 update of the GSOO showed that supply shortfalls could occur in Sydney on peak winter demand days from 2020 if Moomba gas production is diverted to Queensland to supply LNG export project demand. The modeling included new CBM projects in Narrabri (94.8 MMcfd) and Gloucester (75.8 MMcfd) from 2018.

In response to growing concerns from gas consumers, the Australian Department of Industry and the Bureau of Resources and Energy Economics (BREE) conducted a joint study on the outlook for the eastern Australian gas market. The study found that there are sufficient gas resources to meet domestic and export requirements. The study recommended that the short-term focus of gas policy should be on improving transparency of pricing information, making markets more efficient, and the removal of unnecessary regulatory impediments to developing new gas supply.[31]

Gas flows around eastern Australia are expected to change as LNG export projects start drawing upon gas supplies from the Cooper-Eromanga Basin. Over the past five years the increased production of CBM in Queensland has been transported to other markets in eastern Australia, flowing west to Moomba

[31] Department of Industry, 2014, "Eastern Australian Domestic Gas Market Study." Available at: http://www.industry.gov.au/Energy/EnergyMarkets/Pages/GasMarketDevelopment.aspx.

and then onto Sydney and Adelaide demand centers. However, flows are expected to reverse on the SWQP from 2015 as the APA Group, backed by long-term contracts with Santos and GLNG, is installing new compression to allow 322 MMcfd of gas to flow east from Moomba to Wallumbilla.

Gas flows to Sydney and Adelaide from Victorian gas fields are expected to increase to replace Moomba gas that will be diverted to Queensland. In late 2013 the APA Group entered into contracts with three gas retailers[32] (Origin Energy, Energy Australia, and Lumo) to increase the northern flow capacity of the Victoria Transmission System to allow additional Victorian gas supplies to flow to Sydney via the NSW-Victoria Interconnector and the Moomba Sydney Pipeline.

New gas transmission pipelines are being constructed by the LNG export projects to transport gas to the LNG facilities in Gladstone. The capacity of each of these new pipelines exceeds that of any existing pipeline in Australia, and in total, the capacity of pipelines under construction exceeds 4 Bcfd.

Exhibit 10: LNG Project Gas Transmission Pipelines

Project	Length (km)	Capacity (Bcfd)	Status	Description
QCLNG	334	1.34	Under construction	High pressure, 42 inch pipeline from Surat and Bowen Basin gas fields to the QCLNG export facility in Gladstone.
GLNG	435	1.35	Under construction	High pressure, 42 inch pipeline from Fairview gas fields to the liquefaction facilities in Gladstone.
APLNG	362	1.48	Under construction	Two lateral pipelines will feed gas from the gas fields in the Surat and Bowen Basins to the 42 inch mainline that transports gas to the liquefaction facilities in Gladstone.
Arrow Bowen	450	0.46 to 0.95	Proposed	High pressure, up to 42 inch diameter, pipeline that would transport gas from Bowen Basin gas fields, west of Mackay, to the proposed ALNG liquefaction facilities in Gladstone.
Arrow Surat	470	0.46 to 0.95	Proposed	High pressure, 32 to 34 inch diameter, that would transport gas from Surat Basin gas fields to the proposed ALNG liquefaction facilities in Gladstone.

Source: Project websites, AEMO GSOO.

Northern Territory and Western Australia

New LNG export projects are currently under construction in Northern Territory and WA to meet rising international demand. At an estimated cost of over $50 billion USD, the Gorgon LNG project is the largest construction project in Australia and will be the one of the world's largest LNG facilities. Two new projects will source gas from the Browse Basin located off the north west coast of Western Australia, the floating Prelude LNG facility and the Ichthys project, which will use an undersea pipeline over 800km long to transport gas to Darwin for liquefaction.

2.6 Gas Market Structure in Australia

Traditionally, wholesale gas supply has been dominated by long-term bilateral gas supply contracts between producers and retailers, large industrial end users, and power generators. The commercial terms of contracts are confidential and not available to regulators or the public. Key characteristics of

[32] APA Group, 2013, "APA to further expand VIC NSW interconnect." Available at: http://www.apa.com.au/investor-centre/news/asxmedia-releases/2013/apa-to-further-expand-vic-nsw-interconnect.aspx.

these contracts govern the term of the supply (years); the firmness of the supply (e.g., "firm" or "reasonable endeavours"); take-or-pay obligations; annual and daily contract quantities; and price. Price terms typically are for fixed prices with limited periodic price reopeners (often five years) or with known escalation factors that reflect parties' views on market values and costs.

A key distinguishing feature of the Australian market, in comparison with the United States, is that there is no mechanism to relate contract prices to current market price indicators that would reveal the state of the market or market conditions. Delivered prices for gas are confidential with no transparent national price reporting mechanism.[33] The U.S. gas market by contrast has both daily and monthly price indices at widely dispersed geographic locations where contract pricing is tied to the indices most relevant to the buyers and sellers. The liquidity of the U.S. market is supported by the broad transparency of pricing, which is absent in Australia.

There are, however, three gas trading markets in eastern Australia to address daily or short-term supply-demand imbalances, to facilitate the trade of variances between gas delivered and actual withdrawal:

1) **Victoria Gas Market:** The State of Victoria has had an operating spot market for natural gas since 1999 along the Victorian Transmission System, and not at a single hub. The market is operated by the Australia Energy Market Operator (AEMO). The spot market accounts for about 10 to 20 percent of all wholesale volumes in Victoria with the majority of gas traded under bilateral contracts. Nevertheless, AEMO schedules all flows on the pipeline.

   The Australian Stock Exchange (ASX) introduced trading in Victorian wholesale gas futures and options in July 2009. In general, gas futures markets tend to develop only after the underlying physical (spot) markets reach a certain level of maturity, with significant trading between buyers and sellers under transparent short-term contracts. The futures market, therefore, enables participants to manage price volatility and revenue risk by trading in financial gas futures and related options. However, there have been a relatively small number of trades on the exchange.

   The Victorian gas market uses a sophisticated market arrangement for scheduling network injections and withdrawals. An unconstrained market model determines a single market price. An operational model of the physical system determines out-of-market actions in the event of congestion. Payments, based on market bids, are made to those shippers who are scheduled to take out-of-market actions and the costs are allocated to those that cause the congestion. A financial right provides some hedging against congestion related costs.

2) **Short-term Trading Market (STTM):** The STTM is a market-based day-ahead wholesale gas balancing mechanism at defined gas hubs in Sydney, Adelaide, and Brisbane. The STTM facilitates trading between shippers, retailers, and large end users at the intersection of the transmission and distribution network. The STTM overlays a pipeline contract carriage model with pipeline operators continuing to be responsible for system operation. The STTM is a mandatory market that operates in conjunction with longer-term gas supply and transportation contracts. It provides an option for users to buy or sell gas on a spot basis without needing to enter delivery contracts in advance. It also allows contracted parties to manage short-term supply and demand

[33] Natural gas pipeline transmission prices are also confidential. Pipelines nevertheless are required to abide by the Australian Gas Law and Gas Rules.

variations to their contracted quantities. The STTM began its operation in Adelaide and Sydney on September 1, 2010 and in Brisbane on December 1, 2011.

3) **Gas Supply Hub (GSH):** The Gas Supply Hub is a wholesale exchange for trading natural gas at the Wallumbilla gas hub. The Wallumbilla gas hub is located at the intersection of gas transmission pipelines in southern Queensland and is near CBM gas fields, gas-based power plants, and gas storage. The market commenced operation in March 2014.

Unlike in eastern Australia, there are no gas hubs or market pricing points in the Northern Territory or Western Australia. In Western Australia, gas producers, aggregators, and users bilaterally trade their short-term gas requirements and imbalances. Western Australia also has a small number of brokers that provide short-term transaction matching, nomination, and contract management services to gas users.

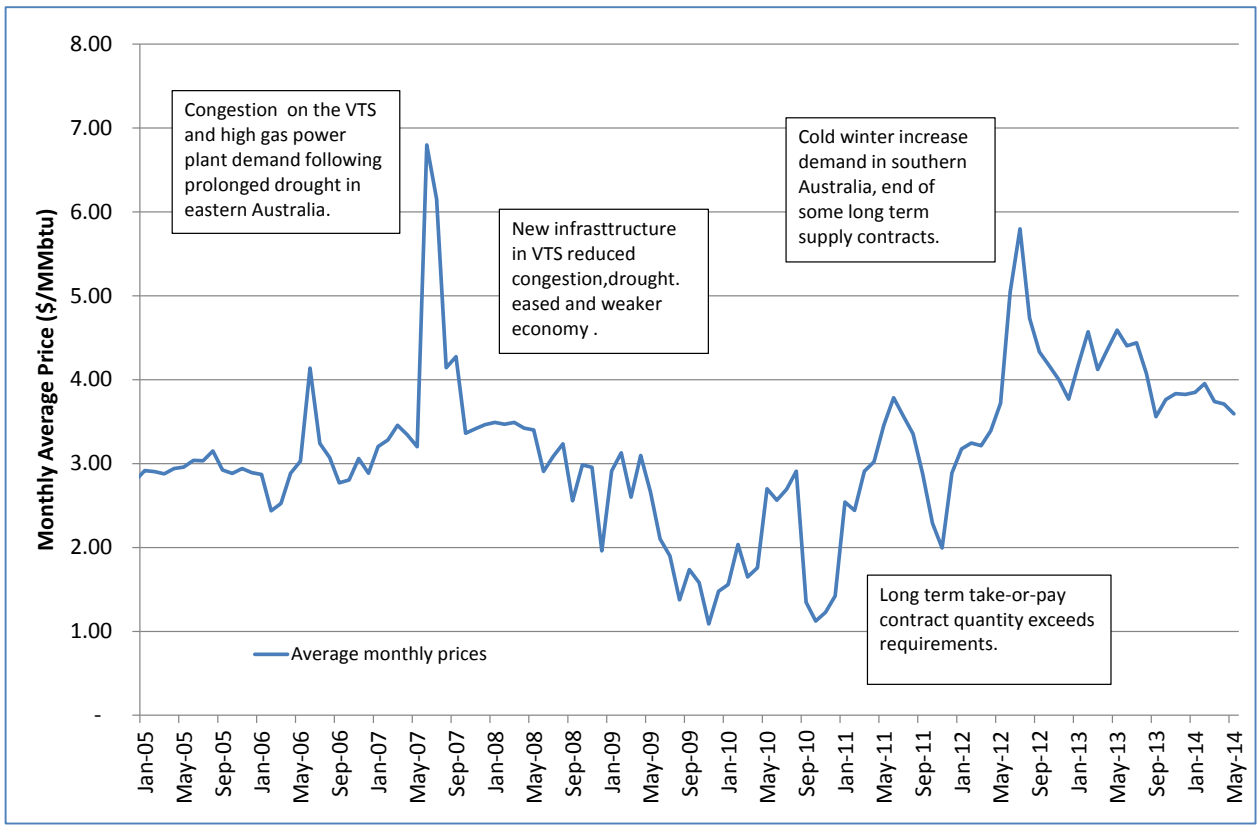
3 Analysis of Recent Australian Natural Gas Trends

In this section, we present the discussion of gas price trends in the Australian gas markets, keeping in mind that the Australian markets are relatively new and the gas prices at the three markets (Victoria, STTM, and GSH) reflect short-term spot prices. Longer-term gas contracts are not linked to these indices, unlike in the United States where long-term gas contracts are linked to a specified hub index price (e.g., the Henry Hub).

3.1 Victorian Gas Market

Data for gas prices in the Victorian market are available from January 2005 from AEMO, as shown in Exhibit 11.

Exhibit 11: Average Monthly Spot Gas Prices in Victoria[34]



Source: AEMO.

Aside from a small number of winter gas days, gas supply and network capacity were sufficient to meet demand during the early years of the Victorian gas market. In 2007, the gas market experienced a very high spike in prices due to increased demand for GPG that occurred as a result of reduced coal-fired and hydroelectric generation from pro-longed drought conditions in eastern Australia. During this period there

[34] In February 2007 reforms to the gas market introduced rescheduling at five time intervals over the day. From the 2007 the average prices are based on the first schedule of each gas day.

were an increased number of injections into the pipeline from LNG storage[35] to meet the higher demand and congestion on the network—the price jumped to a record $330/MMBtu on July 17, 2007.

The combination of drought conditions easing in 2008 and new capacity added in Victoria, reduced the price volatility experienced the previous winter. However, on November 22, 2008 the 10 p.m. schedule price spiked to $786/MMBtu, due to unexpected cold weather combined with planned and unplanned outages of a gas processing plant.[36] With mild winter conditions and a weaker economy, prices trended down between 2009 and 2011 as retailers and consumers had sufficient contracted supply to meet their demand.

Prices increased in 2012, as a result of some long-term supply contracts expiring and a colder winter increasing demand across southern Australia. Current prices remain at about $4/MMBtu and are fairly stable.

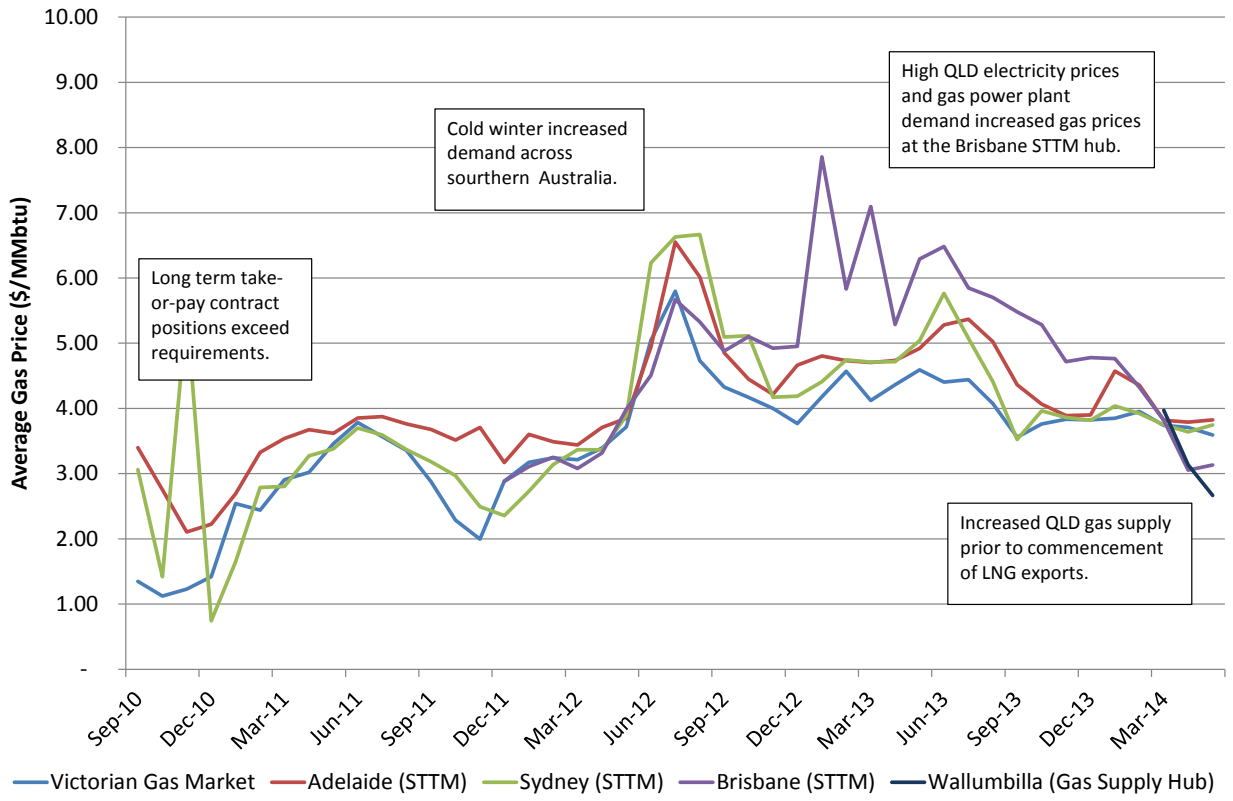
3.2 STTM Gas Prices

Since the commencement of the STTM, prices have moved in lock step across all STTM hubs (Adelaide, Sydney, and Brisbane) and the Victorian gas market. This is despite the fact that the Victorian gas market is a commodity-only market while the STTM prices represents gas delivered to the hub. The majority of gas traded through the STTM is transported on long-term, firm, take-or-pay contracts and as such the transportation charge is often treated as a sunk cost by participants. Victoria supplies a large share of demand in NSW and SA and consequently Victorian supply and demand conditions have a significant bearing on the STTM spot prices. Exhibit 12 shows the monthly average price for the spot markets in eastern Australia. Again, these prices represent the clearing prices for daily imbalances in the system. They do not reflect a robust spot market for trading gas broadly. Most gas continued to move under confidential pricing in the long-term contracts that are the norm.

[35] There is an LNG storage facility that provides peak shaving services to the Victoria gas market and is a supplier of transport fuel.

[36] AEMO, 2010, "Significant Price Event Report Gas Day: 22 November 2008." Available at: http://www.aemo.com.au/Gas/Resources/Reports-and-Documents/~/media/Files/Other/reports/gas/1150-0003%20pdf.ashx.

Exhibit 12: Average STTM Spot Market Prices[37]



Relatively low gas prices were observed during the first 18 months of the STTM. The ex-ante market price at the Sydney hub was regularly below $1/MMbtu during the initial months of the market. It is believed that many retailers and users had long-term take-or-pay contract positions that exceeded their requirements. Excess gas contract positions were offered into the market by these participants at relatively low prices.

A cold winter in 2012 increased demand across southern Australia, which resulted in high prices—as high as $17/MMBtu at the Sydney STTM hub on 23 June 2012. Following the strong winter prices, the spot market prices remained above contract prices (which were believed to be $3.00 to $4.00) during 2012 and 2013. Some long-term contracts supply contract expired during this period. It is believed that in response to the expected rise in contract prices, some participants were banking gas under their long-term contracts so that it could be used to supply their customers at a later date. Therefore, the amount of gas supply offered into the short-term market decreased, resulting in higher prices.

High power prices in Queensland throughout the first quarter of 2013 increased demand from gas power plants located within and upstream of the Brisbane hub. This high demand from gas power plants pushed up prices at the Brisbane STTM. The high electricity prices were triggered by network congestion, disorderly bidding and tight supply conditions.[38]

[37] AEMO, 2014, "Short Term Trading Market." Available at: http://www.aemo.com.au/Gas/Market-Data/Short-Term-Trading-Market-Data.

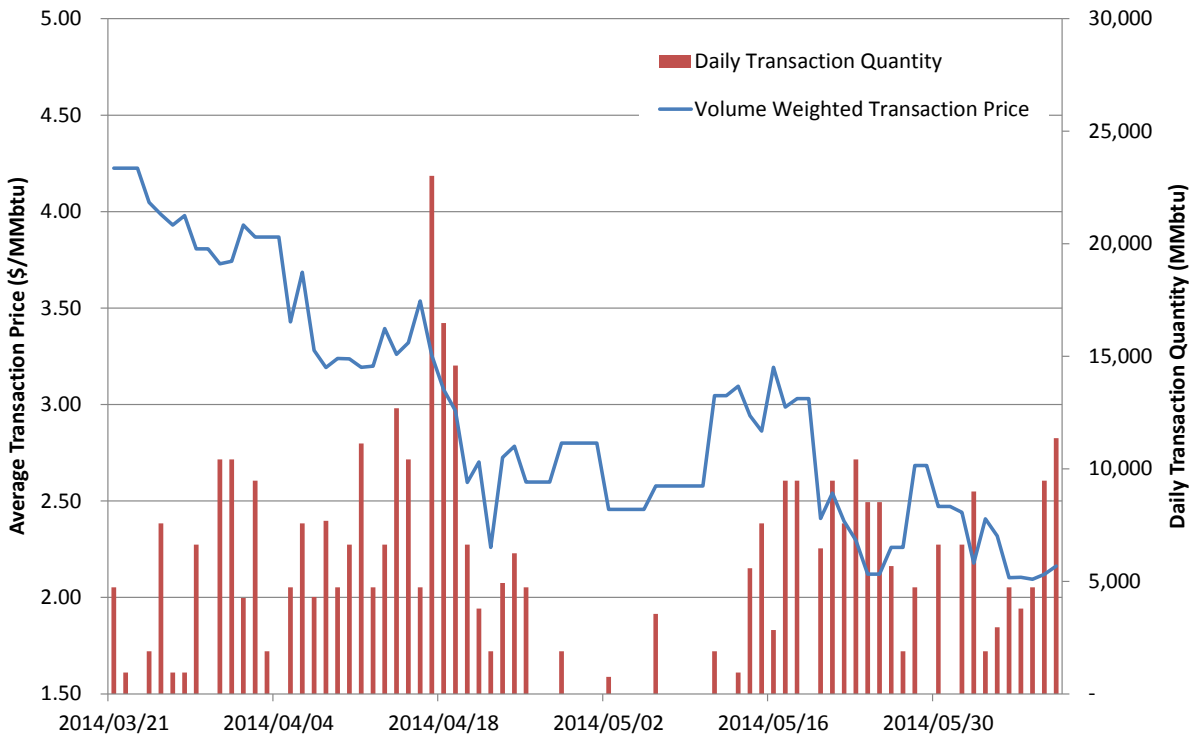
[38] AER, 2014, "State of the energy market 2013." Available at: http://www.aer.gov.au/node/23147.

Spot market prices, particularly those in Queensland, have eased in 2014 due to increased gas production in Queensland, ahead of the first cargo of LNG from Gladstone towards the end of 2014. This injection of "ramp-gas" into the market has decreased spot prices in all of eastern Australia.

3.3 Gas Supply Hub (Wallumbilla) Prices

The higher gas production in Queensland has had the most impact on prices in the new GSH market at Wallumbilla. Relatively low demand, due to mild weather and low electricity prices, combined with increased production has pushed the spot prices below $2.50/MMbtu. Daily transaction price and quantities since the commencement of the GSH are shown below in Exhibit 13.

Exhibit 13: Gas Supply Hub (Wallumbilla) Daily Price and Quantity[39]



3.4 Eastern Australian Contract Markets and Price Discovery

The majority of gas supply in Australia is traded through long-term bilateral contracts between gas producers, direct customers (e.g., industry and power plants) and retailers. Over-the-counter markets and brokers were established over a decade ago in electricity and environmental products, but have not yet established a role in the trading of natural gas products in eastern Australia. A natural gas futures contract, cash settled against the Victorian gas market, is managed by the ASX. However, the contract has only had a small number of trades and a representative forward curve has not been established.

[39] AEMO, 2014, "Gas Supply Hub." Available at: http://www.aemo.com.au/Gas/Market-Data/Gas-Supply-Hub-Market-Data.

Prior to the establishment of the Gas Supply Hub, industry commented that a lack of standardization and forward trading mechanisms increased transaction costs, making it difficult to trade short- to medium-term contracts.

The development of secondary pipeline capacity trading arrangements is seen by industry as an important development to improve liquidity and efficiency of natural gas trading in Australia.

3.4.1 Price Discovery Process

There is limited transparency of forward gas prices in Australia. Wholesale market participants regularly test the market through direct negotiation with gas producers and other wholesale participants. Stock exchange announcements and media reports (see Exhibit 14) are the main source of public information about the forward contract market.

In the retail market, large gas users often run a competitive tender process to procure their long-term gas supplies.

3.4.2 Recent Contract Trends

An increase in the price of long-term gas supply contracts in eastern Australia has been widely reported, as noted in the Introduction. Buyers have also reported a fall in the number of parties able to make long-term offers for gas supply. Exhibit 14 below contains a summary of recent transactions, including indicative pricing and total quantities, reported by one of the counterparties to the transactions through stock exchange reporting requirements or reported by the Australian press.

LNG participants have been the most active and hence they are prominent in the list below. The pricing of most of the transactions are reported as being linked to oil prices, now or in the future. That the sales to the LNG exporters would be linked to oil is not surprising. Sales to domestic consumers linked to oil may represent the competition between LNG exporters and domestic users and may also reflect a desire for more transparent pricing. That said, from the announcements there is no way to determine how the pricing mechanisms work or what oil indices are used.

Exhibit 14: Recent Gas Sales Contract Transaction Announcements

Date	Seller	Buyer	Start Date	Term (Years)	Pricing	Volume	Delivery location
27/03/2014[40]	WestSide Corp. Ltd. (Meridian Field)	GLNG	2015	20	Oil linked in 2016	Up to 62 MMcfd	GLNG pipeline. (passes adjacent to the fields)
19/12/2013[41]	Origin	GLNG	2016	5	Oil linked	95 Bcf over 5 years	Wallumbilla
28/11/2013[42]	Origin	QGC	2014	2	Oil linked	28 Bcf per year	Wallumbilla
19/09/2013[43]	Exxon	Origin	2014	9	Current market price and then oil linked	410 Bcf over 9 years	Sydney, Longford
10/04/2013[44]	Beach	Origin	Mid-2015	8	Combination of an oil linked curve and other parameters	16 Bcf per year (up to 132 Bcf over 8 years)	Moomba
20/12/2012[45]	Origin	MMG	2013	7	Media report estimated $8.85/MMbtu	21 Bcf per year	North West Queensland
2/05/2012[46]	Origin	GLNG	2015	10	oil linked	95 MMcfd	Wallumbilla
25/10/2010[47]	Santos	GLNG	2014	15	oil linked	711 Bcf over 15 years	Wallumbilla

In a notice to shareholders regarding stock value, WestSide Corporation Limited (listed as the first seller in Exhibit 14 above) disclosed a number of details on its long-term gas price contracts. WestSide said it signed a 20-year natural gas sale contract with GLNG to purchase gas starting in 2015. The shareholder disclosure stated that the sales agreement provided WestSide with production flexibility to match the Meridian Field deliverability with available funding, supplying GLNG with up to 62 MMcfd over 20 years. The 20-year agreement was based on oil-indexed market prices referenced to the Japan Customs-cleared Crude (JCC) oil prices in U.S. dollars. The contract prices are roughly three times higher than prices WestSide currently receives. The exhibit below shows estimated prices under the contract at different JCC oil prices.[48]

[40] Santos, 2014, "GLNG sign purchase agreement with Meridian joint venture." Available at: http://www.asx.com.au/asxpdf/20140327/pdf/42nmzqdfl3br44.pdf.

[41] Origin Energy, 2013, "Origin announces new agreement to sell gas to GLNG." Available at: http://www.originenergy.com.au/news/article/asxmedia-releases/1539.

[42] Origin Energy, 2013, "Origin announces gas supply agreement with QGC." Available at: http://www.originenergy.com.au/news/article/asxmedia-releases/1535.

[43] Origin Energy, 2013, "Origin secures 432 PJ of natural gas from ESSO/BHPB to boost its portfolio to meet customer demand." Available at: http://www.originenergy.com.au/news/article/asxmedia-releases/1516.

[44] Beach Energy, 2013, Beach signs major gas sales agreement with Origin Energy." Available at:

http://www.beachenergy.com.au/IRM/Company/ShowPage.aspx/PDFs/2934-16785602/BeachsignsmajorgassalesagreementwithOriginEnergy.

[45] The Australian, 2012, "Origin Energy secures record gas price." Available at: http://www.theaustralian.com.au/business/mining-energy/origin-energy-secures-record-gas-price/story-e6frg9df-1226541447947#.

[46] Origin Energy, 2012, "Origin announces major gas sales agreement with GLNG." Available at: http://www.originenergy.com.au/news/article/asxmedia-releases/1386.

[47] Santos, 2012, "Santos to supply 750PJ of portfolio gas to GLNG." Available at: http://www.santos.com/Archive/NewsDetail.aspx?p=121&id=1230.

[48] WestSide Corporation Limited. "WestSide Targets Statement" (p. 6). WestSide, 16 May 2014: Brisbane, Qld.

Exhibit 15: Estimate of Gas Price under GLNG Gas Supply Agreement from 2017

JCC Oil Price (US$/bbl)	$100.00	$110.00	$120.00
Gas Price (US$/GJ)	$7.95	$8.60	$9.24
Gas Price (A$/GJ)	$8.59	$9.28	$9.98

Source: WestSide Corporation Limited. "WestSide Targets Statement." (p. 6). WestSide, 16 May 2014: Brisbane, Qld.

3.4.3 Contract Price Drivers

Eastern Australia's natural gas contract prices have historically been low compared to other OECD countries due to the large accessible gas reserves and competition from low priced coal. Gas contracts in eastern Australia have historically been priced at a premium to the cost of gas production—typically between $3.00 and $4.00. Drivers of the increase in the long-term natural gas contract price include the following factors:

- *Tight demand and supply conditions*: As discussed in Section 2.2, demand for gas in eastern Australia is expected to increase at unprecedented rates. It is a significant challenge for the LNG export projects, and the industry more broadly, to develop gas fields, processing and transportation facilities to meet such large increases in demand in such a relatively short period of time.

- *Limited supply options*: The LNG export participants are currently large sellers of gas in the domestic market. However, over the next three years, they will transition from sellers to buyers in the domestic market. As shown in Exhibit 16, LNG export participants hold a large share of the 2P CBM reserves, once their focus turns to the production of LNG there will be less wholesale participants that are capable of supplying long-term wholesale transactions.[49]

Exhibit 16: LNG Export Share of CBM Reserves

LNG Export Project	Gas Reserve Classification		
	Quantity of 2P Reserves (Bcf)	Quantity of 3P Reserves (Bcf)	Quantity of 2C Resource (Bcf)
Arrow Energy	8,999	13,242	2,390
APLNG	12,373	15,140	3,626
GLNG	5,096	6,467	1,553
QCLNG	9,788	17,892	12,986
Total LNG projects	**36,255**	**52,741**	**20,554**
% of Total CBM reserves	86%	81%	68%

Source: RLMS, 31 December 2012.

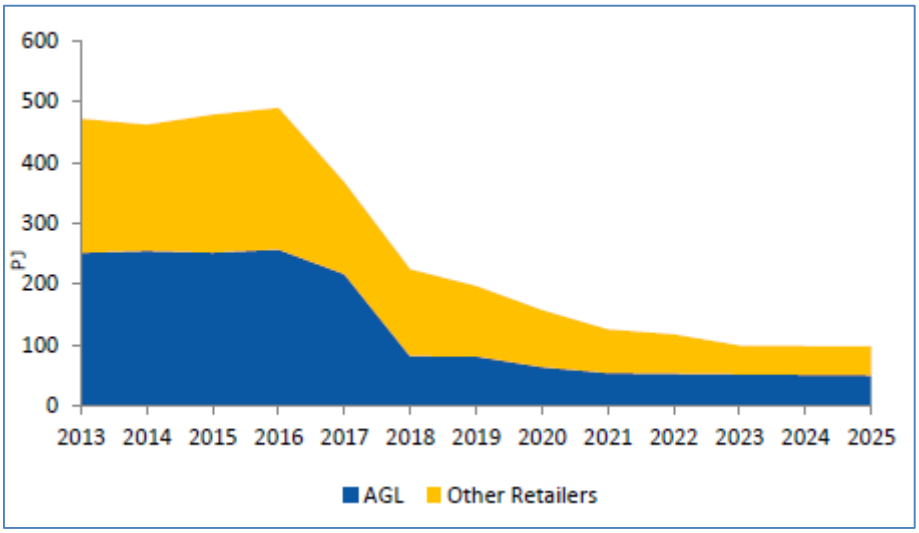
- *Restrictions on CBM developments*: The development of CBM gas fields in New South Wales (NSW) and Victoria, that could provide much needed supply to the domestic market, has been

[49] There are three classes of resources in the SPE Petroleum Resources Management System (PRMS) : Reserves, Contingent Resources, and Prospective Resources. Reserves are those quantities that meet the requirements for commerciality. They have no commercial or technical risk. Estimates of recoverable quantities are designated on the basis of risk are 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible) reserves. Contingent resources are those quantities that are estimated to be potentially recoverable from known accumulations but which are not currently considered commercial. The equivalent categories, based upon degree of risk, for projects with Contingent Resources are 1C, 2C, and 3C. Prospective Resources are even less certain and can have both commercial risk and technical risk (chance of discovery).

impacted by state government regulations. The NSW Government introduced the Strategic Regional Land Use Policy[50] in 2012 which places new regulations on mining and coal seam gas industries, including an exclusion zone around residential and strategic agricultural land across the State. In 2012, the Victorian government imposed a moratorium on hydraulic fracturing and coal seam gas exploration which will remain in place until at least July 2015. The moratorium affects the development of onshore unconventional gas reserves in the Gippsland Basin. In April 2014, the government commenced community consultation on possible onshore gas development in Victoria.[51]

- *Re-contracting period*: A large portion of gas supply contracts will come to an end by 2018 coinciding with the start-up period of the LNG export projects and a period of high demand for contracted supplies. Industry groups in eastern Australia have voiced concerns about increased contract prices[52] and the challenge faced by their members as they re-contract their gas supplies.

Exhibit 17: Eastern Australia Contracted Supply[53]



- *Competition from LNG exporters for long-term supply*: As shown in Exhibit 14, LNG exporters have recently been the main buyers on long-term domestic gas supply. It is believed that this is to ensure they have sufficient production and processing capacity in the near-term and adequate reserves to meet the long-term export obligations.

  As shown in Exhibit 18 below, gas required by GLNG to meet their contracted LNG sales exceeds their reserves. GLNG has entered into third party agreements to shore up the feedstock requirements of its LNG export project. As listed in Exhibit 14, GLNG has contracted for supply of up to 1,611 Bcf from third party providers. In addition QQC contracted for supply of up to 28.4 Bcf

[50] New South Wales Government, 2013, "Strategic Regional Land Use." Available at: http://www.nsw.gov.au/initiative/strategic-regional-land-use.

[51] Victorian Government, 2014, "Natural Gas Community Information: Current status of onshore natural gas in Victoria." Available at: http://naturalgasinfo.vic.gov.au/__data/assets/pdf_file/0017/92321/6746-eer-current-status-factsheet-3.pdf.

[52] ABC News, 2014, "Gas exports, price boom threaten 100,000 Australian jobs: manufacturers." Available at: http://www.abc.net.au/news/2014-03-27/gas-boom-threatens-australian-manufacturing-jobs/5349822.

[53] Source: AGL Merchant Energy Presentation May 2013. Available at: http://www.agl.com.au/about-agl/media-centre/article-list/2013/may/merchant-energy-presentation-may-2013.

of gas during 2014 and 2015 to increase its supply portfolio as it expands its own LNG production capacity.

Exhibit 18: Gas Requirements and Reserves by LNG Export Project (Bcf)

Project Name	Capacity	Annual Gas Demand at Full Capacity	Sales	Annual Gas Required to Meet Sales	Total Gas Required to Meet Sales	Total 2P Reserves	Reserves Long / Short
APLNG	438.3	512	418.82	489	9,782	12,408	2,626
GLNG	379.86	444	340.9	398	7,962	5,096	-2,866
QCLNG	413.95	483	413.95	483	9,668	9,788	119

Source: RLMS, 31 December 2012.

- *LNG netback price*: LNG export projects have recently been the main buyers of domestic gas supplies. It is believed that the LNG netback price, the LNG sales price in Asia less all transportation and processing costs, is being used as a benchmark for the pricing of domestic gas contracts in Australia. This netback price has the following main components:
  - LNG sales price: The long-term LNG transaction price in Asia that is linked to the oil price. The Japanese Customs-cleared Crude (JCC) contract is commonly used as the reference price in Asia for LNG transactions. A factor (or slope) for the conversion of the oil price to the LNG price is negotiated by the contract parties.
  - LNG shipping cost: The cost of LNG tankers required to transport LNG from Gladstone to Asia.
  - Liquefaction cost: The construction and operational cost of liquefaction facilities.
  - Transportation to the LNG plant: The delivery location of a domestic gas deal influences the netback price as the theoretical alternative for the seller is to transport that gas to Gladstone for use as LNG feedstock. The greater the distance from Gladstone the lower the netback price because of the higher theoretical transportation cost to Gladstone.

Such netback pricing is characteristic of LNG commercial arrangements where the source of LNG has substantial stranded gas resources—i.e., limited local markets for domestic gas and LNG is the only way to monetize the resource. By contrast, LNG export pricing in the United States has been based on domestic gas prices, such as Henry Hub, and not netbacks from the Asian or European markets. The reason for this is the size and liquidity of the U.S. domestic market and the ready availability of supply from many producing sources in the United States and Canada and large demand from domestic consumers. The price of gas in the United States and Canada is set in the domestic market, not the overseas markets. Exporters of LNG from North America must enter this domestic market to secure supply for export.

3.5 Gas Supply Cost and Performance Challenges

Gas supply costs are expected to increase in eastern Australia because of higher production costs associated with CBM, shale gas, and tight gas resources, higher pipeline and processing costs associated with new gas fields, and higher input costs that are impacting mining and resource projects across Australia.

While Australia has potentially large shale and tight gas reserves, the cost of extracting this gas (or wellhead cost) is higher than in the United States and higher than current CBM production. A study by

the Australian Council of Learned Academies (ACOLA) [54] reported that the cost of drilling and completion of a shale gas well in Australia (between $11 million to $12 million) is considerably higher than the United States ($3.5 million to $5 million). The cost of extracting shale gas resources is also estimated to be significantly higher than current CBM production in eastern Australia. In a report by consulting firm SKM[55] for ACOLA, the initial cost of shale gas production is estimated to be in the range of $6 to $9 per MMBtu compared $3 to $6 per MMBtu for CBM due to the higher drilling costs (well depth of 2,000 to 3,000 meters for shales compared to 500 to 1,000 meters for CBM), production profile, and the higher material and water requirements for the hydraulic fracking of shale wells.

Australia's coal seam gas producers have had problems in terms of well quality, and drilling and related costs. The big projects including the Santos Gladstone project, Origin Energy/ConocoPhillips' Australia Pacific LNG, and BG Group's Queensland Curtis Island project are relying primarily on CBM for gas supply. Operators plan to drill tens of thousands of CBM wells in coming decades to supply the plants. The producers indicate that a large fraction of the CBM wells have high initial rates in the range of 2–4 MMcfd or greater.[56,57] Most of the wells require de-watering, which creates additional costs and has environmental considerations for water disposal.

It is now apparent that while the "sweet spot" wells are generally meeting expectations, other areas are not. In addition, there is reported to be more variability from well to well than anticipated, even in some of the better areas. Because of the lower well quality, Santos increased the number of required wells for its Gladstone project relative to their initial environmental impact statement. In a February, 2014 presentation, Santos stated that it anticipated the requirement of drilling 200 to 300 new CBM wells per year, apparently for the life of the Gladstone project to maintain deliverability. At a reported cost of around $1.35 million per well (reportedly down 30 percent from 2010 costs), this would equate to additional, previously unanticipated capex of $1.2 to $1.6 billion through 2018. Over 20 years, the additional wells for just this project would total 4,000 to 6,000.

It has been estimated that reliance upon CBM for the three planned LNG projects could result in the drilling of up to 40,000 wells, in contrast to the 18,650 wells originally planned in the environmental impact statements. In addition to increased costs, this increased level of activity is meeting with strong resistance from environmental groups.

Given the difficulties with CBM well quality and costs, LNG developers have been purchasing gas from third parties with reserves in other areas such as the Cooper Basin, to provide a portion of future gas production volumes. The Cooper Basin produces conventional gas and has shale gas potential, for which activity is still in the initial stages.

The combination of the above factors impacting reserves and deliverability may result in significantly lower levels of near-term LNG export than were initially anticipated.

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[54] Australian Council of Learned Academies, 2013, "Engineering Energy: Unconventional Gas Production, A study of shale gas in Australia." Available at: http://www.acola.org.au/index.php/projects/securing-australia-s-future/project-6.

[55] SKM, 2013, "Unconventional Gas in Australia – Infrastructure Needs." Available at: http://www.acola.org.au/index.php/projects/securing-australia-s-future/project-6.

[56] Santos, 2014, "Macquarie Australia Conference." Available at: http://www.santos.com/library/080514_Macquarie_Australia_Conference_Presentation.pdf;

[57] Origin, 2014, "Origin-APLNG Operational Review and Asset Visit." Available at: http://www.originenergy.com.au/files/APLNG_Site_Tour_Combined_Presentations.pdf.

A 2014 report by MDQ Consulting[58] discussed the reserve positions that have been established for each of the major Australian export projects. The author concluded that all three projects are short on "2P" reserves and that the Gladstone project is in the worst reserve situation, especially when considering other reserve categories. The report discusses gas reserve purchase by Gladstone to secure supply from other basins to supplement their CBM reserves.

Project development and construction costs have increased significantly in Australia following an extended growth period in the mining and resource sectors. Some of the most notable examples of increased costs have been observed in the construction of LNG export projects with Chevron's Gorgon project now budgeted to cost $54 billion,[59] up from an original budget of $37 billion, and the QCLNG project which has had an increase in budget of 33 percent to $20.4 billion.[60] The increase in costs at these projects has been attributed to exchange rate movements, higher labor and input costs, increased regulatory hurdles, and delays. With seven LNG export projects currently under construction, competition for skilled labor and equipment is likely to result in higher costs for new gas developments in eastern Australia for the foreseeable future.

Another challenge for the development of domestic reserves in Australia has been management of environmental impacts, particularly of the CBM development that has sparked concern from environmental, agricultural, and community groups. Much of the CBM is located in prime agricultural areas and the impacts on land use have caused tension with farming that has been reported in the media. CBM in Queensland is particularly wet, requiring significant de-watering. The wetness is due to the co-location of subterranean aquifers, such that the drilling is said to put pressure on groundwater resources. Moreover, the de-watering has led to fears of untreated production water at the surface; alleged damage to, and contamination of underground aquifers by hydraulic fracturing; damage to wildlife habitat in sensitive areas; and contamination of surface water resources in drinking water catchments. Some communities feel that CBM development does not fit with the character or objectives of the area, such as wine-producing and tourist regions, and results in adverse health impacts.[61]

Environmental regulation in Australia primarily falls under state oversight. New South Wales has put strict restrictions on CBM development, but has little production. Most of the production is in Queensland, where the government has implemented a comprehensive governance framework to oversee CBM development. The legal framework requires thorough assessment of proposed projects; protects the Great Artesian Basin, local water supplies, and strategic cropping land; requires fair compensation for landholders; sets safety and sustainability standards for CBM operations; and has established a strict compliance and enforcement regime. The industry is also required to support local businesses, train

[58] MDQ Consulting, 2014, "NSW Wholesale Gas Market Report." Available at: http://www.ipart.nsw.gov.au/files/2086952c-5a8f-4aab-b716-a2d5009ff909/Report_-_MDQ_Consulting_NSW_Wholesale_Gas_Market_Report_-_February_2014.pdf.

[59] ABC, 2013, "Chevron reveals second Gorgon gas project cost blowout." Available at: http://www.abc.net.au/news/2013-12-12/gorgon-gas-project-cost-blowout/5151982.

[60] The Australian, 2013, "Triple whammy sparks $5bn blowout for BG's Gladstone project." Available at: http://www.theaustralian.com.au/business/companies/triple-whammy-sparks-5bn-blowout-for-bgs-gladstone-project/story-fn91v9q3-1226346265187#.

[61] The Coal Seam Gas Debate, Parliament of Australia, retrieved July 11, 2014 from http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BriefingBook44p/GasDebate.

workers for new skills and invest in physical and social infrastructure such as roads housing and community services.[62]

Thus a number of factors have contributed to the slower development and higher cost of CBM for LNG in eastern Australia. These higher costs and lower rates of production have led LNG developers to enter into the broader market to secure supplies from other sources in order to meet their LNG delivery obligations.

3.6 Potential New Gas Supplies in Response to High Contract Prices

Some commentators have speculated that contract prices could rise as high as AU$18/GJ[63] if LNG export projects are not able to meet LNG sales contracts with their own gas. In the event that a LNG export project is not able to produce sufficient gas then it could purchase third party domestic gas supplies or purchase spot LNG to ensure it meets its sales contract. In theory, and to the extent that its liquefaction and transportation costs are sunk, it may be more economical for the LNG export project to purchase gas at a price higher than the LNG netback price. However, if domestic contract prices rise above the long run LNG netback price, mostly due to other "suppliers" providing the required shortfall in gas, then it is likely to trigger an increase in supply to the domestic market. Some new sources of supply could include:

- Supply diversion: Arrow Energy has had plans to develop a LNG facility in Gladstone Harbor using CBM supplies. Arrow controls 20 percent of Australia's CBM resources (see Exhibit 15). Rather than develop its own project, Arrow is considering selling its supplies to the other LNG projects or into the domestic market. The *Australian Financial Review* reported that it understood Arrow Energy was in negotiation with the three other LNG export projects in March 2014.[64]

- Shale production: High prices stimulate the development of new gas production facilities. Shale gas is in the early stages of development in Australia, and more exploration and appraisal activity is required to prove the reserves required to justify investment and development of the resources. As discussed in text box below, the increased contract prices have already sparked substantial investment in exploration for unconventional gas in Australia.

- Power generators selling gas into market: Some power plants have already committed to selling their gas supplies rather than generating electricity. There is likely to be further scope for switching to gas sales from gas power plants. This switch may include even the most efficient power stations, as they respond to periods of high gas prices.

[62] Queensland Government, Regulatory Framework for CSG-LNG Development, retrieved July 11, 2014 from http://www.business.qld.gov.au/industry/csg-lng-industry/regulatory-framework-csg-lng.

[63] The Australian, 2014, "LNG demand to force spike in gas prices." Available at: http://www.theaustralian.com.au/business/mining-energy/lng-demand-to-force-spike-in-gas-prices/story-e6frg9df-1226847417206#.

[64] Australian Financial Review, 2014, "Gas sale seen as favoured option from Arrow talks." Available at: http://www.afr.com/p/opinion/gas_sale_seen_as_favoured_option_OCumhgzwy7XGk30IpA1ulL.

Increasing Exploration Investment Due to High Natural Gas Prices

The recent increase in contract prices in eastern Australia has triggered investment of over a billion dollars (USD) in the exploration and appraisal of shale and tight gas resources in Australia. Some of the recent investments are summarized below.

May 2, 2014, Falcon Oil & Gas – Origin Energy, Sasol

Falcon Oil & Gas entered into farm-out agreements with Origin Energy and Sasol[65] covering exploration permits in the Beetaloo Basin located in the Northern Territory. Under the agreements, Origin and Sasol will earn 35 percent interest in the exploration permits for a cash investment ($19 million) and a commitment to fully fund the cost of the exploration activities. The exploration and appraisal program will be carried out in three stages over the next five years with a budget of up to $154 million.

March 25, 2014, Strike Energy – Orica

Strike Energy, an oil and gas company, entered into a second agreement with Orica, an Australian explosives and chemicals maker, to supply an additional 95 Bcf of gas.[66] The parties entered into an initial deal in 2013 for Orica to make $48 million of pre-payments against a 20-year agreement to supply up to 142 Bcf of gas. The pre-payments are providing Strike with the funding required to develop its unconventional gas resources in the Cooper Basin. The innovative deal provides Orica with affordable long-term gas supply at a time of rising contract prices in eastern Australia.

March 10, 2014, Drillsearch – BG Group (through QGC)

Drillsearch, a junior oil and gas company, announced an expansion and extension of its agreement with BG Group (through QGC) for the exploration of shale and tight gas in the Cooper-Eromanga Basin.[67]

Under the original agreement, struck in July 2011, the parties agreed to a three stage exploration and production program of shale and tight gas resources. A commitment was made to invest $120m over five years with $84m of the first $93m to be funded by BG Group. Under the new agreement, the remaining funding has been brought forward and the exploration activity has been expanded and extended.

February 24, 2014, Senex – Origin Energy

Senex, a junior oil and gas company, announced farm-out agreements with Origin Energy covering petroleum exploration licenses in the Cooper-Eromanga Basin.[68] Under the agreements, up to $235 million will be invested to evaluate tight gas sands. The work program involves drilling at least 15 wells and other exploratory activities. Senex sought the partnership with Origin Energy to accelerate the commercialization of the potential large unconventional gas reserves.

February 25, 2013, Beach – Chevron

Beach Energy, a junior oil and gas company, announced a farm-out agreement with Chevron[69] covering exploration licenses in the Cooper-Eromanga Basin in South Australia and Queensland. Under the agreement, Beach Energy will transfer up to 60 percent of its ownership in the exploration licenses in return for payments of up to $350m by Chevron over two stages. The agreement will help to fund the exploration and appraisal program being carried out by Beach Energy.

[65] Falcon Oil and Gas, 2014, "Transformational Farm-out of Beetaloo Unconventional Acreage, Northern Territory, Australia." Available at: http://www.asx.com.au/asxpdf/20140502/pdf/42pdl2f1lxl7m3.pdf.

[66] Strike Energy, 2014, "Southern Cooper Basin Gas Project Update." Available at: http://www.strikeenergy.com.au/images/stories/pdf/20140325_Orica%20Gas%20Sales%20Agreement.pdf.

[67] Drillsearch Energy Limited, 2014, Drillsearch and QGC agree new terms over Cooper Basin acreage." Available at: http://www.asx.com.au/asxpdf/20140310/pdf/42n8j3knd4tkj0.pdf.

[68] Senex Energy Limited, 2014, "Senex and Origin Energy agree Cooper Basin gas farm-out." Available at:

http://www.senexenergy.com.au/uploads/contentFiles/files/2014_02_24%20Senex%20and%20Origin%20agree%20Cooper%20Basin%20gas%20farm-out.pdf.

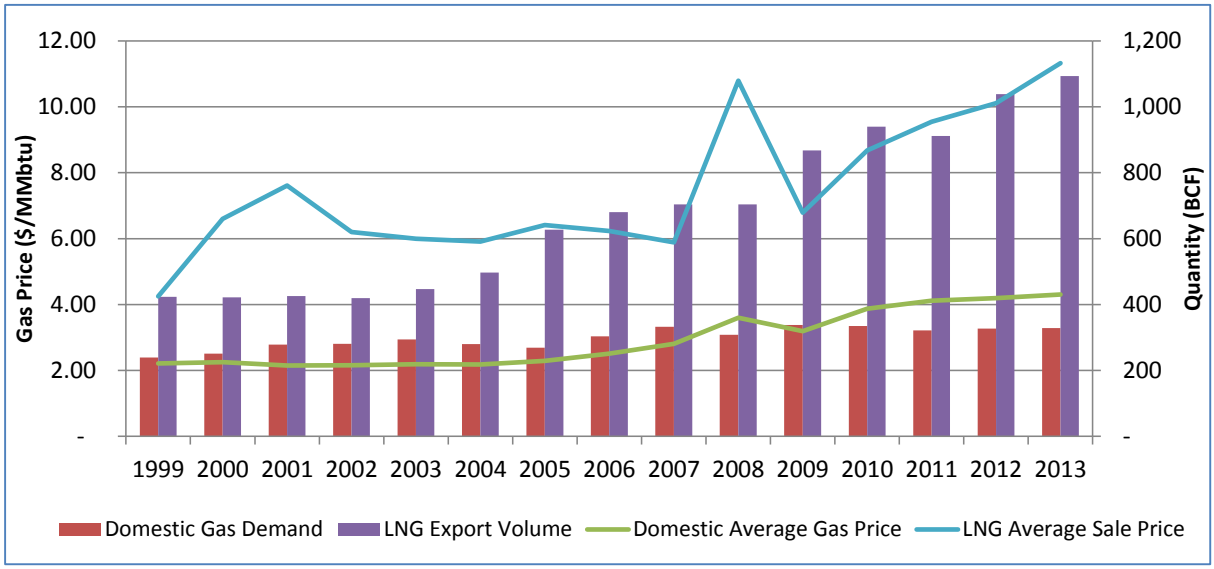
[69] Beach Energy, 2013, "Beach Farm-out of Exploration Acreage in Nappamerri Trough to Chevron." Available at: http://www.beachenergy.com.au/IRM/Company/ShowPage.aspx/PDFs/2865-26815295/BeachfarmoutofexplorationacreagetoChevron.

3.7 Contract Prices in Western Australia

Gas has historically been purchased by the North West Shelf JV under long-term supply contracts. These contracts are thought to expire starting in 2015. Like eastern Australia, there is limited transparency of contract prices in WA.

Exhibit 19 shows the historical average domestic contract price and the average LNG export price. The domestic contract price is heavily influenced by the weighting of lower priced long-term contracts and as such is not representative of prevailing market prices. However, the diagram does provide a good summary of the historical contract prices and the current gas purchase costs in the state.

Exhibit 19: Western Australia LNG Export and Domestic Gas Prices (USD)



Source: Government of Western Australia Department of Mines and Petroleum.

Average gas prices in Western Australia were less than $2.50/MMbtu until 2006 when increased demand from a strong mining sector and higher production costs put upward pressure on domestic contract prices. Short-term gas supplies traded up to $17/MMBtu in July 2008 following the Varanus Island incident which cut domestic supply.[70] The average LNG export price almost doubled between 2007 and 2008, and the domestic gas price increased during the same year.

In 2011, a Western Australian government inquiry into domestic gas prices found that prevailing contract prices had been reported to be in a range of approximately $5.45 to $9.10/MMBtu.[71] The increase in prices sparked new investment in domestic-market-only production facilities, including the Reindeer and Macedon gas fields in the Carnarvon Basin.

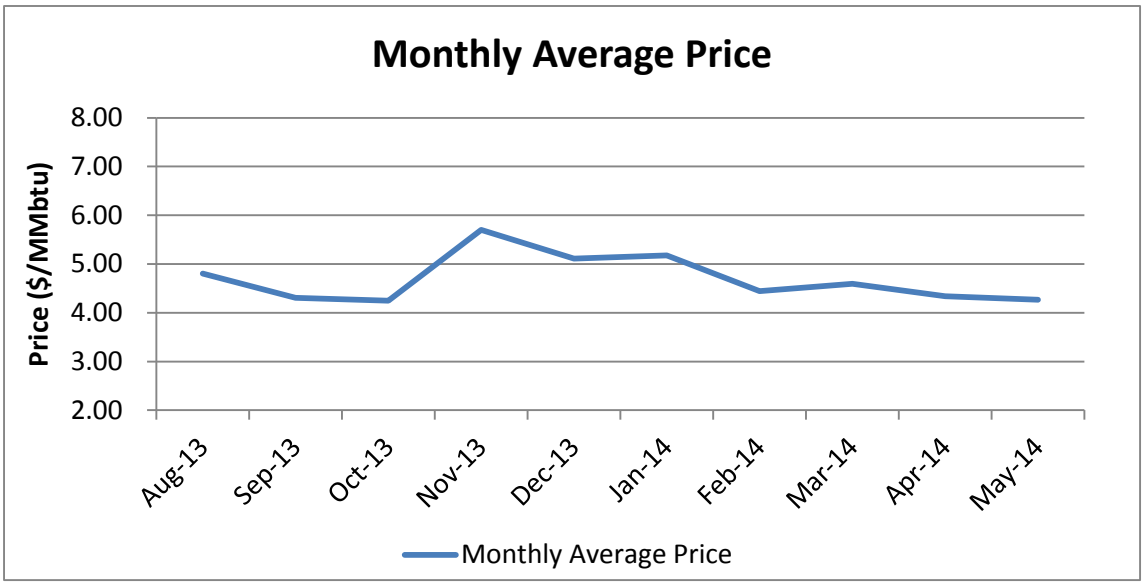
Unlike eastern Australia, there are no regulated spot markets operating in Western Australia. A small number of brokers provide short-term transaction matching, nomination, and contract management services to gas users in the state. GasTrading, a broker established in 2007, publishes aggregated details of trades it matches to support price transparency for the industry. The quantity of transactions matched by the broker has averaged around 9.5 MMcf per day over the past two years, and GasTrading

[70] Australian Energy Regulator, 2010, "State of the energy market." Available at: http://www.aer.gov.au/node/6313.

[71] Economics and Industry Standing Committee, 2011, "Inquiry into Domestic Gas Prices."

reported a fall in the monthly average price from over $6/MMbtu in 2012 to around $4/MMbtu in May 2014. Exhibit 20 shows the average spot prices over the past ten months.

Exhibit 20: Average Spot Price in Western Australia (USD)



Source: GasTrading, http://www.gastrading.com.au/.

The diagram shows that despite strong LNG spot prices in Asia, the domestic spot prices have softened. This softening reflects an easing in demand growth that had been observed in Western Australia.

A retail gas market operates across distribution networks in the south-west of the state, providing customer transfer and metering services and facilitating competition between suppliers in the retail market.

4 Summary Comparison of the United States and Australia

As Exhibit 21 shows, there are major differences between Australia and the United States in terms of natural gas markets. Australian domestic gas market is divided into three markets, which are small, and gas production is driven by LNG exports. In contrast, the United States is part of an integrated North American gas market, and the country's LNG exports are expected to become a small fraction of the much larger market. Australian LNG exports are expected to more than double the total production from 2012, whereas the total LNG exports out of the United States (assuming all of the non-FTA conditionally approved export projects come to fruition), will only be 12 percent of the 2012 production. Therefore, the potential impact of LNG projects in the United States is very small in comparison to the significant potential impacts that LNG exports will have on Australia.

Exhibit 21: Comparison of Natural Gas in U.S. and Australia

Criteria	Unit	U.S.	Australia
2012 GDP	Trillion current US$	$16.2	$1.5
2012 Population	Million people	313.9	22.7
2012 Total Supply (Dry Production + Imports)	Bcf	27,195	2,096
2012 Domestic Consumption	Bcf	25,533	1,045
2013 LNG Export	Bcf	0	1,050
Near-term LNG Export (2013 LNG export + LNG capacity under construction)	Bcf per year	803 (Sabine Pass, 2.2 Bcfd)	4,680
Forecasted LNG Export	Bcf per year	2,570 (per EIA AEO for 2025), 3,840 (assuming all 10.52 Bcfd of non-FTA DOE conditionally approved projects are in place)	4,680 (excluding Arrow LNG), 4,911 (including Arrow LNG)
Forecasted LNG Export as % of 2012 Total Supply	%	9.5%–12.4%	223%–236%
Pipelines	Miles	305,000	15,000
Number of Major Trading Locations	No.	58	5
Producing Gas Wells (2013)	No.	483,000	3,900 (CBM only)
Currently Active Rigs (2014)	No.	1,860	20
Market Structure		Highly integrated, price discovery and transparency, close regulation of pipelines, multiple contract options	Unconnected markets, loose pipeline regulation, no price discovery or transparency, long-term contracts

Source: EIA, World Bank, Baker Hughes, BREE Energy Statistics.

Another source of the differences between Australia and the United States is the lack of transparency in Australian gas prices. The vast majority of gas is traded under long-term contracts (10 to 20 years) under which the pricing terms are confidential. At the same time, there is no liquid wholesale market that can provide any price discovery for longer-term deals. These arrangements are understandable in a small market, where producers must have guaranteed gas off-takers to support drilling programs. This pattern is further reinforced by a pipeline network that is not highly interconnected and that itself operates under long-term service agreements at negotiated rates. There is no regulatory oversight for tariffs, nor are tariffs publicly available in most cases. Gas prices in long-term contracts are thought to be tied largely to

production costs to provide a market guarantee for producers. Much of what is known about gas prices outside the short-term spot trading markets in Australia is by anecdote.

By contrast, in the United States even the long-term contracts, where they exist, tend to be two to five years in duration, and prices are indexed to liquid trading points. The much larger North American market provides producers ready access to multiple buyers, thus prices reported at trading locations represent real opportunity costs. Moreover, U.S. pricing reflects two kinds of trading: the pure daily spot market for gas and the first of the month gas price market, for volumes delivered ratably over the subsequent month. However, the details of gas contracts in the United States are generally confidential. Buyers may be paying premia or discounts to stated indices for a variety of reasons (firm delivery obligations for example) and pricing in bilateral contracts is most certainly undisclosed. That said, the substance of gas pricing in North America is widely reported and parties have a sense of the market.

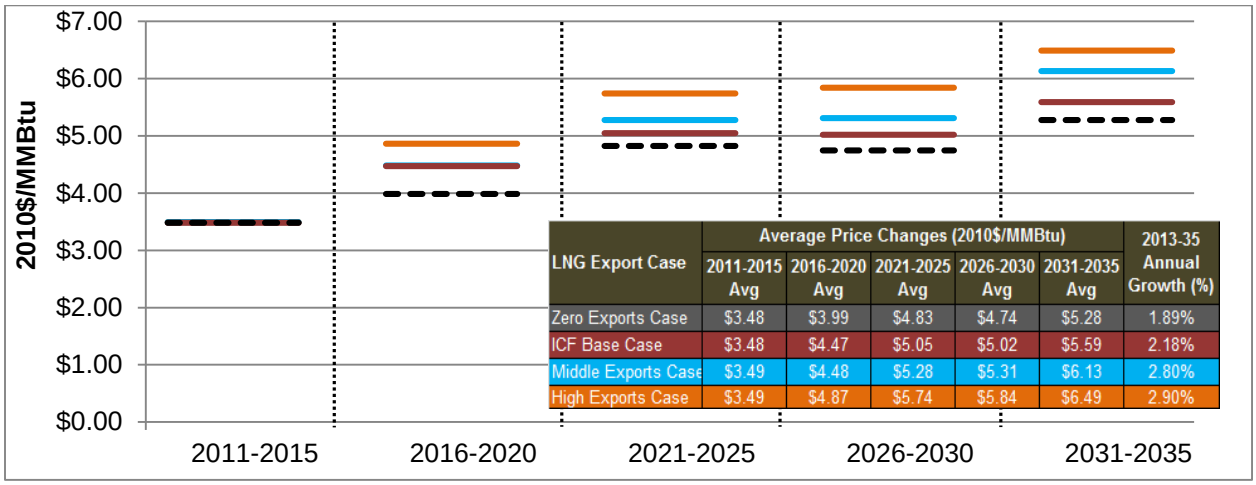
ICF accepts that new Australian contract gas prices have risen and can be expected to stay high in the near future. This appears to be the case for several reasons. LNG developers who have their own gas supply have been having difficulty ensuring that the supplies are sufficient to meet the exports. This difficulty is for primarily technical reasons having to do with production costs and well performance as noted above. LNG developers have gone outside their own production to line up alternative sources of supply from other producers. The same producers that have been supporting domestic production have an opportunity to sell gas at LNG netback pricing, which is considerably higher than domestic prices. Therefore, domestic gas consumers who are looking to renew supply contracts are likely to face a tough market where they are competing for gas with LNG developers. (This is a phenomenon of the eastern Australia market.) The production of gas in eastern Australia is dependent on (CBM). Access to other sources of gas is limited as pipeline infrastructure lacks interconnectivity with other Australian markets.

In the United States, we can expect LNG exporters to seek out long-term supply arrangements that guarantee access to sufficient quantities of gas to meet export obligations. We have seen in the market that these exporters are willing to offer premiums to Henry Hub prices.[72] However, because of the size and the interconnectivity of the U.S. market, competing buyers can turn to other sources of supply, or to other producers. The liquidity of the market will ensure access for both suppliers and buyers. While gas prices will increase slightly with the higher demand for LNG exports, relative to a No LNG Exports Case, access to gas will not be affected. ICF's previous analysis for the API demonstrated that the impact of LNG exports on natural gas prices is modest. With the addition of 4 Bcfd of LNG exports by 2035 in the Gulf Coast, Henry Hub prices were projected to average $5.60/MMBtu over 2031–35, while 16 Bcfd of LNG exports were projected to increase Henry Hub prices to average $6.50/MMBtu over 2031–35 period, compared with $5.28/MMbtu when exports are not allowed. These price increases are of a much smaller magnitude than the forecasts for Australia, which are expected to increase to LNG netback prices. Exhibit 22 shows five-year averages for natural gas prices at Henry Hub (i.e., the main U.S. natural gas pricing hub) for each of the cases assessed, with "ICF Base Case" representing an LNG export case of 4 Bcfd, "Middle Exports Case" comprising exports of 8 Bcfd, and the "High Exports Case" of 16 Bcfd.

[72] ICF knowledge gained through working with a number of private sector LNG clients.

Exhibit 22: Henry Hub Natural Gas Price (USD) Changes

4, 8, and 16 Bcfd Cases Relative to Zero Exports Case



LNG Export Case	Average Price Changes (2010$/MMBtu)					2013-35 Annual Growth (%)
	2011-2015 Avg	2016-2020 Avg	2021-2025 Avg	2026-2030 Avg	2031-2035 Avg	
Zero Exports Case	$3.48	$3.99	$4.83	$4.74	$5.28	1.89%
ICF Base Case	$3.48	$4.47	$5.05	$5.02	$5.59	2.18%
Middle Exports Case	$3.49	$4.48	$5.28	$5.31	$6.13	2.80%
High Exports Case	$3.49	$4.87	$5.74	$5.84	$6.49	2.90%

Source: ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy." The American Petroleum Institute (API), 15 May 2013: Washington, D.C. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf.

The three export cases averaged between $0.32/MMBtu and $1.02/MMBtu between 2016 and 2035 at Henry Hub, as shown in Exhibit 23. However, all cases showed an average price increase of roughly $0.10/MMBtu for every one Bcfd in LNG exports.

Exhibit 23: Wholesale Natural Gas Price Changes

4, 8, and 16 Bcfd Cases Relative to Zero Exports Case

Case	Natural Gas at Henry Hub (2016-2035 Avg)
ICF Base Case	
Avg Price Increase ($/MMBtu)	$0.32
Avg Price Increase/Bcfd ($/MMBtu)	$0.10
Middle Exports Case	
Avg Price Increase ($/MMBtu)	$0.59
Avg Price Increase/Bcfd ($/MMBtu)	$0.11
High Exports Case	
Avg Price Increase ($/MMBtu)	$1.02
Avg Price Increase/Bcfd ($/MMBtu)	$0.10

Source: ICF estimates.

Another way that the U.S. differs from Australia is that a large portion of U.S. onshore drilling activity is oriented toward drilling oil wells and gas wells that produce substantial amounts of lease condensate and natural gas plant liquids. In 2013 78 percent of the annual average Hughes rig count was for liquids-directed drilling. In contrast, eastern Australian drilling is almost completely directed to CBM and other types of gas with very little liquids content. Thus, much of the U.S. drilling activity is incentivized by crude oil and related liquids prices for lease condensate and natural gas plant liquids (ethane, propane, butanes, and pentanes plus).

On the one hand, this emphasis on liquids-directed drilling in the U.S. helps support natural gas production volumes by providing revenue for the approximately 22 percent of gas production that comes from oil wells (classified as associated-dissolved gas) and about 46 percent of the non-associated gas volumes that are processed (along with most of the associated-dissolved gas) to remove NGLs. On the

other hand, now that much of the U.S. drilling activity is directed toward liquids, gas-orientated drilling must compete with liquids-directed drilling for investment dollars and for drilling and completion equipment, materials, and services.

These considerations of competition for investment dollars and resources to drill wells were factored into the ICF analysis of LNG exports performed for API when we estimated the impacts on U.S. natural gas prices of various LNG export volumes. This was part of what we referred to as the "drilling activity price effect" which accounts for (a) competition for investment dollars, (b) the higher prices needed to accommodate short-term factor cost increases that usually accompany increased drilling activity, and (c) the price effects of the delay between when price signals change (due to higher demand) and when drilling activity and wellhead deliverability respond to accommodate that demand. We modeled the domestic gas supply response to greater demand from LNG exports as requiring a greater price increase than might be estimated by simply "moving up the long-run gas supply curve" instantaneously and at constant factor costs.

We expect that continued high oil prices and a geographically widespread and rich domestic resource base for tight oil and wet gas will mean that liquids-directed drilling will continue at a high rate even as U.S. LNG export projects come online and require more (mostly) gas-directed drilling. However, the amount of additional drilling needed will be manageable in that each one bcfd of LNG exports will require about fifty (50) additional rigs during deliverability ramp-up (that is, a period of roughly 12 months in which producers can drill enough wells to add sufficient natural gas productive capacity to rebalance the market). In addition, a one-bcfd LNG export project will then require nine (9) rigs on a sustained basis over the remainder of the export project to replace each year's produced reserves. The nine (9) rigs needed over the long-term for one bcfd of exports represents about 0.5 percent of the 1,762 rigs operating, on average, in 2013. The High LNG Export Case examined by ICF of 16 bcfd would require a sustained increase in the number of rigs of 144 additional, equivalent to 8.0 percent of the 2013 U.S. rig count. Such an increase in activity is well within historical fluctuations (U.S. rig counts have ranged from 900 to 2,000 since 2003) and can be achieved within the wellhead price increases projected in the ICF study.

Another important point of contrast is that the overall economy and population of the United States is much larger than that of Australia. The U.S. Gross Domestic Product is 10.8 times that of Australia and the U.S. population is 13.8 times the size. Australia has a relatively small population base with low levels of unemployment, particularly in construction and high-skilled sectors. During the 2009 recession, the unemployment rate in Australia rose only to 5.8 percent, whereas the unemployment rate was around 10 percent in the U.S. In 2010 and 2011, the Australian unemployment rate fell to about 5.2 percent, whereas it remained around 9 percent in the United States. Since 2012, the unemployment rate in Australia has been slowly rising from about 5 percent to 6 percent (as of June 2014), and in the U.S., the unemployment rate has decreased from above 8 percent to just above 6 percent (as of June 2014). Australia has about 11.5 million employed persons, in contrast to about 146 million in the United States.[73] Currently, Australian wages in manufacturing are about $29/hour, compared to $19/hour in the United States.[74] In certain industries, labor shortages have been acute with reports of some offshore

[73] Available at: http://www.tradingeconomics.com/.

[74] Numbers are in USD, assuming 0.94 USD for 1 AUD and that Australian week is 40 hours. Available at: http://www.tradingeconomics.com/united-states/wages-in-manufacturing and http://www.tradingeconomics.com/australia/wages-in-manufacturing.

welders earning $400,000 per year in Australian dollars.[75] This has led to cost increases in LNG export projects (both upstream and downstream segments and in both western and eastern Australia) and has slowed development of new gas supplies.

The U.S. labor and other markets are much larger and better able to meet incremental demands for labor, equipment, and materials. However, like any free market, U.S. labor markets are subject to supply and demand factors that can affect wages and other prices. The U.S. Gulf Coast is now in the midst of a building boom caused, to a large degree, by increasing production of U.S. natural gas, natural gas liquids, and crude oil. There are a large number of $100+ million USD projects underway and some projects that represent investments well in excess of $10 billion USD. These include planned modifications and new builds of ethylene crackers and other petrochemical plants; petroleum refineries; LNG liquefaction plants; pipelines and shipping terminals for crude oil, natural gas liquids, and natural gas; and power plants.

Recent predictions, indicate that total construction craft labor demand in the U.S. Gulf Coast would increase from 66,000 workers in 2013 to a peak of 86,000 to 93,000 workers in the period from 2015 through 2017 to support these construction projects.[76] The greatest degree in tightness is expected for welders, electricians, pipefitters, millwrights, and crane operators. Wages for these crafts ranged from $19.00-$20.50/hour in 2005 but rose to $24.50-$27.00/hour during the post-Katrina/Rita rebuilding years, and then were flat as the U.S. economy struggled from 2008 to 2011. The start of the current building boom caused these wages to go up again to $28.00-$31.00/hour by 2013 and expectations are that increases may continue at the rate of 7.5 percent per year through 2017.[77]

Such labor tightness will affect upstream and midstream developments in the U.S. Gulf Coast and are part of the expected “drilling activity price effect” discussed above. However, these upstream cost-push effects on natural gas prices are being mitigated by the geographic dispersion of increased activity that extends far beyond the U.S. Gulf Coast. Further price mitigation is being caused by continued technological improvements in drilling efficiency (number of rig days needed per well) and well productivity (reserves produced over the life of each well), as well as “subsidization” of dry gas production by the growth in liquids-directed drilling.

The higher U.S. Gulf Coast wages among construction crafts is also expected to affect the cost and feasible timing of LNG plant construction on the U.S. Gulf Coast. This is one of the factors (along with the limited size of the available international LNG market among credit-worthy buyers) that we expect will limit the number of LNG plants that can realistically be built in the next few years; and, the demand volume for U.S. domestic natural gas as an LNG feedstock. We believe that higher wages and construction costs are some of the factors that are part of the decision-making process of U.S. LNG developers and their creditors. Further, these risk assessment efforts can be expected to provide a degree of “self-regulation” that challenge and reject non-economic projects.

[75] Downstream Today July 23, 2014, http://www.downstreamtoday.com/news/article.aspx?a_id=43824

[76] Mike Kotara, Zachary Holdings before the Gulf Coast Power Association, February 6, 2014.

[77] Ibid.

5 Conclusions

Australia is seeing a large expansion of LNG export facilities in both the traditional export region of the northwestern part of the country (where offshore-based production for LNG has been established for 20 years), as well as new projects drawing on the CBM developments in the east. The demand for labor, materials, and resources has been large for an economy the size of Australia, and this has contributed to increases in the cost of LNG plant construction and other construction around the country. The timing of gas resource development to meet the anticipated LNG demand in eastern Australia—the locus of the controversy—has been stressed by the large scale of development and is further complicated by unforeseen technical difficulties in developing the CBM, which is the source of new supply in eastern Australia. CBM development in eastern Australia has also been affected by environmental concerns related to water disposal and drilling, and fracking moratoria that are in place in some areas. Production costs have been higher than expected and producers are challenged to meet their obligations to the exporters as well as to local markets.

At the same time that liquefaction plant owners are developing and purchasing gas resources to supply their facilities, many domestic supply contracts are expiring and are up for renewal. With the stresses on production and attendant uncertainties, producers appear to be reluctant to commit to new long-term contracts at less than the full opportunity cost of meeting their long-term LNG contract requirements. Thus, it does appear that long-term gas prices supporting power generation and industrial customers have risen from around $3 to $4 per MMBtu to perhaps between $7 and $9 per MMBtu. Although this may very well be a near-term phenomenon until production stabilizes and a new gas supply/demand balance reasserts itself, the difficulty in procuring supplies and high prices are of concern to gas consumers in eastern Australia.

These events in Australian natural gas markets, particularly those in eastern Australia, have been cited by U.S. critics to limit U.S. exports of LNG. The critics assert that U.S. gas consumers will see the same sharp increases in prices if a substantial number of U.S. LNG projects are approved and enter operation. This report presents information on the Australian gas market and shows that the Australian experience is very unlikely to be replicated in the U.S. context due the major differences between the two gas markets.

Size of gas market: The first and most important difference is that the U.S. gas market is much larger than that of Australia. In terms of domestic gas production, the United States is 12.7 times as large as Australia (24.06 Tcf vs. 1.90 Tcf per year) and in terms of the domestic gas consumption, U.S. consumption is about 24 times as large as Australia's (25.53 Tcf vs. 1.045 Tcf per year). The larger North American gas market (i.e., adding Canada and Mexico to the United States) is about 31 Tcf.

Regional interconnections: The second and closely related difference is that regional markets in Australia are not adequately interconnected to each other by pipeline and so demand increases can have big price effects. In the United States the markets are very much interconnected and the impacts of demand increases can be spread out over a much larger market area. Moreover, the United States trades gas through pipelines with Canada and Mexico making the effective market size even larger. The United States has approximately 305,000 miles of gas pipelines compared to 15,000 in Australia. The U.S. network is 20.3 times larger than Australia's.

Diversified resource base: A third difference is that the United States has a much more diversified natural gas resource base to supply gas for liquefaction. The supply sources in eastern Australia for the LNG

projects are new CBM development projects, which have not performed as well as expected. This means that more gas wells and higher capital expenditures will be needed to achieve target production rates. The United States has a much more diverse set of supply options, and shale plays have performed better than expected.

Large upstream infrastructure: Another difference is that there are many more gas producers in the United States, more mature unconventional gas technical knowhow, and much larger drilling and well services infrastructure to support additional gas supplies to meet increased demand from LNG and other sectors. For a recent week in 2014, the Hughes rig count for the United States stood at 1,860 while in Australia it was just 20—a factor 93.0 times different.

More settled environmental regulatory regime: Another difference is CBM development in eastern Australia has also been hampered by environmental concerns related to water disposal, and drilling moratoria that are in place in some areas.

Natural gas market structure: In contrast to Australia's market structure that relies on negotiated long-term contracts with nontransparent, fixed, and oil-linked prices, U.S. gas markets have much more transparent pricing, which is largely linked to spot indices that react to supply and demand changes by re-equilibrating prices over a large, integrated, three-country market.

Larger overall economy and population: The final major difference to note is that the overall economy and population of the United States is much bigger than that of Australia. The U.S. Gross Domestic Product is 10.8 times that of Australia and the U.S. population is 13.8 times as large. Australia has a relatively small population base with low levels of unemployment, especially in construction and high-skilled sectors. The U.S. labor market is much larger and is better able to meet incremental demands for labor, equipment, and materials with manageable cost increases.

Because of these and other differences in market characteristics of Australia in general, and eastern Australia in particular, the large movements seen in eastern Australian long-term contract prices related to LNG exports are not expected to occur in the United States. Instead it is expected that U.S. gas supplies will grow along with new demands from U.S. liquefaction plants and that the U.S. gas market will experience modest price increases and losses of non-LNG loads.

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Appendix A – Australian Gas Resource Base

Conventional Gas

The conventional gas assessment is presented in Exhibit 24, and it totals 157 Tcf (plus 10 Tcf of inferred resources). Most of the remaining resources (as shown by the size of the circles on the map) are found in the Carnarvon, Browse, and Bonaparte Basins, which comprise the Northwest Shelf region. The Northwest Shelf is the site of current LNG exports and facilities as shown in Exhibit 25 as yellow dots.

Coal Seam Methane

The coal seam methane resource base is shown in Exhibit 26 and Exhibit 27. Recoverable resources, including the inferred resources, total 204 Tcf. Exhibit 28 shows that almost all of the coal seam methane is located on the eastern coastal region. This is dominated by the Surat and Bowen Basins in Queensland. Coal seam methane development forms the basis for planned LNG export projects in the eastern part of the country. These include Australia Pacific LNG, Gladstone LNG, Queensland Curtis LNG, Arrow Energy LNG, and Fisherman's Landing. Operators are ramping up production in anticipation of LNG exports.

Shale Gas

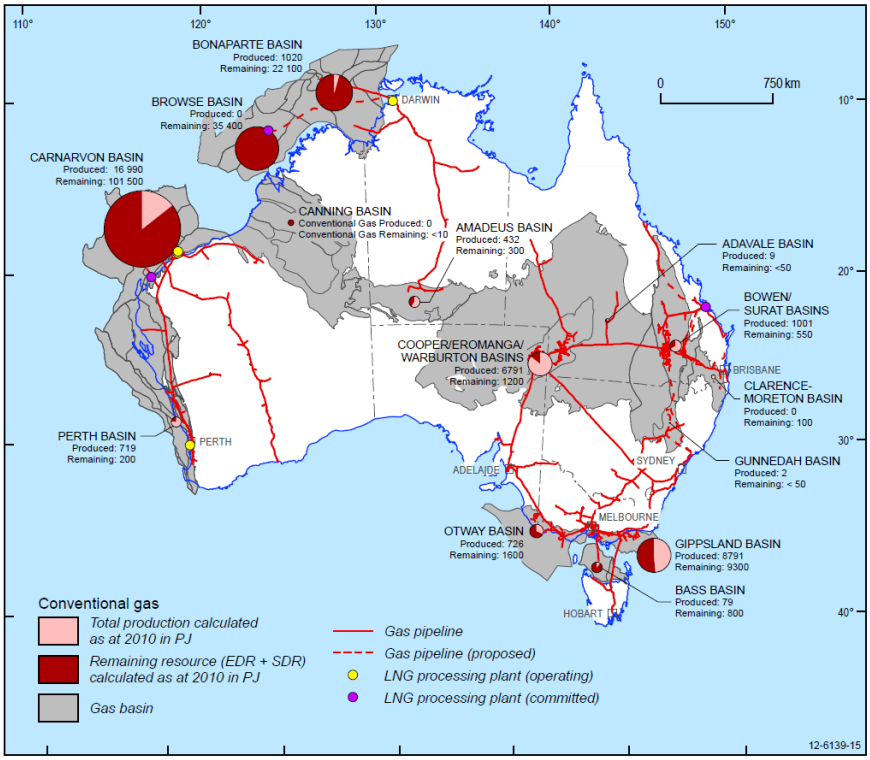
The 398 Tcf of assessed shale gas is based upon the 2011 EIA world assessment and includes resources in the Cooper, Maryborough, Perth, and Canning Basins (see Exhibit 28), with most of the resources in the Canning Basin. In 2013, EIA assessed the resources at 437 Tcf as summarized in Exhibit 29. The EIA studies are generalized and do not include detailed geologic work. The Australian government is working with the USGS to assess the shale gas resource.

Exhibit 24: Conventional Gas Resources by Basin – Excludes Inferred

	Economically Demonstrated (Tcf)	Sub-Economic Demonstrated (Tcf)	Total (Tcf)
Carnarvon	68	24	92
Browse	16	16	32
Bonaparte	9	11	20
Gippsland	6	2	8
Other	4	1	5
Total	103	54	157

Source: BREE (2012) "Australian Gas Resource Assessment," ICF May, 2014.

Exhibit 25: Conventional Resource Distribution



Source: BREE (2012) "Australian Gas Resource Assessment."

Exhibit 26: Coal Seam Methane Recoverable Gas Resources

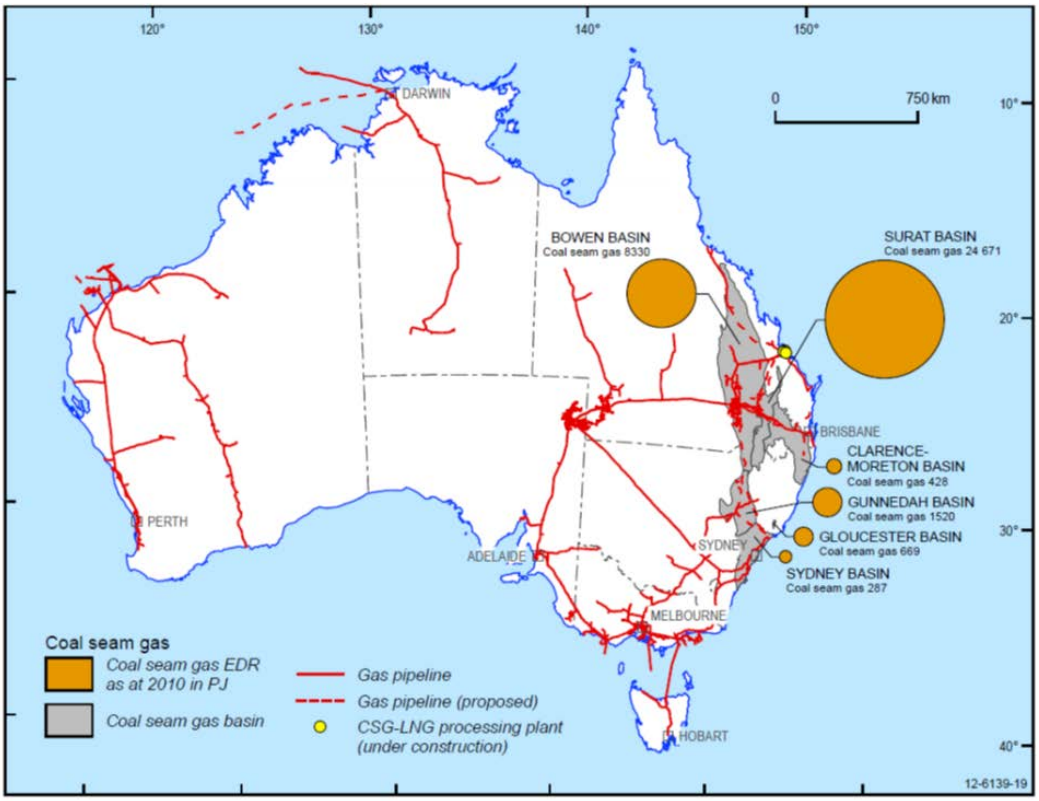
Category	Tcf
Demonstrated	93
Economically Demonstrated (EDR)	33
Sub-Economic Demonstrated (SDR)	60
Inferred	111
Total	204
CSG demonstrated as of January, 2012. CSG 2P and 2C resources used for EDR and SDR respectively. Original sources: Queensland DEEDI (2011, 2012); Australian Energy Market Operator AEMO (2011); Geoscience Australia	

Exhibit 27: Australia Coal Seam Methane Resources by Basin

Basin	Bcf
Bowen	7,573
Surat	22,428
Clarence Moreton	389
Gunnedah	1,382
Gloucester	608
Sydney	261
Total	32,641

Source: BREE (2012) "Australian Gas Resource Assessment," ICF May, 2014.

Exhibit 28: Location of Australian Coal Seam Gas Resources – 2P Resources



Source: BREE (2012) "Australian Gas Resource Assessment."

Exhibit 29: 2013 EIA Australia Shale Gas Assessment (Tcf Recoverable Gas)

Basin	Tcf
Cooper	93
Maryborough	19
Perth	33
Canning	235
Georgina	13
Beetaloo	44
Total	437

Appendix B – Australian LNG Project Details

Eastern Australia LNG Projects

Exhibit 30: East Coast LNG Export Projects

Project Name	Status	Ownership	Capacity	Contracted Sales	Commencement Date
Queensland Curtis LNG (QCLNG)	under construction	BG Group (73.75%) CNOOC (25%) Tokyo Gas (1.25%)	8.5 mt/pa (2 trains)	8.5 mt/pa	Train 1 by end of 2014, Train 2 6 months later
Gladstone LNG (GLNG)	under construction	Santos (30%) PETRONAS (27.5%) Total (27.5%) KOGAS (15%)	7.8 mt/pa (2 trains)	7 mt/pa	Train 1 H1 2015, train 2 12 months later
Australia Pacific LNG (APLNG)	under construction	Origin Energy (37.5%) ConocoPhillips (37.5%) Sinopec (25%)	9 mt/pa (2 x 4.5 mt/pa trains)	8.6 mt/pa	Train 1 H2 2015, train 2 H1 2016
Arrow LNG (ALNG)	proposed	Shell (50%) PetroChina (50%)	8 mt/pa (2 trains)	Likely that JV partners would receipt some, if not all, of the production.	2017+

Source: BREE, project / company websites.

Western and Northern Australia

Exhibit 31: North and West LNG Export Projects

Project Name	Gas Basin / Location	Status	Ownership	Capacity (mtpa)	Commencement Date
North West Shelf (NWS)	Carnarvon (WA)	Existing	Woodside (16.6%), BHP Billiton (16.6%), BP (16.6%), Chevron (16.6%), Japan Australia LNG (16.6%) and Shell (16.6%)	16.3 (5 trains)	1984 – supply to WA 1989 – LNG Train 1 1989 – LNG Train 2 1992 – LNG Train 3 2004 – LNG Train 4 2008 – LNG Train 5
Pluto	Carnarvon (WA)	Under construction	Woodside (90%), Tokyo Gas (5%) and Kansai Electric (5%)	4.3 (1 train)	2012
Gorgon	Carnarvon (WA)	Under construction	Chevron (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (0.417%)	15.6 (3 trains)	2015
Wheatstone	Carnarvon (WA)	Under construction	Chevron (64.14%), Apache (13%), KUFPEC (7%), Shell (6.4%) and Kyushu Electric Power Company (1.46%)	8.9 (2 trains)	2016
Prelude Floating LNG	Browse (WA)	Under construction	Shell (100%)	3.6 (1 train)	2017
Darwin LNG	Timor Sea (NT)	Existing	ConocoPhillips (56.7%), Santos (10.6%), INPEX (10.5%), Eni (12%), TEPCO (6.7%) and Tokyo Gas (3.4%)	3.7 (1 train)	2006
Ichthys	Browse (NT)	Under construction	Inpex Holdings (66%), Total (30%), Tokyo Gas (1.5%), Osaka Gas (1.2%), Chubu Electric (0.7%) and Toho Gas (0.4%)	8.4 (2 trains)	2017

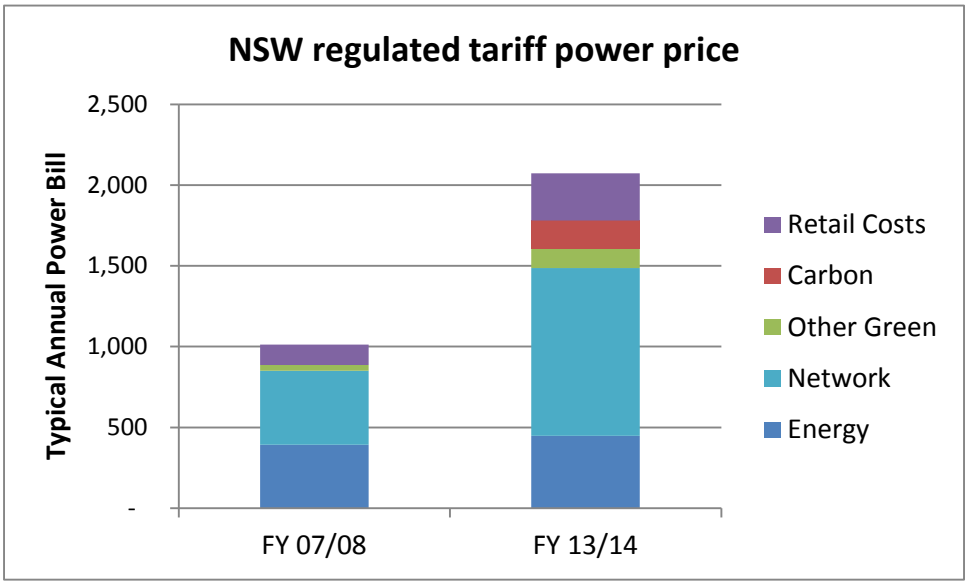
Source: BREE, project / company websites.

Appendix C – Increase in Electricity Prices in Eastern Australia

Australia has experienced a significant increase in retail power prices. The increase in retail power prices are unrelated to the increase in gas contract prices that have also been observed by Australian consumers.

An example of the power price increases in Australia is the NSW regulated retail tariff. Residential and small business customers in NSW can sign a market contract with one of a number of electricity retailers, or be supplied under the regulated tariff by a standard retailer. The Independent Pricing and Regulatory Tribunal (IPART) is responsible for regulating retail electricity prices in NSW. The tariff price approved for 2013/14, while only a 1.7% increase from the previous year, is double the price approved for 2007/08. As illustrated in Exhibit 32, the main driver of this increase is the change in network costs.

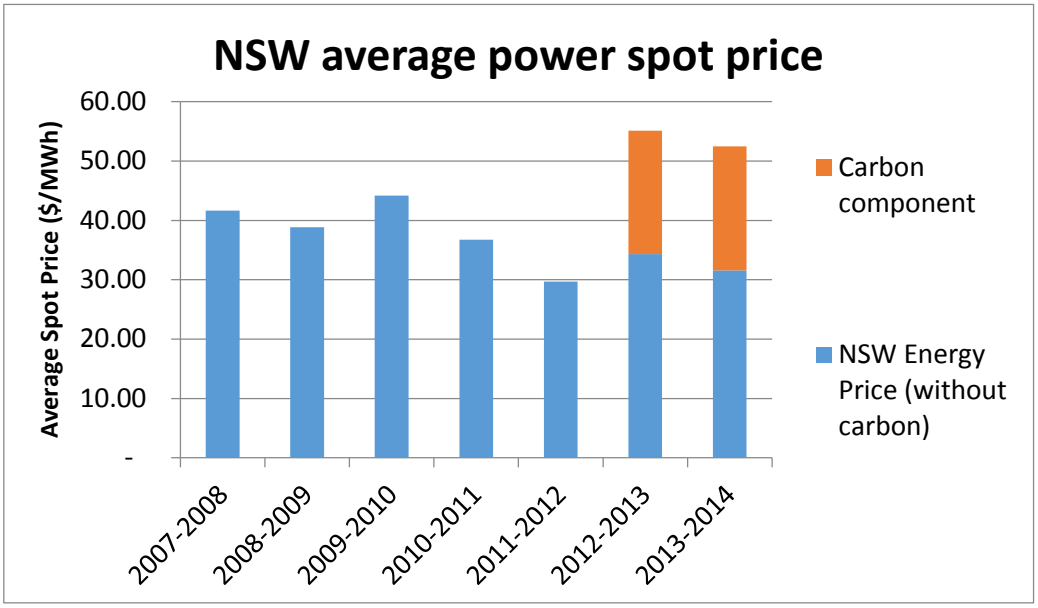
Exhibit 32: Comparison of Typical NSW Power Bills



Source IPART June 2013.

The increase in retail power prices is contrary to the subdued wholesale market prices. Exhibit 33 shows that if the effects of the carbon tax are ignored, wholesale power prices in NSW have been stable over the same period that the retail price has doubled. An expansion of renewable energy capacity and a fall in demand across the National Electricity Market (NEM) have been the main contributors to the subdued wholesale power prices.

Exhibit 33: NSW Average Power Spot Prices



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