Gas Market Report

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Foreword

Gas is an important component of the global energy supply. As a flexible and clean-burning fuel, its role in the energy mix is expected to increase over the coming decades, particularly as the world transitions to a lower carbon economy.

Global gas markets have been through a major transformation, driven largely by North America, where technological developments have enabled extensive utilisation of shale gas resources. This has contributed to a rapid decline in domestic (Henry Hub) gas prices in the United States and, more significantly, essentially removed the United States from the international liquefied natural gas (LNG) import market. The United States is now in a position to export LNG, with a number of projects at varying levels of development.

The majority of trade outside the United States relies on long term contracts, often with a link to the oil price. The changing dynamics of global gas markets have raised questions about the sustainability of traditional pricing mechanisms. In particular, there is growing pressure on traditional oil-linked pricing mechanisms in Europe and the Asia-Pacific.

Mirroring the trends in global markets, the Australian gas market is also changing. Increased demand for gas in Australia, and globally, has supported the large-scale investment and development of new gas and LNG projects. The development of gas from coal seams on the east coast of Australia, and their use as a feedstock in LNG, is supporting a rapid expansion in export capacity. As a result, Australia is expected to play a more important role in world gas markets, and is set to become the world's largest LNG exporter.

The development of gas from coal seams has not come without challenges, with mounting concern surrounding the effect of these developments on communities and the environment. However, government and industry are working to ensure safe and sustainable development of reserves.

The 2013 edition of the BREE gas market report contains in-depth analyses of these issues by invited authors and provides additional insights into global and Australian gas markets.

Bruce Wilson
Executive Director
October 2013

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Acronyms and abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
bcf	billion cubic feet
bcm	billion cubic metres
BREE	Bureau of Resources and Energy Economics
CCGT	closed cycle gas turbine
cif	cost, insurance and freight
CMA	catchment management authority
COAG	Council of Australian Governments
CSG	coal seam gas
DEWNR	South Australian Department of Environment, Water and Natural Resources
DMITRE	South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy
DOE	Department of Energy (United States)
DPTI	South Australian Department of Planning, Transport and Infrastructure
EDR	economic demonstrated resources
EIA	Energy Information Administration (United States)
EIR	environmental impact report
ESD	environmentally sustainable development
FOB	free on board
EPA	Environmental Protection Authority
EPBC Act	*Environmental Protection and Biodiversity Act 1999*
FTA	free trade agreement
GDP	Gross Domestic Product
GJ	gigajoule
GW	gigawatt
HHV	higher heating value
ICN	industry capability networks
IEA	International Energy Agency
IES	Intelligent Energy Systems
ILUA	indigenous land use agreement

IP	initial production
JCC	Japan customs-cleared crude/ Japanese crude cocktail
Kg	kilogram
kW	kilowatt
LCOE	levelised cost of electricity
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
MIT	Massachusetts Institute of Technology
MMBtu	million British thermal units
mmcm	million cubic metres
mmcf	million cubic feet
Mt	million tonnes
MW	megawatt
MWh	megawatt hour
NBP	National Balancing Point (United Kingdom)
NES	national environmental significance
NGO	non-government organisation
NPC	National Petroleum Council (United States)
NWS	North West Shelf
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
PGC	Potential Gas Committee (United States)
PGE Act	*South Australian Petroleum and Geothermal Energy Act 2000*
PJ	petajoule
SCER	Standing Council on Energy and Resources
SEO	statement of environmental objectives
STTM	short term trading market
tcm	trillion cubic metres
TJ	terajoule
TTF	title transfer facility (Dutch)
US	United States
WTI	West Texas Intermediate

Conversion rates

From	To	mmcm	bcm	tcm	mmcf	bcf	Mt LNG	GJ	TJ	PJ	MMBtu
mmcm	Multiply by:	1	0.001	1.00 x10^{-6}	35.31	3.53 x10^{-2}	7.35 x10^{-4}	38800	38.80	3.88 x10^{-2}	36775
bcm		1000	1	1.00 x10^{-3}	35313	35.31	0.735	3.88 x10^{7}	38800	38.80	3.68 x10^{7}
tcm		1.00 x10^{6}	1000	1	3.53 x10^{7}	35313	735	3.88 x10^{10}	3.88 x10^{7}	38800	3.68 x10^{10}
mmcf		0.028	2.83 x10^{-5}	2.83 x10^{-8}	1	1.00 x10^{-3}	2.08 x10^{-5}	1099	1	1.10 x10^{-3}	1041
bcf		28.32	0.028	2.83 x10^{-5}	1000	1	0.021	1.10 x10^{6}	1099	1.099	1.04 x10^{6}
Mt LNG		1361	1.361	1.36 x10^{-3}	48045	48.04	1	5.28 x10^{7}	52787	52.79	5.00 x10^{7}
GJ		2.58 x10^{-5}	2.58 x10^{-8}	2.58 x10^{-11}	9.10 x10^{-4}	9.10 x10^{-7}	1.89 x10^{-8}	1	1.00 x10^{-3}	1.00 x10^{-6}	0.948
TJ		0.026	2.58 x10^{-5}	2.58 x10^{-8}	0.910	9.10 x10^{-4}	1.89 x10^{-5}	1000	1	1.00 x10^{-3}	948
PJ		25.77	0.026	2.58 x10^{-5}	910	0.910	0.019	1.00 x10^{6}	1000	1	9.48 x10^{5}
MMBtu		2.72 x10^{-5}	2.72 x10^{-8}	2.72 x10^{-11}	9.60 x10^{-4}	9.60 x10^{-7}	2.00 x10^{-8}	1.055	1.06 x10^{-3}	1.06 x10^{-6}	1

Notes:

1. To convert 10 million tonnes of LNG into million cubic metres, multiply by 1361—10 million tonnes LNG = 13 610 million cubic metres of gas

2. 1 million cubic metres	= 10^{6}	x 1.0 cubic metre (m^3)	
3. 1 billion cubic metres	= 10^{9}	x 1.0 cubic metre (m^3)	
4. 1 trillion cubic metres	= 10^{12}	x 1.0 cubic metre (m^3)	
5. 1 gigajoule	= 10^{9}	x 1.0 joule (J)	
6. 1 terajoule	= 10^{12}	x 1.0 joule (J)	
7. 1 petajoule	= 10^{15}	x 1.0 joule (J)	
8. 1 British thermal unit	= 1055 joules (J)		
9. 1 tonne	= 10^{3}	x 1.0 kilogram (kg)	= 2205 pounds (lbs)

Overview—developments in world and Australian gas markets

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Introduction

Natural gas is an increasingly important source of energy globally and in Australia. Its principal component is methane (CH_4) and, when produced and consumed efficiently, it offers a lower carbon emissions footprint than other fossil fuels used in comparable technologies or processes.

Natural gas can be produced from a wide variety of sources. Most commonly it is extracted from subterranean storage similar to (or often associated with) conventional crude oil products. However, new drilling and extraction technologies have, over the past decade, opened up vast new reserves in the form of gas embedded in coal seams and shale and tight rock formations. These newer sources of gas account for about 40 per cent of the world's recoverable resources (IEA 2013b, pp. 40–42) and about 18 per cent of total gas supply[1]. Gas can also be produced from other sources such as biogas from the decomposition of waste matter.

A principle attraction of gas is its flexibility. As a transportable fuel that requires little end-use processing it can be used in a wide number of applications—in the residential sector for space heating, cooking, and heating water; in the industrial sector for process heat or in other applications where clean combustion is particularly important. It is also used in the production of glass or certain non-ferrous metals; and increasingly in electricity generation where it can provide base load or fast start generation capacity (see Box).

Despite its attractions, the growing demand for gas is placing pressure on costs as well as generating a range of environmental and social tensions associated with production and supply. Successfully managing these factors will prove crucial if the gas industry is to develop to its potential in coming decades.

1 The IEA (2013a) estimates total global gas production in 2012 at around 3433 billion cubic metres while global unconventional gas production is estimated to be around 620 billion cubic metres.

The global role of gas

Gas currently accounts for about one fifth of global energy consumption (IEA 2012a, p. 53). Historically, gas was predominantly consumed in the region or country where it was produced. However, over the past few decades international gas trade has grown rapidly, initially through large diameter transcontinental pipeline delivery, and more recently as liquefied natural gas (LNG). LNG now represents about 10 per cent of total global gas supply—around 240 million tonnes a year[2], but accounts for about 60 per cent of the interregional trade in gas (IEA 2013a, p.121). By contrast, interregional pipeline gas trade in 2011 was around 238 billion cubic metres or about 40 per cent of total gas trade (IEA 2013a, p. 121), although pipelines deliver a much larger proportion of gas that is transported within regions.

While the cost of transporting gas can be significant—for example in terms of LNG the costs of liquefaction, transportation and regasification can account for as much as 80 per cent of the final delivery cost (IEA 2013b, p. 103)—the advantages of gas as a fuel, including its relative cost competitiveness, has seen growth in total global gas consumption increase more than four fold over the past 50 years (MIT 2011, p. 4).

2 Gas can be measured in terms of its energy content (in joules or British thermal units) or by volume (in cubic metres or cubic feet) or, for LNG, in terms of weight (in metric tonnes or tons). In this chapter we use a volume measure of billion cubic metres because gas from different sources varies in its energy content. To convert 1 million tonnes (Mt) of LNG to its equivalent in billions of cubic metres (bcm), multiply by 1.361. Thus, 240 million tonnes of LNG is equivalent to about 330 billion cubic metres.

Electricity from Gas

There are two main types of gas-fired power generation technologies—conventional open cycle gas turbines (OCGT) and combined cycle gas turbine technology (CCGT). CCGT combines existing high performance gas turbines with a steam turbine that utilises waste heat from the gas turbine, the so-called bottoming cycle, thus delivering much higher levels of thermodynamic efficiency than conventional thermal power plants.

Newer gas plants are generally delivered quickly, have high certainty on capital costs, and high operational and economic flexibility. Typically, CCGT has higher load factors and can generate power for longer periods each year than OCGT, which are more commonly used in peak applications. In the longer run there is the potential for CCGT to be combined with carbon capture and storage technologies to reduce its emissions footprint by up to 90 per cent (BREE 2012a).

Table 1. Key performance parameters and cost estimates for gas generating options

Technology Description	CCGT	OCGT
Fuel Type Assumed LCOE of existing CCGT plant A$/ MWh		
Capital Costs A$/kW net	1062	723
Construction profile % of capital Cost	Year 1 = 60%	Year 1 = 100%
	Year 2 = 40%	
Typical new entrant size MW gross/net	386/374	564/ 558
Economic Life (years)	40	30
Lead time for development (years)	2	1
Average capacity factors	83%	10%
Thermal Efficiency (sent out – HHV)	49.50%	35%
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	0.35%	0.30%
Emissions rate per kgCO_2e/MWh	357 (Gross)/368 (Net)	509 (Gross)/515 (Net)

Source: BREE 2012a.

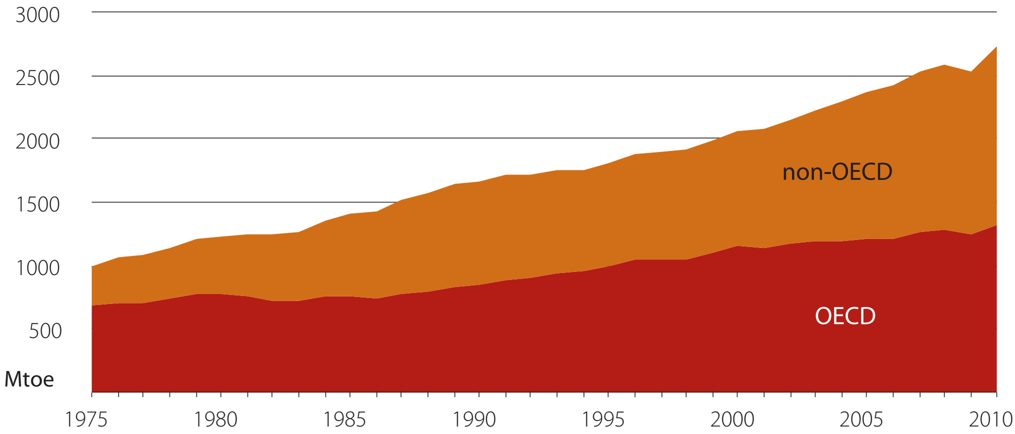
As modelled in the International Energy Agency's (IEA) 2012 World Energy Outlook, a concerted global action to substantially limit increases in carbon emissions will provide further impetus for a larger uptake of gas in the future (particularly as the world transitions away from higher emitting fuels and technologies).

The internationalisation of gas trade has also been a key factor in promoting global energy security through more mature and interlinked energy markets, which provide for greater inter-fuel substitutability—a factor of particular attraction to energy import dependant countries such as Japan and the Republic of Korea.

The power sector has driven the growth in gas consumption over the last decade

In 2010, gas accounted for nearly 22 per cent of global energy consumption; in Organisation for Economic Co-operation and Development (OECD) countries it was somewhat higher at 24 per cent.

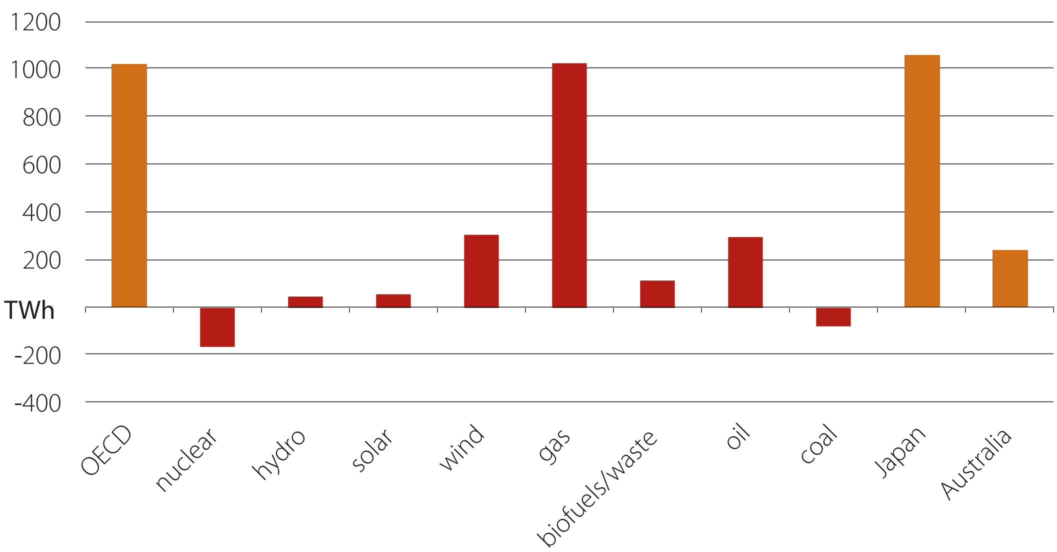
Figure 1. Trends in global gas use, 1975–2010



Source: IEA 2012b.

Gas use in OECD countries particularly accelerated from the early to mid-1990s as it emerged as the key source of new power generation. Between 2000 and 2011, OECD gas-fired power generation increased by 1026 terawatt hours, or around two-thirds, equivalent to Japan's current total power output from all sources (Figure 2).

Figure 2. Incremental power output in OECD, by power source 2000–11



Source: IEA 2012c.

Outside the OECD, gas use is more prominent in large gas producing countries or regions such as the Russian Federation and the Middle East where it is relatively low cost. For instance, the Russian Federation (which has very large reserves) sources more than 55 per cent of its energy needs from gas, including for more than half of its power needs. Similarly, gas provides more than half of the Middle East's energy needs, and more than 60 per cent of power sector requirements. By contrast, gas has been historically far less important in China and India, where coal dominates the power sector.

While global trade is growing, markets and pricing remain divergent

Overall, the global gas trade picture is complex. As with many commodities, there is no global market, rather there are a set of (albeit increasingly interlinked) regional markets defined by their own different supply and demand characteristics.

Gas trade in Europe is dominated by pipelines supplied from a mix of domestic reserves and large scale imports from the Russian Federation, Norway and North Africa. More recently, Europe has increased LNG imports (largely in response to high Russian gas prices) with trade growing by more than 40 per cent between 2007 and 2011 to 330 billion cubic metres. This has been supported by the rapid expansion of supplies from Qatar—the world's largest LNG producer.

North American gas markets are effectively self-sufficient. US gas demand has historically been met by domestic supply and imports from Canada through a highly mature and interconnected pipeline system. This is changing as the rise of shale/tight gas is altering trade patterns and market dynamics in ways that are yet to be fully understood (see discussion in the next section and chapter 5).

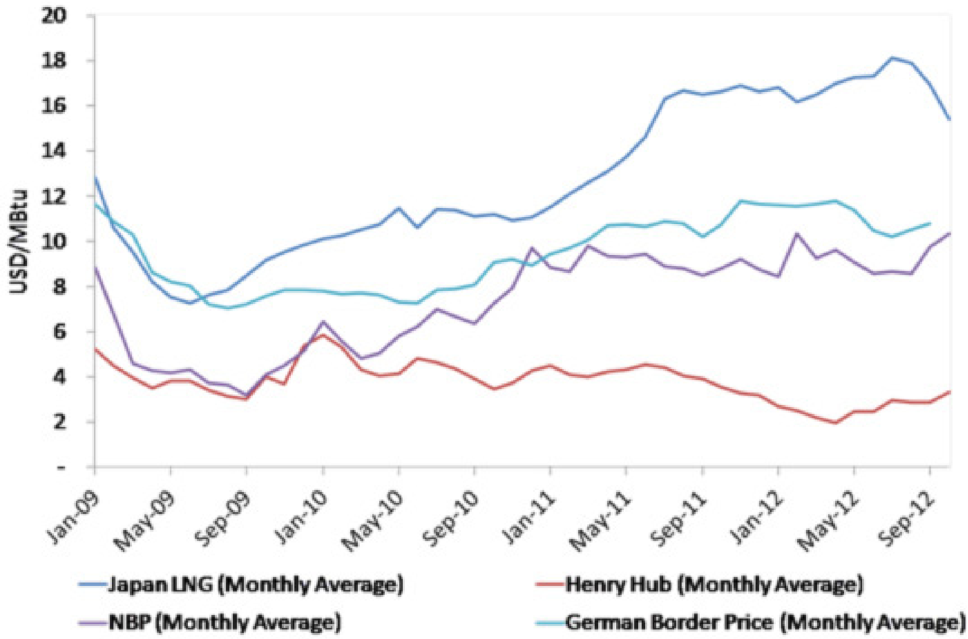
The Asia-Pacific market, with comparatively less indigenous gas resources, has a much higher reliance on LNG to meet its needs. Japan and the Republic of Korea are both totally reliant on LNG imports and, in the case of Japan, LNG currently supplies more than one third of electric power needs. Collectively, Japan and the Republic of Korea import 160 billion cubic metres of gas, equivalent to about 120 million tonnes, and buy about half of the global LNG production. This has been the foundation for large scale LNG development in countries such as Australia. While LNG trade into China has grown significantly this is from a relatively small base in terms of China's overall energy consumption.

The differing characteristics of each market, notably the predominant mode of supply (pipeline versus LNG), the traded volumes in each, along with their historical evolution and a relative lack of interregional trade have resulted in different pricing mechanisms and an ongoing separation of prices (Figure 3).

Long term gas contracts tied to a form of oil indexation dominated the early growth of pipeline trade, especially in Europe in the 1970s and 1980s, and subsequently the growing LNG trade (although the actual oil index formulas vary considerably). There is evidence to suggest that this is beginning to change towards a greater use of spot trading. However, it is yet to be clearly established whether this will result in a sustained broad shift in pricing models (see the paper by Stern in chapter 6 for a more detailed discussion).

In North America, a long process of market reform was the key to producing a strongly competitive and essentially spot market, where gas is priced on the fundamentals of supply and demand. While this can lead to sudden price spikes if demand increases suddenly or supply is disrupted, such as when hurricanes affected production in the Gulf of Mexico region in 2005, it has been a significant reason why North American gas prices remain the lowest in OECD.

Figure 3. Wholesale gas prices in major OECD gas markets 2009–12



Source: IEA.

The outlook for gas to 2020: pipeline trade and LNG growth[3]

Gas consumption to grow strongly

Increased utilisation of gas in the power sector is expected to continue to drive an expansion of gas use in all major regions over the next decade. Global consumption is expected to grow by between 2 to 3 per cent a year over the next five years (IEA 2013a), and by around 50 per cent over the period to 2035.

Of the 640 billion cubic metre increase in global consumption that is projected between 2010 and 2020, around 80 per cent will come from outside the OECD, with China accounting for one third alone. Middle East consumption is expected to grow by nearly a third, and to account for one sixth of the global increase. Indian gas consumption is projected to increase by around 50 per cent, albeit from a low base.

Conventional and new sources of gas production will increase

Conventional gas production will continue to be dominated by non-OECD countries. China's production will almost double to 175 billion cubic metres. Production increases are also expected in Qatar (56 billion cubic metres, almost all by 2015), the Russian Federation (50 billion cubic metres) and Turkmenistan (40 billion cubic metres), which will contribute to a projected 659 billion cubic metre increase in global production (see table 2).

European conventional production is expected to continue the decline observed in the last decade, most clearly in the United Kingdom as the reserves in existing fields diminish.

Gas output in the United States (largely shale/tight gas) and Australia (new offshore and coal seam fields) is projected to increase by around 150 and 53 billion cubic metres, respectively, over the period 2010 to 2020.

3 The gas supply and demand outlook discussed in this paper draws heavily on the 2012 IEA World Energy Outlook, except where otherwise identified.

Table 2. Projected global gas production

	2010	2020
	Bcm	Bcm
OECD	1178	1328
Americas	816	970
Canada	160	171
Mexico	50	51
United States	604	747
Europe	304	250
Norway	110	118
Asia Oceania	58	107
Australia	49	102
Non-OECD	2106	2616
Eastern Europe/Eurasia	842	968
Azerbaijan	17	30
Russian Federation	657	704
Turkmenistan	46	84
Asia	420	548
China	95	175
India	51	62
Indonesia	86	109
Middle East	472	609
Iran	143	150
Iraq	7	41
Qatar	121	177
Saudi Arabia	81	107
United Arab Emirates	51	57
Africa	209	277
Algeria	80	105
Libya	17	20
Nigeria	33	58
Latin America	163	213
Argentina	42	49
Brazil	15	32
Venezuela	24	37
World	3284	3943

Source: IEA 2012a.

LNG trade will continue to grow strongly but so will supply competition

Growing gas demand in key Asia-Pacific countries is expected to be largely met through LNG imports, although there is potential for pipeline supply from the Russian Federation and Middle East into some areas.

LNG is expected to play a much more important role in Japan's energy future than was previously anticipated, following the large scale shut-down of nuclear plants in the wake of the incident at the Fukushima Dai-ichi plant. As a result of the shut-down of its nuclear power plants, Japanese gas imports have increased by about 20 per cent. Large increases are projected for imports to India, mostly via LNG, and to China, via both pipelines and LNG. Growth in other major LNG importing countries in Asia, such as the Republic of Korea and Chinese Taipei, is projected to be more moderate.

As a result of increased demand in the Asia-Pacific region, LNG is projected to rapidly increase its share of inter-regional trade, with production capacity by 2020 expected to approach 500 billion cubic metres, from 240 billion cubic metres in 2006. This will be underpinned by large LNG expansions, totalling 105 billion cubic metres, in Qatar that were commissioned between 2006 and 2010, several major expansions in Australia and, towards the end of this decade, through new projects in North America (Table 3).

Table 3. LNG projects under construction (as of May 2013)

Country	Project	Capacity (Bcm/yr)	Major stakeholders	Online date
Angola	Angola LNG	7.1	Chevron, Sonangol, ENI, Total, BP	mid-2013
Algeria	Gassi Touil LNG	6.4	Sonatrach	end 2013
Indonesia	Donggi Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas, Medco	2014
Papua New Guinea	PNG LNG	9.4	ExxonMobil, Oil Search, Papua New Guinea government	2014-15
Australia	Queensland Curtis LNG*	11.6	BG, CNOOC, Tokyo Gas	2014-15
Malaysia	MNLG train 9	4.9	Petronas	end 2015
Australia	Gorgon LNG	20.4	Chevron, Shell, ExxonMobil	2015-16
United States	Sabine Pass LNG	24.5	Cheniere Energy	2015-17
Australia	Gladstone LNG*	10.6	Santos, Petronas, Total, Kogas	2015-16
Australia	Australia Pacific LNG*	12.2	ConocoPhillips, Origin, Sinopec	2015-16
Australia	Wheatstone	12.1	Chevron, Apache, KUFPEC, Shell	2016-17
Australia	Prelude LNG**	4.9	Shell, Inpex, Kogas, PCP	2017
Australia	Ichthys	11.4	Inpex, Total	2017-18
Total		**138.2**		

*CSG-to-LNG projects.
** Floating LNG project.

Source: IEA 2013a.

A moratorium on gas development in Qatar seems likely to continue to limit further expansion of its LNG output. As a result, Qatari output is expected to peak before 2015.

Over the coming decade, Australia will expand its capacity to rival Qatar as the world's leading LNG exporter with a number of trains scheduled to be commissioned from 2015. This is expected to peak from 2020 or shortly after. Additional Australian projects are possible, but this is likely to require options such as Floating LNG to support cost-competitive investment in new greenfield projects offshore Northern and Western Australia.

A limited number of North American LNG exports are expected to commence before 2020, following the commissioning of Gulf Coast projects as early as 2016 and Canadian Pacific projects near to or after 2020 (see discussion on North American developments below). As additional US projects have now received government approval, forecasts for United States LNG exports of around 60 billion cubic metres by 2020 now appear at the lower end of expectations.

The Canadian Government has also given export approval to a Shell-led project on its Pacific Coast for 32 billion cubic metres a year. Should this project proceed (a final investment decision may be made in 2014), it would contribute to a large increase in North American LNG exports soon after 2020.

Buyers, in particular from Asia, have shown considerable interest in North American LNG, especially gas from the US Gulf Coast. The first export LNG facility, Sabine Pass, with a projected annual output of around 22 billion cubic metres, will export gas at prices based on the Henry Hub price (see box) plus liquefaction and transport costs. Buyers include Indian and Korean companies, as well as BG Group and Spain's Gas Natural. In May 2013, a second United States project received all project approvals, with two more rapidly advancing through the approval process.

Oil indexed pricing will increasingly be challenged

This Henry Hub based pricing approach represents a radical departure from traditional oil indexed pricing in Asia-Pacific markets, and promises to bring moderating pressure to overall LNG prices in the Asia-Pacific region. Should the United States move faster on LNG project development/approval, and this pricing model continues to be favoured, these downward pressures may become stronger.

Beyond North American LNG exports, East Africa (Mozambique, and possibly Tanzania) may support new greenfield projects, but probably not until after 2020, and only if a number of challenges are resolved including sovereign risk and ways to reduce the risk of capital cost overruns. Nigeria may also be capable of substantial expansions in LNG output, but again only if a number of institutional and political challenges are overcome.

European imports are projected to increase through both pipeline (Russian Federation, Algeria) and LNG. Oil indexed pricing mechanisms used for these imports are also coming under increasing pressure as European utilities struggle with weak demand, competition from renewables in the power sector, and high priced take or pay contracts.

The Henry Hub

The Henry Hub is located in Louisiana, near the US Gulf Coast, and is the site where a number of major interstate gas pipelines converge, and large storage facilities are close at hand. It has grown to become the major trading point for physical delivery of gas, and the major marker price in the North American market. Prices are quoted in US$ per million British thermal units[4]. While prices in other locations in North America differ from this, the difference is generally the transport cost associated with getting Henry Hub gas to that location. Only at times of very high demand, when transport systems can become congested, do regional prices diverge markedly from this formula.

Trading on Henry Hub is transparent, with many buyers and sellers. High turnover rates, or churn, give high levels of confidence to market participants on the accuracy of price discovery. The Henry Hub price is the major reference for the NYMEX gas futures market. Notwithstanding these sophisticated trading arrangements, Henry Hub prices have been subject to spectacular price spikes, generally caused by strong demand in extreme weather, such as in 2001, or supply shortages, as in 2005, caused by hurricane damage.

Henry Hub prices are used for pricing inter-country pipeline trade of gas from the United States to Mexico. Long-term LNG export contracts have been signed based on Henry Hub prices. The agreements to date have included a fixed charge for the capacity allocated at the export facility. The gas is sold at a premium to the Henry Hub with the option, but not the obligation, to purchase gas free on board (FOB). The Henry Hub price could possibly become a global spot price for LNG trade at new export facilities and not just for contracted supply from the United States. For instance, BP Singapore is negotiating a 15 year contract to supply a Japanese customer at a gas price linked to the Henry Hub price, even if the gas is not supplied from the United States (IEA 2013a, p. 143).

Regardless of how gas is priced, with Qatar and Australia each likely to represent around 20 per cent of global LNG supplies by 2020 and the prospect of sustained high prices, Asia-Pacific buyers are clearly focussed on increasing supply competition through diversifying supplies from the US, the Russian Federation and Canada.

Developments in North America have changed the global energy equation

Perhaps the most outstanding development in current global energy markets has been the rapid turnaround in the North American gas and oil markets over the last five years (see chapter 5 for a more detailed discussion). This has, and will continue, to reshape the global energy equation over the rest of the decade if not longer.

As recently as 2007, the US President's National Petroleum Council projected that by 2030 lagging domestic production would require the US to meet more than one sixth of US gas needs through LNG imports. This was matched by IEA forecasts which indicated that, by 2030, North America would produce around 84 per cent of its gas requirements, needing to import more than 155 billion cubic metres annually.

4 To convert gas prices in US$ per million British thermal units to A$ a gigajoule, divide by the appropriate exchange rate, and then divide by 1.055. For example, at A$1=US$0.95, a Henry Hub price of US$4 per million British thermal units equates to around A$4.00 a gigajoule.

This commonly held view was instrumental in generating very large scale investments in liquefaction plants in a number of locations, notably the Middle East. In Qatar, LNG plants were built with more than 100 billion cubic metres of capacity over the period 1996 to 2010, with a view to providing one-third of this capacity to each of the North American, European (especially United Kingdom) and Asian markets. In North America, corresponding regasification plants were constructed; by 2010, the capacity of these plants, mostly in the Gulf of Mexico, exceeded 100 billion cubic metres annually.

Beginning around 2008, the underlying demand–supply picture in North America underpinning these massive investments began to change with the widespread and rapid application of several technologies, notably horizontal drilling and hydraulic fracturing. This saw US gas output rise from 524 billion cubic metres in 2006 to 651 billion cubic metres in 2011, and higher again in 2012.

At the same time, previously record high Henry Hub gas prices fell sharply after 2009, reaching lows around US$2 per million British thermal units in mid-2012. These low prices were also sustained by co-production of gas liquids and light tight oil, associated with gas extraction.

This has already had a major effect on actual and anticipated gas flows, both directly and indirectly. Canadian exports to the United States have declined sharply, while LNG destined for North American markets has been sold in European and Asia-Pacific markets, putting volume and price pressure on pipeline gas sales from the Russian Federation and other suppliers, which are typically sold on an oil indexed basis.

The rapid increase in gas supply (and low prices) has also pushed coal out of parts of the power market in the United States, where environmental rules were already reducing its role. As a result, coal producers have responded by sharply increasing coal exports via seaborne markets, mainly to Europe, but also to Asia. Coal production from Colombia that was destined for the United States has also been diverted to mainly European markets, further pressuring oil indexed gas sales.

While North American gas prices have more recently increased to a more sustainable US$3–4 or so per million British thermal unit, these prices correspond to less than US$25 per barrel of oil equivalent. At a time when oil prices are around US$100 or so a barrel, gas still represents a very competitive proposition to buyers by historical standards.

It appears that this pricing differential between North American gas prices and those prevailing in other markets, will continue to exist, especially where oil indexation is maintained as the most common pricing mechanism. The difference in prices will drive the growth in LNG exports from North America.

The first US exports will occur through LNG import facilities that are now being reconfigured for export. Such conversions are not cheap, quick, or straightforward, and require liquefaction facilities to be provided alongside the existing shipping and storage facilities. Nonetheless, for capital expenditure of around US$3 billion and with lead times of around three years, such facilities are being built.

Allowing for liquefaction, shipping and regasification costs of around US$5–7 a gigajoule, the transportation of LNG from the Gulf of Mexico to Asian markets is profitable at current (US$14–15 a gigajoule) and likely prices in Asia-Pacific markets. Provided Henry Hub prices remain below about US$5 a gigajoule, the export of US LNG to Europe is also possible.

There are other factors that will influence the pace of North American LNG exports.

LNG exports from the United States are subject to approval by the Federal Government. For exports to non-Free Trade Agreement (FTA) countries (including most of the lucrative Asian buyers), this decision is not automatic and is subject to a public interest test around the likely impact on the domestic market.

Around 20 projects have been submitted for approval, with proposed volumes in excess of 200 billion cubic metres annually. 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.

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.

Canada has a large gas industry and a substantial exportable surplus of gas. With the decline in US gas imports, Canada is moving to export gas from its Pacific Coast.

Unlike in the United States, these proposed facilities will be greenfield plants, with extensive new infrastructure such as ports and supplying pipelines required. Consequently, LNG from this source is not likely to be cheap or based on Henry Hub type pricing.

To date, two plants have received approvals with total capacity of around 16 billion cubic metres annually, and a third, much larger, project recently received export approval. This Shell-led project would export as much as 32 billion cubic metres annually, although a final investment decision is probably a year away. Further, discussions are underway to construct an export terminal on Canada's Atlantic Coast.

Taken together with current and likely US developments, it appears that forecasts of annual exports of 60 billion cubic metres of LNG from North America by 2020 is a lower bound, with as much as 80 billion cubic metres a year possible. At these export volumes, North America would exceed the combined LNG exports of Indonesia and Malaysia.

China—a growing market for LNG

China is one of, if not the largest, growth market for LNG. However, relative to its massive and growing energy needs, gas continues to play a modest role in China's total energy mix.

In 2005, China's gas use at around 50 billion cubic metres was similar to that of France, with gas accounting for only around 2 per cent of China's energy needs, and a very small role in the power sector. All of China's gas consumption was sourced domestically.

Since this time, gas use has grown faster than total energy use. By 2011, Chinese gas demand, at 130 billion cubic metres, was larger than any OECD gas user, bar the United States, and fourth largest in the world.

Internal infrastructure constraints and the high cost of domestic gas production saw this growth increasingly met through pipeline imports from Turkmenistan and, after 2006, through LNG imports via coastal terminals.

Recent demand growth has been particularly marked from the power sector, despite the fact that gas-fired power is still less than 2 per cent of total power output, compared with an average of more than 23 per cent in OECD countries. City gas use, which is now the largest demand sector, provides gas to around 200 million people, or around one third of the urban population.

Chinese gas demand is expected to rise rapidly as gas supply is extended to more cities, especially in coastal China; and used in the peak power sector. IEA projections have China's gas-fired power at around 350 terawatt hours by 2020, a niche product, but like everything in China, a rather large niche. Gas is also an important means to achieve energy diversification and address challenging air pollution problems. Gas use is likely to increasingly penetrate the industrial sector, both as a feedstock and displacing oil.

By 2015, Chinese gas consumption is projected to reach around 240 billion cubic metres, with imports accounting for up to 100 billion cubic metres split roughly equally between LNG and pipeline sources. Nevertheless, even at these levels, gas use will still only account for less than 8 per cent of Chinese energy requirements, compared with an average of around 24 per cent in OECD countries.

In terms of domestic supply, China is moving to develop unconventional gas from shale and coal bed methane, but large increases in production are unlikely before 2020 because of the need to adapt existing technologies for China and the currently high costs of extraction. Reform of China's gas pricing policy (Kate et al. 2012) will be an important factor in stimulating new production and enabling imports. These imports are likely to come via a combination of pipeline and LNG.

By 2020, China is expected to consume between 300 and 350 billion cubic metres of gas, with some scenarios targeting as much as 400 billion cubic metres. Production can be expected to roughly double from 2010 levels (95 billion cubic metres to 180 billion cubic metres) in that timeframe, with imports supplying the balance. This represents an enormous market opportunity for cost competitive gas suppliers.

Australia's gas markets and its role in global LNG trade

Australia is a gas rich country

Australia is endowed with significant gas resources with around 3.8 trillion cubic metres of economic demonstrated gas resources. However, their use in Australia has historically been overshadowed by coal, especially in the power sector (see chapter 2 for further discussion on Australia's gas resources and market circumstances).

Gas has grown in importance over the last decade, with gas representing the majority of new electricity generation investment. As such, gas demand growth has been faster than other fossil fuels. The emergence of a world class LNG industry in the West and more recently developments on the East Coast has also brought renewed attention to the importance of gas to the Australian economy.

As is common in other OECD countries, gas is an important fuel in both domestic and industrial applications, and makes up around 21 per cent of Australia's energy supply. Total gas production in 2011–12 was around 59 billion cubic metres, more than one third or 19 million tonnes of which was exported from North and Western Australia.

Australia has three gas markets (Eastern, Western and Northern) which although physically and economically separate from each other, are becoming increasingly integrated with global gas markets through the expansion of LNG exports. The vast majority of trade in these markets is through long term bilateral contracts although short term trading markets have been established in the Eastern Market and one is proposed for the Western Market.

In 1989, gas was first exported in the form of LNG from the North West Shelf Project in Western Australia. Exports increased in the years following with the completion of the LNG project in Darwin in 2006, and the Pluto LNG project, also in Western Australia, in 2012.

Starting in 2009, a series of new LNG projects have been approved and are now under construction. In all, seven new projects are underway, representing more than two thirds of new global investment in LNG production. When completed and operating at capacity, these plants will result in a five-fold increase in LNG exports compared with 2008, and Australia should exceed Qatar's current exports to become the largest LNG exporter, providing around 20 per cent of global LNG supplies. These LNG plants will be located in both Eastern and Western Australia.

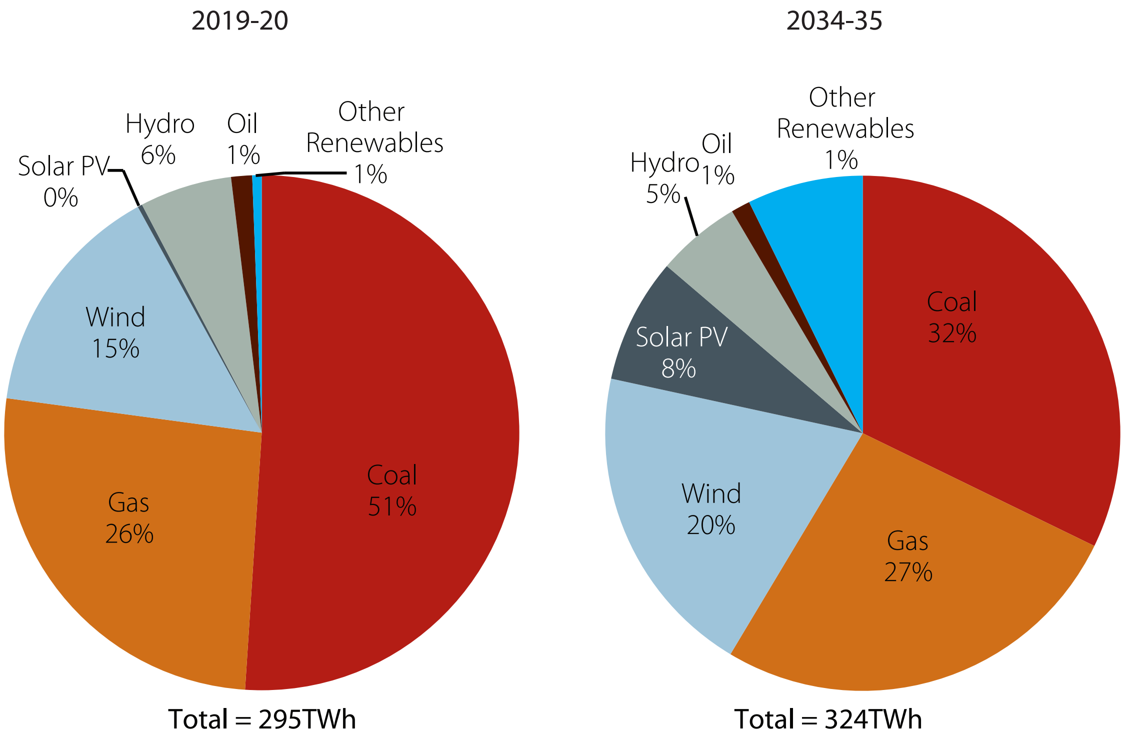
There are emerging issues in Australia's gas markets

As is the case in other major gas producing and consuming countries, Australia's major gas markets in East and West Australia are experiencing major changes. These changes are largely being driven by the development of new gas resources and large export projects.

Domestic gas consumption is projected to grow at a more subdued rate than previously forecast into the future reflecting both higher gas prices and lower demand growth for grid-based electricity.

Australian electricity generation is projected to increase from 253 terawatt hours in 2013 to 295 terawatt hours and 324 terawatt hours in 2020 and 2035, respectively. The share of gas-fired electricity is projected to increase from 24.6 per cent in 2013 to 26 per cent in 2020 and 27 per cent in 2035. In absolute terms, gas-fired electricity is projected to increase from 62 terawatt hours in 2013 to 77 terawatt hours in 2020 and 85 terawatt hours in 2035. The share of coal-fired electricity is projected to decline from 60.5 per cent in 2013 to 51.0 per cent and 32.2 per cent in 2020 and 2035, respectively (Syed 2012).

Figure 4. Projected electricity generation, by energy source, 2019–20 and 2034–35



Source: Syed 2012.

New gas supplies are being developed, but at a much higher cost than historical fields, which in some cases date back to the 1960s. Australia's domestic gas markets are also becoming more integrated with international gas and LNG markets, particularly the high priced Asia-Pacific LNG market. Australia's imminent rapid rise from a modest LNG exporter to a major force in global LNG trade has raised concerns about the ensuing effects of this ascent on domestic gas prices and gas availability.

Prices have risen in the Western market

In the Western Australian gas market, prices began to rise in 2006–07 reflecting the combination of tight supply, the higher cost of developing new gas and the demand competition from LNG exports.

New gas developments in Western Australia tend to be in deeper waters and, in general, are more costly to develop than historical supplies. Higher prices are also stimulating onshore exploration for newer unconventional gas (shale gas and tight gas). The Perth and Canning Basins are considered prospective for unconventional gas, with exploration and drilling currently underway in both regions.

Prices in new contracts are in the range A$5.50–$9 a gigajoule. New supply through projects such as Macedon and Gorgon has emerged in response to the higher prices.

The East Coast market has yet to establish a new equilibrium

The Eastern Australian market, by contrast, has not historically been exposed to international markets with long-term prices around A$2–$3 a gigajoule. Traditional gas supplies from fields in the Cooper basin and in Bass Strait are now complemented by gas from coal seams, particularly in the Surat and Bowen basins which, in turn, are supporting the development of a major LNG export industry in Queensland.

The East Coast market is now transitioning as LNG projects are commissioned, and with many domestic long term wholesale contracts expiring in the next few years. The problem is particularly acute in New South Wales, where a large number of wholesale gas supply contracts are set to expire between 2014 and 2018. By 2018, less than 15 per cent of New South Wales' demand will be met by existing contracts.

While supply has expanded, the additional demand competition from LNG exports has seen a significant tightening in the gas market with prices reported to have risen substantially towards (if not already reaching) netback levels ($6–$9+ a gigajoule). Some large industrial gas users have also reported that they are unable to secure long term forward gas supplies (claims disputed by gas suppliers) with some users calling for a policy that reserves a portion of gas for the domestic market.

The degree to which the market will experience further tightening and potential price spikes is unclear. Much will depend on the rate of development and commissioning of new LNG projects; the time to reach capacity and flow rates for coal seam reserves; and the ability to quickly bring forward new projects in New South Wales.

As in the Western market, higher prices are already stimulating unconventional gas development, especially tight gas in the Cooper Basin although this remains very much at an early stage. Development costs for new gas resources vary but are generally thought to be significantly higher than existing supplies (between $4–$6+ a gigajoule).

The development of coal seam and shale gas resources has raised community concerns about the potential flow-on effect of operations on waterways and native vegetation (see chapter 3). This has been a material factor in the slow rate of development of some projects, notably in New South Wales which has imposed restrictions on their development around communities.

The need for further market reform

Transitional pressures on supply will continue between 2015 and 2020 (BREE 2012b). Gas market reform, designed to support transparent and competitive markets, which has been pursued for around two decades, will need to be pushed vigorously if the long-term interests of users are to be supported, and additional supply brought to market. This will need to be reinforced by leading practice regulation (see chapter 4 for further discussion).

The Henry Hub model in North America, with its high levels of transparency, and efficient physical and financial markets, may be a possible long term model for Australia. The UK hub market, based on a virtual balancing point, the National Balancing Point (NBP), is another hub based market that shows the potential of markets to deliver increased supply and lower prices, even as UK domestic gas production has fallen sharply. Nevertheless, Australian gas markets relative to the United States and United Kingdom lack multiple supply sources, pipeline and storage interconnection and infrastructure, and, in particular, the commercially available information flows that underpin effective markets and market development.

Developments in continental Europe also offer lessons, as European gas markets are moving away from long-term oil indexed contracts, to increasingly more interconnected and resilient markets, with greater market information and transparency. While European markets are still far from the mature hub based models of Henry Hub in the United States or the United Kingdom NBP, the emerging Dutch TTF (Title Transfer Facility) is trading rapidly increasing volumes based on gas market fundamentals.

Overall, overseas markets suggest some key priorities for ongoing market reform in Australia:

- improved information on both gas and power markets, some provided by market participants, some by market operators
- greater transparency and trading opportunities, based on a physical hub, where gas can be delivered and traded
- enhanced pipeline, storage and infrastructure that has been a key development in European markets to overcome capacity hoarding that has blocked greater pipeline access and limited competition
- better understanding of the links with the power sector, including coal and renewables use
- additional market liquidity, which has been an important factor in the efficient functioning of overseas markets.

It is unrealistic to assume that the success of North American markets in developing new very low cost unconventional sources of gas and petroleum liquids can be replicated in Australia. Nevertheless, tight gas, shale gas and coal seam gas can all contribute significantly to increased gas supplies, albeit at higher extraction costs than in the past (Cook et al. 2013).

Gas exploration, development and pipeline infrastructure provision has and will continue to be, a long term, capital intensive process, placing a premium on investment certainty for both producers and buyers. Open, competitive markets and transparent and evidence-based regulations are the key to seeing this gas, plus newer conventional gas, being developed and brought to the market in a timely way.

Concluding remarks

Gas will continue to increase in importance in the global energy mix, with substantial growth projected in both consumption and imports in the emerging economies of Asia. On the supply side, global markets are changing rapidly, with unconventional gas, especially in North America, increasing supply at previously unexpected rates. This has altered market dynamics, with potential implications for gas pricing.

Massive investments in gas field extraction, processing and delivery will enable LNG exporters, including Australia, to capture an increasing share of the global gas trade out to 2020. Over the short term there will be limited opportunity to increase gas supplies, at least via LNG, until LNG facilities currently under construction become operational from 2015 onwards. The current supply bottleneck for LNG is likely to result in continued higher gas prices over the short run in markets dependent on LNG as a feedstock, especially in Asia. The prospect of sustained high gas prices in the Asia-Pacific region has already encouraged massive investments in LNG export and import facilities, including in Australia where seven of the world's 13 LNG plants currently under construction are located.

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Gas in Australia—an overview

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Introduction

As is the case in many other major gas producing and consuming countries, Australia is experiencing important changes in its domestic and export gas industry and markets. Confidence in stable long-term gas prices is eroding as new and more costly supply is commissioned. Furthermore, Australia's emergence as a leading liquefied natural gas (LNG) exporter has introduced new competition for gas in domestic markets, with consequent pressure on supply and price, and is hastening integration with international gas markets.

These changes bring substantial economic benefit to Australia, notably through higher national income, more extensive gas infrastructure and enhanced regional development. However, higher prices pose risks, particularly for gas exposed end users. These pressures are not expected to abate without significant new supplies of gas. As evidenced by recent experiences, timely development of new unconventional gas resources also requires careful environmental and social management.

This chapter provides a high level overview of Australia's gas resources and market outlooks to 2020. It consciously does not canvass possible policy or regulatory solutions to issues raised, noting that BREE is working with the Department of Industry on a more detailed gas market report to be released by the end of 2013.

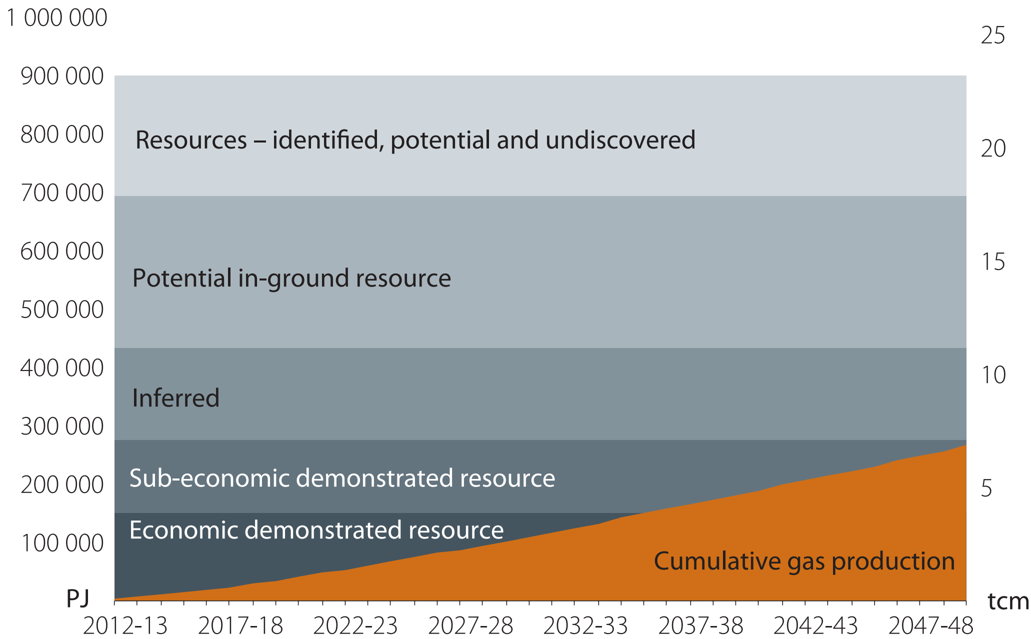
Australia's gas profile

Gas resources

Australia's economic demonstrated resources (EDR) of gas comprise around 2.92 trillion cubic metres of conventional gas and around 0.93 trillion cubic metres of gas from coal seams (GA and BREE 2012). Australia does not currently have any EDR of tight or shale gas, however, there are considerable sub-economic, inferred and identified resources spread around Australia of up to 17.9 trillion cubic metres (BREE and GA 2012).

The Cooper-Eromanga basin contains a large tight gas resource in low permeability (or tight) reservoirs that until recently has not been economically recoverable (IES 2012). Furthermore, a recent report by the Australian Council of Learned Academies (Cook et al. 2013) suggests that around 27 trillion cubic metres of shale gas are located in Western Australia's (WA) Canning basin alone (considerably more than other current estimates of Australia's entire gas resources). However, the report notes that this estimate should be treated with caution given the very early stage of resource understanding in the Canning basin.

Figure 1. Australia's total gas resources and cumulative production



Note: Gas resources are plotted by volume, not time.

Sources: GA and BREE 2012, and BREE 2012b.

Figure 1 illustrates Australia's total gas resources, inclusive of conventional, coal seam, tight and shale gas compared with BREE's most recent long term gas production projection (BREE 2012b). The gas resource shows current estimates, but it is expected that over time significant resources will move into the EDR category as exploration and appraisal confirms the resource base, prices rise and technology and exploitation techniques improve.

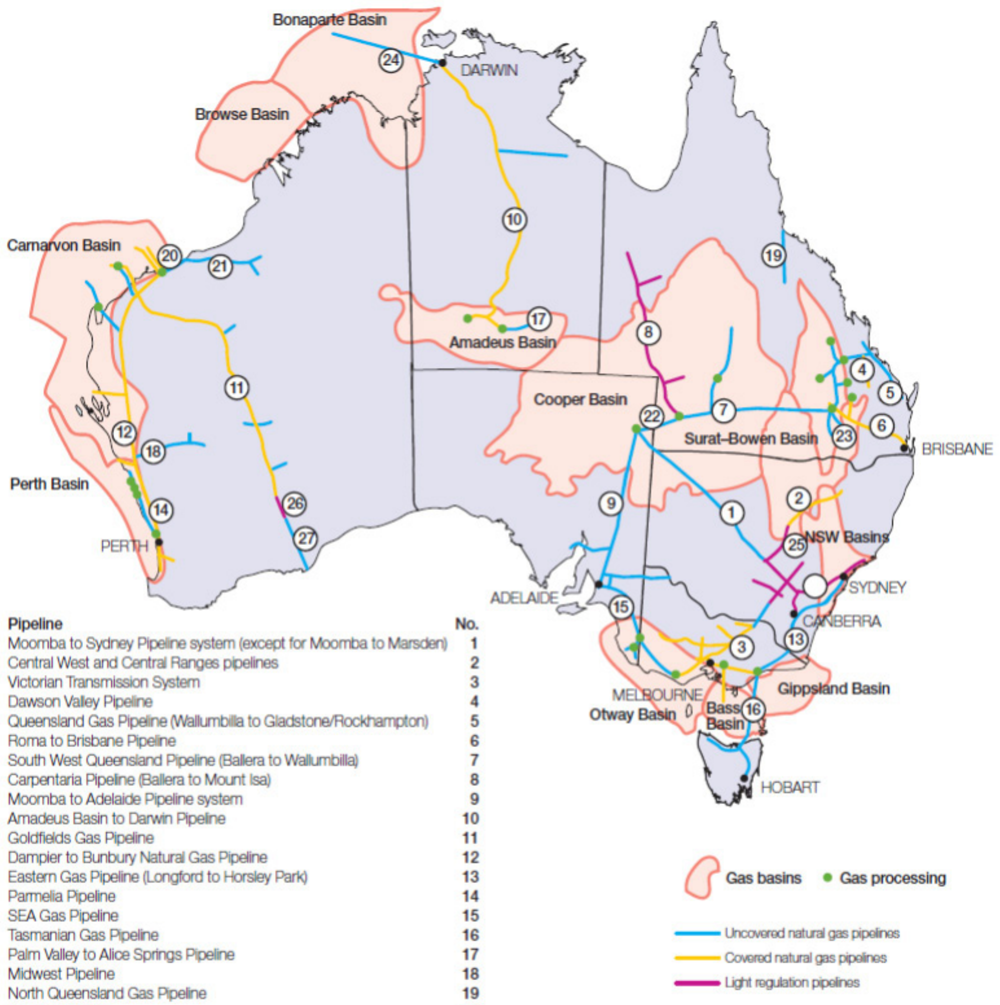
Gas markets and infrastructure network

Australia has three geographically and economically distinct gas markets: the Eastern gas market, the Western gas market and the Northern gas market. The characteristics of these markets reflects underlying fundamentals, such as the size and location of gas resources, the demand profile and relative exposure to international markets (which makes for noticeable price differentials between markets, and even within each market). A common characteristic across these markets is that the vast bulk of trade (around 90 per cent) occurs through long term bilateral contracts complemented by a small (but growing) level of spot trade in the Eastern Market. This means that each market has varying levels of transparency around price and supply.

Interconnection of Australia's domestic markets is considered highly unlikely for the foreseeable future because of the vast distances separating the associated population and demand centres, which makes development uneconomic.

Australia's gas system has evolved to support domestic consumption and LNG export trade with extensive transmission pipelines supplying the geographically diverse Eastern, Western and Northern Markets. Figure 2 shows Australia's main gas basins and transmission pipeline infrastructure.

Figure 2. Gas basins and transmission pipeline infrastructure



Pipeline	No.
Moomba to Sydney Pipeline system (except for Moomba to Marsden)	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline system	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Notes: A number of basins (such as the Canning in WA) that do not currently produce gas are not displayed. The Blacktip pipeline in the NT is not shown. Covered pipelines are subject to economic regulation under the National Gas Law.

Source: AER 2012a.

The Eastern gas market covers the eastern seaboard of Australia, from Queensland in the north to South Australia in the south west. Growing interconnection (driven by private sector ownership) over the past decade has provided improved security of supply and competitiveness for gas consumers.

Infrastructure in WA and the Northern Territory (NT) is state-based and, because of their smaller size (in terms of population) and more challenging economics, considerably less interconnected. The Blacktip pipeline and northern portion of the Amadeus pipeline is the backbone of the Northern market as it links Darwin to domestic supply from the Blacktip gas field. The two main pipelines in the Western market are the Goldfields and Dampier to Bunbury pipelines which link the Carnarvon basin to both mining demand (along the goldfields pipeline) and electricity, residential and industrial demand (along the Bunbury pipeline).

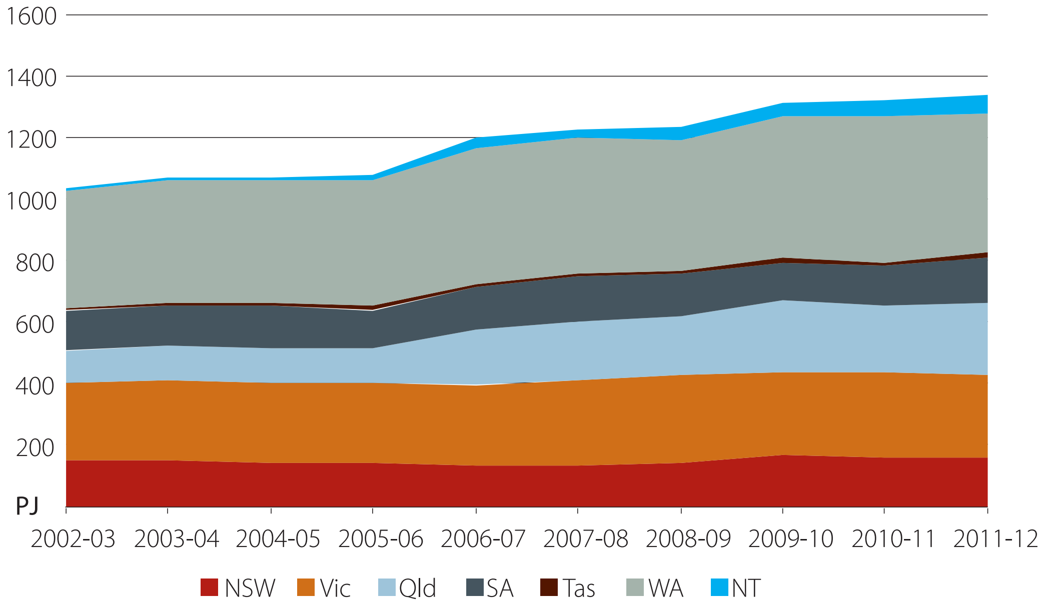
Australia's export gas supply is currently served by offshore gas fields (the Carnarvon basin off WA and the Bonaparte basin off the NT—in the Joint Petroleum Development Area with East Timor). LNG facilities at both of these fields are located onshore and receive gas via pipelines connected to offshore platforms. These pipelines are integrated into the LNG process, so are owned and operated by the companies responsible for both the production and export of gas.

There are currently three LNG projects under construction in Queensland that will be the first in Australia to make use of onshore gas resources. These projects are in the process of linking gas fields in the Surat-Bowen basins to export terminals in Gladstone via high pressure transmission pipelines.

Gas consumption

Australia's gas consumption was around 1335 petajoules in 2011–12, an increase of around 9 per cent over the past 5 years, from 1226 petajoules in 2007–08 (Figure 3) (BREE 2013a). The growth in gas consumption over this period largely reflects an increase in gas-fired electricity generation and strong growth in use for mining and other industrial purposes.

Figure 3. Australian gas consumption, by state, 2002–03 to 2011–12

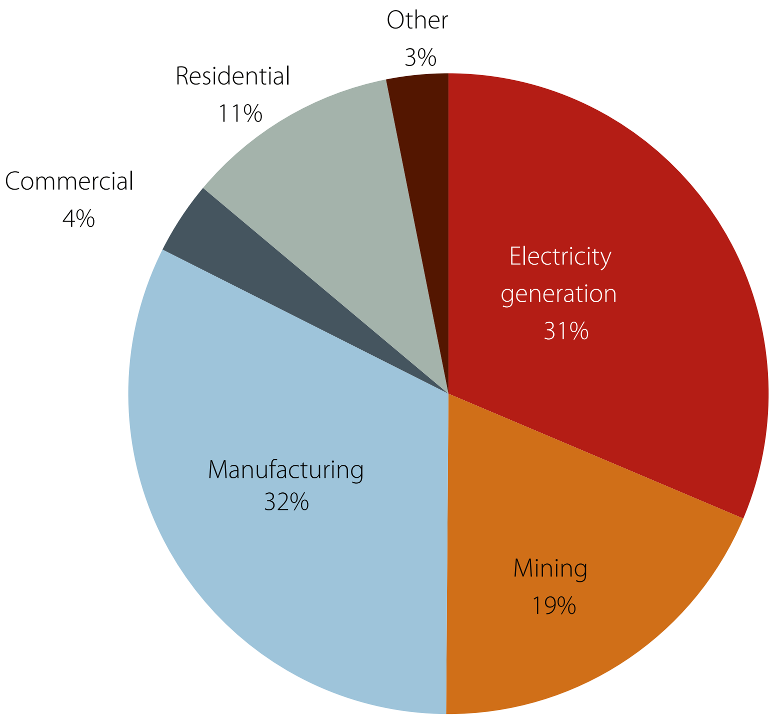


Note: In effect, the total of gas consumption in New South Wales, Queensland, South Australia, Tasmania and Victoria represents consumption in the Eastern Gas Market.

Source: BREE 2013a.

Gas consumption in 2011–12 accounted for around 23 per cent of total primary energy consumption in Australia. The manufacturing sector was Australia's largest consumer of gas, followed by the electricity generation, mining, residential and commercial sectors (Figure 4).

Figure 4. Australian gas consumption, by sector, 2011–12

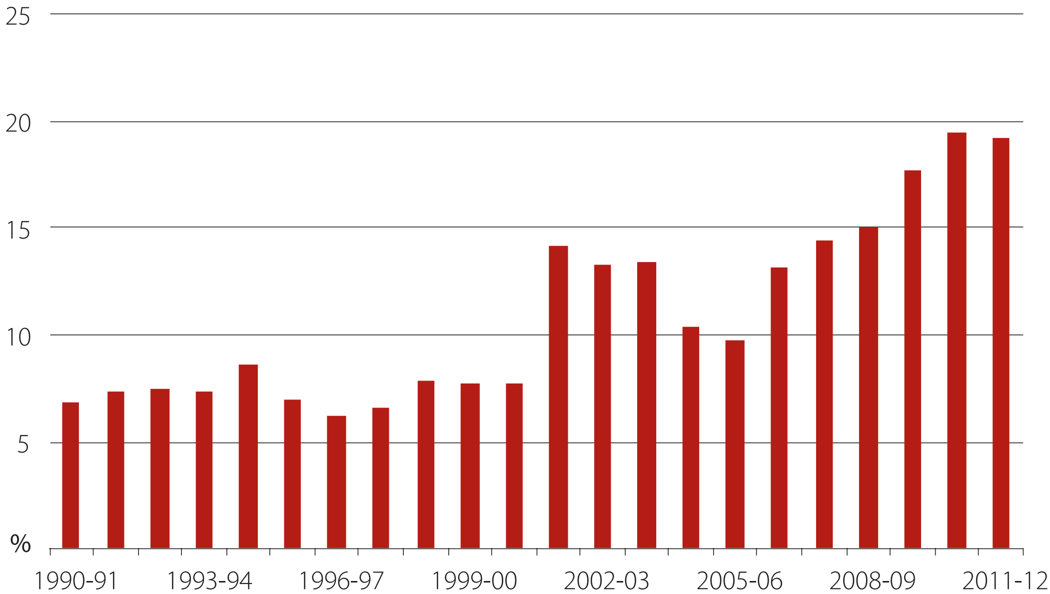


Source: BREE 2013a.

Gas is used widely in the manufacturing sector although it is of particular importance to a relatively small number of large consumers in the metal product industries (mainly smelting and refining activities) and the chemical industry (fertilisers and plastics) where gas is a major energy source and/or production input.

The relatively large share of gas consumption in the electricity generation sector is a result of the large increase in gas-fired generation capacity since 2005–06. Over the six years to 2011–12 the share of gas-fired generation relative to total electricity generation increased from 9.8 per cent to 19.3 per cent (Figure 5). Most of this was in the form of open-cycle gas turbine generation capacity, installed to meet rapidly growing levels of peak electricity demand.

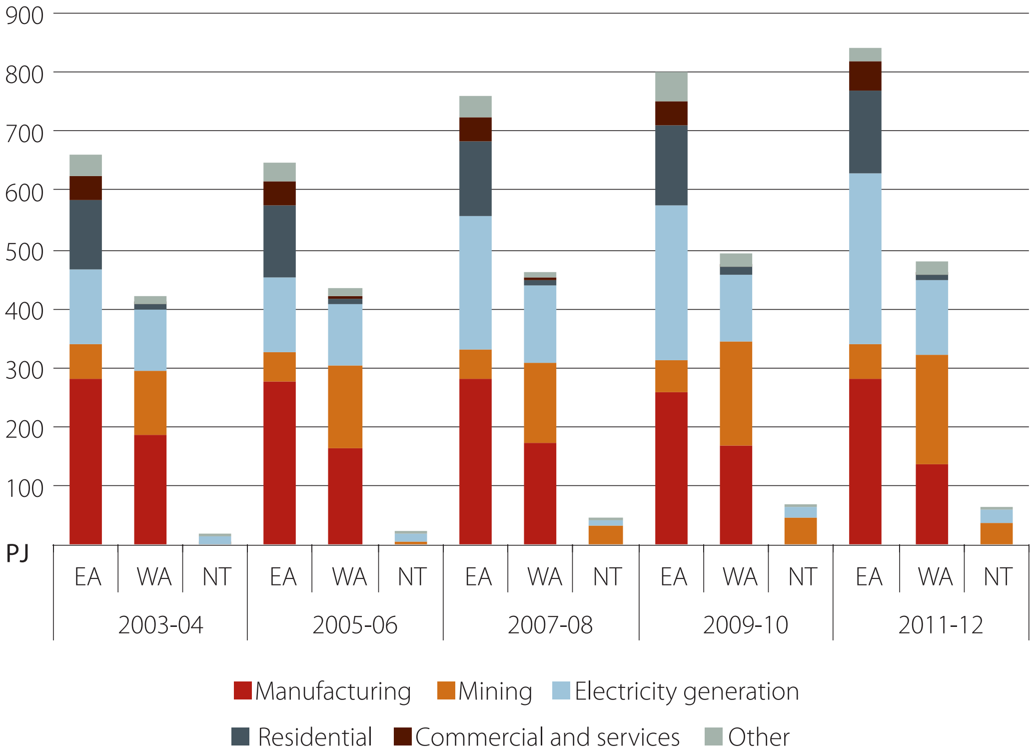
Figure 5. Share of gas in total electricity generation, 1989–90 to 2011–12



Source: BREE 2013a.

The Eastern market accounts for around 59 per cent of Australia's gas consumption: 839 petajoules in 2011–12, a 4 per cent increase on the previous year's consumption (BREE 2013a). Queensland and Victoria are the two largest consumers in the Eastern market, which together accounted for around 509 petajoules of gas demand in 2011–12. Both are considerably smaller users than WA (which accounted for 479 petajoules of consumption in 2011–12). In contrast to the Eastern Market (where the electricity generation sector has been a key source of new gas demand), growth in gas consumption in the Western and Northern markets over the past decade has been driven by growth in the mining industry (see Figure 6).

Figure 6. Gas consumption, by market and sector, selected years, 2003–04 to 2011–12



Note: Mining gas use includes use by LNG plants in the liquefaction process.

Source: BREE 2013a.

Gas production

Australia's gas production has historically been sourced largely from three basins: the Carnarvon, the Cooper-Eromanga and the Gippsland. In recent years, production from a number of other basins has increased rapidly. In particular, production from unconventional resources in the Surat-Bowen basins and conventional offshore resources in the Bonaparte basin and the Otway basin have grown strongly. Around 36 per cent of production in the Eastern Market is currently sourced from gas in coal seams (EnergyQuest 2013a).

Australia's total gas production in 2012–13 was estimated to be 59 billion cubic metres (BREE 2013a). Of this, around 29 billion cubic metres supplied the domestic market (EnergyQuest 2013c). Details of gas production, by field are provided in Table 1.

Table 1. Australian domestic gas production, by field, 2012–13[a]

Basin	State or nearest state	Field	Production (mmcm)
Amadeus	NT/WA		5
Bass Strait	VIC/TAS		284
Bonaparte	WA/NT	Blacktip	621
Carnarvon	WA		8 681
		NWS	4 890
		J Brookes, Halyard, Spar	2 781
		Other	1 010
Cooper JV	QLD/SA		2 493
Gippsland	VIC		7 352
		Gippsland JV	7 061
		Longtom	291
Otway	SA/VIC		2 816
		Casino	870
		Minerva	650
		Thylacine	1 296
Perth	WA		170
Surat-Bowen	QLD/NSW		6 428
		Berwyndale South	2 050
		Fairview	1 031
		Spring Gully	1 018
		Talinga	952
		Other	1 376
Sydney	NSW		138
Total			**28 987**

a includes methane, ethane and gas from coal seams but excludes gas feedstock into LNG facilities

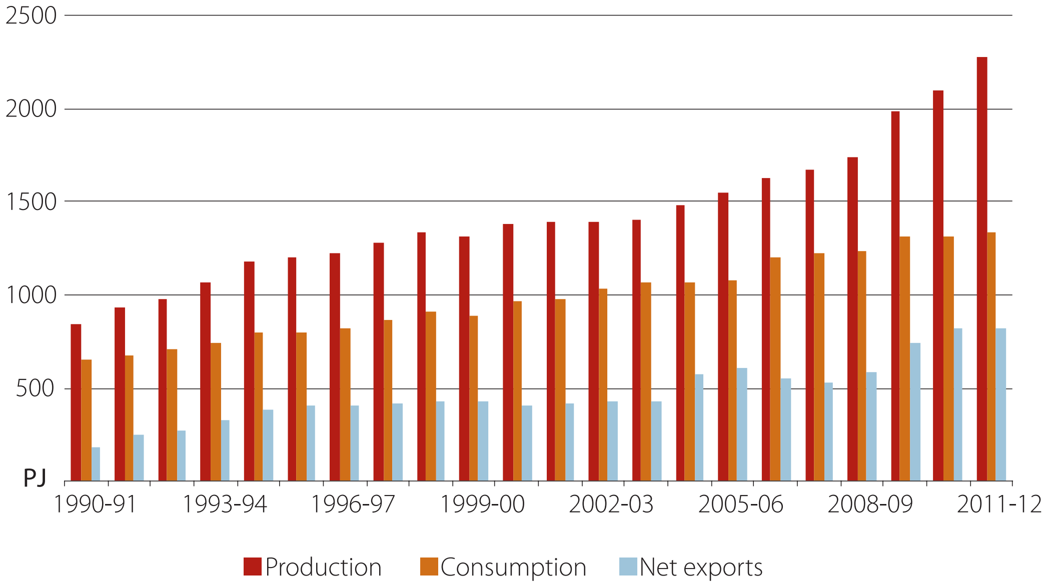
Source: EnergyQuest 2013c.

Over the medium term, gas production is expected to increase, driven largely by export demand. The completion of new projects and upgrading of existing projects in the Eastern market (Surat, Bowen, Gippsland and Otway basins) and Western market (Reindeer, Macedon and Spar gas fields in the Carnarvon basin) will mostly replace ageing fields. While there are significant reserves of gas from coal seams in New South Wales (NSW), these are not projected to be developed in the short term owing to ongoing regulatory and community issues.

LNG exports

Australia first exported LNG following the completion of the North West Shelf (NWS) LNG project in Western Australia in 1989. By 2011–12, Australia's LNG exports were around 19 million tonnes and accounted for about 36 per cent of Australia's gas production (BREE 2013a) (see Figure 7).

Figure 7. Australia's gas balance, 1990–91 to 2011–12



Source: BREE 2013a.

Exports of LNG have increased strongly in recent years—by around 8 per cent a year over the past five years, as new LNG projects (Darwin and Pluto) have been commissioned in response to growing international demand. In 2012, around 79 per cent of Australia's LNG exports were sold to Japan and 16 per cent to China (IEA 2013).

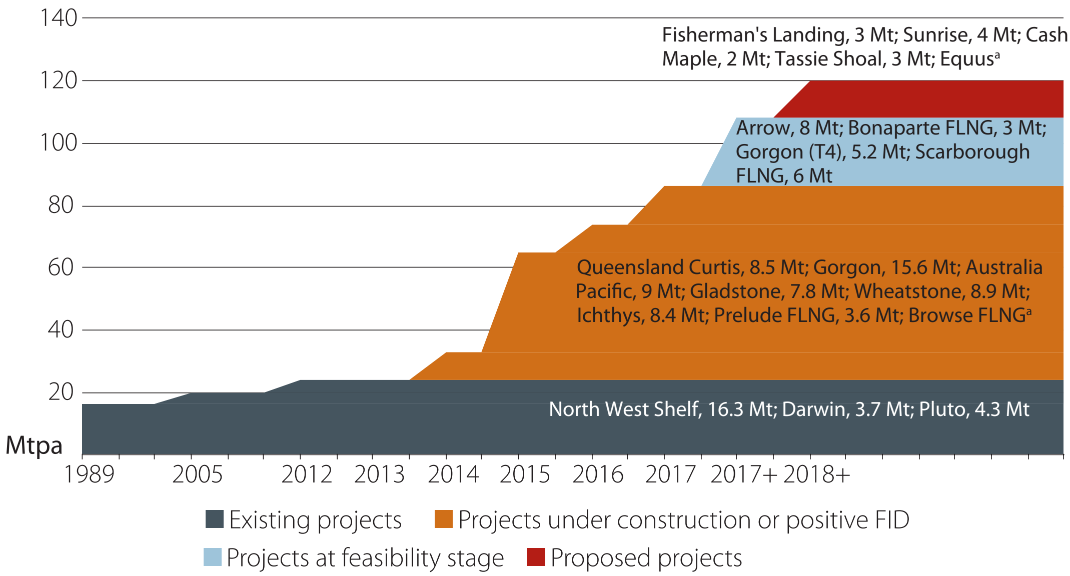
There are currently three export-operational LNG projects in Australia—the North West Shelf Venture project, the Darwin LNG project and the Pluto project—representing 24.3 million tonnes of LNG export capacity (see Figure 8 and Table 2).

There are a number of other projects currently under construction that are expected to be completed over the next few years. In particular, Gorgon LNG, one of the world's largest LNG projects and Australia's largest ever resource project, and the three LNG projects using gas from coal seams in Queensland (Australia Pacific LNG, Queensland Curtis LNG and Gladstone LNG) are world leading projects that will materially change the dynamics of both the Western and Eastern markets (further discussion on the effects of Queensland LNG projects is in the Eastern market outlook section).

These projects will collectively see Australia's LNG export capacity increase to more than 80 million tonnes annually by 2018. Beyond these projects, there are a number of other LNG projects at the feasibility and proposal stages, which if brought into operation would increase Australia's LNG capacity to more than 100 million tonnes a year and make Australia one of the world's largest LNG exporters by the end of the decade.

While growing international competition and rising costs have dampened the prospects for further greenfield LNG in Australia, the commercial success of new floating LNG operations (Prelude will be among the first to enter production in 2017) has the potential to be transformative and unlock previously uneconomic remote offshore gas resources.

Figure 8. Outlook for Australia's LNG production capacity



a *Browse and Equus have not proposed a liquefaction capacity yet.*

Note: Mtpa refers to million tonnes per annum of liquefaction capacity.

Source: BREE 2013c, Company reports.

Table 2 provides further details on Australia's current LNG export capacity, projects currently under construction and projects at the feasibility and proposed stages of development.

Table 2. Australian LNG projects

Project	Owner/proponent	Capacity (Mtpa)	Trains	Indicative cost estimate A$b	Estimated completion
Eastern market					
Under construction					
Australia Pacific LNG (APLNG)	Origin (37.5%), ConocoPhillips (37.5%) and Sinopec (25%)	9	2	24+	2015
Queensland Curtis LNG (QCLNG)	BG Group (73.75%), CNOOC (25%) and Tokyo Gas (1.25%)	8.5	2	US 20.4	2014
Gladstone LNG (GLNG)	Santos (30%), Petronas (27.5%), Total (27.5%) and Kogas(15%)	7.8	2	US 18.5	2015
Proposed					
Arrow LNG (ALNG)	Shell (50%), PetroChina (50%)	8	2	24	2017+
Western market					
Existing					
North West Shelf (NWS)	Woodside (16.6%), BHP Billiton (16.6%), BP (16.6%), Chevron (16.6%), Japan Australia LNG (16.6%) and Shell (16.6%)	16.3	5	n/a	1989 (stage 1) to 2006 (most recent)
Pluto	Woodside (90%), Tokyo Gas (5%) and Kansai Electric (5%)	4.3	1	15	2012
Under construction					
Gorgon	Chevron (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (.417%)	15.6	3	52	2015
Wheatstone	Chevron (64.14%), Apache (13%), KUFPEC (7%), Shell (6.4%) and Kyushu Electric Power Company (1.46%)	8.9	2	29	2016
Prelude Floating LNG	Shell (100%)	3.6	1	12.6	2017
Feasibility Stage					
Scarborough FLNG	ExxonMobil (50%), BHP Biliton (50%)	6	1	14	2018+
Gorgon LNG (4th train)	Chevron (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (.417%)	5.2	1	12	2018+
Browse FLNG	Woodside, Shell, BP, Japan Australia LNG and PetroChina	n/a	n/a	n/a	2018+

Proposed					
Equus	Hess (100%)	n/a	1	1.5 to 2.5	2018+
Northern market					
Existing					
Darwin LNG	ConocoPhillips (56.7%), Santos (10.6%), INPEX (10.5%), Eni (12%), TEPCO (6.7%) and Tokyo Gas (3.4%)	3.7	1	n/a	2006
Under Construction					
Ichthys	Inpex Holdings (66%), Total (30%), Tokyo Gas (1.5%), Osaka Gas (1.2%), Chubu Electric (0.7%) and Toho Gas (0.4%)	8.4	2	33	2017
Feasibility Stage					
Bonaparte FLNG	GDF Suez (60%) and Santos (40%)	3	1	13	2018+
Proposed					
Sunrise	Woodside (33.44%), ConocoPhilips (30%), Shell (26.56%) and Osaka Gas (10%)	4+	1	5+	2017+
Cash Maple	PTTEP Australasia (100%)	2	1	5+	2018+

Sources: BREE 2013c, EnergyQuest 2013a, LNG Insight 2013 and Company reports.

Wholesale gas prices

Domestic gas trade in Australia is dominated by the use of long term bilateral contracts. In the early stages of Australia's gas market development these contracts were essential in underpinning the large investments required to develop new gas fields and provide security of price and supply for users.

However, the development of LNG export projects linking Australian markets to international conditions has altered the supply, demand and pricing dynamics of the Eastern and Western markets. The three LNG projects currently under construction in Queensland (see Table 2 for further details) are creating significant uncertainty for market participants on the future direction, and price in particular, of the Eastern market.

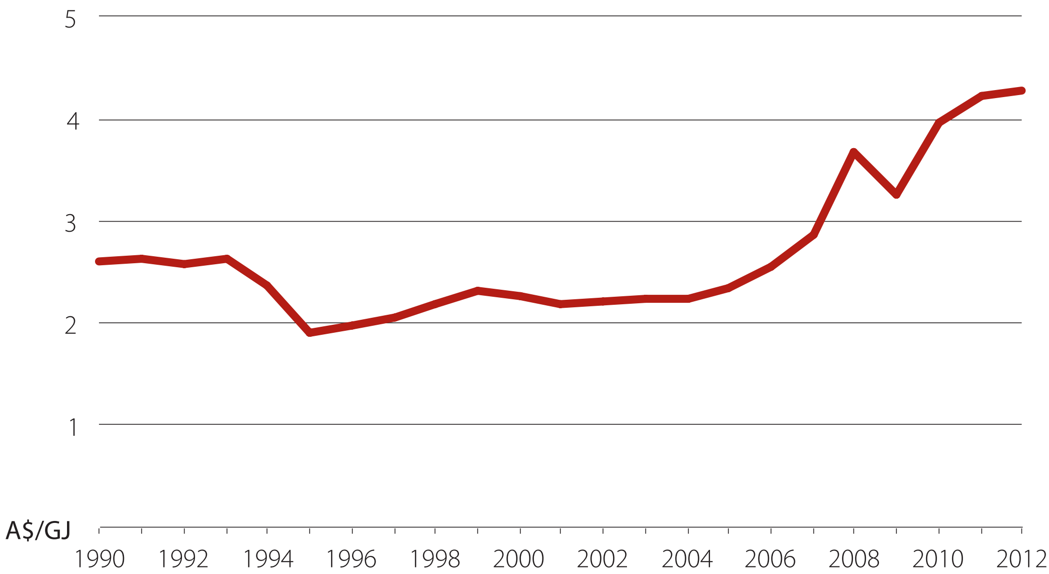
The Western market

The development of the Western gas market was underpinned by Australia's first LNG exports to the Asia-Pacific. In particular, the development of the North West Shelf project provided the foundation for the development of an interconnected network through the WA goldfields and to Perth. The stable long term gas prices provided by the North West Shelf project also attracted a number of large gas using industries.

As demand began to grow and initial gas contracts expired, the market tightened, with a delay in sourcing new (and more expensive) gas. From around 2007, gas prices began to increase with a large spike in 2008 following the Varanus Island gas explosion, and a fall in 2009 due to the global economic downturn (see Figure 9). More recently, new gas from the Macedon and Reindeer fields has become available for the domestic market.

In 2012, Western market domestic gas prices increased by around 2 per cent, relative to 2011, to average $4.30 a gigajoule. However, this average price reflects the balance of several long term take-or-pay contracts. A draft report by ACIL Tasman for the Western Australian Independent Market Operator (IMO) suggested that it would be difficult, if not impossible, to source new supply at that price. ACIL Tasman estimated new gas contract prices might range between $5.24 and $12.08 a gigajoule with a likely median price of around $8.23 a gigajoule (ACIL Tasman 2013). This would appear consistent with prices reported privately by a number of market participants.

Figure 9. Western market domestic gas prices, 1990 to 2012



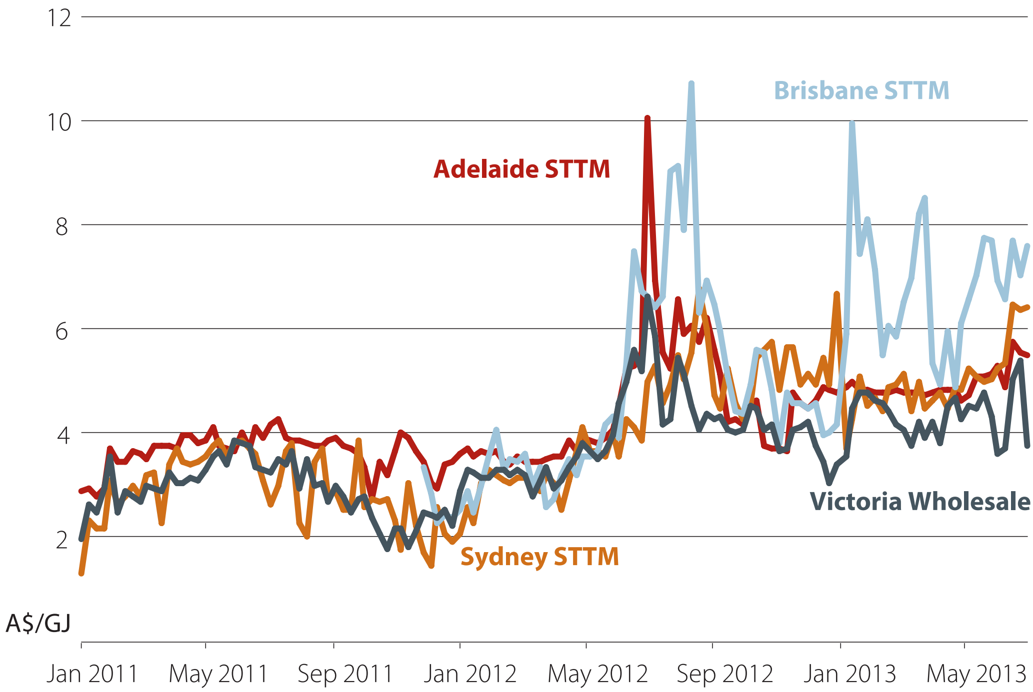
Source: Western Australia Department of Mines and Petroleum 2013.

The Eastern market

As is the case in other gas markets, long term contract gas prices in the Eastern market are not transparent, and thus are difficult to identify with confidence.

Gas prices are therefore generally quoted at the three main hubs that connect transmission and distribution networks in Adelaide, Brisbane and Sydney (Short Term Trading Markets, STTMs) and for the Victorian wholesale market[1]. Over the past two and a half years, gas prices at these key Eastern market hubs have changed considerably (Figure 10). Historically, they were characterised by relatively low and stable wholesale gas prices. Over the past year, prices have been considerably more volatile, and on average, higher.

Figure 10. Average weekly gas prices [a] in the Eastern market, January 2011 to July 2013



a the STTM prices are ex-ante and include both the cost of the gas and the cost to transport it to each hub. The Victoria wholesale price is ex-post and includes only the cost of the gas.

Source: AEMO 2013.

1 It is important to note that while the Victorian Wholesale market is representative of the majority of gas traded in that state, the STTMs in other states only act to clear the market. The majority of gas in Queensland, New South Wales and South Australia is still traded in existing retail markets, predominantly under long term contracts.

There are a range of factors that may have contributed to the recent increase in price volatility in the Eastern market. In particular, the competition for gas from Queensland LNG developments on supply availability, and therefore future prices, creates an incentive for producers to seek to rollover contracts at higher short run prices rather than renegotiate them at long run prices.

Other factors may include: a particularly cold winter in 2012, strategic bidding by market participants and the rapid growth in gas-fired electricity generation. The winding up of the Queensland Gas Scheme (QGS) in 2013, flatter projected growth in electricity demand and a return towards historical weather conditions could ease price pressures in the short term (although, given the amount of gas-fired infrastructure currently in place, it is unclear as to whether the QGS, which mandated retailers source 15 per cent of electricity from gas fired generation, has had a tangible effect on retailers' purchasing decisions in recent years).

The STTMs are market balancing mechanisms and so prices may not be fully reflective of underlying existing long term contract trade. Recent price realisations for Eastern market contracts, as quoted by EnergyQuest (2013c), are generally higher. For example, Santos and Origin contracts are up from $4.83 and $3.86 a gigajoule in June 2012 to $5.61 and $4.05 a gigajoule in June 2013, respectively. Other market and media reports, such as that by the Australian Industry Group, suggest new long term gas prices are currently averaging around $8.72 per gigajoule (AIG 2013).

Australia's gas outlook

Western and Northern Market Outlook

The Northern Market has a relatively stable price and supply outlook over the coming decade given the Northern Territory Government's long term contracts to supply Darwin and surrounding regions. Recently, a long term contract was also signed for the supply of gas from the Dingo field for Alice Springs. There continues to be discussions about the extension of pipeline supply of gas to the Gove Alumina refinery at Nhulunbuy.

The outlook for the Western Market is less clear due to ongoing uncertainty over both demand and supply forecasts. Despite the emergence of new supply through the Macedon and Gorgon projects, the outcome of a future decision by the North West Shelf proponents on recontracting for domestic gas supply remains unknown. If they decide not to renegotiate domestic contracts, this could see a re-emergence of medium to longer term supply tightness.

The WA IMO's 2013 Gas Statement of Opportunities forecasts declining prices for the next two years until Gorgon and Wheatstone LNG are commissioned in 2015 and 2016, respectively (IMO 2013).

The IMO anticipates the linkage between domestic and LNG netbacks will increase following the opening of these projects with ongoing domestic price increases from 2015 (the relationship between netbacks and domestic prices is explained in the Eastern market outlook section).

Eastern market outlook

The development of gas from coal seams (and the longer term potential for shale gas) and major LNG export projects in Queensland have dramatically altered the dynamics of the Eastern gas market. In particular, the creation of an LNG export industry is leading to the integration of the domestic and Asia-Pacific gas markets.

A consequence of this has been a sudden increase in demand competition for gas, market tightness and higher prices. A further consequence (not explored in the paper), has been to generate a high profile public debate on Australia's gas security, particularly for gas-exposed domestic industries.

This section explores the effects of interconnection with the international gas market with particular consideration of the effect competing global LNG demand will have on domestic pricing.

LNG netback prices in the Eastern market

In an integrated domestic-international market, the LNG netback price is an important benchmark which indicates the theoretical maximum price an LNG producer would be prepared to pay for gas. Alternatively, it may also be interpreted as the price at which a gas producer is financially indifferent between selling gas for LNG production and selling to the domestic market.

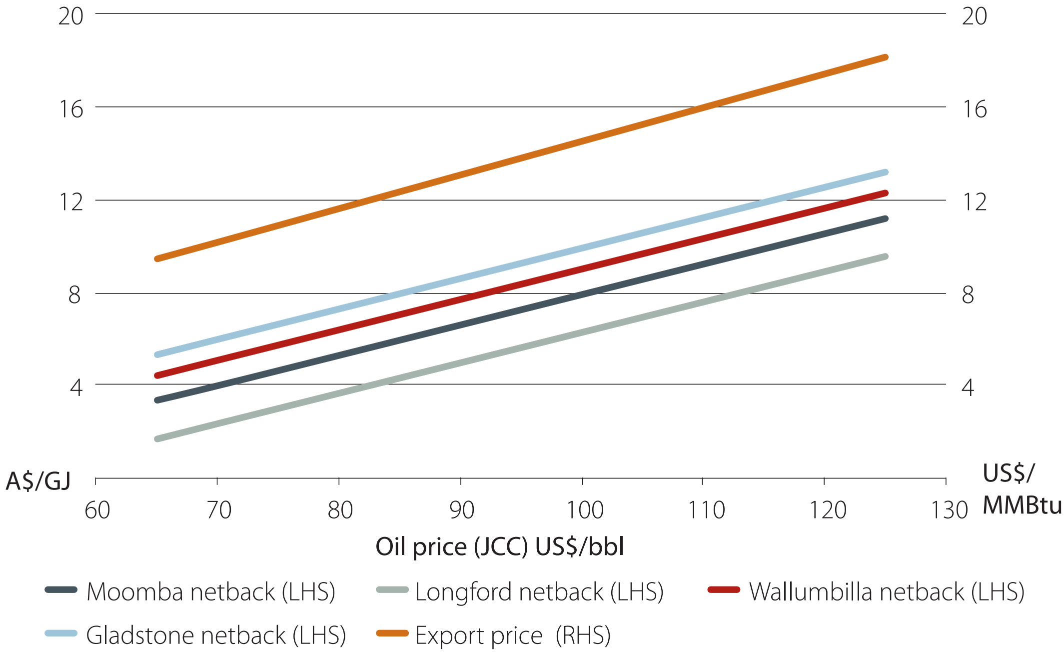
Simply put, the LNG netback price is calculated as the LNG sale price, less the costs incurred in producing and transporting the LNG to the point of sale (for example, liquefaction costs, shipping costs if sold 'delivered ex shipping' and the exchange rate as well as a margin for risk and marketing overheads).

The netback price will decrease the closer to the point of production on the supply chain it is measured (for example, the further along a pipeline network from the point of production the netback price is calculated, the greater the transport costs and, therefore, the higher the netback price). At the point of LNG delivery to the customer, the delivery price minus the netback is essentially the producer's per unit profit. When calculated at the point of LNG production, the netback price is an approximation of the delivered cost of domestic gas, as all further costs incurred downstream in the supply chain such as liquefaction and transport are excluded.

It is important to note that the LNG netback price should not be thought of as a price that can be readily observed in the market. Rather, it is a tool for understanding the maximum price that LNG exporters would be prepared to pay for gas under normal conditions.

Eastern market long run netback prices calculated by EnergyQuest (2013a) are presented in Figure 11. They illustrate the prices at which producers would be financially indifferent between selling gas for LNG production or domestic consumption at various supply locations in the Eastern market (for a range of oil prices on which the LNG price is linked and an AUD/USD exchange rate of 0.95). At Wallumbilla in Central Queensland, the netback prices are lower than at LNG plants in Gladstone, but higher than at (lower production cost, but more distant) fields in Moomba (South-Eastern Queensland) and Longford (Victoria).

Figure 11. Eastern market long-run oil linked LNG netback prices



Source: EnergyQuest 2013a.

Comparing EnergyQuest's netback calculations with current and historical long term contract pricing in the Eastern domestic market highlights the potentially higher prices available to gas producers with the introduction of a LNG export market.

It is also worth noting that in the short run, LNG operators may be willing to pay considerably higher prices than the long run netback prices in order to ensure plants operate at capacity and meet their supply commitments.

Gas supply curve

While netback prices can provide an indication of a long run demand driven ceiling price, another key consideration is the cost to bring new gas to market. This (plus the cost of transport and business margins) reflects what could be considered a long run market floor.

This can be visualised on a supply curve which shows the production cost for each additional unit of gas extracted based on existing and potential gas resources (i.e. the marginal cost).

A number of market analysts have developed gas supply curves for the Eastern market as part of their modelling. A characteristic of gas supply curves is an increase in production costs as the quantity of gas supplied increases. This tends to occur because cheaper more accessible resources are the first to be extracted, leaving behind progressively more expensive sources of supply.

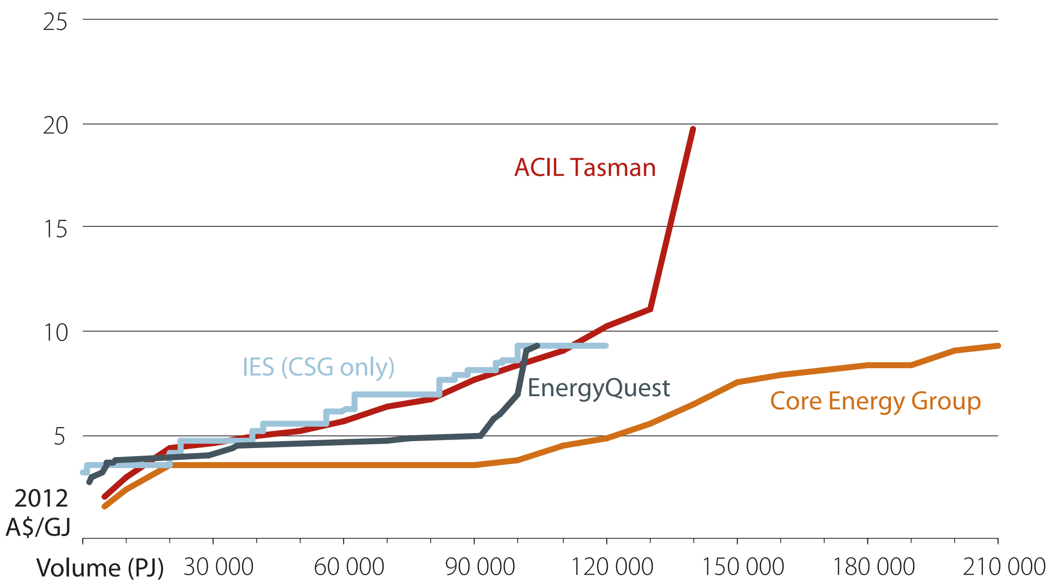
Figure 12 shows four gas supply curves developed by ACIL Tasman, Intelligent Energy Systems (IES), EnergyQuest and Core Energy Group (ACIL Tasman, EnergyQuest and Core's supply curves are for the entire Eastern market while IES's supply curve is only for unconventional gas resources). Differences in supply curves arise from differing assumptions on the quantity of gas, accessibility, well flow and depletion rates, and a number of other factors.

Based on IES's analysis, gas production costs for gas from coal seams and other unconventional gas begin around $3.50 a gigajoule, but rise steadily after that as new reserves are exploited. Under their scenario, around 80 000 petajoules of unconventional gas can be extracted at less than $7 a gigajoule, and 120 000 petajoules can be extracted at less than $10 a gigajoule.

This view is reasonably consistent with ACIL Tasman and EnergyQuest's supply curves for the entire Eastern market (which includes conventional sources) as both show costs moving towards $10 a gigajoule at around 100 000 petajoules.

Core Energy Group, in modelling conducted for AEMO, present a considerably lower supply curve than the other three analysts. This outcome appears to be a result of the assumed quantity and cost of gas resources in coal seams in the Surat-Bowen basins. Core assumes that around 80 000 petajoules are available at $3.53 a gigajoule, which is considerably more gas at a lower cost than other analysts' expectations. ACIL Tasman argues that variations in average well performance in the Surat-Bowen basins will drive prices considerably higher than those assumed by Core Energy.

Figure 12. Estimated Eastern market gas supply curves



Note: Projected supply costs represent the cost of extraction/production but exclude transport costs.

Sources: ACIL Tasman 2013, Intelligent Energy Systems (IES) 2012, EnergyQuest 2012 and Core Energy Group 2012.

Eastern market consumption outlook

Long run gas demand in the Eastern market is expected to be affected by a range of factors, notably lower projected growth in electricity demand and upcoming LNG exports and the associated effect of linking to international LNG prices.

As outlined previously, the increasing exposure to international market prices as well as (barring extensive low cost new discoveries) rising extraction costs are likely to place upward pressure on domestic wholesale gas prices and downward pressure on domestic demand in coming years.

A number of market demand forecasts, including those by ACIL Allen (2013), AEMO (2012) and EnergyQuest (2013a) have either recently downgraded growth or are forecasting falling consumption in the Eastern domestic market in coming years (Figure 13).

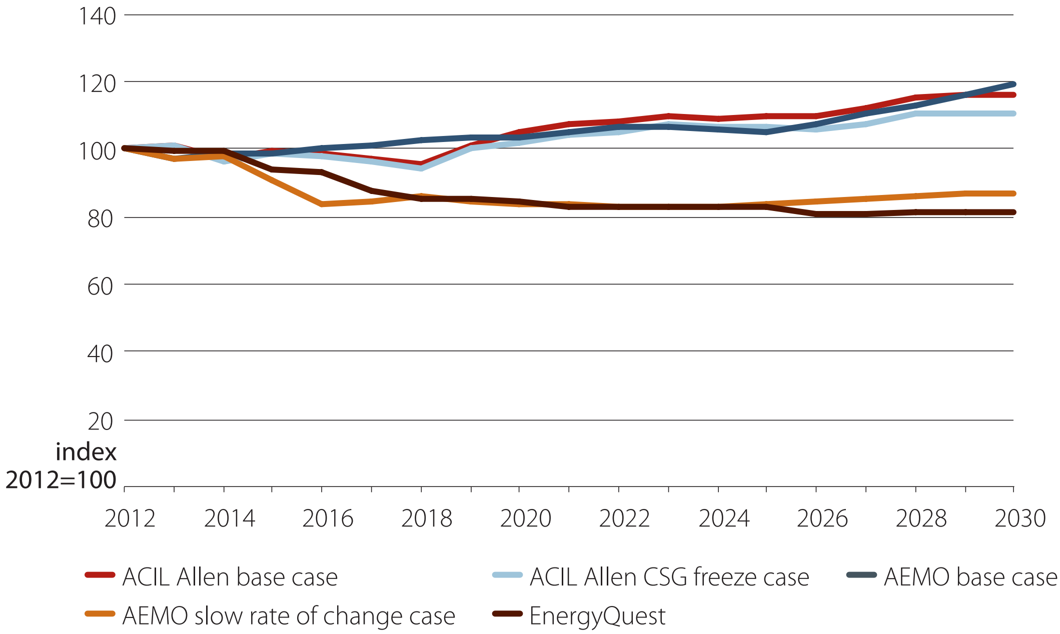
The lower growth forecasts reflect expectations of higher prices and a number of other recent market developments. The cessation of contract for closure negotiations in Victoria (which would have seen several large coal plants shut down), increasing generation from renewable energy sources, and falling growth in electricity demand are all likely to subdue gas-fired electricity generation demand in the medium term.

Pressure on large domestic consumers (such as manufacturers) from a strong Australian dollar and global economic uncertainty could see their consumption fall. Furthermore, increasing demand as LNG projects increase production towards full capacity and changes in NSW Government policy regarding coal seam gas development are expected to reduce the volume of new gas being delivered to the domestic market and contribute to tight market conditions for a number of years.

Over the next decade, higher prices could change some consumers' (large and small) preferences for gas. Gas-fired electricity generation plants may be deferred or cancelled, and large manufacturing and industrial operations as well as residential consumers may seek cheaper energy sources. However, as has been the case in Western Australia[2], higher prices will likely bring on new supply (which would draw on Australia's plentiful resources), and along with advancements in technology, ensure demand in both the Eastern domestic market and the LNG market is satisfied in the medium to long term.

2 As covered in IMO 2013, gas prices in the Western market increased considerably between 2003 and 2011 which in turn attracted investment in domestic production capacity in the form of the Devil Creek processing facility in 2012.

Figure 13. Index of subdued Eastern market gas consumption scenarios

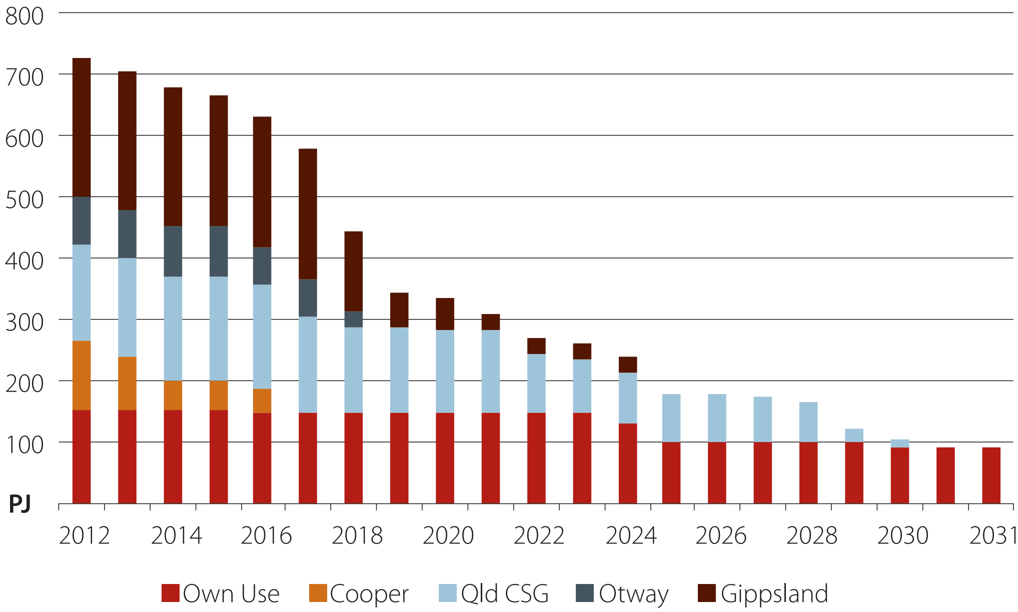


Note: The ACIL Allen CSG freeze case assumes no development of CSG in NSW. The AEMO slow rate of change case assumes lower coal prices and economic growth.

Sources: ACIL Allen (2013), AEMO (2012) and EnergyQuest (2013a)

Contractual arrangements covering around 260 petajoules of gas that is currently supplied in the Eastern market are due to expire in the coming five years. Figure 14 shows the falling quantity of contracted gas in key Eastern market basins. As a result, large gas users are currently seeking to recontract gas in coming years in order to ensure long term supply. At the same time, large gas suppliers and LNG producers are focused on commissioning new projects and managing significant project and production risks associated with new coal seam developments (EnergyQuest 2013a). This has introduced considerable tension and uncertainty into the market.

Figure 14. Eastern market gas contracts, by basin, 2012 to 2031



Source: EnergyQuest 2013b.

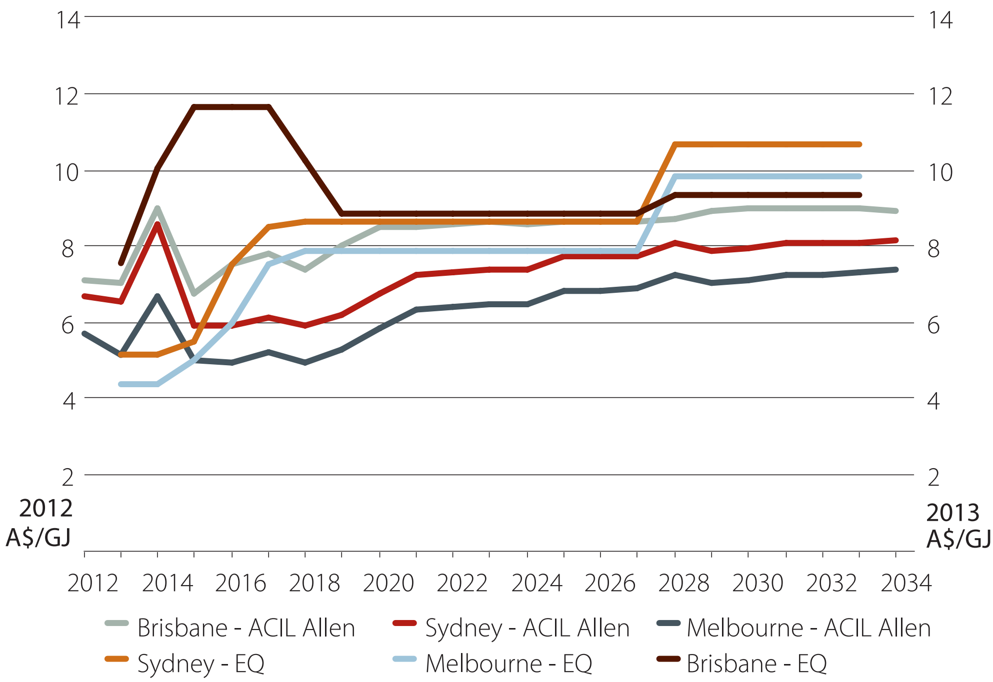
Gas price outlook

Given the lack of transparency regarding contracted gas arrangements it is not surprising that there is a wide variety of projected gas prices for the Eastern market among analysts. These arise from the use of different models, assumptions, parameters and oil price forecasts.

Despite the differences, there are some trends that appear across projections. The two scenarios in Figure 15 illustrate these trends. ACIL Allen (2013) assume a sizeable price shock around 2014 when Queensland LNG commences, and expect a return towards production costs (which increase consistently in the long run) in the years after LNG reaches capacity. ACIL Allen note a return towards production costs may take longer than forecast depending on the market's ability to rapidly expand production.

Similarly, EnergyQuest's (2013a) base scenario forecasts a considerable price jump in coming years (particularly in Brisbane) as medium-term prices approach short run LNG netback prices. This jump is expected to last through the middle of the decade. Prices are expected to return towards production costs once all the Queensland LNG projects are operating and fully producing from their own reserves (around 2019–20). EnergyQuest, like ACIL Allen, consider the key determinant of medium term pricing is whether projects can source sufficient gas from their own reserves without having to purchase from the market (which would drive prices even higher).

Figure 15. Eastern market gas price projections, 2012 to 2034



Notes: ACIL Allen is the base scenario and is plotted on the left hand side. EQ is EnergyQuest's $95 JCC scenario and is plotted on the right hand side.

Sources: ACIL Allen 2013 and EnergyQuest 2013a.

BREE also expects Eastern market prices to increase in the short to medium term (particularly in Queensland), reflecting a tightening market associated with competition for gas resources as well as uncertainty among market participants.

Until significantly more supply is commissioned and/or domestic demand falls sharply, the Eastern market is likely to be a sellers' market (in that gas sellers will have considerably more power in contract negotiations with domestic buyers because of the profits available to them in selling gas for export). EnergyQuest (2013a) suggests that, due to the length of time it will take for new supplies to be brought to market, this will remain the case until towards the end of the decade.

The ability of the wells in the Surat-Bowen basins which supply LNG projects to reach capacity and maintain production rates over a number of years will be a key determinant of this timespan. Three other critical factors in this equation are whether there are any delays to commissioning of new LNG projects, the strategies LNG producers employ in the market to manage production and/or contract risks and the extent to which new gas resources, particularly in New South Wales, can be developed.

Conclusion

Abundant gas resources have attracted investment that has seen Australia develop into a globally significant LNG exporter as well as developing its domestic markets to supply industry and households.

In coming years, all three of Australia's gas markets will become more closely linked with international gas markets, especially the Asia-Pacific LNG market, as new LNG production and export facilities commence production. First LNG exports from the Eastern market are expected to begin in 2014 and will herald a wave of export capacity growth in Queensland, Western Australia and the Northern Territory.

This represents both a challenge and an opportunity for Australia. While the domestic market will become more influenced by changes in the global gas market (and is likely to experience ongoing supply and price tightness in the near to medium term) there is an opportunity for further investment in LNG liquefaction and exports to continue to grow.

In the short term, higher domestic prices and subdued demand are likely in the Eastern domestic market as it adjusts to significant export gas demand from LNG projects. There is a need for further market and regulatory reform to promote market development and to address barriers to potential new supply.

Over the longer term, however, the interconnection of Australia's gas markets with the world will provide the necessary investment signals to ensure both domestic and LNG export demand is satisfied.

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Coal seam gas production: challenges and opportunities

John Williams, John Williams Scientific Services Pty Ltd; Ann Milligan, ENRiT: Environment and Natural Resources in Text; and Tim Stubbs, Yellow and Blue Pty Ltd: Environmental and Natural Resource Consulting[1].

Introduction

Coal seam gas (CSG) is a naturally occurring methane found in coal seams. Australia has sizeable known and inferred reserves of CSG, occurring mainly in the large coal basins of Queensland and New South Wales (NSW). The development of Australia's CSG reserves will contribute to meeting household, commercial and industrial demand in eastern Australia, and supply export markets.

The rapid expansion of CSG production on the east coast has been the topic of much debate, stemming from apprehensions relating to the social, economic, technical and environmental implications of CSG operations. Communities have been unprepared for this expansion and, in some cases, unwilling to accommodate the industry.

Governments and industry have responded with the introduction of legislation and codes of leading practice to minimise technical failures and protect communities and natural resource assets. However, there is not currently a 'nationally consistent application of leading practices for the regulation of industry activities' (SCER 2013).

The *National Harmonised Regulatory Framework for Natural Gas from Coal Seams* (SCER 2013) offers information about CSG operations for governments, industry and communities, particularly in relation to well integrity, water management and monitoring, 'fracking', and management of chemicals. It sets out approaches agreed between the Australian state and federal Ministers responsible for resources, to provide guidance on leading practices for CSG operations, based on state and federal policies, legislation and regulations (SCER 2013).

If carefully regulated and managed, CSG production has the potential to have positive economic and social effects, with minimal damage to the natural environment.

CSG in Australia

Australia started using 'conventional' gas (a relatively easily accessed form of methane) in the mid-1960s (APH 2008) and CSG in the last decade. When burnt, gas provides twice the

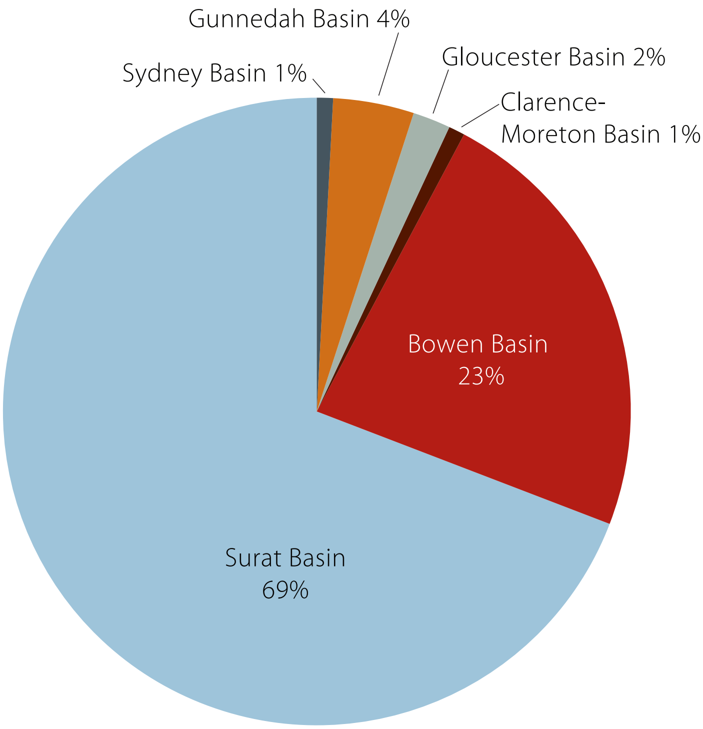
1 The ideas expressed in this chapter draw on earlier writings in works published by ACEDD, ACOLA and ANU (listed in the references). In particular, the authors would like to acknowledge use of information and insights provided by John Toomey, ATSE, on the history and technical evolution of methodology in the Queensland CSG industry. The authors also gratefully acknowledge the assistance and advice provided by John Scott of ScottCromwell on interpretation and text to explain the new approach to risk analysis.

energy of coal per unit of weight, with half the greenhouse effect, and it does not produce by-products such as sulfur, mercury, ash and particulates (Cathles et al. 2012). Gas is expected to play an important role in Australia's energy supply.

The largest reserves of CSG are in Queensland's Surat and Bowen basins while in NSW the CSG reserves are relatively small (Figure 1). The largest reserves of conventional gas in eastern Australia are offshore of Victoria and in the Cooper Basin (northern South Australia) (AGRA 2012; Figure 2). Western Australia's gas demand is supplied from its very large conventional gas reserves offshore. These reserves are also shipped as liquefied natural gas (LNG) to meet export demand.

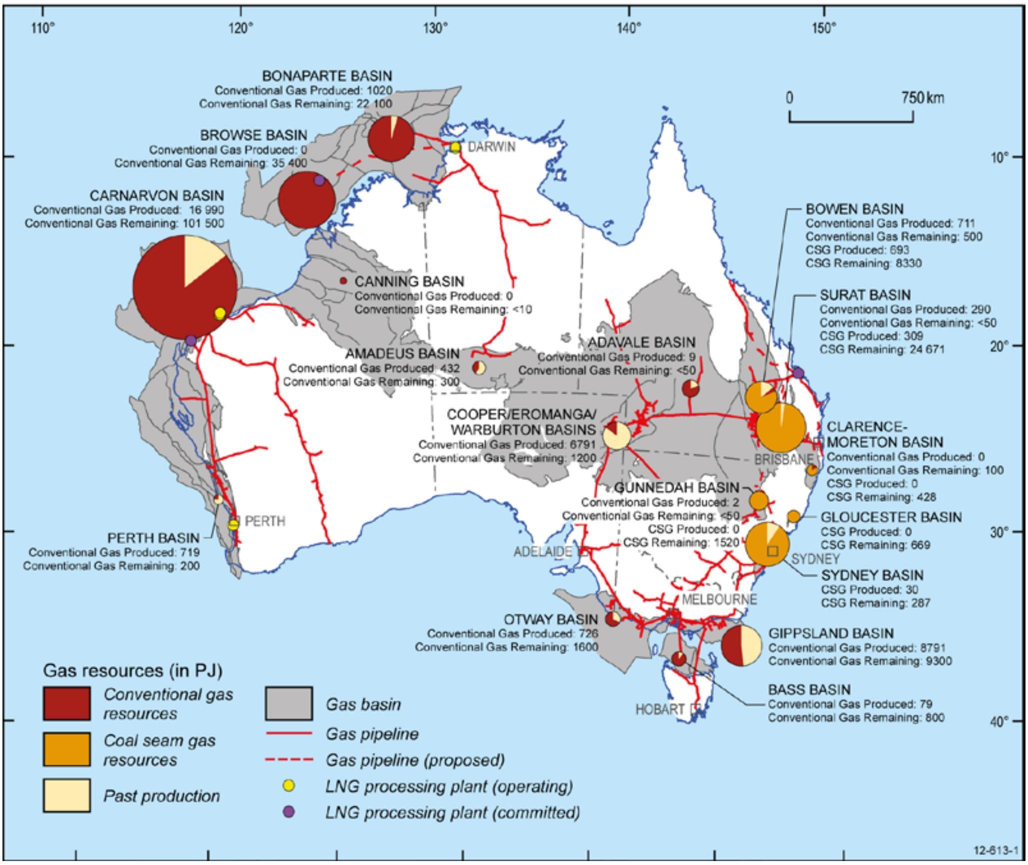
By 2012, annual production of CSG was 252 petajoules in Queensland and 6 petajoules in NSW. This accounted for around 35 per cent of Australian east coast gas consumption (SCER 2013). New capacity to produce LNG is being developed on the east coast of Australia, which will enable export of CSG. To meet known domestic and overseas commitments, including new LNG projects, the rate of drilling CSG wells in Queensland is forecast to intensify during 2014–15 (ACIL Tasman 2012 p. 38).

Figure 1. Reserves of coal seam gas, by basin



Source: AGRA 2012.

Figure 2. Australia's gas resources and infrastructure

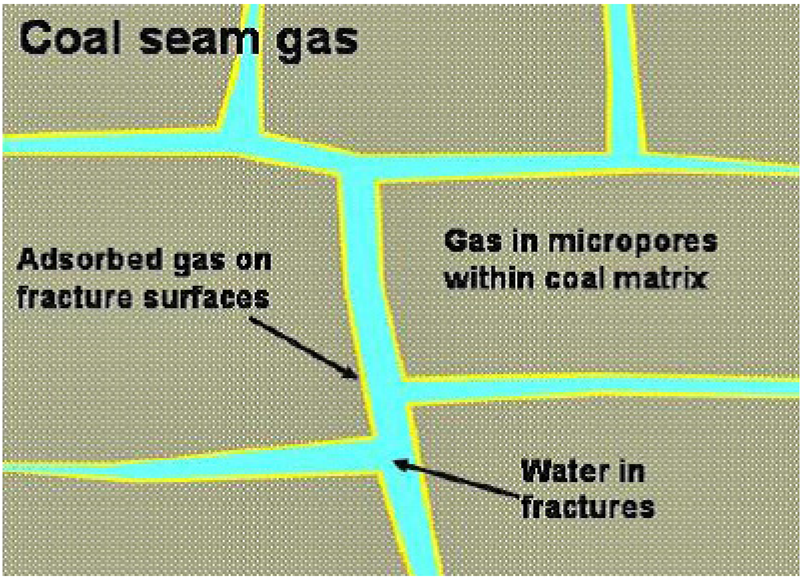


Source: AGRA 2012.

Coal Seam Gas extraction

Coal seam gas is found in cracks, pores and micropores in coal seams, where it is held in place either as free gas, or adsorbed onto coal surfaces (Figure 3). To extract the gas via wells drilled into a coal seam, the hydraulic pressures exerted by water in the seam and/or overlying aquifers must be reduced. Dewatering these strata by pumping groundwater up to the surface (as 'produced' water) releases the CSG. The gas rises at atmospheric pressure to the top of the well where it is collected and fed at low pressure to the treatment plant and then into a high pressure transmission pipeline. In most cases the CSG is naturally of 'pipeline quality' and, apart from drying, requires minimal treatment. Seams that have plenty of natural fractures are less costly to develop as sources of CSG than those that are more solid and need to be artificially fractured ('fracked') to make passage for the gas.

Figure 3. Schematic of gas within a coal seam



Source: Geoscience Australia.

Coal seams likely to be tapped for CSG in Australia occur mostly 250–1000 metres below the ground surface. Most CSG production to date in Australia, particularly in Queensland, has not entailed fracking of the coal seams (contrary to the history of gas production in the United States). However, as Australian production taps into deeper coal seams or those less naturally permeable, the need for fracking[2] may increase from the current 10 per cent of wells to upwards of 40 per cent (UTS ISF 2011).

2 Fracking is the process of pumping water at very high pressure into the coal seam to force open narrow fractures and keep them open so the gas will flow out when the fracking water is removed. The water (often some of the 'produced' water already pumped from the seam) is augmented by 'proppant' materials and chemical additives. These have various purposes, including easing the widening process and protecting the equipment involved.

CSG and the environment

Potential for contamination

The potential for various types of leaks and spills has been a major reason for concern about contamination during CSG production. Fracking chemicals can include small amounts of toxic substances, and there is potential that if spilled, or not prevented from leaking, such chemicals may contaminate aquifers or catchments used for drinking water (Batley & Kookana 2012). CSG operators in Australia are required to publicise the names of substances they apply during fracking, and they are increasingly using environmentally friendly chemicals (Batley & Kookana 2012).

Water that has been pumped from a coal seam, whether initially to dewater it or after use for fracking, is often brackish or saline and contaminated with other substances dissolved from the coal seam itself, such as metals and radionuclides, which can be toxic to plants, animals and humans (Vink et al. 2008; Moran & Vink 2010; NWC 2011, 2012; QWC 2012; Batley & Kookana 2012). Concentrated brines (with or without toxic chemicals) produced by treating this groundwater need safe and environmentally sensitive management and disposal—a situation for which industry and governments are seeking solutions.

Contaminated produced water needs careful storage and transport or treatment. It cannot be spilt or leaked into crops, native vegetation, surface waters or shallow and deeper groundwaters (which are connected components of the one hydrological system). Even after treatment of the water, its disposal into natural streams can affect stream ecosystems if not matched to stream temperature and natural flow regimes, which can vary from no-flow to flood (Levick et al. 2008; Smythe-McGuinness et al. 2012).

Ensuring well integrity is an essential element in managing potential effects of CSG operations on groundwater resources. Well integrity refers to the permanence and solidity of the cement casing—the lining of a well. If the cement were to shrink as it ages, there could be potential for unwanted groundwater to leak into the well, or of water or gas into the surrounding strata, possibly causing contamination (TRS RAE 2012; Eco Logical Australia 2013). Auditing of well performance with respect to failure can alleviate public concern about well leakage and loss of integrity (Nikiforuk 2013; NSW CSE 2013). Well integrity has improved in wells installed in the last decade following the introduction of stricter standards for preparing wells.

The National Harmonised Framework (SCER 2013) requires that:

> *'Decommissioning and well abandonment must ensure the environmentally sound and safe isolation of the well for the long term. It must ensure the protection of groundwater resources, isolation of the productive formations from other formations, and the proper removal of surface equipment'.*

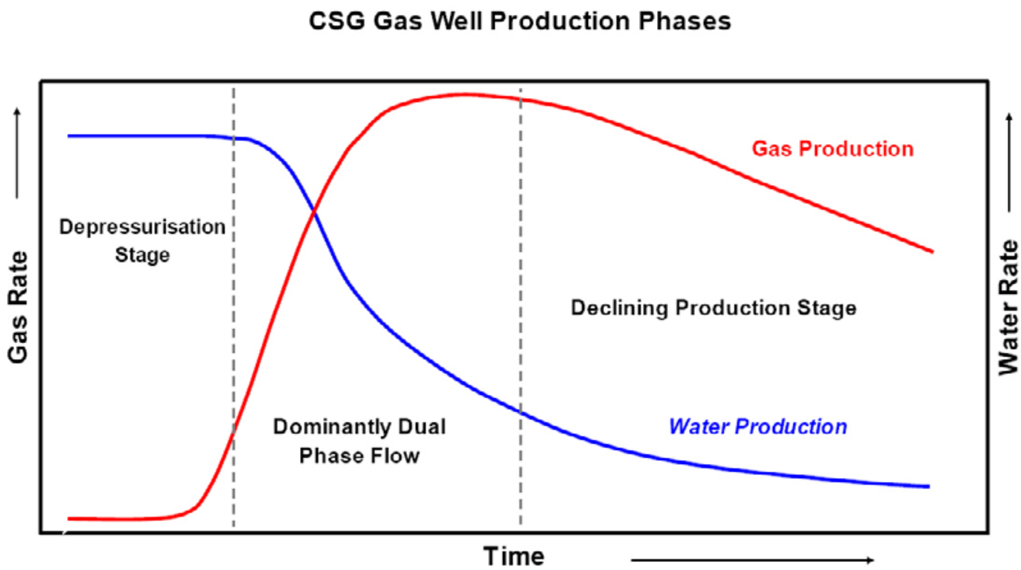
It cites the Queensland *Code of Practice for Construction and Abandoning CSG Wells* and the NSW *Code of Practice for Coal Seam Gas—Well Integrity*, both of which are intended to ensure 'long-term well integrity, containment of gas and protection of groundwater resources'.

Sound well integrity can also minimise leakage of CSG into the air—a direct greenhouse gas emission (e.g. Alvareza et al. 2012). Greenhouse gas data for CSG are being collected, including the primary sources of emissions and reasons for variance in leakage rates (Commonwealth of Australia 2013).

Water management

Volumes of 'produced' groundwater are typically large in the early stages of CSG production, and the volumes of gas released are small. However, later in the life of a well (which can be several years) the water produced decreases and methane production increases (Figure 4). Seams that need fracking may produce less water than other seams.

Figure 4. Typical changes in the rates of water and gas production from a CSG well



Source: QWC 2012.

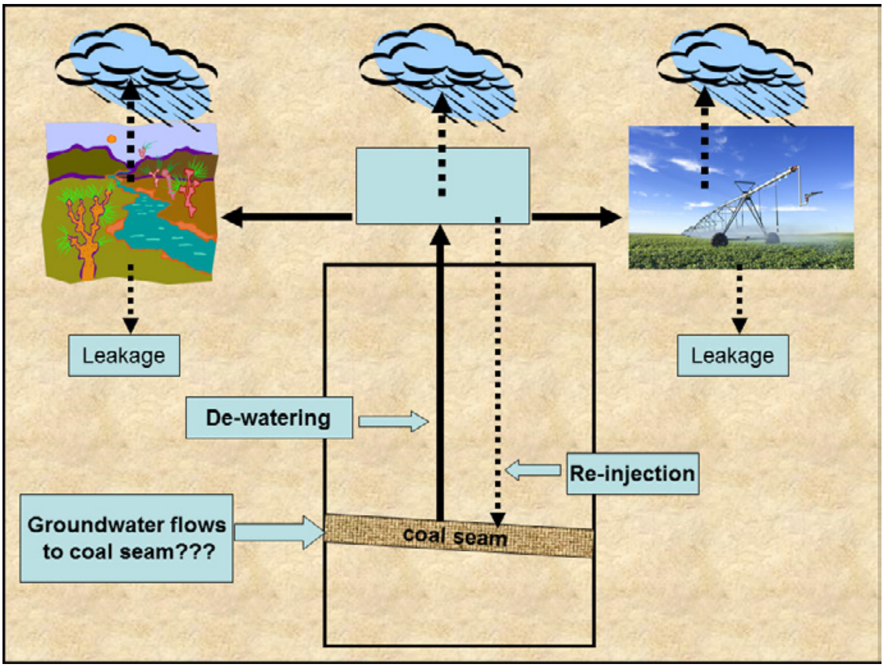
Dewatering of aquifers or otherwise depressurising coal seams to release gas can be followed by a range of potential impacts (NWC 2012; Osborn et al. 2011; Warner et al. 2012). These are listed in the National Harmonised Framework as:

- reduced aquifer levels and pressures with volume and quality implications for other users, groundwater-dependent ecosystems and unwanted surface water interactions with groundwater over the short and long term (intergenerational equity)
- cumulative impacts from multiple projects and local versus regional impacts
- altered hydraulic gradients produce mixing and cross-contamination between different aquifers and between aquifers and surface waters with different quality characteristics
- migration of gas (and its rate) into surrounding aquifers, wells and water bores, and the surface

- reduced water pressure in subsurface layers that enables compression of layers, alteration of hydraulic properties and subsidence at the surface (SCER 2013).

There are positive aspects to the considerable volumes of groundwater pumped from CSG wells. Once treated for quality, it can be a resource for sale for irrigation purposes. Use of treated produced water for irrigated agriculture and horticulture has shown promise in short-term trials (Santos 2011). Urban and industrial uses have also been suggested (APLNG n.d.; QEHP 2012).

Figure 5. Essential components of the water balance for CSG extraction, simplified



Source: John Williams Scientific Services Pty Ltd.

Alternatively, the produced water may be used for restoring the hydraulic pressure in aquifers that have been over-pumped (Figure 5). Reinjection appears to be a nontrivial process, but it is seen as a leading practice for beneficial use (SCER 2013):

> *'Providing treated water to water users as a substitute for current aquifer extractions has the potential to reduce demand on a particular resource provided the current water extraction ceases or is reduced…If water reinjection is adopted by the project operator for either beneficial use as an aquifer recharge mechanism or disposal, the evaluation and risk assessment of the reinjection program should include consideration of potential impacts.'* (SCER 2013)

It is often overlooked that groundwater removed by dewatering will over time be replaced from elsewhere to re-establish hydraulic equilibrium. Reinjection of water into a seam when the CSG has been extracted is one way of managing this.

Land and biodiversity management

The rapid expansion of CSG drilling activity also brings some other significant environmental and natural resource challenges (CSIRO 2012; NWC 2012; Williams et al. 2012; Randall 2012), such as:

- loss of biodiversity through fragmentation of habitat and native vegetation in the landscape
- land use conflict and loss of landscape hydrological and ecological functions.

By its scale and nature, the 'footprint' of an energy-production field of this type cuts across landscape and biological habitat (Figure 6). Within CSG developments in Australia, average density is approximately 1.1 well pads (and 1.6 kilometres of road) per square kilometre of land (Eco Logical Australia 2012).

Figure 6. Roads and other infrastructure in a CSG field near Dalby State Forest, southern Queensland. Scale widthways: 6.8 kilometres

Source: Eco Logical Australia 2013.

It is possible that with time, new technology will let well pads be spaced farther apart. Using Australian-developed technology for guidance of drilling deep underground, it is now possible to drill from a vertical well for more than a kilometre horizontally along a target coal seam (e.g. Metgasco 2013). The fewer drill pads needed at the surface, even if each is a bit larger, reduces intrusion on other land uses in an area. Multiple wells on a single pad imply fewer inroads and gas-gathering systems.

Establishing CSG infrastructure entails direct removal of native vegetation to allow access and clear a firebreak and workspace around the drilling site. As with any other activity that requires land clearing, this could lead to the introduction of invasive species especially weeds, invertebrates and people, and cut into the home or breeding ranges of native fauna such as lizards and birds. A number of scientific studies have confirmed the negative impacts of fragmentation of bushland, regardless of the activity, on native fauna (e.g. Wiens 1985; Forman & Gordon 1986; Franklin & Forman 1987; Saunders et al. 1991; Ries et al. 2004; Cushman 2006; Fischer & Lindenmayer 2007).

Where a landscape has already been extensively cleared for urbanisation or agriculture, in many cases the vegetation that is left is of high ecological value (Hansen & Clevenger 2005; Fischer & Lindenmayer 2007). Clearing for a single well pad and the associated service road and pipeline may intrude into but not badly fragment a patch of bushland. Clearing enough space for many well pads, roads and pipelines in a single patch of bushland results in cumulative fragmentation and requires careful consideration and attention (Shoemaker 1994; New York City Department of Environmental Protection 2009).

The Native Vegetation Acts in both NSW and Queensland, prior to recent revisions, dealt well with issues of clearing of native vegetation, but CSG operations are exempt from these Acts. If there is a particular threat to threatened species then the Commonwealth *Environment Protection and Biodiversity Conservation Act 1999* applies, as does state threatened species legislation. However, these Acts do not easily deal with broad-scale fragmentation and cumulative loss of habitat.

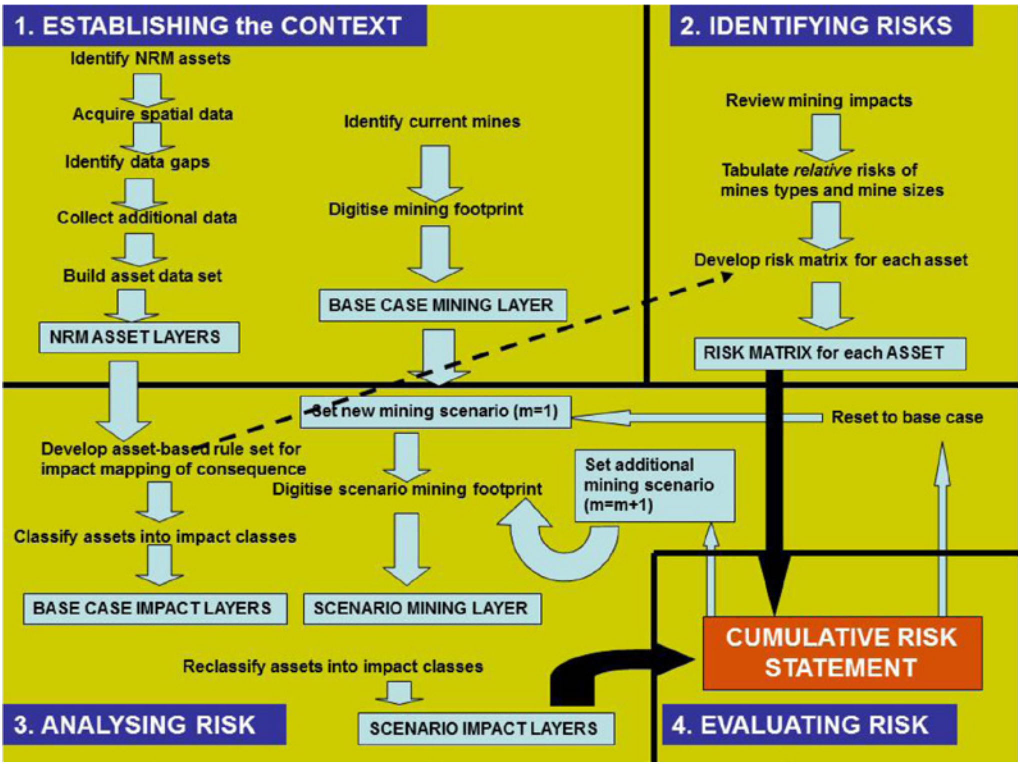
Productive farming for food and fibre is also perceived to be at risk from the cumulative fragmentation and potential resource-contamination impacts of CSG operations. Both fragmentation and contamination reduce the usability of strategic agricultural land and water resources.

To mitigate that situation, the Namoi Catchment Management Authority (CMA) has pioneered a new way to undertake cumulative analysis of multiple industry development (Eco Logical Australia 2011, 2012, 2013). The Namoi catchment supports a range of productive land uses including irrigated agriculture. It also has large coal reserves and consequently there is significant pressure for additional coal mining as well as CSG extraction. The CMA recognised that mining had the potential to deliver substantial benefits to the region but also that mining (not just CSG) was a potential threat to the natural resource assets of the catchment.

The CMA was able to use its detailed understanding of the natural resource assets of its region, through its catchment planning process, to assess the impacts of any one mining development on the natural resource assets of the catchment and the potentially cumulative impacts of a number of mining developments.

The result of this planning process is a strategic vision for the Namoi catchment in the form of a framework inside which a risk assessment process can be undertaken for mining and CSG development. Using this framework (Figure 7) and a GIS modelling tool, the CMA has produced a cumulative risk statement on the individual and cumulative impacts associated with any real or hypothetical mining scenario. A further aim is to enable mining and CSG developers to run a range of scenarios and determine how best to structure their operations to minimise, or remove completely, any negative effects on the natural resource assets of the Namoi catchment.

Figure 7. Framework for cumulative risk assessment in the Namoi catchmen



Source: Eco Logical Australia 2011.

Like the Namoi CMA, the Murray CMA has now made its own cumulative risk assessment (MCMA 2012), and other catchment management teams across Australia have been applying locally collected data to manage their areas of responsibility in a holistic, cumulative way, via Catchment Action Plans. Where water catchments are managed as whole units (as in Integrated Catchment Management), there are now tested and practical processes and methods available for determining the points at which landscape function[3] will stop being resilient and begin to fail (NSW Natural Resources Commission 2012; Williams 2012).

3 Landscape function is, for example, the capacity of a hillslope to retain water, resist erosion, and sustain plant growth and cycling of plant nutrients (Tongway & Hindley 2005).

While extensive grazing would appear to be a form of agriculture better at co-existing with CSG production than dryland and irrigated cropping, the experience in the Namoi catchment suggests a balanced co-existence of mining and the various forms of agriculture and forestry may be possible—with careful management supported by bioregional planning and cumulative risk assessment.

Other examples of cumulative risk assessment have included the Land Use Conflict Risk Assessment (NSW DPI 2011), and methods applied in the Alligator Rivers Region of the Northern Territory (which encompasses mining, indigenous values and conservation; SEWPaC 2011), and the land use impact model developed in Victoria (MacNeill et al. 2006).

The Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development (IESC) and the Council of Australian Governments (COAG) agreement with the States on these matters offer a means by which integrated risk management incorporating cumulative risk assessment could be achieved as part of the bioregional assessment process.

CSG and the community

A number of residential communities have also been resisting co-existence with CSG industry development in Queensland and NSW, for a range of reasons including access and nuisance (Poisel 2012; Swayne 2012; Lloyd et al. 2013). With conventional open-cut coal mining, the standard practice for decades has been for the mining company to purchase the land at valuations well above commercial value. As a result, there are rarely any disputes with property holders about access. For CSG, the intensity of well-field developments proposed and the distributed placement and irregular spacing of wells make total acquisition of properties impractical. Under current mining legislation and regulation in Australia, property holders have virtually no ownership rights to minerals (including CSG) below the topsoil.

During 2013, the Queensland Government is expected to revise its 'land access and compensation framework that governs how resource companies access private land for resource exploration and production' (Carter Newell 2013). In NSW, in response to rising public concern, recent changes to government policy have restricted the freedom of CSG companies to develop potential gas fields. According to draft legislation being prepared (as at May 2013), gas operations may not proceed within two kilometres of residential areas or industry cluster areas in NSW, unless the company already possesses a Development Approval. Companies may have already completed exploration and found a potentially valuable field, but the field cannot be developed any further unless it had received approval before mid-February 2013 (Corrs et al. 2013).

Nevertheless, a rapidly growing CSG industry in Queensland and NSW has the potential to deliver large social and economic benefits to those States and to Australia as a whole (Rayner & Bishop 2013).

For example, economic studies by the Queensland Government indicated that a medium-size 28 million tonne a year industry converting CSG to LNG could (Queensland Government 2013):

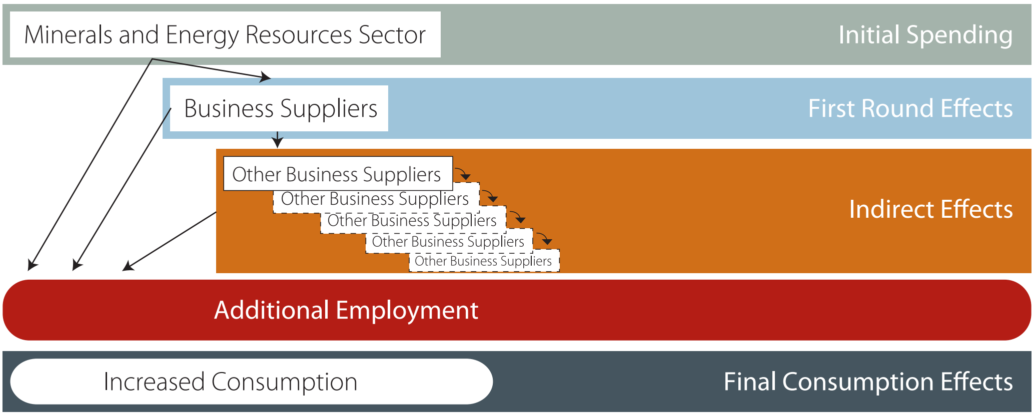
- generate more than 18 000 jobs in Queensland, with 4300 jobs in the Surat Basin alone
- increase gross state product by more than $3 billion or 1 per cent
- generate private sector investment of more than $45 billion
- provide royalty returns of more than $850 million a year, which could help fund schools, hospitals and other vital services.

Likewise, APPEA (Australian Petroleum Production and Exploration Association) claims that in Queensland 'the gas industry has created about 30 000 jobs in recent years, is working in partnership with more than 4000 landholders, and is today revitalising regional communities' (APPEA 2013). This contrasts against earlier analyses of likely social and economic benefits from CSG and mining (e.g. Petkova et al. 2009, and references cited in Williams et al. Ch. 4), which suggested that capital cities and large centres would gain while regional and communities and landholders bore many of the costs and negative impacts.

Patterns of social and economic impact appear to depend on the size of project, community structure and history, and the extent to which a non-resident work force is involved. The level of local support for resource development including CSG is contingent upon economic benefits and opportunities accruing at the community level (Haslam-McKenzie et al., 2013).

Australian governments hold the gas resources in trust, and seek to gain positive economic and social benefits from these resources. One way in which this happens is via the multiplier effects of a series of successive spending rounds (Figure 8; Rolfe et al. 2011). The size of the economic multiplier in a local or regional area principally depends on the extent to which project operators purchase inputs, including labour and goods and services, from the local or regional economy, and the extent to which that money spent in the local or regional economy remains there rather than being spent in larger regional centres (Jensen & West 2002).

Figure 8. Possible multiplier effects



Source: Rolfe et al. 2011.

To ensure local and regional benefits from industry development, the federal and several state governments have established Industry Capability Networks (ICN). State-based ICN consultants that are familiar with the region match project operators with local and regional Australian suppliers so that these companies and communities can share in the wealth generating opportunities from CSG (ICN 2013).

In Australia, there is strong industry support for the role of a 'social licence to operate' as a complement to the regulatory licence issued by government. From an industry perspective a social licence to operate is about operating in a manner that is attuned to community expectations and which acknowledges that businesses have a shared responsibility with government and society, to help facilitate the development of strong and sustainable communities.

Given the proposed intensity of CSG development in Queensland over the next four years, particularly in the Surat Basin, extraordinary demands will be made on rural infrastructure, housing, and community services in health and education. As a result, communities are likely to raise concerns about the adequacy of infrastructure. The Queensland Government (2012) has published a guideline for the industry, stating that new developments must have a social impact management plan.

Community health, safety and social well-being have increasingly been considered part of the risk management and social responsibilities of resource development proponents. Companies appear to be rising to the challenge, with Santos, for example, announcing good progress in new housing construction in southern Queensland (Santos 2013).

Several studies of social impacts of mining and CSG have identified issues (see summary in Williams et al. 2012 Ch. 4), such as good communication and transparent sharing of information with the communities, as being critical for improving community understanding and acceptance of new industry. They are also critical for good governance, ongoing management of opportunities, and for policy and planning for investment in supporting hard and soft infrastructure, which will underpin long-term benefits to the community.

With respect to human health, a recent report by the Queensland Department of Health (2013) (drawing on the findings of a Darling Downs Public Health Unit investigation conducted in 2012, along with independent medical assessment and scrutiny), concluded that there were no adverse health impacts resulting from CSG operations near Tara, which is 300 kilometres west of Brisbane.

Risks and opportunities in summary

The rapid development of the CSG industry and the subsequent challenges it has faced highlight risks as well as opportunities for Australia's legislative approaches, both in management of social and economic effects of industries, and in balanced use of natural resources.

There are mechanisms for managing risks to landscape function. However, they are often not consistent across state and federal jurisdictions or applicable to all landscape users in the same jurisdiction (ANEDO 2013). In response to this inconsistency and subsequent community concern, new laws are being implemented specifically to address potential effects of CSG extraction. The *National Harmonised Regulatory Framework for Natural Gas from Coal Seams* (SCER 2013) attempts to remove some of the inconsistencies in management of CSG across state and federal jurisdictions.

In practical terms, it is important for all involved with CSG operations to understand the nature of the risks the industry poses. Society and economy depend on the ecological, hydrological and geochemical processes in the landscape. Their vulnerability to failures of CSG safeguards, not the calculated probability of failure, defines the level of risk. A new approach to risk management 'demotes' the probability assessment, and promotes realisation of the importance of the consequences of events (ARPI & ScottCromwell 2013). This model of risk thinking is consistent with the new cumulative risk assessment approaches in use in the Namoi and Murray Catchment Management Authorities (MCMA 2012; Eco Logical Australia 2011, 2012, 2013).

The effects of CSG operations on water resources, food and fibre production systems, and biodiversity can be managed in a whole-of-landscape framework that takes account of long term cumulative impacts. It involves:

- understanding regional landscape capacity, and determining if there is capacity for the development without crossing landscape limits
- updating current development approval processes so that new developments can only be approved on the basis of landscape limits and the expected cumulative impacts of the existing and proposed developments
- using insights gained from whole-of-landscape cumulative risk assessment and aligned with the limits and thresholds to landscape function, to establish regulation, leading practice, and monitoring and compliance arrangements to manage risks.

Building trust is a key to securing a social licence to operate for any major resource project, including CSG operations, and it is important to have a transparent approach to collection and dissemination of reliable data (NSW CSE 2013). Communities are more likely to accept information as credible if it comes from a source perceived to be truly independent (Lacey et al. 2012; Lloyd et al. 2013). Involving local people and landowners in the collection and understanding of environmental monitoring data has also been shown to increase trust.

Social research suggests that there are better opportunities for the industry if it makes a direct financial return to communities most affected by CSG operations, improves communication and collaboration with stakeholders, and invests in infrastructure. These approaches facilitate ongoing access and strengthen the social licence to operate. The challenge for the industry is to articulate an agenda that balances its own commercial needs in a context of broader expectations about contributions to the development of affected communities and regions.

Research by the CSG industry and relevant research bodies will benefit regulation and management as well as the industry. There are large areas of Australia where there is only moderate data about the natural resources and features relevant to CSG or other mining operations. The National Harmonised Framework calls for companies to establish baseline monitoring and continue monitoring their areas. Independent research bodies can also contribute by obtaining:

- baseline data against which to measure change
- knowledge, predictive tools and appropriate data for predicting cumulative impact and change so that minor impacts can be prevented from significant consequences.

Australia has the capability to meet the challenges posed by CSG operations and to make the most of the opportunities CSG offers. With modern whole-of-landscape strategic planning in place, supported by effective regulation and governance, CSG production has the potential to deliver positive economic and social benefit, and need not damage the natural environment.

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Leading practice gas regulation

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Introduction

The objective of leading practice regulation is to drive and sustain community and investor trust in projects that consistently meet joint expectations for social, environmental and economic outcomes for lifecycle operations. In short, environmentally sustainable development (ESD) must be more than a marketing motto.

Implementing ESD that simultaneously meets the expectations of both the public and business is no mean feat. Operations that constitute ESD in one location may not be compatible with pre-existing or planned land use elsewhere. Regardless, leading practice regulation starts with well-considered legislated objectives that drive the behaviour of both industry and regulators. Experience demonstrates that the foundations for regulation that consistently meet community expectations are:

1. Certainty: The regulatory objectives are uniform, clear, and predictable for all stakeholders.
2. Openness: Stakeholders are appropriately consulted on the establishment of the regulatory objectives and information on outcomes is publically available.
3. Transparency: The regulatory decision-making processes are visible and comprehensible to all stakeholders and industry performance in terms of compliance with the regulatory objectives is clear to all stakeholders.
4. Flexibility: The level of regulatory scrutiny, surveillance and enforcement needed to ensure compliance is determined on the basis of individual company compliance capability and the outcomes to be achieved.
5. Practicality: The regulatory objectives are achievable and measurable. Hand in hand with the flexibility principle and the objective based legislation this also means that licensees are able to innovate to use the most effective technologies and practices to achieve the best outcomes.
6. Efficiency: The compliance costs imposed on both government and the licensee by the regulatory requirements are minimised and justified. Negative impacts on communities are minimised, and licensees remain liable for the cost of their impacts. Furthermore, an appropriate rent (royalty) is paid to the community from the value realised from the development and production of its natural resources.

There are a range of initiatives that may be employed to ensure that these principles are adhered to. These include: the development of regulatory objectives and assessment criteria; broad stakeholder consultation involving industry, government agencies and community groups; timely provision of public access to details of environmental risks through Environmental Impact Reports, regulatory objectives through the Statements of Environmental Objectives; provision of a mechanism for regulation to be contested, and for disputes to be resolved in a fair and expeditious manner; fairly compensating land users for any costs, losses and deprivation of land used due to operations; resourcing and empowering regulatory bodies to effectively deploy regulations and prevent, persuade or direct operations to avoid undesirable outcomes.

The above-stated precepts are offered as a non-exclusive check-list for regulation capable of sustaining trusted land access for the life-cycle of gas operations. The introduction of new energy development technologies is inevitable, so best practice regulation will remain an aspiration. Expeditious, welcomed access to land for safe, compatible, multiple uses is the metric for regulatory performance. Public and investor trust is the most valuable starting point and the most desirable outcome of a virtuous exploration and production life-cycle (Goldstein et al. 2007).

This approach has been discussed by the Australian Productivity Commission (2009). Among its conclusions was that the legislative and regulatory framework under which petroleum exploration and development activities in South Australia are conducted provide an excellent example of where these principles have been followed and that other jurisdictions should strive to emulate them.

The South Australian approach

Petroleum exploration and development activities in South Australia are administered by the Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) under the *South Australian Petroleum and Geothermal Energy Act 2000*[1] (PGE Act, onshore), the *Commonwealth Offshore Petroleum and Greenhouse Gas Storage Act 2006* (offshore) and the *South Australian Petroleum (Submerged Lands) Act 1982* (offshore). The PGE Act was proclaimed on 1 October 2009 and supersedes the *Petroleum Act 2000*. The PGE Act has a number of aspects that are considered a comparative advantage without precedent in other Australian legislation.

High level objectives of the PGE Act are to:

- sustain trusted practical, efficient, effective and flexible regulation for upstream petroleum, geothermal and gas storage enterprises, and the construction and operation of transmission pipelines in the state
- encourage and maintain competition in the upstream petroleum and geothermal sectors
- minimise environmental damage from activities and protect the public from risks inherent in petroleum and geothermal operations
- sustain effective consultation processes with people affected by regulated activities, and the public in general
- ensure as far as reasonably practicable the security of supply of natural gas.

These objectives drive certainty for business by providing clarity in terms of regulatory requirements and for investment timelines, and for the public so the community can expect their interests to be protected. The objectives refer to the protection of the public's interest

1 For more information go to www.legislation.sa.gov.au and Go to 'Acts' > 'P' > Petroleum and Geothermal Energy Act 2000

in the sustainability of the natural, social and economic environments. It is important in this discussion to highlight that in the context of the PGE Act the definition of environment includes: land, air, water (including both surface and underground water); organisms and ecosystems—this includes native vegetation and fauna; buildings, structures and cultural artefacts; productive capacity or potential; the external manifestations of social and economic life which includes aspects such as human health and wellbeing; and the amenity values of an area.

This definition of environment is consistent with the *Environment Protection Act 1993*, and is broad to ensure that potential impacts on all natural, social and economic aspects of the environment are identified, considered, and appropriately addressed through the environmental assessment and approval provisions of the PGE Act.

A key lesson learnt in post-event investigations of significant incidents is that regulators must have relevant and up-to-date capabilities (competence and capacity) to be trusted to act in the interests of the public in protecting natural, social and economic environments during upstream petroleum industry activities. Additionally the risks of regulatory capture must be effectively managed. As the regulator of upstream petroleum and geothermal energy activities in South Australia, administering the PGE Act, DMITRE strives to maintain a one-stop-shop or lead agency approach. Through this approach DMITRE works closely with its local co-regulatory agencies, such as, the South Australian Environment Protection Authority, the Department of Environment, Water and Natural Resources (DEWNR), SafeWork SA, SA Health, the Department of Planning, Transport and Infrastructure (DPTI) and the Aboriginal Heritage Branch of the Aboriginal Affairs and Reconciliation Division, to deliver an efficient application of all relevant laws and regulations applicable to the petroleum and geothermal industries in South Australia.

Properly resourced lead agencies transparently facilitate the delivery of all co-regulatory objectives and requirements, and hence earn trust from the industry, co-regulatory agencies and the public. A one-stop-shop approach enables management of approval processes in parallel rather than in series. The PGE Act has been designed to enable a one-stop-shop approach such that in complying with the objectives of the Act and its processes upstream petroleum operations' compliance with obligations under other legislation will also be facilitated. Other legislation and requirements are listed in Table 1.

Compliance with these pieces of legislation is facilitated through collaborations and working arrangements between DMITRE and the government agencies that administer these Acts, to ensure that the Statements of Environmental Objectives (SEO) that must be complied with for specific activities are consistent with the relevant objects of each of these Acts. The SEO and the collaborative relationships between DMITRE and co-regulatory agencies including consultation arrangements are described further during description of the approval processes under the PGE Act.

Table 1. Legislation governing upstream gas regulation in South Australia

Legislation	Objective	Stewardship
Commonwealth		
Commonwealth's Environmental Protection, Biodiversity and Conservation Act 1999	Protect and manage nationally and internationally important flora, fauna, ecological communities and heritage places	Department of Sustainability, Environment, Water, Population and Communities
Native Title Act 1993	Recognition and protection of native title	Commonwealth's Attorney General's Department
South Australian		
National parks and Wildlife Act 1972	Protection of natural environments within parks and regional reserves in South Australia	Department of Environment, Water and Natural Resources (DEWNR)
Native Vegetation Act 1991	Provide incentives and assistance to landowners in relation to the preservation and enhancement of native vegetation and control the clearance of native vegetation	
Natural Resources Management Act 2004	Promote sustainable and integrated management of the State's natural resources and make provision for the protection of the State's natural resources	
Adelaide Dolphin Sanctuary Act 2005	Establish a sanctuary to protect the dolphin population of the Port Adelaide River estuary and Barker Inlet and its natural habitat and provide for the protection and enhancement of that natural habitat	
Marine Parks Act 2007	Provide for a system of marine parks for South Australia	
River Murray Act 2003	Provide for the protection and enhancement of the River Murray and related areas and ecosystems	
Arkaroola Protection Act 2012	Establish the Arkaroola Protection Area, provide for the proper management of the Arkaroola Protection Area and prohibit mining activities in the Arkaroola Protection Area	
Public Health Act 2011	Promote and provide for the protection of the health of the public of South Australia and to reduce the incidence of preventable illness, injury and disability	SA Health
South Australian Public Health (Wastewater) Regulations 2013	Regulations relating to waste control	
Environmental Protection Act 1993	Protect South Australia's environment including land, air and water	Environmental Protection Agency (EPA)

Development Act 1993	Provide for planning and regulate development in South Australia, the use and management of land and buildings, and the design and construction of buildings; and to make provision for the maintenance and conservation of land and buildings where appropriate	Department of Planning, Transport and Infrastructure (DPTI)
The Work Health and Safety Act 2012 (SA)	Protect people in the workplace	SafeWork SA
Native Title (South Australia) Act 1994	Recognition and protection of native title	Attorney General's Department
Aboriginal Heritage Act 1988	Provide for the protection and preservation of the Aboriginal heritage	Aboriginal Affairs and Reconciliation Division

Licensing and approval processes

In the context of the definition of environment under the PGE Act, and the principles of best practice regulation, the approval processes under the PGE Act comprise of three key stages as detailed in Figure 1[2], Figure 2 and Figure 3 and described below.

Stage 1: Licensing approval

The first stage relates to the licence application and approval process, where a proponent applies for the appropriate licence to give them the right to undertake regulated activities within a licence area. A licence granted under this stage is not a right to do any on ground activities; rather it is simply an exclusive right to an area within which the licensee can then apply for approval to undertake activities. Regulated activities are defined in Section 10 of the PGE Act and include exploration for regulated resources, operations to establish the nature and extent of a discovery of that resource and the potential commerciality of its production; and production, construction and operation of transmission pipelines for carrying regulated substances. Such activities can only be undertaken subsequent to approvals granted under Stages 2 and 3, which address the environmental and operational aspects of activities.

Only parties with the demonstrated capacity to invest in and safely conduct regulated activities are eligible to become PGE Act licence holders. Licences are available for exploration, retention of explored areas to conduct assessments of commerciality, production, pipelines, preliminary and speculative surveys, associated activities and for special facilities relevant to regulated activities.

2 For more information go to www.petroleum.dmitre.sa.gov.au/legislation/activity_approval_process

At the licensing approval stage, prior to the grant of any licence, if and where applicable, a Native Title Land Access Agreement or Indigenous Land Use Agreement (ILUA) signed by all parties, the Crown, the Licensee and relevant Native Title Claimant Group must be in place. Publicly available Native Title land access agreements[3], first deployed in October 2001 in South Australia, remain benchmarks for leading practice deeds that meet requirements of the Commonwealth *Native Title Act 1993*. To date, Aboriginal people, the upstream petroleum industry and the South Australian Government have agreed upon conjunctive native title land access agreements for 53 petroleum exploration licences, and two conjunctive ILUAs. Conjunctive land access agreements for petroleum have also been expeditiously agreed by current Petroleum Exploration Licensees over part of the South Australian Officer Basin that coincides with lands owned by the Anangu Pitjantjatjara Yankunytjatjara (APY) and Maralinga Tjarutja (MT) peoples.

3 For more information go to www.petroleum.dmitre.sa.gov.au/environment/native_title,_aboriginal_lands,_iluas

Figure 1. South Australian licensing and approvals process within a one-stop-shop approach led by DMITRE for exploration, retention, production and associated activities

Stage 1 of licensing and approval process for exploration, retention and production activities pursuant to South Australia's *Petroleum and Geothermal Energy Act 2000.*
(Blue box = initiated by proponent/Licensee and Green box = initiated by DMITRE/ SA Government)

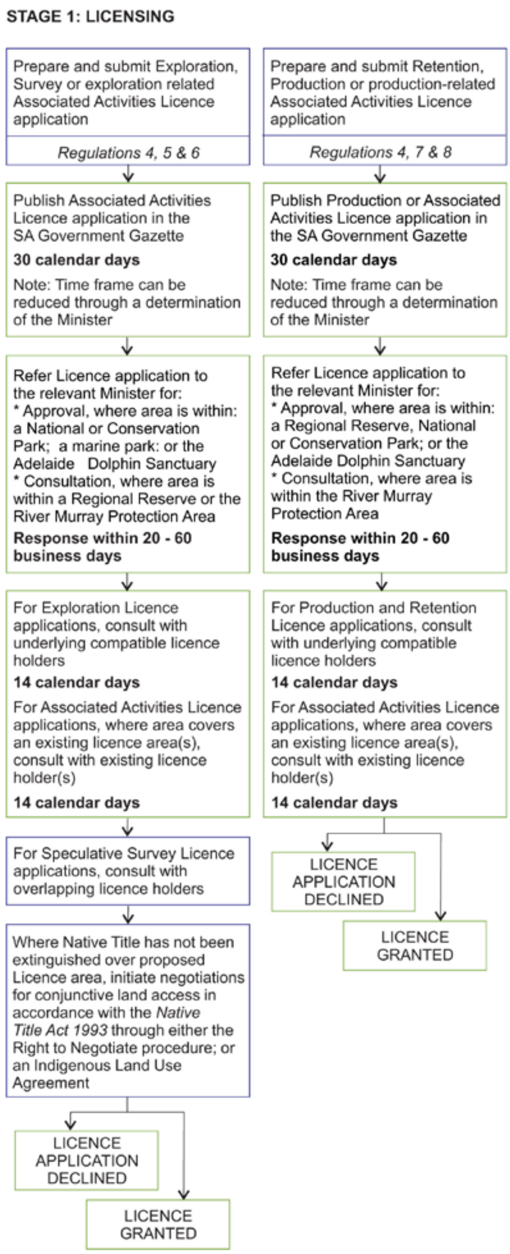


Figure 2. South Australian licensing and approvals process within a one-stop-shop approach led by DMITRE for exploration, retention, production and associated activities

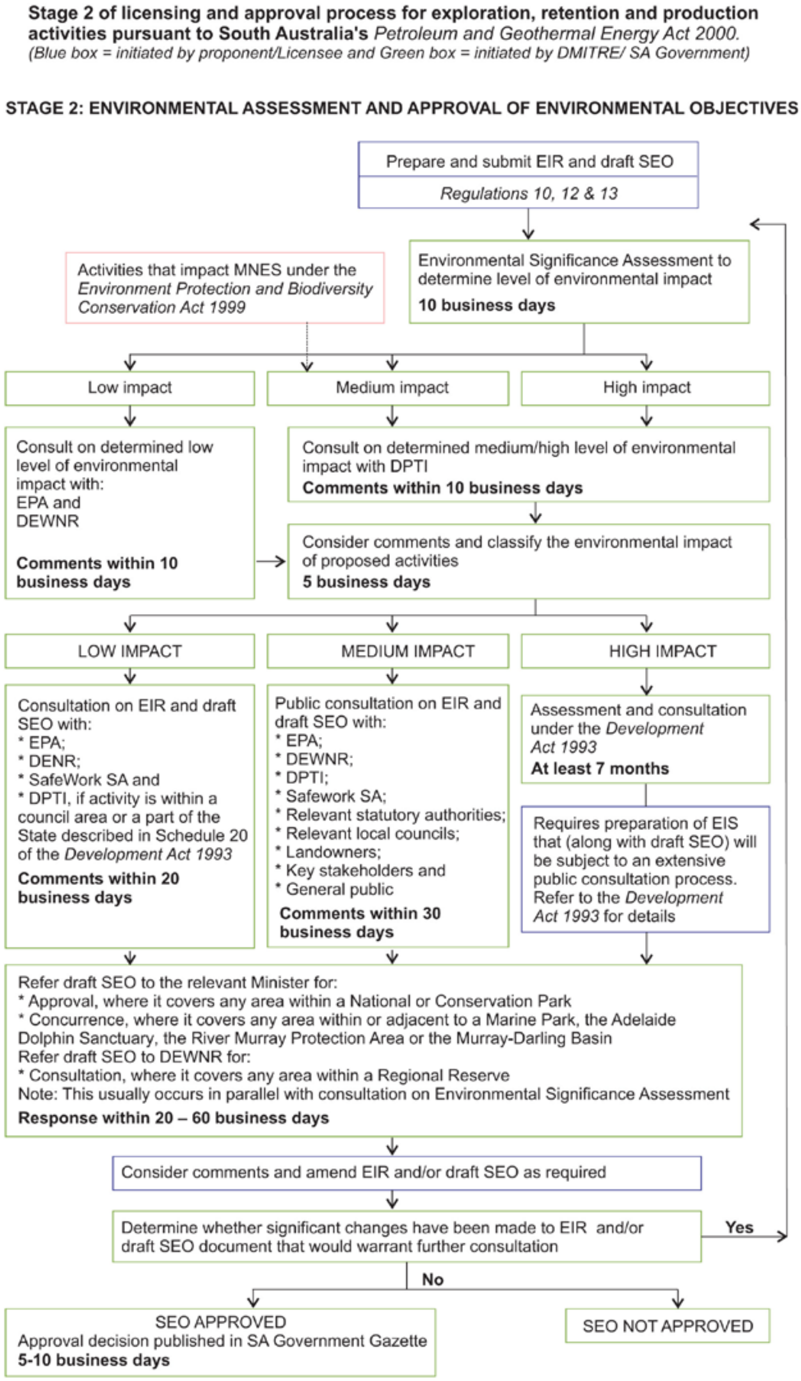
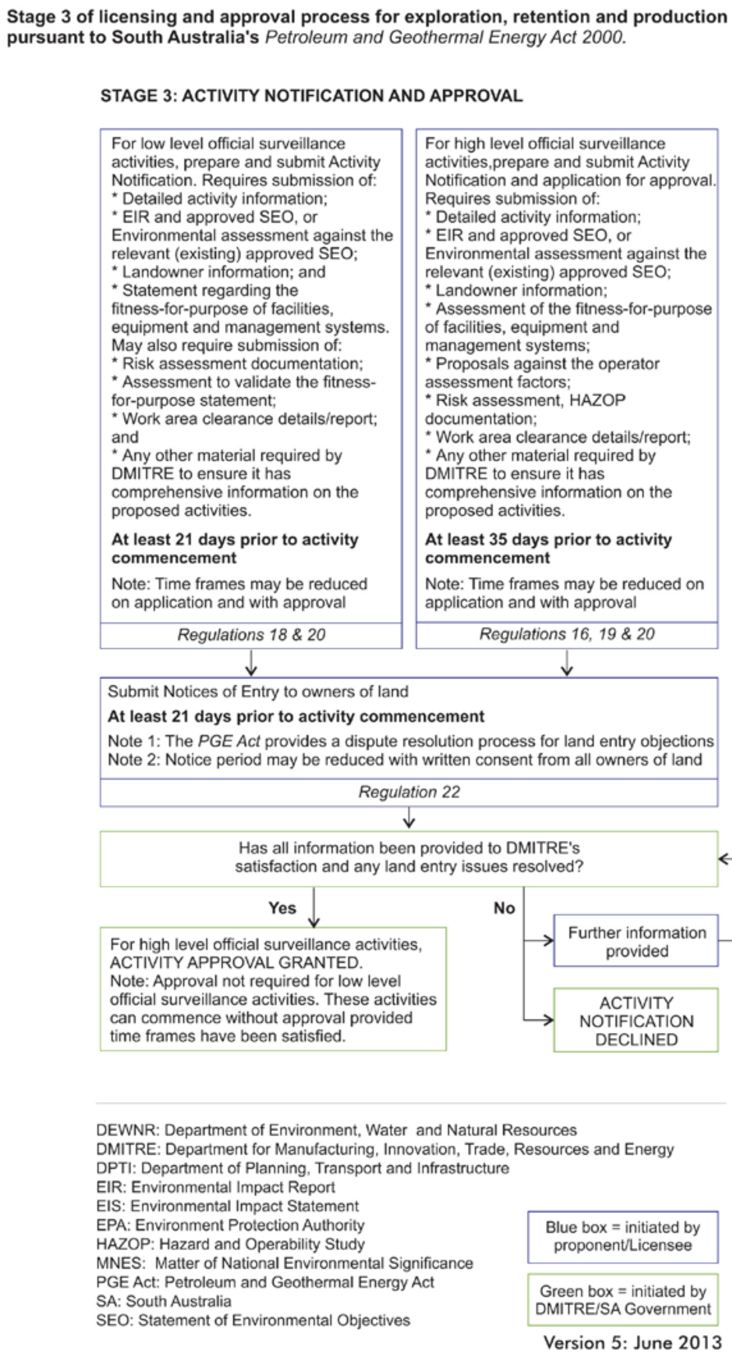


Figure 3. South Australian licensing and approvals process within a one-stop-shop approach led by DMITRE for exploration, retention, production and associated activities



With reference to the principles for leading practice regulation, adopting the transparency principle, South Australia publishes Native Title land access agreements on DMITRE's website, providing the benefits of experience for subsequent negotiations. No other Australian jurisdiction has this requirement to publish land access agreements. It is worth considering the risk and reward implications of industry opting to provide public access to at least template terms for leading practice, to enable experience based learning, and adding certainty for outcomes in future land access negotiations.

Prior to the grant (or refusal) of licence areas DMITRE are also required to refer some licence applications to DEWNR for comment and in some cases approval from the Minister for Sustainability, Environment and Conservation or the Director of National Parks and Wildlife, for regulated activities within the protected area network in South Australia. In tandem with the PGE Act, the *National Parks and Wildlife Act 1972* establishes the approval regime for petroleum and geothermal energy exploration and production within the reserve system. As detailed in Figure 1 and in accordance with the administrative arrangement[4] between DMITRE and DEWNR[5], licences require approval from the Minister for Sustainability, Environment and Conservation if the area falls within a National Park, a Conservation Park or the Adelaide Dolphin sanctuary. Exploration, survey, or exploration related associated activities licences also require the Minister's approval if the licence area falls within a Marine Park, and retention, production, and production related associated activities licences require approval within Regional Reserves. Through this process, matters of interest to DEWNR can be addressed prior to the grant of a licence to avoid potential land use conflicts, which in turn gives greater certainty to the proponent with respect to security of title. Some production and pipeline licences may also need to be referred to the Minister administering the *Development Act 1993* in certain circumstances.

The second and third stages of approval as detailed in Figure 1 relate to the environmental and activity approvals under the PGE Act. It is at these stages that potential specific on ground activity impacts and risks, and strategies for their management, are detailed and addressed. Concerns of people and enterprises that are potentially affected (by regulated activities) are also addressed during these stages.

Stage 2: Environmental assessment and approval

The grant of PGE Act licences does not provide an automatic entitlement to land access to conduct operations. Rather, regulated activities under the PGE Act (under section 96) may not be carried out unless an approved SEO is in place, prepared on the basis of an Environmental Impact Report (EIR).

The EIR describes the specific features of the environment where the activities will take place and identifies all potential impacts, their risks relating to the activity and the proposed risk mitigation strategies. The SEO identifies the environmental objectives to be achieved to address the risks identified in the EIR and the criteria to be used to assess achievement of the objectives.

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4 Administrative Arrangements are available on the DMITRE website. See: www.petroleum.dmitre.sa.gov.au/environment/regulation/admin_arrangements

5 Formerly the Department of Environment and Heritage (DEH) at the time the agreement was prepared.

Examples of the information and potential impacts that the EIR and final SEO are expected to address include:

- impacts on aquifers including pressure and contamination
- impacts on groundwater use
- contamination of surface water and shallow groundwater
- soil contamination
- impacts on native vegetation and native fauna caused by clearance required for above ground infrastructure (e.g. track clearance, water storage ponds, flow back storage ponds, other infrastructure, etc)
- interaction of stock or native fauna with water storage ponds
- potential impacts of introduction or spread of pest plants and animals
- disturbance to existing land uses (e.g. within reserves under the National Parks and Wildlife Act 1972, pastoral land, etc) or to local heritage features
- air pollution and greenhouse gas emissions
- impacts on the health and wellbeing of the local community
- remediation and rehabilitation requirements.

Division 3 of the *Petroleum and Geothermal Energy Act* and Part 3 of the Regulations describe the information that must be provided in Environmental Impact Reports and Statements of Environmental Objectives.

In accordance with the definition of the environment in the PGE Act, the EIR and SEO must also address potential impacts on the 'external manifestations of social and economic life' which includes aspects such as human health and wellbeing. Doctors for the Environment Australia advise that potential health impacts include: physical and mental health consequences from chemical exposure, air emissions, water contamination or impacts on food production; and socioeconomic impacts. Further information on potential impacts can be found in a report from the Province of New Brunswick in Canada, the Chief Medical Officer of Health's Recommendations Concerning Shale Gas Development in New Brunswick, which provides an example of the public health concerns that are being raised for consideration in the region. Guidance for licensees is provided by DMITRE in the Criteria for Classifying the Level of Environmental Impact of Regulated Activities with examples of events and consequences to be considered in an EIR, including health impacts, however each proposal will need to be assessed individually to ascertain its potential natural, social and economic environmental consequences.

Furthermore, potential impacts on Matters of National Environmental Significance (NES) as defined under the EPBC Act can also be addressed in the EIR and SEO where relevant.

Through the consultation requirements of the PGE Act, stakeholders including landholders and other government agencies are required to be informed and consulted on the potential risks associated with proposed activities, and management strategies to be deployed to minimise such risks to an acceptable level. Stakeholders are also provided with opportunities to raise any issues of concern they may have prior to the commencement of regulated activities. Other agencies with a duty of care for ensuring the objects of the legislation that they administer are met are consulted to ensure their requirements are included within the objectives detailed in the SEO.

DMITRE expects that licensees will initiate consultation with stakeholders prior to and during the development of their EIR and SEO, to describe their planned activities and the potential impacts, positive or otherwise, which may be experienced by the stakeholders. This is also an opportunity for the licensee to respond to any queries that their stakeholders may have and to understand concerns to ensure that they are addressed within the EIR and SEO.

Once an EIR and draft SEO have been prepared and submitted for assessment, DMITRE uses the information provided in the EIR to complete an environmental impact assessment to determine the level of environmental impact of the activity. The significance assessment is conducted in accordance with publicly documented criteria[6] to assess the level of certainty in the predicted impacts such as those listed above and their potential consequences related to the proposed activities and the degree to which these consequences can be managed. The environmental significance criteria enable identification of deficiencies in stakeholder consultation during the development of the EIR and draft SEO. Where DMITRE's assessment identifies such a deficiency, the determined level of environmental significance may be greater and likely to trigger more extensive stakeholder consultation by DMITRE. This ensures relevant stakeholders are provided with appropriate time for opinions to be considered and represented equitably in advance of SEO and subsequent activity approvals.

The combination of the outcomes of the assessment criteria lead to the determination of the level of significance for each event relating to the activity cumulating in the determination of an overall level of environmental impact of the activity as low, medium or high. The level of environmental impact that a particular activity is classified as in turn determines the consultation that DMITRE undertakes, both with co-regulatory agencies on the level assigned, and more broadly on the content of the EIR and draft SEO documents. The consultation arrangements are outlined within the PGE Act and regulations and within administrative arrangements between DMITRE and its co-regulatory agencies, which are all available on the DMITRE website[7].

For example where activities are classified as low impact activities, DMITRE consults on its determination of the low level of environmental impact and the content of the EIR and draft SEO with the Environment Protection Authority (EPA) and DEWNR. DMITRE also consults on the content of the EIR and draft SEO documents with SafeWork SA, and DPTI if the area is within a council area or an area described in Schedule 20 of the *Development Act 1993*.

Where activities are classified as medium impact activities, DMITRE consults on the determined level with DPTI; and initiates a public consultation process inviting comments on the EIR and draft SEO from the public, and directly from the EPA, DEWNR, DPTI, SafeWork SA, relevant statutory authorities and local councils, landowners and stakeholders. During the public consultation process, the EIR and draft SEO are made available to the public through the DMITRE website and at its office for at least 30 business days. Members of the public are notified of the consultation process through an advertisement in the local newspaper as well as on the DMITRE website, and in addition directly affected stakeholders are provided with targeted correspondence from DMITRE.

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6 For more information go to: https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGRG004.pdf

7 For more information go to: www.petroleum.dmitre.sa.gov.au/environment/regulation/admin_arrangements

For activities classified as high impact activities, DMITRE consults with DPTI on this determination, and where DPTI agree with the assessment, proposed activities are referred to DPTI for assessment and consultation under the *Development Act 1993*. This requires preparation of an Environmental Impact Statement and extensive public consultation.

For all activities within a National or Conservation Park, a Marine Park, or the Adelaide Dolphin Sanctuary, the draft SEO is referred to DEWNR for approval from the Minister for Sustainability, Environment and Conservation in line with agreements within the administrative arrangement between DMITRE and DEWNR. For activities within the River Murray Protection Area or the Murray-Darling Basin then DMITRE will seek concurrence on the SEO approval with DEWNR.

Case study: Beach Energy

An example of the 'Stage 2' EIR and SEO process was demonstrated recently through the development of Beach Energy's EIR and SEO for *Fracture Stimulation of Deep Shale Gas and Tight Gas Targets in the Nappamerri Trough (Cooper Basin), South Australia*. Beach Energy conducted early consultation with key stakeholders including government departments, non-government organisations (NGOs), landowners and the local community at two meetings held in Adelaide and Innamincka in February 2012.

Incorporating feedback and addressing queries raised at these meetings, Beach Energy with their environmental consultants RPS prepared the EIR and draft SEO documents, and after extensive consideration and review formally submitted these to DMITRE on 5 April 2012. DMITRE then assessed the proposed activities on the basis of the EIR and in accordance with the published criteria for classifying the level of environmental impact of regulated activities, and found them to be of medium environmental impact, partly due to the level of community interest in the activities, leading to a public consultation process.

The Minister for Mineral Resources and Energy invited public comments via a notice in the Advertiser on 14 April 2012, and through a notice and links to the documents on the Department website. The public consultation period was conducted from 16 April to 28 May and included invitations for comments from landowners and co-regulatory agencies. Following consultation, the EIR and SEO were again reviewed to provide adequate responses for all comments received, and finalised and submitted to DMITRE on 5 July 2012. The EIR and SEO were approved and gazetted on 2 August 2012. These documents, as well as DMITRE's significance assessment, can be found on the DMITRE website within the Activity Reports section of the Environmental Register.

Concerns raised during consultation are incorporated into the EIR and draft SEO documents as appropriate, enabling changes to address the comments prior to approval by the Minister. As noted previously, all of this happens well before any licensee can apply to undertake any on-ground activities regulated pursuant to the PGE Act.

All SEOs and associated EIRs are public documents and can be found on the DMITRE website[8].

8 For more information go to: www.petroleum.dmitre.sa.gov.au/environment/register/seo,_eir_and_esa_reports

Stage 3: Activity notification and application for approval

The grant of PGE Act petroleum exploration, retention, production and pipeline licences does not provide an automatic entitlement to land access for regulated upstream petroleum operations.

Once the EIR and SEO are in place, a licensee can apply for approval to undertake a specific activity that is described within those documents. With the activity approval application the licensee provides DMITRE with an Activity Notification which contains detailed activity information including[9]:

- an environmental assessment of the activity against the SEO, including where relevant assessment as to whether the activity may have potential significant impacts on Matters of National Environmental Significance (MNES)
- landowner information (including copies of notices of entry sent to landowners)
- an assessment of the fitness for purpose of the licensee management systems and any facilities or equipment to be used
- work area clearance details and report
- risk assessment documentation
- any further information or material as required by DMITRE to ensure that the department has comprehensive information on the proposed activities.

Where MNES are identified, referral to the Commonwealth Minister for Environment will be made by the licensee or the Department, for assessment and a decision as to whether the activity requires approval under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act)[10]. If the activity (called an 'Action' under the EPBC Act) is assessed to be likely to have significant impact on a matter of national environmental significance, then it will be declared to be a controlled action that requires Commonwealth environmental impact assessment and approval.

Licensees can be classified as carrying out activities requiring high or low level official surveillance. The level of official surveillance determines the information that must be provided in the notification, the level of scrutiny that DMITRE applies during review of the notification, and the period of notice prior to the proposed commencement of activities. The PGE Act outlines operator assessment factors[11] that consider the licensee's policies, procedures, management systems and track record to classify the licensee's level of official surveillance. Initially licensees are classified as carrying out high level official surveillance activities and must address the operator assessment factors within their activity notification. High level official surveillance operators must apply for approval to undertake activities at least 35 days in advance of the proposed activity commencement date, and cannot commence until approval is provided.

9 Information to be provided within an Activity Notification is detailed in Regulation 20 of the PGE Act
10 For more information see www.environment.gov.au/epbc/assessments
11 Operator assessment factors are outlined in regulation 16 of the PGE Act

Operators can apply to be classified as carrying out low level official surveillance activities[12], and once classified can provide a shorter period of notice (at least 21 days) to the Minister through DMITRE before commencing activities, and do not require approval but still must provide detailed activity information with their activity notification. Although approval is not required, if further information has been requested the licensee cannot commence until the department has comprehensive information on the activity.

Notice of entry

Mutual trust for compatible, sustainable land access for upstream petroleum operations are traditionally indemnified with formal land access agreements struck between licensees, potentially affected people and enterprises. To provide impetus for fair and sustainable land access for petroleum, geothermal energy and gas storage operations in the state, the PGE Act was amended in 2009 to expand the 'owner of land' definition to cover all persons who may be directly affected by regulated activities, entitling them to notices of entry and compensation. This amendment has proved to be a driver for mutual respect. With this incremental legislated requirement, owners of land are provided with opportunities to raise concerns prior to the commencement of regulated activities, and the state's regulations require operations to effectively manage risks and meet community expectations for net outcomes, or the activities will not be approved. The outcome is demonstrable leverage to all persons who may be directly affected by regulated activities, not just those holding land titles, but also people such as Native Title claimants, persons holding a tenement over or in relation to the land, and anyone leasing potentially affected land for enterprises.

Notice of Entry is provided to landowners at least 21 days prior to the licensee's entry to the land to conduct an activity, and forms part of the activity notification process. Landowners are provided with information on the nature of the activities to be carried out including any anticipated events and the management of their consequences to minimise risks to an acceptable level, to enable the landowner to make informed decisions on whether this would have an impact on the land.

Landowners are entitled to object to the licensees proposed entry by giving notice to the licensee within 14 days of the notice of entry. In this circumstance the Licensee must notify the Minister that their entry is disputed and the activity cannot be undertaken until the dispute is resolved. The licensee and the landowner should attempt to reach an agreement on terms under which the licensee may enter the land, or if the risks of the activity to the landowner are too high the licensee may choose to modify the activity and re-issue the Activity Notification or cancel the activity. In rare cases where the licensee and the landowner cannot resolve the dispute, then the Minister may attempt to mediate between the parties or either party may apply to the Warden's Court for resolution. To date disputed Notices of Entry have been resolved through satisfactory negotiation and have not reached the Warden's Court.

12 Information on operator classification and the operator assessment factors is available on the DMITRE website. See www.petroleum.dmitre.sa.gov.au and go to >legislation and compliance > activity approval process > high and low surveillance classification.

Also, under the PGE Act, owners of land are entitled to appropriate compensation from licensees for any losses, deprivation or reasonable costs sustained during both the process of negotiating land access and for the full period of land access, right through to the decommissioning of any facilities.

In summary, the PGE Act gives all stakeholders (farmers, Aboriginal land owners, Native Title owners and claimants, concurrent licensees etc) entitlements to be consulted well ahead of land access through stakeholder engagement during the development of EIRs and SEOs, and again ahead of land access with the required Notice of Entry process describing the proposed activities and associated impacts. This provides ample opportunity to all relevant stakeholders to discuss the activities with licensees and where appropriate negotiate compensation. The obligations for licensees to consult and provide Notices of Entry, and the right of owners of land to object, underpin the balance of sustainable development under the PGE Act.

Compliance and Enforcement

DMITRE continuously monitors licensee performance and compliance with the PGE Act.

South Australia's approach to provide fair, predictable and trustworthy regulation has been described by Malavazos (2001) and entails a publicly available compliance policy[13] which is available on the DMITRE website. South Australia's compliance policy is centred on the prevention of harmful incidents, however depending on the severity of an incident may culminate in prosecution and licence cancelation when warranted. The compliance policy is summarised as a compliance pyramid as shown below in Figure 4.

- DMITRE prepares a PGE Act Annual Compliance Report for the purpose of outlining:
- the compliance monitoring and surveillance activities carried out by DMITRE during each year for activities regulated under the PGE Act
- the regulatory performance of the petroleum and geothermal industries in accordance with the requirements of the PGE Act
- all serious incidents that may have occurred from the previous year
- all step 2, 3 or 4 enforcement actions (Figure 4) that may have been taken during the year.

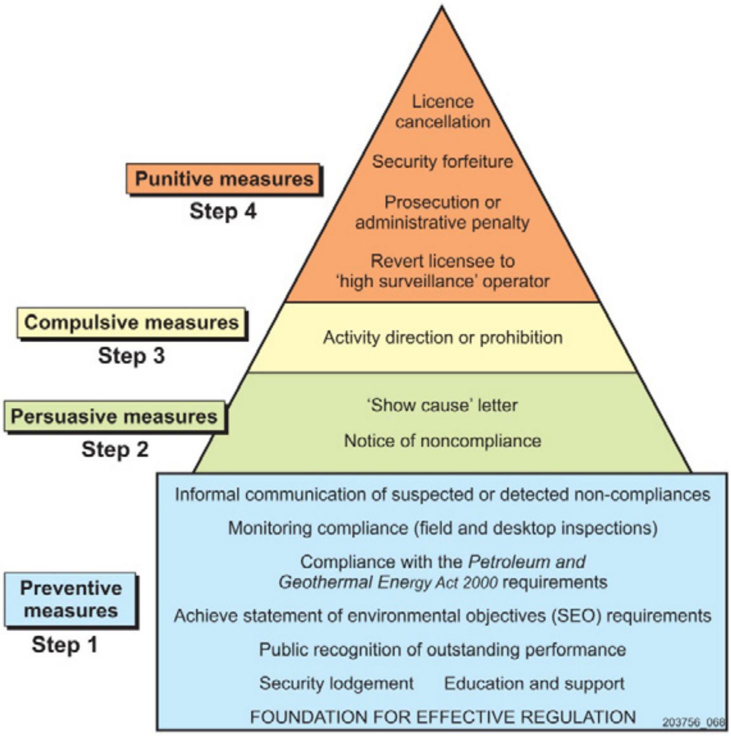
DMITRE's Petroleum and Geothermal Energy Act Compliance Report[14] and Company Annual Reports[15] are all publicly available through DMITRE's website. As well as information provided through the Activity Notifications, DMITRE regularly meets with licensees to discuss their activities and compliance, and conducts ongoing monitoring and surveillance through both field and desktop studies. In addition to risk assessments and fitness-for-purpose assessments conducted prior to the construction of facilities, assessments must also be conducted thereafter at least once every five years to ensure that the integrity of facilities is maintained.

13 Download from: https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/gui/image/DDD/RB201000013.pdf
14 For more information go to: www.petroleum.dmitre.sa.gov.au/legislation/compliance/petroleum_act_annual_compliance_report
15 For more information go to: www.petroleum.dmitre.sa.gov.au/legislation/company_annual_reports

In addition, Licensees are required to submit annual reports reporting on activities undertaken within each licence area during the respective licence year, and their performance and compliance with the PGE Act and the relevant statement of environmental objectives. Company Annual reports also provide information on the activities proposed for the ensuing licence year.

Where there have been instances of serious and reportable incidents as defined under section 85 of the PGE Act, licensees are required to investigate such incidents to determine the root cause; and corrective actions to prevent their recurrence.

Figure 4. South Australia's compliance enforcement policy under the PGE Act



Co-regulation and co-regulatory agencies

The most highly leveraged aspect of the PGE Act is its definition of the environment as the social, natural and economic environment, and its application of SEOs to set standards for environmental risk management and environmental outcomes in alignment with co-regulation. In doing this a breach of an SEO is a breach of the PGE Act and other cognate legislation. This effectively aligns objectives across government.

Through collaboration with co-regulatory agencies and processes outlined in administrative agreements, DMITRE maintains a one-stop-shop for the regulation of upstream petroleum, geothermal energy and pipeline activities in South Australia. Licensees have obligations under legislation other than the PGE Act, and where possible the objectives of those other legislation are captured within Statements of Environmental Objectives for activities under the PGE Act. This is only possible by maintaining good working relationships with co-regulatory agencies and by maintaining an understanding of the requirements for PGE Act licensees under other legislation. DMITRE values the expertise and assistance of its co-regulatory agencies particularly when seeking advice during consultation on the content of EIR and SEO documents. A description of the agencies that administer the legislation and the legislation that they have duty of care for is listed in Table 1 and also provided in DMITRE 2012.

Concluding remarks

Regulation for compatible, multiple-use of land in Australia is undertaken with both risks and net benefits in mind. Considerable net benefits flow from community ownership of subsurface resources when development effectively manages risks to social, natural and economic environments. Industry must act early to effectively engage and inform stakeholders so they can make informed decisions on activities.

Trustworthy, efficient and effective regulation is fundamental to attracting investment with community support. The key ingredients of best practice regulation are frameworks that: elicit community trust and investor confidence; provide certainty; entail robust public consultation processes; are transparent; enable flexibility; are open to amendment; are efficient; are practical; and focus on outcomes. New energy development technologies will necessitate evolutionary improvement to regulatory frameworks, and best practice regulation will continually evolve.

A one-stop-shop approach to regulation enables co-regulators to do their jobs in parallel, rather than in series. This fosters efficiency without reducing stringent standards for ecological, social, heritage and economic outcomes.

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The gas renaissance in the United States—the impact of unconventional resources

Dr. Francis M. O'Sullivan, Research Engineer, Massachusetts Institute of Technology Energy Initiative

Introduction

The past decade has borne witness to tremendous change for the natural gas industry in the United States. During this period, US production has risen from a twenty year low of 18 trillion cubic feet (510 billion cubic metres) in 2005, to an all-time high of 24 trillion cubic feet (680 billion cubic metres) in 2012[1]. At the same time, natural gas prices have fallen to levels not seen since the period immediately following US gas market deregulation in the mid-nineties. The underlying driver of these dynamics has been very rapid growth in the production of unconventional natural gas resources, and in particular shale gas resources, which historically were considered unrecoverable.

Technical advances in the areas of drilling and reservoir stimulation have been key to unlocking shale gas. Today's shale gas is almost entirely sourced from wells drilled with horizontal bores, which have been subjected to large-scale hydraulic fracture stimulation treatments. The combined efficacy of these technologies in producing gas from shale formations (and indeed other low permeability reservoir settings) is such that their development has led to enormous upward revisions to assessments of the total recoverable natural gas resource in the United States. Today, analysis by organisations including the US Energy Information Administration (EIA), and the Potential Gas Committee (PGC) suggest the likely recoverable US shale gas resource is in the range of 800–1000 trillion cubic feet (23–28 trillion cubic metres). By contrast, the 2003 National Petroleum Council (NPC) assessment estimated the shale resource at 35 trillion cubic feet (1 trillion cubic metres).

The prospect of a much larger and lower-cost domestic natural gas resource in the US is having major impacts on both the US and international energy sectors. In the US, unsurprisingly, many are now projecting a more gas-centric future than was envisioned even a few years ago. For example, in the power generation sector, gas-fired generation is now expected to make up a much higher proportion of total US output over the coming twenty to thirty years than was anticipated before the full extent of the so-called shale gas revolution became apparent. On the international front, the impacts of shale gas on the global energy system are likely to be significant. Already, shale gas has essentially removed the US from the global market for liquefied natural gas (LNG) imports. In fact there are now a range of proposed projects planning to export LNG from the US at various levels of maturity. How these developments ultimately alter the shape of global gas markets remains to be seen; however,

1 Marketed production as reported by US Energy Information Administration, June 2013.

it is undeniable that US shale gas is leading to a shift in both global gas market structures and altering energy-related geopolitical balances.

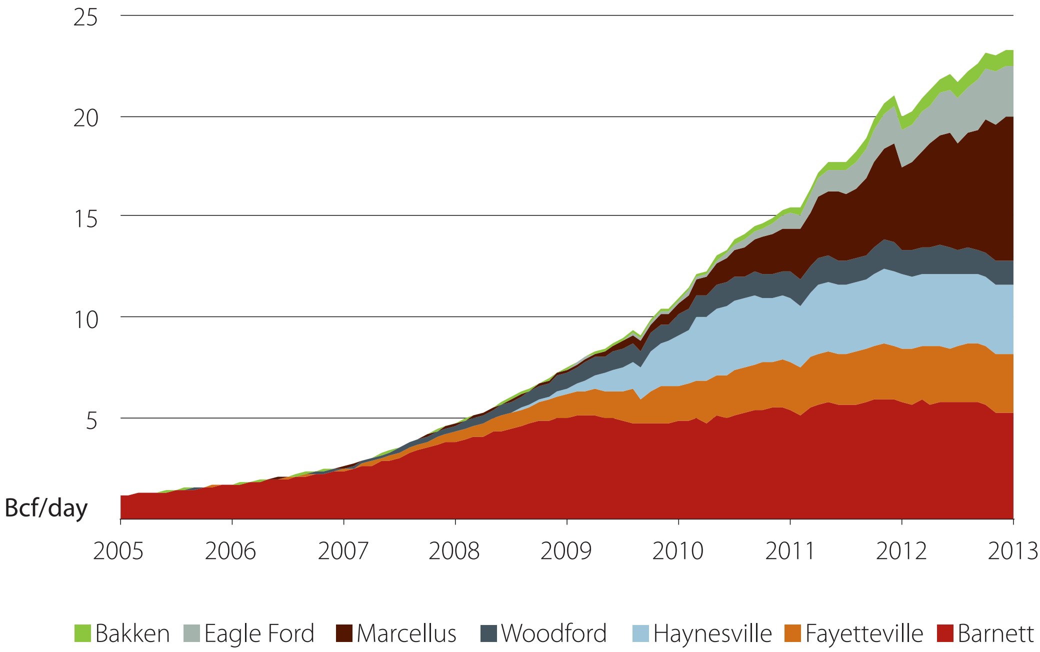
The emergence of large-scale shale (and other unconventional) natural gas production over the past decade has not been without significant controversy. In particular, the potential adverse environmental consequences associated with the hydraulic fracturing treatments necessary to produce unconventional gas have been hotly debated. It is undeniable that various environmental risks accompany hydraulic fracturing. These include the potential for ground and surface water pollution, local air quality degradation, fugitive greenhouse gas emissions, induced seismicity, ecosystem fragmentation, and a range of negative community impacts. Many of these issues are not unique to unconventional gas and oil production, but rather apply to all hydrocarbon extraction. However, there has been a particular focus on them in the context of shale extraction owing to the larger-scale of the hydraulic fracture treatments in use and the fact that much of the shale development is taking place in geographies without a recent history of large-scale gas and oil production.

US natural gas production—the shale effect

The United States, along with the Russian Federation, have for many years been by far the world's largest natural gas producing nations. Traditionally, Russian output has been higher than in the US; however, this paradigm has reversed over the past five years. In 2012, US dry natural gas production reached 24 trillion cubic feet (680 billion cubic metres), an all-time high, and more than 3 trillion cubic feet (85 billion cubic metres) higher than Russian output. In fact since 2005, US gas output has increased by a remarkable 33 per cent, with shale gas being almost entirely responsible for this growth (United States Department of Energy 2013a).

In the 15 years between 1990 and 2005, annual US gas production oscillated between 18 and 20 trillion cubic feet (510–570 billion cubic metres). A major dynamic in the producing base during this period was the decline in output from conventional resources, with this being offset by growth in the production of tight gas. Since 2005, output from conventional resources has continued to fall and tight gas production has also dropped. However, these declines have been more than offset by growth in shale gas production, which did not just allow for production levels to be maintained, but has driven output to record high levels. The temporal evolution of shale gas production between 2005 and 2012 is shown in Figure 1. In 2005, shale gas output stood at less than 1 billion cubic feet a day (28 million cubic metres a day). Today it stands at more than 23 billion cubic feet a day (650 million cubic metres a day), and now accounts for 33 per cent of total production.

Figure 1. Natural gas production from the main US shale plays since 2005



Source: Drilling Info LLC, HPDI Production Database, June 2013.

It is noteworthy that a relatively small number of plays have been responsible for supporting this production growth. Today, the major US shale gas plays are the Barnett shale in Texas' Fort Worth Basin, Haynesville shale on the Texas-Louisiana border, Fayetteville shale in Arkansas, Oklahoma's Woodford shale, and Marcellus shale underlying portions of Pennsylvania, New York and West Virginia in the US northeast. Along with these gas plays, an increasing amount of natural gas is being produced from shale oil plays, particularly the Bakken play in North Dakota and the Eagle Ford play in Texas.

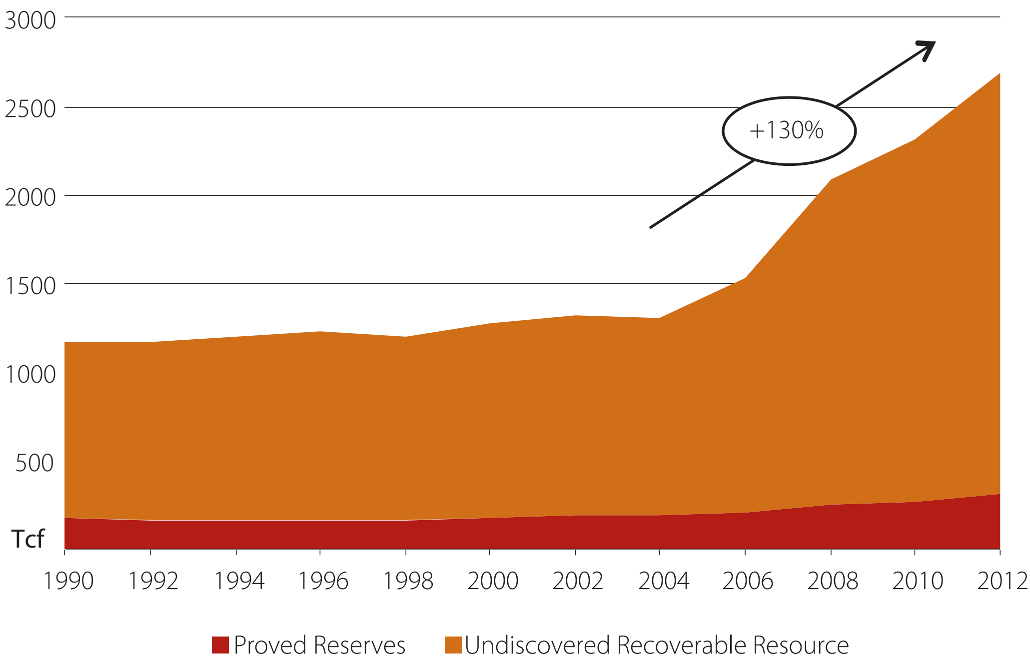
Going forward, the relative importance of shale gas to overall US natural gas production is expected to continue to increase. The EIA is projecting that by 2030, US shale gas production will reach 39 billion cubic feet a day (1.1 billion cubic metres a day), 70 per cent higher than current output, at which point shale will support around 50 per cent of total US production (United States Department of Energy 2013b). Certainly, these longer-term projections seem plausible; however, in the much shorter-term the rate of shale gas production growth seen over the past five years is likely to moderate appreciably. This is due to a very significant drop in shale gas targeted drilling activity over the past two years as the price of natural gas reached record lows and operators shifted focus to oil-prone rocks.

The shale gas resource—scale and uncertainty

Initial production success from the Barnett shale formation in the early part of the last decade led to a wide-scale re-evaluation of the productive potential of other US shale formations. Over the past several years this process has led to dramatic increases in estimates of the technically recoverable shale gas resource. In 2003, the NPC estimated the technically recoverable US shale gas resource amounted to 35 trillion cubic feet (1 trillion cubic metres) (National Petroleum Council 2003). Ten years later, and in light of the successful development of several major plays, many estimates of the technically recoverable resource now exceed 1000 trillion cubic feet (28 trillion cubic metres), with the most recent biennial assessment from the PGC estimating the "most likely" shale resource at 1073 trillion cubic feet (30 trillion cubic metres) (Potential Gas Committee 2013).

Needless to say, the dramatic increase in the estimated size of the recoverable shale resource over the past few years has been such that it has profoundly altered perceptions of the scale of overall natural gas resources. Figure 2 illustrates this by plotting how the PGC's biennial estimate of total recoverable natural gas resource (proved reserved plus undiscovered, technically recoverable resource) has changed between 1990 and 2012. In 1990, the estimate of total future available resource stood at 1171 trillion cubic feet (33 trillion cubic metres), or 61 times that year's total consumption. Today, the total future resource is estimated at 2689 trillion cubic feet (76 trillion cubic metres), or 105 times annual consumption (Potential Gas Committee 2013). This very significant increase in the estimated scale of the total recoverable resource is almost entirely due to shale gas, and as is evident in Figure 2, almost all of this growth has occurred since 2005. This parallels with the rapid growth in production from the major shale plays shown in Figure 1.

Figure 2. Potential Gas Committee's biennial mean estimate of total recoverable US natural gas resource 1990–2012



Source: Potential Gas Committee 2013.

Although it is now clear that large volumes of shale gas are technically recoverable, there remains a significant envelope of uncertainty around contemporary mean resource estimates. Many factors contribute to this uncertainty, with a relative lack of geological and petrophysical data being important drivers. In their 2012 assessment, the PGC's analysis shines some light on the level of uncertainty surrounding their estimates by reporting both "minimum" and "maximum" resource estimates along with their "most likely" (median) estimate for each resource category in each shale basin. Table 1 provides some synthesis of this uncertainty. Along with the most likely estimate of the recoverable resource in each basin, the table shows aggregations of both the minimum and maximum estimates for each resource category in each basin[2].

Table 1: Uncertainty associated with the 2012 Potential Gas Committee's assessment of the technically recoverable US shale gas resource

	Minimum	Most likely	Maximum
	Tcf	Tcf	Tcf
Fort Worth Basin: Barnett shale	11	48	83
Arkoma Basin: Fayetteville and Woodford	75	104	137
East Texas and Los Angeles Basin: Haynseville and Bossier	76	149	293
Texas Gulf Coast Basin: Eagle Ford and Pearsall	29	59	105
Appalachian Basin: Marcellus, Ohio and Utica	220	563	1242
Uinta Basin: Mancos and Manning Canyon	37	60	129
Other Basins	34	90	234
Total	**482**	**1073**	**2223**

Source: Potential Gas Committee 2013.

As the development of the shale resource moves forward, it is certain that the derived data will allow for a narrowing of the uncertainty envelope; however, a very dramatic reduction in assessment uncertainty is unlikely to be realised in the foreseeable future.

Shale gas economics—what does it really cost?

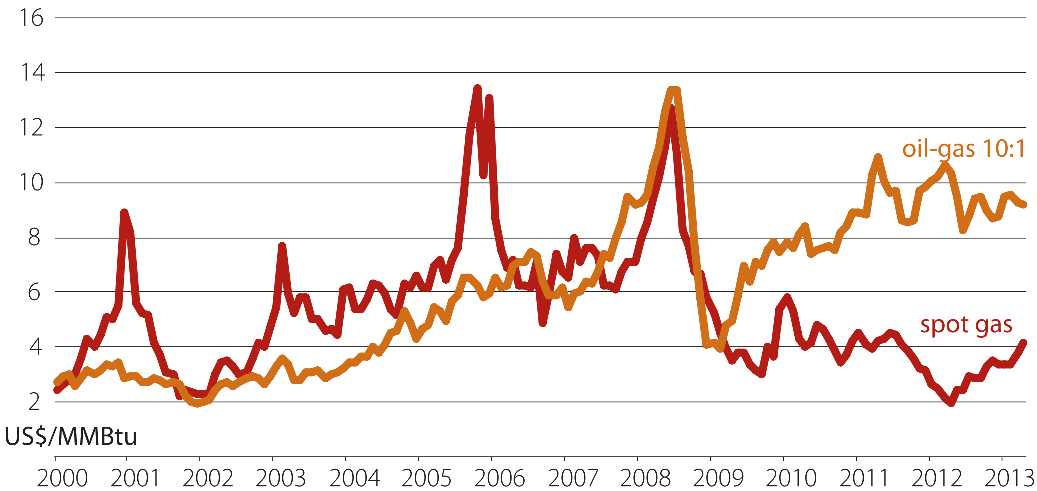
As described in the preceding sections, the past decade has seen a dramatic rise in both the level of gas production from the US shale resource, and the estimated size of that resource. At the same time, the price of natural gas in the US has fallen to levels not seen since the gas market was fully deregulated in the mid-nineties. The evolution of the US natural gas benchmark Henry Hub price since 2000 is shown in Figure 3, along with a trace that plots what the gas price would have looked like had it tracked the West Texas Intermediate (WTI) crude oil price at a ratio of 10 million British thermal units of natural gas to one barrel of oil (United States Department of Energy 2013a). This 10:1 ratio is one of a number of loose "rules of thumb" that have historically tended to reasonably characterise the price of gas in the US

2 Aggregations of the minimum and maximum resource estimates are made arithmetically and as such they assume perfect statistical correlation. This assumption maximizes the spread between minimum and maximum estimates and so is the extreme case.

market. In reviewing Figure 3, a qualitative linkage can be observed between oil and gas prices up until 2009. However, since 2009 the price of gas has not tracked the oil-linked index in any meaningful manner. This "decoupling" of the US natural gas price from the global oil price has received a great deal of attention, and it is the rise of shale gas that has been credited for precipitating this development.

It is certain that the very strong increase in gas production from US shale plays over the past half-decade has allowed a situation to develop where US prices have reached extremely low levels. However, as will be discussed later in this section, the gas prices seen over the past 2–3 years have been so low that relatively little shale gas production is economically attractive over the longer-term. Because of this, drilling activity for shale gas has plummeted, particularly through the second half of 2012 and first half of 2013. Today, only around 350 of the North American rig fleet of around 1800 is drilling for gas[3]. At the start of 2012 that figure stood at around 800, and at the peak of activity in late 2008 approximately 1600 rigs were targeting gas formations. The substantial slowdown in gas-targeted drilling this year in particular will certainly lead to a softening of gas supply and some moderate price increases over the coming year or two as producers begin to focus more on returns than production growth, and the need to hold newly leased acreage by drilling wanes.

Figure 3. Evolution of the Henry Hub US benchmark natural gas price between 2000 and 2013, along with an illustration of what a 10:1 gas price (1 million British thermal units) to oil (1 barrel WTI) would have been during the same period



Source: United States Department of Energy 2013a.

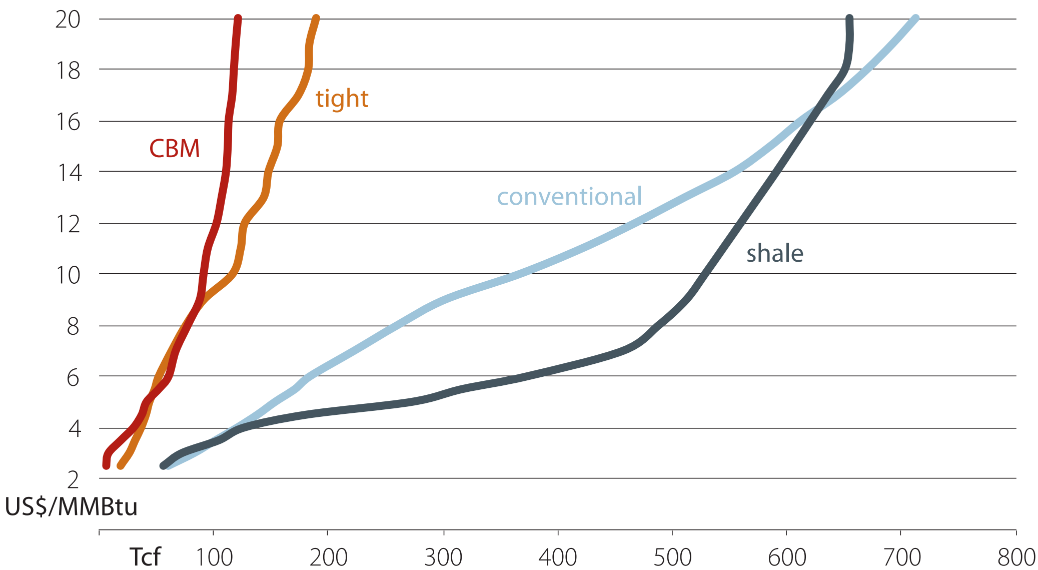
Although a number of organisations develop and make public assessments of the technically recoverable US shale gas resource, few integrate economics to establish supply curves. Of the publically available US shale gas supply curves, one of the most widely referenced is that produced and published as part of the 2011 MIT Future of Natural Gas Study (Massachusetts

3 Baker Hughes Rig Count, June 2013.

Institute of Technology 2011). The shale supply curve, along with those for conventional gas, tight gas and coal bed methane that were developed by the MIT team are shown in Figure 4. Some key insights are provided by these supply curves. The first is that shale gas makes up the lions' share of the low to moderate cost natural gas resource in the US. As such, the relative importance of shale to the overall supply base will only grow over the coming decades as is being projected by the EIA, and other agencies who develop credible long-term economic projections for the US and global energy systems.

A second salient feature of the shale supply curve in Figure 4 is that of the low to moderate cost shale gas. Most of the volume is in the US$4–6 per million British thermal units range, with very little of the gas being extremely cheap. This is an important point in that it suggests that an appropriate characterisation of the shale resource is that it is a "large, moderate cost resource". This is slightly counter to the perception held by some that shale gas is a very low cost resource. The very low gas prices seen over the past several years are partly to blame for this perception. However, as discussed in the preceding paragraphs, much of the recent very low gas prices can be explained by a supply heavy market that has seen excessive drilling for the purpose of holding acreage.

Figure 4. Supply curves for US natural gas resource produced as part of the 2011 MIT Future of Natural Gas Study

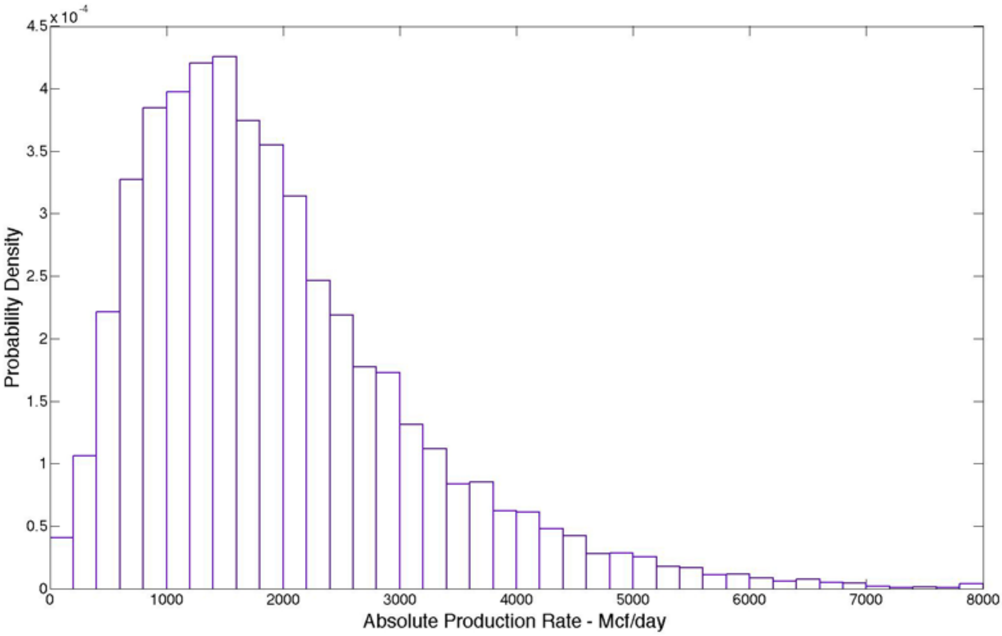


Source: Massachusetts Institute of Technology 2011.

The nascent nature of the shale resource, and the resulting dearth of data on well productivity, particularly longer-term productivity, has, until recently, made carrying out detailed analysis of the economics of the shale gas resource challenging. Fortunately, useful volumes of data, spread over a reasonable temporal horizon are now available and are shedding light on the nuances of the productivity of shale gas resources. One particularly important characteristic of the resource that is now beginning to become clear is that well-to-well productivity varies significantly both within and between plays, and that this variability appears to be consistent from year-to-year.

Figure 5 plots a probability density distribution of the initial production (IP) rates for every horizontal well completed in the Barnett Shale between 2005 and 2011[4]. In total, around 11 000 wells make up this ensemble. Clearly, the IP rate distribution is both broad and skewed. Certainly, there are some very productive wells, which would be expected to have very attractive economics; however, the median IP rate is lower than the mean, and the spread between the twentieth percentile and eightieth percentile IP rates is around three times. Combined, this suggests that within the 2005–11 well ensemble there are likely to be a large number of wells that had much less attractive economics.

Figure 5. Probability distribution of initial production rates from each horizontal well completed in the Barnett Shale from 2005 to 2011



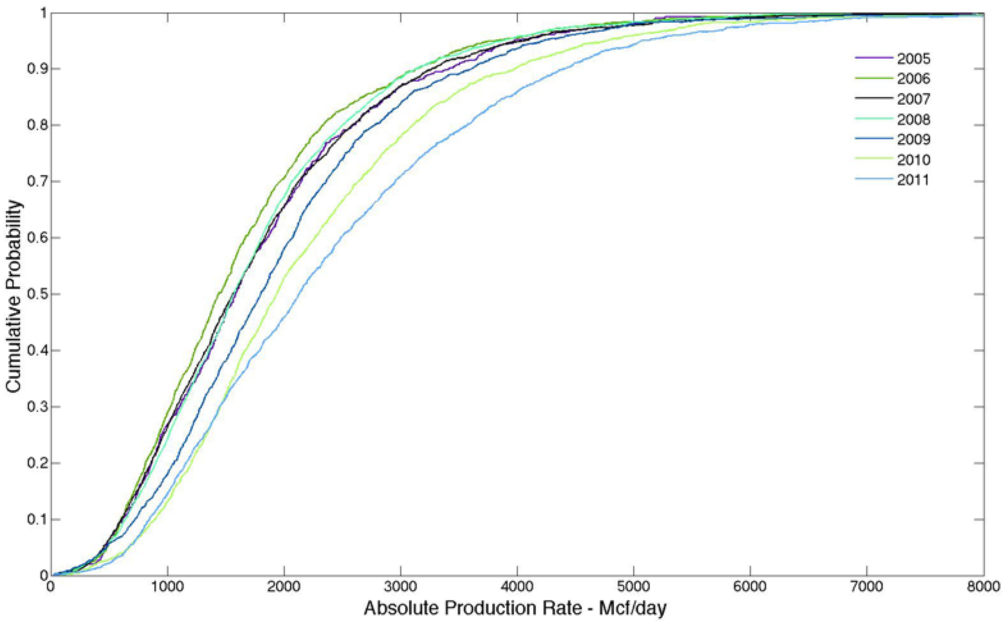
Source: Drilling Info LLC, HPDI Production Database, June 2013.

To better assess the issue of well-to-well variability, it is useful to disaggregate the overall ensemble shown in Figure 5 into individual vintages. The results of this are shown in Figure 6, which plots the well productivity in cumulative probability terms. The figure shows that between 2005 and 2011 there was an overall shift towards higher productivity, something

4 The initial production (IP) rate is the average daily production rate of a well in its peak production month, typically month 1 or 2 of recorded production. This metric is a key determinant of longer-term well productivity since the IP rate anchors production decline.

that is not surprising considering well lateral lengths have been increasing and operators have been gaining experience. However, what is somewhat surprising is that the level of well-to-well variability has not reduced at all since 2005. In fact for both the 2005 and 2011 well vintages the twentieth–eightieth percentile spread is three times. The practical result of this level of variability is that the economic profile of the wells drilled each year also varies significantly.

Figure 6. Cumulative distribution functions of horizontal well initial production rates in the Barnett Shale from 2005 to 2011

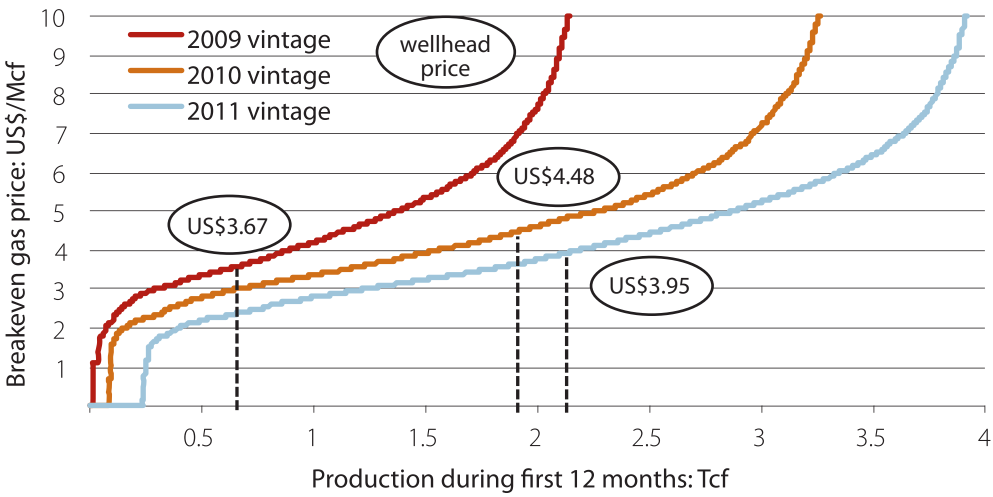


Source: Drilling Info LLC, HPDI Production Database, June 2013.

The well productivity data for the Barnett Shale shown in Figures 5 and 6 essentially mean that it has not been possible to just drill low cost (high productivity) shale wells. Each year operators essentially sample along the entire shale supply curve shown in Figure 4. This is not just a feature of the Barnett play. Rather, it is a salient feature of all the shale plays that have been developed to date. Furthermore, the spatial characteristics of well productivity within all the contemporary shale plays are very complex, with large levels of well-to-well productivity variation even among wells drilled from the same well pad and completed with the same specifications. All of this points to the shale resource having a significant stochastic aspect to its productivity, the nature of which has been studied in depth as part of recent work at MIT (Ejaz and O'Sullivan 2013).

Naturally, the variation in shale well productivity discussed in the preceding paragraphs has a very direct impact on the economics of the resource. Experience to date has revealed that shale well production tends to decline significantly over the first 2–3 years, after which decline rates moderate. This means that the initial production rate strongly influences a well's breakeven economics, and because the cost of drilling wells within plays tends to be relatively similar, the large variation in initial production rates results in a wide range of breakeven prices. Higher performance wells can have very attractive breakeven economics, while those wells with much lower initial production rates can end up having very poor economic performance.

Figure 7. Retrospective US shale gas supply curves for the 2009, 2010 and 2011 well vintages along with an illustration of the average Henry Hub gas price for each year



Source: O'Sullivan 2013.

A retrospective analysis of the economic performance of the shale gas resource commissioned over the past several years reveals exactly this trend. In the case of each vintage, a significant volume of gas is low cost, with increasing volumes of gas having a breakeven price of US$0 per million British thermal units owing to the value of the liquids being co-produced from the same wells. However, along with this low cost gas, a significant amount of expensive gas is also being produced. The result of this is that a large proportion of the shale gas produced over the past 2–4 years has comes from wells with breakeven costs significantly above the market price for natural gas that year.

Figure 7 plots retrospective supply curves for the shale gas commissioned in the US in 2009, 2010 and 2011 (O'Sullivan 2013). The analysis used to construct these curves considered the production performance of each horizontal well brought online in each of the major US shale plays in those years, and based on applicable drilling and completion costs, among others, calculated the breakeven cost of that gas. The figure also shows what the average Henry Hub gas price was for each year. Unsurprisingly, the supply curves reveal major variations in the economics of the shale gas brought online in each vintage and that much of the gas was marginal if not sub-economic. Naturally, improvements in well performance and reductions in well drilling and completion costs have served to improve the overall picture. However, even in the case of the 2011 vintage, only about 50 per cent of the shale gas commissioned that year had a breakeven price below US$4 per million British thermal units.

An important development for the economics of US shale gas that has occurred over the past 2-3 years has been the growth in shale oil production. In the face of very low gas prices, operators have switched their focus from gas to oil-targeted drilling. Certainly, the US shale oil resource is not as significant as its shale gas resource; however, some prolific shale oil plays have emerged, most notably North Dakota's Bakken formation and the Eagle Ford Shale in West Texas. Oil-associated gas production in these plays tends to have exceptionally low breakeven costs, US$0 per million British thermal units in many cases, and the effect of this gas is to keep natural gas market prices lower than they would be in the absence of shale oil production. The impact of the growing shale oil-associated gas production on the overall shale gas supply curve is clearly evident in the 2011 curve shown in Figure 7. There, most of the around 0.25 trillion cubic feet of 2011 shale gas production with a breakeven cost of US$0 per million British thermal units was produced in association with oil from wells in the Bakken and Eagle Ford plays.

It is certain that shale oil production will continue to grow over the medium term in the US, and this will continue to yield a certain volume of very low cost gas. However, if the growth in shale gas production being projected for the next few decades is to be realised, most production will have to come from the "dry" [5] shale gas plays, with their higher cost supply curves. Projecting future gas prices is of course a folly of sorts; however, a consensus is beginning to emerge, which says that the US shale gas resource will need natural gas prices in the US$4–6 per million British thermal units range over the coming decade in order to be economically attractive.

New Perspectives on the Future Shape of the US Energy Sector

The newfound sense of natural gas supply assurance that has resulted from the emergence of the shale gas resource, coupled with the sense that large volumes of this gas will be low to moderate cost has led many to project a much more gas-centric future for the US than was projected even five years ago. A natural venue for this dynamic to play out is in the power generation sector where coal and natural gas compete. Traditionally, coal has dominated US base load generation, with gas-fired combined cycle units coming online midway in the dispatch stack. However, lower gas prices seen over the past several years have resulted in gas-fired units becoming more and more competitive relative to coal units, particularly the older, smaller and less efficient coal units, of which there are many in the US.

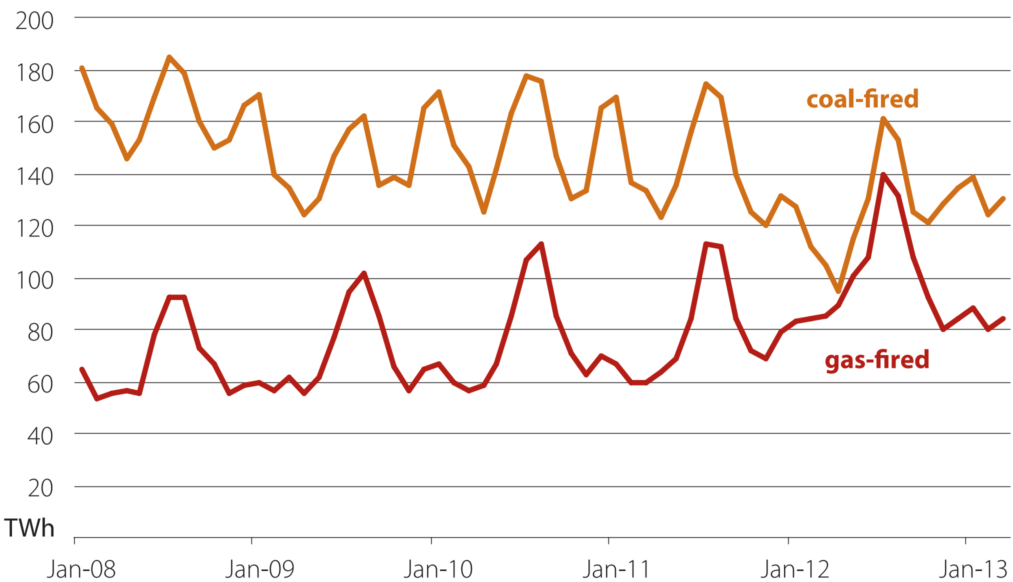
An illustration of how the relative importance of natural gas in US power generation has increased is shown in Figure 8, which plots how the monthly generation from coal and gas-fired units has changed since 2008 (United States Department of Energy 2013a). In 2008, coal accounted for 48 per cent of total US generation with gas making up 21 per cent. In 2012, coal output made up 37 per cent, while gas output reached 30 per cent. The particularly high level of gas-fired generation in 2012 was driven by very low gas prices during that year. With gas prices increasing to slightly higher levels during the first half of 2013, it is likely less gas will

5 "Dry" shale deposits contain mostly methane whereas "wet" deposits contain other compounds in addition to methane, such as ethane and butane, which can be separated and sold on their own.

be used for power generation in 2013 than in 2012; however, the relative importance of gas in power is unquestionably increasing.

Longer-term projections of what will fuel US power generation have changed radically with the emergence of shale gas. In the 2008 EIA Annual Energy Outlook, it was projected that by 2030 coal generation would make up 54 per cent of total output with gas accounting for only 14 per cent (United States Department of Energy 2008). In the 2013 edition of the Outlook, and in light of the obvious abundance of shale gas, the projection for coal-fired generation in 2025 has declined to 38 per cent, with gas now accounting for 30 per cent (United States Department of Energy 2013b).

Figure 8. Monthly coal and gas-fired power generation in the US between 2008 and early 2013



Source: United States Department of Energy 2013a.

The relative abundance of natural gas brought on by the development of the shale resource that has caused the significant changes in the power generation sector described above is also having impacts on both the US and international energy sectors. One of the most dramatic of these impacts is how shale gas has altered thinking regarding US natural gas imports and exports. In the early part of the last decade concerns regarding declining domestic natural gas production led to the construction of very extensive LNG import capacity. In fact, the US currently has the capacity to import 17 billion cubic feet per day (500 million cubic metres per day) of natural gas via LNG, or around 25 per cent of average daily demand.

The shale driven growth in domestic natural gas production over the past number of years has effectively rendered US LNG import infrastructure redundant, so much so that in 2012, the utilisation of LNG import facilities was less than 5 per cent (United States Department of

Energy 2013a). These developments are having broader impacts on international gas markets. Significant investments in LNG liquefaction facilities around the world over the past decade were made with an eye to supplying gas to the US. Due to shale gas, these LNG supplies now need to find other markets, and are in fact now facing additional competition because a number of US LNG export projects are now being developed.

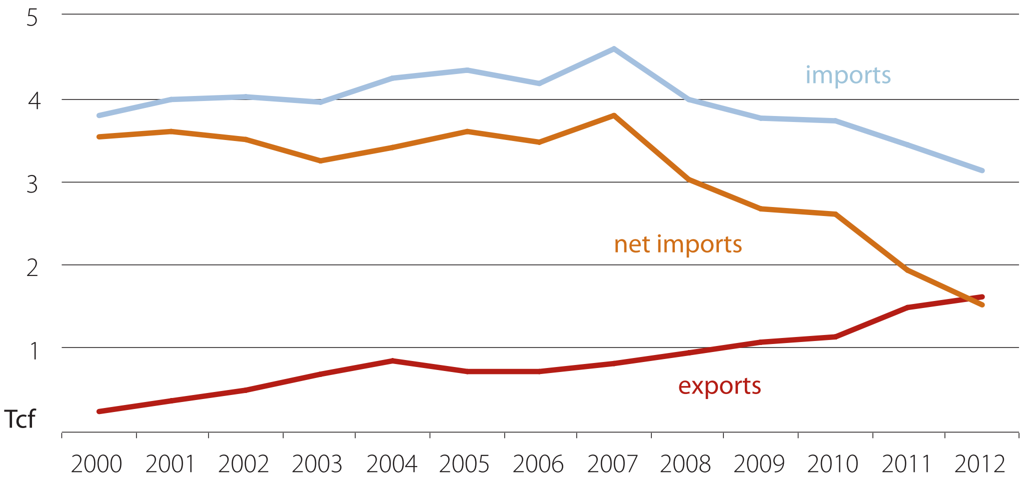
As of mid-2013, application for approval of a combined total of around 30 billion cubic feet a day (850 million cubic metres a day) of LNG export capacity had been received by the US Department of Energy, the US agency responsible for approving LNG export licenses. Many of these applications relate to the "turning around" of existing import facilities; however, a number are greenfield projects. Most of these applications have received permission to export to countries with which the US has free trade agreements (FTAs). However, the Republic of Korea is the only FTA country with meaningful LNG demand. Because of this, most applications are seeking approval to export to non-FTA countries, but to date only 3.6 billion cubic feet a day (100 million cubic metres a day) of exports to non-FTA countries have been approved.

The prospect of large-scale LNG exports has become a politically charged issue in the US. Opponents include the somewhat unlikely pairing of major US petrochemical manufacturers and environmental non-government organisations (NGOs). Much of the petrochemical and manufacturing sectors' objections relate to concerns that LNG exports will increase US natural gas prices and erode domestic competitiveness. The environmental NGOs are opposed owing to fear that exports could spur further expansion of gas production and lead to more hydraulic fracturing, a dynamic that would go against their objectives of seeing the production and consumption of fossil fuels reduced if not eliminated. Proponents see LNG exports as a means of increasing the market for abundant US gas supplies, helping to bolster the economy through job creation and improving the US trade balance, along with enabling the US to have greater geopolitical influence on the global gas and broader energy sectors.

Certainly, many of the concerns voiced by the opponents of LNG exports would seem reasonable if exports were to approach the levels for which initial permission has been sought. However, the likelihood of anything near 30 billion cubic feet a day (850 million cubic metres a day) of LNG exports being realised within a decade seems extremely remote. The Department of Energy has conducted studies examining the likely impacts of LNG exports under a number of development scenarios and the results of this work have indicated that LNG exports will not have a major impact on US natural gas prices or overall economic output (NERA Economic Consulting 2012).

In fact, the entire debate regarding whether exports of LNG should be allowed has taken place in a manner that has missed a bigger point, that the US has been dramatically increasing its overall gas exports in recent years. Figure 9 illustrates how US imports and exports of natural gas have varied since 2000 (United States Department of Energy 2013a). Today, the US exports around 4.2 billion cubic feet a day (120 million cubic metres a day) of gas, almost all via pipelines to Canada and increasingly Mexico. This figure is twice the level of exports in the middle of the last decade before shale gas production began to take off. During the same period overall gas imports, the vast majority from Canada, have fallen by approximately 35 per cent while domestic consumption has grown by around 16 per cent. Today, net imports account for just 6 per cent of US natural gas needs and by 2020 it is expected that the US will become a net exporter of gas (United States Department of Energy 2013b).

Figure 9. Illustration of how US natural gas imports and exports have changed since 2000



Source: United States Department of Energy 2013a.

LNG exports will play a role in the US becoming a net gas exporter; however pipeline export growth, particularly to Mexico will be the major driver of this dynamic over the coming decade. Beyond that point, the relative importance of LNG could grow, particularly if more non-FTA export licenses are granted over the next few years. However, even then LNG exports are not expected to be much greater than 1.5 trillion cubic feet a year, or around 5 per cent of annual production (United States Department of Energy 2013b). Given the scale of the US resource base, it is expected that meeting this level of additional demand without materially impacting US natural gas prices should be possible.

Shale gas—the many and complex environmental issues

Without doubt, the emergence of shale gas has completely altered perceptions regarding the scale and economics of the US natural gas resource. However, this rise has not been without controversy. In particular, the environmental impact of producing shale gas and other unconventional hydrocarbons has now become an issue of heated public debate in the US, and of course this debate is being mirrored internationally. This subject is exceptionally complex and the technical issues of relevance are beyond the scope of this article; however, it is possible to provide a broad overview of the issues, and the ongoing debate.

To begin, it must be acknowledged that all oil and gas development and production activities bring with them environmental risks and impacts. However, the development of unconventional resources brings some added challenges. Principal among these is the need for very large-scale reservoir stimulation in order to induce economically acceptable production levels from the very low permeability hydrocarbon-bearing formations that make up the unconventional resource. A range of significant environmental risks accompany hydraulic fracturing-enabled gas and oil development. They include, but are certainly not limited to, the pollution of both ground and surface water resources, the imposition of excessive stress on local water availability, induced seismicity, the degradation of local air quality, the emission of fugitive greenhouse gases, the disturbance of local communities, and the fragmentation of ecosystems.

Water related environmental impacts have been of concern since the commencement of large-scale shale gas production. The hydraulic fracturing treatments needed to stimulate production pump large volumes of water and chemicals into shale formations at pressure, and the potential for this fluid to infiltrate and contaminate fresh groundwater aquifers has been widely cited. Limited confirmed instances of such contamination have emerged. One potential case may have occurred in Pavillion, Wyoming. However, that case remains unconfirmed, with the US Environmental Protection Agency (EPA) recently pulling back from their investigation of the incident.

Several expert studies on the water risks of hydraulic fracturing have concluded that the risks of direct contamination of groundwater by fracturing fluids should be very low, particularly if well construction is correctly executed (United States Department of Energy 2011). Of course this leads to the question of how many wells are correctly constructed? Nevertheless, the focus of concern regarding water has shifted somewhat to the handling of polluted water produced from wells immediately following hydraulic fracturing. This water tends to contain a complex range of pollutants, typically native to the target formation, and its safe handling and disposal is critical. Technology does exist to treat much if not all this effluent to a dischargeable standard. However, this can be expensive and so, where possible, this water has been disposed of via injection into deep disposal wells. It is this practice that has been associated with almost all the noted instances of induced seismicity.

A more recent focus for those concerned about the environmental impacts of shale development is the air quality and greenhouse gas impacts of the process. The drilling and hydraulic fracturing processes needed to commence production at a shale well is generally reliant on large numbers of diesel engines running for prolonged periods in small areas. As such, this can lead to a lot of noise pollution and local air quality degradation. The greenhouse gas concerns centre around how natural gas produced during the very early stages of production immediately following fracturing is handled. If this gas is simply vented to the atmosphere, then a reduction in CO_2 emissions arising from the burning of gas instead of coal for example could be eroded due to the potency of methane as a greenhouse gas.

Clearly, the environmental issues associated with shale and other unconventional hydrocarbon production are challenging. In many areas it appears they are being managed reasonably well through current regulation and with operator buy-in. However, it is certain that real issues do exist. In the US the continued development of the shale resource can only be possible if environmental risks can be absolutely minimised. Achieving this will need more regulation and a more widespread adoption of evolving best practices as a minimum. However, even then it is entirely reasonable to expect that development will not take place in areas where a social license to operate is not present. States including New York and Vermont have placed moratoria or outright bans on hydraulic fracturing based on community concerns.

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Future developments in gas pricing in Europe and Asia[1]

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Introduction

The literature on oil pricing is huge. By comparison, there is very little to read on natural gas pricing, despite the fact that the fuel is approaching 25 per cent of global primary energy consumption. In the majority of countries outside North America, international gas prices are not transparent and accurate public domain data are very difficult to obtain. This may not have been a great problem when the fuel comprised only a few percentage points of energy balances, but as gas has become more important, so has the way in which it is priced. There is very little help from academic theory on the principles of how natural gas should be priced. Most of the classic texts on commodity pricing were written before natural gas became an important fuel in energy balances and could therefore not have foreseen the organisational and contractual specificities of the industry[2].

The vast majority of international gas trade outside North America is still conducted on the basis of 10–30 year contracts with complex price clauses. The most important elements of these clauses are: the base price (Po) and the index (which determines how the base price is adjusted over time). Related to pricing is the take or pay clause present in the majority of long term contracts, which requires the buyer to pay for a specified minimum quantity of the annual contract quantity of gas at the contract price, whether or not that volume of gas is taken. Long term contracts between domestic producers and exporters, and national or regional utilities, provided the basis for the establishment and initial decades of the gas industry's growth, particularly in Continental European and Asian LNG importing countries which are the focus of this article.

International trade allowed gas industries to develop and expand beyond their indigenous resource base, but contracts needed to be long enough for investments to be recovered in both exporting and importing countries, and to provide a guaranteed cash flow to assist the financing of those investments. It is useful to briefly review the pricing principles that negotiators originally applied (or at least should have been trying to apply) in long term gas contracts, making a distinction between economic and market fundamentals. Economic fundamentals refer to the cost of developing and delivering domestic or imported gas to end-users. Market fundamentals refer to the size of the customer base and the price of gas, compared with the price of market substitutes.

1 Many of the arguments, and some of the text, of this article are taken from Stern (2012).
2 For example the work of Ricardo in the 19th century and Hotelling in the 1950s. For some theoretical aspects of gas pricing, which emphasise the importance of discriminatory monopoly, see: Allsopp and Stern (2012).

The logic of the division of risk inherent in these contracts was that:

- the exporter assumed the price risk i.e. the risk that the price, however determined, would be sufficient to remunerate economic fundamentals—the investment in production and transportation of gas to the border of the importing country
- the importer assumed the volume risk (via the take or pay provision) i.e. that a large enough market would be developed in order to honour the volume commitments in the contract. An important element of developing sufficient market size was the price-competitiveness of gas against other energy sources.

In European contracts, it was always assumed that market conditions would be affected by a combination of changes in: prices of competing fuels, gross domestic product (GDP) growth rates, inflation and taxation, industrial structure, environmental regulations and a range of other country- (or possibly region-) specific conditions. These changes were generally dealt with by means of a "price review" clause which allowed the base price (Po) and the indexation formula to be "reset" (generally) every three years. Asian LNG contracts generally had much less flexibility and the scope to make more than marginal changes to the price formula was limited.

While these rigidities caused some problems in the decades prior to 2008, the situation subsequently became substantially more difficult because of rapid changes in oil prices and the "globalisation" of gas markets, which increasingly means that movements in the supply, demand and prices of gas (and other energy commodities) in other regional markets have much more immediate impacts on gas prices than previously[3]. The most important events during the period 2008–12 have been:

- the increase in crude oil prices above US$100 a barrel on a sustained basis
- the unexpectedly rapid development of unconventional (primarily shale) gas production in North America which caused Henry Hub prices to fall to much lower levels than had previously been thought possible, reducing US LNG imports to levels far below expectations, and raising the possibility of substantial US exports of LNG in the second half of the 2010s
- substantial fluctuations in international coal prices which caused equivalent fluctuations in gas demand in the power generation sector
- short term power and carbon price movements which have led to changes in the "spark spread" and "dark spread" (gross margins for gas-fired and coal-fired generation, respectively)
- the March 2011 Fukushima nuclear disaster in Japan, which significantly increased Japanese demand for short term LNG supplies
- the emergence of significant new LNG markets in China, India, South East Asia, Latin America and the Middle East
- the post 2008 recession in Europe, which has been longer and deeper than expected, impacting energy and gas demand, particularly when coupled with significant increases in renewable generating capacity in many countries
- political developments in (principally) North African countries (the "Arab Spring") which curtailed gas exports from Libya for most of 2011.

3 i.e. developments in North America and Asia have impacts on Europe, and North America and Europe have impacts on Asia.

The combination of these events have meant that, since 2008, the commercial environment for international gas trade has been subject to new (and increasingly difficult to predict) forces which have exacerbated the problems of adherence to the relatively rigid oil-linked price formulae in long term contracts. This article concentrates on the situation in Continental Europe and LNG importing Asia, but outside these regions different problems are found in relation to international gas prices. In particular, countries with low or very low domestic gas prices are starting to import high price LNG instead of developing much lower cost domestic gas[4].

International gas pricing in Continental Europe[5]

The commercial model of the traditional Continental European gas utilities, established in the 1970s and 80s, was relatively simple: they segmented their customer base depending on the ability of the customers to access alternative fuels (and hence the relative value of gas for each customer group); and they differentially priced between (and sometimes within) classes of customers, confident that without either access to pipelines or transparent prices, their customer base was essentially captive. Long term gas contracts were intended to reflect this relatively simple commercial model, but with sufficient flexibility to allow adaptation if and when market fundamentals changed. For the first several decades of European gas trade, they were (largely) successful in this task, assisted by the fact that importers had a significant measure of control over market fundamentals, because they were mostly monopsony (single) buyers and monopoly sellers to a customer base whose only alternative to buying their gas was to use a different fuel.

Starting around 1990, several trends began to appear which had not been anticipated either by governments or by European gas stakeholders. First, it was never intended or expected that gas would become such an important fuel in European energy balances. With the exception of the Netherlands, where the discovery of the huge Groningen gas field meant that there was an incentive to use as much as possible of a domestic energy source, gas was deemed to be a "premium fuel" which should only be used in high value sectors such as residential heating and cooking, and industrial processes requiring a clean and controllable heat source. Using gas for power generation was not only frowned upon but prohibited by a 1975 European Directive with restrictions being lifted only in the early 1990s[6]. From 1980–2005, European gas demand expanded continuously and dramatically due to a combination of:

- the success of gas in taking market share from oil products, significantly assisted by the almost continuous increase in oil prices during this period
- the failure of coal and nuclear power to expand to the extent anticipated in many countries, partly for (local and regional) environmental reasons, and partly due to cost and risk considerations, particularly for nuclear power.

4 This is the case in much of Latin America, Middle East and Asia, Stern (2012).
5 The UK liberalised its gas market in the 1990s and created a hub (the National Balancing Point—NBP) which had become the dominant price formation mechanism by the end of that decade (see Heather 2010).
6 Official Journal, L178/24, 9 July 1975; Official Journal L75/52, 21 March 1991.

As gas expanded its market share, the pricing logic which had been established in long term contracts began to break down. The dominant price mechanism in European long term gas contracts is the netback market value principle; the origins can be traced back to the early 1960s[7]. The price paid by the gas company to the foreign or domestic gas producer at the border or the beach is negotiated on the basis of the weighted average value of the gas in competition with other fuels and adjusted to allow for transportation and storage costs from the beach or the border and any taxes on gas.

In Continental Europe the competitive fuels were largely oil products—gas oil and (heavy or light) fuel oil. Economic and market fundamentals should determine—or at least play a significant part in determining—gas supply and demand, and when the long term contract pricing mechanisms were originally created, it could be argued this was the case[8]. Beginning in the 1990s, the pricing of internationally traded (and domestically produced) gas moved increasingly out of line with market fundamentals. However, this did not cause major problems because of the commercial model of Continental European gas utilities, and changes in the structure of the utility sector.

The logic behind the netback market value mechanism was robust for as long as oil (and other energy) products remained genuine substitutes for gas i.e. as long as end users retained the ability to switch between gas and other fuels. But this logic began to disappear in the 1990s, a trend which accelerated in the 2000s. Despite protestations to the contrary by gas industry stakeholders (exporters and importers) during this period, by the mid-2000s, fuel switching between gas and oil products in the major gas markets of Europe had fallen to minimal levels (Stern 2007).

The position of the utilities, which traditionally purchased and imported the majority of Continental Europe's gas, changed fundamentally over the past two decades due to the merger and acquisition activity set in motion by the EU-imposed liberalisation of gas and power industries. Until the mid-1990s, a single company had a de facto monopoly of gas purchase and sale in each Continental European country[9]. This change in the industrial organisation model of the European utility sector— from national/regional gas or power companies to multi-energy (or multi-utility) pan-European companies—removed much of the historically strong cultural support for the traditional gas business model, including long term contracts. That said, for security reasons the new utilities continued to express a desire to obtain supplies of gas under long term contractual arrangements; but on a different pricing basis. This became particularly evident in the post-2008 period, as managements recognised the huge financial exposure resulting from oil-linked prices in their long term contracts.

7 For details of this pricing structure and its historical importance in European gas markets see Stern and Rogers 2012, especially pp. 54–59.

8 In relation to production costs this was, in many cases, manifestly untrue, particularly for associated and even for non-associated gas production, but it had a certain logic which, given higher transportation costs compared with oil, was not completely unreasonable. In many non-OECD countries, particularly oil-producing and exporting nations, gas prices were extremely low reflecting the economic fundamentals of producing gas in association with oil.

9 The only significant exception was Germany where gas companies had regional monopolies but were dominated by Ruhrgas which purchased the majority of imported gas.

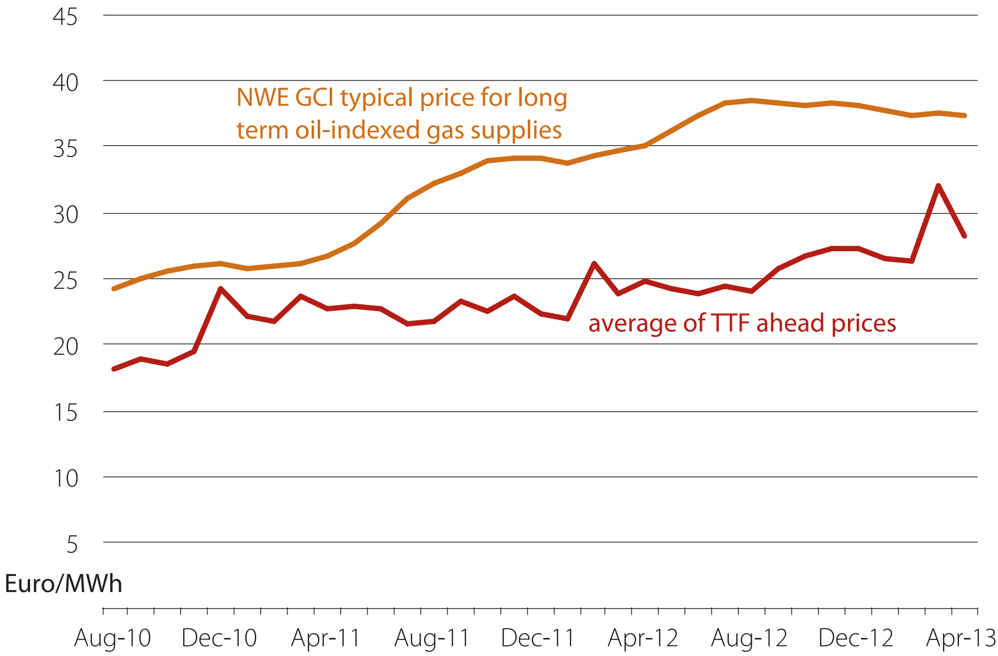
The perfect storm: 2009–12

In the second half of the 2000s, European energy and competition law created increasing momentum towards effective third party access, ownership unbundling and regulatory oversight. These developments, combined with the elimination of destination clauses, completely transformed the regulatory and market context in which the existing contracts were operating. Two developments were fundamental to that contextual change: (1) the arrival of workable third party access, and (2) the emergence of hubs with transparent prices which could be readily accessed by any customer via the internet. By the end of the decade, the majority of consumers in the largest EU gas markets increasingly had a credible choice of suppliers, and in many cases competition was fierce, particularly for large customers.

During 2009–10, other developments had a significant impact on European gas utilities with long term contracts. The shale gas revolution collapsed North American gas prices to extremely low levels. In anticipation of gas shortage and high prices, nearly 200 billion cubic metres of regasification capacity had been built in North America during the 2000s, with LNG supplies arranged to fill it. By 2009, those supplies were no longer needed in North America and large volumes of LNG became available for Europe, exerting significant downward pressure on spot gas prices just as oil prices began to march upwards beyond US$100 a barrel. This happened just at the time when financial crisis and global recession hit Europe and (energy and) gas demand collapsed. Demand briefly recovered in 2010 due to extremely cold weather, but by 2012 European gas demand had fallen to the levels of a decade earlier—10 years of growth had been lost[10].

10 Excluding Turkey, which has been a rapidly growing market throughout the 2000s, the picture is even worse. Recession and pricing were not the only reasons for this; a huge increase in (mainly subsidised) renewable energy, low coal and carbon prices were also important contributors to gas' loss of market share. IEA 2012b, table 4, pp. V8–9; IEA, 2013b, Table 1.1, p.3.

Figure 1. European long term oil-linked and spot prices (monthly averages) August 2010–April 2013



Note: TTF is the Dutch gas hub.

Source: Platts monthly averages for respective months.

For European utilities this represented a perfect storm of commercial problems: progressive loss of monopoly, surplus supply, falling demand and sharply increasing long term contract prices (because of the increase in oil prices). In 2009, European hub prices fell significantly, up to 50 per cent below oil-linked contract prices. The response of exporters was two-fold: first that hub prices would return to oil-linked contract levels as gas demand recovered after the recession (and surplus LNG supplies were absorbed by fast-growing Asian economies); second that hub trades were not representative of European market (supply–demand) prices because they comprised only a small percentage of purchases. Over the following three years, both of these assertions proved to be wrong.

Since 2008, spot prices at the Dutch Title Transfer Facility (TTF) hub briefly touched oil-linked contract levels for a few days in December 2009/January 2010, February 2012, and March 2013. However, during 2011 and 2012, they averaged 25–30 per cent below long term contract levels (Figure 1). Over the same period, the share of gas traded at North West European gas hubs increased substantially; liquidity increased particularly at TTF in the Netherlands and by the end of 2012 there was good (although not perfect) correlation of prices across British, Belgian, French, Dutch, German and Austrian hubs (Petrovich 2013). Two separate estimates, based on different methodologies, arrived at the conclusion that in 2011–12 around 45 per cent of the gas sold in Europe was based on hub, rather than oil-linked, prices and this percentage was increasing significantly year on year (IGU 2012, Bros 2013).

Thus, by the end of the 2000s, the traditional utilities were no longer monopolies that could refuse to take notice of demands from their customers to supply gas at transparent hub price quotations. Nor could they any longer stop customers in their service areas gaining access to lower prices, either by using exclusivity and "no resale" clauses in their contracts with customers, or by maintaining that because they had to pay oil-linked prices in their long term contracts, their customers had to accept similar prices. If they refused to sell to their customers at "market" (hub-based) prices they would lose those customers to competitors. This left them two options: (1) to lose market share or (2) to purchase spot gas themselves in preference to long term contract gas. However, both options meant that they would have difficulty meeting take or pay commitments in their long term contracts and this is exactly what happened during 2009–12.

This period progressively revealed the failure of prices in long term gas contracts to reflect market fundamentals and why, in a changed market environment, this had become commercially untenable for European utilities. The problems were two-fold:

- gas prices needed to reflect market fundamentals, which increasingly meant hub prices, although debate continued about exactly which hub(s) and over which time period (average of the day, day-ahead, month-ahead, etc)
- price adjustments needed to be rapid—certainly no more than monthly—and arguably more frequent.

Contractual transition

By early 2013, there was strong anecdotal evidence that the majority of Dutch and Norwegian long term contracts had moved to hub prices but with much reduced (or no) flexibility i.e. the optionality enjoyed by the buyer in relation to contract quantity had been removed. Buyers were paying hub prices, but needed to organise their own volume flexibility requirements, either purchasing these services from the seller or developing their own capabilities (e.g. storage). Prices in Algerian long term contracts remained linked to crude oil or oil products, reflecting its greater reliance on LNG sales (with the option to sell into non-European markets), and near-total sales of pipeline gas into southern Europe (less immediately impacted by hub-based pricing). However, it was also rumoured that the number of Sonatrach's ongoing international price arbitrations had reached double figures[11].

The position of the Russian Federation is of particular importance because of the size and remaining length of its long term contracts, and because Gazprom has been the most outspoken opponent of moving to hub-based prices. The vast majority of the failures of European utilities to meet take-or-pay levels during 2009–11 were in Russian contracts, resulting in renegotiations between Gazprom and its buyers. At the beginning of 2010, it was widely reported that a number of companies had demanded both reductions in contractual take-or-pay volumes and reductions in prices. As a result of these demands, Gazprom had agreed with a number of companies that a 15 per cent share of the price indexation would

11 If parties to a long term gas contract are unable to agree on how prices should be changed in response to changed economic circumstances (this is explained in Frisch 2010), the contract allows them to take their dispute to an international arbitral tribunal. This used to be a very rare occurrence but since the mid-2000s has become much more common.

be moved to hub-based prices for three years beginning in October 2009. In addition, most companies were allowed to "roll over" volumes not taken below minimum take-or-pay levels to future years without penalty. Although Gazprom sold nearly 9 billion cubic metres more gas to its European customers in contract year 2009–10 compared with 2008–09, Gazprom's customers incurred take-or-pay liabilities of 5 billion cubic metres in 2008–09 and around 10 billion cubic metres in 2009–10 (Rogers 2012). The reasons for these liabilities, however, appear to be different: in 2009 the take-or-pay shortfall was spread across a number of companies; while in 2009–10 the shortfall was concentrated in two countries—Italy (ENI and Edison) and Turkey (Botas)—while all others appeared to have taken their minimum quantities. During 2011, Russian export volumes to Europe recovered, principally because of significant increases in exports to Turkey (due to a nearly 20 per cent increase in gas demand compared with the previous year) and Italy (due to the loss of Libyan supplies for most of that year) (Honore 2013).

In early 2012, Gazprom agreed with European customers exposed to competition that the base price in their long term contracts would be reduced by 7–10 per cent, and take or pay levels would be reduced to around 60 per cent[12]. This had the effect of closing the gap between the Russian contract price and the hub price without requiring Gazprom to agree to hub pricing. In July 2012, Gazprom reached agreement with EON, its largest customer, on a new price basis which resembled those reached with other buyers earlier in the year, with a lower base price and greater protection against oil price exposure, and arbitral proceedings were discontinued[13]. In addition, a mechanism was introduced into Russian contracts whereby if the gap between the contract price and the spot price became too great, the buyer received a rebate at the end of the price period[14]. Although this gave greater relief to the buyers, it did not resolve the fundamental price formation problem in Russian contracts.

Gazprom has publicly supported the concept of hybrid pricing—i.e. co-existence of oil linked and hub-based pricing—in Europe[15]. But in its long term contract negotiations it has adopted a different type of hybrid pricing which involves lowering the base price but retaining traditional oil indexation. Hybrid pricing seems destined to be a transitional stage in a process which, in the opinion of this author, will inevitably lead to European gas prices in long term contracts being set at hubs[16].

12 While the figures are from fragmentary commentary in the trade press, Gazprom confirmed that price adaptation had occurred with German, Dutch, Italian, Austria, Danish, Polish, Bulgarian and Romanian customers, although the mechanism in the latter three countries without hubs is likely to have been different. Management Report, p.18.

13 With the exception of Germany's RWE and the Lithuanian company Lietuvos Djuos which were still ongoing in May 2013.

14 For 2012, these rebates amounted to US$3.3 billion, Platts European Gas Daily, May 1, 2013, p.1 (Platts 2013).

15 See the arguments of Komlev in Stern and Rogers (2013).

16 Another reason is the new and unfolding regulation of gas transportation within the EU which creates strong incentives to deliver gas at hubs, see Yafimava 2013.

LNG Import Pricing in Asia

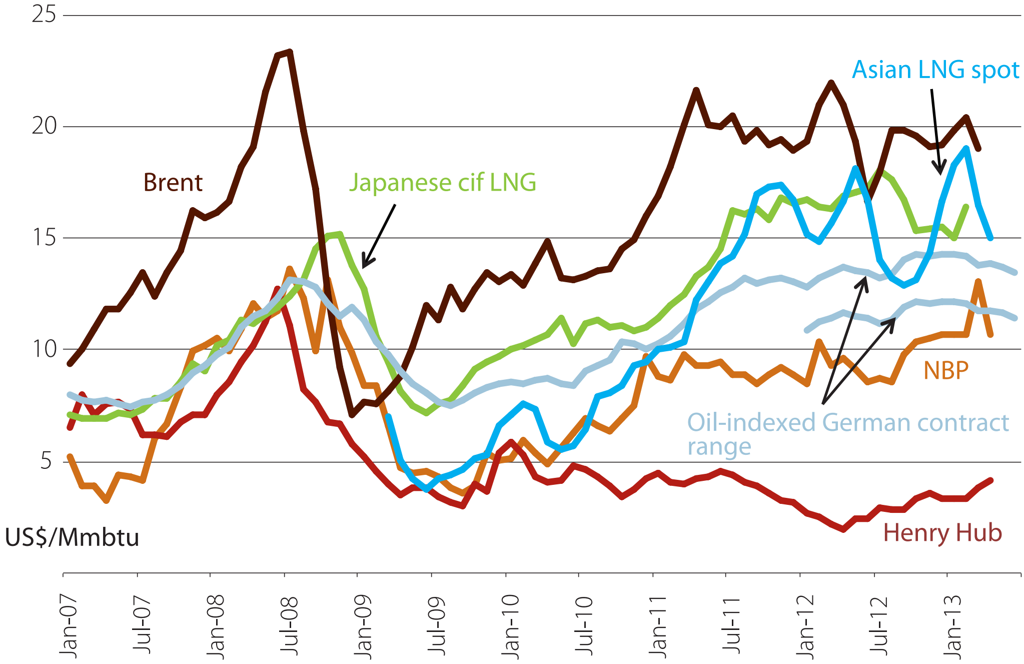
International gas pricing in LNG-importing Asia reflects some of the European features described above. However, there are significant differences: the crude oil price linkage was introduced into Japanese LNG import contracts in the 1970s when crude was the main competing fuel to gas in power generation. A cost pass-through mechanism allowed Japanese utilities to adjust gas and power tariffs to their customers by the same percentage as the country's average LNG procurement cost movements regardless of an individual buyer's actual purchase costs. By the time that Japan was joined by other LNG importers in the Pacific Basin (the Republic of Korea in 1986 and Chinese Taipei in 1990), the pricing principle of the "Japan Crude Cocktail" (or JCC)[17], or the average price of crude oils imported into Japan, was well established and exporters were unwilling to countenance any other mechanism[18]. The main focus of commercial negotiations was the index—known in Pacific LNG contracts as "the slope"—or the extent to which the LNG price would change in response to a change in crude oil prices.

Despite the fact that over the decades, Japanese electric power utilities moved away from crude oil-fired generation (for city gas companies crude oil was never a competing fuel); and the clearly strange assumption that gas markets in the Republic of Korea and Chinese Taipei (later followed by China and India) should price gas relative to crude oils imported into Japan, the system worked well for many decades. This was the result of a number of factors including (1) the cost pass-through mechanism (described above); (2) that in all of the countries gas was replacing oil products (of various kinds) in stationary energy balances; and (3) although Japan and the Republic of Korea flirted with liberalising their gas and power markets in the 1990s and 2000s, this never progressed to exposing incumbents to (what would generally be considered) serious competition.

This situation began to change post-2008 as oil prices moved—and with the exception of short periods remained—above US$100 a barrel into 2013 and was compounded by the Fukushima nuclear disaster which resulted in the progressive closure of Japanese nuclear power capacity by early 2012[19]. The closure of nuclear power plants deprived Japanese electric utilities of their low-cost generating capacity, at a time when the cost of their fossil fuel power generation was rising rapidly, creating major pressure to pass these increased costs through to their customers. Given that the latter were already paying some of the highest gas and power prices in the world, resistance to further increases was increasingly supported by politicians, resulting in all of the major power companies losing substantial sums of money in 2011 and 2012[20]. By 2013, the Ministry of Economy, Trade and Industry (METI), which approves the cost pass-through mechanism for utilities, had begun to suggest that substantially tougher pass-through yardsticks would be imposed in the future.

17 Official name: the "Japan customs cleared crude oil price".
18 For details of the history see Stern 2012a, and for the more recent period Flower and Liao in Stern (2012).
19 At the time of writing in May 2013, only two out of 54 stations were operating.
20 In 2011 Chugoku and Okinawa, and in 2012 only Hokuriku and Okinawa were the only companies that did not lose money. Company data supplied by Institute of Energy Economics Japan.

Figure 2. Regional Gas Prices, January 2007–April 2013



Source: Rogers 2012 (updated).

In addition to these difficulties, the collapse of North American gas prices due to the shale gas revolution; and developments in European liberalisation, competition and hub-based pricing (described above), led to a situation where Pacific Basin LNG importers were paying prices substantially higher than their counterparts in the Atlantic Basin (Figure 2). Very broadly speaking, in 2012 and the first quarter of 2013, Henry Hub prices were US$2–4 per million British thermal units, United Kingdom National Balancing Point prices were US$10–11 per million British thermal units with oil-linked long term contract prices around US$2–3 higher and Japanese LNG import prices were US$15–17 per million British thermal units. Not only did this place Japanese industry at a serious competitive disadvantage, but it starkly revealed the lack of logic of using a price mechanism that reflected fundamentals from a different era.

A consequence of the US gas surplus has been the conclusion, in 2012, of the first LNG export contracts from the Sabine Pass project priced on a "Henry Hub plus" basis[21]. In one important respect, an Asian price mechanism based on Henry Hub is irrational because it reflects the fundamentals of the US, rather than the Asian, market. When these contracts were signed, Henry Hub prices were around US$2–3 per million British thermal units, which translated into delivered Asian prices which seemed "cheap". However, higher Henry Hub prices (around US$6 per million British thermal units) and lower oil prices (around US$80 a barrel), would produce

21 The first contracts with international gas companies, Korean and Indian buyers, are priced using a formula of 1.15 times Henry Hub plus a constant which is individual to each buyer, varying from US$2.25–3.00 per million British thermal units. For details see Flower and Liao (2012).

delivered prices in Asian markets comparable with (and even higher than) the traditional JCC mechanism[22]. Despite this, the appearance of a Henry Hub-linked price has been a game-changer for Pacific LNG importers for two reasons: (1) it was the first time for many decades that buyers could discuss pricing with a seller on any basis other than JCC, and as such it created a degree of price competition which had been notably lacking in this market and (2) it gave rise to a discussion of market fundamentals which had been almost completely absent up to the end of the 2000s[23].

To a very limited extent, LNG market fundamentals in Asia had been represented by spot priced cargoes of LNG which first emerged in the early 1990s, rising from less than 3 billion cubic metres in 1994 to more than 48 billion cubic metres in 2011[24]. The notion of a natural gas "hub" in Asia is relatively recent, but in the early 2010s Singapore began to establish itself as a regional trading point, with pipeline gas, LNG and storage. The main problem for Singapore is the relatively limited size of the country's gas market, and physical limitations on establishing additional storage (Ledesma 2012; IEA 2013a, pp. 60–62).

While Singapore can certainly serve to demonstrate the advantages of LNG spot trading and price discovery in the Pacific Basin, an Asian LNG hub will eventually require a location with a larger gas market with greater regional significance. Such a location could be Shanghai, where the Chinese authorities—in the December 2011 price reform—announced their intention to create a hub[25]. This process is at an early stage, with only four Chinese provinces currently involved in the reform. However, with domestic and imported pipeline gas and LNG being delivered to Shanghai, this location has all of the attributes necessary for a national and regional marketplace. If the aim of benchmarking prices throughout China from the Shanghai citygate becomes a reality, it will create a powerful market signal. A major reservation about a Shanghai hub as a reference price for Asian LNG is the potential for prices to be overly influenced by the three state-owned companies that dominate the Chinese market. In addition, the lack of liberalisation of the Chinese gas market, while not necessarily a barrier to creating a reference price at the Shanghai citygate, remains a major challenge to the development of a regional hub (IEA 2012a, pp. 57–59).

For many years it has seemed that the obvious place to create a natural gas hub in Asia would be Japan—the region's oldest and largest LNG importer—but most of the gas and power utilities were completely opposed to such a development fearing that it would undermine the existing contractual status quo and security of supply. Post-2008 events (described above) have changed that view, as the need to find a more appropriate means of pricing imported LNG gathered support. In late 2012, the government announced a consultation process to create an LNG futures market listed on the commodity exchange to start operations in 2014 (IEA 2013a, pp. 52–55). But it is unclear how a futures market can be created in the absence of a substantial spot or short term market with significant liquidity. The experience of gas markets in North

22 Such speculation appeared apposite approaching mid-2013, with Henry Hub above US$4 per million British thermal units and oil prices appearing to weaken below US$100 a barrel.

23 One exception to this was Miyamoto and Ishiguro (2009).

24 Spot trade fell slightly in 2012. Stern (2012) table 14.3, p.482, GIIGNL 2013, p.9. Terminology and definitions are a major problem here. "Spot" is better thought of as short term trades, or trades outside long term contracts. The major source of information on LNG spot trade (GIIGNL) defines this trade as contracts with a duration of four years or less.

25 For an overview of Chinese gas pricing including the Shanghai Hub see Chen (2012).

America and Europe has thus far demonstrated that futures markets grow out of a strong underlying physical market and that without the latter, it is not clear how the former can be created. The relatively unliberalised state of Japanese gas and power markets suggest that this process could take at least the rest of the 2010s to resolve.

However, the consequences of price liberalisation and transition to market pricing will be potentially severe for both new, and particularly for existing, LNG contracts and this promises to be extremely problematic as we approach the end of this decade. One of the most worrying trends over the past few years for the gas industry has been cost inflation in large projects, of which greenfield LNG projects have been a particularly vivid example. Estimates of economic fundamentals of LNG projects under construction (which will begin deliveries during the 2010s) are around US$12–15 per million British thermal units delivered to Japan, which means that in order to remunerate their investments, exporters need the price levels of the post 2008 period to continue through the 2010s and beyond[26]. However, it is increasingly uncertain whether buyers can continue to purchase at such high prices given changing market fundamentals. This suggests a future of at least very difficult renegotiations, and at worst litigation, a phenomenon never before experienced in Asian LNG contracts.

The Future of Gas Pricing in Europe and Asia: a difficult transition

The failure of long term contract gas prices in Europe and Asia to reflect market fundamentals is not a new phenomenon, but by the early 2010s it had become a serious problem in Europe and Japan. Moreover, it had become increasingly difficult for stakeholders to claim that oil product linked pricing in Europe, and crude oil linked pricing in Asia, should be considered appropriate gas price formation mechanisms[27]. The emerging, and increasingly urgent, question was how to deal with these problems.

Europe

While there is strong support from all Continental European gas stakeholders for the continuation of existing long-term gas contracts, this will be dependent on a progressive transition from oil-linked prices with rigid adjustment terms, to hub-based (spot) prices with rapid adjustments to prevailing market conditions. By mid-2013, all of the major stakeholders with the exception of Gazprom and Sonatrach seemed to have accepted this principle and adjusted the majority of their contracts accordingly. Public domain information suggests that negotiations between Norwegian and Dutch sellers and their customers have resulted in adjustment to hub-based prices with a reduction in volume flexibility. Russian contractual adjustments had been made, retaining oil indexation but introducing a reduction in base prices and rebates, depending on the relationship of the contract price to the hub price, at the end of the price period. No changes had been reported in Algerian contracts and this may account for the significant number of arbitrations which are understood to be ongoing between Sonatrach and its customers. Thus the transition to hub-based prices in continental Europe seem unlikely to be accompanied by the large-scale termination of long-term contracts

26 That price range is probably applicable to contracts based on Henry Hub prices in excess of US$5 per million British thermal units.

27 Although Gazprom in particular continued to advance this argument, see Stern and Rogers (2013).

that had been seen during the liberalisation of North American and UK gas markets in the 1980s and 90s.

Asia

Post-2011, the buyers of LNG in Asia—particularly in Japan—encountered increasing problems with the traditional JCC price mechanism. They are at the early stages of identifying whether the solution can be a modification of JCC or whether an entirely new mechanism, such as hub pricing, needs to be created; answers need to be found for both new and existing contracts. There is confusion among Asian buyers as to whether the problem is price level i.e. the price is too high; or price formation, i.e. crude oil linkage is the wrong price mechanism. Some believe that a simple solution would be to reduce the slopes (indexation) in the long term contracts in order to give relief to the buyers. Some contracts signed in 2012 and 2013 began to combine different price elements such as Henry Hub, National Balancing Point and JCC. None of these solutions are likely to be a satisfactory long term basis for gas pricing in Asia.

Resolving Asian price problems may be a substantially more difficult task than for Europe, due to the economic fundamentals of companies involved in high cost LNG projects under construction which will start deliveries later this decade. While European exporters were certainly not delighted to be faced with demands to switch to hub prices, and as we have seen some continue to resist such demands, the majority of their production and transportation investments had already been amortised. In Asia, a number of LNG projects with capital investments in the range of US$30–50 billion will just be coming on stream in the late 2010s, at a time when price changes and demands from the buyers to move away from JCC pricing are likely to become increasingly urgent. Thus buyers and sellers may find themselves in an ever-more difficult situation where the commercial stakes are so high that there is very little room for compromise on either side. A reduction in oil prices below US$100 a barrel would both soften the current impact on buyers and provide more time for longer term solutions to be found. However, such reductions (assuming they occur) can only be a temporary solution.

Concluding remarks

This article has advanced the view that hub pricing is likely to be the eventual long term gas price mechanism in both European and Asian markets. Transition is well-advanced in Europe, but has barely begun in Asia. In both regions, the solution does not need to be the same for all countries. Southern and south-eastern Europe (specifically Spain and the Balkan countries) have been and will be slower to move to hub-based prices. In Asia, there is no reason to expect China and India to adopt identical price mechanisms to those of Japan and the Republic of Korea. However, the problem of how to price a fuel which has become a much more important element in energy balances than had previously been expected is similar and, in the 2010s, has become urgent. And it is very clear that in Asia, pressure for change will strengthen during the 2010s.

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