



**PART ONE**  
ESSAY



Woodside

# AUSTRALIA'S NATURAL GAS MARKETS: CONNECTING WITH THE WORLD

A report by EnergyQuest

## ESSAY

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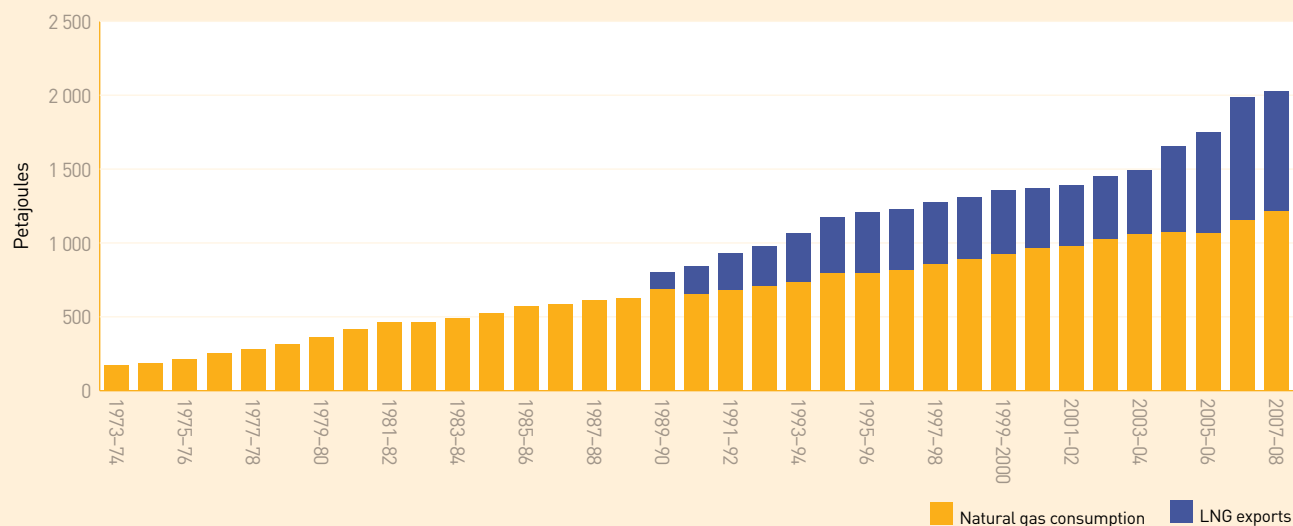
*EnergyQuest is an advisory firm focused on energy analysis and strategy.*

Historically, natural gas markets in eastern Australia were isolated from the rest of the world. While Western Australia's gas market was linked to global markets through liquefied natural gas (LNG) exports, the impact on the domestic market was limited. A number of developments are now leading to closer integration of gas markets in Australia and the rest of the world. This essay explores some of these developments.

Australia's LNG is a pivotal link between domestic and international markets. In the early 1970s Woodside discovered immense gas resources off the Western Australian coast, which could not only meet the state's domestic needs but also supply Asian markets. Export

production began in the late 1980s. The North West Shelf now has five trains (processing plants) with a total annual capacity of 16.3 million tonnes. In 2006 Australia's second LNG plant commenced exporting from Darwin. With these developments, Australia's annual LNG capacity has risen to 19.5 million tonnes (nearly 1100 petajoules (PJ) a year—close to Australia's total domestic demand for natural gas). Figure E.1 illustrates Australian LNG export growth relative to domestic demand. As will be discussed, Western Australia's domestic gas market is increasingly integrated with the global market by way of LNG, and similar events look set to occur on the east coast.

**Figure E.1**  
**Australian natural gas production**



Source: ABARE.

A second link between Australian gas markets and the rest of the world is the exponential rise of coal seam gas (CSG) on the east coast. This has become closely linked with major LNG developments and is attracting significant foreign investment.

Interest in CSG began in the United States and has contributed to a reversal in the historic decline in US gas production. With its world class coal resources, Australia has been recognised as having immense CSG potential since the 1980s. A number of major international oil and gas companies tried to commercialise CSG in Queensland and New South Wales but with mixed results. Texan father and son Dr James Butler and James Butler Jr, founders of Tri-Star Petroleum, are credited with Australia’s first commercially viable CSG, produced from the Fairview field in 1998. They also discovered the Durham Ranch field, later developed by Origin Energy as the Spring Gully project. Ultimately, after years of trial and error, the industry began to develop early this decade.

The early focus of CSG production was as a supplement to conventional gas for domestic use in Queensland. In particular, the Queensland Government promoted the use of CSG for electricity generation through the Queensland Gas Scheme. The state previously planned to import gas from Papua New Guinea to address

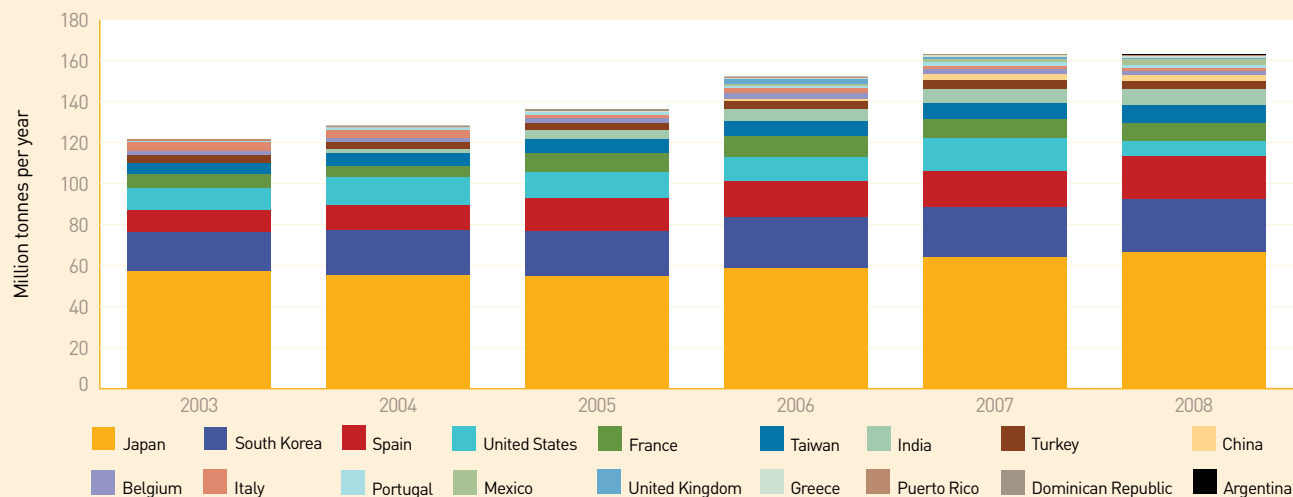
supply issues, but the growth of CSG ultimately eroded the commercial viability of that option.

It soon became apparent that while Queensland had more CSG than could be absorbed by the east coast domestic gas market—or commercialised at low Australian gas prices—the burgeoning global LNG market had potential, as with the North West Shelf discoveries three decades earlier.

This created interest among international LNG companies who wanted gas reserves in the Asia Pacific region and were familiar with the growth of unconventional gas in the United States. As a result, several international companies have taken a stake in Queensland CSG for LNG projects. The east coast gas market now appears set to follow Western Australia in becoming more closely integrated with the rest of the world through LNG.

Climate change is a third global influence on Australian gas markets. For many years natural gas played a lead role in power generation in only South Australia and Western Australia, which lacked large supplies of commercial coal. Along the east coast, coal has been king in power generation. But global concerns about climate change, as reflected in Australia’s proposed Carbon Pollution Reduction Scheme, now look set

**Figure E.2**  
World imports of liquefied natural gas



Source: BP, *Statistical review of world energy 2009*, London, 2009.

to change the technology mix in power generation. A range of fuels and technologies will increasingly compete to provide cleaner electricity. Natural gas produces around half the greenhouse emissions of coal when used in combined cycle gas turbines for electricity generation. Wind produces no emissions but has reliability issues. Geothermal has promise but is in the pilot stage. While the outlook for power generation a decade or two out is unclear, gas will likely play an increasing role in providing reliable baseload capacity and filling the growing demand for peaking capacity.

A fourth global influence considered in this essay is the financial and economic crisis. The recession has affected energy demand and prices across the world. The cost of developing gas fields, plants and pipelines can run to billions of dollars. After years of easy credit and low financing costs, interest costs have spiked and credit availability has shrunk, making it more difficult to refinance existing borrowings and fund new projects. Tighter financial markets do not appear so far, however, to have impeded any major gas developments in Australia.

Finally, security of gas supply is an important issue for all markets. This essay provides some perspectives on recent developments in the security of Australia's natural gas supply system.

## E.1 Liquefied natural gas

Global LNG consumption has risen strongly over the past decade. From 2003 until 2008, when the recession flattened growth, LNG consumption was rising annually by around 7 per cent. The world's largest import customers are Japan and South Korea (figure E.2). Japan is a critical market for Australia: 79 per cent of Australia's LNG goes to Japan (supplying 17 per cent of its LNG demand).

Demand for LNG is linked to various factors. Japan, South Korea and Taiwan lack alternative sources of natural gas, and China has insufficient infrastructure to meet gas demand in coastal cities from domestic sources. In Europe, an increasing number of countries are seeking to diversify their sources of gas supply away from Russia.

While global LNG demand has eased in the recession, it is likely to regain strength over the medium term as existing importers add further re-gasification capacity and new countries become importers. In addition to the 18 countries that import LNG, a further 17 countries have import plants under construction or planned. In the Asia Pacific region, these include Malaysia, Singapore, Thailand, Indonesia, Chile and the Philippines (figure E.3).

Figure E.3  
Countries importing liquefied natural gas, 2009



**Key to LNG regasification terminals**

- Operational
- Under construction
- ▲ Planned or proposed

Source: EnergyQuest, based on International Energy Agency, *Natural gas market review*, Paris, 2009.

On the supply side, the largest LNG exporters are Qatar, Malaysia and Indonesia. According to BP, Australia was the world's sixth largest exporter in 2008, supplying around 9 per cent of global exports. In the current decade, production has increased from Qatar, Malaysia, Nigeria, Australia, Trinidad and Oman (figure E.4). Qatar is increasing its capacity enormously, from 30 million tonnes per year to 77 million tonnes per year by 2012. In the Asia Pacific region, two projects were scheduled to commence production in 2009—Sakhalin 2 in Russia and Tangguh in Indonesia.

While Indonesia was the world's largest LNG producer until 2006, its annual exports have fallen from over 25 million tonnes early this decade to 19 million tonnes in 2008. This fall reflects reduced gas availability and the prioritisation of gas for domestic use.<sup>1</sup> Output from Tangguh will only partly offset the recent decline in Indonesian production.

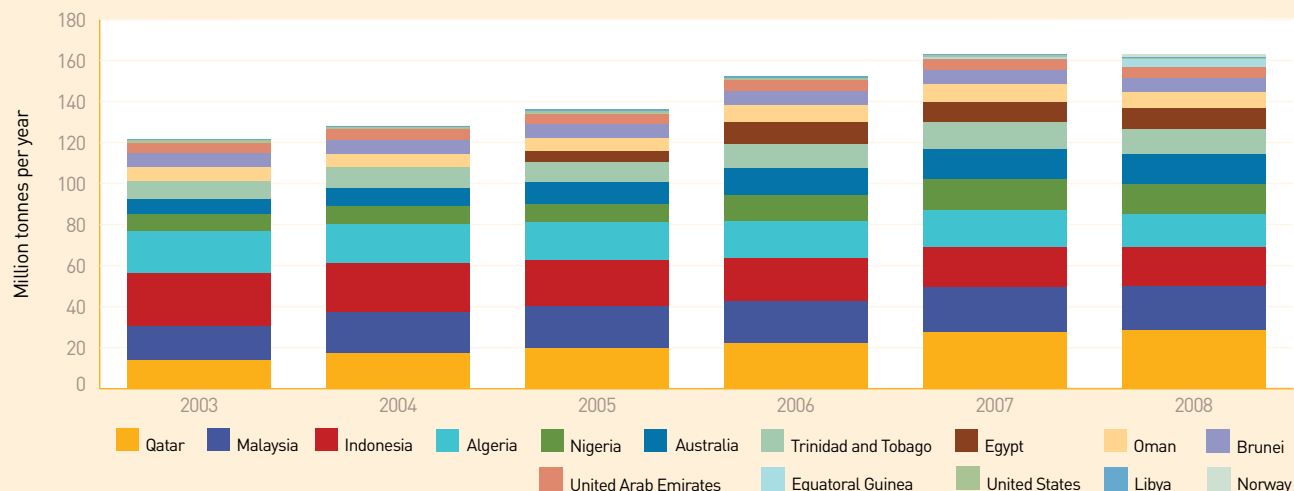
There is the risk of a looming surplus of LNG over the next few years, due to the recession and increased capacity, particularly from Qatar. But LNG liquefaction projects take many years to build, and only five new projects have reached final investment decision since mid-2005. As the International Energy Agency noted:

In the LNG sector, notwithstanding the massive increases in capacity that will be seen in the next few years from projects under construction, very few new projects have been sanctioned in recent years. Unless 2009 and 2010 see a number of new project approvals, there will be a dearth of new capacity in the period after 2012. Globally there is nearly twice as much regasification capacity operating or well under construction, compared to liquefaction capacity.<sup>2</sup>

1 J Stern, *Natural gas in Asia*, Oxford Institute for Energy Studies, Oxford, 2008.

2 International Energy Agency, *Natural gas market review*, Paris, 2009, p. 14.

**Figure E.4**  
World exports of liquefied natural gas



Source: BP, *Statistical review of world energy 2009*, London, 2009.

It questioned where the next generation of LNG projects will come from after 2012. Many developers think the answer is Australia. While Australia is only one of a number of countries proposing new liquefaction projects, it has the most ambitious expansion plans of any country.

### E.1.1 Liquefied natural gas prices

Interest in further developing Australian LNG export projects is driven by Australia's abundant gas resources—over 200 000 PJ, one of the largest endowments in the Asia Pacific region—as well as disparities between domestic and international gas prices. While international gas prices have trended significantly higher over the past decade (figure E.5), Australian domestic gas prices have been relatively low. Until recently, upstream prices were around \$2–3 per gigajoule in Western Australia and \$3–4 per gigajoule on the east coast. In contrast, US gas prices (an indicator of gas prices globally) peaked at over US\$12 per gigajoule in mid-2008.

Like domestic gas, most LNG is sold under long term contracts (although the spot market is growing). But unlike domestic gas, global gas prices have increasingly tended to settle around energy equivalent oil prices. An energy equivalent price for gas is 17.2 per cent

of the oil price, based on the energy composition of LNG compared with a barrel of oil. At an oil price of US\$70 per barrel, an energy equivalent price for gas would be US\$12.04 per million British thermal units (US\$11.35 per gigajoule).

Australian LNG export prices are linked to Asian oil prices, and are increasingly quoted on a straight percentage basis—typically, a percentage of average Japanese oil import prices (known as the 'Japanese crude cocktail'). Over the past year or two some long term LNG contracts have been written at oil parity and others at close to oil parity.

To compare this with Australian gas prices, it is necessary to account for the costs of liquefaction and freight. After adjusting for these costs, the equivalent Australian gas price received by producers at the gas field would still be significantly higher than historical Western Australian domestic gas prices or current east coast prices.

International gas prices have fallen since the peaks of 2008, with US prices falling below US\$4 per gigajoule in 2009—around one third of oil parity, based on an oil price of US\$70 per barrel. The proponents of Australian LNG projects consider, however, there will be significant commercial benefits over the longer term from exporting Australian gas as LNG.

## E.1.2 Australian liquefied natural gas developments

Notwithstanding the recent easing in LNG demand, oil and gas companies are committing to spend billions of dollars on new Australian projects. The Gorgon project in Western Australia alone could involve a \$50 billion investment.<sup>3</sup> Also on the west coast, the 4.3 million tonne per year Pluto project is under construction and set to become Australia's third operational LNG project. Pluto is due for completion in 2010 and will supply the major Japanese buyers Tokyo Gas and Kansai Electric. Other potential LNG projects in north west Australia are at an advanced stage of planning, including the Ichthys project in the Browse Basin, which is aiming to reach final investment decision (FID) by the end of 2010 (table E.1).

In Queensland, four LNG projects reliant on CSG are at an advanced stage of planning. Most are at the front end engineering and design (FEED) stage and aiming for FID by the end of 2010. Section E.2 considers the Queensland proposals in more detail.

Nationally, these projects have a combined potential annual capacity of 47–72 million tonnes. Over 20 million tonnes per year from these projects is already

committed to buyers—a similar magnitude to Australia's total current LNG capacity.

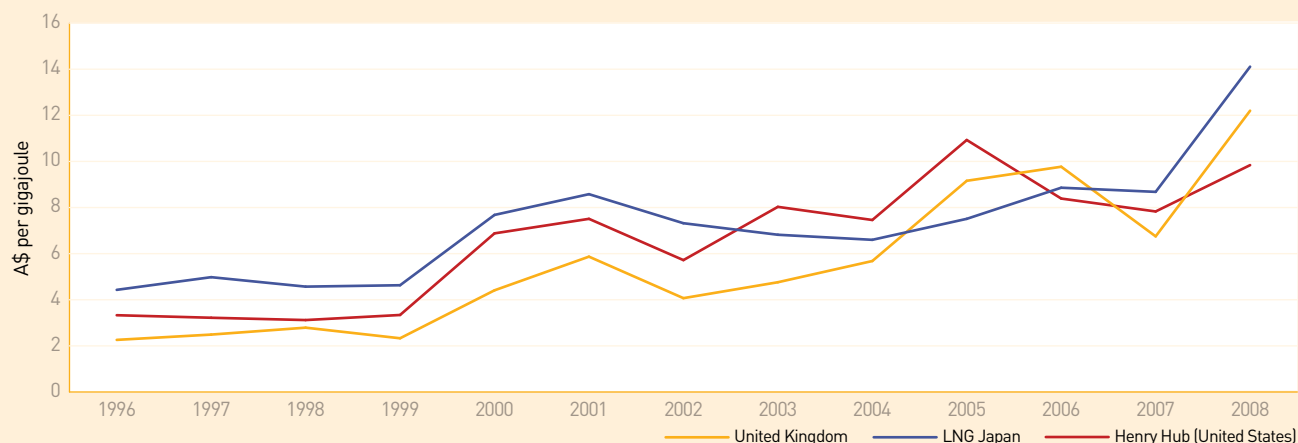
There are further proposed projects: additional trains for the Pluto project; the Browse Basin LNG project operated by Woodside; a floating LNG development on the Prelude field in the Browse Basin (Shell); the project based on the Sunrise field between Australia and Timor Leste (Woodside); a project based on the massive Scarborough field in the Carnarvon Basin (BHP Billiton); and another CSG–LNG project in Queensland (Shell).

At the time of writing, the global financial crisis and recession have not affected the momentum behind these projects—notwithstanding higher financing costs and reduced funding availability. It can take five years to build an LNG project, and companies are looking through the current downturn to the middle of the next decade.

## E.1.3 Domestic implications

Australia produces almost as much gas for LNG as for domestic use. Even if only some of the proposed LNG projects proceed, LNG will increasingly drive domestic markets.

Figure E.5  
International gas prices



Source: EnergyQuest, based on BP, *Statistical review of world energy 2009*, London, 2009.

3 Hon M Ferguson, Minister for Resources and Energy (Queensland), Speech to Queensland Resources Council, 20 July 2009, <http://minister.ret.gov.au/TheHonMartinFergusonMP/Pages/QUEENSLANDRESOURCESCOUNCIL.aspx>.



**Table E.1** Near term potential of Australian liquefied natural gas projects

| PROJECT                                       | OPERATOR                         | LOCATION        | SCALE<br>(MILLION TONNES<br>PER YEAR) | OFFTAKE<br>AGREEMENTS | STATUS AT<br>JULY 2009 | PLANNED<br>START |
|---|----------------------------------|-----------------|---------------------------------------|-----------------------|------------------------|------------------|
| <b>WESTERN AUSTRALIA</b>                      |                                  |                 |                                       |                       |                        |                  |
| Pluto   | Woodside                         | Carnarvon Basin | 4.3                                   | ✓                     | Over 70% complete      | 2010             |
| Gorgon  | Chevron                          | Carnarvon Basin | 15.0                                  | ✓                     | In FEED                |                  |
| Wheatstone                                    | Chevron                          | Carnarvon Basin | 9.0                                   |                       | In FEED                |                  |
| <b>WESTERN AUSTRALIA / NORTHERN TERRITORY</b> |                                  |                 |                                       |                       |                        |                  |
| Ichthys                                       | INPEX                            | Browse Basin    | 8.4                                   |                       | In FEED                |                  |
| <b>QUEENSLAND</b>                             |                                  |                 |                                       |                       |                        |                  |
| Fisherman's Landing LNG                       | LNG Ltd and Arrow Energy         | Gladstone       | 1.5-3.0                               | ✓                     | In FEED                | Late 2012        |
| Queensland Curtis LNG                         | BG Group                         | Gladstone       | 7.4-12.0                              | ✓                     | In FEED                | 2014             |
| Gladstone LNG                                 | Petronas and Santos              | Gladstone       | 3.5-10.0                              | ✓                     | In FEED                | 2014             |
| Australia Pacific LNG                         | ConocoPhillips and Origin Energy | Gladstone       | 3.5-14.0                              |                       | Pre-FEED               | 2014 or 2015     |

FEED, front end engineering and design.

Source: EnergyQuest.

Western Australia has substantial gas resources available for LNG (over 100 000 petajoules) but a shortage of gas for domestic use. In 2007 this led to gas prices for new long term domestic contracts increasing from around \$2–3 per gigajoule to over \$7 per gigajoule. Higher prices have been attributed to a range of factors:

- > Strong global demand significantly raised international energy prices, making LNG exports an attractive alternative to domestic sales.
- > Historically low domestic prices created little incentive to explore for new sources of domestic gas supply.
- > Western Australia's resources boom pushed up input prices generally. Development costs for gas fields have also increased for both LNG and domestic gas. In part, this is because new fields tend to be located in deeper water and are more expensive to develop.
- > Western Australia has a limited number of fields producing domestic gas. Most recently discovered offshore fields are large enough to have LNG potential. The relative shortage of gas fields that are unsuitable for LNG makes domestic gas users relatively dependent on LNG projects.

- > Much of Western Australia's domestic market relies on a single transmission pipeline—the Dampier to Bunbury Pipeline (see below).

The Western Australian Government is undertaking measures in response to domestic supply issues. One issue is that the gas specification for the Dampier to Bunbury Pipeline is narrower than the Australian standard, which has prevented development of the Macedon field.<sup>4</sup> The government plans to introduce legislation to broaden the specification.<sup>5</sup> Under the proposal, gas producers that supply at the broader specification will compensate pipeline owners and large consumers for increased costs to their operations, as part of their commercial negotiations. Suppliers providing gas at the broader specification will also pay a levy to fund the replacement of some pre-1980 gas appliances that may have safety issues. The broader gas specification and appliance prohibition will apply from 1 January 2012.

<sup>4</sup> Gas from the Macedon field does not meet the pipeline's current specification.

<sup>5</sup> Hon. P Collier, Minister for Energy and Training (Western Australia), 'State Government opens door to greater domestic gas supplies', Media release, Perth, 27 December 2008.

There has also been concern about the quantity of gas held under retention leases for discoveries that are not currently commercial. The leases allow successful explorers to retain rights over a gas field until it becomes commercial. Australia’s Department of Resources, Energy and Tourism is reviewing the retention lease system.<sup>6</sup> The Western Australian Government has also released and promoted onshore exploration acreage considered to have gas potential, and has reduced the royalty rate for onshore tight gas from 10 per cent to 5 per cent.<sup>7</sup>

The development of significant volumes of domestic gas depends (at least in part), however, on the early development of LNG projects. In 2006 the Western Australian Government introduced a policy to reserve gas from LNG projects for domestic purposes. Under the policy, the government negotiates with project proponents to include a domestic gas supply commitment as a condition of land access for processing facilities. The state aims to secure domestic gas commitments up to the equivalent of 15 per cent of LNG production from each project. Commitments have been made in relation to the Gorgon, Pluto and Wheatstone projects. The price

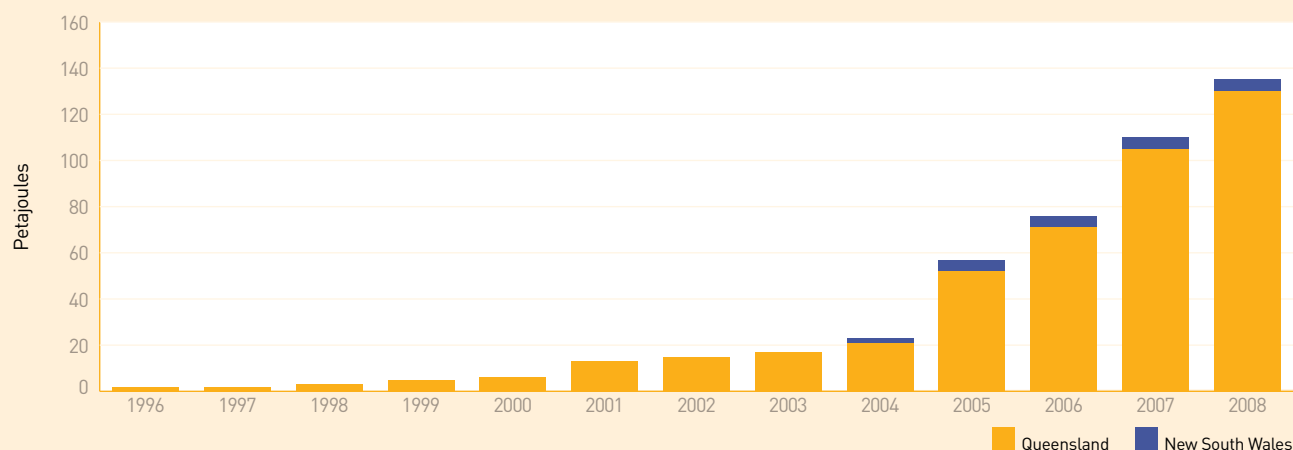
of gas sold into the domestic market is to be determined through commercial arrangements between gas buyers and sellers. The prices are likely to be comparable to the returns that gas producers can obtain from LNG.

One risk mitigation approach that some major gas buyers are starting to adopt is to move up the supply chain and participate directly in gas field exploration and development. This approach provides a hedge against gas supply and price risk. It increasingly occurs on the east coast, where major gas and electricity utilities have acquired interests in gas exploration and development. In Western Australia, Alcoa has taken interests in onshore exploration.

## E.2 Coal seam gas

The fastest growing source of gas supply in eastern Australia is CSG, with production having grown from around 17 PJ to 135 PJ in the five years to 2008. It now supplies around 21 per cent of the east coast gas market (figure E.6). Around 96 per cent of east coast CSG production is sourced from Queensland, with the remainder from the Sydney Basin.<sup>8</sup>

**Figure E.6**  
Australian coal seam gas production



Source: EnergyQuest.

6 Hon. M Ferguson, Minister for Resources and Energy (Australian Government), ‘Retention lease discussion paper released’, Media release, Canberra, 12 June 2009.

7 Tight gas is gas with low flow rates due to low reservoir permeability. Such gas is less commercially viable than gas from highly productive reservoirs.

8 As well as CSG activity in Queensland and New South Wales, interest in unconventional gas and increased recovery from existing fields is increasing elsewhere in Australia. In 2008 Santos identified 6900 PJ (gross) of contingent resources in the South Australian Moomba and Big Lake fields. This substantial gas resource could be commercialised at somewhat higher than current gas prices. Lakes Oil is having success with tight gas onshore in Victoria. Tight gas reservoirs onshore in Western Australia are also being actively assessed.

### Box E.1 What is coal seam gas?

Like conventional natural gas, coal seam gas (CSG) is mostly methane but may also contain trace elements of carbon dioxide and/or nitrogen. While CSG is essentially transported, sold and used in the same way as conventional gas, the geology differs (table E.2). In particular, CSG is produced from coal deposits permeated with methane rather than sandstone reservoirs.

Coal seam gas is either biogenic or thermogenic in origin. Biogenic methane is generated from bacteria in organic matter in coal. Biogenic processes occur at depths of up to 1 kilometre. Thermogenic methane forms when heat and pressure transform organic matter in coal into methane. Thermogenic methane is generally found at greater depths than biogenic methane is found. Queensland basins have biogenic gas, thermogenic gas and mixed gases.

The natural fractures in coal create a large internal surface area that can hold larger volumes of gas than conventional sandstone reservoirs hold. A cubic metre of coal can contain six or seven times the volume of natural gas that exists in a cubic metre of a conventional reservoir.

The coal formation process generates methane, carbon dioxide and water. The large quantities of methane produced during the formation of the high rank bituminous and anthracite coals generally flush away most of the carbon dioxide. The bituminous coals of the Sydney and Bowen basins typically contain gas consisting of over 95 per cent methane, with smaller quantities of carbon dioxide, nitrogen and inert gases.

Table E.2 Conventional and coal seam gas

| CONVENTIONAL NATURAL GAS   | COAL SEAM GAS   |
|--|---|
| Gas is generated in coals or shales at depth.  | Coal seams are both the source and the reservoir.   |
| Conditions must be right to generate gas and expel it from the source rock.  | Methane is generated as coals are buried, heated and compressed.  |
| Gas must migrate to a suitable structural trap in a suitable reservoir where it is stored in the pore spaces between the grains of the rock. | Gas is adsorbed as a thin film on the surface of the coal, and is held there by water pressure. No structural trap is required. |
| Natural pressure drives the gas to the surface.  | The gas is liberated by removing water from the seam. The gas desorbs and flows to the surface.                                 |

Source: Origin Energy/EnergyQuest, *Australian coal seam gas 2008: CSG meets LNG*, Adelaide, 2008

Management of CSG production is more difficult than management of conventional gas production. While production from conventional gas wells can usually be shut in and then recommenced, CSG wells generally cannot be shut in without repeating the entire dewatering process. There are, however, 'free flow' holes in which the gas can flow freely without the need for further pumping of water.

From a commercial point of view, CSG requires considerably more drilled wells than conventional gas does to deliver comparable quantities of gas. While the cost per well is much lower for CSG, conventional fields also may contain high value oil or liquids that increase their potential economic value, which is not the case with CSG. Conversely, CSG has the advantage of being onshore and, in the majority of cases, relatively close to destination markets.

Certified proved and probable CSG reserves are increasing even faster than production rates—from 3176 PJ at the end of 2004 to 17 599 PJ in May 2009. Most reserves are in Queensland, but there is also

significant growth in New South Wales (figure E.7). There are also substantial volumes of higher risk possible reserves (24 566 PJ) and contingent resources (32 319 PJ). Table E.3 summarises the details.<sup>9</sup>

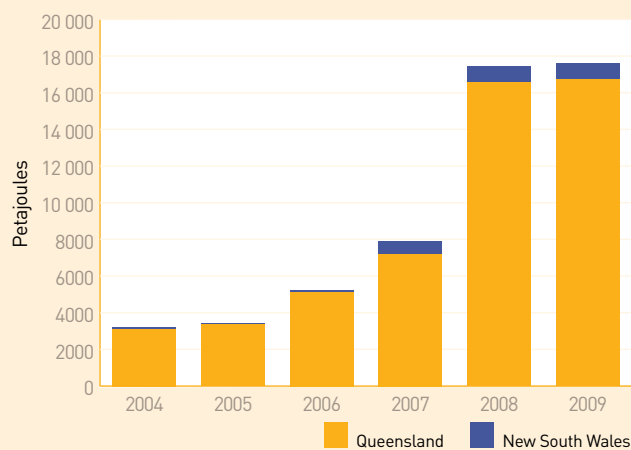
9 *Proved and probable reserves (2P)* are those that geoscience and engineering data indicate are more likely than not to be recoverable. There is at least a 50 per cent probability that the quantities recovered will equal or exceed the sum of estimated proved plus probable reserves. *Possible reserves* are those that are recoverable to a low degree of certainty (10 per cent confidence). There is relatively high risk associated with these reserves. *Proved plus probable plus possible reserves* are also known as 3P or P10. *Contingent resources* are those estimated, at a given date, to be potentially recoverable from known accumulations, but not considered to be commercially recoverable.

**Table E.3 Gas reserves and resources—eastern Australia, May 2009**

| GAS BASIN                    | BOOKED RESERVES (PETAJOULES) |               | RESOURCES (PETAJOULES) |                             | 2008 PRODUCTION (PETAJOULES) |
|------------------------------|------------------------------|---------------|------------------------|-----------------------------|------------------------------|
|                              | PROVED AND PROBABLE          | POSSIBLE      | CONTINGENT             | SPECULATIVE POTENTIAL       |                              |
| Cooper (South Australia)     | 1 138                        |               | 6900                   |                             | 140                          |
| Otway (Victoria)             | 1 416                        |               | 205                    | 2000-4000                   | 110                          |
| Bass (Victoria)              | 306                          |               | 420                    | Underexplored               | 16                           |
| Gippsland (Victoria)         | 5 637                        |               | 3000                   | Possible upside             | 261                          |
| East Queensland conventional | 144                          |               |                        |                             | 19                           |
| Queensland CSG               | 16 708                       | 22 141        | 29 094                 | Possible significant upside | 130                          |
| New South Wales CSG          | 891                          | 2 425         | 3225                   | Possible significant upside | 5                            |
| <b>Total</b>                 | <b>26 240</b>                | <b>24 566</b> | <b>42 844</b>          |                             | <b>681</b>                   |

Source: EnergyQuest.

**Figure E.7 Coal seam gas—proved and probable reserves**



Source: EnergyQuest.

A key reason for the rapid growth in CSG reserves and resources has been a greater understanding of the nature of Queensland CSG, which has helped stakeholders identify the most suitable resources and understand how best to exploit them. There has been a continuing accumulation of geoscience and engineering data from producing fields and from the large number of wells being drilled. Around 600 new wells were drilled in 2008.

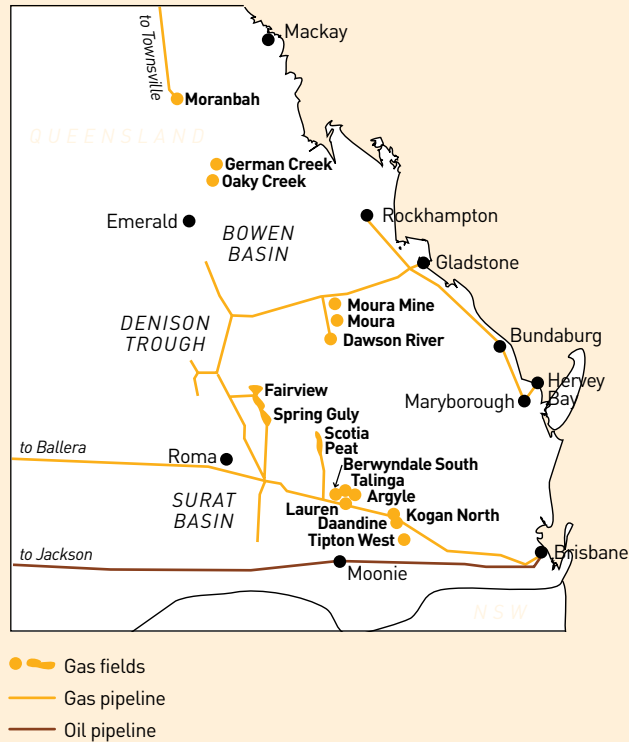
In addition, higher gas price assumptions play a role. Estimates of reserves and resources are sensitive to assumptions about future gas prices. The higher the price, the larger is the resource base that can be commercialised. In particular, the bookings of contingent resources are generally premised on the assumption that significantly higher gas prices can be achieved from LNG developments.

### E.2.1 Australian regions that produce coal seam gas

Coal seam gas is produced from the bituminous coals of the Bowen and Sydney basins and the sub-bituminous coals of the Surat Basin. There is also exploration and early commercialisation in the Clarence-Morton, Gunnedah and Gloucester basins in New South Wales.

The major Queensland fields are shown in figure E.8. In 2008 Spring Gully had the largest production (36 PJ), followed by Berwyndale South (27 PJ) and Fairview (22 PJ). Spring Gully and Fairview are in an area known as the Comet Ridge. Berwyndale South is on the Undulla Nose.

**Figure E.8**  
Coal seam gas fields—Queensland

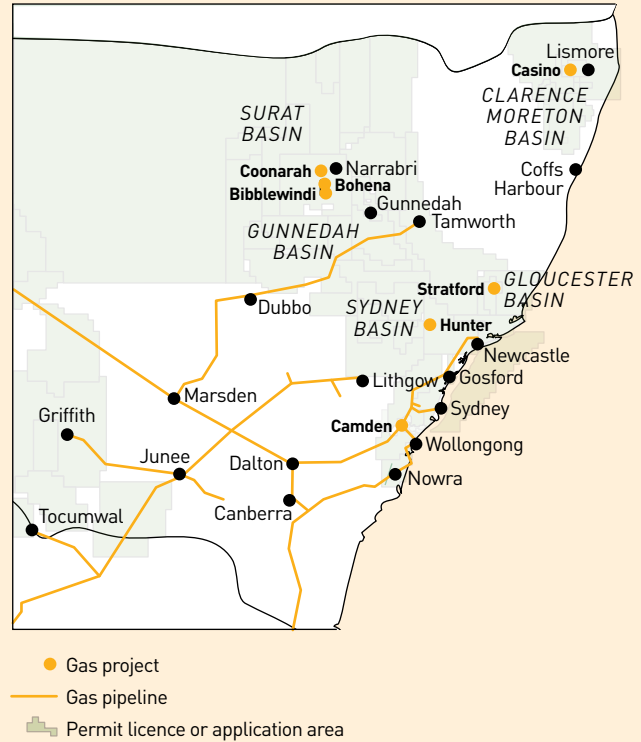


Source: EnergyQuest.

Spring Gully (operated by Origin Energy) has contracts with Queensland customers and with AGL Energy for gas sales to the southern states. Origin Energy is building a 630 megawatt combined cycle power station to be supplied from Spring Gully and its Walloon acreage. The new station, located on the Darling Downs near Braemar, is expected to commence operating in 2010. Berwyndale South (operated by BG Group) commenced production in 2006 and supplies various Queensland power stations. BG also has gas contracts with AGL, which has completed a pipeline from Berwyndale South to Wallumbilla, to join with the South West Queensland and QSN Link pipelines to supply gas to the southern states.

Fairview (operated by Santos) has contracts with Queensland customers and also with Origin Energy for supply to AGL Energy for transport to the southern states.

**Figure E.9**  
Coal seam gas projects—New South Wales



Source: EnergyQuest.

Arrow Energy operates four producing fields:

- > Moranbah (operated by Arrow Energy in joint venture with AGL Energy) commenced production in 2004 and supplies gas to the Townsville Power Station.
- > Kogan North commenced production in 2006. Gas from the field is contracted to CS Energy for the Swanbank E Power Station.
- > Daandine and Tipton West commenced production in 2007. Daandine supplies gas to a power station development, and Tipton West is contracted to Braemar Power.

There is also considerable interest in the CSG potential of the vast coal resources in New South Wales (figure E.9). Active CSG exploration and appraisal are continuing in northern New South Wales in the Gunnedah and Clarence-Morton basins. Santos considers the Gunnedah Basin may contain 40 000 PJ of recoverable gas. There has also been success in the Gloucester Basin, near Newcastle.

AGL Energy operates the Camden gas project in the Sydney Basin. This project, which is being expanded, produced just over 5 PJ in 2008.

Success with CSG in New South Wales would be significant, given the state's historical reliance on gas imported from interstate. The potential for New South Wales CSG will become clearer over the next few years.

## E.2.2 Liquefied natural gas proposals

Until 2007 the focus of CSG development was on the Queensland domestic market, particularly on gas for power generation. Many early CSG contracts were for the Swanbank and Braemar power stations. In the past two years it became apparent that eastern Australia has considerably more CSG potential than can be commercialised for the domestic market alone. The supply curve for CSG is quite sensitive to price, and the CSG resource base that could be commercialised at LNG prices is significantly greater than could be developed at historic east coast prices. This has led to a shift in focus to the LNG market.

Four major LNG projects are proposed for Gladstone in Queensland (totalling 39 million tonnes per year). In 2007 Santos and Arrow Energy announced LNG development plans. Queensland Gas Company (later acquired by BG Group) and Origin Energy followed suit in 2008. (Table E.1 summarises details.) There are also smaller proposals.

While these plans were originally greeted with scepticism in Australia, they offered opportunities to major international LNG companies looking for substantial gas resources in the Asia Pacific region (the largest and fastest growing LNG market in the world), with low barriers to entry and low exploration risk. Accordingly, the Australian proponents were joined in 2008 by major international companies Petronas, Shell, BG Group and ConocoPhillips. In total, these entities spent around \$20 billion to acquire CSG interests.

- > Origin Energy entered an alliance with ConocoPhillips to develop a four train LNG project with ultimate capacity of 16 million tonnes per year,

requiring more than 25 000 PJ of gas over 30 years. As part of the transaction, ConocoPhillips acquired 50 per cent of Origin Energy's CSG interests.

- > BG Group acquired Queensland Gas Company (which had acquired Sunshine Gas and Roma Petroleum). It has since also acquired Pure Energy, and is developing an LNG project with initial production capacity of 7.4 million tonnes of LNG a year. It is seeking approval for capacity of 12 million tonnes per year.
- > Santos entered an alliance with Petronas to develop its proposed Gladstone LNG project, targeting up to 10 million tonnes per year. As part of the arrangement, Petronas acquired 40 per cent of Santos's CSG interests.
- > Shell acquired a 30 per cent interest in Arrow Energy's CSG fields. Arrow Energy has agreed to supply sufficient gas for up to 3 million tonnes per year of LNG for the project proposed for Fisherman's Landing at Gladstone.

New entry has led to extensive industry consolidation over the 18 months to June 2009. As noted, Queensland Gas Company, Pure Energy, Sunshine Gas and Roma Petroleum are now all part of the BG Group. AGL Energy, Origin Energy and Arrow Energy have also acquired various interests. At the same time, total CSG reserves have grown significantly, and the interest in CSG has encouraged a flurry of interest in exploration and in new basins.

The entry of major international companies is a significant development, underlining their confidence in both the future demand for LNG and the quality of Queensland CSG resources. Notwithstanding the softening of immediate LNG demand, the four major LNG projects proposed for Gladstone are all pushing ahead (and with further interest from Shell and other companies). There is an increasing likelihood of LNG exports from Gladstone, with three of the four major projects at the FEED stage and having gas sale contracts in place. All four are aiming for FID by late 2010 (table E.1).

The degree of confidence has been highlighted by the decisions of Petronas and the Chinese company CNOOC to buy Australian CSG based LNG for the Malaysian and Chinese markets.

If all successful, these LNG projects could require 2750 PJ of gas per year—more than Australia's total current gas production of 1600 PJ per year—and CSG reserves of at least 55 000 PJ. Queensland's proved, probable and possible reserves in May 2009 stood at 38 849 PJ, with a further 29 094 PJ of contingent resources.

A number of challenges are associated with using CSG for LNG. There is no associated liquids production (which improves the economics of conventional LNG projects); the gas has lower energy content than that of conventional LNG; and the process of managing the CSG production profile to meet LNG production requirements is more complicated.

Water disposal and treatment is a particular issue and is becoming a significant cost. In 2007 Queensland CSG fields produced 12.5 billion litres of water. The quality of the water can vary from drinkable to highly saline. Water production is now around 22 billion litres and could grow to 250–480 billion litres per year if LNG development reaches annual production of 40 million tonnes.<sup>10</sup>

The CSG proposals are competing with conventional LNG projects proposed for Australia and Papua New Guinea, all involving large scale gas resources and experienced international LNG participants. A number of these competing projects are progressing quickly. Conventional LNG projects can also have various challenges, however, depending on the field. Some fields contain significant quantities of carbon dioxide. Others may have a low concentration of liquids, significant water depth, distance from shore or remoteness of location.

### E.2.3 Implications for the domestic gas market

With four major east coast LNG projects aiming for FID by late 2010, there have been concerns that prices for new domestic gas contracts may rise close to international levels, as has occurred in Western Australia. There are some similarities between the Queensland and Western Australian market contexts.

In each case:

- > the LNG market is potentially larger than the domestic market
- > the bulk of gas resources is owned by a small number of entities targeting LNG exports.

One important difference relates to the amount of 'ramp-up' gas likely to be produced by the east coast projects. LNG projects require substantial annual gas volumes of around 200 PJ per year for each train. In a conventional LNG project, this requirement may be met by six or eight gas development wells that would be drilled and then shut in until the plant is ready for commissioning. Providing the same gas volumes from CSG may require 500–700 wells, however, given the much lower flow rates per well. Drilling this number of wells may take a couple of years, rather than a few months. Each well then has to 'ramp up', first producing water and then increasing volumes of gas. This may take months for each well.

Once a CSG well is in production, it is generally difficult to shut it in without having to start the process again. The result is that substantial volumes of 'ramp up' gas are likely to be produced in the lead-up to the commissioning of Queensland's CSG-LNG projects. In the short to medium term, this is likely to mean that increased supplies of gas will be available at relatively low prices for domestic purposes such as power generation. There is evidence, however, that domestic buyers are already finding it difficult to secure long term gas supply commitments beyond the likely start-up times for LNG projects.<sup>11</sup>

10 M Helmuth, 'Developing Queensland's CSM and LNG industries: a Queensland Government perspective', Paper presented at the FutureGas Conference, Brisbane, 22 March 2009.

11 Rio Tinto, *Energy white paper submission*, 11 June 2009, [www.ret.gov.au/energy/Documents/ewp/pdf/EWP%200102%20DP%20Submission%20-%20Rio%20Tinto.pdf](http://www.ret.gov.au/energy/Documents/ewp/pdf/EWP%200102%20DP%20Submission%20-%20Rio%20Tinto.pdf).

While real prices may rise in the medium to longer term, this would likely increase gas supply for both LNG and domestic markets. Experience has been that higher gas prices lead to substantial increases in the volume of commercially viable CSG.

Any significant increase in demand (such as would occur from LNG exports) over the long term, however, is likely to raise production costs. In particular, the resources targeted for LNG projects are among the highest quality, and using these for LNG may force domestic use towards lower quality/higher cost reserves. This would put upward pressure on prices. The use of CSG for LNG will also tighten the gas demand-supply balance generally.

A number of features of east coast markets may cushion price impacts. Unlike Western Australia, the east coast has a number of gas basins, with greater diversity of supply. There is substantial exploration acreage with relatively low barriers to entry, and an extensive gas transmission network linking the producing basins.

### E.3 Climate change policies

Climate change is a third global influence impacting on energy markets. While natural gas is a fossil fuel, it can produce large volumes of reliable baseload electricity with around half the greenhouse emissions of coal. Increased use of gas in electricity generation is likely, therefore, to form part of the suite of responses needed to shift economies to a lower carbon footprint. In particular, gas can play an important role as a transition fuel. Its increased use can avoid the locking in of higher emissions from coal fired generation, thereby buying more development time for other clean energy solutions to grow.

The Garnaut climate change review predicted the introduction of emissions trading would lead to an increased role for gas in power generation in Australia.<sup>12</sup> This would imply substantial increases in demand

for natural gas. In 2007–08 Australia produced 30 terawatt hours of gas fired power, consuming 307 PJ of natural gas.<sup>13</sup> According to Australian Treasury estimates published in December 2008, gas fired power generation could increase to 60–64 terawatt hours by 2020 under the Garnaut scenarios. This would increase gas demand to 530–560 PJ—a doubling of current gas use in power generation.<sup>14</sup>

The Garnaut review also predicted greenhouse mitigation policies overseas would expand opportunities to export gas. It expected, however, that while gas use would continue to grow in absolute terms, its role may be constrained beyond 2020 as rising permit prices make renewable sources and coal with carbon capture and storage more competitive.

The International Energy Agency came to similar conclusions. It projected continued global growth in the longer term use of natural gas under carbon abatement scenarios—but at a slower rate than under business-as-usual conditions. The agency projected that if greenhouse gases are stabilised at 450 parts per million, gas demand would grow at an average rate of 0.9 per cent per year over the period to 2030—half the rate of growth under business-as-usual conditions.<sup>15</sup> A high carbon price would make low carbon generation more attractive than gas. Rising electricity prices in the residential sector would encourage energy efficiency and renewable investment, which reduce the use of fossil fuels.

These projections rely on assumptions about long term energy prices, carbon prices, the outcomes of future research and development, and costs of competing forms of energy—all of which are subject to considerable uncertainty. In particular, the long term economics and operational performance of carbon capture and storage (and of some renewable energy technologies) are not known with certainty. In contrast, gas has a proven record as a reliable supplier of relatively clean baseload power on a large scale.

12 R Garnaut, *The Garnaut climate change review: final report*, Canberra, October 2008, p. 498.

13 ESAA, *Electricity gas Australia*, Melbourne, 2009.

14 MMA, *Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets*, Report to Federal Treasury, Melbourne, December 2008. The spread of outcomes reflects different emissions target scenarios. See R Garnaut, *The Garnaut climate change review: final report*, Canberra, October 2008, p. 296.

15 International Energy Agency, *World energy outlook 2008*, Paris, 2008.



Governments in Australia and overseas have tended to focus on the development of renewables and low emission coal technologies, rather than gas, as preferred long term options for reducing greenhouse emissions.<sup>16</sup> The 2009 Australian Government budget, for example, allocated \$4.5 billion to support the growth of clean energy generation and new technologies, including \$2.4 billion for clean coal technologies and \$1.3 billion for solar technology.<sup>17</sup>

Consistent with this, the Australian Government has expanded the renewable energy target. The expanded scheme aims to increase renewable energy generation to 20 per cent of all generation by 2020 (an increase from the current level of around 20 terawatt hours to 60 terawatt hours). The Australian Treasury noted that one likely effect of the expanded scheme would be to 'crowd out' gas fired generation.<sup>18</sup>

In its 2008 report to Treasury, McLennan Magasanick Associates estimated that in the absence of mandated renewables, there would be 62 terrawatt hours of gas fired generation by 2020 under the proposed Carbon Pollution Reduction Scheme (assuming a 5 per cent targeted reduction in emissions from 2000 levels). With mandated renewables, gas fired generation would be around 59 terrawatt hours, regardless of whether the targeted reduction in emissions is 5 or 15 per cent from 2000 levels.

The future role of gas depends on the prices of gas, coal and carbon. For existing power stations, coal is still much cheaper than gas, ranging from less than \$0.50 per gigajoule in Victoria to \$1.50–2.00 in New South Wales and Queensland.<sup>19</sup> If ramp-up gas from LNG projects keeps gas prices low on the east coast, then gas could be competitive for power generation. Likely higher gas prices once LNG projects commence, however, would make gas less competitive.

Higher carbon prices favour gas over coal but give renewables an advantage. Some major gas users—such as aluminium and cement—are also emissions intensive, and their treatment under the Carbon Pollution Reduction Scheme will affect gas demand.

Gas is likely to play an important role under climate change policies in complementing intermittent renewable electricity generation. Wind generation—the likely primary renewable technology to 2020—has intermittent output and must be backed up by other generation. Open cycle gas plants can respond quickly when there is insufficient wind generation, but any new plant is likely to operate at relatively low capacity factors. There will also be an increased need for gas transmission and storage to provide gas at short notice.

In addition to the impacts of climate change policies on gas use for electricity generation, there may be implications for the LNG industry. In Asia, climate policies are likely to increase the demand for LNG (and LNG prices) as a cleaner alternative to coal for power generation. At the same time, LNG production creates greenhouse emissions that may be priced under the Carbon Pollution Reduction Scheme. Some gas reservoirs being proposed for Australian LNG projects contain significant volumes of carbon dioxide, and the process of liquefaction also emits carbon dioxide. The proponents have plans to manage these emissions, but have also sought relief under the proposed Carbon Pollution Reduction Scheme.

#### E.4 Global financial crisis

The global financial and economic crisis is a fourth global influence potentially affecting Australian gas markets. Overseas, the recession has led to a significant easing in the demand for gas. Australian LNG exports have increased against this trend, with a fifth train on the North West Shelf recently becoming

16 J Snyder, 'Natural gas companies challenge coal industry on climate change bill', *The Hill*, 29 July 2009, <http://thehill.com/business--lobby/natural-gas-companies-challenge-coal-industry-on-climate-change-bill-2009-07-29.html>.

17 Hon. M Ferguson, Minister for Resources and Energy (Australian Government), Speech to Queensland Resources Council, Rockhampton, 20 July 2009, <http://minister.ret.gov.au/TheHonMartinFergusonMP/Pages/QUEENSLANDRESOURCECOUNCIL.aspx>.

18 Australian Treasury, *Australia's low pollution future: the economics of climate change mitigation*, Canberra, October 2008, p. 181.

19 ACIL Tasman, *Fuel resources, new entry and generation costs in the NEM*, Report to AEMO, Melbourne, April 2009.

fully operational. Domestically, the downturn does not appear to have significantly affected east coast gas consumption.

Billions of dollars are needed to fund the suite of proposed Australian upstream developments, processing facilities and infrastructure. So far, the signs are that companies have been tightening their belts but not deferring or cancelling gas developments in the context of lower revenues and tighter financial markets.

Companies typically finance development projects from:

- > cash flow
- > asset sales and/or cuts to exploration
- > debt raising
- > equity raising.

While many Australian upstream oil and gas companies have reasonably strong balance sheets, the recent fall in commodity prices has reduced their capacity to fund new developments. This has led a number of upstream companies to sell non-core assets, look for partners and reduce exploration spending.

Generally, the credit ratings of oil and gas companies operating in Australia have been largely unaffected by the crisis, although Standard and Poor's outlook for Woodside's long term A- rating was revised from stable to negative. The agency said this revision reflected the fall in oil prices and ongoing funding requirements for Woodside's Pluto LNG project.

In relation to debt raising, companies typically seek bank funding, issue bonds or seek project financing. Generally, the global financial crisis has increased the cost of debt and reduced its availability. In particular:

- > banks have become more inward focused as they give priority to resolving their own financial positions. This behaviour has included withdrawal from some offshore markets, including Australia.
- > banks have less capital and are using it cautiously
- > banks are repricing risk across the credit curve, reflecting increases in their own funding costs

- > banks have been giving priority to supporting key existing customers and attractive new clients
- > more banks are needed to fund any one transaction
- > borrowing terms have been reduced, typically to three years, and interest costs have more than doubled.<sup>20</sup>

Companies operating in Australia's gas sector have nonetheless been able to raise debt. In May 2009 Woodside announced it had executed a US\$1.1 billion syndicated loan facility with 26 banks—a large number. This followed a US\$1 billion issue in the US bond market in February 2009. Interest spreads, however, have typically been around 400 basis points over the five year swap rate, giving an overall funding cost of 9–10 per cent.

AGL Energy has successfully refinanced its 2009 and 2010 debt maturity obligations of \$800 million but at a cost of 280 basis points over the relevant base rates, and requiring the participation of Australia's four major banks and 13 offshore banks.

Pipeline companies have generally been more negatively affected than upstream gas companies by higher borrowing costs and reduced financing availability. In particular, the higher gearing of pipeline companies has made it more difficult for them to obtain finance for new projects at an acceptable cost. A proposed expansion of the South West Queensland Pipeline to provide capacity for Origin Energy, for example, was subject to obtaining the necessary funding on acceptable commercial terms. The availability of project finance is also reported to have shrunk. A year ago industry found it relatively easy to source project finance for a gas fired power station project, but this is no longer the case.

The other financing option for companies is to raise equity. Santos raised \$3 billion of new equity from institutional and retail investors to fund its commitments to the Papua New Guinea LNG project and to redeem a previous issue. This was successful but was made at a 27 per cent discount to the previous share closing price.

20 Based on EnergyQuest discussions with market participants. See also: S3 Advisory, *Financing of future energy sector investments in Australia: the potential effects of the Carbon Pollution Reduction Scheme and Renewable Energy Target*, Report prepared for the AEMC, Sydney, December 2008; and I Little, *Envestra open briefing*, Adelaide, 8 July 2009.



Peter Hendrie (Getty Images/Photographer's Choice)

There has also been an increase in the number of assets offered for sale. Companies are reviewing their portfolios and disposing of non-core assets to fund core projects. While there have been some sales by distressed buyers, however, there has not been a flood of properties onto the market, and competition has been keen for those that have come up for sale.

Generally, financing is much more difficult and expensive than it was before 2007, but this has not yet stopped any major gas projects. Financing conditions in the gas sector appear to be mostly more favourable than, for example, conditions for refinancing coal fired power stations.

### E.5 Security of gas supply

Security of gas supply is a critical issue globally and one of the key drivers of LNG demand—particularly in Europe, which depends on Russian gas supplies.

Australia’s Department of Resources, Energy and Tourism recently reviewed Australia’s natural gas security.<sup>21</sup> It assessed security as being only ‘moderate’ through to 2023 on three criteria: adequacy, affordability and reliability.<sup>22</sup> It found affordability to be currently ‘high’, but with the potential to fall to ‘low’ by 2018. The department assessed the current adequacy of natural gas supplies readily available for domestic consumption as ‘moderate’ on the east coast but ‘low’ in Western Australia.

With only two major gas producing facilities and one major pipeline to Perth, Western Australia is vulnerable to gas supply disruptions. The structural shortage of domestic gas in Western Australia was exacerbated by a pipeline rupture and fire at Varanus Island on 3 June 2008, which curtailed 30 per cent of the state’s gas supply. Production was shut in from both the Harriett and John Brookes fields. Major gas and electricity customers—such as Alcoa, Newcrest, Iluka, Rio Tinto, BHP Billiton, Oxiana, Newmont, Alinta, Verve Wesfarmers and Burrup Fertilisers—

were affected. There was substantial switching to North West Shelf gas (an extra 50 terajoules per day of output, which was limited by transmission pipeline capacity) and diesel, while major gas users brought forward maintenance. The Western Australian Government also recommissioned the coal fired Muja AB power station at Collie, freeing up 75 terajoules per day of gas supply for other users. A total 150 terajoules per day of additional gas was sourced, including gas surplus to requirements or capable of being freed up through use of diesel.

The Western Australian Treasury estimated the crisis cost the state economy \$2 billion. The Reserve Bank of Australia estimated a reduction in state economic output of 3 per cent for the duration of the incident, and a reduction in Australian gross domestic product growth of 0.25 per cent in the June and September quarters of 2008.<sup>23</sup> It has taken 12 months to repair the Varanus Island facilities and return to pre-incident production rates. The Western Australian Government is reviewing the security of the state’s gas supplies.

The east coast is now much less vulnerable to supply disruptions than is the west coast. East coast gas markets have continued to evolve rapidly, with a range of new supply sources. Historically, most east coast gas was supplied from two sources: the Gippsland Basin in offshore Victoria and the Cooper Basin in north east South Australia. The basins are still important, with Gippsland supplying 37 per cent of east coast gas in 2008 and the Cooper Basin supplying 20 per cent. East coast supply is now more diversified, however, with almost 20 per cent of east coast gas supplied from the Otway and Bass basins in offshore Victoria and 23 per cent supplied from Queensland CSG fields.

The east coast transmission pipeline system also continues to expand. Sydney, Melbourne, Adelaide and Canberra are now each served by transmission pipelines connecting multiple gas basins. Until early 2009 there was no pipeline between Queensland and the southern states, but this has now been rectified

21 Department of Resources, Energy and Tourism (Australian Government), *National energy security assessment*, Canberra, 2009.

22 The possible assessments are ‘high’, ‘moderate’ and ‘low’.

23 Senate Standing Committee on Economics (Australian Senate), *Matters relating to the gas explosion at Varanus Island, Western Australia*, Canberra, 2008.

with the completion of the QSN Link from Ballera in Queensland to Moomba in South Australia. The QSN Link and the associated South West Queensland Pipeline are also being upgraded. Stage 1 of the South West Queensland Pipeline expansion is fully contracted from 2009 at up to 168 terajoules per day. AGL Energy has exercised an option for a stage 2 expansion, with gas deliveries commencing by 1 January 2013. This will take capacity to 220 terajoules per day. Origin Energy subsequently committed to a transportation agreement that will underpin an increase in capacity to 380 terajoules per day. This will enable Origin Energy to transport its CSG to southern markets. These arrangements will make the South West Queensland Pipeline/QSN Link one of Australia's largest gas transmission pipeline systems.

## E.6 Conclusion

Australia is becoming a gas supplier of international significance on the back of its rapidly expanding resource base. It is now among the top 10 nations in terms of gas reserves and resources—with over 200 000 PJ—and in the next decade will likely become a major international producer. A significant driver has been gas price expectations. The Australian experience shows gas supply is highly price elastic. Rising price expectations are encouraging major investment in exploration and infrastructure.

The development of LNG will potentially benefit Australia's terms of trade, economic growth and employment. A significant benefit may be the buffer that LNG can provide against our declining oil production. Australia is relatively oil intensive by international standards.<sup>24</sup> Crude oil is Australia's largest import, followed by refined petroleum products.<sup>25</sup> Australia's self-sufficiency in oil and liquid

fuels is 60 per cent and likely to decline further. This dependence exposes the economy to the risk of rising oil prices—something to which it has been relatively immune since the discovery of oil in the 1950s.

There are options for reducing this exposure, including increasing the efficiency of oil use and the development of liquid fuels from Australia's bountiful resources of shale and coal. That LNG development plans are progressing rapidly and have not been greatly affected by the global financial crisis is a positive development in the context of declining oil production and relatively high oil prices by historical standards. Further gas development may be part of the menu for offsetting and reducing Australia's oil vulnerability. As discussed, LNG export prices are indexed to oil prices. While Australia's current LNG exports of almost \$6 billion are only a fraction of our \$33 billion oil imports, LNG growth can help offset oil imports and volatility in the terms of trade due to fluctuating oil prices.

The growth in Australia's gas resources can also provide environmental benefits. While there is great enthusiasm to develop renewables, gas is a proven lower emissions fuel. Despite relatively low domestic prices, Australian gas use still accounts for only 18 per cent of primary energy consumption—low by international standards, and the same as a decade ago.<sup>26</sup> Of the world's largest holders of gas reserves, only Norway makes less use of gas domestically than Australia. In the United States, gas comprises 26 per cent of primary energy consumption; in the United Kingdom, it is 40 per cent. In Japan, which does not have its own gas and relies on relatively expensive imports, gas has a similar share of the primary energy mix as it does in Australia. Indonesia, the world's largest coal exporter and a major oil producer, uses gas for 27 per cent of its energy mix.

24 Geoscience Australia, Submission to the Senate Rural and Regional Affairs and Transport Committee Inquiry into Australia's Future Oil Supply and Alternative Transport Fuels, Canberra, February 2006; Queensland Energy Resources, *Australia's future transport fuel supply options*, Report by ACIL Tasman, EnergyQuest, Rurvin & Gertz and RARE Consulting, Brisbane, 2009.

25 Department of Foreign Affairs and Trade (Australian Government), *Composition of trade Australia 2008*, Canberra, 2009.

26 BP, *Statistical review of world energy*, London, 2009.

The increasing use of gas for domestic purposes—not only in power generation, but also in transport, business and retail applications—would reduce greenhouse emissions and deliver environmental and economic benefits. While wholesale Australian gas prices may rise in real terms, they are likely to remain relatively low compared with prices in gas importing countries.

The world wants and understands the value of Australian gas. The timing may be right for Australian gas to assume a more significant role at home as well as contributing to the energy needs of Asia.