briefing paper

NSW Parliamentary Research Service

Gas: resources, industry structure and domestic reservation policies

Briefing Paper No 12/2013

by Andrew Haylen and Daniel Montoya

RELATED PUBLICATIONS

- A history of mineral and petroleum ownership and royalties in NSW. Issues Backgrounder 05/2012 by Daniel Montoya
- Mining in NSW (October 2012). Statistical Indicators 07/2012 by Nathan Wales
- Exploration and mining on private land in NSW: a brief legislative history. E-brief 17/2012 by Lenny Roth
- Coal seam gas royalties in Australian States & Territories. E-brief 03/2012 by Daniel Montoya
- Key Issues in Energy. Background Paper 04/2011 by Daniel Montoya and Nathan Wales

ISSN 1325-5142

ISBN 978-0-7313-1910-7

December 2013

Gas: resources, industry structure and domestic reservation policies

by

Andrew Haylen and Daniel Montoya

NSW PARLIAMENTARY RESEARCH SERVICE

Gareth Griffith (BSc (Econ) (Hons), LLB (Hons), PhD),
Manager, Politics & Government/Law .... (02) 9230 2356

Lenny Roth (BCom, LLB),
Senior Research Officer, Law... (02) 9230 2768

Lynsey Blayden (BA, LLB (Hons), GradDipLaw),
Research Officer, Law .... (02) 9230 3085

Jack Finegan (BA (Hons), MSc),
Research Officer, Environment/Planning .... (02) 9230 2906

Andrew Haylen (BResEc (Hons)),
Research Officer, Public Policy/Statistical Indicators .... (02) 9230 2484

Daniel Montoya (BEnvSc (Hons), PhD),
Research Officer, Environment/Planning .... (02) 9230 2003

John Wilkinson (MA, PhD),
Research Officer, Economics.. (02) 9230 2006

Should Members or their staff require further information about this publication please contact the author.

Information about Research Publications can be found on the Internet at:

http://www.parliament.nsw.gov.au/prod/parlment/publications.nsf/V3LIstRPSubject

CONTENTS

LIST OF TABLES

LIST OF FIGURES

ACRONYMS

1P:	at least a 90% probability that the quantities actually recovered will equal or exceed the low estimate.
2P:	at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.
3P:	at least a 10% probability that the quantities actually recovered will equal or exceed the high estimate.
AEMC:	Australian Energy Market Commission
AEMO:	Australian Energy Market Operator
AER:	Australian Market Regulator
APPEA:	Australian Petroleum Production and Exploration Association
bcm:	billion (10^9) cubic metres
BREE:	Bureau of Resources and Energy Economics
COAG:	Council of Australian Governments
CSG:	Coal seam gas
DAE:	Deloitte Access Economics
DBNGP:	Dampier to Bunbury natural gas pipeline (WA)
DTIRIS:	Department of Trade & Investment, Regional Infrastructure & Services (NSW)
DWGM:	Declared Wholesale Gas Market (Victoria)
EDR:	Economic Demonstrated Resources
FET:	Fair and equitable treatment
FLNG:	Floating Liquefied Natural Gas
FPS:	Full protection and security
FTA:	Free Trade Agreement
GATT:	General Agreement on Tariffs and Trade (WTO)
GBB:	Gas Bulletin Board
GJ:	Gigajoule (10^9 joules)
GPG:	Gas powered generation

GSOO: Gas Statement of Opportunities

INF: Inferred Resources

IPART: Independent Pricing and Regulatory Tribunal

JDPA: Joint Development Petroleum Area

LNG: Liquefied Natural Gas

LPG: Liquefied Petroleum Gas

MCE: Ministerial Council on Energy (COAG)

MCMPR: Ministerial Council on Mineral and Petroleum Resources (COAG)

mmbbls: Million barrels

Mt: Million tonnes

Mtpa: Million tonnes per annum

NCC: National Competition Council

NECF: National Energy Customer Framework

NEM: National Electricity Market

NERL: National Energy Retail Law

NERR: National Energy Retail Rules

NGL: National Gas Law

NGR: National Gas Rules

NIEIR: National Institute of Economic and Industry Research

NWS: North West Shelf

OPGGSA: *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth)

PAL: Petroleum Assessment Lease

PCIA: Plastics and Chemicals Industries Association

PEL: Petroleum Exploration Licence

PELA: Petroleum Exploration Licence Application

PEP: Petroleum Exploration Permit

PGPLR: Prospective Gas Production Land Reserve policy (Qld)

PJ:	Petajoule (10^{15} joules)
PPL:	Petroleum Production Lease
PPLA:	Petroleum Production Lease Application
PSPAPP:	Petroleum Special Prospecting Authority
SCER:	Standing Council on Energy and Resources (COAG)
SDR:	Sub-economic Demonstrated Resources
SECWA:	State Energy Commission of Western Australia
STTM:	Short Term Trading Market
tcf:	Trillion (10^{12}) cubic feet
tcm:	Trillion (10^{12}) cubic metres
TJ:	Terajoule (10^{12} joules)
WTO:	World Trade Organisation

SUMMARY

What is gas?

Petroleum resources include oil, conventional gas and unconventional gas. Conventional gas and unconventional gas is the same product: natural gas, which primarily consists of methane. There are three types of unconventional gas: coal seam gas, shale gas and tight gas. Conventional and unconventional gas may be converted to Liquefied Natural Gas (LNG). LNG is natural gas that has been cooled to approximately -160^{o}C until it forms a liquid. This makes it easier and cheaper to transport long distances in LNG tankers to markets.

Gas resources are classified according to geological certainty and economic feasibility [see Appendix 1]. In order of declining economic feasibility, petroleum resources may be defined as Reserves, Contingent Resources or Prospective Resources. Reserves are further broken down into three categories in accordance with the level of certainty that the quantity actually recovered will equal or exceed the estimate: 1P (proved) reserves have a 90% certainty level, 2P (proved & probable) reserves have a 50% certainty level and 3P (proved, probable & possible) reserves have a 10% certainty level. **[2.1]**

Australia's regional gas markets

There are three geographically and economically distinct gas markets in Australia: the western market (Western Australia); the northern market (Northern Territory); and the eastern market (ACT, NSW, Queensland, South Australia, Tasmania and Victoria). Physically, the eastern market is the largest and most mature, competitive and interconnected gas market in Australia. The western market is the largest market in terms of production, and the northern market is the smallest of the three. **[2.2]**

The gas supply chain

The gas supply chain is comprised of a number of distinct stages. The upstream sector generally encompasses exploration, development and production. Downstream sector activities include processing, distribution, storage, wholesaling and retailing. **[2.3 & 2.4]**

The upstream gas sector

Several key statistics on the upstream sector are as follows:

- in 2011-12, six major producers met 65% of domestic gas demand: Santos, BHP Billiton, ExxonMobil, Origin Energy, Woodside and Apache Energy;
- in 2012, the six companies with the largest shares of 2P gas reserves in Australia together held 61% of the total (85,120 petajoules or PJ): Chevron, Shell, ExxonMobil, BG, Inpex and Woodside;
- in 2012, the six companies with the largest shares in 2P gas reserves in the eastern market together held 66% of the total (48,858PJ): BG, Origin,

ConocoPhillips, Santos, PetroChina and Shell; and

- in 2012, four companies held 99.4% of total 2P gas reserves in NSW (2,824PJ): Santos, AGL, Metgasco and EnergyAustralia. **[2.4.3]**

The downstream gas sector

Gas is transported to markets by pipeline or in LNG tankers. Australia's gas pipelines are privately owned. In the eastern market, APA Group and Singapore Power International (through its subsidiary Jemena) are the principal owners in the transmission sector. Envestra and Singapore Power International (through its subsidiaries Jemena and SP AusNet) are the principal owners in gas distribution. **[2.5.1]**

The types of transportation contracts and services available in eastern market transmission pipelines depend upon the pipeline in question. In Victoria, gas shippers bid daily for transportation services through the Victorian Declared Wholesale Gas Market. In all other States, transport services are supplied by bilateral contracts between the pipeline owner and the gas shipper. **[2.5.2]**

Wholesale gas supply contracts are bilateral contracts between producers and large buyers (e.g. retailers, large industrial companies, mining companies, gas fired generators and LNG exporters) that set out the volume of gas to be supplied, the price to be paid and other terms and conditions. Historically, the wholesale supply of gas in Australia has been underpinned by long term contracts of ten or more years, enabling producers, pipeline owners and large end-users to underwrite significant capital investment. Currently, the predominant form of contracting in the eastern market is a mix of medium (1 to 3 years) and long-term contracts. **[2.5.3]**

Several facilitated markets allow for some wholesale gas trade, enabling participants to trade any gas supply imbalances that arise on a day-to-day basis because their actual demand differs from their contracted supply. The availability of gas market information has been boosted through the operation of the National Gas Bulletin Board and the Australian Energy Market Operator's (AEMO) annual Gas Statement of Opportunities (GSOO). A new gas market brokerage hub, to be opened at Wallumbilla, Queensland in 2014, is expected to further enhance the transparency of gas trading. **[2.5.4]**

Gas retailers buy gas in wholesale markets and package it with network services for sale. NSW is the only State that regulates retail gas prices. In 2013, the Australian Energy Market Commission (AEMC) reviewed the NSW gas retail market and found that competition is delivering benefits to the majority of small gas consumers. Consequently, it recommended removal of gas price regulation. The NSW Government is preparing its response to the recommendation.

As of 30 June 2012, AGL held the largest share of the residential gas retail market in NSW, with 63% (696,616) of customers. EnergyAustralia and Origin Energy held the next largest shares with 22% and 8% respectively. AGL, EnergyAustralia and Origin Energy also hold the three largest shares of the non-residential gas retail market, with 71%, 13% and 9% respectively. **[2.5.5]**

Key gas statistics

Table 1 presents key 2011-12 gas statistics. 2012-13 data is only available for gas exploration and production. In Australia, exploration expenditure rose from $897.4 million in June 2012 to $1,137.3 million in June 2013. Over the same period, NSW exploration expenditure is projected to grow from $65 million to $112 million. Total Australian production rose from 2,256 PJ in 2011-12 to 3,023PJ in 2012-13. Eastern market production rose from 667PJ to 1,006PJ. **[3.0]**

Table 1: Key gas statistics (2011-12)

Indicator	NSW	Eastern market	Australia
Reserves			
Gas reserves (2P) (PJ)	2,885	48,498	139,010
Gas reserves (total) (PJ)	95,003	422,478	912,166
Conventional gas reserves (2P) (PJ)	0	7,344	98,249
Coal seam gas reserves (2P) (PJ)	2,885	41,154	41,154
Shale and tight gas reserves (2P) (PJ)	0	0	0
Exploration			
Exploration expenditure ($m)	$65m	$211m	$897m
Expenditure (5-yr av ann growth)	3.3%	6.3%	2.8%
Production			
Production (PJ)	6	667	2,256
Production (5-yr av ann growth)	1.4%	7.8%	8.0%
Projected production (2034-35)	-	2,836	8,092
Projected av ann growth 2012-13 to 2034-35	-	4.8%	4.6%
Consumption			
Consumption (PJ)	165	839	1,401
Consumption (5-yr av ann growth)	6.1%	2.5%	1.8%
Projected av ann growth 2012 to 2032	0.8%	1.1%	-
LNG exports			
LNG exports (PJ)	-	-	1,090
LNG exports ($m)	-	-	$12,005m
Projected LNG exports (PJ) (2018+)	-	1,916	6,351
Prices			
Wholesale price ($/GJ)	$2.46	-	-
LNG price ($/GJ)	-	-	$11.46
Retail price ($/GJ)	$24.80	-	-

As of December 2011, approximately 8,300PJ of 2P gas reserves in the eastern market were domestically contracted/earmarked. 40,298PJ (76.6%) of gas was contracted/earmarked for LNG export. Approximately 4,000PJ of gas was uncommitted, being available for either the domestic or export market. **[3.1]**

Table 2: Contract status of 2P gas reserves in the eastern market

Reserves	Total 2P	Domestic		LNG		Uncommitted
		Contracted	Earmarked	Contracted	Earmarked	
Conventional	7,344	3,141	220	750	607	2,625
CSG	41,154	3,324	1,595	26,168	12,773	1,419
Total	48,497	6,465	1,815	26,918	13,380	4,043

As of 1 November 2013, there were 47 current petroleum titles in NSW. A further 19 petroleum title applications were with the Government awaiting assessment. AGL holds the largest number of petroleum titles, being in possession of five exploration licences and five production licences with one production licence application pending. Santos is the only other company in possession of a current production licence. Two production licences submitted by Metgasco and AGL are being assessed. **[3.2.1]**

Table 3: Petroleum titles in NSW (November 2013)

Petroleum title applications		Current titles	
Title	No.	Title	No.
Petroleum Exploration Licence Application	10	Petroleum Assessment Lease	1
Petroleum Production Lease Application	2	Petroleum Exploration Licence	39
Petroleum Special Prospecting Authority	7	Petroleum Exploration Permit	1
		Petroleum Production Lease	6
Total	19		47

In 2012-13, regulated residential and business gas bills in NSW varied substantially by retailer (see Table 4). Between 2012-13 and 2013-14, IPART expects regulated gas bills to rise by 9.2% for all AGL customers and between 5.2-5.8% for the customers of all other retailers. According to IPART, network costs will account for 48% of the total increase, retail and wholesale costs 47% of the increase, and the carbon component the remaining 5%. **[3.7]**

Table 4: Indicative annual gas bills in NSW (nominal $, inc GST)

Residential customer			Business customer		
Retailer	2012-13	Av ann growth 2009-10 to 2012-13	Retailer	2012-13	Av ann growth 2009-10 to 2012-13
AGL	$822	10.0%	AGL	$3,864	3.7%
ActewAGL	$1,217	2.2%	ActewAGL	$4,423	2.2%
Origin Energy (Wagga Wagga)	$965	1.7%	Origin Energy (Wagga Wagga)	$3,262	5.3%
Origin Energy (Albury/Murray Valley)	$886	6.0%	Origin Energy (Albury/Murray Valley)	$3,133	-3.3%

History of gas developments in Australia

Government involvement in the gas industry may take place for several reasons, including achieving energy security, encouraging and regulating development of Crown owned petroleum resources, and regulating gas transmission and distribution pipelines due to their natural monopoly characteristics. Two economic ideologies have influenced gas developments in Australia: economic nationalism and economic liberalism. Nationalism emphasises national industrial capacity and self-sufficiency while liberalism stresses the importance of free trade and market forces.

In broad terms, the economic nationalism that dominated government policies in the 1970s has given way in recent decades to an emphasis on economic liberalism. While the 2000s and early 2010s have seen further liberalisation of the gas industry, there has also been significant debate over the merits of a signature nationalistic gas policy option: domestic gas reservation. Domestic gas market reforms took place under a 2004 intergovernmental agreement – the Australian Energy Market Agreement – and included introduction of the National Gas Law and National Gas Rules, and several facilitated gas markets. In 2006, Western Australia adopted its *WA Government Policy on Securing Domestic Gas Supplies*. In 2009, Queensland adopted its *Prospective Gas Production Land Reserve (PGPLR)* policy.

Current COAG Standing Council on Energy and Resources gas reforms are focused on an increased role for markets, improved gas market information, effective regulation and improved pipeline capacity trading. The Australian Energy Market Commission is planning to create a strategic plan for gas market development. **[4.1]**

The upstream regulatory framework

Under Australian law, petroleum (including natural gas) and mineral resources are generally owned by the Crown. Onshore petroleum and mineral resources are owned and regulated by State and Territory Governments, while the majority of offshore resources are controlled by the Commonwealth, depending on the location of the resource with respect to the territorial sea baseline. Commonwealth resources are regulated under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*. NSW resources are regulated under the *Petroleum (Offshore) Act 1982* and the *Petroleum (Onshore) Act 1991*. **[4.2.1 & 5.1]**

The downstream regulatory framework

The downstream sector is regulated under National, State and Territory legislation. The National Gas Law and National Gas Rules regulate some transmission pipelines and all distribution pipelines, the Gas Bulletin Board (GBB), the Victorian Domestic Wholesale Gas Market (DWGM) and the Short Term Trading Markets (STTM). The arrangements applying to retail markets in those jurisdictions that have implemented the National Energy Customer Framework, including NSW, are set out in the National Energy Retail Law and the National Energy Retail Rules.

A number of bodies hold key regulatory functions and responsibilities:

- the COAG Standing Council on Energy and Resources develops and administers the legislative framework and provides policy direction;

- the Australian Energy Market Commission is responsible for market development and rule-making;
- the National Competition Council advises on regulation of gas scheme pipelines;
- the Australian Energy Regulator is responsible for the economic regulation of pipelines, monitoring trading activity in the DWGM and STTMs, and monitoring compliance with the National Gas Rules;
- the Australian Energy Market Operator operates the DWGM, STTMs and Gas Bulletin Board, prepares the annual Gas Statement of Opportunities, and operates the gas retail markets in NSW, the ACT, Queensland, South Australia and Victoria;
- the Australian Competition Tribunal conducts merits based reviews of regulatory decisions and the Federal Court of Australia carries out judicial reviews; and
- the NSW Independent Pricing and Regulatory Tribunal (IPART) provides for regulated retail gas prices for residential and small business customers in accordance with the *Gas Supply Act 1996* (NSW). **[4.2.2]**

Domestic gas reservation policies

At present, Western Australia and Queensland are the only States which implement any form of domestic gas reservation. The Commonwealth and the remaining States and Territories do not implement reservation policies for their respective offshore and onshore resources.

In the *Energy White Paper 2012*, the Gillard Government affirmed its opposition to a domestic gas reservation policy, a standpoint confirmed by the current Industry Minister Ian Macfarlane in a speech to the Energy Users Association of Australia. The Abbott Government is in the early stages of drafting a national energy White Paper and an east coast gas supply strategy which will make clear its official position on this and other energy reform agendas. **[5.0]**

Western Australia domestic gas reservation policy

A domestic gas reservation policy has been in place in Western Australia, at least in principle, for some time. Prior to 2006, two State Agreements underpinned reservation policy in WA. The first State Agreement was applied to the North West Shelf (NWS) LNG project in 1979 and is legislated under the *North West Gas Development (Woodside) Agreement Act 1979*. The other State Agreement was applied by the State Government to the Gorgon LNG project and is legislated under the *Barrow Island Act 2003*. **[6.1]**

In 2006, a formal reservation policy, *WA Government Policy on Securing Domestic Gas Supplies*, was adopted by Premier Alan Carpenter, and later reaffirmed by the Barnett Government. Like previous reservation arrangements, this policy is enforced using individual State Agreements. The Pluto LNG project, which is located in the Carnarvon Basin north-west of Karratha, was approved for development in July 2007 conditional on it complying with the State's reservation policy. The *Natural Gas (Canning Basin Joint Venture) Agreement Act 2013*, which applies to the gas development in the onshore Canning Basin, is also consistent with the State's reservation policy. The Agreement provides that if commercially viable gas is discovered by mid-2016, the parties must submit a plan for construction of the domestic gas project, which will include a 600km pipeline south to Western Australia's existing Pilbara gas network.

In the absence of a Commonwealth reservation policy, producers can conduct all processing offshore using FLNG plants to avoid becoming subject to the WA reservation policy and there is evidence to suggest that this is already occurring. **[6.2]**

Queensland domestic gas reservation policy

The uncertainty around gas supply and the risk of sharply rising prices saw the Queensland State Government introduce the *Prospective Gas Production Land Reserve (PGPLR)* policy. In May 2011, the Queensland Government passed the *Gas Security Amendment Act 2011*, which amended the *Petroleum and Gas (Production and Safety) Act 2004* to enable implementation of the PGPLR policy. Under this policy, the State may, when granting a production license, require that any gas produced from an area be supplied domestically. To date, no gas field has been set aside for domestic gas only development. **[7.0]**

Stakeholder perspectives

Given the respective vested interests of stakeholders on either side of the policy spectrum, domestic gas reservation has divided opinion which is reflected in the contrasting policy perspectives to date. Manufacturing Australia, for example, argues that expected gas shortages and price expectations have impacted investment decisions and contributed to plant closures. They also argue that intervention by State and Federal governments is urgent and necessary and should be in the form of a reservation policy. The Australian Petroleum Production and Exploration Association, on the other hand, argues that domestic gas reservation is highly dangerous, short-sighted and self-interested; and that this policy would impair local gas supply and affordability, rather than improve it. **[8.0]**

Economic effects of domestic gas reservation

There are potential supply and price benefits for wholesale consumers from domestic gas reservation. In the short term, a fixed proportion reservation policy would guarantee a quantity of gas be supplied domestically, irrespective of domestic demand, which may place downward pressure on prices. The gains to wholesale gas consumers from lower gas prices, however, would be offset by the losses to producers who are obliged to sell a share of their production at a lower price. With diminished returns and weak investor sentiment, some analysts argue that a reservation policy may reduce prospective upstream investment and result in lower production and higher domestic prices in the long run. **[9.0]**

International gas market policies

International approaches can provide useful indictors for Australia, with different policies yielding contrasting price and supply outcomes. A review of selected jurisdictions suggests that wholesale government interventions have generally been unsustainable and have tended to reduce domestic gas prices in the short term, followed by perverse economic outcomes over the longer term, including: reduced foreign investment; stagnant or negative production growth; strained government budgets; and/or inefficient energy usage. Conversely, it is suggested that moderate government intervention, as evident in the United States and Canada, may be more economically viable in ensuring domestic gas supply. **[12.0 & 13.0]**

Outlook for domestic prices: factors and forecasts

Once east coast LNG exports commence, Australia will become a significant net exporter of gas. Prospective domestic prices in both the eastern and western markets will then be linked with the netback price (i.e. the LNG sale price, less the costs incurred in producing and transporting the LNG to the point of sale) and largely influenced by highly variable international supply and demand factors. If a national reservation policy is implemented, and depending on the extent of this policy, the domestic market would be disconnected from the international market. In this case, domestic supply and demand variables will have a greater influence in determining domestic prices, which at least in the short run, are likely to be lower than the netback. With or without a reservation policy, the price outlook is highly uncertain because of exposure to domestic and international supply and demand variables. **[10.0]**

Estimates of the costs and benefits of a reservation policy

Two studies have estimated the net economic effects of introducing a domestic gas reservation policy. The first, commissioned by the Australian Industry Group (AIG) and the Plastics and Chemicals Industries Association (PCIA), examined the net effects specific to the east coast market. The second, commissioned by the Australian Petroleum Production and Exploration Association (APPEA), examined the net effects to the national economy of a reservation policy.

As these Associations are gas consumer and producer groups respectively, they represent different sides of the policy debate, each with vested interests in whether a reservation policy is implemented. Unsurprisingly, the two studies used different methodologies and produced contrasting sets of estimates of the costs and benefits of reservation. The National Institute of Economic and Industry Research (commissioned by AIG and PCIA) estimated the net annual GDP cost of unrestricted east coast LNG exports to the Australian economy to be $22 billion (2009 dollars) in 2040; while Deloitte Access Economics (commissioned by APPEA) estimated the net annual GDP cost of a national reservation policy to be $6 billion (2011-12 dollars) in 2025.

Aside from these estimates, the economic costs and benefits of domestic gas reservation have been largely discussed at a theoretical and conceptual level to date, with arguments presented from both sides of the policy debate. The costs and benefits of reservation would ultimately have to be quantified independently to fully appreciate the net effect of such a policy on the Australian economy. **[9.5]**

International implications of a reservation policy

The *General Agreement on Tariffs and Trade* (GATT) is a multilateral agreement regulating international trade which is still in effect under the World Trade Organisation (WTO) framework. As a member of the WTO, Australia has legal obligations under this agreement which, among other things, includes rules regarding export restrictions. This may be of relevance if a national domestic gas reservation was implemented.

Article XI of the GATT prohibits export restrictions “other than duties, taxes or other charges” but allows exceptions to alleviate critical shortages of essential items or when the restrictions are necessary to enforce classification standards. It is highly unlikely that either of these exceptions could be reasonably invoked by Australia with respect to domestic gas reservation. Article XX allows a country to ignore Article XI and impose export restrictions if they meet very specific requirements. Export restrictions may be imposed if they are “necessary to protect human, animal or plant life or health”; or if they relate “to the conservation of exhaustible natural resources”. However, as an additional requirement, in order to qualify for either exception, Australia would have to impose restrictions on domestic production and consumption of natural gas as restrictions cannot be limited to LNG exports.

It is unclear as to whether or not the WA and Queensland domestic gas reservation policies would be in breach of GATT Article XI. Other countries with a gas reservation policy, such as Egypt, have not been subject to a WTO dispute case. **[11.1]**

Australia is also a signatory to a number of free trade agreements (FTAs) which contain provisions that are consistent with Article XI of the GATT and prohibit quantitative restrictions on imports and exports. It is difficult to ascertain what obligations individual States have under these FTAs and what would specifically constitute a breach of these quantitative restrictions.

With regards to the investment interests of foreign corporations, it appears that implementation of a domestic gas reservation policy may be in breach of FTA provisions if the policy infringes upon existing gas rights. Based on analysis by Martignoni and Nygh (2010), were the Western Australia or Queensland policies to be implemented in a manner that infringed on existing gas rights, it appears that they may breach one or more FTA provisions. For example, the Western Australia policy could breach Chapter 11, Art 9 of the ASEAN FTA, which prohibits indirect expropriation. The Western Australia policy could also breach the Fair and Equitable Treatment Standard of a relevant FTA, by failing to honour an investor’s reasonable and legitimate expectations. Further, both policies could breach Chapter 8, Art 19 of the ASEAN FTA which, following GATT Article XX, relates to the conservation of exhaustible natural resources. **[11.2]**

1. INTRODUCTION

Australian mineral and petroleum (including natural gas) resources are, for the most part, vested in the Crown. Government involvement in the gas industry is therefore partly predicated upon a desire to see the Crown's resources effectively and efficiently developed. Other reasons include the policy objective of achieving energy security and, owing to their natural monopoly characteristics, the regulation of gas transmission and distribution pipelines. While these policy objectives and imperatives have been common to governments of all political persuasions since the commencement of gas production in Australia in the early 1960s, different *policies* have been adopted to achieve those goals. For example, with regards to energy security, some advocate adoption of a domestic gas reservation policy, while others argue that a robust gas market will produce the desired goal.

Natural gas is Australia's third largest energy source after coal and uranium. In 2012-13, gas accounted for one quarter of Australia's total primary energy consumption (1,552 petajoules or PJ). Australia produced twice as much as it consumed (3,023PJ); the other half was exported in the form of liquefied natural gas (LNG) to international markets. As of 2012, Australia had 139,010PJ proved and probable (2P) gas resources.

In 2011-12, NSW was the fourth-largest consumer of natural gas (165PJ). It is almost entirely dependent on gas imports from other States, importing 96% of total consumption. NSW produced 6PJ of gas in 2011-12 and has 2,885 PJ of 2P gas reserves, all of which are coal seam gas. Given NSW's reliance upon other States for gas, future developments in the eastern gas market (NSW, the Act, Queensland, South Australia, Victoria and Tasmania) are likely to significantly affect NSW.

The eastern market is one of three in Australia along with the western (Western Australia) and northern markets (Northern Territory). The eastern market is entering a transition period. Gas fields currently in production are reaching the end of their economic life, existing domestic long-term gas supply contracts are approaching expiration, and LNG exports are expected to commence in 2014. Production in the eastern market will have to treble over the next 3 to 5 years to satisfy both domestic and LNG export demand. There is a general perception in the market that the following will occur as a result:

- supply in the market will tighten in the short to medium term, with the effects of this tightness being felt most acutely in Queensland;
- new sources of supply will be required. The key question is whether domestic production will be able to expand rapidly enough to address the supply shortfall that is expected to arise from 2015 onward. Some commentators are of the opinion that this is unlikely; and
- gas prices will converge toward the LNG netback price (i.e. the LNG sale price, less the costs incurred in producing and transporting the LNG to the point of sale). The development of new sources of supply is unlikely

to result in gas prices falling back to historic levels of \$3-\$4/GJ because these sources are expected to incur higher production costs than existing sources of supply.

With gas supplies being reserved for LNG export, prices have already risen sharply in both eastern and western markets. In WA, prices have risen from an average of \$2 to \$3 a gigajoule in the 1990s and early 2000s, to around \$8 to \$9 a gigajoule for new contracts in 2013. In Queensland, gas prices have risen from \$3 to \$4 a gigajoule in early 2012 to as high as \$7 a gigajoule in 2013 for short-term contracts.

Domestic gas reservation is one of the policies available to State and Federal Governments in seeking to ensure the availability of affordable gas to domestic consumers. This policy would involve quarantining a proportion of gas production and/or segments of gas producing land for the domestic market. At present, Western Australia has applied a reservation policy to several gas projects, and Queensland may put its policy into effect should domestic supply constraints arise. In October 2013, the Commonwealth Industry Minister said that the Abbott Government does not support the introduction of a national domestic gas reservation policy. The Victorian Government also opposes domestic gas reservation, but the Victorian Opposition has flagged the introduction of a policy should it win the 2014 election.

In May 2012, the NSW Legislative Council General Purpose Standing Committee No.5 released its report into coal seam gas, in which it recommended that 'the NSW Government should implement a domestic gas reservation policy, under which a proportion of the coal seam gas produced in New South Wales would be reserved for domestic use'. The Government's response was that a reservation policy was unnecessary at present, and would be a disincentive to investment and add to project development costs. It also noted that it may reconsider the issue once the CSG industry has been established, if required by circumstances.

With rising labour costs and a relatively high exchange rate, gas consumers argue that competitively priced gas is one of the few remaining comparative advantages for manufacturers and processors in Australia. This comparative advantage is perceived to be compromised due to the uncertainty around the provision and price of domestic gas. Many stakeholders have therefore called for the introduction of a national reservation policy. On the other hand, gas producers oppose the introduction of any form of reservation policy. They argue that the policy would impair local gas supply and affordability, rather than improve it.

As argued by stakeholders at contrasting ends of the policy spectrum, there are likely to be significant economic costs and benefits associated with domestic gas reservation. This paper aims to provide a variety of stakeholder perspectives, while also discussing the costs and benefits of domestic gas reservation at a theoretical and conceptual level. A range of international gas policy approaches are also assessed, with the aim of providing insights into the varying price and supply outcomes from different levels of government intervention.

Without a reservation policy, and with the expansion of LNG on the eastern and western markets, it is widely expected that gas prices will rise and converge to the netback price. Prospective domestic gas prices under this scenario will be largely determined externally by international supply and demand factors. With a domestic gas reservation policy, the domestic price may be disconnected from the international price. In this case, domestic supply and demand will have more of an influence on price. In either scenario, the price outlook is highly uncertain and dependent on a number of domestic and international factors which are discussed in this paper.

The current debate in Australia about natural gas concerns a broader range of issues than the question of a domestic gas reservation policy. Of these, coal seam gas is perhaps the most controversial. Others include the environmental impacts associated with gas extraction and consumption and the prospects of developing other unconventional gas resources, such as shale gas. Some of these issues are touched upon in Part One of the paper. The focus of the paper, however, is on the policy of domestic gas reservation, linked as it is with the pressing issues in NSW of a potential gas shortfall and relatively rapid price increases.

Part One of this paper sets out background material to the discussion of domestic gas reservation. Australia's gas markets are described together with an overview of the gas supply chain. Key statistics are presented at three scales, where available – national, the eastern market, and NSW. Data includes gas reserves, exploration expenditure, production, consumption, LNG exports, wholesale and retail prices. A history of gas developments in Australia and an overview of the current regulatory framework are also provided.

Parts Two and Three consider domestic gas reservation. Part Two sets out the Commonwealth position on domestic gas reservation, and describes in detail the WA and Queensland policies. A range of stakeholder perspectives are presented prior to a theoretical analysis of the costs and benefits of the policy. Discussion of the factors that may affect domestic prices in coming years is followed by consideration of the implications of a reservation policy on international trade. Part Three contains an overview of gas policies in other gas producing countries, and includes a case study of the United States.

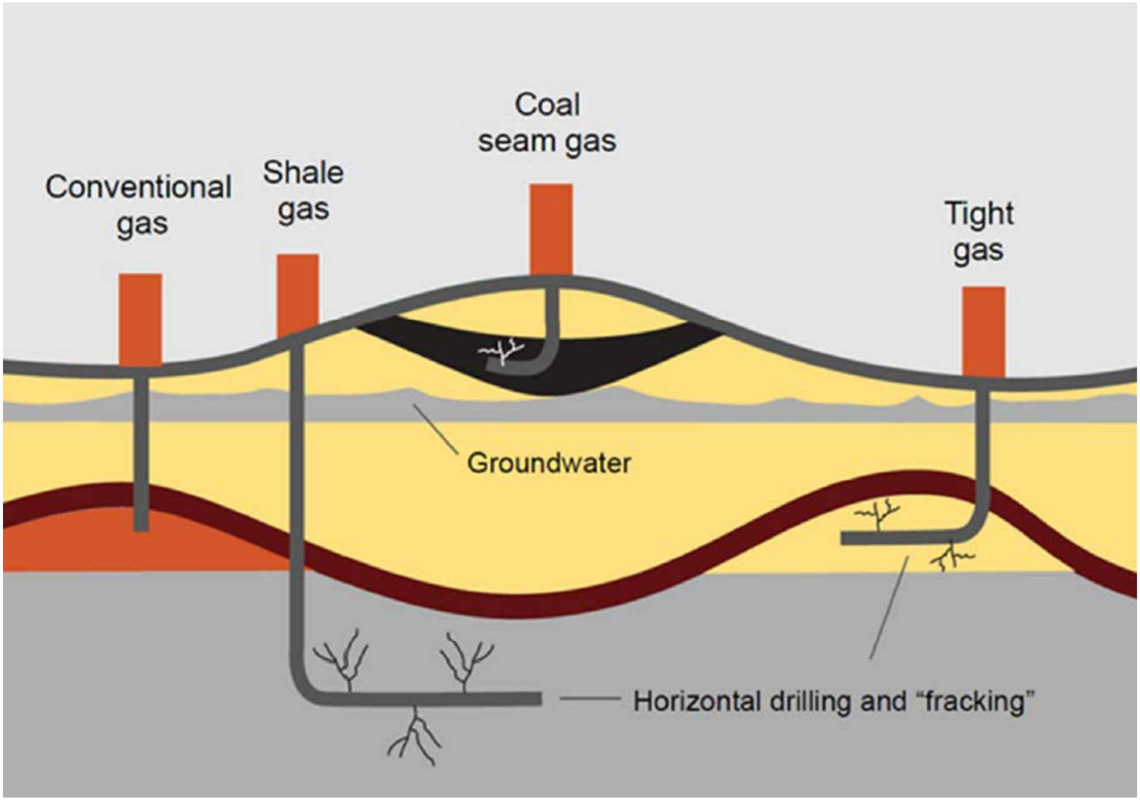
PART ONE – RESOURCES AND INDUSTRY STRUCTURE

2. THE GAS INDUSTRY

2.1 What is gas?

Petroleum resources include oil, conventional gas and unconventional gas. Conventional gas and unconventional gas is the same product: natural gas, which primarily consists of methane, with varying levels of heavier hydrocarbons, such as propane and butane, and other gases such as carbon dioxide. Conventional gas is extracted from large underground chambers (Figure 1), where the gas is trapped in porous sandstone below a dense layer of impermeable rock, having migrated there from a source rock (e.g. shale). Unconventional gas accumulations reflect the failure or under-performance of the petroleum system. Shale gas and coal seam gas arise where the natural gas remains within the source rock, not having migrated to a reservoir. Tight gas accumulations form within a poor quality reservoir.[1]

Figure 1: Extraction of conventional and unconventional gas[2]



Conventional and unconventional gas may be converted to Liquefied Natural Gas (LNG). LNG is natural gas that has been cooled to approximately -160°C until it forms a liquid. This makes it easier and cheaper to transport long

---

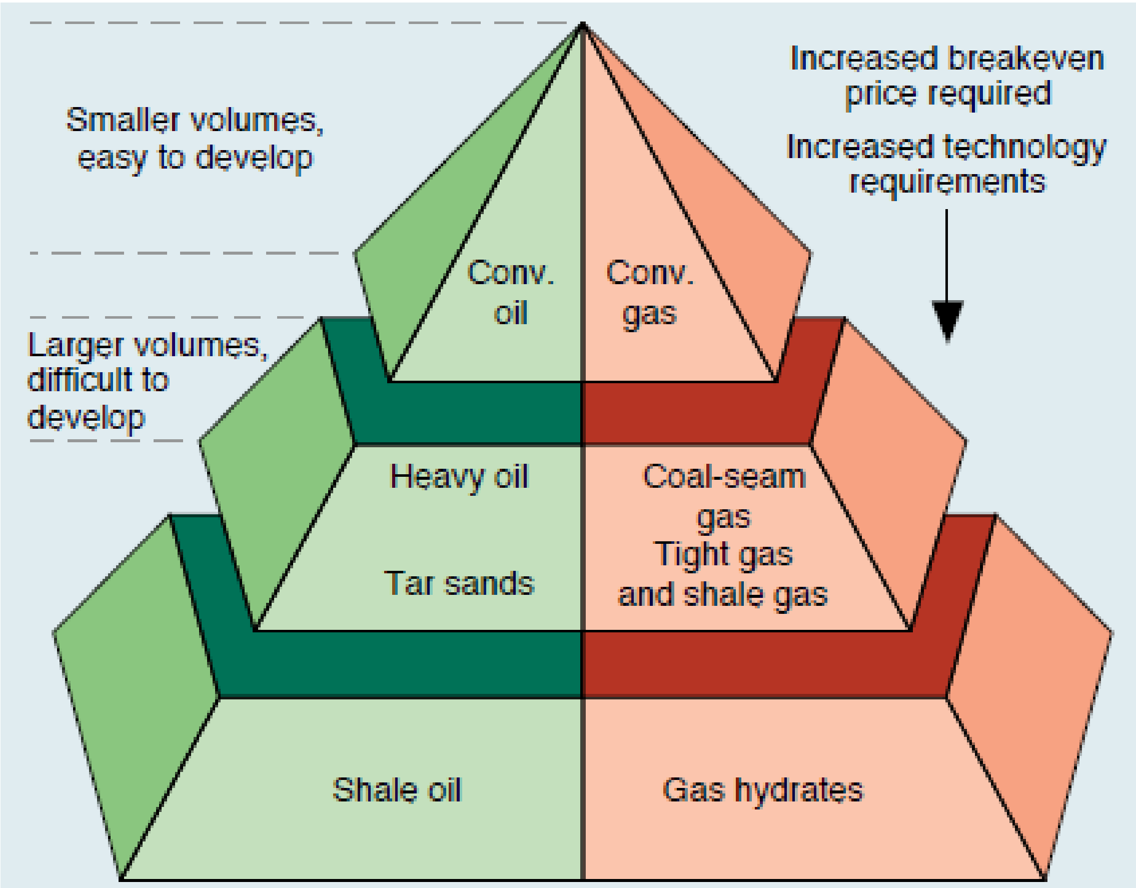
[1] Geoscience Australia and Bureau of Resources and Energy Economics, *Australian Gas Resource Assessment 2012*, 2012

[2] T Wood et al, *Getting gas right: Australia's energy challenge*, Grattan Institute, June 2013, p.7

distances in LNG tankers to overseas markets.[3]

The petroleum resource pyramid illustrates how a smaller volume of conventional gas is easier and cheaper to extract compared to larger volumes of unconventional gas (Figure 2). For unconventional resources, additional technology, energy and capital is required to extract the gas. Technological developments and gas price rises can make the lower parts of the resource pyramid accessible and commercial to produce.

Figure 2: Petroleum resource pyramid[4]



2.1.1 Petroleum classification systems

Two classification systems are commonly applied to petroleum resources in Australia. Government sources generally use the McKelvey Classification Scheme. This scheme is used for both mineral and petroleum resources, allowing easy comparison between different energy sources. The Petroleum Resources Management System was developed by the Society of Petroleum Engineers and is used by most oil and gas companies. Both classification systems employ an economic feasibility versus geological certainty matrix, but

[3] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit.

[4] Ibid., p.7

use different terminology.[5]

Appendix 1 outlines the two classification systems in depth. For the purposes of this paper, the key aspects of each classification system are as follows. In the McKelvey Classification Scheme, resources of the highest geological certainty are described as **Demonstrated resources**. Within this category, **Economic Demonstrated Resources** (EDR) are those resources with the highest level of economic feasibility. For petroleum resources classified as EDR, profitable extraction or production has been established, analytically demonstrated or assumed with reasonable certainty. Petroleum resources for which profitable extraction or production has not been established are denoted as **Sub-economic Demonstrated Resources** (SDR).

Under the Petroleum Resources Management System, in order of declining economic feasibility, petroleum resources are defined as **Reserves**, **Contingent Resources** or **Prospective Resources**. **Reserves** are further categorised in accordance with the level of certainty associated with the estimates as follows:

- **Proved Reserves** can be estimated with reasonable certainty to be commercially recoverable. Also known as 1P Reserves, there is at least a 90% probability that the quantities actually recovered will equal or exceed the low estimate;
- **Probable Reserves** are less likely to be recovered than Proved Reserves. For proved and probable reserves together (2P reserves), there is at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate; and
- **Possible Reserves** are least likely to be recoverable. For proved, probable & possible reserves together (3P reserves), there is at least a 10% probability that the quantities actually recovered will equal or exceed the high estimate.[6]

2.2 Regional gas markets

There are three geographically and economically distinct gas markets in Australia: the western market (Western Australia); the northern market (Northern Territory); and the eastern market (ACT, NSW, Queensland, South Australia, Tasmania and Victoria) (Figure 3). Each of these markets varies by size and location of gas resources, the demand profile and relative exposure to international markets. Interconnection of the gas markets is highly unlikely in the foreseeable future because of the vast distances separating the associated population and demand centres.[7]

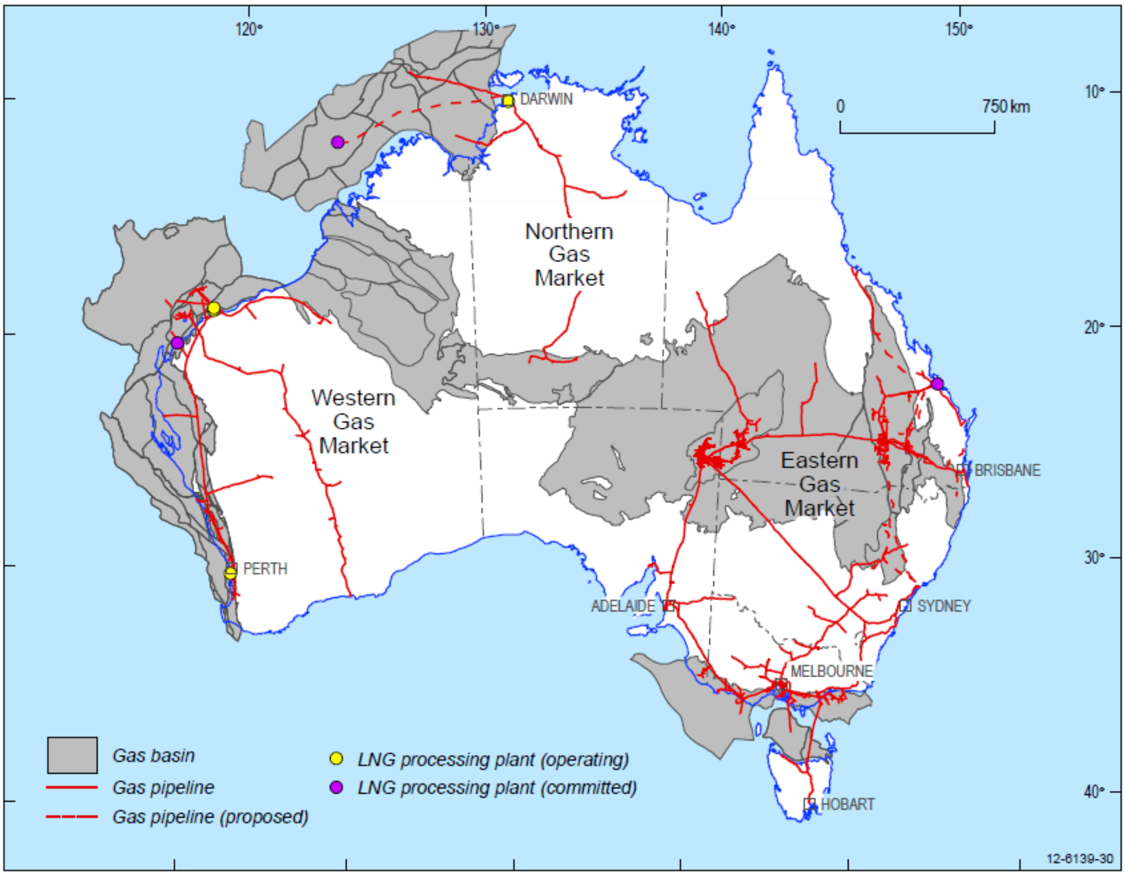
---

[5] Ibid.

[6] Ibid. Note that the categories are not mutually exclusive. For example, Probable Reserves include Proved Reserves such that 2P reserves are often described as 'proved and probable'.

[7] Bureau of Resources and Energy Economics, *Gas Market Report*, October 2013

Figure 3: Australia's regional gas markets[8]



Physically, the eastern market is the largest, most competitive and interconnected gas market in Australia. Eastern market consumption has increased by 3% over the past decade, underpinned primarily by increased gas-fired electricity generation. LNG exports from Queensland are expected to commence in 2014.[9]

The western market is the largest market in terms of production. In 2010-11, it produced twice as much gas as the eastern market, the majority of which was exported. Western market consumption has grown by an average annual rate of 6% over the past decade, underpinned by strong demand from the mining, manufacturing and electricity generation sectors.[10]

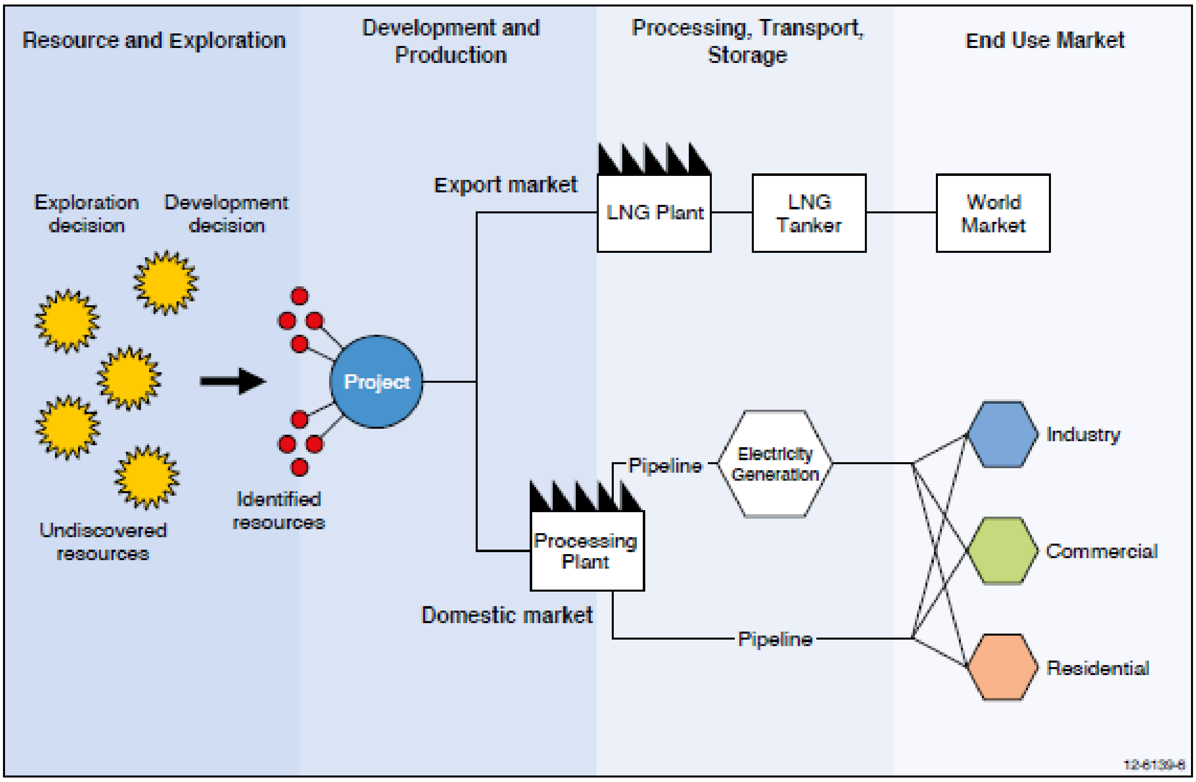
The northern market is the smallest of the Australian markets. It is expected to grow in coming decades due primarily to increased LNG exports. Development of other downstream gas and related industries are also expected to contribute to future growth.[11]

[8] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit., p.23
[9] Department of Resources, Energy and Tourism, *Energy White Paper 2012*, 2012
[10] Ibid.
[11] Ibid.

2.3 The gas supply chain

The gas supply chain is comprised of a number of distinct stages (Figure 4). The upstream sector generally encompasses exploration, development and production. Downstream sector activities include processing, distribution, storage, wholesaling and retailing.

Figure 4: Australia's gas supply chain[12]



2.4 Upstream sector

2.4.1 Exploration

The primary focus of exploration is information gathering. Prior to drilling, a number of scientific techniques are used to assess the petroleum potential of a sedimentary basin. Drilling is required to test whether or not petroleum is present; appraisal wells are then drilled to determine the nature and size of the discovery. The chemical make-up of the gas affects its cost of extraction and marketability. The geology of the sedimentary basin also affects the cost of extraction and recovery estimates. Between 75 and 90 per cent of estimated resources can usually be extracted from gas fields.

Australian governments have taken a key role in providing pre-competitive geological data to encourage private sector investment in exploration. Companies access prospective exploration areas either by competitive bidding

[12] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit., p.6

or by taking equity in existing petroleum acreage holdings. The costs of exploration vary according to a number of factors including the scope and location of the project and the logistics involved. Petroleum exploration is a high-risk activity for which a return is not guaranteed, even in the event of a gas discovery as the resources may be marginal or non-commercial. Exploration expenditure is a small component (18% in 2005) of total upstream petroleum expenditure compared to expenditure on development and production.[13]

2.4.2 Development and production

Infrastructure and production facilities are developed once financial and regulatory requirements are addressed. Infrastructure for onshore developments includes production wells, field infrastructure, on-site production and processing facilities, and transmission facilities to connect with downstream refineries and distribution systems. Infrastructure for offshore developments includes offshore production facilities, pipelines to onshore processing plants or, in some cases, floating LNG (FLNG) processing facilities. In May 2011, Shell made the decision to construct Australia's first FLNG plant for the Prelude gas field off the coast of Western Australia.[14] On 2 September 2013, Woodside announced that it plans to develop its Browse gas fields using FLNG.[15]

The production stage commences after a field has been developed. It involves higher operating expenditure and lower ongoing capital expenditure than the development stage. Production and development stages account for the majority of gas project costs (82% in 2005).[16]

2.4.3 Industry structure

In 2011-12, six major producers met 65% of domestic gas demand in Australia: Santos, BHP Billiton, ExxonMobil, Origin Energy, Woodside and Apache Energy. When shares in 2P gas reserves are considered, the top six companies held 60.8% of total 2P gas reserves in Australia: Chevron, Shell, ExxonMobil, BG, Inpex and Woodside (Table 5). For comparative purposes, Table 5 also includes the companies that hold the largest shares in NSW's total 2P reserves (Santos, AGL, Metgasco and EnergyAustralia).[17]

[13] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit.; Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, Productivity Commission Research Report, April 2009

[14] Shell, *Prelude*, no date [online – accessed 3 October 2013]

[15] Woodside, *Browse LNG*, 2013 [online – accessed 3 October 2013]

[16] Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, Productivity Commission Research Report, April 2009

[17] Australian Energy Regulator, *State of the Energy Market 2012*, 2012, p.88. See Chapter 3.1 of this paper for additional information on gas reserves in Australia.

Table 5: Shares in 2P gas reserves in Australia (August 2012)[18]

Company	Share	Gas reserves (PJ)
Chevron	19.1	26,740
Shell	13.2	18,480
ExxonMobil	8.6	12,040
BG	7.1	9,940
Inpex	6.9	9,660
Woodside	5.9	8,260
Santos	3.8	5,320
AGL	1.5	2,100
Metgasco	0.3	420
EnergyAustralia	0.2	280
Other	33.4	46,759
Total Australian gas reserves	**100.0**	**139,998**

When examining the eastern market, the top six companies together held 66.3% of total gas reserves in 2011-12 (Table 6). The company with the largest share, BG, held 25.6% of gas reserves in the Surat-Bowen basin in Queensland.

Table 6: Shares in 2P gas reserves in the eastern market (August 2012)[19]

Company	Share	Gas reserves (PJ)
BG	20.5%	9,998
Origin	11.7%	5,724
ConocoPhillips	10.1%	4,921
Santos	9.1%	4,427
PetroChina	7.8%	3,827
Shell	7.1%	3,476
Other	33.7%	16,485
Total eastern market gas reserves	**100.0**	**48,858**

In NSW, four companies held 99.4% of total 2P gas reserves in 2012: Santos, AGL, Metgasco and EnergyAustralia (Table 7). Santos held the largest share at 40.4% (1,141PJ), all of which was located in the Gunnedah basin.

[18] Adapted from: Australian Energy Regulator, *State of the Energy Market 2012*, 2012, p.91
[19] Adapted from: Ibid., p.91

Table 7: Shares in 2P gas reserves in NSW gas basins (August 2012)[20]

Company	Clarence-Morton (NSW-Qld) (PJ) (% share)	Gunnedah (PJ) (% share)	Gloucester (PJ) (% share)	Sydney (PJ) (% share)	Hunter (PJ) (% share)	Total (PJ) (% share)
Santos	0	1,141PJ 80%	0	0	0	1,141PJ 40.4%
AGL	0	0	669PJ 100%	142PJ 100%	142PJ 100%	953PJ 33.7%
Metgasco	428PJ 96.2%	0	0	0	0	428PJ 15.2%
EnergyAustralia	0	285PJ 20%	0	0	0	285PJ 10.1%
Other	17PJ 3.8%	0	0	0	0	17PJ 0.6%
Total	445PJ	1,426PJ	669PJ	142PJ	142PJ	2,824PJ

2.5 Downstream sector

2.5.1 Processing, transport and storage

After extraction but prior to transportation, gas is processed to separate out the impurities. Gas is transported to markets by pipeline or in LNG tankers. Gas in pipelines is pressurised to reduce the volume of gas being transported and to provide the force required to move through the pipeline. Liquefied Natural Gas (LNG) is natural gas that has been cooled to approximately -160°C, at which point it becomes a liquid and has shrunk in volume some 600 times. While liquefaction reduces the cost of transportation over long distances, it typically consumes 10-15 per cent of the gas in the process.

Transmission pipelines transport gas from production facilities to either the entry point of the distribution system or to users directly connected to the transmission system, such as major industrial users and electricity generators. Distribution systems enable gas to be transported under lower pressures from the city gate to users connected to the distribution system, such as residential customers and small to medium sized industrial and commercial customers. Natural gas not used immediately may be stored either underground in large reservoirs or in liquefied form.[21]

Australia's gas pipelines are privately owned. In the eastern market, APA Group and Singapore Power International (through its subsidiary Jemena) are the principal owners in the transmission sector (Tables 8 and 9). Envestra and

[20] Adapted from: Ibid., p.91
[21] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit.

Singapore Power International (through its subsidiaries Jemena and SP AusNet) are the principal owners in gas distribution (Tables 10 and 11).

Table 8: Gas transmission pipeline ownership in the eastern market[22]

Owner	Number of pipelines	Total length of pipeline (km)
APA Group	10	8,133
APA Group; REST Group	1	680
DUET Group	1	250
Jemena	2	1,424
Origin Energy	1	205
Palisade Investment Partners	1	734
Victorian Funds	1	391
Westside; Mitsui	1	47
Total	**18**	**11,864**

Table 9: Gas transmission pipelines in NSW[23]

Pipeline	Length (km)	Capacity (TJ/day)	Covered	Owner
Moomba to Sydney Pipeline	2,029	420	Partial (light)	APA Group
Central West Pipeline (Marsden to Dubbo)	255	10	Yes (light)	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	300	7	Yes	APA Group
Eastern Gas Pipeline (Longford to Sydney)	795	268	No	Jemena (Singapore Power International)

Table 10: Gas distribution pipeline ownership in the eastern market[24]

Owner	Number of networks	Total length of pipeline (km)
ACTEW Corporation (ACT Govt) 50%; Jemena (Singapore Power International) 50%	1	4,720
APA Group	1	180
APA Group 20%; Marubeni 40%; RREEF 40%	1	2,900
DUET Group	1	9,960
Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)	4	21,350
Jemena (Singapore Power International)	1	24,430

[22] Adapted from: Australian Energy Regulator, *State of the Energy Market 2012*, 2012, p.106
[23] Adapted from: Ibid., p.106. Notes: TJ/day – terajoules per day. Covered – indicates the level of regulation to which the pipeline is subject.
[24] Adapted from: Ibid., p.108

Owner	Number of networks	Total length of pipeline (km)
SP AusNet (Singapore Power International 51%)	1	9,860
Tas Gas (Brookfield Infrastructure)	1	730
Total	**11**	**74,130**

Table 11: Gas distribution pipelines in NSW[25]

Network	Customer numbers	Length (km)	Asset base ($m)	Owner
Jemena Gas Networks (NSW)	1,050,000	24,430	$2,396	Jemena (Singapore Power International)
ActewAGL	124,000	4,720	$288	ACTEW Corporation (ACT Govt) 50%; Jemena (Singapore Power International) 50%
Wagga Wagga	23,800	680	$62	Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)
Central Ranges System	7,000	180	na	APA Group

2.5.2 Gas transport contracts

Two markets are required for the competitive supply of gas to end users: a market for gas transport services; and a market for the commodity 'natural gas'.[26] The commodity markets through which gas is traded are dealt with in later sections of this chapter.

The types of transportation contracts and services available in the eastern market depend upon the network pipeline in question. The Victorian Declared Transmission System (DTS) uses a market carriage model in which gas shippers, amongst other things:

- bid daily for transportation services through the Victorian Declared Wholesale Gas Market;
- enter into an agreement with the DTS owner; and
- enter into separate agreements with the owners of other networks from which or to which they will be transporting gas.

All other transmission pipelines use a contract carriage model, in which the services provided by transmission pipelines are supplied by bilateral contracts between the pipeline owner and the gas shipper. Some secondary trading between gas shippers of pipeline capacity takes place as a means of managing volume risks i.e. the risk that gas demand will be higher or lower than the contracted quantity.[27]

---

[25] Adapted from: Ibid., p.108

[26] ABARES, *Australian Gas Markets: Moving Toward Maturity*, eReport 03.23, December 2003

[27] K Lowe Consulting, *Gas Market Scoping Study: A report for the AEMC*, July 2013

Access to some transmission networks is regulated by the Australian Energy Regulator (AER). The AER also regulates access to pipeline capacity in all the distribution networks of the eastern market, except for the Tasmanian network.[28] The AER approves an 'access arrangement' for each network, which sets out the terms and conditions under which third parties can use the network. The 'access arrangement' specifies the tariffs which are charged for use of the network.[29]

2.5.3 Wholesale gas supply agreements

Wholesale gas supply contracts are bilateral contracts between producers and large buyers (e.g. retailers, large industrial companies, mining companies, gas fired generators and LNG exporters) that set out the volume of gas to be supplied, the price to be paid and other terms and conditions. Historically, the wholesale supply of gas in Australia has been underpinned by long term contracts of 10 or more years. These contracts have benefitted producers, pipeline owners and consumers, enabling:

- producers and pipeline owners to underwrite significant capital investment in new production facilities, pipelines and further exploration; and
- large end-users to make significant investments in their own facilities (e.g. gas fired generators, LNG exporters, mining companies and large industrial customers).

Today, while long-term contracts are still being used to underwrite new projects and pipelines and by some large end-users, the predominant form of contracting in the eastern market is a mix of medium (1 to 3 year) and long-term contracts.[30]

The prices specified in wholesale gas supply contracts have usually been expressed on a $/GJ basis that has escalated in line with inflation. With LNG prices generally linked to an international oil benchmark and with LNG exports due to start in Queensland in 2014, some new domestic contracts in the eastern market are now being linked to an international oil benchmark; provision is made for the benchmark to be updated at discrete intervals over the life of the contract.[31]

2.5.4 Facilitated markets

Wholesale gas trading hubs have been established in Adelaide, Brisbane and Sydney (otherwise known as Short Term Trading Markets) and in Victoria (the Domestic Wholesale Gas Market).[32] These markets enable participants to trade

[28] See also Chapter 4.2 of this paper
[29] Australian Energy Regulator, *State of the Energy Market 2012*, 2012
[30] K Lowe Consulting, op. cit.
[31] Ibid.
[32] Bureau of Resources and Energy Economics, *Gas Market Report*, October 2013

any gas supply imbalances that arise on a day because their actual demand differs from their contracted supply. Each market therefore operates as a market-based balancing mechanism that overlays bilateral wholesale gas supply agreements, rather than as a commodity market.[33]

The Sydney and Adelaide Short Term Trading Markets (STTMs) commenced operation in September 2010. The Brisbane STTM commenced operation in December 2011. Each is operated by the Australian Energy Market Operator (AEMO) under a set of common rules. Participation in the STTM is compulsory for facility operators (facilities include transmission pipelines, production facilities and storage facilities), shippers, distributors and users. Each STTM enables participants to:

- trade gas imbalances;
- purchase gas on a short term basis without contracting for delivery; and
- efficiently allocate gas during system constraints and emergencies and, potentially, forestall the need for government intervention and market suspension.

The STTMs were also designed to allow for price transparency in the market so that the price of gas set daily in the STTM properly reflects the true supply-and-demand situation, which in turn provides a more reliable price indicator for future investment in production, transmission and distribution infrastructure.[34]

In March 1999, the Victorian Government established the Declared Wholesale Gas Market (DWGM). The DWGM provides the framework for a number of functions, including:

- a mechanism by which participants may trade gas imbalances;
- maintenance of a reliable and secure system for the transportation of gas; and
- management of metering data for operational and market balancing.

While similar in some respects to the STTMs, the DWGM differs on several key points, including:

- the STTM operates on a day ahead basis while the DWGM operates on an intra-day basis;
- the STTM has a contingency gas mechanism, which can be called upon by the AEMO when the normal operation of the STTM is unable to balance demand and supply; and
- the STTM has a lower market cap of $400/GJ than the DWGM

[33] K Lowe Consulting, op. cit.

[34] K Lowe Consulting, op. cit.; Australian Energy Market Operator, *Overview of the Short Term Trading Market for Natural Gas*, 14 December 2011

($800/GJ).[35]

In December 2012, the COAG Standing Council on Energy and Resources (SCER) announced that a voluntary brokerage hub would be established at Wallumbilla in Queensland by March 2014. The hub will operate as a web-based exchange platform that will facilitate the matching and clearing of trades between buyers and sellers at three different trading nodes.[36] At least three types of products may be traded: a day-ahead product; a balance of day product; and a monthly forward product. The AEMO expects the hub will:

- enhance the transparency of gas trading;
- improve the ability of participants to allocate and price gas efficiently in the short term;
- support the efficient trade and movement of gas between regions; and
- support the development of a financial product that can be used to manage risk.[37]

Together with the facilitated markets, the availability of gas market information has been boosted through the operation of the National Gas Market Bulletin Board (GBB) and AEMO's annual Gas Statement of Opportunities (GSOO).[38] The GBB provides data on pipeline capacity, actual and forecast gas flows and forecast supply. The GSOO provides information on the eastern market for the purpose of facilitating a competitive market and efficient investment, operations and use of energy. In particular, it assesses the adequacy of gas reserves, processing, storage, and transmission facilities to meet projected demand under several different scenarios. The GSOO also presents gas reserve adequacy over a 20-year outlook period and gas supply and transmission adequacy over a 10-year outlook period.[39]

2.5.5 Retail markets

Gas retailers buy gas in wholesale markets and package it with network services for sale to customers. Retailers, as with other large gas-users, generally acquire gas on a confidential basis through long-term contracts with suppliers. They also source pipeline capacity to ship the gas to customers through long-term contracts with pipeline owners.

NSW is the only State that provides for regulated retail gas prices. On 3 October 2013, the Australian Energy Market Commission (AEMC) released its review of competition in the NSW gas retail market. The AEMC found that

[35] K Lowe Consulting, op. cit.; Australian Energy Market Operator, *Guide to Victoria's Declared Wholesale Gas Market*, February 2012

[36] The South West Queensland Pipeline (SWQP), Queensland Gas Pipeline (QGP) and Roma to Brisbane Pipeline (RBP)

[37] K Lowe Consulting, op. cit.

[38] The WA Government also recently introduced a Gas Bulletin Board for the western market.

[39] Australian Energy Market Operator, *2012 Gas Statement of Opportunities*, 2012

competition in the gas market is delivering discounts and other benefits to the majority of small gas consumers. Consequently, it recommended removal of gas price regulation. It also suggested that the NSW Government consider maintaining gas price regulation in those parts of regional NSW outside the Jemena gas distribution network where there may be insufficient competition in the market. Other key findings in the review include the following:

- 70 per cent of small gas consumers have chosen a market offer, and 14 per cent switched their retailer in 2012;
- while new retailers have entered and gained market share, there are some barriers to entry related to the difficulties in accessing gas supply and pipeline capacity;
- there are limited signs of independent rivalry, with high market concentration and limited product differentiation;
- the majority of gas consumers are generally satisfied with quality of service; and
- profit margins are consistent with a competitive market.[40]

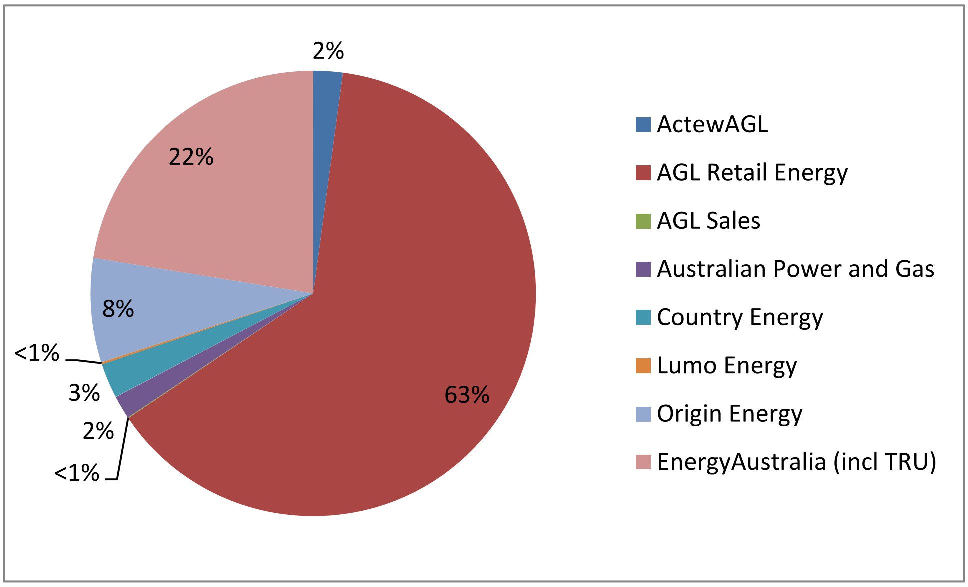
The NSW Government is preparing its response to the recommendation.[41]

As of 30 June 2012, AGL Retail Energy held the largest share of the residential gas retail market (Figure 5), with 63% (696,616) of customers. EnergyAustralia and Origin Energy held the next largest shares with 22% and 8% respectively.

[40] Australian Energy Market Commission, *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales*, Final Report, 3 October 2013

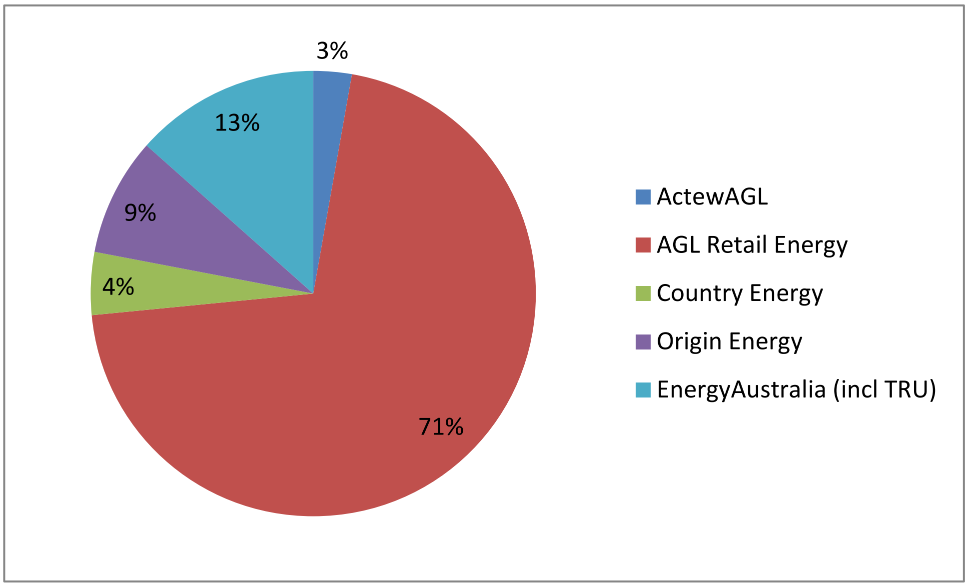
[41] The NSW Government is currently awaiting a further report from the AEMC before making a decision on whether or not to remove retail price regulation; *The Australian*, Energy rivalry pays for users, 4 October 2013

Figure 5: The NSW residential gas retail market (30 June 2012)[42]



AGL Retail Energy, EnergyAustralia and Origin Energy also hold the three largest shares of the non-residential gas retail market, with 71%, 13% and 9% respectively (Figure 6).

Figure 6: The NSW non-residential gas retail market (30 June 2012)[43]



[42] Independent Pricing and Regulatory Tribunal, *Customer service performance of gas retail suppliers 1 July 2007 – 30 June 2012*, Information Paper, December 2012

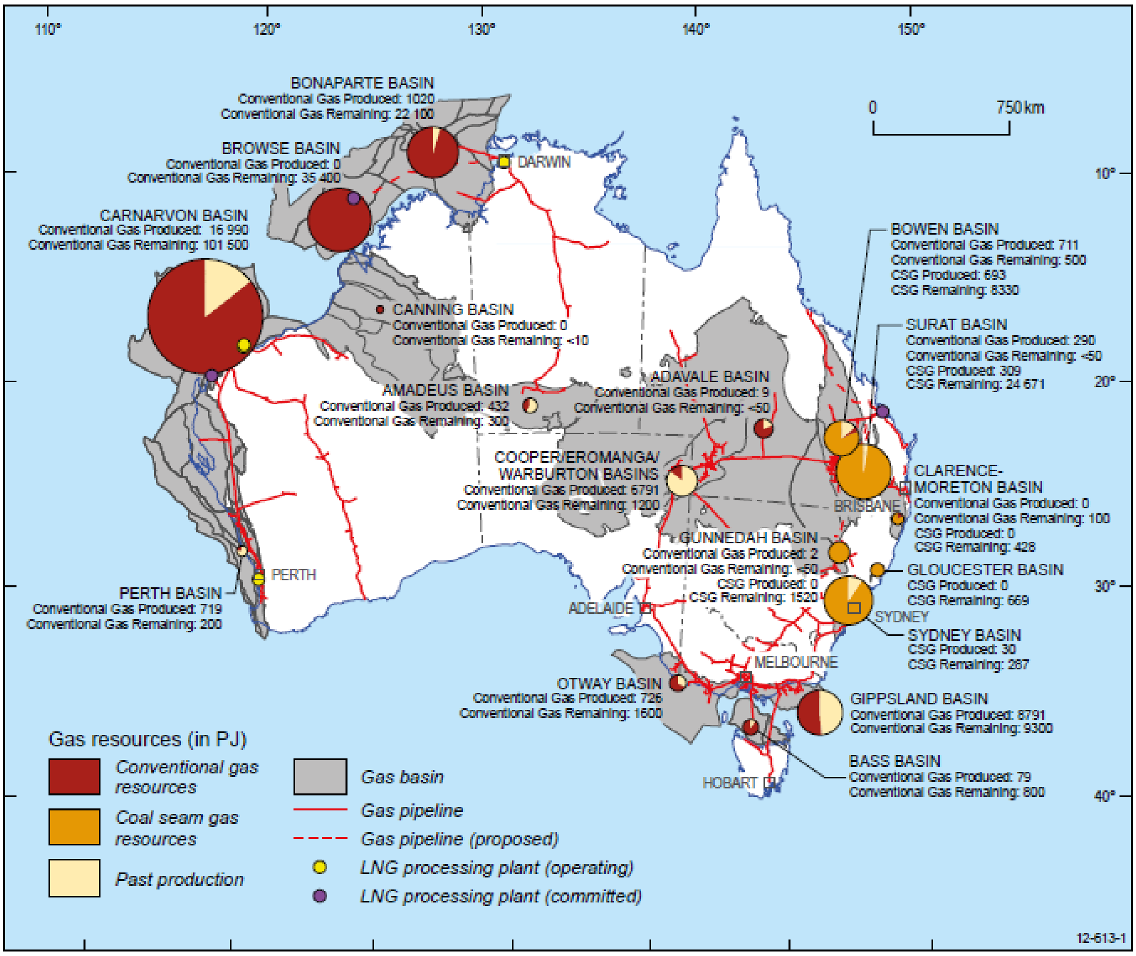
[43] Ibid.

3. RESOURCES

3.1 Gas reserves

Most of Australia's conventional gas resources lie off the coast of Western Australia (Figure 7). Other significant conventional gas accumulations are found in South Australia and Victoria. Queensland has recently been found to have significant amounts of coal seam gas (CSG) resources. Coal seam gas is also found in NSW and may be contained in the brown coal basins of Victoria. Known tight gas accumulations are located onshore in South Australia, Western Australia, and Victoria, while contingent and potential shale gas resources are located in NSW, Queensland, Northern Territory, South Australia, and Western Australia.[44]

Figure 7: Location of Australia's gas resources and infrastructure[45]



As of January 2012, Australia had a total of 900,450PJ of identified and potential gas resources (Table 12). Of these, 149,305PJ were economic-demonstrated resources (EDR) and a further 127,329PJ were sub-economic

[44] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit.

[45] Ibid., p.2. Note: For remaining resources, conventional gas values represent total demonstrated resources; CSG values show 2P reserves

demonstrated resources (SDR). Australia potentially has more shale gas than any other type of gas (435,600PJ). 76% of EDR gas is conventional gas and the remaining 24% is coal seam gas.

Table 12: Australian gas resources[46]

Resource category	Conventional gas (PJ)	Coal seam gas (PJ)	Tight gas (PJ)	Shale gas (PJ)	Total gas (PJ)
EDR	113,400	35,905	-	-	149,305
SDR	59,600	65,529	-	2,200	127,329
Inferred	11,000	122,020	22,052	-	155,072
All identified resources	184,000	223,454	22,052	2,200	431,706
Potential in ground	Unknown	35,434	Unknown	433,400	468,834
Total – identified & potential	184,000	258,888	22,052	435,600	900,540

In 2012, gas fields in the eastern market contained an estimated 422,478PJ of gas, compared with a combined 489,688PJ in the western and northern markets (Table 13). Of the proven & probable gas reserves (2P) in the eastern market, almost 80% (38,393PJ) are located in the Surat & Bowen basins in Queensland. 50% (34,934PJ) of total 2C gas resources in the eastern market are also located in the Surat & Bowen basins. The next most significant basin in terms of 2P reserves in the eastern market is the Gippsland basin in Victoria, with 4,153PJ of gas.

[46] Derived from: Geoscience Australia and Bureau of Resources and Energy Economics, op. cit., p.17. Note: Conventional gas demonstrated resources as of January 2011; CSG demonstrated resources as of January 2012. Note CSG 2P reserves and 2C reserves are used as proxies for EDR and SDR respectively.

Table 13: Gas reserves and resources by basin[47]

Basin	Reserves (2P) (PJ)	Contingent Resources (2C) (PJ)	Prospective Resources (PJ)	Total gas (PJ)
Eastern market				
Adavale (Qld)	22	-	-	22
Bass (Vic)	254	239	10,070	10,563
Clarence Moreton (NSW-Qld)	445	13,529	3,816	17,790
Cooper (SA-Qld)	1,792	7,602	109,597	118,991
Denison (Qld)	85	1,106	-	1,191
Eromanga (NSW-NT-SA-Qld)	12	-	2,479	2,491
Galilee (Qld)	-	2,129	25,393	27,522
Gippsland (Vic)	4,153	3,460	5,546	13,159
Gloucester (NSW)	669	176	-	845
Gunnedah (NSW)	1,426	4,564	48,745	54,735
Maryborough (Qld)	-	-	24,380	24,380
Otway (SA-Vic)	902	171	11	1,084
Surat & Bowen (Qld-NSW)	38,393	34,934	40,753	114,080
Sydney (NSW)	345	1,890	33,390	35,625
Total	**48,498**	**69,800**	**304,180**	**422,478**
Western and northern markets				
Amadeus (NT)	149	3,616	-	3,765
Beetaloo (NT)	-	-	171	171
Bonaparte (NT/WA)	1,054	20,958	0	22,012
Browse (WA)	17,384	17,916	-	35,300
Canning (WA)	-	10	264,046	264,056
Carnarvon (WA)	71,885	29,615	-	101,500
McArthur (NT)	-	38	-	38
Perth (WA)	40	160	62,646	62,846
Total	**90,512**	**72,313**	**326,863**	**489,688**
Grand Total	**139,010**	**142,113**	**631,043**	**912,166**

47 Sources: Core Energy Group, *Eastern & Southern Australia: Existing Gas Reserves & Resources*, Report for AEMO GSOO 2012, April 2012; Australian Energy Regulator, *State of the Energy Market 2012*, 2012; Independent Market Operator, *Gas Statement of Opportunities 2013*, July 2013; Northern Territory Department of Mines and Energy, *Northern Territory Onshore Hydrocarbon Reserves and Resources*, 2 October 2013. Notes: The total column equals 2P + 2C + prospective gas reserves and resources. The grand total of 912,166 for total Australian gas resources differs slightly from Table 12 because different sources are used.

As at December 2011, CSG made up 84.9% (41,154PJ) of total 2P gas reserves in the eastern market (Table 14). Of this total, 2,885PJ were located in NSW. NSW contained a total 95,003PJ identified and potential gas resources, equivalent to just under one-quarter of the total identified and potential gas resources in the eastern market.

Table 14: Gas reserves and resources in the eastern market and NSW by gas type (December 2011)[48]

	Reserves (2P) (PJ)	Contingent Resources (2C) (PJ)	Prospective Resources (PJ)	Total gas (PJ)
Eastern market				
Conventional gas	7,344	4,969	29,608	41,921
Coal seam gas	41,154	58,327	164,143	263,624
Shale and tight gas	0	6,504	110,429	116,933
Total	**48,498**	**69,800**	**304,180**	**422,478**
NSW				
Coal seam gas	2,885	20,159	71,959	95,003
Total	**2,885**	**20,159**	**71,959**	**95,003**

As of December 2011, approximately 8,300PJ of 2P gas reserves in the eastern market were domestically contracted/earmarked, equivalent to just over 10 years of production coverage assuming a 700PJ per annum demand level (Table 15). 40,298PJ (76.6%) of gas was contracted/earmarked for LNG export. Approximately 4,000PJ of gas was uncommitted, being available for either the domestic or export market.[49]

Table 15: Contract status of 2P gas reserves in the eastern market[50]

Reserves	Total 2P	Domestic		LNG		Uncommitted
		Contracted	Earmarked	Contracted	Earmarked	
Conventional	7,344	3,141	220	750	607	2,625
CSG	41,154	3,324	1,595	26,168	12,773	1,419
Total	48,497	6,465	1,815	26,918	13,380	4,043

[48] Adapted from: Core Energy Group, op. cit.

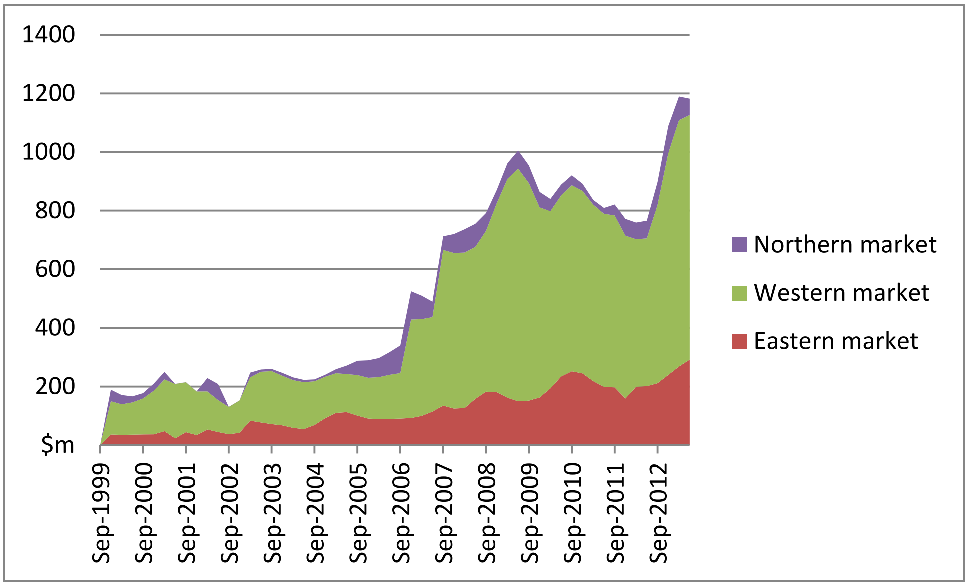
[49] Uncommitted volumes are defined as uncontracted volumes less any volumes that are likely to be used in a specific market. Reserves held by gas retailers (TRUenergy, AGL and Origin Energy) are assumed to be committed or earmarked for use in the domestic market. Reserves held by companies with committed or proposed LNG projects (APLNG, BG, GLNG and Arrow Energy) are assumed to be committed or earmarked for use in the export market.

[50] Source: Core Energy Group, op. cit.. Note that the original report contains an error that has been replicated in this paper – the breakdown of 2P CSG by contract status does not equate to the reported total in the second column. The error has been carried over because the authors are unable to ascertain exactly where the error lies in order to correct it. The percentages given in the text assume a different total for 2P gas reserves, in accordance with the error, of 52,621PJ.

3.2 Exploration

Petroleum exploration expenditure, which includes gas exploration expenditure, reached an all-time high in the eastern market in June 2013 of $301.6 million, up by $265.3 million in the fifteen years since September 1999 (Figure 8). This represents 26.5% of all Australian petroleum exploration expenditure. Also in June 2013, $799.8 million (70.3%) was spent in the western market, slightly down from a high of $840.3 million in December 2012, and $35.9 million in the northern market.

Figure 8: Petroleum exploration expenditure by market (June 2013; trend data)[51]



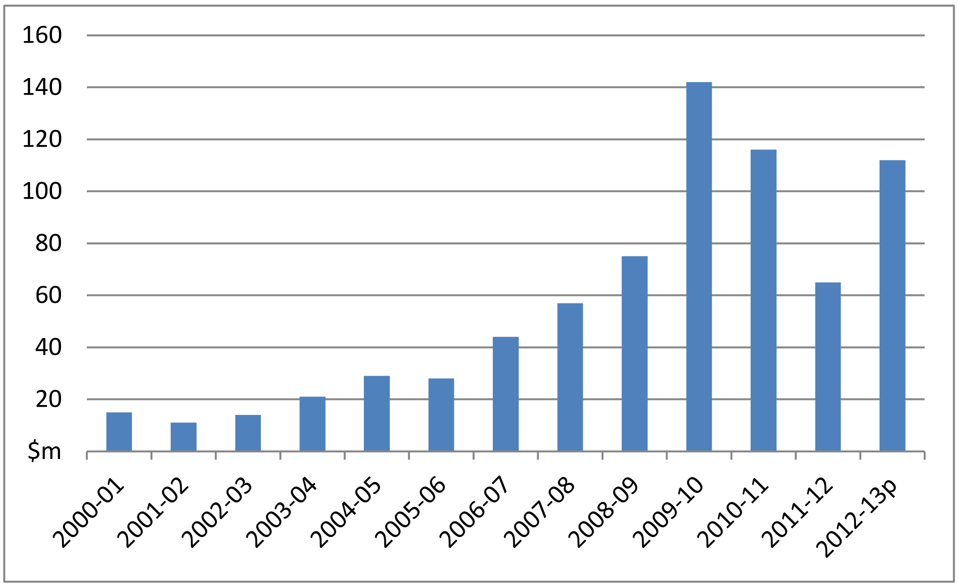
While exploration expenditure in the eastern market has increased in recent years, the converse is true of NSW (Figure 9). From an all-time high of $142 million in 2009-10, expenditure fell to $65 million in 2011-12. The NSW Government considers that this may be due in part to the moratorium on Petroleum Exploration Licence (PEL) grants and renewals introduced in March 2011 prior to the release of the Strategic Regional Land Use Policy. Expenditure was projected to rise to $112 million in 2012-13 according to work program commitments.[52]

---

[51] Source: ABS, *Mineral and Petroleum Expenditure, Australia*, Cat. No. 8412.0, June 2013

[52] NSW Department of Trade & Investment, Regional Infrastructure & Services, *2013 New South Wales Minerals Industry Profile*, 2013

Figure 9: Petroleum exploration expenditure in NSW (2011-12)[53]



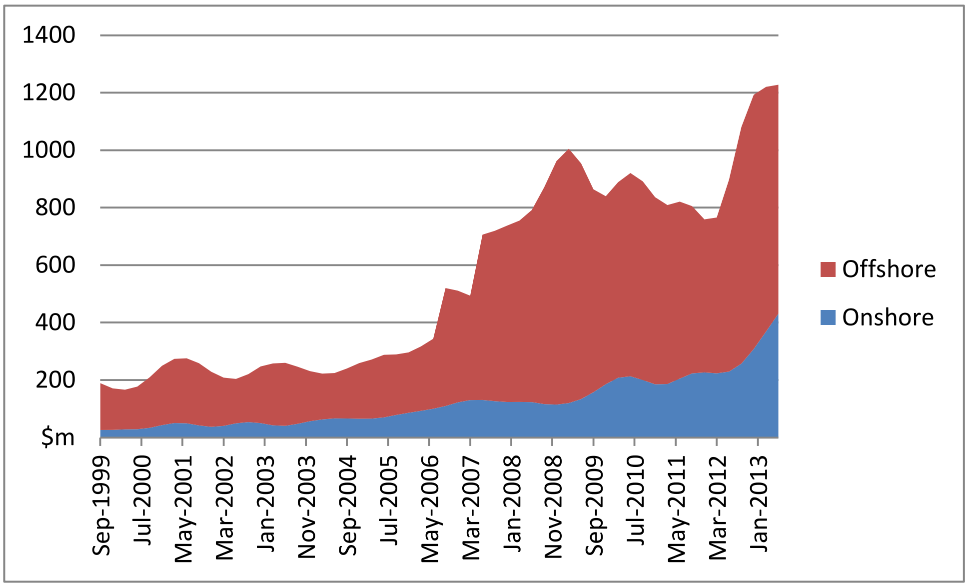
According to the NSW Department of Trade & Investment, Regional Infrastructure & Services (DTIRIS):

> NSW remains significantly under-explored for petroleum resources, both conventional and CSG, compared to neighbouring States. Geophysical surveys, studies and basin evaluation undertaken by the government through pre-competitive initiative funding have demonstrated that the sedimentary basins in NSW have all the elements of petroleum systems suitable for the generation of oil and gas. Many of the geological formations and sedimentary basins that host economic gas and oil production in South Australia and Queensland extend into NSW. Recent discoveries in Queensland are closely located to the border with NSW.[54]

Historically, onshore petroleum exploration expenditure in Australia has been significantly lower than offshore expenditure (Figure 10). However, while offshore exploration has fluctuated considerably over the past five years, onshore exploration has progressively risen to make up 35% ($431m) of total expenditure as of June 2013, up from a low of 12% ($115m) in December 2008.

[53] Ibid.
[54] Ibid.

Figure 10: Petroleum exploration in Australia (June 2013; trend data)[55]



3.2.1 Gas titles in NSW

As of 1 November 2013, there were 47 current petroleum titles in NSW (Table 16). Of these, 39 were petroleum exploration licences (PEL) and 6 were petroleum production leases (PPL). A further 19 title applications were with the Department awaiting assessment, two of which were production leases.

Table 16: Petroleum titles in NSW (November 2013)[56]

Title	Number
Petroleum title applications	
Petroleum Exploration Licence Application (PELA)	10
Petroleum Production Lease Application (PPLA)	2
Petroleum Special Prospecting Authority (PSPAPP)	7
Total	**19**
Current titles	
Petroleum Assessment Lease (PAL)	1
Petroleum Exploration Licence (PEL)	39
Petroleum Exploration Permit (PEP)	1
Petroleum Production Lease (PPL)	6
Total	**47**

[55] Source: ABS, op. cit.

[56] NSW Department of Trade & Investment, Regional Infrastructure & Services, *Petroleum Titles*, Petroleum Titles and Applications Current as at 1 November 2013. Note: Petroleum Exploration Licences (PELs) are granted under the *Petroleum (Onshore) Act 1991* (NSW) for onshore resources. Petroleum Exploration Permits (PEPs) are granted under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth) for offshore resources.

AGL holds the largest number of petroleum titles, being in possession of five exploration licences and five production licences, with one production licence application pending (Table 17). Santos is the only other company in possession of a current production licence. Two production licences submitted by Metgasco and AGL are being assessed.

Table 17: Petroleum titles in NSW by selected company (November 2013)[57]

Company	PELA	PPL A	PSP-APP	PAL	PEL	PEP	PPL	Total
AGL	-	1	-	-	5	-	5	11
Apex Energy	-	-	-	-	3	-	-	3
Clarence Moreton Resources	-	-	1	-	3	-	-	4
Comet Ridge	1	-	-	-	3	-	-	4
Leichhardt Resources	-	-	-	-	3	-	-	3
Macquarie Energy	-	-	-	-	7	-	-	7
Metgasco	1	1	-	-	3	-	-	5
NSW Aboriginal Land Council	1	-	4	-	-	-	-	5
Petro Tech	3	-	-	-	-	-	-	3
Santos	-	-	-	1	6	-	1	8
Other	4	-	2	-	6	1	-	13
Total	10	2	7	1	39	1	6	66

3.3 Production

In 2011-12, Australia produced 17,460PJ of primary energy (Table 18). Of this amount, gas accounted for 2,270PJ (13%). Gas production has increased by 8.3% per annum on average over the past five years. In comparison, total primary energy production has decreased on average by -0.3% per annum over the past five years.

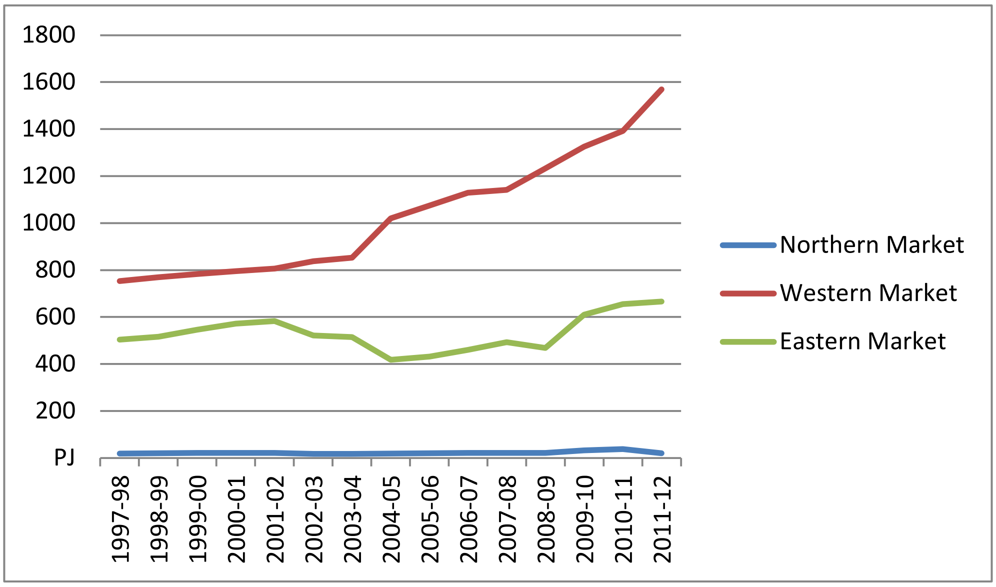
[57] NSW Department of Trade & Investment, Regional Infrastructure & Services, *Petroleum Titles*, Petroleum Titles and Applications Current as at 1 November 2013. The companies listed here are the top ten by total number of applications/titles. The Department published a map of petroleum projects and exploration highlights in NSW in May 2013, which is available online.

Table 18: Australian energy production by fuel type[58]

Fuel	PJ	Growth (%)		Share (%)
	2011-12	2010-11 to 2011-12	5 year average annual growth	2011-12
Black coal	9,672	5.3%	2.4%	55.4%
Brown coal	735	5.7%	0.6%	4.2%
Oil and LPG	994	-6.2%	-1.4%	5.7%
Gas	2,270	8.4%	8.3%	13.0%
Uranium oxide	3,525	6.1%	-9.3%	20.2%
Renewables	265	-7.3%	-2.8%	1.5%
Total	17,460	4.9%	-0.3%	100%

In 2011-12, 2,256PJ[59] of gas was produced in Australia. Of this amount, 667 PJ (29.6%) was produced in the eastern market. The drop in eastern market gas production between 2001-02 and 2008-09 occurred because of the dramatic fall in South Australian production over this period (Figure 11). Subsequent growth has been driven by a ramp up in production for LNG in Queensland. Annual gas production in the western market has risen steadily between 1997-98 and 2011-12 from 753PJ to 1,569PJ.

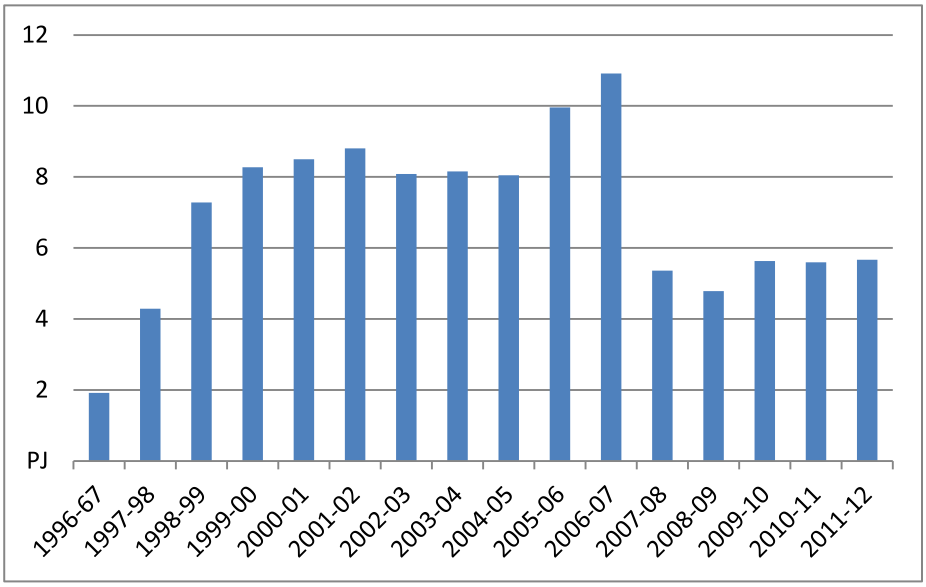
Figure 11: Gas production by market[60]



[58] Bureau of Resources and Energy Economics, *2013 Australian Energy Update*, July 2013
[59] Note that this is differs slightly to Table 18 as a different source was used.
[60] Source: Bureau of Resources and Energy Economics, *2013 Australian Energy Update*, Table H, July 2013. Note that this does not include gas from the Joint Petroleum Development Area used in Darwin LNG.

Gas production in NSW has been relatively insignificant compared to production in other States (Figure 12). It first began in 1996-97, at which time only 2PJ were produced. As at 2011-12, NSW gas production only accounted for 0.9% of total eastern market gas production.

Figure 12: Gas production in NSW[61]



Australian gas production is projected to nearly triple between 2012-13 and 2049-50, from 3,023PJ to 8,595PJ (Table 19). The western market is expected to grow by 2.2 per cent a year between 2012-13 and 2049-50, driven by strong growth in both domestic and global demand for gas. Projected growth in the eastern market of 3.2 per cent a year is also expected to be driven by both domestic and global demand. Several large LNG export projects are due to be completed in Queensland from 2014 onwards to supply gas to the international market. At the time the projections were published, BREE expected that domestic demand would drive increased gas production, with particular reference to an expected increase in gas-fired electricity generation. However, several stakeholders have noted recently that domestic consumption is likely to either remain steady or decline in the short term.[62]

[61] Bureau of Resources and Energy Economics, *2013 Australian Energy Update*, Table H, July 2013

[62] See for example: Australian Pipeline Industry Association, *Downstream Gas Supply and Availability in NSW (Inquiry)*, Submission, 21 June 2013

Table 19: Australian gas production projections[63]

Market	Production			% share of total		Average annual growth 12-13 to 49-50
	2012-13	2034-35	2049-50	2012-13	2049-50	
Eastern	1,006	2,836	3,267	33%	38%	3.2%
Western	1,777	3,982	4,036	59%	47%	2.2%
Northern	240	1,274	1,293	8%	15%	4.7%
Total	3,023	8,092	8,595	100%	100%	2.9%

3.4 Domestic consumption

In 2011-12, Australia consumed 1,401PJ of gas (Table 20). 839PJ was consumed in the eastern market and, of this amount, 165PJ was consumed in NSW. Gas consumption in NSW has increased by an average of 6.1 per cent a year between 2007-08 and 2011-12, higher than the eastern market average growth rate of 2.5 per cent a year. Despite this growth rate exceeding all other jurisdictions except for the Northern Territory, NSW still has the lowest share of gas consumption as a percentage of its total energy consumption (10%).

Table 20: Domestic gas consumption[64]

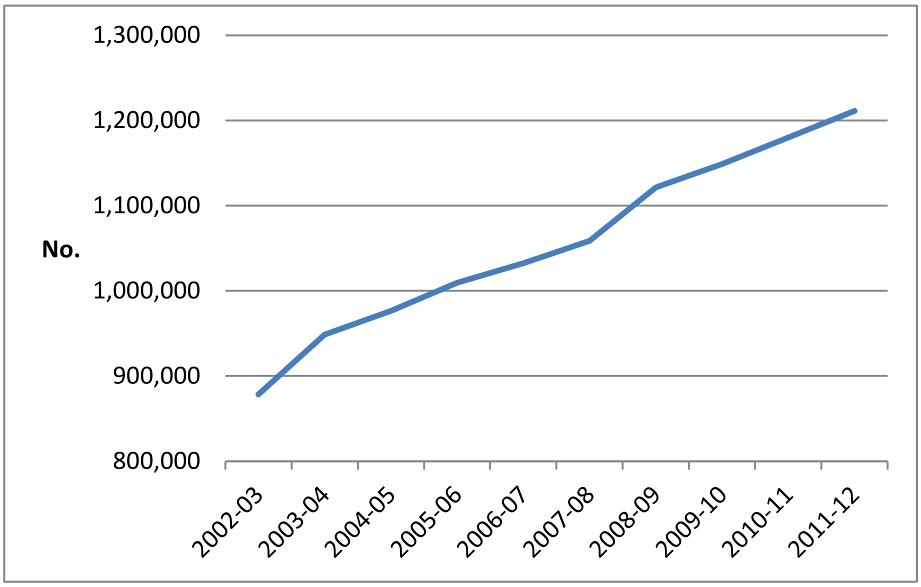
	2011-12 (PJ)	% of total gas consumption	Average annual growth 2007-08 to 2011-12	% of total energy consumption
Eastern Market	839	59.9%	2.5%	16.6%
NSW	165	11.8%	6.1%	10.0%
Western Market	479	34.2%	0.8%	47.2%
Northern Market	62	4.4%	18.5%	49.6%
Australia	1,401	100.0%	1.8%	22.6%

Total gas consumer connections in NSW have risen an average of 3.6 per cent per annum between 2002-03 and 2011-12 (Figure 13). By the end of 2011-12, there were a total of 1,211,172 gas consumer connections in NSW.

[63] A Syed, *Australian Energy Projections to 2049-50*, Bureau of Resources and Energy Economics, December 2012, p.54. Note: These figures include imports from the Joint Petroleum Development Area, East Timor

[64] Bureau of Resources and Energy Economics, *2013 Australian Energy Update*, Table F, July 2013. Total gas consumption for the eastern, western and northern markets does not add up to the Australian figure. It is unclear from the original data why this is the case.

Figure 13: Total gas consumer connections in NSW[65]



In 2011-12, the most significant gas-consuming sectors in Australia and NSW were manufacturing and construction, and energy (Table 21). Mining is also a significant consumer of gas at the national scale, consuming 262.4PJ in 2011-12 (18.7%). However, it is a relatively minor gas consumer in NSW, consuming only 0.1PJ in 2011-12. Gas consumption for electricity production in NSW increased significantly between 2007-08 and 2011-12, by 29.4 per cent a year.

Table 21: Gas consumption by sector in Australia and NSW[66]

Sector	Australia			NSW		
	2011-12	% of total	Av ann growth 07-08 to 11-12	2011-12	% of total	Av ann growth 07-08 to 11-12
Agriculture	0.1	0.0%	0.4%	0.0	0.0%	0.0%
Mining	262.4	18.7%	6.0%	0.1	0.1%	-42.3%
Manufacturing and construction	455.9	32.6%	-0.1%	81.0	49.1%	0.3%
Energy	456.9	32.6%	4.5%	47.1	28.5%	29.4%
Transport	21.9	1.6%	3.6%	1.5	0.9%	1.7%
Commercial	52.6	3.8%	4.7%	10.2	6.2%	1.2%
Residential	150.8	10.8%	2.5%	25.1	15.2%	4.2%
Total	1,400.6	100.0%	1.8%	165.0	100.0%	6.1%

65 NSW Department of Trade & Investment, Regional Infrastructure & Services, *Downstream Gas Supply and Availability in NSW Inquiry*, Submission, 16 August 2013

66 Bureau of Resources and Energy Economics, *2013 Australian Energy Update*, Table F, July 2013

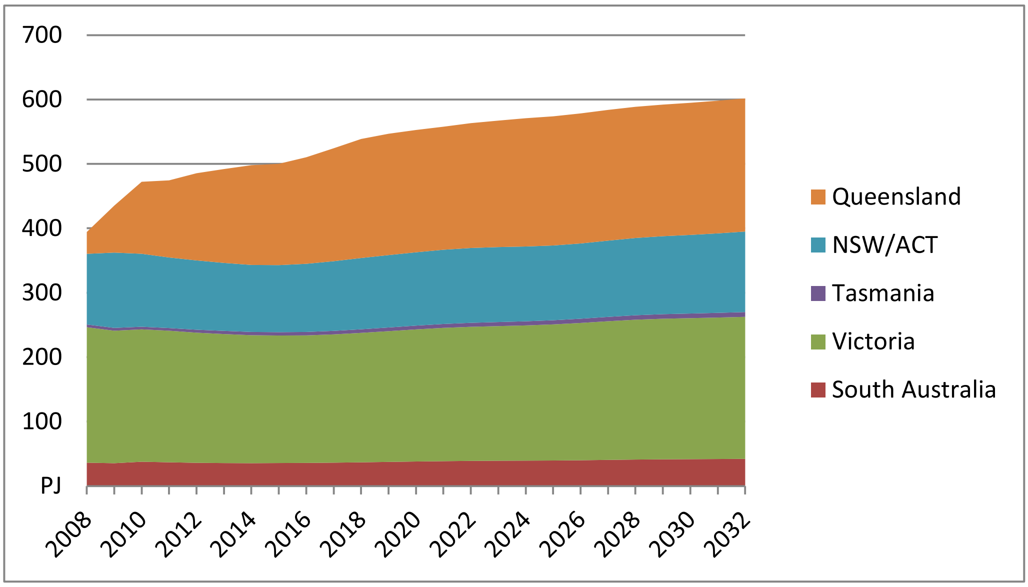
Between 2012-13 and 2049-50, Australian primary energy consumption is projected to increase at an average annual rate of 0.5 per cent (Table 22). Of all non-renewables, gas consumption is expected to increase the most at an average annual rate of 1.3 per cent from 1,552PJ to 2,469PJ.

Table 22: Primary energy consumption by energy type[67]

Energy type	Level (PJ)		Share (%)		Average annual growth 2012-13 to 2049-50 (%)
	2012-13	2049-50	2012-13	2049-50	
Non-renewables	**5,793**	**6,337**	**95%**	**86%**	**0.2%**
Black coal	1,212	478	20%	6%	-2.5%
Gas	1,552	2,469	26%	34%	1.3%
Renewables	**276**	**1,032**	**5%**	**14%**	**3.6%**
Total	**6,069**	**7,369**	**100%**	**100%**	**0.5%**

Gas consumption in the eastern market is expected to increase from 486PJ in 2012 to 602PJ in 2032 (Figure 14).[68] Gas consumption in NSW is expected to decline marginally, from 108PJ in 2012 to 104PJ in 2015, before rising to 125PJ in 2032.

Figure 14: Projected gas demand in the eastern market[69]



[67] Adapted from: A Syed, *Australian Energy Projections to 2049-50*, Bureau of Resources and Energy Economics, December 2012, p.36

[68] Note that the AEMO consumption figures appear radically different from BREE consumption figures cited earlier. It is unclear why this is the case.

[69] Australian Energy Market Operator, *Gas Statement of Opportunities 2012*, 11 December 2012; Planning Scenario data. Note: 2008 to 2012 figures are actual figures; 2013 to 2032 figures are projections.

The Australian Energy Market Operator (AEMO) uses two scenarios to explore gas demand projections:

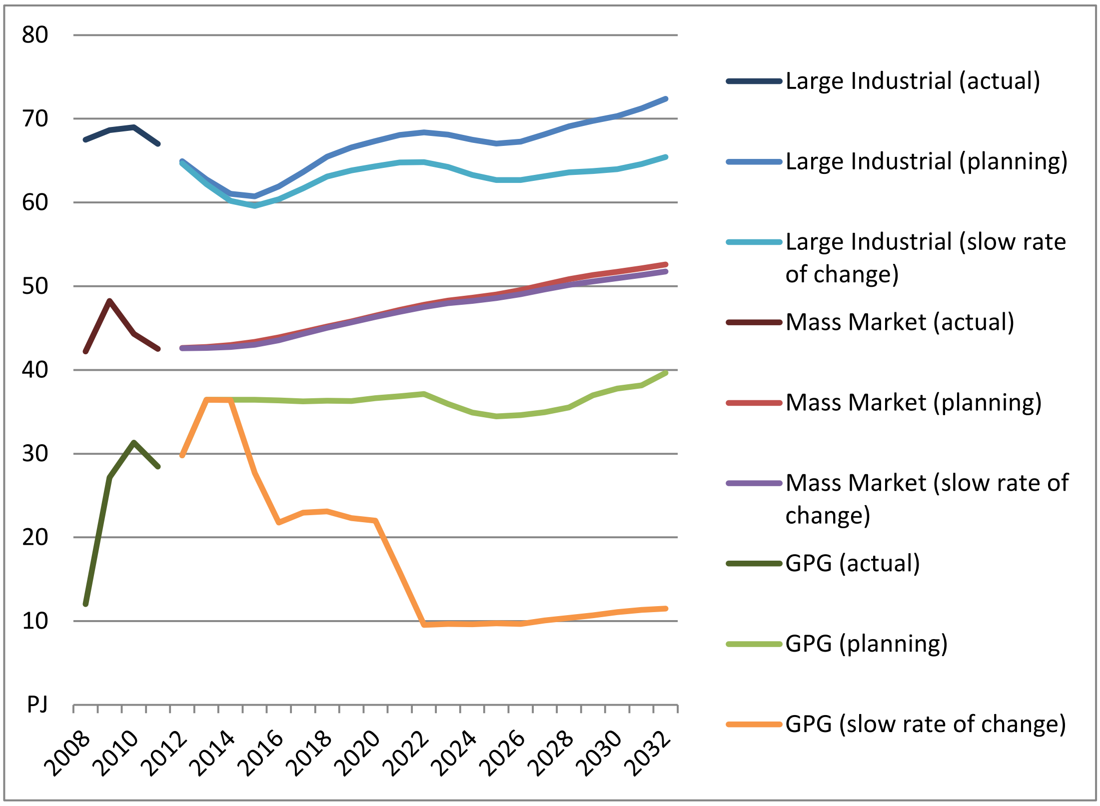
- Planning: a central growth scenario, which includes the expected economic effects of currently legislated carbon policies, as well as currently estimated rates of new technology development
- Slow rate of change: this scenario reflects a lower rate of economic growth, which enables Australia to meet its international emissions targets with minimal effort. Under this scenario, the Australian carbon price effectively drops to zero after the three-year fixed price period.[70]

With regard to gas demand in NSW (Figure 15), the AEMO expects that:

- Large Industrial demand will decline until 2015 due to a series of announced industrial closures, followed by a period of moderate growth;
- Mass Market (residential, commercial and small industrial) demand is expected to grow by 1.1 per cent per annum under each scenario; and
- Gas Powered Generation (GPG) demand differs widely under the two scenarios. Under the Planning scenario, demand is expected to increase from 30PJ in 2012 to 40PJ in 2032. Under the Slow Rate of Change scenario, annual GPG demand reaches a minimum of 9.5PJ per annum in 2022, less than half of current levels, before growing slowly to 11.5PJ by 2032.[71]

[70] Ibid.
[71] Ibid.

Figure 15: Annual demand projections by segment and scenario for NSW (incl the ACT)[72]



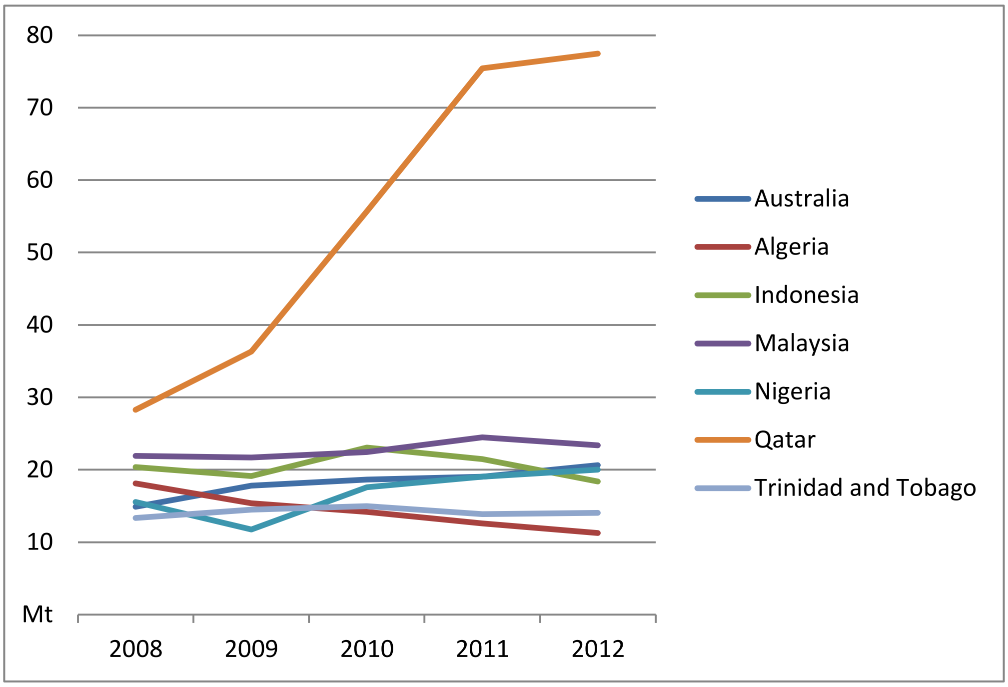
3.5 Exports

In 2012, Australia was the third largest LNG exporter in the world (Figure 16). It exported 20.7Mt of LNG, equal to 8.6% of total world LNG exports. In 2008, it was the sixth largest exporter, having exported 14.9Mt of LNG.[73]

[72] Ibid.

[73] 1 Mt of LNG is equivalent to 52.79PJ of gas (Bureau of Resources and Energy Economics, *Gas Market Report 2013*, October 2013)

Figure 16: LNG exports by country[74]



Historically, Japan has been the largest consumer of Australian LNG (Table 23). In 2012, Australia exported 15.9Mt of LNG to Japan, 76.9% of total LNG exports.

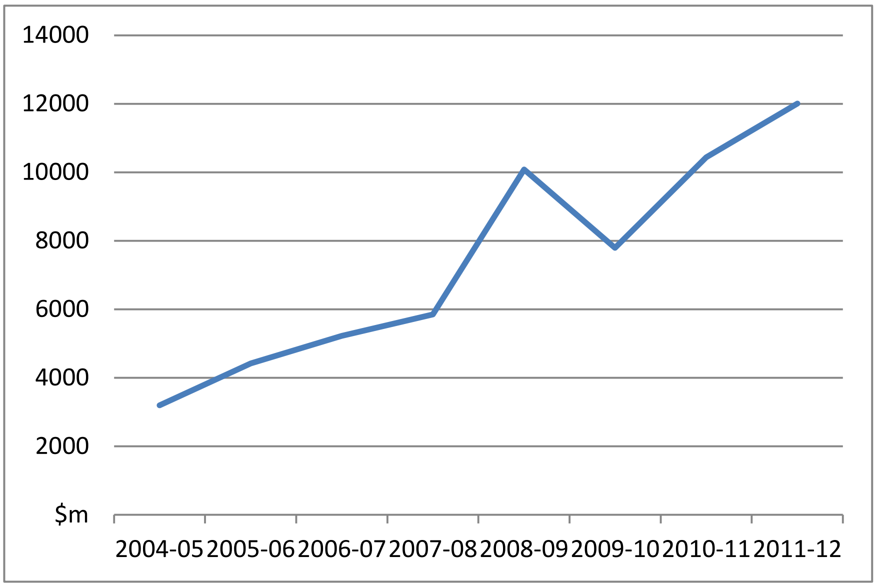
Table 23: Australian LNG exports by country[75]

Country	Amount (Mt)		Share of total (%)	
	2002	2012	2002	2012
Middle East	0.0	0.1	0.0%	0.4%
China	0.0	3.5	0.0%	17.1%
Japan	7.1	15.9	96.9%	76.9%
South Korea	0.2	0.8	2.4%	3.9%
Taiwan	0.0	0.2	0.0%	1.1%
Spain	0.1	0.0	0.7%	0.0%
Total	7.4	20.7	100.0%	100.0%

The value of Australian LNG exports has increased dramatically, rising at an average annual growth rate of 20.8 per cent between 2004-05 and 2011-12 (Figure 17). In 2011-12, LNG exports were valued at $12 billion, up from $3.2 billion in 2004-05.

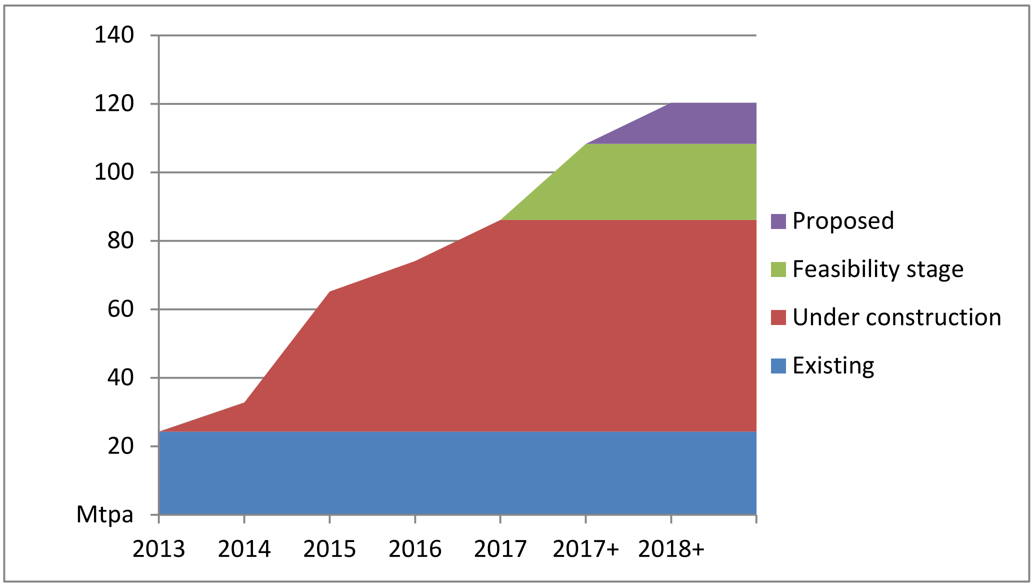
[74] Source: BP, *Statistical Review of World Energy*, 2008 to 2013
[75] Ibid.

Figure 17: Value of Australian LNG exports[76]



Australia's LNG export capacity is expected to undergo rapid expansion over the next five years, rising from 24.3 million tonnes per annum (Mtpa) in 2013 to 120.3 Mtpa after 2018 (Figure 18). If brought into operation, these projects will make Australia one of the world's largest LNG exporters by the end of the decade.

Figure 18: Projected LNG export capacity[77]

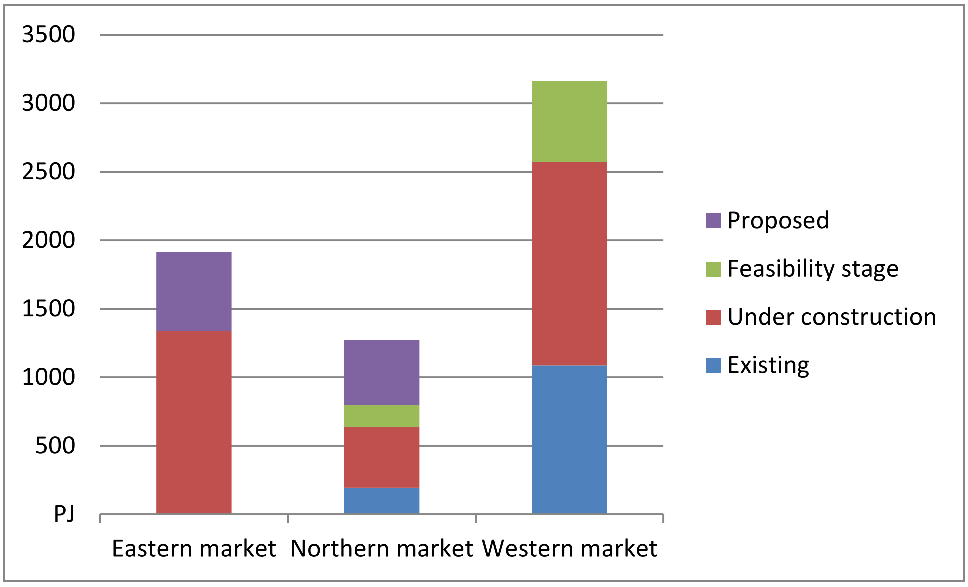


[76] G Armitage, *Resources and Energy Statistics 2012*, Bureau of Resources and Energy Economics, December 2012

[77] Bureau of Resources and Energy Economics, *Gas Market Report*, October 2013

Broken down by gas market, the western market contains 50 per cent (59.9Mtpa) of total LNG export capacity that may be in place after 2018 (Figure 19). 30 per cent (36.3Mtpa) of LNG export capacity is expected to be built in the eastern market.

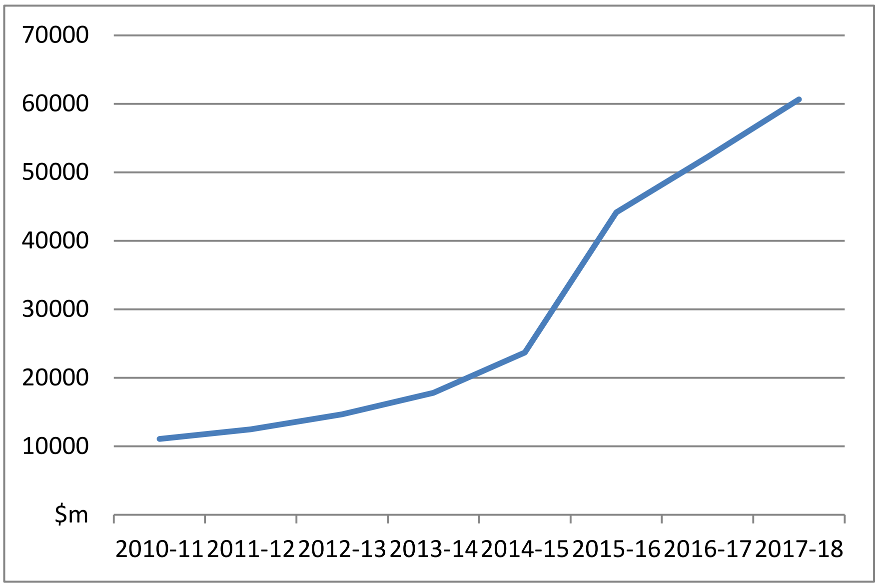
Figure 19: Projected LNG export capacity by market[78]



In line with the projected expansion in LNG export capacity, the value of LNG exports will increase markedly in the near future (Figure 20). BREE projections show that LNG export value will increase from $14.7 billion in 2012-13 to $60.6 billion 2017-18, an average annual growth rate of 32.8%.

[78] Ibid.

Figure 20: Gas LNG export value ($A2013-14; real)[79]



3.6 Prices

In 2011-12, the average Victorian wholesale gas spot price was $3.42/GJ (Table 24).[80] While prices have been relatively affordable in recent years, they are expected to increase over the next couple of years as LNG exports commence from the eastern market. Over the past five years, LNG prices have been significantly higher than domestic wholesale prices. For example, in 2011-12, LNG prices were over three times greater than the Victorian domestic price.

Table 24: Australian gas prices ($A2011-12; real)[81]

	2007-08	2008-09	2009-10	2010-11	2011-12
Wholesale gas ($/GJ)	$4.12	$3.52	$2.10	$2.43	$3.42
LNG ($/GJ)	$8.56	$12.68	$8.26	$9.61	$11.46

In 2012, the NSW gas retail cost was just below $25/GJ, lower than Queensland and South Australia but double the Victorian price (Figure 21). Breaking down the NSW retail price, the wholesale gas, pipeline and retail costs respectively comprise 33%, 47% and 20% of the total price. The Victorian price is significantly lower in part because Victorian consumers are much closer to major supply sources compared with the other States.

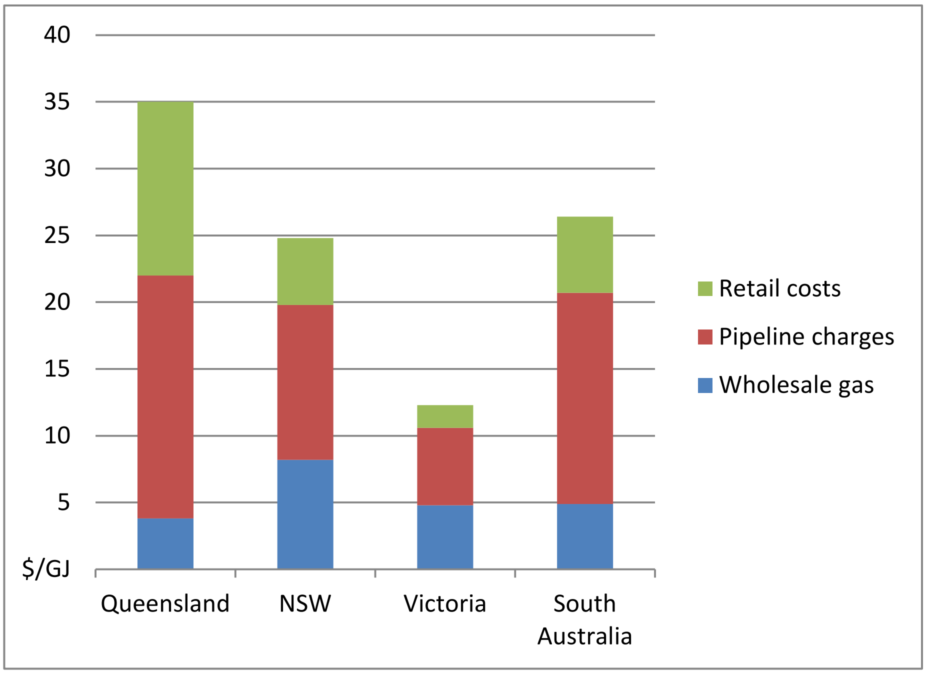
---

79 Bureau of Resources and Energy Economics, *Resources and Energy Quarterly*, September Quarter 2013, October 2013

80 See Chapter 10 of this paper for a more detailed examination of Australian wholesale gas prices.

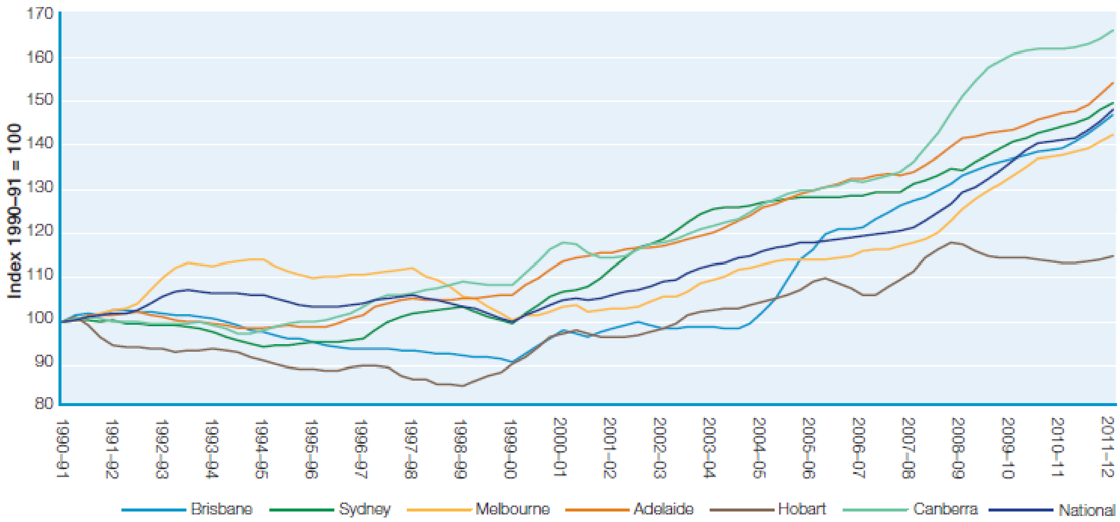
81 Bureau of Resources and Energy Economics, *Energy in Australia 2013*, 2013. Note: The wholesale gas price is the average Victorian wholesale gas spot price

Figure 21: Comparison of residential gas cost components across eastern Australia (2012)[82]



Aside from Canberra and Hobart, the gas price indexes of all Australian capital cities have risen by a similar amount between 1990-91 and 2011-12 (Figure 22).

Figure 22: Gas retail price index (inflation adjusted) – Australian capital cities[83]



82 Victorian Gas Market Taskforce, *Gas Market Taskforce Supplementary Report*, October 2013, p.85

83 Australian Energy Regulator, *State of the Energy Market 2012*, 2012. Note: Consumer price index gas series, deflated by the consumer price index for all groups

In 2012-13, a regulated gas bill for a typical residential customer varied between $822 and $1,217 per annum, depending on gas retailer (Table 25).[84] IPART expects that the average annual gas bill will rise by between $46 and $76 between 2012-13 and 2013-14.

Table 25: Indicative annual bill for typical residential customers of each Standard Retailer in NSW (nominal $; inc GST)[85]

Retailer	2009-10	2012-13	Average annual growth 2009-10 to 2012-13	Estimated 2013-14	% growth 2012-13 to 2013-14
AGL	$618	$822	10.0%	$898	9.2%
ActewAGL	$1,141	$1,217	2.2%	$1,283	5.4%
Origin Energy (Wagga Wagga)	$919	$965	1.7%	$1,021	5.8%
Origin Energy (Albury/Murray Valley)	$743	$886	6.0%	$933	5.3%

Regulated business bills have risen at a lower rate than residential bills between 2009-10 and 2012-13 (Table 26). In 2012-13, regulated gas bills for a typical business customer ranged between $3,133 and $4,423 per annum, depending on gas retailer. IPART expects regulated gas bills for businesses to increase between 2012-13 and 2013-14 at roughly the same rate as bills for residential customers.

[84] See Chapter 4.2 for information on retail price regulation

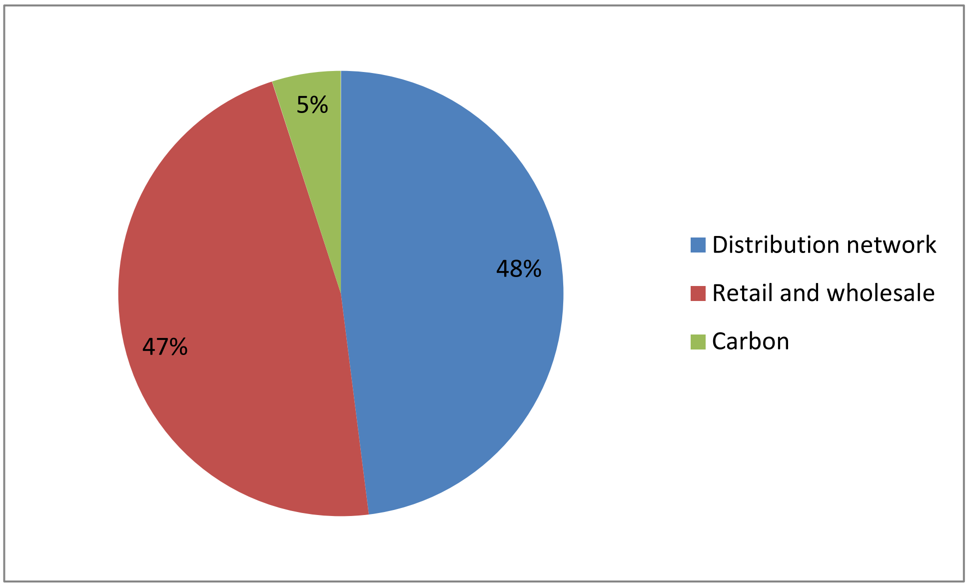
[85] Sources: Independent Pricing and Regulatory Tribunal, *Review of regulated retail tariffs and charges for gas 2010-2013*, Final Report, June 2010; Independent Pricing and Regulatory Tribunal, *Review of regulated retail prices and charges for gas From 1 July 2013 to 30 June 2016*, Final Report, June 2013. Notes: Origin Energy bought Country Energy in 2011. Country Energy supplied gas to several South Western areas of NSW, including Wagga Wagga, Gundagai and Tamworth. These customers are referred to as Origin Energy (Wagga Wagga). This Table assumes a typical customer uses 23GJ, 45GJ, 37GJ and 45GJ of gas per annum in the AGL, ActewAGL, Origin Energy (Wagga Wagga) and Origin Energy (Albury/Murray Valley) areas respectively. Bills are for regulated prices.

Table 26: Indicative annual bill for typical business customers of each Standard Retailer in NSW (nominal $; inc GST)[86]

Retailer	2009-10	2012-13	Average annual growth 2009-10 to 2012-13	Estimated 2013-14	% growth 2012-13 to 2013-14
AGL	$3,460	$3,864	3.7%	$4,220	9.2%
ActewAGL	$4,139	$4,423	2.2%	$4,665	5.5%
Origin Energy (Wagga Wagga)	$2,791	$3,262	5.3%	$3,452	5.8%
Origin Energy (Albury/Murray Valley)	$3,462	$3,133	-3.3%	$3,296	5.2%

According to IPART, network costs will contribute to 48% of the total increase in gas costs between 2012-13 and 2013-14 (Figure 23). Retail and wholesale costs make up 47% of the increase, with the carbon component to account for the remaining 5%.

Figure 23: Drivers of increase in average regulated retail gas prices for AGL on 1 July 2013 (nominal)[87]



[86] Sources: Independent Pricing and Regulatory Tribunal, *Review of regulated retail tariffs and charges for gas 2010-2013*, Final Report, June 2010; Independent Pricing and Regulatory Tribunal, *Review of regulated retail prices and charges for gas From 1 July 2013 to 30 June 2016*, Final Report, June 2013

[87] Independent Pricing and Regulatory Tribunal, *Review of regulated retail prices and charges for gas From 1 July 2013 to 30 June 2016*, Final Report, June 2013

4. GAS POLICY IN AUSTRALIA

This chapter briefly considers a history of key gas developments in Australia. While particular attention is given to domestic gas reservation policy developments and related issues, detail of the most recent debate and events in this field is left for Part Two of this paper. The regulatory frameworks for upstream and downstream petroleum are set out at the end of the chapter.

4.1 History

Government involvement in the gas industry takes place for several reasons:

- to encourage the development of energy resources in a manner which maximises 'national' or 'State' interests;
- to achieve energy security by ensuring the continued availability of energy to satisfy domestic demand at reasonably stable prices;
- to set the terms on which firms explore for and produce gas, which is owned by the Crown until recovered;
- the natural monopoly characteristics of gas transmission and distribution create both economic and political rationales for government involvement; and
- to regulate the externalities that may arise from gas development, such as pollution or environmental damage, or threats to public/employee safety.[88]

Two economic ideologies have influenced gas developments in Australia: economic nationalism and economic liberalism.[89] Nationalism emphasises national industrial capacity and self-sufficiency while liberalism stresses the importance of free trade and market forces. Key differences exist between each when it comes to responses to the reasons for government involvement in the gas industry. For example, with regards to energy security, nationalism advocates adoption of domestic gas reservation, while liberalism argues that a robust gas market will produce the desired goal.

Gas was first discovered in Australia at Roma, Queensland in 1900 (Table 27). Since then, significant discoveries of gas have been made in all Australian States and Territories except for Tasmania. Gas production did not commence until much later, starting in Queensland in 1961-62, Western Australia in 1966-67, Victoria in 1968-69, South Australia in 1969-70 and the Northern Territory in 1983-84. Natural gas production began in NSW in 1996-97, at which time only 2PJ were produced. In 2001, coal seam gas production commenced at Camden, Sydney. Production in NSW peaked at 11PJ in 2006-07 and has since

[88] Industry Commission, *Study into the Australian gas industry and markets*, 6 March 1995; Productivity Commission, *Review of the regulatory burden on the upstream petroleum (oil and gas) sector*, Research Report, April 2009; J.L. Hay, Challenges to liberalism: The case of Australian energy policy, 2009, *Resources Policy*, Vol 34(3): 142-149

[89] J.L. Hay, op. cit.

declined to just under 6PJ per annum as of 2011-12.[90]

Table 27: Timeline of key gas developments[91]

Date	Event
1837	A private Act establishes the Australian Gas Light Company (AGL)
1837	Reticulated town gas first provided in Sydney
1900	First discovery of natural gas at Roma in Queensland
1912	*1912 Gas Act* (NSW)
1935	*Gas and Electricity Act 1935* (NSW)
1961-62	First production of natural gas in Queensland
1966-67	First production of natural gas in Western Australia
1968-69	First production of natural gas in Victoria
1969-70	First production of natural gas in South Australia
1973	Commonwealth legislation establishes the Pipeline Authority, to create the Moomba (SA) to Sydney pipeline
1976	Moomba to Sydney pipeline completed
1977	Commonwealth Ministerial Statement to the effect that gas exports will be permitted in future once the Government is satisfied that domestic requirements have been considered
1977	Approval for LNG exports from the North West Shelf (NWS) first granted, together with tax concessions
1979	*North West Gas Development (Woodside) Agreement Act 1979* (WA) notes that the Commonwealth has approved the sale of up to 6.5 million tonnes per annum of LNG over a term of not less than 20 years
1983-84	First production of natural gas in Northern Territory
1984	Domestic gas from NWS project first produced
1985	*Natural Gas (Interim Supply) Act 1985* (SA) reserves gas for domestic consumption
1986	*Gas Act 1986* (NSW), included the Third Party Access Code for Natural Gas Distribution Networks

---

[90] Bureau of Resources and Energy Economics, *2013 Australian Energy Update*, Table H, July 2013

[91] Sources: R Wilkinson, *A thirst for burning: The story of Australia's oil industry*, Revised Ed. 1988, David Ell Press, Sydney; Industry Commission, op. cit.; I Ireland and P Kay, *Gas Pipelines Access (Commonwealth) Bill 1997*, Bills Digest No.126 1997-98, Commonwealth Parliamentary Library, 1997; Productivity Commission, *Review of the gas access regime*, Inquiry Report No.31, June 2004; MMA, *Report to the Joint Working Group on Natural Gas Supply*, 16 July 2007; Productivity Commission, *Review of the regulatory burden on the upstream petroleum (oil and gas) sector*, Research Report, April 2009; WA Economics and Industry Standing Committee, *Inquiry into domestic gas prices*, Report No.6, March 2011; SKM MMA, *WA domestic gas market analysis for the Strategic Energy Initiative*, SKM Report to Office of Energy, 5 May 2011; Australian Government, *Energy White Paper 2012*, Department of Resources, Energy and Tourism, 2012; Bureau of Resources and Energy Economics, *2013 Australian energy statistics update*, 2013; NSW Government, *History of mining, oil and gas production in NSW*, no date [online – accessed 26 November 2013]

Date	Event
1988	*Gas Act Amendment Act 1988* (Qld) provides for the Governor in Council to do 'all acts and things necessary' to ensure sufficiency of gas supply
1989-90	First Australian LNG exports (via two LNG trains connected to the North West Shelf Project, WA)
1991	A National Strategy for the Natural Gas Industry
1992	Third LNG train constructed in WA
1993	Joint Study on the long term supply of natural gas for NSW: Report to the NSW Minister for Energy
1994	COAG agrees to the removal of all remaining legislative and regulatory barriers to the free trade of gas within and across jurisdictional boundaries by 1 July 1996: Agreement to Implement the National Competition Policy and Related Reforms included agreed implementation of the National Framework for Free and Fair Trade in Gas
1996-97	First production of natural gas in NSW
1997	National Third Party Access Code for Natural Gas Pipeline Systems approved by COAG
1997	Gas Pipeline Access Law
1997	Commonwealth control on LNG exports removed
1999	Victoria establishes the Declared Wholesale Gas Market (DWGM)
2001	NSW Camden coal seam gas production commences
2002	COAG Energy Market Review
2003	Inquiry: Exploring Australia's Future – impediments to increasing investment in minerals and petroleum exploration in Australia [House of Representatives Standing Committee on Industry and Resources]
2003	Ministerial Council on Energy (MCE) report to COAG: Reform of Energy Markets
2003	*Barrow Island Act 2003* (WA), Gorgon LNG project required to supply 2,000 PJ of natural gas for domestic use over the life of the project. Domgas plant with 300 TJ/day capacity to be constructed
2004	Expansion of gas program contained in the MCE 2003 report, Reform of Energy Markets
2004	Australian Energy Market Agreement signed by COAG to establish national energy market institutions
2004	Fourth LNG train constructed in WA
2005	Gas Market Leaders Group established by the MCE to develop actions to address market issues
2005-06	LNG first exported from NT (3.7 Mtpa)
2006	Policy on Securing Domestic Gas Supplies (WA)
2008	Gas Bulletin Board established for the eastern market
2008	National Gas Law and National Gas Rules enacted (replaces the Gas Access Code)
2008	Fifth LNG train constructed in WA
2009	Queensland releases its *Blueprint for Queensland's LNG Industry*, which flagged the possibility of a domestic gas reservation policy

Date	Event
2009	Queensland releases a consultation paper: *Domestic Gas Market Security of Supply*
2009	Queensland adopts its Prospective Gas Production Land Reserve (PGPLR) policy
2010	Gas Short-Term Trading Markets established in NSW and SA
2011	*Gas Security Amendment Act 2011* (Qld) implements the PGPLR policy
2011	Inquiry into domestic gas prices [WA Legislative Assembly Economics and Industry Committee]
2011	Gas Short-Term Trading Market established in Queensland
2012	*Gas Market Development Plan* [Standing Council on Energy and Resources]
2012	Coal seam gas inquiry [NSW Legislative Council General Purpose Standing Committee No. 5]
2012	Inquiry into the economics of energy generation [NSW Legislative Assembly Public Accounts Committee]
2012	Pluto LNG project – first LNG project subject to 2006 WA Domgas Policy, 15% of LNG production to be supplied to domestic market within 5 years of LNG exports commencing or after 30 million tonnes of LNG have been shipped (4.3 Mtpa)
2013	*Natural Gas (Canning Basin Joint Venture) Agreement Act 2013* (WA) provides that if commercially viable gas is discovered by mid-2016, the parties must submit a plan for construction of the domestic gas project
2013	Inquiry into Downstream gas supply and availability in NSW begins [NSW Legislative Assembly State and Regional Development Committee]
2013	Inquiry into the economic implications of floating liquefied natural gas operations begins [WA Legislative Assembly Economics and Industry Standing Committee]
2013	Inquiry into the implications for Western Australia of hydraulic fracturing for unconventional gas begins [WA Legislative Council Environment and Public Affairs Committee]
2013	Inquiry into key challenges and opportunities begins [NT Legislative Assembly Committee on the Northern Territory's Energy Future]
2014	Queensland Curtis LNG due for completion with capacity of 8.5 Mtpa
2014	Expected completion of a gas supply hub at Wallumbilla, Queensland

The 1970s were marked primarily by a nationalistic approach to gas policy. In 1973, the Whitlam Government established the National Pipeline Authority. It had a twofold purpose:

(1) To provide an integrated system of pipelines from gas sources to population centres and export points in Australia; and

(2) To ensure that adequate oil and gas reserves remained in the country to meet long-term requirements and to ensure uniform gas prices.[92]

The first activity of the Authority involved the construction of the Moomba-to-Sydney gas pipeline, which was completed in 1976 to transport gas from South Australia to NSW. Rex Connor, then Commonwealth Minister for Energy,

[92] R Wilkinson, op. cit.

envisaged this pipeline becoming one part of a 'national grid' of gas pipelines across Australia. A key objective of the grid was to transport gas from the North West Shelf to the eastern States. Connor was keenly concerned with ensuring national energy security. In 1973, he imposed an embargo on gas exports from the North West Shelf.[93]

In 1977, the Fraser Government lifted the embargo on granting export licences for gas from the North West Shelf (NWS), after bipartisan agreement was reached. On 24 August 1977, the Minister for National Resources stated:

> In considering proposals for the development of other gas fields in the future the Government will continue to give proper weight to domestic requirements. The Government has decided that it will continue its policy of allowing exports of reasonable quantities of gas but exports will be permitted only after the Government is satisfied that domestic requirements of gas and gas liquids, including petrochemical feedstocks, have been considered. Any proposals to meet domestic requirements would, of course, have to be realistic and economically justified.[94]

Government and industry agreed that the development of the NWS resources for either the domestic market alone or solely for export as LNG would not be economically viable.[95] In 1977, the WA Government negotiated an agreement with the North West Shelf JV Partners that was later ratified via the *North West Gas Development (Woodside) Agreement Act 1979*. The policy and financial assistance package secured both LNG and domestic gas (domgas) projects for the State. The assistance included infrastructure and land provision as well as tax and royalty concessions. To underwrite the development, the State Energy Commission of Western Australia (SECWA) entered into a contract to purchase approximately 414 TJ/day of gas for 20 years (3,020PJ in total) commencing in 1985. SECWA also funded the construction of a gas transmission pipeline from Dampier through to Bunbury. The 20 year sales agreement included a 95% take-or-pay level at a price comparable to the expected netback from the LNG development at the time. This proved expensive for the WA Government, because it paid for its daily commitment regardless of whether it took delivery of the full balance. The Government paid for a lot of gas that it did not need in the early years of the contract.[96]

During the 1980s, Australian energy policy began the transition from a nationalistic approach to a liberal one in line with the liberalisation and deregulation of the Australian economy as a whole. Most foreign ownership limitations were removed and energy infrastructure began to be privatised. Energy resources such as coal became a significant component of total

[93] Ibid.

[94] National Energy Advisory Committee, *Exploration for oil and gas in Australia*, Report No.6, December 1978, p.18

[95] SKM MMA, op. cit.

[96] MMA, op. cit.; WA Economics and Industry Standing Committee, op. cit.

Australian exports, and LNG exports commenced in 1989.[97] However, at the State level, most jurisdictions retained policies that effectively operated as barriers to interstate trade and competition in the industry (e.g. commercial retail franchises). In 1985, the South Australian Government introduced the *Natural Gas (Interim Supply) Act 1985* to ensure the future supply of natural gas to South Australia's industrial, commercial and domestic consumers. The Act reserved all natural gas for South Australia apart from that needed to ensure sales gas specifications were met. In 1988, Queensland introduced similar legislation to amend its *Gas Act 1965*, at a time when the Government held concerns about the limited supply of gas to the Queensland market. The Act empowered the Governor in Council to do 'all acts and things necessary' to ensure the sufficiency of gas supply. At this time, price and/or profit regulation also took place in most States (e.g. retail price regulation).[98]

A national approach to gas market reform commenced in 1991 with the release of A National Strategy for the Natural Gas Industry. Following this, COAG meetings in 1992, 1993 and 1994 considered the need to remove impediments to free and fair trade in gas. At the 1994 COAG meeting, all governments agreed to take steps to stimulate competition and achieve 'free and fair trade in natural gas'. The agreement had three goals:

(1) to remove policy and regulatory impediments to competition in the natural gas sector;

(2) to remove restrictions on interstate trade in natural gas; and

(3) to develop a nationally integrated and competitive natural gas market by establishing a national regulatory scheme for third party access to natural gas pipelines and thereby facilitate investment in exploration and development, and the interconnection of gas pipelines.[99]

By 1999, all Australian jurisdictions had completed the following reforms:

- publicly owned transmission and distribution entities had been corporatised and vertically separated; and
- privately owned transmission and distribution activities were isolated through ring-fencing.

The Natural Gas Pipelines Access Regime was also implemented. It comprised the Intergovernmental Natural Gas Pipeline Access Agreement, the Gas Pipelines Access Law and the National Third Party Access Code for Natural Gas Pipeline Systems. The Regime established a uniform national regulatory framework for third party access to natural gas transmission pipelines and distribution networks.[100]

[97] J.L. Hay, op. cit.
[98] Industry Commission, op. cit.
[99] Productivity Commission, *Review of the gas access regime*, Inquiry Report No.31, June 2004
[100] The Allen Consulting Group, *Options for the development of the Australian wholesale gas market*, Final Report, Report to the Ministerial Council on Energy Standing Committee of

Until 1997, Commonwealth approval of exports was required to ensure the adequacy of gas reserves and that prices received were satisfactory, including ensuring that transfer pricing did not occur. Federal controls on LNG exports were removed in 1997, when the Howard Government adopted the policy of allowing gas developers to sell their products into the markets of their choice.[101]

While the 2000s and early 2010s have seen further liberalisation of the gas industry, there has also been significant debate over the merits of a signature nationalistic gas policy option: domestic gas reservation.[102] National gas market reform progressed in the 2000s with the release of COAG's energy market review – *Towards a Truly National and Efficient Energy Market*. In response to the review, on 11 December 2003 the COAG Ministerial Council on Energy (MCE) submitted a report to COAG on reform of energy markets in which it made a number of relevant recommendations:

- development of a national legislative framework for governance of energy markets under a new inter-governmental agreement;
- establishment of two new statutory commissions: the Australian Energy Market Commission, with responsibility for rule-making and market development; and the Australian Energy Regulator, with responsibility for market regulation; and
- reform of the National Gas Access Regime upon receipt of the Productivity Commission review of the Regime.

It also noted that the Ministerial Council on Mineral and Petroleum Resources (MCMPR) was investigating:

- joint marketing of gas by producers;
- the treatment of unproduced areas in existing petroleum licences that are due for renewal; and
- the gas industry's principles for third party access to upstream facilities.[103]

The MCE submitted an expanded gas program to COAG on 19 May 2004, in which they committed to:

- working with industry to develop a high level agreement on the fundamental principles and design concepts for the gas market and examine options, such as increased transparency, to encourage new market entrants, promote further efficient investment in gas infrastructure and provide efficient management of supply and demand interruptions; and

Officials – Gas Market Development Working Group, June 2005

[101] MMA, op. cit.

[102] See Part Two of this paper for discussion of domestic gas reservation policies

[103] Ministerial Council on Energy, *Report to the Council of Australian Governments: Reform of Energy Markets*, 11 December 2003

- investigating the long-term security of supply of gas to Australian power generators and to industry.[104]

A new inter-governmental agreement was signed by COAG in 2004: the Australian Energy Market Agreement. Key developments since include introduction of the National Gas Law and National Gas Rules in 2008, the Gas Bulletin Board in 2008 and Short-Term Trading Markets in Sydney and Adelaide in 2010 and Brisbane in 2011.

Future policy developments are driven in large part by the COAG Standing Council on Energy and Resources (SCER) and the Australian Energy Market Commission (AEMC). SCER has identified three key areas of reform within its 2012 Gas Market Development Plan:

- an increased role for markets;
- improved information, key to which is establishment of a gas supply hub at Wallumbilla; and
- effective regulation.

It has also released a Regulation Impact Statement on Gas Transmission Pipeline Capacity Trading for consultation. The purpose of the Statement is to test the case and options for possible changes to the way in which unused natural gas transmission pipeline capacity is traded. The Statement expects that increased capacity trading would:

- efficiently re-allocate unused capacity and gas to higher-value uses;
- maximise the efficiency of capital stock;
- incentivise pipeline investment;
- create opportunities for gas trading;
- support gas market growth; and
- assist with bringing additional gas to market.

Four options were proposed:

- Option 1: status quo – no change;
- Option 2: improved information – provision of additional information and the standardisation of contractual terms and conditions;
- Option 3: voluntary trading platform – establishment of a capacity trading platform with market participants voluntarily offering up unused capacity for trade; or
- Option 4: mandatory trading obligation – shippers or pipeliners are

[104] Ministerial Council on Energy, *Supplement to the Ministerial Council on Energy Report to the Council of Australian Governments on Reform of Energy Markets: Expanded Gas Program*, 19 May 2004

compelled to release unutilised capacity via a transparent market mechanism.[105]

As part of its *Strategic Priorities for Energy Market Development 2013* paper, the AEMC is committed to promoting the development of efficient gas markets with a view to ensuring a reliable, competitive and secure gas market that allows for efficient and timely investment in gas infrastructure and the supply of gas at least cost to consumers. To this end, it commissioned a gas scoping study in 2013, which found that the eastern market is currently undergoing a number of fundamental demand- and supply-side changes:

- the most significant changes are being driven by the development of LNG facilities in Queensland, the first of which is due to come online in 2014;
- the proposed development of a number of new sources of supply in the Bowen/Surat, Cooper, Gippsland, Gunnedah and Gloucester basins; and
- climate change policies and the conditions in National Electricity Market (NEM).[106]

The AEMC has committed to the creation of a strategic plan for gas market development. It is envisaged that this will take the form of a review that examines the evolving role, in changing market conditions, of the Short Term Trading Market, Victorian Declared Wholesale Gas Market and the Wallumbilla gas supply hub. The review will examine the mix and location of trading markets, the size of the markets, types of participants, and costs and benefits.[107]

4.2 Current regulatory framework

4.2.1 Upstream sector

Offshore petroleum resources are regulated in accordance with the 1979 Offshore Constitutional Settlement between the Commonwealth, States and Territories. The Commonwealth *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGSA) regulates all petroleum exploration and mining activities and all greenhouse gas storage activities in Commonwealth waters. The NSW *Petroleum (Offshore) Act 1982* regulates all petroleum exploration and mining in NSW coastal waters (up to three nautical miles from the territorial sea baseline). Under this Act, provision is made for the application of all NSW laws and statutory instruments under those laws to petroleum exploration and mining in NSW coastal waters. Part 4 of the *Petroleum (Offshore) Act 1982* provides for a number of titles related to petroleum exploration and mining. The

[105] Standing Council on Energy and Resources Officials, *Regulation Impact Statement: Gas Transmission Pipeline Capacity Trading*, Consultation Paper, 15 May 2013

[106] K Lowe Consulting, op. cit.

[107] AEMC, *Strategic Priorities for Energy Market Development 2013*, October 2013

provisions for each of these titles 'mirrors' the provisions made under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth).

As is the case in all other States and Territories, all onshore petroleum resources in NSW fall under State jurisdiction. The *Petroleum (Onshore) Act 1991* vests all petroleum resources in the Crown. Provision is made for a number of titles related to petroleum exploration and mining. When granting a title, the Government may attach environmental protection conditions where appropriate. Royalties and fees payable are also set out in the Act.

4.2.2 Downstream sector

The downstream sector is regulated under both National and State/Territory legislation. The National Gas Law (NGL) and the National Gas Rules (NGR) regulate some transmission pipelines and all distribution pipelines, the Gas Bulletin Board (GBB), the Victorian Domestic Wholesale Gas Market (DWGM) and the Short Term Trading Markets. The arrangements applying to retail markets in those jurisdictions that have implemented the National Energy Customer Framework (NECF), including NSW, are set out in the National Energy Retail Law (NERL) and the National Energy Retail Rules (NERR).

Table 28 provides a snapshot of gas regulatory and emergency arrangements in the eastern market. The functions and responsibilities of bodies that play a key role in transportation of gas, the facilitated markets and/or retail markets are as follows:

- **Policy direction**: the COAG Standing Council on Energy (SCER) is the energy market governance body responsible for developing and administering the legislative framework and providing policy direction
- **Market development and rule-making**: the Australian Energy Market Commission (AEMC) is responsible for making and amending the NGR and NERR, market development, providing advice to SCER and maintaining the gas pipeline scheme register
- **Pipeline coverage and form of regulation**: the National Competition Council (NCC) makes recommendations to the relevant minister on coverage applications and deciding on the form of regulation to apply to scheme pipelines (i.e. light or full regulation)
- **Economic regulation and enforcement**: the Australian Energy Regulator (AER) is responsible for the economic regulation of scheme pipelines in the eastern and northern markets, monitoring trading activity in both the DWGM and STTMs, monitoring compliance with, and investigating breaches of, the NGR and has a range of functions under the NERR
- **Market operator**: the Australian Energy Market Operator (AEMO) is responsible for a range of functions including operating, administering and improving the effectiveness of the DWGM and the STTMs, operating and maintaining the Gas Bulletin Board, preparing the Gas Statement of Opportunities (GSOO), providing planning advice in Victoria and being

the retail market operator in NSW, the ACT, Queensland, South Australia and Victoria

- **Appeals bodies**: the Australian Competition Tribunal is responsible for conducting merits based reviews on reviewable regulatory decisions under the NGL and NGR while the Federal Court of Australia is responsible for carrying out judicial reviews[108]

Table 28: Snapshot of gas regulatory and emergency arrangements[109]

<table>
<thead>
<tr><th colspan="2" rowspan="2">Type of regulation</th><th colspan="2">Transportation</th><th colspan="2">Market</th></tr>
<tr><th>Transmission</th><th>Distribution</th><th>Facilitated market</th><th>Retail market</th></tr>
</thead>
<tbody>
<tr><td rowspan="7">Economic regulation</td><td>General competition laws</td><td colspan="4">Competition & Consumer Act 2010 (Cth) applies across all sectors</td></tr>
<tr><td>Gas pipeline regulation
(i.e., of services, prices, access)</td><td colspan="2">NGL and NGR provisions for scheme pipelines only
Potential State/Territory licences, codes, other rules</td><td>n/a</td><td>n/a</td></tr>
<tr><td rowspan="3">Retail regulation</td><td rowspan="3">n/a</td><td>NECF or State/Territory regulation in non-adoptive jurisdictions</td><td rowspan="3"></td><td>NECF or State/Territory regulation in non-adoptive jurisdictions</td></tr>
<tr><td rowspan="2">AEMO Retail Gas Market Procedures</td><td>AEMO Retail Gas Market Procedures</td></tr>
<tr><td>Regulated in NSW only</td></tr>
<tr><td>Bulletin Board</td><td>NGL and NGR for pipelines deemed to be BB facilities</td><td>n/a</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Facilitated market regulation</td><td>n/a</td><td>n/a</td><td>NGL and NGR provisions for STTM and DWGM</td><td>n/a</td></tr>
<tr><td rowspan="2">System operation</td><td>Integrated market and system operation</td><td>DWGM (Vic)</td><td>n/a</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Safety requirements</td><td colspan="2">Commonwealth, State, Territory technical regulation</td><td>n/a</td><td>n/a</td></tr>
<tr><td rowspan="2">Emergency</td><td>Cross border emergency</td><td colspan="2">National Gas Emergency Response Protocol</td><td></td><td></td></tr>
<tr><td>State and Territory emergencies</td><td colspan="4">Each jurisdiction has emergency powers that override other regulatory and contractual obligations</td></tr>
</tbody>
</table>

[108] K Lowe Consulting, op. cit.

[109] Adapted from: K Lowe Consulting, op. cit.

A number of State/Territory economic regulators and technical regulators have various responsibilities under State legislation. In NSW, the Independent Pricing and Regulatory Tribunal (IPART) is responsible for regulating retail gas prices for residential and small business customers in accordance with the *Gas Supply Act 1996*. IPART regulates prices using a relatively light-handed approach that involves making multi-year pricing agreements with each Standard Retailer, known as Voluntary Pricing Agreements. The Standard Retailers then set their own regulated prices to comply with these agreements. IPART monitors compliance with the agreements.[110]

[110] IPART, *Review of regulated retail prices and charges for gas From 1 July 2013 to 30 June 2016*, Final Report, June 2013

PART TWO – DOMESTIC GAS RESERVATION POLICIES IN AUSTRALIA

Under Australian law, petroleum (including natural gas) and mineral resources are generally owned by the Crown. Onshore petroleum and mineral resources are owned and regulated by State and Territory Governments, while the majority of offshore resources are controlled by the Commonwealth depending on the location of the resource with respect to the territorial sea baseline.

High overseas prices for natural gas, particularly in nearby Asian markets, have seen Australia's LNG industry develop rapidly in recent years. With gas producers now reserving supplies for the higher value export market, domestic wholesale consumers are finding it increasingly difficult to secure long-term contracts for gas. The tightening in supply contract provision has resulted in price increases.

Domestic gas reservation is one of the policies available to Government that may ensure the availability of affordable gas to domestic consumers. This policy would specifically involve quarantining a proportion (either fixed or variable) of gas production and/or segments of gas producing land for the domestic market.

At present, Western Australia and Queensland are the only States which implement any form of domestic gas reservation policy. The Commonwealth and the remaining States and Territories do not implement domestic gas reservation policies for their respective offshore and onshore resources.

In its May 2012 *report* on Coal Seam Gas, the Legislative Council, General Purpose Standing Committee No. 5 recommended that a domestic gas reservation policy be implemented in NSW and modelled on the WA reservation policy. Specifically, the report stated:

> …the Committee recommends that the NSW Government implement a domestic gas reservation policy, under which a proportion of the coal seam gas produced in New South Wales would be reserved for domestic use. Such a policy could assist to contain price increases, enhance energy security, and reduce the State's dependence on coal for power generation.[111]

In its *response* to the report, the NSW Government rejected the immediate need for a reservation policy:

> As prospective CSG fields in NSW are not currently tied to liquefied natural gas export facilities, the only location for NSW CSG reserves to be utilised is the NSW domestic market, making a reservation policy unnecessary. Additionally, implementing a reservation policy as the industry is trying to develop will be a disincentive to investment and add to project development costs.
>
> The NSW Government could reconsider this issue once the CSG industry has

[111] NSW Legislative Council General Purpose Standing Committee No. 5, *Coal seam gas*, May 2012, p.xiii

> been established, if required.[112]

In its November 2012 *report* into the Economics of Energy Generation, the Legislative Assembly, Public Accounts Committee stated that it also does not support a domestic gas reservation policy:

> The Committee does not support a domestic gas reservation policy, as this would inappropriately interfere with the operations of the gas market. The Committee considers that the best way to encourage future gas production and supply is to allow the market to operate freely. However, if additional incentives are required in the future to encourage the domestic supply of gas, offering a reduction in royalties for domestic gas suppliers may be an option. The Committee notes that the recent removal of the five year royalty holiday for coal seam gas production would provide greater scope for this option to be explored, if it is required in the future.[113]

The Victorian Government Gas Market Taskforce recently released its *final report and recommendations* which recommended that eastern market governments do not adopt a policy for domestic gas reservation. The report stated that:

> …a government-imposed domestic gas reservation would not deliver lower priced gas to domestic consumers [and] is inconsistent with an open and competitive modern economy…[114]

The Victorian Opposition has, however, flagged domestic gas reservation as a policy it intends to take to the State election in 2014.[115]

---

[112] NSW Government, *Legislative Council General Purpose Standing Committee No. 5 Inquiry into Coal Seam Gas: NSW Government response*, October 2012, p.12

[113] NSW Legislative Assembly Public Accounts Committee, *The Economics of Energy Generation*, Report 6/55, November 2012, p.109

[114] Victorian Gas Market Taskforce, *Final Report and Recommendations*, October 2013, p.34

[115] Australian Financial Review, *ALP flags Vic gas reservation*, November 2013

5. COMMONWEALTH

5.1 Legislation

Many of the regulatory arrangements currently in place for the offshore upstream petroleum sector stem from Australia's federal system of government and reflect the historical development of institutional arrangements.[116]

The Commonwealth *Petroleum (Submerged Lands) Act 1967* was the first offshore petroleum law to be enacted in Australia. Following its introduction, there was disagreement between the States and the Commonwealth regarding jurisdiction over the territorial sea (which extends up to 12 nautical miles from the territorial sea baseline). The *Seas and Submerged Lands Act 1973* was subsequently introduced and provided that the States' powers ended at the territorial sea baseline.[117]

Following an unsuccessful High Court challenge by the States, this disagreement was not resolved until the *Offshore Constitutional Settlement*[118] was agreed to between the States and the Commonwealth in 1979. Under this agreement, the States were given authority over coastal waters (including the seabed) which extend three nautical miles from the territorial sea baseline. These rights were legislated in Commonwealth law — under the *Coastal Waters (State Title) Act 1980* and the *Coastal Waters (State Powers) Act 1980*.

Regulatory authority over offshore petroleum resources and associated activities in Commonwealth waters is established under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*. This Act provides for a series of permits and licences by which petroleum exploration and mining activities may be carried out. Safety arrangements for these activities are also provided for by the Act.[119]

5.2 Domestic gas reservation policy

The Commonwealth does not have a domestic gas reservation policy for its offshore resources. In the *Energy White Paper 2012*,[120] the Gillard Government affirmed its opposition to a domestic gas reservation policy:

> …the Australian Government does not support calls for a national gas reservation policy or other forms of subsidy to effectively maintain separation between domestic and international gas markets or to quarantine gas for

[116] Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas Sector)*, 2009

[117] Ibid.

[118] Offshore Constitutional Settlement (OCS), completed in 1979, is an agreement between the Commonwealth, the States and the Northern Territory which established the States' right over coastal waters (generally three nautical miles from the low watermark). It includes arrangements for managing oil, gas and other seabed minerals.

[119] Hunter, T, and Chandler, J., *Petroleum Law in Australia*, 2013

[120] Department of Resources, Energy and Tourism, op. cit.

> domestic supply.[121]

In doing so, the Government argued that a national reservation policy would have a negative impact on investment and market development:

> …a national reservation policy would add to, rather than reduce, long-term market risk by eroding development and supply incentives. It would be likely to impede the development of efficient gas markets and reduce returns to the economy from the development of our natural gas resources…a reservation policy would also be damaging to the nation's investment reputation, and would be at odds with our longstanding national commitment to open and fair trade.[122]

The Government emphasised the role of price as an incentive to develop additional gas supplies:

> …the key to stimulating effective and timely market response is to maintain open trading arrangements that do not constrict the proven ability of the market to deliver. This must allow price to play its role as a balancing incentive that can drive the development of additional supply.[123]

The Government suggested that the eastern and western markets have the production capacity to respond to tightening conditions:

> In the eastern market this can occur through a range of options, including adjusting production schedules, increasing production from existing fields, such as Gippsland, bringing forward incremental capacity from new CSG reserves, or any combination of those options.[124]

Rather than a reservation policy, the Government also argued that:

> The policy objective should be to provide the most efficient framework for the market to flexibly manage emerging pressures while monitoring market outcomes closely to ensure that the market is responding as necessary. The provision of better information on production, supply, demand and prices will also work to increase market confidence and give industry greater certainty in its decision-making.[125]

In a speech to the Energy Users Association of Australia, Industry Minister Ian Macfarlane emphasised the Abbott Government's opposition toward a domestic gas reservation policy:

> As I have made clear repeatedly in the past, the Coalition will not consider any retrospective or blanket domestic gas reservation policy.[126]

---

[121] Ibid., p.144
[122] Ibid., p.144
[123] Ibid., p.143
[124] Ibid., p.143
[125] Ibid., p.144
[126] Energy Users Association of Australia, *EUAA National Conference Speech: Ian Macfarlane*, October 2013

The Federal Government is in the early stages of drafting a national energy white paper and an east coast gas supply strategy which will make clear the Government's official position on this and other reform agendas for the energy sector.

6. WESTERN AUSTRALIA

Western Australia is Australia's most gas dependent State. Natural gas supplies 55% of its primary energy and 73% of its electricity generation,[127] equivalent to around 646 petajoules (PJ) of natural gas in 2010-11[128].

In 2011-12, Western Australia produced 1,458PJ of gas, with the majority of this being directed to the liquefied natural gas (LNG) export market. In 2012, Western Australia's 2P gas reserves were estimated to be 89,900PJ.[129]

A domestic gas reservation policy has been in place in Western Australia, at least in principle, for some time. Domestic gas supply obligations had previously been legislated through two State Agreements: *North West Gas Development (Woodside) Agreement Act 1979*; and *Barrow Island Act 2003.* In 2006, as a response to rising prices and concerns of domestic supply shortages, Western Australia became the first State in Australia to establish a formal gas reservation policy. The main objective of this policy was to secure domestic gas commitments, up to the equivalent of 15 per cent of production from each prospective LNG project.

6.1 Legislation

All petroleum (including natural gas) exploration and production in Western Australia is regulated under the *Petroleum and Geothermal Energy Resources Act (PGERA) 1967* (which applies onshore and includes islands and internal waters); and the *Petroleum (Submerged Lands) Act (PSLA) 1982* (which applies in coastal waters extending three nautical miles from the low watermark). These Acts together establish a 'common petroleum code' for application to onshore and offshore petroleum exploration and extraction.[130]

Western Australia and the Commonwealth also have a common petroleum code. This was developed under the Offshore Constitutional Settlement to provide legal consistency and continuity of rules and practices between State and Commonwealth jurisdictions.[131]

6.2 Domestic gas reservation policy

Prior to 2006, two State Agreements underpinned reservation policy in WA. State agreements, which are ratified by an Act of the State Parliament, specify the rights, obligations, terms and conditions of a project and establish a framework for relations between the Government and the project proponent.[132]

---

[127] DomGas Alliance, *Australia's domestic gas security*, 2012

[128] Bureau of Resources and Energy Economics, *Energy in Australia 2013*, May 2013

[129] Australian Energy Regulator, *State of the Energy Market*, 2012

[130] Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas Sector)*, 2009

[131] Hunter, T, and Chandler, J., op. cit.

[132] Department of State Development, *State Agreements*, 2012

The first State Agreement was applied to the North West Shelf (NWS) LNG project in 1979. Under this agreement, the State Energy Commission of WA, following a review of the State's gas requirements, agreed to purchase 3,023 petajoules of gas for domestic supply and fund the Dampier to Bunbury natural gas pipeline (DBNGP).[133] Under a 1995 revision of the *North West Gas Development (Woodside) Agreement Act 1979*, the NWS project was obligated to supply 5,064PJ of gas to the domestic market.[134] Although this commitment is anticipated to be met by 2014, the NWS project is expected to continue to supply the domestic market, with further supplies to be negotiated under provisions within the agreement.[135]

The other State Agreement was applied by the State Government to the Gorgon LNG project, which is currently being constructed on Barrow Island, around 60 kilometres off the northwest coast of Western Australia. To ensure onshore domestic gas supply, under the *Barrow Island Act 2003*, the Gorgon joint venture partners are required to build a 300 terajoule (TJ) per day capacity domestic gas plant on Barrow Island and supply 2,000PJ domestically over the life of the entire project.[136] A domestic gas processing plant will be integrated within the LNG processing facilities on Barrow Island and a pipeline will transport gas to the DBNGP.[137] Delivery of 150TJ per day will commence on the 31 December 2015, with 300 TJ per day to be supplied annually from 2021.

In 2006, a formal reservation policy, *WA Government Policy on Securing Domestic Gas Supplies*, was adopted by Premier Alan Carpenter, and later reaffirmed by the Barnett Government[138]. Like previous reservation arrangements, this policy is enforced using individual State Agreements (or contracts) between the Government of Western Australia and proponents of LNG export projects.

All onshore and offshore gas regulated by the WA Government under the PGERA and the PSLA falls under this policy. Gas resources located in Commonwealth waters fall under this policy where there is a need to locate LNG processing facilities either onshore or within WA territorial waters.[139] Floating LNG (FLNG) facilities located in Commonwealth waters are not subject to the policy.

The main objective of the WA reservation policy is to:

---

[133] DBP, *Pipeline history*, 2013

[134] WA Economics and Industry Standing Committee, *Inquiry into domestic gas prices*, Report No.6, March 2011

[135] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[136] WA Economics and Industry Standing Committee, *Inquiry into domestic gas prices*, Report No.6, March 2011

[137] Department of State Development, *Gorgon Project (Barrow Island)*, November 2009

[138] Barnett Government reaffirmed its commitment as part of its *Strategic Energy Initiative*

[139] Synergies Economic Consulting, *WA Gas Supply and Demand: the need for policy intervention*, 2007

> …ensure secure, affordable domestic gas supply to meet WA's long term energy needs and to sustain economic growth, development and value adding investment.[140]

Under this policy, proponents of gas export projects are required to reserve up to 15 per cent of production for supply to the domestic market as a condition of access to WA land for the location of processing facilities. This target reflects Government estimates of future domestic gas demand, gas reserves and forecast LNG production in WA. These estimates could change over time and the reservation target may be altered to reflect these changes.[141]

This policy does provide for case-by-case flexibility, allowing prospective LNG producers to negotiate with the government on the amount and manner in which gas will be supplied to the domestic market. LNG producers may, for example, have the option of fulfilling their domestic supply obligations from a different source.

The reservation policy is designed to ensure the availability of gas to the domestic market, but does not directly constrain price. The price of gas sold onto the domestic market is determined through commercial negotiations between the gas producers and consumers.[142]

The Pluto LNG project, which is located in the Carnarvon Basin north-west of Karratha, was approved for development in July 2007 conditional on it complying with the State's reservation policy. Although it is not yet legislated by a State Agreement, it is understood that under the arrangement between the Government and Woodside Petroleum, the Pluto field will be able to export LNG for 5 years before carrying out an economic evaluation of domestic gas production. The first gas from the project entered the LNG processing train in March 2012 and domestic gas production is expected to begin in 2016.[143]

On 12 November 2012 the State of Western Australia entered a joint venture agreement (*Natural Gas (Canning Basin Joint Venture) Agreement Act 2013*) with the proponents[144] of the prospective gas development in the onshore Canning Basin. This agreement, which includes five exploration permits for an initial term of 25 years, is consistent with the WA Government reservation policy. The Agreement provides that if commercially viable gas is discovered by mid-2016, the parties must submit a plan for construction of the domestic gas project, which will include a 600km pipeline south to Western Australia's existing Pilbara gas network. The Agreement provides for the use of local

[140] Department of Premier and Cabinet, *WA Government Policy on Securing Domestic Gas Supplies*, 2006

[141] Ibid.

[142] Ibid.

[143] Sinclair Knight Merz, *WA Domestic Gas Market Analysis for the Strategic Energy Initiative*, 2011, Report to Office of Energy Western Australia

[144] Proponents include Buru Energy Limited, Diamond Resources (Fitzroy) Pty Ltd, Diamond Resources (Canning) Pty Ltd and Mitsubishi Corporation (as guarantor)

labour and materials as well as the creation and implementation of a community development plan and local industry participation plan.[145]

In the absence of a Commonwealth reservation policy, producers can conduct all processing offshore using FLNG plants[146] to avoid becoming subject to the WA reservation policy and there is evidence to suggest that this is already occurring. Woodside Petroleum, for example, have begun developing a $46 billion floating LNG facility offshore in the Browse gas fields, while Shell is in the process of developing the $13 billion Prelude FLNG plant. A FLNG plant is also being developed in the Scarborough gas field by Exxon Mobil and BHP Billiton.[147] These developments are of major concern to the WA Government. In May 2013, the WA Legislative Assembly Economics and Industry Standing Committee resolved to commence an inquiry into the Economic Implications of Floating Liquefied Natural Gas Operations.[148]

6.2.1 WA Parliamentary Inquiry into Domestic Gas Prices

In March 2011, the Economics and Industry Standing Committee submitted its report for the Inquiry into Domestic Gas Prices. In this report, the Committee supported domestic gas reservation, concluding that:

> In the absence of a gas reservation policy it is unlikely that LNG producers would develop adequate domestic gas processing facilities [and that] …reservation obligations remain a valuable tool for policy makers to ensure that a proportion of the state's gas reserves are supplied to local consumers in volumes and at prices that are consistent with a well-functioning market. However, this policy requires delicate handling to ensure that market outcomes reflect those of a well-functioning competitive market …[149]

Making reference to the NWS Agreement, the Committee was aware of the potential effects of excessive reservation and emphasised the importance of flexibility in domestic gas reservation:

> The Committee had considered the merit of the state assuming the role of an aggregator to correct the imbalance in the current market dynamic. However, the earlier experience of the SECWA contract—which led to an extended period of oversupply and discouraged the development of other gas resources—suggests this would be a retrograde step. Instead, the Committee wants to encourage diversity of supply, multiplicity of participants and greater liquidity in the domgas market. A flexible and actively managed domestic reservation process is not inconsistent with these objectives.[150]

---

[145] FindLaw Australia, *Canning Basin Bill marks new chapter of gas development*, 2013

[146] DomGas Alliance, *Australia's domestic gas security*, 2012

[147] *The Australian*, LNG Revenue set to reach $61bn by 2018, September 2013

[148] Parliament of Western Australia, *Inquiry into the Economic Implications of Floating Liquefied Natural Gas Operations*, Legislative Assembly, May 2013

[149] WA Economics and Industry Standing Committee, op. cit., p.84

[150] Ibid., p.82

The Committee went further and concluded that:

> Flexibility in the application of this policy is crucial, particularly pertaining to the volumes to be supplied... the aim should be to foster the supply and competition needed to allow domgas prices to settle at levels substantially below LNG netback values, whilst offering producers returns that encourage exploration and development. The Committee remains wary that, whilst domestic reservation policies remain a necessity, any heavy-handedness with the application of this tool could conspire against this outcome.[151]

[151] Ibid., p.84

7. QUEENSLAND

Queensland consumed around 240PJ of natural gas in 2010-11, making it the third largest consumer of gas in Australia behind WA and Victoria. In 2011-12, Queensland produced 245PJ of gas, with 241PJ of this being accounted for by coal seam gas production.[152]

As at 30 June 2012, Queensland had 35,435PJ and 590PJ of coal seam and conventional 2P gas reserves, respectively.[153] Despite the abundant gas reserves in Queensland, there are domestic supply concerns as wholesale consumers find it increasingly difficult to secure long-term gas contracts at affordable prices.[154] This is because a large proportion of reserves have been contracted for LNG export.

The uncertainty around gas supply and the risk of sharply rising prices saw the Queensland State Government introduce the *Prospective Gas Production Land Reserve (PGPLR)* policy in 2009. Under this policy, the State may, when granting a production license, require that any gas produced from an area be supplied domestically. To date, no gas field has been set aside for domestic gas only development.

7.1 Legislation

Gas and oil exploration and production in Queensland is regulated under the *Petroleum and Gas (Production and Safety) Act 2004* (which applies onshore); and *Petroleum (Submerged Lands) Act 1982* (which applies in coastal waters extending three nautical miles from the low watermark). In certain circumstances, a petroleum lease may be applied for or granted under the *Petroleum Act 1923*. This would only occur if the applicant held an authority to prospect under the *Petroleum Act 1923*. All new applications for an authority to prospect may only be granted under the *Petroleum and Gas (Production and Safety) Act 2004.*[155]

Activity in the offshore area of Queensland has been minimal. The Coral Sea and the Great Barrier Reef cover much of the coastline, and are protected areas. The *Petroleum (Submerged Lands) Act 1982* has seldom been applied. The vast majority of Queensland's gas reserves are onshore in the Bowen and Surat Basins and are covered by the *Petroleum and Gas (Production and Safety) Act 2004*.

[152] Bureau of Resources and Energy Economics, *Energy in Australia 2013*, May 2013

[153] Department of Natural Resources and Mines, *Production and reserve statistics*, June 2012

[154] Carbon Market Economics, *The impact of liquefied natural gas on Queensland's gas markets and gas users*, March 2010

[155] Department of Natural Resources and Mines, *Petroleum and gas tenure types and forms*, 2013

7.2 Domestic gas reservation policy

In 2009, the Government released its *Blueprint for Queensland's LNG Industry*, which highlighted the restrictions to industry development because of domestic gas supply shortages. In this report, two policies were proposed to rectify the supply shortages in Queensland.

> 1. Conventional gas reservation policy: similar to that implemented in WA, where producers would have been required to sell or make available between 10 and 20 per cent of production to the domestic market.
>
> *2.* Prospective Gas Production Land Reserve (PGPLR) policy: where the State may, when granting a production license, require that any gas produced from an area only be supplied to the domestic market.

Following submissions to the *Domestic Gas Market Security Supply* Consultation Paper, Cabinet rejected the proposed conventional gas reservation policy and approved the PGPLR. The Director-General of Queensland Ian Fletcher explained the decision by stating:

> The government's decision against imposing a mandatory domestic gas supply regime was based on the conclusion that policy settings that support gas market growth would benefit local gas users by delivering a vastly larger gas market.
>
> In coming to its non-reservation policy decision, the State Government was conscious of the global competition both in Australia and overseas for these multi-billion dollar facilities and wants to give these projects every opportunity to provide up to 18,000 jobs if they succeed in becoming established.
>
> While the government will not impose the reservation policy, it has in-built safeguards to ensure LNG industry proponents do not leave local projects on the shelf.
>
> That insurance policy involves establishing a prospective Gas Production Land Reserve that will give the government the option to release prospective gas land if there is a forecast supply shortfall in the market. Further, the released land may be preserved to only supply the domestic market.[156]

This decision was also supported by a study commissioned to compare a "standard" LNG scenario with another under which a 15 per cent reservation policy was applied to Queensland's coal seam gas reserves. The results showed marginally poorer outcomes in terms of GDP, GSP, royalty revenues, employment rates and standard of living indicators under the 15 per cent reservation regime.[157]

In May 2011, the Queensland Government passed the *Gas Security*

---

[156] I Fletcher, Message from the Director-General, *Queensland Government Mining Journal*, Summer 2010, p.2

[157] WA Economics and Industry Standing Committee, op. cit.

Amendment Bill 2011, which amended the *Petroleum and Gas (Production and Safety) Act 2004* to enable implementation of the PGPLR policy. The PGPLR policy is legislated under Chapter 2, Part 2A of the *Petroleum and Gas (Production and Safety) Act 2004*.

The Queensland Government now has the ability to impose conditions on exploration licenses which would require that all gas produced from any subsequent production tenures be supplied domestically.[158] The PGPLR policy may only be exercised if the Government's annual Gas Market Review process identifies domestic supply constraints. To date, no gas field has been set aside strictly for domestic supply. Three major LNG plants are currently under development in Gladstone, all of which have been approved to proceed without any conditions or domestic supply arrangements.[159]

There are two main concerns about the effectiveness of this policy. Firstly, there are no guarantees of domestic gas supply, as it only ensures that gas is available underground in its natural state, for the domestic market. In principle, a gas producer may be able to comply with the PGPLR policy without ever producing gas and selling it into the domestic market.[160] Secondly, even if this policy was applied to an exploration licence, there is a considerable lag between exploration (in terms of delays in developing extraction, processing and distribution infrastructure) and gas being supplied domestically.

[158] Queensland Legislation, *Gas Security Amendment Bill 2011: explanatory notes*, May 2011
[159] National Institute of Economic and Industry Research, *Large scale export of East Coast Australia natural gas: Unintended consequences*, October 2012
[160] Carbon Market Economics, op. cit.

8. STAKEHOLDER PERSPECTIVES ON DOMESTIC GAS RESERVATION

The gas industry is presented with a range of opportunities and challenges going forward. For producers, LNG provides access to Asia's higher value export market which will underpin prospective upstream investment. For consumers, gas supply shortages and resulting price rises will have implications on their cost base and competitiveness in Australia and abroad.

Domestic gas reservation is consequently seen as both an obstacle to export earnings for producers and a necessity for consumers in being able to access secure and affordable supplies of natural gas. Given their respective vested interests, gas reservation has divided opinion which is reflected in the contrasting stakeholder policy perspectives to date.

8.1 Manufacturing Australia

Manufacturing Australia (MA), which represents some of the largest manufacturing companies in Australia, recently published the report *Impact of gas shortage on Australian Manufacturing*. In the report, MA emphasised the importance of gas to manufacturing and the threat shortages will have on jobs and industry growth:

> This is a difficult time for manufacturers to face this gas shortage, as they are simultaneously dealing with a number of other unusual events such as the high Australian dollar, carbon taxes and other increased compliance costs, and high labour costs driven by the boom in mining, oil and gas development.
>
> Secure, low cost natural gas is an important part of the cost base of many Australian manufacturers. Expected gas shortages and price expectations are already having an impact on current investment decisions, contributing to plant closures and redirected investments.
>
> If not managed well, substantial sections of Australian manufacturing will be negatively impacted by this near term gas crisis, to the point of reduced production, investment and jobs.
>
> We estimate that 40% of our domestic chemicals industry, 25% of our non-ferrous metals industry, 10% of our other manufacturers (including building products) and 2% of our wood, paper and printing industry are at risk (including opportunity cost of future investment). If this comes to pass, we will have lost 12% of our manufacturing value added and 9% of our manufacturing jobs.[161]

MA was strongly supportive of Government intervention (including a reservation policy) in resolving these shortages:

> With good policy, Australia can support a thriving manufacturing sector while transitioning to a leading LNG exporter.

[161] Manufacturing Australia, *Impact of gas shortage on Australian manufacturing*, May 2013, p.4

> There are many precedents for dealing with this issue. A number of other countries have addressed this issue specifically through introducing a 'national interest test' for export, intervention in resource tax structures, reservation of certain supply for domestic use or other incentives.
>
> Australia has similar policy levers at their disposal should they choose to use them. In fact, Western Australia has a reservation system in place with no obvious negative impact on its thriving gas production and LNG export industries.
>
> Intervention by State and Federal governments is urgent and necessary, before our energy advantage is sent offshore, never to return.[162]

8.2 DomGas Alliance

The DomGas Alliance (DA) is Western Australia's peak energy user group and represents around 80 per cent of Western Australia's domestic gas consumption and transmission capacity. In its report *Australia's Domestic Gas Security*, DA highlighted the success of the reservation policy in WA and made a case for a national reservation policy in allowing for consistency across State and Commonwealth jurisdictions:

> Australia should implement a national reservation policy that would require major LNG projects to set aside 15% of gas production for local industry and households.[163]
>
> While the WA domestic reservation policy has proven to be effective, the State's ability to secure domestic supply is limited. The bulk of gas resources are located offshore in Commonwealth waters regulated by the Federal Government. In the absence of Commonwealth domestic supply obligations, gas producers can conduct all processing offshore through floating LNG plants or transport gas to Darwin without supplying the Australian market. The[se] projects therefore represent a significant lost opportunity for Australian energy users and manufacturing in the absence of Federal Government action.[164]

In supporting a national reservation policy, DA claimed that it would not discourage investment or increase sovereign risk:

> Australia is the *only* country in the world that allows unrestricted exports of natural gas. A national reservation policy will not discourage investment or increase sovereign risk. These concerns have been proven unfounded. The sky did not fall down and WA instead saw a massive expansion in gas exploration and investment. Major projects underway or already completed include Wheatstone, Gorgon, Devil Creek, Macedon and Pluto. Exploration expenditure also significantly increased following the announcement of the reservation policy in 2006.[165]

---

[162] Ibid., p.7

[163] DomGas Alliance, *Australia's Domestic Gas Security*, Report 2012, 2012, p.18

[164] Ibid., p.20

[165] Ibid., p.25

8.3 Australian Industry Group

The Australian Industry Group (AIG) is a peak industry association in Australia which represents the interests of businesses across a spectrum of sectors, including mining and manufacturing. It recently surveyed business gas users in eastern Australia to assess the state of the gas market. The results of the survey and subsequent recommendations were published in the report *Energy Shock: the gas crunch is here*. While recognising the implications tight supply and prices would have on gas dependent industries, AIG was reluctant to recommend 'aggressive' reservation policies:

> Tight supply and massive price escalation will have a serious effect on gas dependent industries – and on electricity prices, since gas fired generators play an important role in the National Electricity Market. Discussion is increasingly turning to policy responses, though much debate has focused on the idea of domestic gas reservation – despite the fact that relatively few stakeholders actually call for this approach. Aggressive reservation policies could carry legal and investment risks, and are widely opposed. But a price transition and supply squeeze as serious as that now confronting eastern Australia demands a policy response.[166]

AIG made the following recommendations, which included a 'national interest test' approvals process as a policy mechanism to regulate gas exports:

> Increase gas production, particularly from unconventional gas resources, by ensuring that regulatory arrangements are in place at all levels of government which command community confidence and make timely, workable and consistent decisions;
>
> Enhance the transparency and competitiveness of the gas market, by accelerating the current market reform agenda and urgently developing more options; and
>
> Build confidence among gas users in future supply and the merits of production, by introducing a national economic approvals process for additional LNG export capacity.[167]

Even with these policies, AIG recognised that gas price rises were almost inevitable:

> …gas users face serious pressures and a major transition. Prices will likely never return to the lows that have underpinned many businesses' international competitiveness over the last few decades. A near term supply squeeze may be unavoidable.[168]

---

[166] Australian Industry Group, *Energy Shock: the gas crunch is here*, July 2013, p.6

[167] Ibid., p.6

[168] Ibid., p.6

8.4 Australian Petroleum Production and Exploration Association

The Australian Petroleum Production and Exploration Association (APPEA), which is the peak national body representing Australia's oil and gas exploration and production industry, recently published the report *2013 Policy Priorities*. In the report, APPEA highlighted the economic benefits that may be obtained from prospective oil and gas projects in Australia:

> Almost $200 billion is currently being invested in oil and gas projects including seven major LNG projects. According to economic modelling commissioned by APPEA and conducted by Deloitte Access Economics, this will increase Australian GDP by up to 2.2 per cent a year and require a construction workforce peaking at over 100,000 full-time equivalent jobs. By 2025, the construction and operation of these projects will add more than $260 billion (in net present value terms) to Australian GDP and contribute between $6.3 billion and $7 billion a year in taxation revenue.[169]

APPEA, which supports the recommendations made in the *2012 Energy White Paper*, is firmly against additional government intervention in the gas industry and focussed on the role of the market-based policy to support industry growth:

> Australia's gas industry is delivering substantial, economy-wide benefits in terms of investment, jobs, and regional development. But for this benefit to be sustained, governments must resist calls for policy interventions that force non-commercial outcomes.
>
> The White Paper clearly articulates the important role that Australian natural gas will play in delivering economic growth and energy security. It also recognises the critical importance of market-based energy policies and sends an important signal to investors in its rejection of domestic gas reservation policies and other such industry protection measures.
>
> Arguments for domestic gas reservation are highly dangerous, short-sighted and self-interested. Gas reservation policies actually impair local gas supply and affordability, rather than improve it. Laws that dictate where and how gas can be sold invariably deter the very investment needed to develop Australia's abundant gas reserves.
>
> LNG projects, to which Australia now looks to underpin the national economy for decades to come, are complex, extremely costly and require a decades-long horizon.
>
> Australia's LNG industry is a source of comparative advantage that should be harnessed, not hindered. Just as Australia's long-term national interest is served by maintaining access to open and competitive markets for coal, wheat, and iron ore, the same is true for gas.[170]

[169] Australian Petroleum Production and Exploration Association, *2013 Policy Priorities*, 2013, p.1
[170] Ibid., p.2

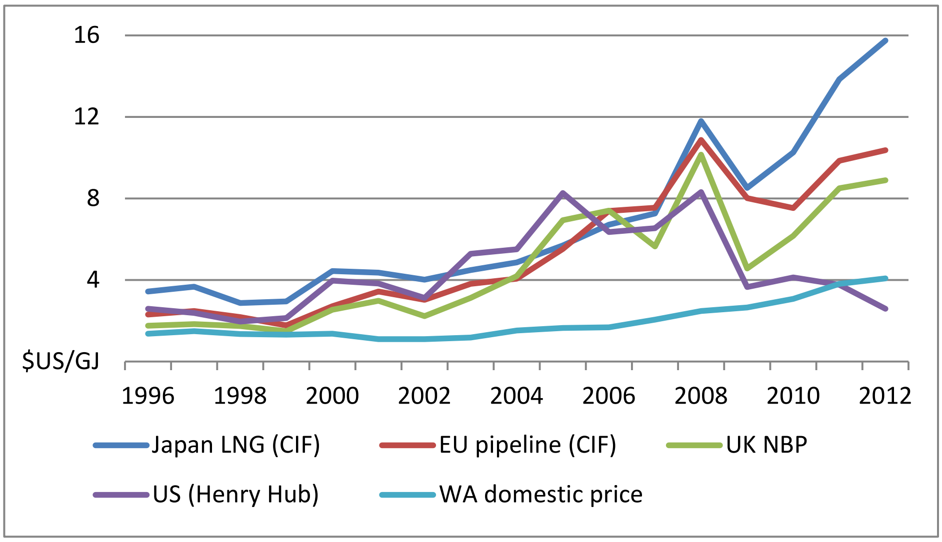
9. ECONOMIC EFFECTS OF DOMESTIC GAS RESERVATION

The purpose of this section of the paper is not to draw conclusions about one side of the debate or other but, rather, to explore further the economic arguments for and against a fixed proportion domestic gas reservation policy. To this end, it focusses on key issues in the debate and draws on a wide range of sources, analytical reports and stakeholder commentary. Available estimates of the net economic effects of domestic gas reservation have been provided at the end of the chapter.

9.1 Effect on short-run domestic supply and prices

Because the eastern gas market was disconnected from the international market, historically increases in gas prices were subdued. In the western market, domestic supply obligations under the *North West Gas Development (Woodside) Agreement Act 1979* also contributed to gas prices remaining relatively low (at an average of around $2/GJ) and stable through the 1990s and early 2000s compared with overseas markets (Figure 24).

Figure 24: International natural gas and LNG prices[171]



However, that situation is now changing in both the eastern and western markets. The development of extensive LNG facilities has increased the demand for gas and supplies are now being reserved for higher value export markets. Subsequent gas shortages have seen domestic prices rise sharply in both markets. In WA, prices have risen from an average of $2 to $3 a gigajoule in the 1990s and early 2000s, to around $8 to $9 a gigajoule for new contracts

---

[171] BP, *Statistical Review of World Energy*, 2013; Western Australia Department of Mines and Petroleum, *Resources data files*, 2013; Note: WA gas prices are calculated by the WA Department of Mines and Petroleum using annual aggregate value and quantity data. These prices do not reflect new contract pricing as gas still may be supplied under lower priced long term contracts

in 2013.[172] The WA Parliamentary Economics and Industry Standing Committee (2011) confirmed that:

> …local WA domgas prices now trade at a significant premium to interstate markets and in a range where netback LNG equivalents can be reached or exceeded.[173]

In Queensland, gas prices increased from $3 to $4 a gigajoule in early 2012 to as high as $7 a gigajoule in 2013 for short-term contracts (Figure 25). In response, stakeholders and industry groups have been lobbying their respective governments to implement reservation policies to secure affordable supplies of gas.[174]

In the context of the WA gas market, the WA Parliamentary Economics and Industry Standing Committee (2011) emphasised the role a reservation policy would serve in alleviating domestic supply constraints:

> …the market does not appear to have responded in a timely manner to the looming domgas capacity constraints that were evident in 2007. This failing has contributed significantly to the excessive price outcomes that are now being realised [and that reservation policies] will play a critical role in alleviating current capacity constraints and offers evidence that government intervention can occur without generating adverse market outcomes. In the absence of a gas reservation policy it is unlikely that LNG producers would develop adequate domestic gas processing facilities.[175]

The introduction of a domestic reservation policy is one possible response to the current challenge of gas shortages and high prices in Australia. There are potential supply and price benefits for wholesale consumers from domestic gas reservation. In the short term, a fixed proportion reservation policy would guarantee a quantity of gas be supplied domestically, irrespective of price or domestic demand. If this quantity supplied is greater than what consumption would have been at the netback price[176], domestic prices will be lower and separate from the netback price. In other words, by diverting gas away from LNG, a surplus of domestic gas will place downward pressure on domestic prices.

---

[172] T Wood et al., op. cit.

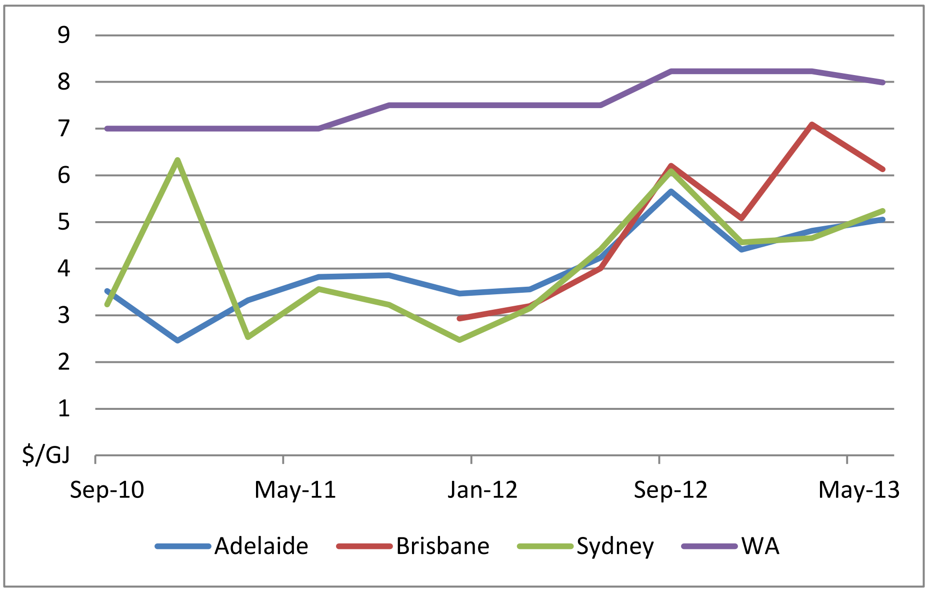
[173] WA Economics and Industry Standing Committee, op. cit., p.77

[174] DomGas Alliance, *Draft Energy White Paper Submission*, 2012

[175] WA Economics and Industry Standing Committee, op. cit., p.82

[176] The netback price is the LNG sale price, less the costs incurred in producing and transporting the LNG to the point of sale.

Figure 25: Wholesale short term gas prices[177]



In the short term, lower prices would reduce the cost base for wholesale consumers (e.g. manufacturers and processors), improving their competitiveness in local and overseas markets. The Bureau of Resources and Energy Economics (BREE) argues that lower gas prices for an extended period of time, in the form of long term supply contracts, would increase domestic gas consumption and promote greater investment in the downstream industry.[178]

These investments may, however, only be viable while prices remain below the netback. According to BREE, gas reservation is a form of protectionism and may distort the market by supporting industries that would otherwise not be sustainable in the long-run without discounted gas prices.[179] The Grattan Institute[180] argues that this distortion may come in the form of diminished productivity and a reduction in a firm's incentive to innovate. For example, if Australia's gas-dependent industries continue to access discounted supplies of gas it may impede the transition to less carbon intensive fuels and more efficient technologies. Protecting industries from international prices also prevents economies from shifting investment and labour to other industries that have a comparative advantage and are more competitive.

[177] Australian Energy Regulator, *STTM - Quarterly Prices*, 2013; Independent Market Operator, op. cit.; Note: Data collected from the Australia Energy Regulator is quarterly data for Adelaide, Brisbane and Sydney commencing September 2010. Data collected from the Independent Market Operator is annual mean price data commencing in 2010-11.

[178] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[179] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[180] T Wood et al., op. cit.

9.2 Effect on investment

The Grattan Institute argues that a reservation policy may undermine the sentiment of prospective upstream investors in Australia.[181] This is because large investments in LNG, particularly those on the east coast, have been made on the premise of existing government policies. Any retrospective changes to those policies may create investor uncertainty and undermine prospects of securing future investment. According to BREE, with diminished returns and weak investor sentiment, in the long run, a reservation policy may reduce investment and result in lower production and higher domestic prices.[182]

The WA Parliamentary Economics and Industry Standing Committee (2011) stated that it:

> …was not persuaded by producer arguments that reservation policies will deter ongoing investment [and that] there is no evidence to suggest that the state's current approach to domestic gas reservation obligations has deterred LNG producers from pursuing development opportunities in Western Australia.[183]

The Committee did, however, emphasise the risk that excessive reservation posed in undermining the incentives for exploration and development:

> …the aim [of a reservation policy] should be to foster the supply and competition needed to allow domgas prices to settle at levels substantially below LNG netback values, whilst offering producers returns that encourage exploration and development. The Committee remains wary that, whilst domestic reservation policies remain a necessity, any heavy-handedness with the application of this tool could conspire against this outcome. The Committee remains concerned that a rigid application of a 15 per cent reservation obligation risks flooding the local market with more gas than it genuinely needs, thus driving prices down to a level where development again becomes uneconomic for current and prospective producers.[184]

DomGas Alliance also argues that a reservation policy will not discourage investment or increase sovereign risk, citing that exploration expenditure had increased since the WA policy was implemented.[185] According to ABS statistics, WA quarterly petroleum exploration expenditure (which is a proxy for investment) more than doubled from $336 million to $800 million between September 2006 and June 2013 (Figure 26).

---

[181] Ibid.

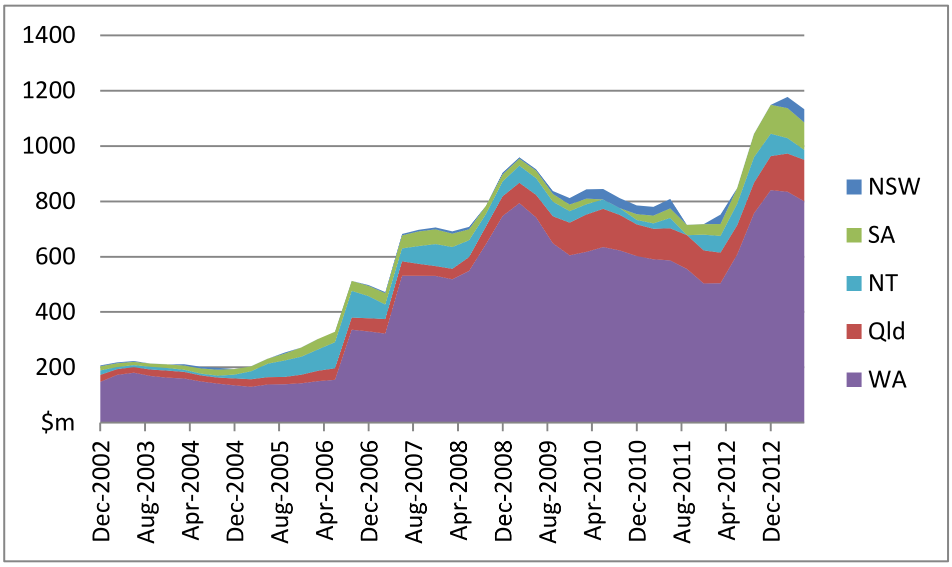
[182] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[183] WA Economics and Industry Standing Committee, op. cit., p.83

[184] Ibid., p.84

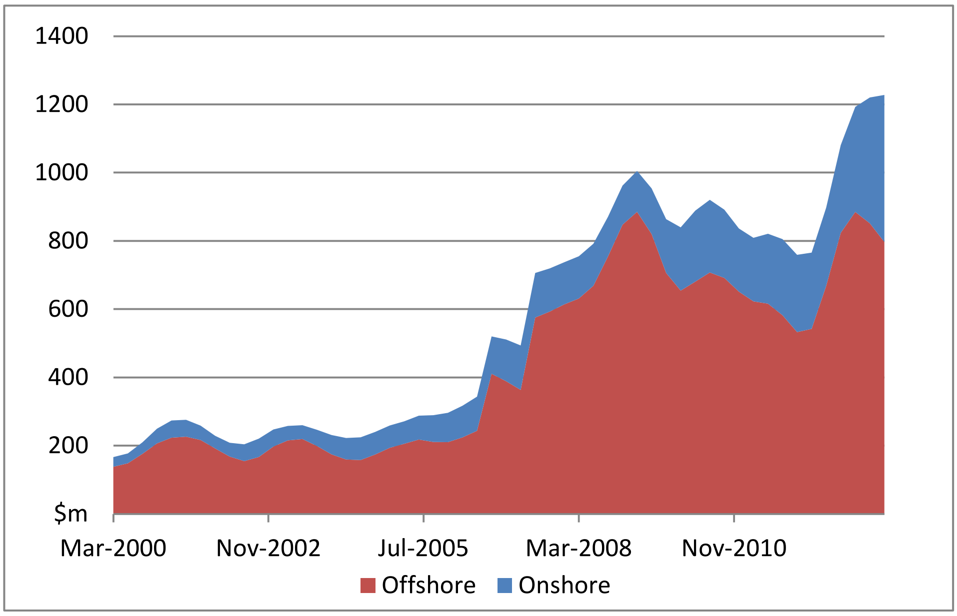
[185] DomGas Alliance, *Australia's domestic gas security*, 2012

Figure 26: Quarterly petroleum exploration expenditure, by State[186]



The increase in exploration expenditure, however, coincided with the sharp rise in the Asian LNG price (see Figure 24), which would have been the main catalyst for investment growth during this period. The evidence also suggests that most of this expenditure occurred offshore in Commonwealth jurisdiction and exempt of the reservation policy.[187] For example, national quarterly offshore exploration expenditure, which is almost entirely attributable to WA, increased by $573 million between March 2006 and June 2013 (Figure 27).

Figure 27: Quarterly petroleum exploration expenditure, by location[188]



[186] ABS, op. cit.
[187] See Section 5.1
[188] ABS, op. cit.

Based on the evidence available, it does not appear to be possible to draw any conclusions about the direct effect (either positive or negative) of the reservation policy on upstream investment under WA jurisdiction.

9.3 Effect on producers

If a domestic gas reservation policy was introduced, the gains to wholesale gas consumers from lower gas prices would, at least in part, be offset by the losses to producers who are obliged to sell a share of their production at a lower price. This reduces returns to producers whose investments generated the increased gas supplies for export in the first instance.[189] This has led some economists to argue that this policy is an implicit tax on domestic gas producers.[190] Unlike an explicit or conventional tax, Governments do not obtain any additional revenue. Rather, this implicit tax is transferred directly as a subsidy to domestic gas consumers. According to Deloitte Access Economics, a reservation policy, similar to other taxes and subsidies, can distort economic decisions and generate economic loss.[191] This was recognised as an issue by a number of stakeholders in the WA Parliamentary Inquiry into Domestic Gas Prices (2011):

> Consultants, producers and regulators argued that reservation policies represent a subsidised price for gas, which produces an economically inefficient outcome [and] such inefficiencies manifested in unsustainable developments in downstream industry that would be overly reliant on artificially priced gas.[192]

Opponents of gas reservation, including the Commonwealth Government[193], believe that the market is best left to determine the price and supply of gas and perverse outcomes may result from sustained subsidised prices. A higher netback linked price is perceived to be an important incentive for infrastructure investment. For example, around $188 billion has been committed to developing LNG export facilities in Queensland and WA.[194] Along with investments in extraction and domestic pipeline infrastructure, this will likely create economies of scale in production which will minimise potential cost of production increases. BREE argues that this will allow for a sustained increase in supply and medium to long run price stability.[195]

---

189 Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

190 Stephen King, 2013, *A gas reservation scheme is protectionism in disguise*, The Conversation

191 Deloitte Access Economics, *The economic impacts of a domestic gas reservation*, 2013

192 WA Economics and Industry Standing Committee, op. cit., p.81

193 Energy Users Association of Australia, op. cit.

194 BREE, *Resources and energy major projects*, April 2013

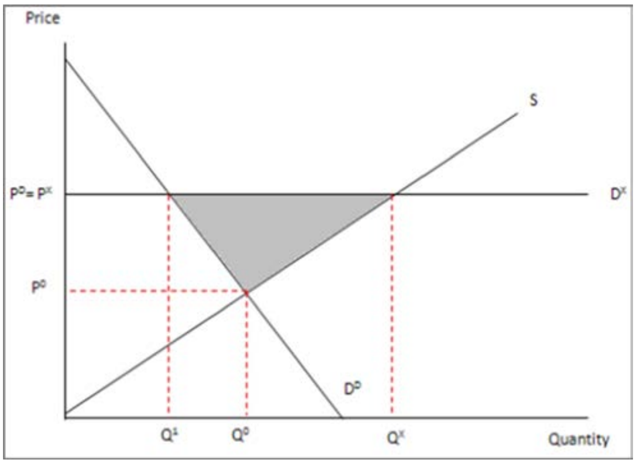
195 BREE, *Gas Market Report*, 2012

Theoretical analysis of fixed proportion domestic gas reservation

The economic principle underlying free trade is that while there are winners and losers, there is generally an overall net gain to an economy. When trade restrictions are removed, the domestic price converges to the international price (netback price). Producers benefit if the domestic non-trade price is lower than the netback price, with consumers being worse off and vice versa.

For example, if the domestic non-trade price (P^0) is below the netback price (P^x), as trade restrictions are removed, domestic users respond to the price increase by reducing their demand (Q^0 to Q^1). There is no limit on domestic consumption of gas, as long as they are willing to pay the export parity price (P^x). Under free trade, supply increases (Q^0 to Q^x) as producers are able to sell at a higher price (P^x). Exports also increase (Q^x - Q^1) and price guides resources to their most valuable use and the economic value is maximised. The net gain to an economy in this situation is represented by the shaded area in Figure 28. This represents the gain to producers less the loss to consumers.

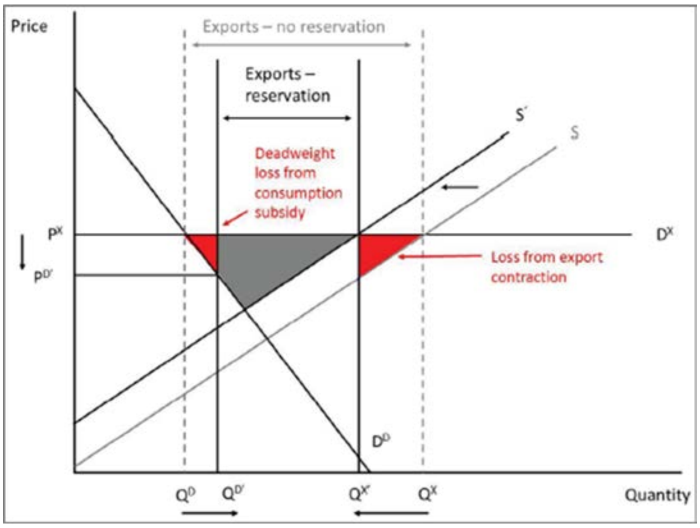
Figure 28: Net gain from restricted to unrestricted trade



A fixed proportion reservation policy (e.g. 15 per cent of exports) entails setting aside an amount of gas for domestic users greater than they would have consumed under free trade ($Q^{D\prime}$). This would result in excess supply of gas at the initial export price, causing the domestic price to fall.

Since gas producers receive a lower price for the quantity produced under a reservation policy, it is essentially a tax on production. In the short run, gas producers respond by reducing total supply (S to S') (Figure 29). This results in a contraction in the total supply of gas and a reduction in exports (Q^x to $Q^{x\prime}$). Deadweight loss, or economic loss, is generated from this policy (red shaded area) because of: reduced returns to producers from foregone export revenue; and the direct subsidy provided to gas consumers, as the marginal benefit of gas to domestic users is below its opportunity cost to producers.

Figure 29: Gas market with a reservation policy imposed



In the long run domestic producers will respond to the lower return on gas production though their investment decisions. Less profitable gas production will lead to a reduction in investment in the industry and total supply will fall even further. This would suggest that long run domestic supply is compromised by the reservation policy rather than assured by it.

It should be noted that this model assumes gas consumers and producers are domestically owned and any net gain from trade would be absorbed by the local economy. In reality, not all upstream gas producers and wholesale gas consumers are domestically owned. Any net gains from trade, or gains from a reservation policy, may be obtained by foreign owned producers and consumers, respectively. While these companies employ local workers and have tax liabilities, any profits resulting from free trade or reservation may be obtained by foreign owned companies. This is an aspect of the reservation debate that would need to be examined.

Source: Deloitte Access Economics (2013)

9.4 Market failure

Proponents of gas reservation[196] argue that the expansion of LNG exports, combined with the inability of wholesale consumers to secure long term contracts at low prices is a form of market failure.[197] Synergies Economic Consulting (SEC) specifically cites a lack of competition in gas supply, particularly in WA, as further evidence of market failure. SEC argues further that, without intervention, it could lead to significant efficiency losses within the economy and result in a reduction in income.

[196] Synergies Economic Consulting, op. cit.

[197] Market failure occurs when resource allocation is not efficient, or when someone is made better off without making someone else worse off.

This has been disputed by a number of key economists and research organisations.[198] The Grattan Institute and Carbon Market Economics argue that sustained high prices and illiquidity in long-term contracts does not lead to a conclusion of market failure and is simply a reflection of changing market dynamics. Previously in Queensland, for example, there were a number of smaller, emerging producers that offered long-term contracts because of the income certainty these provided in allowing them to raise capital for further exploration.[199] This occurred in an isolated market with relatively weak demand and subdued prices because of export constraints. With investments in gas processing and transport technology, the export market is now viable. Although prices and returns from exports are higher, in the short run, the exposure to international markets creates more risk meaning large producers are less willing to enter into medium or long term contracts with domestic consumers. Without a reservation policy, the Australian gas market is now expected to be characterised by shorter term, higher priced contracts at the netback price.[200]

9.5 Estimates of net economic benefits of a reservation policy

Two studies have estimated the net economic effects of introducing a domestic gas reservation policy. The first, commissioned by the Australian Industry Group (AIG) and the Plastics and Chemicals Industries Association (PCIA), examined the net effects specific to the east coast market. The second, commissioned by the Australian Petroleum Production and Exploration Association (APPEA), examined the net effects of a reservation policy to the national economy.

As these Associations are gas consumer and producer groups, they represent different sides of the policy debate, each with vested interests in whether a reservation policy is implemented. Unsurprisingly, the two studies used different methodologies and produced contrasting sets of estimates of the costs and benefits of reservation. The National Institute of Economic and Industry Research (commissioned by AIG and PCIA) estimated the net annual GDP cost to the Australian economy of unrestricted[201] east coast LNG exports to be $22 billion (2009 dollars) in 2040; while Deloitte Access Economics (commissioned by APPEA) estimated the net annual GDP cost of a national reservation policy to be $6 billion (2011-12 dollars) in 2025.[202]

---

[198] Carbon Market Economics, op. cit.; T Wood et al., op. cit.; Deloitte Access Economics, op. cit.

[199] Carbon Market Economics, op. cit.

[200] T Wood et al., op. cit.

[201] This is under the assumption of 24 million tonnes per annum of natural gas export from Queensland

[202] National Institute of Economic and Industry Research, op. cit.; Deloitte Access Economics, op. cit.

9.5.1 National Institute of Economic and Industry Research[203]

The National Institute of Economic and Industry Research (NIEIR), using input-output multiplier analysis[204], estimated that for each petajoule of natural gas shifted away from industrial use towards east coast exports, whether because of tight supply or uneconomic pricing, $255 million in industrial output was lost for a $12 million gain in export output. That is, for every dollar gained, $21 would be lost. This increases to $24 when economy-wide impacts are taken into account.

According to NIEIR, by 2040, the annual gross production benefit for east coast LNG expansion will be $15 billion. However, once the costs of adjustment on other sectors are accounted for, annual GDP would be $22 billion lower than it would be with secure and affordable gas. An alternative approach used by NIEIR (which also accounts for private consumption, tax receipts and net national product) estimates annual GDP would be reduced by $46 billion in 2040 with LNG exports.

9.5.2 Deloitte Access Economics[205]

With forecast investment in LNG production facilities standing in excess of $190 billion, Deloitte Access Economics (DAE) estimated that the development of Australia’s gas export industry could generate $53 billion in annual export earnings by 2017.

The analysis presented in their report demonstrated that the introduction of a 15 per cent fixed proportion reservation policy on the east coast of Australia would come at a significant cost to economic welfare. Against a scenario where production, investment and export decisions are not impeded, DAE estimates that the introduction of this policy on the east coast will cost the Australian economy $6 billion in forgone annual GDP by 2025.

Using economy-wide, general equilibrium methodology[206], DAE estimated that for every one per cent of future gas exports which is artificially re-directed towards the domestic market, annual GDP is reduced by an estimated $150 million by 2025.

---

[203] National Institute of Economic and Industry Research, op. cit.

[204] See NIEIR paper for detailed methodology and results discussion

[205] Deloitte Access Economics, op. cit.

[206] See DAE paper for detailed methodology and results discussion

10. OUTLOOK FOR DOMESTIC PRICES: FACTORS AND FORECASTS

Australia's gas prices have historically been sheltered from international markets, determined largely by domestic supply and demand factors. Abundant supplies of gas, combined with relatively weak demand, meant that long term gas contracts were able to be secured at relatively low and stable prices.

The development of LNG in all three domestic markets has increased the demand for Australian gas. The exposure to higher and more volatile international markets has consequently meant that producers are now less willing to offer domestic medium to long term contracts. Without a reservation policy, prospective domestic prices are now likely to be linked with the netback price and largely influenced by international supply and demand factors.

To date, the reservation debate has been largely focussed on the role such a policy would have on increasing domestic supply at lower prices. While a reservation policy is likely to place downward pressure on prices, there are a number of other factors that will influence price beyond whether a reservation policy is implemented or not. The purpose of this section is to assess the influence these factors will have on short and long run domestic prices.

10.1 Expiration of long-term contracts

Long term contracts have traditionally been the principal instrument for trading gas domestically, as they provided investment certainty to both producers and wholesale gas users. The pricing structure for many of these contracts was based on the cost of production plus an annual price escalator such as the consumer price index.[207]

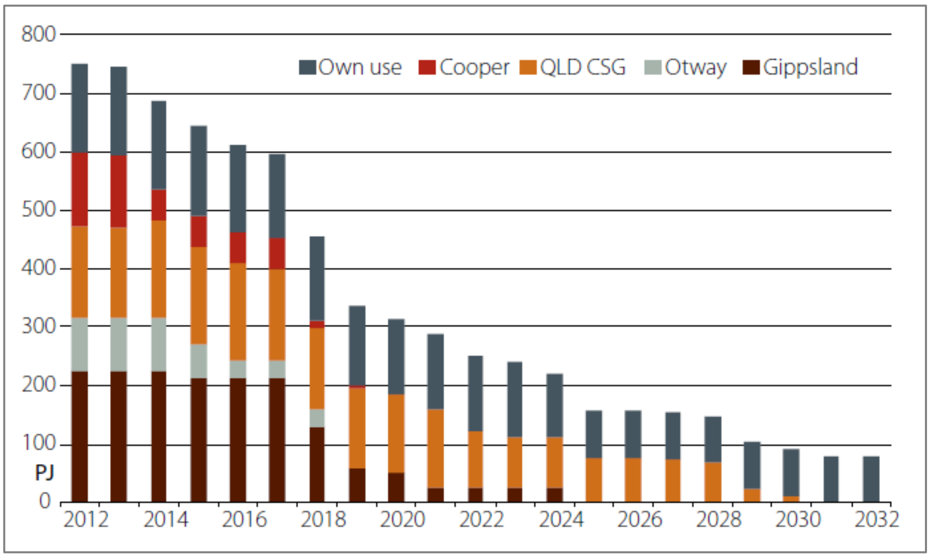
Many of these affordably priced long term contracts were typically negotiated for periods of up to 30 years or more in the 1970s and 1980s. A significant proportion of these long-term gas contracts in the eastern market expired within the last five years, and more are due to expire in the next five years (Figure 30).

With gas producers now able to obtain higher returns from exports, they have a preference to negotiate for overseas contracts and are unwilling to sell forward domestically for extended periods. As more long term contracts expire, the domestic market is expected to be characterised by shorter-term, higher priced contracts[208] as the domestic price converges to the netback price.

[207] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[208] Carbon Market Economics, op. cit.

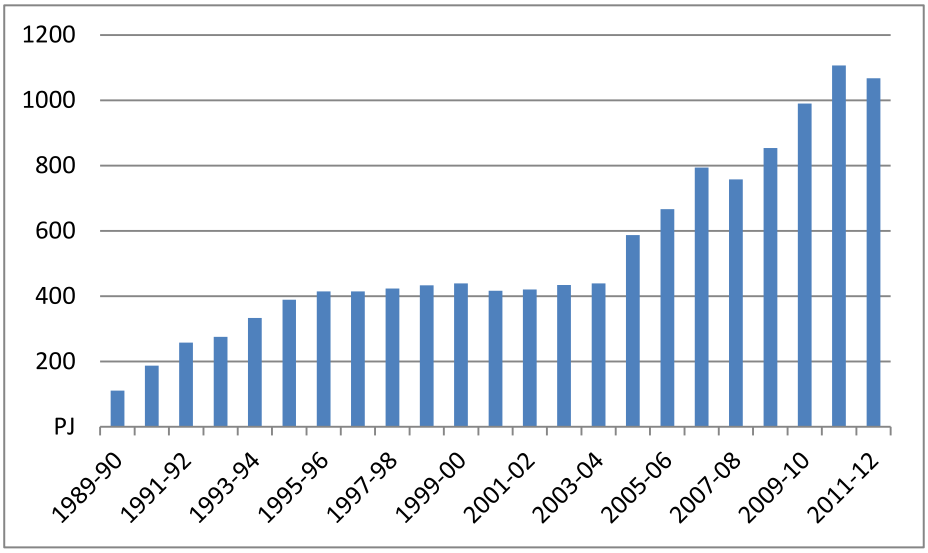
Figure 30: East coast domestic gas contracts[209]



10.2 LNG demand

Australia's LNG exports have increased signficantly over the last two decades. Between 2003-04 and 2011-12, LNG exports have more than doubled from 439PJ to 1,067PJ (Figure 31). This growth has been driven solely by LNG exports from the Western and Northern gas markets, as LNG exports are not expected to be active on the east coast until late 2014.

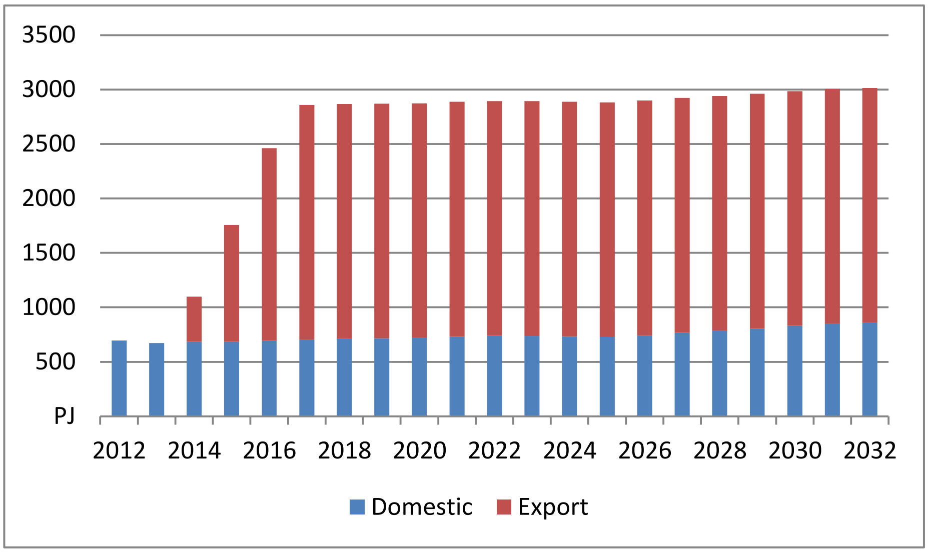
Figure 31: Australian LNG exports[210]



[209] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012
[210] Bureau of Resources and Energy Economics, *Australian energy statistics data*, 2013

According to the Australian Energy Market Operator, between 2013 and 2017, east coast gas demand is forecast to increase fourfold from about 700PJ to 2,800PJ; with most of this to be LNG export demand (Figure 32). The increased demand from the commencement of east coast LNG exports in 2014 will place upward pressure on gas prices in the Eastern market, which should converge over time to the LNG netback price.[211]

Figure 32: Forecast gas demand for eastern Australia[212]



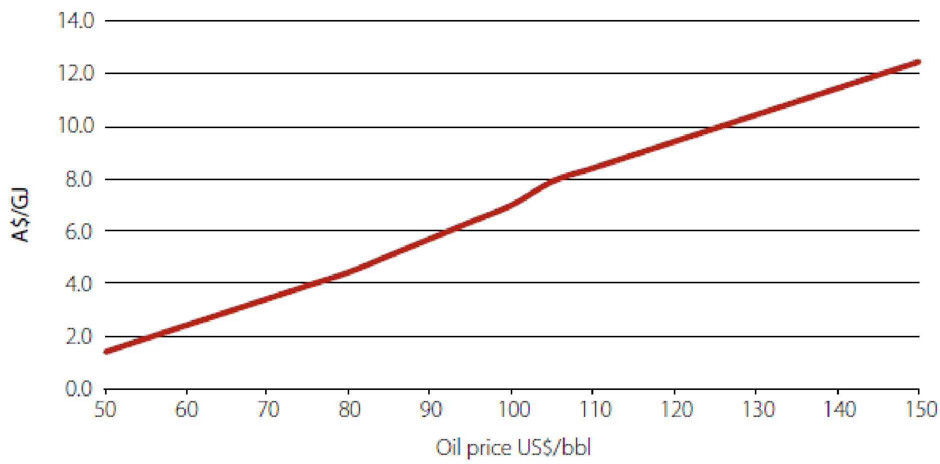
According to the Bureau of Resources and Energy Economics (BREE), because LNG prices in Asia are linked with oil prices, the netback price from the export projects in Queensland will be positively correlated with the price of crude oil. BREE estimate the netback price based on a shipping cost of US$0.75 per GJ, a liquification cost of US$5.10 per GJ and exchange rate of $1.02. As at 14 November 2013, the WTI crude oil price was around US$93 per barrel. This would translate into an LNG netback price equivalent to around $6 per GJ (Figure 33).

---

[211] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[212] Australian Energy Market Operator, *Gas Statement of Opportunities*, 2012

Figure 33: Oil linked LNG netback prices to the Eastern market[213]



10.3 International supply and demand

East coast gas prices have already begun to rise and are expected to converge toward the netback price once the Gladstone LNG facilities are fully operational. A netback linked domestic price is consequently exposed to volatility contingent on international supply and demand factors.

The LNG import price in Japan is, for example, one of the highest in the world at around US$15 per GJ in 2013 but was as low as $9 per GJ in 2009. Prior to 2011, nuclear power supplied around 30 per cent of its energy requirements. Following the Fukushima disaster in 2011, a number of nuclear power plants were closed down. This decreased Japan's domestic energy supply and increased their dependency on LNG imports, placing upward pressure on the LNG import price.

The US, which is one of the largest gas producers in the world, currently has restrictions on LNG exports.[214] LNG exports from the United States are subject to approval by the Federal Government. For exports to non-Free Trade Agreement (FTA) countries, this decision is not automatic and is subject to a public interest test around the likely impact on the domestic market. This has limited the expansion of its LNG facilities and supply to the international market and to date, only two projects have received full export authorisation. If the US Government were to permanently lift export restrictions to countries that have not entered into free trade agreements with the US, there is potential for a significant increase in supply to Asian markets. This would place downward pressure on Asian LNG prices which could become more closely linked to the Henry Hub gas price[215], resulting in a lower netback price in the Eastern

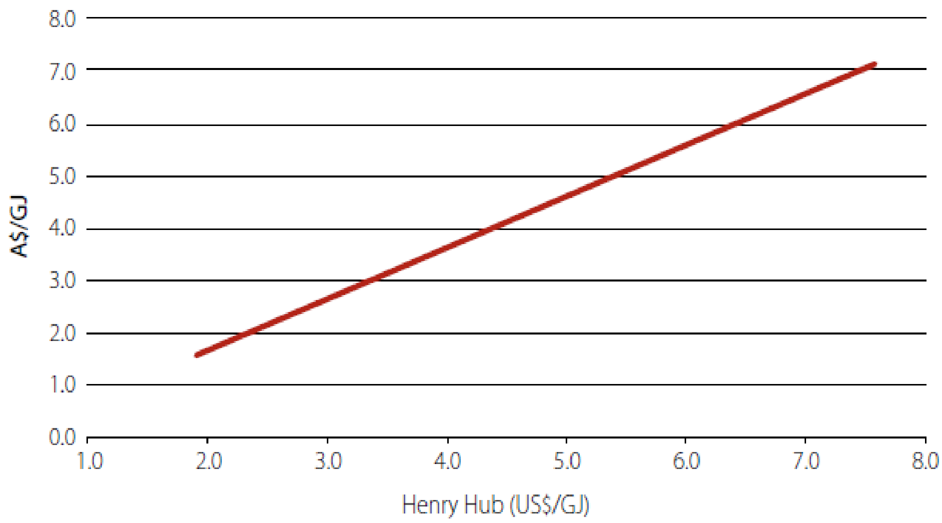
[213] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[214] LNG exports are restricted to countries without free trade agreements with the US. To date, LNG exports have been approved in the US but the restrictions still remain in place

[215] The Henry Hub price is used for gas at is the official delivery location for futures contracts and the main trading point in the US

market. At current Henry Hub prices of around US$3.00/GJ, it would be possible for gas to be delivered to Asia at around US$8.60/GJ. If this was to become the basis for the Asia-Pacific gas price it would equate to a netback price in the Australian Eastern market of about $2.65/GJ (Figure 34).[216]

Figure 34: Henry Hub linked LNG netback prices to the Eastern market[217]



The Henry Hub price is currently not sustainable and industry analysts estimate that it will average around US$4.00–5.00/GJ. This would equate to an eastern market LNG netback price of $3.50–4.50 per GJ.

There would also be downward pressure on Asian LNG prices if Japan restarts a significant number of its nuclear power stations, or if other countries in the region, such as China, were to develop a local shale gas industry.

Although the international price outlook for gas is highly uncertain, based on the aforementioned and other supply and demand factors, there is potential for the prospective netback price to decline.

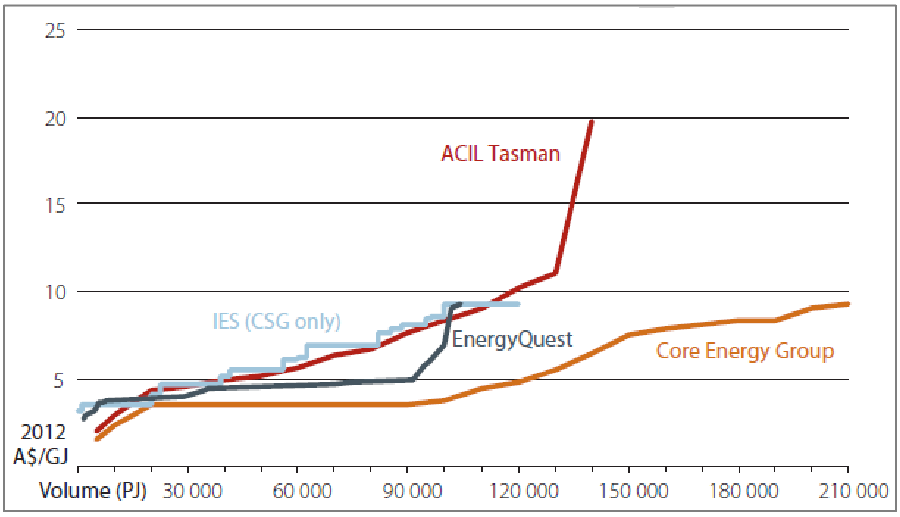
10.4 Production costs

Rising costs of production are likely to contribute to higher gas prices domestically. Much of the gas in Australia is extracted from unconventional sources onshore or conventional sources offshore, significant distances from processing and distribution hubs. Capital and operating costs are consequently higher relative to other conventional natural gas fields. Given the lower cost resources are generally exploited first, over time, production costs are expected to increase as higher cost resources are extracted. This (plus the cost of transport and business margins) reflects what could be considered a long run market price floor.[218]

[216] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012
[217] Ibid.
[218] Ibid.

BREE published EnergyQuest, ACIL Tasman and IES estimates of the eastern market production costs for cumulative reserves and resources below 150,000 PJ (Figure 35). Based on these estimates, gas production costs are expected to increase, albeit at different trajectories, as more gas resources are extracted. Core Energy also estimated gas production costs to increase in Eastern Australia. These costs are lower than those estimated by the other firms, but do illustrate the rising costs of production as more gas is extracted (Figure 35).

Figure 35: Estimated eastern market gas production costs per GJ[219]

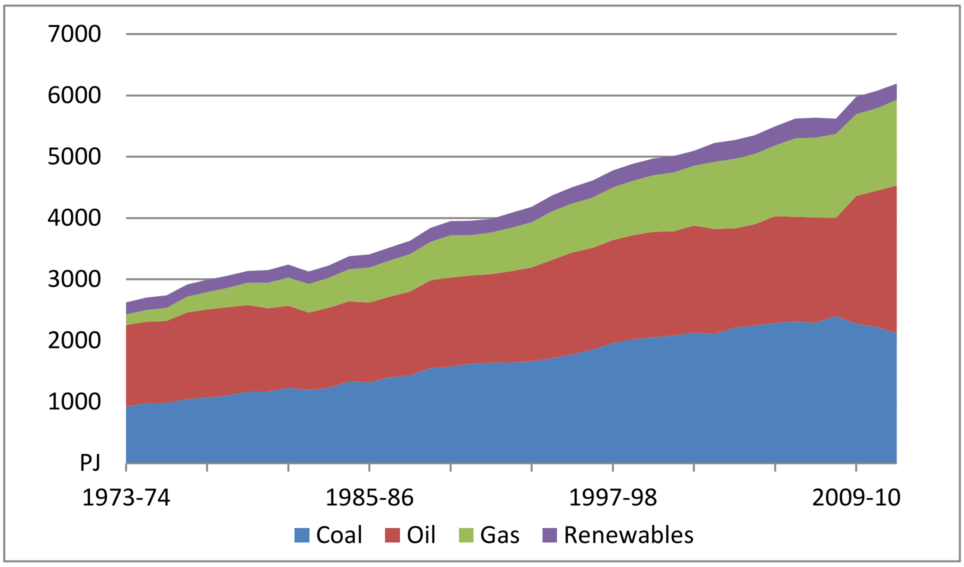


10.5 Domestic demand

Between 1981-82 and 2011-12, gas consumption more than tripled from 462PJ to 1,399PJ. During this period, the share of gas consumption as a proportion of total energy consumption in Australia increased from 14 to 23 per cent (Figure 36).

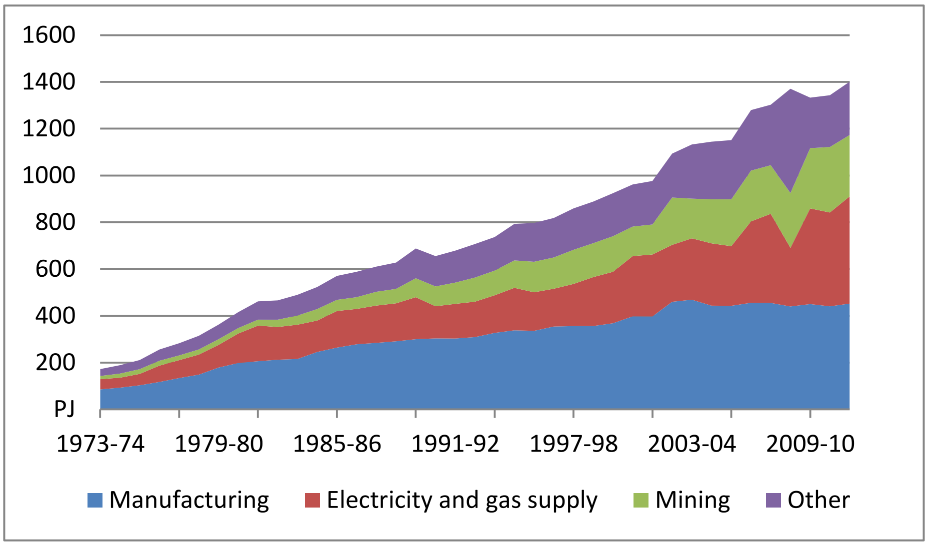
[219] Bureau of Resources and Energy Economics, *Gas Market Report*, 2013

Figure 36: Australia's energy consumption by fuel type[220]



Driven by low historical prices and the availability of long term supply contracts, gas consumption increased significantly for energy intensive industries, such as manufacturing, during the 1970s and 1980s (Figure 37). Investment and production growth in these industries was underpinned by this supply certainty,[221] creating a dependency on gas as a principal source of energy.

Figure 37: Australia's gas consumption by industry[222]



Subdued growth in manufacturing has seen its gas consumption plateau since 2002-03. The recent growth in consumption has instead been associated predominantly with mining and electricity supply. In Western Australia, for

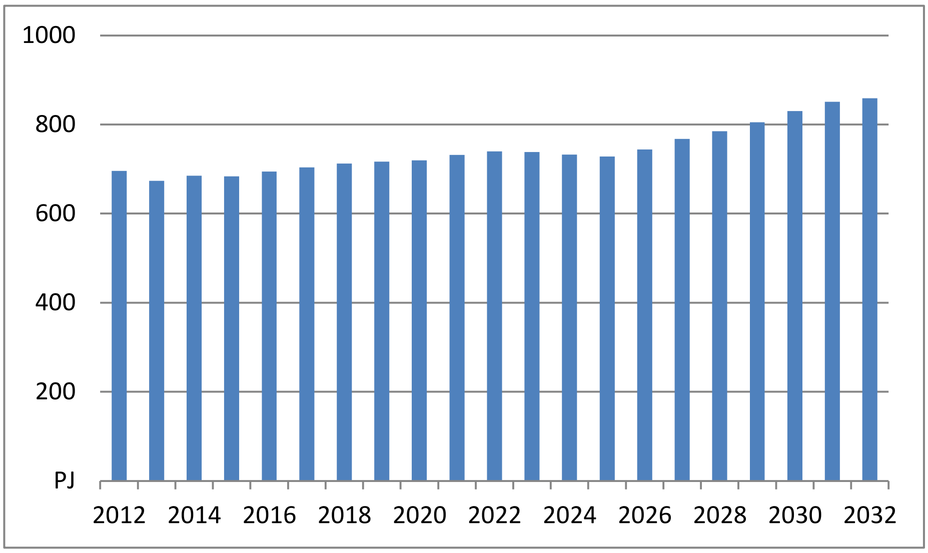
[220] Bureau of Resources and Energy Economics, *Australian energy statistics data*, 2013
[221] T Wood et al., op. cit.
[222] Bureau of Resources and Energy Economics, *Australian energy statistics data*, 2013

example, gas consumption from mining accounted for 184PJ in 2011-12, up from 69PJ in 2001-02. For eastern States such as NSW and Victoria, demand is likely to be underpinned by residential consumption. According to the Australian Energy Market Operator, gas demand in Australia is forecast to increase by 23 per cent between 2012 and 2032 (Figure 38).

Once LNG exports commence on the east coast, domestic gas producers will sell at the netback price which is determined by external supply and demand factors. The Australia Institute argues that, without the introduction of a reservation policy, domestic supply and demand will have virtually no influence on the price of gas.[223] This is because future domestic consumption will only account for a relatively small share of production which will continue to be supplied at the netback price, irrespective of domestic demand.

Under the scenario of a fixed proportion reservation policy, if the quantity of gas reserved for domestic consumption is surplus to those requirements under a free trade scenario, then the price will decline relative to the netback price; in which case, prices are likely to fluctuate depending on domestic demand, in particular gas-fired electricity demand.

Figure 38: Forecast domestic gas use for eastern Australia[224]



10.6 Gas-fired electricity demand

In 2011-12, around a third of the gas consumed in Australia was used for electricity generation. Once converted to electricity, gas-fired generation supplies about 19 per cent of Australia's electricity requirements (Figure 39),[225] with the remainder accounted for by black coal (46 per cent), brown coal (22 per

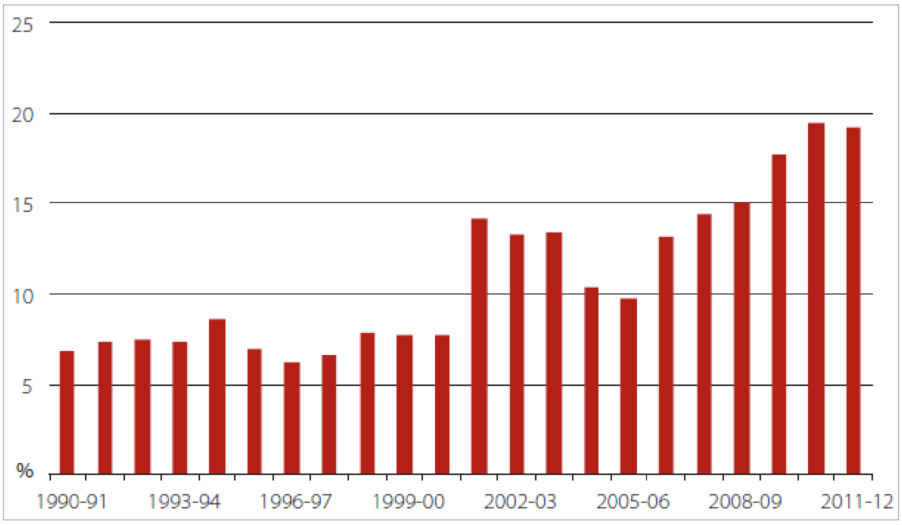
[223] Grudnoff, M., *Cooking up a price rise: Will CSG exports push up the price of gas?*, 2013, The Australia Institute, Policy Brief No. 53

[224] Australian Energy Market Operator, *Gas Statement of Opportunities*, 2012

[225] Bureau of Resources and Energy Economics, *Australian energy statistics data*, 2012

cent), renewable energy (10 per cent) and oil (2 per cent).

Figure 39: Share of gas in total electricity generation, 1989–90 to 2011–12[226]



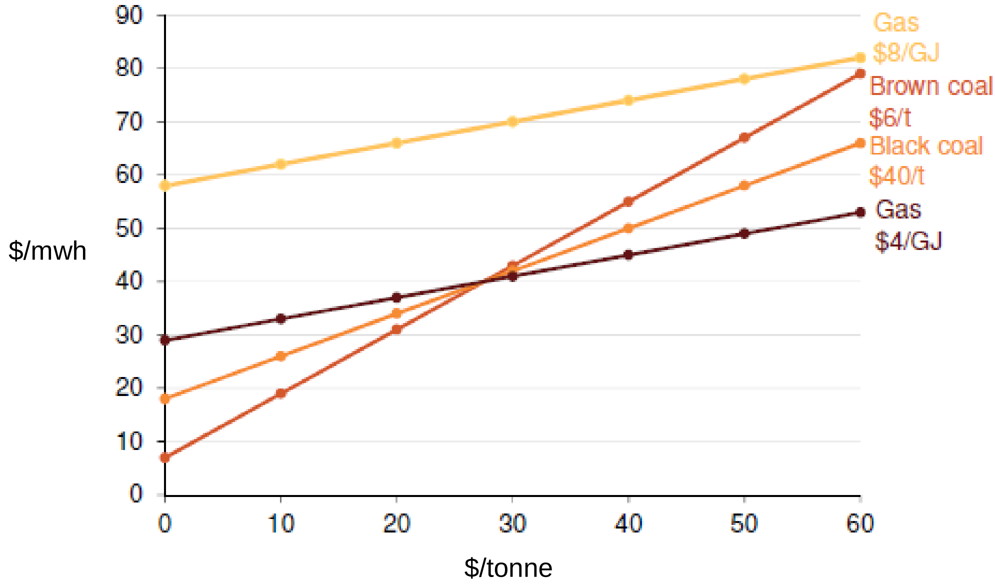
If a reservation policy is implemented, the rate of conversion from coal-fired electricity to less carbon intensive gas-fired electricity will be a factor influencing prospective domestic gas demand and prices. This rate of conversion will be influenced by the prevalence and size of a carbon price.

In July 2012, the Australian Government introduced a carbon price of $23 per tonne of emitted carbon dioxide which was scheduled to rise by 5 per cent a year, until transitioning to a flexible-price emissions trading scheme in 2015. According to the Grattan Institute, with low gas prices and a carbon price of at least $30 per tonne of carbon dioxide, existing gas fired generators are cheaper to operate than black or brown coal-fired generators. Given the carbon price is likely to be removed by the Abbott Government, the likelihood of coal-fired generators switching to gas on this basis is small (Figure 40). The current Renewable Energy Target, which requires energy retailers to buy more than 20 per cent of their electricity from renewable sources by 2020, will also undermine growth in gas demand.

While current conditions may not be favourable for substitution to gas, future developments could reignite the demand for gas in Australia, including: electricity demand growth; stronger and more secure carbon reduction targets under climate change policies; lower gas prices; or a major reduction in the Renewable Energy Target.[227]

[226] Bureau of Resources and Energy Economics, *Gas Market Report*, 2013
[227] T Wood et al., op. cit.

Figure 40: Required electricity price to justify running fossil fuel power plants, at various carbon prices[228]



10.7 Domestic supply

Coal seam gas (CSG) production on the east coast has increased from 1 PJ in 1996 to 247 PJ in 2012, with 97 per cent of current production accounted for by Queensland. Because most of Queensland's CSG production will be diverted to LNG facilities, there are concerns of supply shortages for wholesale domestic consumers. The Australia Institute argues that domestic demand will be met, and diverted from LNG export, provided consumers are willing to pay the netback price for gas; and that changes to domestic supply will have virtually no influence on price.[229] This assumes that there are no production delays; and gas is not tied up in LNG contracts and can be readily diverted to the domestic market. This may not necessarily be the case.

The three LNG facilities being developed in Gladstone are expected to have a combined capacity of 1,346 PJ per annum. AEMO reports that proposed LNG facilities could expand capacity by between 2,316 PJ and 6,612 PJ per annum. East coast gas production in 2012-13 was 700 PJ[230] and will have to increase signficantly to meet projected LNG export demand. According to AEMO, the eastern market has sufficient gas resources to meet demand (from both the domestic and LNG markets) over the 20-year outlook period to 2032, based on industry developing 2P reserves in a timely way.[231] Because of the significant costs associated with developing LNG facilities, their viability is dependent on

[228] Ibid.

[229] Grudnoff, M., op. cit.

[230] Australian Energy Regulator, *State of the Energy Market*, 2012; this includes conventional natural gas and CSG from South Australia, Victoria, NSW and Queensland

[231] Australian Energy Market Operator, *Gas Statement of Opportunities*, 2012

processing capacity being fulfilled. Should domestic production fall short of domestic demand (including LNG), which is acknowledged as a distinct possibility by the AEMO, producers may reserve supplies for LNG facilities that would have otherwise been allocated domestically. In this case, any constraints to production, particularly in Queensland, may place upward pressure on domestic prices.

According to the Grattan Institute, New South Wales faces potential supply constraints because of delays to the CSG approval process, brought about by community and land-holder concerns of groundwater contamination. These delays could place upward pressure on prices on the east coast if gas from the Cooper Basin is diverted to Gladstone and the pipelines from Victoria are insufficient to consistently meet NSW demand.[232] Under these conditions, the severity of supply constraints to the eastern market and any subsequent price increases may be contingent on the approval process and the growth of CSG production in NSW.

NSW currently has 2P gas reserves of 2,827 PJ[233] and with annual gas consumption at 165 PJ in 2011-12. According to BREE, it has the opportunity to significantly increase its production at a lower cost to interstate producers and alleviate potential supply constraints. The marginal cost of production from NSW basins (Gunnedah, Gloucester or Sydney) is estimated to range from $2.70–5.00 per GJ. By contrast, production costs in the Gippsland or Cooper Basin are estimated to be above $4.00 per GJ.[234] Accounting for transport costs, gas could be supplied to NSW from its own reserves at lower cost than is currently sourced from interstate.

In 2012, Australia only accounted for around 9 per cent of global LNG exports.[235] At that market share, it is unlikely that fluctuations in domestic production will have an influence on the netback linked domestic price. Because the European, Asian and North American LNG import markets are, at present, separate and have independent pricing structures, Australia's share of Asian LNG imports, rather than global imports, is of more significance on the netback price. In 2012, Australia accounted for 12 per cent of Asia's LNG imports and 18 per cent of Japan's LNG imports.[236] Once east coast LNG facilities become operational in 2014, it is likely that Australia's share of Asia's LNG imports will increase significantly. Under this scenario, fluctuations in domestic production (which will impact exports) are likely to have more of a bearing on LNG supply and prices in the Asian market. In turn, any changes in Asian LNG prices will correspond with changes in the netback linked domestic price.

[232] T Wood et al., op. cit.

[233] Australian Energy Regulator, *State of the Energy Market*, 2012

[234] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[235] BP, *Statistical Review of World Energy*, 2013

[236] Ibid.

10.8 Gas price forecasts

In the *Gas Market Report 2012*, BREE published price forecasts from a range of market analysts. There was considerable variation in the price forecasts published which arose due to the use of different models, assumptions and parameters by each of the analysts. Almost all of the forecasts, however, show an increase in prices in the eastern and western markets (Table 29).

There is an expectation among analysts that the majority of the price increases will occur in the short to medium term as the domestic price converges to the netback price with expansion of LNG exports on the east coast.

Table 29: Summary of gas price forecasts by various analysts (2011-12 $/GJ)[237]

Analyst	Eastern market		Western market	
	Present[238]	2030	Present	2030
ACIL Tasman 2010	5.2	7.5	8.1	7.9
ACIL Tasman 2011	5.5	10.6	-	-
ACIL Tasman 2012	6	11.7	11.2	11.8
AEMO (IES) 2011	5.9	8.7	-	-
DCCEE (SKM-MMA and ACIL Tasman) 2012	5	5.8	6.3	9.5
Australian Treasury 2011 (SKM-MMA)	-	9	-	9
Australian Treasury 2011 (ROAM)	-	9.3	-	9.3

According to BREE, over the longer term, the linkage between the eastern and international markets, and a competitive domestic gas market should support investment and increase production of gas in Eastern Australia.[239] Prices are consequently expected to stabilise over the longer term (Figure 41). There are, however, international supply and demand variables which may create volatility in the netback-linked domestic price. While gas prices in Australia are generally forecast to rise, it is highly unlikely that wholesale gas prices will reach the same level as the prices seen in Japan, which has no domestic gas supply and imports at a cost of around $5 to $6 per GJ.[240]

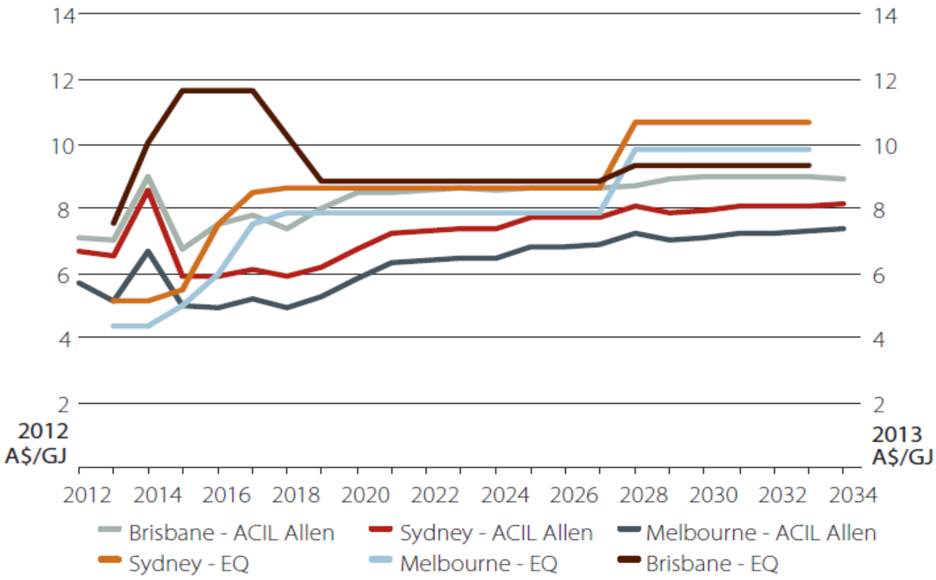
[237] Adapted from: Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[238] 'Present prices' are those which were current at the time in which each of the reports were published

[239] Bureau of Resources and Energy Economics, *Gas Market Report*, 2012

[240] T Wood et al., op. cit.

Figure 41: Eastern market gas price projections, 2012 to 2034[241]



[241] Bureau of Resources and Energy Economics, *Gas Market Report*, 2013

11. INTERNATIONAL IMPLICATIONS OF A RESERVATION POLICY

11.1 WTO Trade Rules

The *General Agreement on Tariffs and Trade*, which was originally signed in 1947, is a multilateral agreement regulating international trade. The GATT was implemented to bring about substantial reduction of tariffs and other trade barriers. The GATT is still in effect under the World Trade Organisation (WTO) framework which was established in 1995. Being a member of the WTO, Australia has legal obligations under this agreement which, among other things, includes rules regarding export restrictions. This may be of relevance if a domestic gas reservation was implemented. Although individual States are not signatories to this agreement, the Commonwealth has responsibility to ensure regulations are adhered to by provincial governments.

Article XI of the GATT provides that:

> No prohibitions or restrictions other than duties, taxes or other charges, whether made effective through quotas, import or export licences or other measures, shall be instituted or maintained by any contracting party on the importation of any product of the territory of any other contracting party or on the exportation or sale for export of any product destined for the territory of any other contracting party.

Article XI allows for several exceptions, including when a country imposes temporary export restraints to alleviate critical shortages of foodstuffs or other essential items, or when the restrictions are necessary to enforce standards for the classification, grading, or marketing of commodities in international trade.[242]

It is highly unlikely that the exception in GATT Article XI for critical shortages could be reasonably invoked by Australia as it is a significant net exporter of gas. The exception in Article XI for ensuring proper standards may allow for proper safety and greenhouse gas emission regulations for LNG exports, but not for a blanket prohibition.

GATT Article XX (General Exceptions) allows a country to ignore Article XI (as well as other GATT articles) and impose export restrictions if they meet very specific requirements.[243] To invoke GATT Article XX, a country must satisfy that export restraints do not constitute a "disguised restriction on international trade" or a means of "arbitrary or unjustifiable discrimination between countries where the same conditions prevail." Provided this is adhered to, export restrictions may be imposed under: Article XX(b) if they are "necessary to protect human, animal or plant life or health"; or Article XX(g) if they relate "to the conservation of exhaustible natural resources". However, as an additional requirement, in order to qualify for either exception, Australia would have to impose restrictions

---

[242] Peterson Institute for International Economics, *Liquefied Natural Gas Exports: an opportunity for America*, 2013, Policy Brief 13-6

[243] World Trade Organization, *WTO rules and environmental policies: GATT exceptions*, 2013

on domestic production and consumption of natural gas as restrictions cannot be limited to LNG exports.

There have been two relevant WTO dispute cases, both brought against China, with respect to breaches of the above GATT Articles.

The first dispute was filed against China by the US (along with a number of other petitioners) in 2009 regarding restrictions on raw materials exports (including bauxite, coke, magnesium and silicon metal), specifically violating GATT articles VIII, X and XI, as well as China's Protocol of Accession to the WTO. The US and other petitioners argued that China's export restraints created scarcity and higher prices in global markets, while China's downstream industries enjoyed an advantage from access to cheaper raw materials.[244] The WTO panel ruled in favour of the US, finding that China's export quotas were inconsistent with WTO rules. China was also unable to prove compliance with Articles XX(b) and XX(g).

The other dispute, which was again filed by the US against China in 2012, related to rare earth metal exports. The US alleged that China's export restrictions (including export duties, quotas, minimum export price requirements and licenses) were violations of Articles VII, VIII, X and XI. China has argued that its policies on rare earth metals were aimed at protecting natural resources and achieving sustainable development[245], in line with Article XX(g) of the GATT. This case is yet to be decided.

WTO disputes were brought by the US against China because, in each case, it accounted for a significant share of global production and exports. From this perspective, these export restrictions were perceived to undermine the competitiveness of the US by increasing the international price of the products (of which the US are a large consumer) and improving the competitiveness of China, whose domestic consumers were able to access the products at significantly discounted prices.

There is therefore a clear distinction between China's export restrictions and prospective reservation policies in Australia. Firstly, China has a 97 per cent share of the global rare earths market and any trade restrictions imposed would have implications on global supply and prices. Australia only had an 8 per cent share of the global LNG export market in 2011-12 and any restrictions on exports would, at present, have minimal effect on global supply and prices. Secondly, China's restrictions were direct violations of GATT Articles and its Protocol of Accession to the WTO.

Western Australia and Queensland are currently the only jurisdictions in Australia with a form of gas reservation policy. It is unclear whether States are

[244] Peterson Institute for International Economics, *Liquefied Natural Gas Exports: an opportunity for America*, 2013, Policy Brief 13-6

[245] World Trade Organisation, *China blocks panel request by the US, EU and Japan on rare earths dispute*, 2012, WTO News

obligated to comply directly with WTO rules. Under Article 3 of the Agreement on Technical Barriers to Trade, however, it is obligatory on a Member to ensure that the regulations of local governments (including States) at the level directly below the central government are notified to the WTO Secretariat.[246] The obligation of a Member is limited to taking reasonable measures as may be available to ensure compliance by local government and non-government bodies.[247] It is unclear what avenues the Commonwealth may have available to prevent States from implementing reservation policies or other export restrictions.

When considering the question of whether or not a domestic gas reservation policy is in breach of GATT Article XI, it is worth noting that other WTO member countries with domestic gas reservation policies have not been subject to a WTO dispute case on the matter. For example, Egypt has an ongoing reservation policy, allocating one-third of proven natural gas reserves for domestic market requirements, one-third for future generations and the remainder for exports. Since 2008, Egypt has also imposed a moratorium on new LNG export projects. To date, no WTO dispute cases have been brought against Egypt involving LNG exports.

It is unclear as to whether or not the WA and Queensland domestic gas reservation policies would be in breach of GATT Article XI. Nonetheless, several observations may be made. First, the WA policy does not actually restrict exports; rather, it sets aside a fixed proportion of gas production for domestic supply. Queensland, not having implemented its policy to date, is not in breach of any WTO trade rules. Second, it appears that, were it the case that the WA policy breached GATT Article XI, it could not claim exception under GATT Article XX(g). This is because it does not impose restrictions on domestic production and consumption of natural gas.

11.2 Free Trade Agreements

Australia is a signatory to the following free trade agreements (FTAs)[248]:

- ASEAN-Australia-New Zealand FTA
- Australia-Chile FTA
- Australia-New Zealand Closer Economic Relations
- Australia-United States FTA
- Malaysia-Australia FTA
- Singapore-Australia FTA
- Thailand-Australia FTA

[246] World Trade Organization, *WTO Agreement on Technical Barriers to Trade*, 2013
[247] Lal Das, B., *World Trade Organisation: A guide to the framework for International trade*, 1999
[248] Department of Foreign Affairs and Trade, *Australia's Trade Agreements*, 2013

These free trade agreements contain provisions that are consistent with Article XI of the GATT and prohibit quantitative restrictions on imports and exports. For example, Chapter 2, Article 7 of the ASEAN-Australia-New Zealand FTA states that:

> No Party shall adopt or maintain any prohibition or quantitative restriction on the importation of any good of any other Party or on the exportation of any good destined for the territory of any other Party, except in accordance with its WTO rights and obligations or this Agreement. To this end, Article XI of GATT 1994 shall be incorporated into and shall form part of this Agreement, mutatis mutandis.[249]

It is difficult to ascertain what obligations individual States have under these FTAs and what would specifically constitute a breach of these prohibitions or quantitative restrictions (with respect to domestic gas reservation).

With regards to the investment interests of foreign corporations, it appears that implementation of a domestic gas reservation policy may be in breach of FTA provisions if the policy infringes upon existing gas rights. Such a possibility would have to be evaluated on a case by case basis.[250] Martignoni and Nygh suggest that this may be the reason why the Queensland Government adopted its Prospective Gas Production Land Reserve policy instead of a fixed proportion reservation policy:

> The decision to adopt the more light handed approach may have been influenced by concerns about claims arising under investment treaties. In particular, the investment interests of Petronas (a Malaysian corporation) and ConocoPhillips (a US corporation) in proposed Gladstone LNG projects are protected under the recently negotiated ASEAN FTA, which came into force on 1 January 2010, and the Australia/USA FTA (AUSFTA) which came into effect on 1 January 2005.[251]

There are at least two limbs to this issue, one concerning standards relating to expropriation and compensation, and exceptions that may apply, the other to minimum standards in respect to the fair and equitable treatment of the investments of foreign corporations. On the first issue, Martignoni and Nygh evaluate the implications of the ASEAN and Singapore-Australia FTAs on a domestic gas reservation policy. Chapter 11, Article 9 of the ASEAN FTA deals with Expropriation and Compensation in relation to investments. Article 9.1 provides as follows:

> A Party shall not expropriate or nationalise a covered investment either directly or through measures equivalent to expropriation or nationalisation (expropriation), except:

[249] Department of Foreign Affairs and Trade, *Agreement Establishing the ASEAN-Australia-New Zealand Free Trade Area*, 2009

[250] A Martignoni and N Nygh, Impact of investment treaties on taxation and market regulation of gas in Australia, *Australian Resources and Energy Law Journal*, 2010, 29(3) pp354-369

[251] Ibid., p.356

a. for a public purpose
b. in a non-discriminatory manner;
c. on payment of prompt, adequate and effective compensation; and
d. in accordance with due process of law.

The FTA provides that Article 9 shall be interpreted in accordance with the Annex on Expropriation and Compensation. Paragraph 2 of the Annex provides that Art 9.1 addresses two situations: direct expropriation, and measures that have an effect equivalent to direct expropriation without formal transfer of title or outright seizure. The second situation is of relevance to domestic gas reservation. Martignoni and Nygh state that:

> The question which arises is whether the imposition of a condition on existing petroleum leases requiring the lessee to retain not less than (say) 15% of gas reserves for supply to the domestic market amounts to an indirect expropriation. Such a condition clearly has the effect of prohibiting export of 15% of the reserves. Depending upon prices available for that gas in the domestic market, such a condition may mean that reserves which would otherwise have been able to be sold profitably as LNG will not be able to be sold other than at a loss.[252]

Under Paragraph 3 of the Annex, the determination of whether any actions constitute an expropriation of the second type requires a case by case, fact-based enquiry that considers, amongst other things:

a. the economic impact of the government action, although the fact that an action or series of related actions by a Party has an adverse effect on the economic value of an investment, standing alone, does not establish that such an expropriation has occurred;
b. whether the government action breaches the government's prior binding written commitment to the investor whether by contract, licence or other legal document; and
c. the character of the government action, including, its objective and whether the action is disproportionate to the public purpose.

With regards to the Singapore-Australia FTA, Chapter 8, Art 19 provides an exception to prohibitions on export restrictions that mirrors GATT Article XX(g); that is, allowing for measures:

> (d) relating to the conservation of exhaustible natural resources if such measures are made effective in conjunction with restrictions on domestic production or consumption.

Martignoni and Nygh observe that this exclusion:

> … is quite limited and would not seem to extend to measures such as those in Queensland and Western Australia to secure gas supply to meet domestic

[252] Ibid., p.360

> demand, in the absence of restrictions on domestic production or consumption.[253]

After reviewing jurisprudence on indirect expropriation, Martignoni and Nygh found that tribunals generally only find that expropriation has occurred where the investor has either lost all or substantial control over the investment or has lost all or most of the economic value of the investment. For this reason, indirect expropriation as a result of regulatory action can be difficult to establish.

On the second issue of the treatment of the investments of foreign corporations, Martignoni and Nygh observe that tribunals are far more likely to find that the Fair and Equitable Treatment (FET) standard of an FTA has been breached. FTAs contain minimum standards for treatment of the investments of foreign corporations, including the FET standard and a full protection and security (FPS) standard. For example, Chapter 8, Article 4.1 of the Singapore-Australia FTA provides that:

> Each Party shall accord to investments of investors of the other Party treatment in accordance with the customary international law minimum standard of treatment of aliens, including fair and equitable treatment and full protection and security.

According to Martignoni and Nygh's review of the relevant jurisprudence, the FET standard is of most relevance to the matter at hand. A breach of the FET provisions can occur, despite the taking being not sufficient to amount to expropriation, if the State has failed to honour the investor's reasonable and legitimate expectations. Martignoni and Nygh conclude that:

> The introduction of the Western Australian gas reservation policy against the practice of negotiated outcomes in Western Australia may … breach the FET Standard … [however] In order to establish a breach of the FET standard it will be necessary to look at each investment on a case by case basis and to carefully consider the reasonable expectations of each investor.[254]

---

[253] Ibid.,p.362
[254] Ibid., p.369

PART THREE – INTERNATIONAL GAS MARKET POLICIES

12. OVERVIEW

Internationally, there have been a range of policies implemented to control domestic gas supply and prices. Most OECD jurisdictions have opted for market approaches without trade restrictions, allowing supply and demand mechanisms to determine prices and quantities. Supply in other jurisdictions, particularly in non-OECD countries (Table 30), is heavily regulated and government intervention most commonly takes the form of: price regulation; majority government ownership; volume reservation; quarantining of acreage for domestic use; and/or export controls.[255]

International approaches can provide useful indicators for Australia, with different policies yielding contrasting price and supply outcomes. According to Energy Quest, wholesale government interventions have generally been unsustainable and have tended to reduce domestic gas prices in the short term, followed by perverse economic or environmental outcomes over the longer term, including: reduced foreign investment; stagnant or negative production growth; strained government budgets; and/or inefficient energy usage.[256]

Table 30: Summary of international gas markets and policies[257]

Country	Majority gov't ownership	Export restrictions	Domestic supply controls	Pricing regulation	% change product'n (2007 to 2012)	% change cons'n (2007 to 2012)
United States	No	Yes	No	No	25.9	10.4
Russia	Yes	Yes	Yes	Yes	0.04	-1.3
Qatar	Yes	No	No	Yes	148.5	35.1
Canada	No	Yes	No	No	-14.3	4.7
Norway	No	No	No	No	28.1	1.1
China	Yes	No	No	Yes	54.8	103.9
Algeria	Yes	No	Yes	Yes	-3.9	27
Indonesia	No	No	Yes	Yes	5.1	14.33
Malaysia	Yes	No	No	Yes	0.9	-0.23
Netherlands	No	No	No	No	5.5	-1.6
Egypt	Yes	Yes	Yes	Yes	9.3	37
Mexico	Yes	No	No	Yes	8.9	31.8

[255] Energy Quest, *Domestic gas market intervention: International experience*, April 2013

[256] Ibid.

[257] Ibid. Note: This is a highly simplified assessment and does not account for the complexity of individual countries' gas policies. Further information relating to specific countries is available later in this report or in the Energy Quest (2013) report.

Country	Majority gov't ownership	Export restrictions	Domestic supply controls	Pricing regulation	% change product'n (2007 to 2012)	% change cons'n (2007 to 2012)
UAE	Yes	No	No	Yes	2.6	36
Australia	No	No	Yes	No	22.8	-4.3
Thailand	No	No	No	Yes	59.2	44.9
United Kingdom	No	No	No	No	-43.1	-14
India	Yes	No	Yes	Yes	33.6	36.1
Argentina	No	No	Yes	Yes	-15.8	7.7
Oman	Yes	Yes	Yes	Yes	20.5	na
Peru	No	Yes	Yes	No	381.3	180.1

Non-OECD countries **Algeria** and **Egypt** are both heavily regulated in terms of ownership, price regulation and supply controls. Domestic gas is highly subsidised in both countries (at US$0.5/MMbtu for Algeria and $US2.13 for Egypt), usually below marginal cost and at significant expense to their respective governments. These prices have catalysed demand growth in both countries (37 per cent for Egypt and 27 per cent for Algeria) over the last five years, resulting in a dependency from wholesale and household consumers. At the same time, gas production has either slowed or declined in these jurisdictions (Table 31), as the price incentives for investment in supply infrastructure are diminished. At current supply and demand trends, gas markets in both countries are unsustainable, with supply shortages, import dependency and price hikes likely outcomes.[258]

Qatar has a similar government ownership regime to Algeria and Egypt and prices are heavily subsidised at less than US$1/MMbtu. However, given Qatar has substantially more reserves and production (Table 31), and a much smaller population, price subsidies are more affordable and sustainable.

Europe has adopted a more deregulated approach, and in most jurisdictions, government ownership and price regulation is minimal, while trade is almost unrestricted. **Norway**, for example, has almost no export barriers and has consequently become one of Europe's largest exporters (predominantly by pipeline), resulting in significant export earnings for its economy. The Norwegian government's emphasis on renewable energy has also seen it transition toward a more carbon efficient economy, with natural gas only accounting for around 5 per cent of its energy requirements. The **United Kingdom** and the **Netherlands** have also adopted deregulated approaches to natural gas, becoming major trading hubs in Europe. The UK has seen production decline, mainly due to a lack of reserve replacement, and has

[258] Energy Quest, op. cit.

become increasingly dependent on natural gas imports. Prices have subsequently increased in recent years resulting in a decline in consumption (Table 31). The UK is responding to price signals by sourcing alternative forms of renewable energy and in the next decade gas consumption is expected to decline as it transitions to a less carbon intensive economy.[259]

Table 31: International gas market statistics[260]

Country	Production	Consumption	Reserves	LNG Exports	LNG Imports	Wholesale gas price
United States	681.4	722.1	8.5	0.8	4.9	4.39
Russia	592.3	416.2	32.9	14.8	0	2.30
Qatar	157.0	26.2	25.1	105.4	0	0.98
Canada	156.5	100.7	2.0	0	1.8	3.69
Norway	114.9	4.3	2.1	4.7	0	3.04
China	107.2	143.8	3.1	0	20	6.31
Algeria	81.5	30.9	4.5	15.3	0	0.50
Indonesia	71.1	35.8	2.9	25	0	5.80
Malaysia	65.2	33.3	1.3	31.8	0	3.84
Netherlands	63.9	36.4	1.0	Na	0	7.00
Egypt	60.9	52.6	2.0	6.7	0	2.13
Mexico	58.3	83.7	0.4	0	4.8	4.90
UAE	51.7	62.9	6.1	7.6	0	1.00
Australia	49.0	25.4	3.8	28.1	0	
Thailand	41.4	51.2	0.3	0	1.4	6.70
United Kingdom	41.0	78.3	0.2	0	13.7	6.56
India	40.2	54.6	1.3	0	20.5	4.36
Argentina	37.7	47.3	0.3	0	5.2	2.41
Oman	29.0	-	0.9	11.2	0	1.50
Peru	12.9	7.5	0.4	5.4	na	2.15
World	3363.9	3314.4	187.3	327.9	327.9	

Russia, which is one of the world's largest producers, exporters and consumers of natural gas, has a heavily regulated market, characterised by majority government ownership, supply controls and significant prices subsidies. These

[259] Ibid.

[260] BP, *Statistical Review of World Energy*, 2013; Energy Quest, *Domestic gas market intervention: International experience*, April 2013; Note: Production, consumption and trade statistics are in billion cubic metres (bcm); Reserves are in trillion cubic metres (tcm); the wholesale gas price is for 2010 in US$/MMbtu.

structures have resulted in highly affordable gas supplies and have been beneficial to many energy intensive industries in Russia. The government owned Gazprom has a monopoly on the pipeline system and exports, which has made market access difficult for non-government producers. Weak incentives from below cost domestic prices have seen investment and production slow. Without sufficient price incentives, supply and demand is likely to continue on current trajectories, making this approach fiscally unsustainable.[261]

North American countries, including the **United States** and **Canada,** have adopted mostly deregulated gas market approaches. Higher prices, particularly in the mid-2000s for the US, were a by-product this approach, but provided the incentive for investment in supply and distribution infrastructure. The distribution network established in the US has connected the east and west coast markets, resulting in increased gas supplies and a decline in prices (Table 31). Pipeline trade is not restricted between the US, Canada and Mexico as they are part of the North American Free Trade Agreement (NAFTA); however, LNG trade has been limited in Canada and the US because of their respective export approval processes.

The regulatory frameworks of the US, Russia, Algeria and Egypt have been outlined to provide a range of perspectives on the effectiveness of different international gas policies.

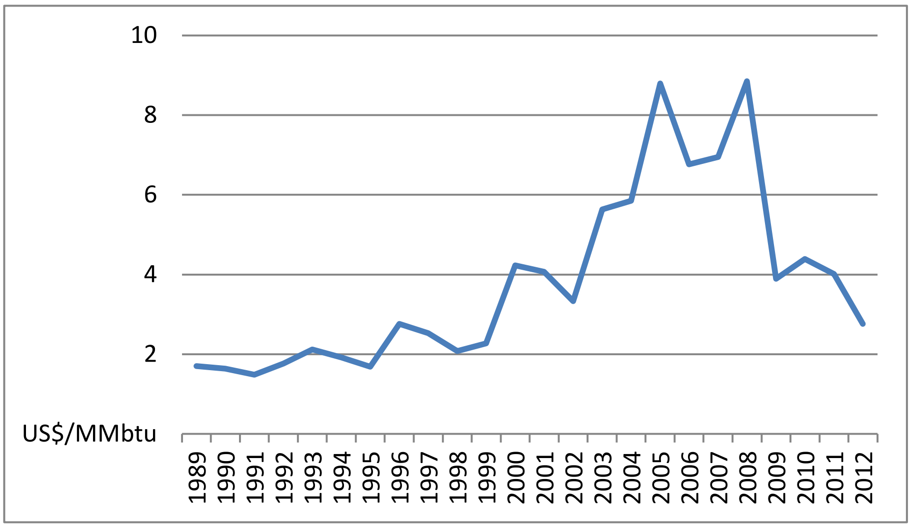
[261] Energy Quest, op. cit.

13. CASE STUDY: UNITED STATES

The US is a significant gas consumer (722 bcm in 2012) and producer (681bcm) and is ranked fifth globally in terms of proven gas reserves (8.5 tcm), equivalent to around 13 years of production. The US is still a net importer of gas, predominantly from Canada.

Domestic supply operates independently of government in the US, with wholesale prices set by the market, having been deregulated in 1989. Because consumption exceeds production US LNG exports have been limited and the domestic price, which is below the netback, is determined internally. Innovations in shale gas extraction and distribution have increased supply and lowered the costs of production, resulting in a significant decrease in the Henry Hub price (from around US$9/MMbtu to below US$4/MMbtu) since 2008 (Figure 42).

Figure 42: US Henry Hub natural gas price[262]



The only form of market intervention in the US is that projects planning to export LNG to non-free trade agreement (FTA) countries require approval. Exports and imports of gas to and from countries without an FTA with the US are permitted provided they are consistent with the public interest. This requirement was introduced in 1938 at a time when the gas industry was being regulated and before the development of LNG or international trade in pipeline gas.[263] The original requirement for approval for all exports and imports was modified in the 1990s to automatically allow gas trade with FTA countries.

The Department of Energy (DOE), which regulates the gas trade in the US, developed a set of Policy Guidelines in 1984 to evaluate import or export applications. While emphasising the role of markets in determining price, these Guidelines highlight the government's responsibility in ensuring that trade arrangements will provide competitively priced gas for the length of a

262 BP, *Statistical Review of World Energy*, 2013
263 Energy Quest, op. cit.

contract.[264] In reviewing export applications, the DOE focusses on the domestic need for natural gas and whether the exports pose a threat to the security of domestic supplies. The US Government has commissioned a number of studies to assess the cumulative impact of large scale LNG exports; several of these studies have clearly indicated that exports would be in the national interest.[265]

To date, two projects have received full export authorisation. The first, the Sabine Pass facility, when completed, will export around 22 billion cubic metres annually, starting in 2016. The second, Freeport, was approved in May 2013. Two others already have sales contracts in place, and are advancing rapidly through the regulatory process with both recently receiving Department of Energy approval. The US Government has indicated that while there is no regulatory timetable for approval, it will process further export applications without undue delay.[266]

US policy has been relatively effective in providing efficient economic outcomes. By allowing the market to determine price, sufficient incentives were in place for investment in the early stages of shale gas production. With an expansion in production (at 3 per cent annually since 2005) and pipeline investment (more than US$32 billion)[267], gas supply has become less costly, resulting in a decline in prices and economic benefits to wholesale consumers.

Because of the population size and distribution networks, the US has sufficient demand domestically to allow for the viability of large scale investment. This is a clear distinction between the US and Australian gas markets. Without this domestic demand, partly because of the physical separation of the east and west gas markets, Australia is mostly dependent on export demand and returns to ensure the viability of large-scale investment in production and distribution facilities. As Australia is a significant net exporter of gas, once the east coast market is connected to the export market, price will be determined externally with domestic supply and demand factors becoming less significant in determining the domestic price.

[264] Department of Energy, *Order Conditionally granting long-term multi-contract authorization to export LNG by vessel from the Cove Point LNG terminal to non-FTA nations*, 2013, Office of Fossil Energy

[265] Office of Fossil Energy, *DOE program regulating LNG export applications*, 2013

[266] Bureau of Resources and Energy Economics, *Gas Market Report*, October 2013

[267] International Gas Union, *Wholesale gas price formation*, 2012, World Gas Conference, Kuala Lumpur

14. CONCLUSION

Until recently, gas prices have remained relatively low and stable in both the eastern and western gas markets. High overseas prices for natural gas, particularly in nearby Asian markets, has seen Australia's LNG industry develop rapidly in recent years. With the expiration of long-term contracts, gas supplies are being reserved for export and prices have risen in both the eastern and western markets. Prices are expected to rise further with the commencement of LNG exports from Queensland in 2014. A domestic gas supply shortfall also appears likely to eventuate from 2015 onwards.

Domestic gas reservation is one of the policies available to State and Federal Governments seeking to ensure the availability of affordable gas to domestic consumers. Government support for domestic gas reservation varies across the country. Western Australia and Queensland have policies in place, and the Victorian Opposition has flagged introduction of a policy should it win the 2014 election. On the other hand, the Commonwealth, Victorian and NSW Governments oppose domestic gas reservation, although the NSW Government has stated that it may reconsider the issue upon establishment of the CSG industry.

In the short term, it is likely that domestic gas reservation would result in benefits for gas consumers and losses for gas producers. However, the potential long-term impacts are contested. According to a study by the National Institute of Economic and Industry Research, commissioned by the Australian Industry Group and the Plastics and Chemicals Industries Association, unrestricted east coast LNG exports will cost the Australian economy $22 billion in 2040. According to a study by Deloitte Access Economics, commissioned by the Australian Petroleum Production and Exploration Association, a national reservation policy would cost the Australian economy $6 billion in 2025. Independent quantification of the possible long-term effects would go some way towards shedding light on the net effect on the Australian economy. However, the difficulty facing governments, consumers and producers alike is that, whether or not a reservation policy is introduced, exposure to domestic and international supply and demand variables makes the price outlook highly uncertain.

GLOSSARY

Coal seam gas (CSG): Naturally occurring methane in coal seams.

Conventional gas: the term generally refers to methane held in a porous rock reservoir frequently in combination with heavier hydrocarbons.

Economic Demonstrated Resources (EDR): resources with the highest levels of geological and economic certainty. For petroleum these include remaining proved plus probable commercial reserves. For these categories, profitable extraction or production has been established, analytically demonstrated or assumed with reasonable certainty using defined investment assumptions.

Export parity price: also known as the netback price, the export parity price is the LNG sale price, less the costs incurred in producing and transporting the LNG to the point of sale

Gas hydrates: Naturally occurring ice-like solids (clathrates) in which water molecules trap gas molecules in deep-sea sediments or in and below the permafrost soils of the polar regions.

Inferred resources: resources with a lower level of confidence that have been inferred from more limited geological evidence and assumed but not verified. Where probabilistic methods are used there should be at least a 10 per cent probability that recovered quantities will equal or exceed the sum of proved, probable and possible reserves.

Liquefied Natural Gas (LNG): Natural gas that is cooled to around -160°C until it forms a liquid, to make it easier and cheaper to transport long distances in LNG tankers to markets.

Natural gas: is a combustible mixture of hydrocarbon gases. It consists mainly of methane (CH_4), with varying levels of heavier hydrocarbons and other gases such as carbon dioxide.

Netback price: see ‘export parity price’

Shale gas: Natural gas which has not migrated to a reservoir rock but is still contained within low permeability, organic-rich source rocks such as shales and fine-grained carbonates. Natural or hydraulically induced fracture networks are needed to produce shale gas at economic rates.

Sub-economic Demonstrated Resources (SDR): resources for which, at the time of determination, profitable extraction or production under defined investment assumptions has not been established, analytically demonstrated, or cannot be assumed with reasonable certainty (this includes contingent petroleum resources).

Tight gas: Gas occurring within low permeability reservoir rocks. In practice it is a poorly defined category that merges with conventional and shale gas, but generally tight gas can be considered as being found in low permeability reservoirs that require large scale hydraulic fracture treatments and/or horizontal wells to produce at economic flow rates or to recover economic volumes

Unconventional gas: Resources within petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences. Typically, such accumulations require specialised extraction technology. Examples include coal seam gas (CSG), tight gas, shale gas and gas hydrates.

APPENDIX 1: RESOURCE CLASSIFICATION SCHEMES[268]

McKelvey Classification Scheme

The McKelvey resource classification system classifies **known (identified) resources** according to the certainty or degree of (geological) assurance of occurrence and the degree of economic feasibility of exploitation either now or in the future (Figure A1). The first takes account of information on the size and quality of the resource, whereas the economic feasibility considers the changing economic factors such as commodity prices, operating costs, capital costs, and discount rates.

Demonstrated resources are resources that can be recovered from an identified resource and whose existence and quality have been established with a high degree of geological certainty, based on drilling, analysis, and other geological data and projections.

Economic demonstrated resources (EDR) are resources with the highest levels of geological and economic certainty. For petroleum these include remaining proved plus probable commercial reserves. For these categories, profitable extraction or production has been established, analytically demonstrated or assumed with reasonable certainty using defined investment assumptions.

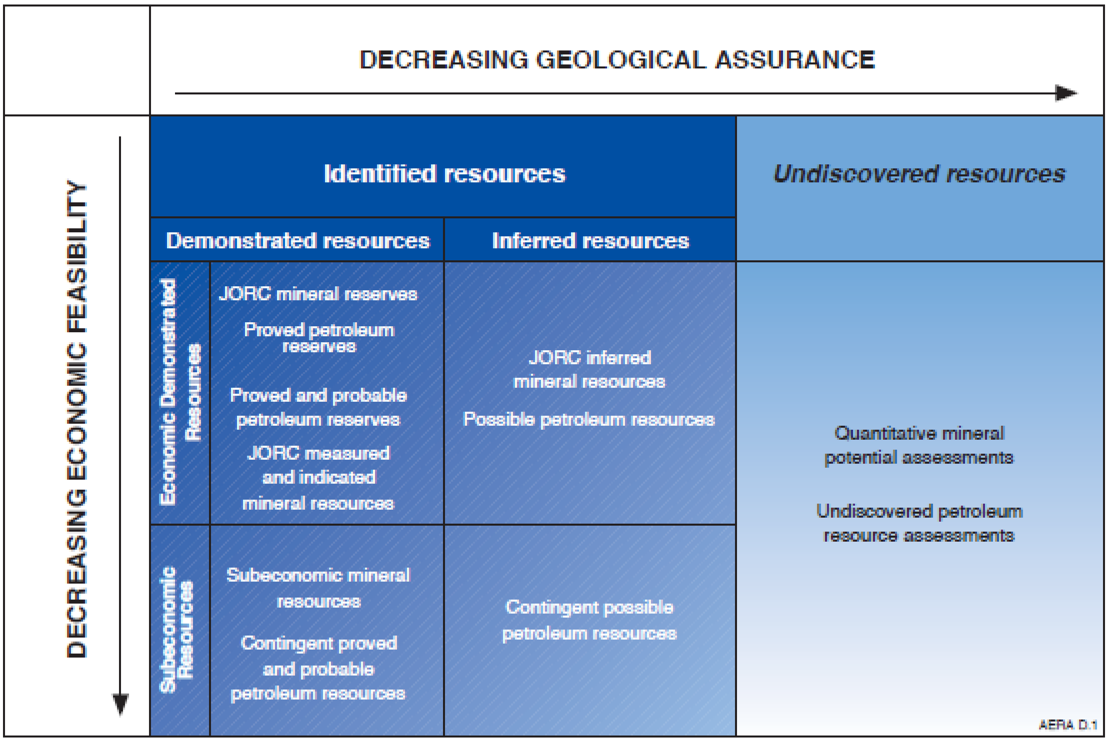
Sub-economic demonstrated resources (SDR) are resources for which, at the time of determination, profitable extraction or production under defined investment assumptions has not been established, analytically demonstrated, or cannot be assumed with reasonable certainty (this includes contingent petroleum resources).

Inferred resources (INF) are those with a lower level of confidence that have been inferred from more limited geological evidence and assumed but not verified. Where probabilistic methods are used there should be at least a 10 per cent probability that recovered quantities will equal or exceed the sum of proved, probable and possible reserves.

Undiscovered or potential resources are unspecified resources that may exist based on certain geological assumptions and models, and be discovered through future exploration. Undiscovered resource assessments have inbuilt uncertainties, and are dynamic and change as knowledge improves and uncertainties are resolved.

[268] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit.

Figure A1: Australia's national energy resources classification scheme (based on the McKelvey resource classification scheme)[269]



Petroleum Resources Management System

While in principle the Society of Petroleum Engineers' Petroleum Resources Management System (SPE-PRMS) applies a similar matrix system to the McKelvey classification schema, of economic feasibility versus geological certainty, the terminology used differs. The system defines the major recoverable resources classes as Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum (Figure A2).

Production is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage

Total petroleum initially-in-place is the quantity of petroleum estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Discovered petroleum initially-in-place is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to

[269] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit., p.50

production. This is equivalent to “identified resources” in Australia’s energy resource classification scheme.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied.

Reserves are further categorized in accordance with the level of certainty associated with the estimates. Low best, and high estimates are donated as 1P/2P/3P, respectively and equate to the following:

- **1P (or P90):** at least a 90% probability that the quantities actually recovered will equal or exceed the low estimate.
- **2P (or P50):** at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.
- **3P (or P10):** at least a 10% probability that the quantities actually recovered will equal or exceed the high estimate.

The different reserves categories are then based on these certainty levels as follows:

- **Proved Reserves** are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (1P or P90) that the quantities actually recovered will equal or exceed the estimate.
- **Probable Reserves** are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P or P50). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
- **Possible Reserves** are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P or P10) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10%

probability that the actual quantities recovered will equal or exceed the 3P estimate.

Contingent resources are those quantities of petroleum estimated to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

As for reserves, contingent resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status. In this case, the low/best/high estimates are denoted as **1C/2C/3C** respectively.

Undiscovered petroleum initially-in-place is that quantity of petroleum estimated, to be contained within accumulations yet to be discovered.

Prospective resources are those quantities of petroleum estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

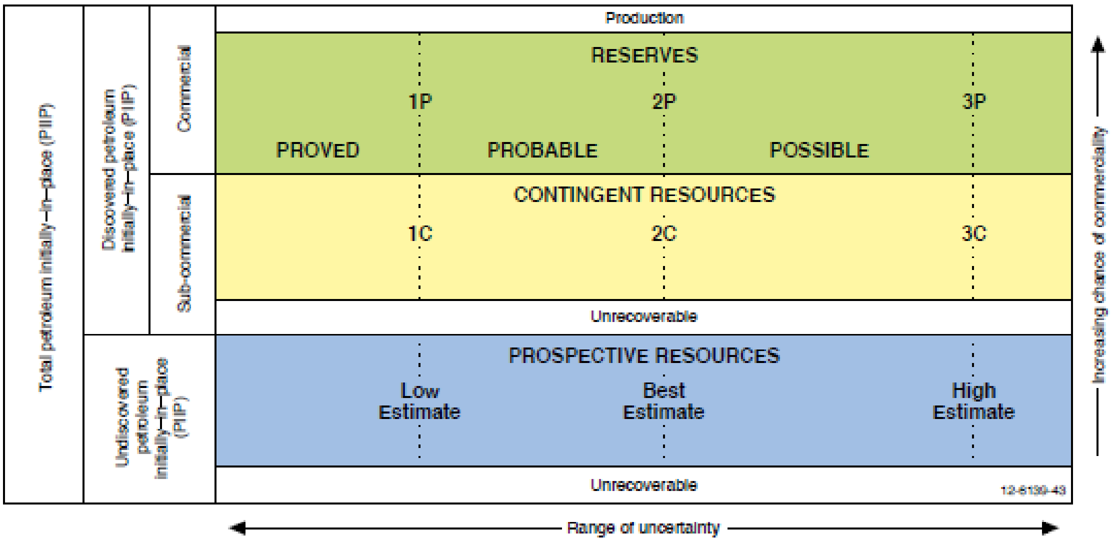
Unrecoverable is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

While in principle SPE-PRMS applies a similar matrix system to the McKelvey classification scheme, of economic feasibility versus geological certainty, the terminology and definitions used differ.

Demonstrated resources (EDR + SDR) of the McKelvey classification are of equivalent certainty to proved + probable resources (P50) of SPE-PRMS. McKelvey inferred resources are of lower certainty and are of equivalent confidence to the SPE-PRMS possible resources (approximately the difference between P50 and P10).

Whilst both schemes differentiate between levels of commerciality, different definitions are used to distinguish between economic and sub-economic resources of the McKelvey scheme, and reserves and contingent resources of SPE-PRMS (see above descriptions for details). The result is that EDR captures a slight larger range of scenarios within the ‘economic’ category, than would be captured as 'commercial' reserves.

Figure A2: Resource classification framework based on the Petroleum Resources Management System of the Society of Petroleum Engineers[270]



[270] Geoscience Australia and Bureau of Resources and Energy Economics, op. cit., p.52