



ENERGYQUEST



**ESAA Domestic Gas Study**

**Stage 1**

**1 September 2010**



This Report is produced by EnergyQuest Pty Ltd, Level 30 91 King William St Adelaide Australia 5000. Any queries should be directed to Dr Graeme Bethune: Telephone +61 8 8431 7903 Mobile +61 419 828 617. This report is confidential and is provided subject to the Terms of Use on Page 51.

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**Cover photograph:**

Process operator at the Santos-operated Fairview coal seam gas processing facility, eastern Queensland, courtesy of Santos. Photograph: Robert Garvey.

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## Summary

- Australian gas demand is driven by gas-fired electricity generation, mining, mineral processing and export demand and forecasts require assumptions about each of these drivers. Supply forecasts require assumptions about exploration success and the rate of conversion of discoveries to reserves.
- Forecasts of domestic gas demand a decade ago tended to assume strong growth in GDP, assumptions for which have since been scaled back. They also assumed strong growth in mineral processing, much of which has not eventuated. On the other hand assumed growth in gas-fired power generation has been growing.
- Gas supply on the east coast has turned out to be much greater than assumed in the past due to the growth of coal seam gas (CSG).
- Current east coast demand forecasts are sensitive to assumptions about economic growth, carbon policy and prices, LNG exports, gas prices and the timing of commercially viable carbon capture and storage (CCS). Forecasts are more sensitive to GDP growth than gas prices. However, some forecasters are now anticipating a downturn in east coast demand next decade due to growth in CCS.
- East coast supply forecasts are sensitive to further exploration success and development in the Bowen and Surat basins and progress in the Gunnedah and Galilee basins, as well as the rate of LNG development.
- WA domestic gas demand (which is expected to double in the next 20 years) is particularly sensitive to gas prices and development of major resources projects. Supply is sensitive to the timing of major LNG projects, which also supply domestic gas.
- As the Australian domestic gas sector is increasingly affected by LNG developments, it is also necessary to make assumptions about LNG demand, which depends on demand from other major economies and Australian competitiveness.
- The Report discusses major factors affecting gas markets.
- Generally the world has seen a revolution in gas supply through unconventional gas. Australia has benefitted so far and may have considerable further potential but how much is not known.
- Oil and gas development costs have increased significantly in recent years and have remained high despite the economic downturn.
- Policies on climate change and renewable energy have significant implications for gas demand. Generally demand is not expected to increase as much as might have been expected, with a shift also from baseload to peaking demand.
- After a long period of stability, there are currently uncertainties about fiscal arrangements. Governments are also becoming more active on acreage management and gas reservation policies.
- The structure of the east coast gas market is also changing and contracting arrangements are also becoming more mature, with more diversity of supply and greater transparency.

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## Terms of reference

In the light of uncertainty in Australia's major domestic gas markets moving forward, the ESAA is commissioning a three-stage domestic gas project. The project will not involve any additional quantitative modelling of Australia's gas markets. Instead it will use publicly available energy market forecasts, any quantitative resources that may be readily available to the consultancy and the knowledge embedded within ESAA's membership to develop a well targeted, qualitative analysis of the major influences on Australia's major domestic gas markets to 2030.

The aim of the project and Stage 1 in particular is to enable ESAA to better understand the outlook for the domestic gas market and the factors that may influence it to promote discussion within its membership, including by members not currently heavily involved in gas, and ultimately to inform its policy positions. The aim of Stage 1 of the project is to inform the remaining two stages of the project and assist in defining their scope.

The project will cover eastern Australia, Western Australia and the Northern Territory and the time horizon is to 2030.

Stage 1 involves a preliminary analysis of the outlook for Australia's major gas markets to identify key areas of uncertainty and/or change moving forward that could materially impact outcomes in Australia's major domestic gas markets to 2030.

This includes a comparative analysis of recent forecasts of domestic gas demand and consumption, gas reserves, gas supply and production, international LNG sales and gas prices (energy only and delivered) to identify variations in assumptions or modelling inputs that have contributed to material divergences in forecast gas market outcomes.

Additionally, this will include an overview of the main features of the current commercial and regulatory environments facing Australia's major gas markets and an assessment of future developments in key areas such as gas supply and transportation contracting, wholesale gas markets, royalties and taxation, energy market settings and climate change policies.

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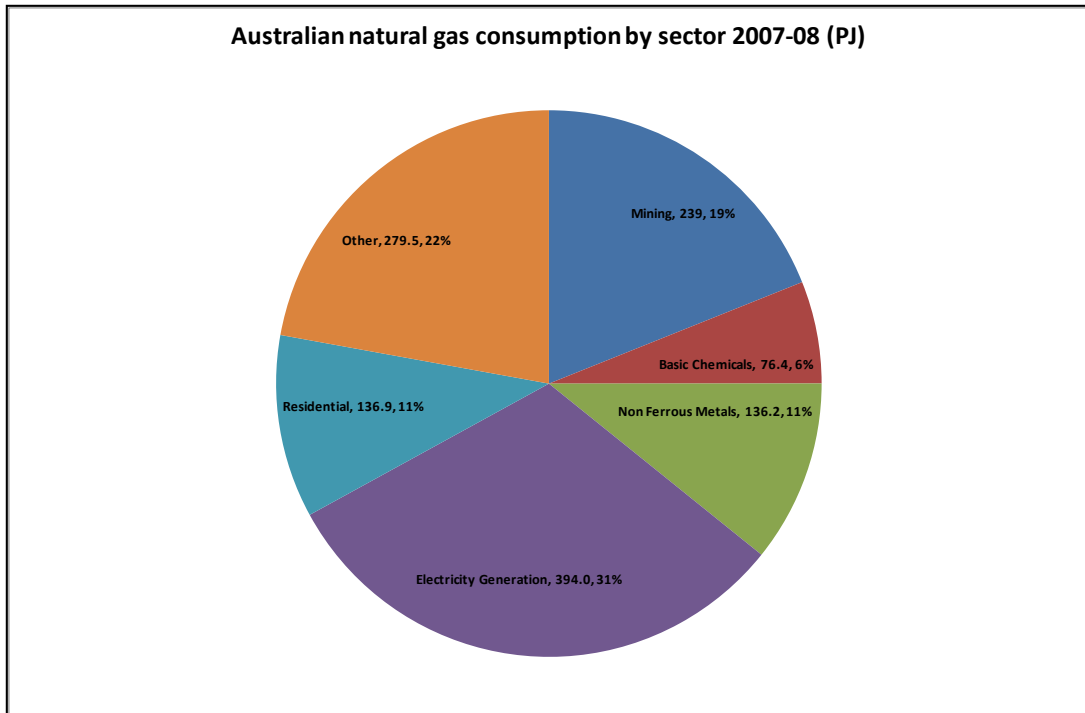
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## 1. Australian gas demand and supply

This analysis starts with a brief profile of current Australian gas demand and supply to highlight the major factors that have traditionally driven sector outcomes.

**Figure 1 Australian natural gas consumption by sector 2007-08**



Source: Australian Bureau of Agricultural and Resource Economics (ABARE)

Figure 1 shows Australian natural gas consumption by industry sector in 2007-08. Gas-use is dominated by Electricity Generation, followed by Mining, Non-ferrous Metals (mainly alumina and aluminium production), Residential Use and Basic Chemicals (mainly fertiliser production). Electricity generation comprised 31% of gas consumption in that year. A large proportion of gas used in mining is also used to generate power, at mine sites.

Figure 2 shows growth in gas consumption since 2000-01. Overall gas demand has grown at an average annual rate of 4.0%. The fastest growth has occurred in Mining (9.6% per annum) and Electricity Generation (7.2%), while Non-ferrous Metals have grown by 2.2% and Residential demand by 1.7%, with Basic Chemicals and Other uses essentially flat. It is important to note that Mining also includes use of gas for upstream processing of gas for domestic uses and export so growth of LNG exports contributes to domestic gas consumption through fuel gas used for liquefaction.

Among Other uses, use of gas has been growing in the Water (11.7%), Construction (5.7%), Cement Production (5.6%), Transport (4.6%), Food (2.3%), Petroleum Refining (1.9%) and Paper Manufacturing sectors (1.3%) but falling in Iron and Steel production and flat or falling in other miscellaneous areas.

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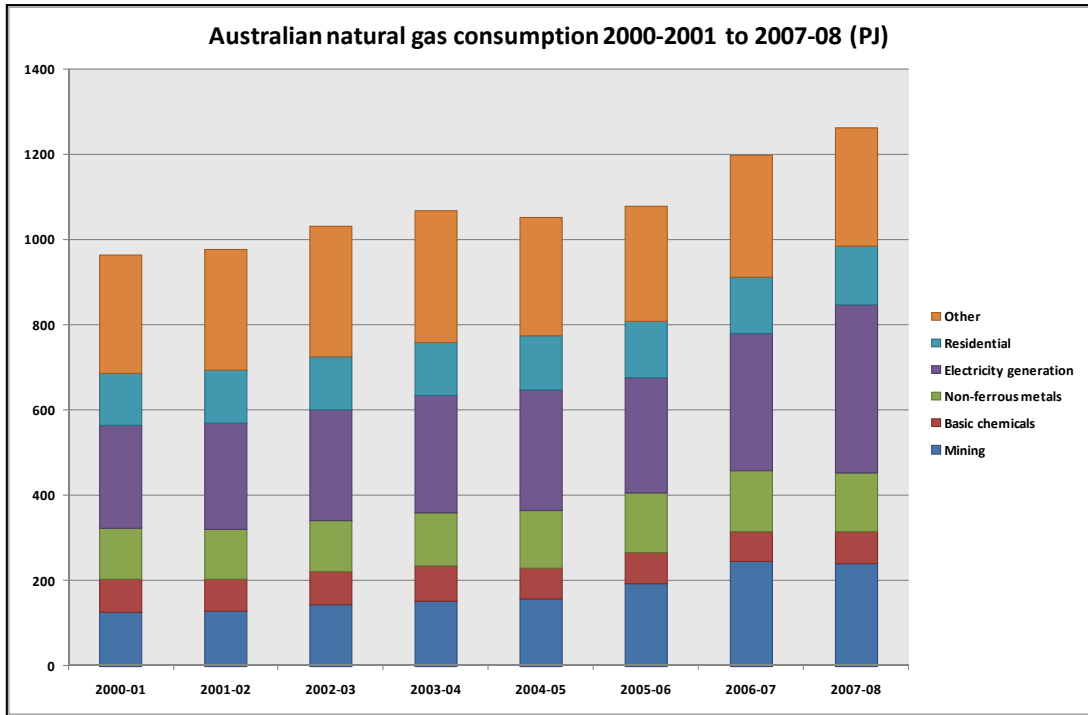
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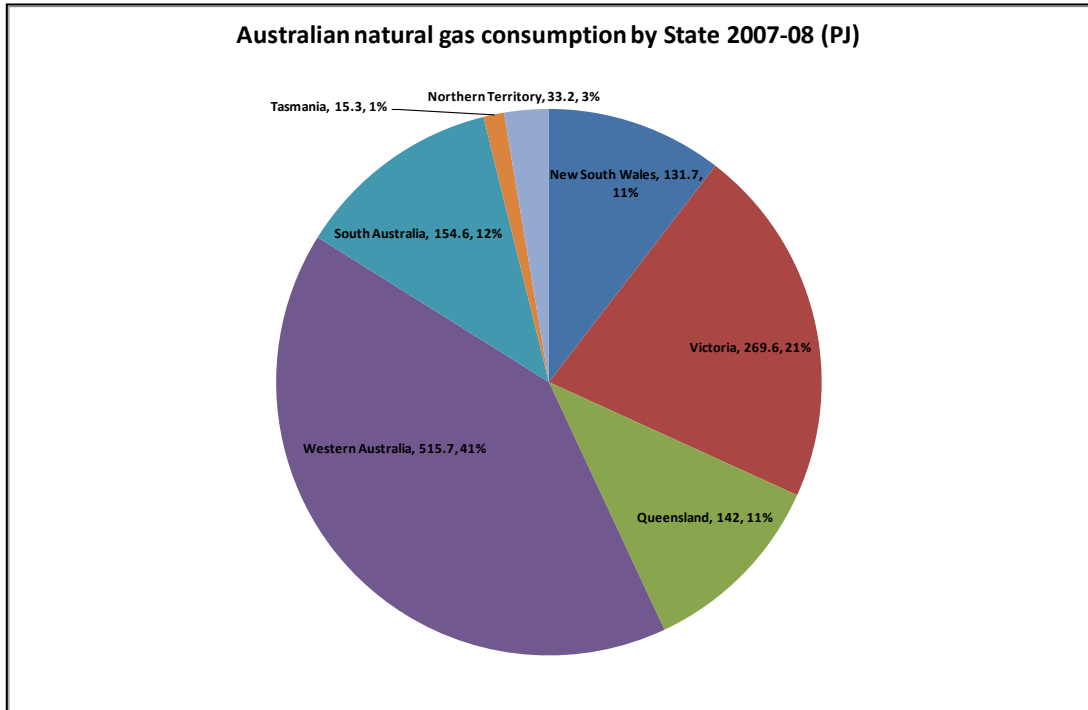


Figure 2 Australian natural gas consumption 2000-01 to 2007-08



Source: ABARE

Figure 3 Australian natural gas consumption by State 2007-08



Source: ABARE

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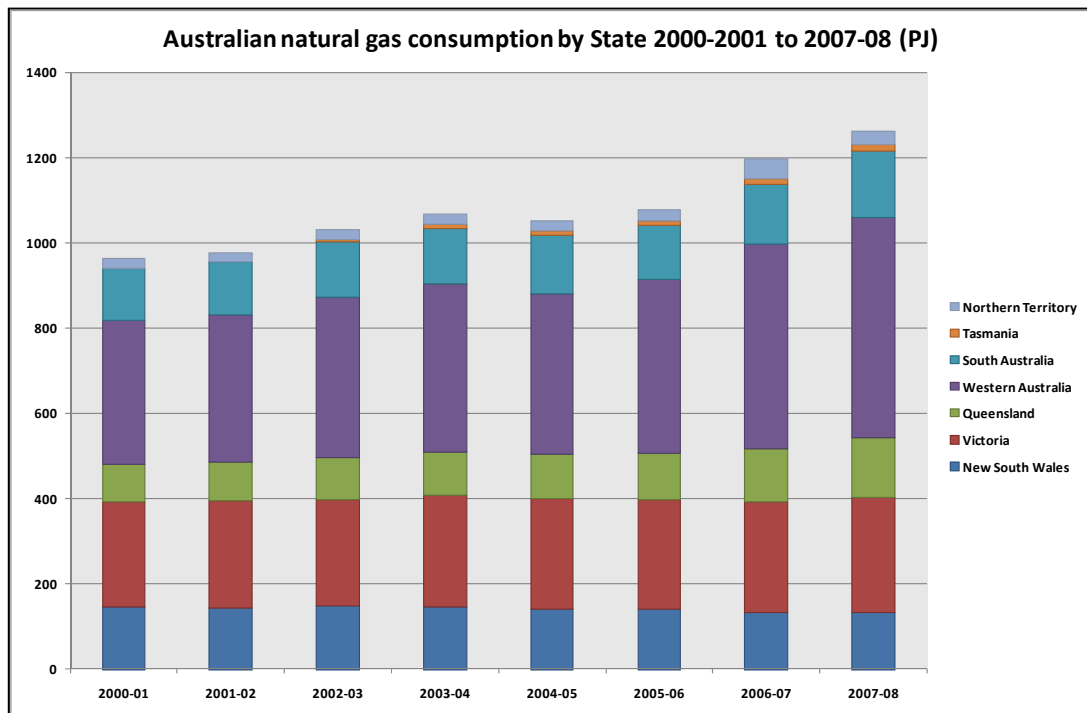


The use of gas and rate of growth in different states reflects the differences in industrial structure and, in the case of electricity generation, availability of alternative fuels (Figure 3).

Western Australia is the largest gas consuming state, with a large mining sector, aluminium and fertiliser industries, petroleum production and reliance on gas for power generation. Gas-use has been growing at an average 6.2% a year since 2000-01 (Figure 4 Australian natural gas consumption by State 2000-01 to 2007-08).

Victoria is the second-largest gas consuming state, with a large residential consumption sector and use of gas in manufacturing but relatively slow growth (1.5% a year) in the absence of significant gas-fired power generation.

**Figure 4 Australian natural gas consumption by State 2000-01 to 2007-08**



Source: ABARE

South Australia is a significant gas-user, particularly for electricity and upstream gas production. According to ABARE, gas consumption has been growing at 3.5% per annum.

Gas-use is growing quickly in Queensland (7.0% per annum), which has now overtaken NSW. Use of gas for power generation has been growing quickly and Queensland also has significant consumption in the aluminium and fertiliser industries and in mining.

NSW has relatively low gas-use due to the predominance of coal for power generation and the fall in gas-use for steel production. According to ABARE gas-use fell over the period to 2007-08, although it has increased since with the commissioning of the Tallawarra and Uranquinty gas-fired power stations.

Tasmania has only had natural gas since 2003, mostly for power generation but with a small residential load.

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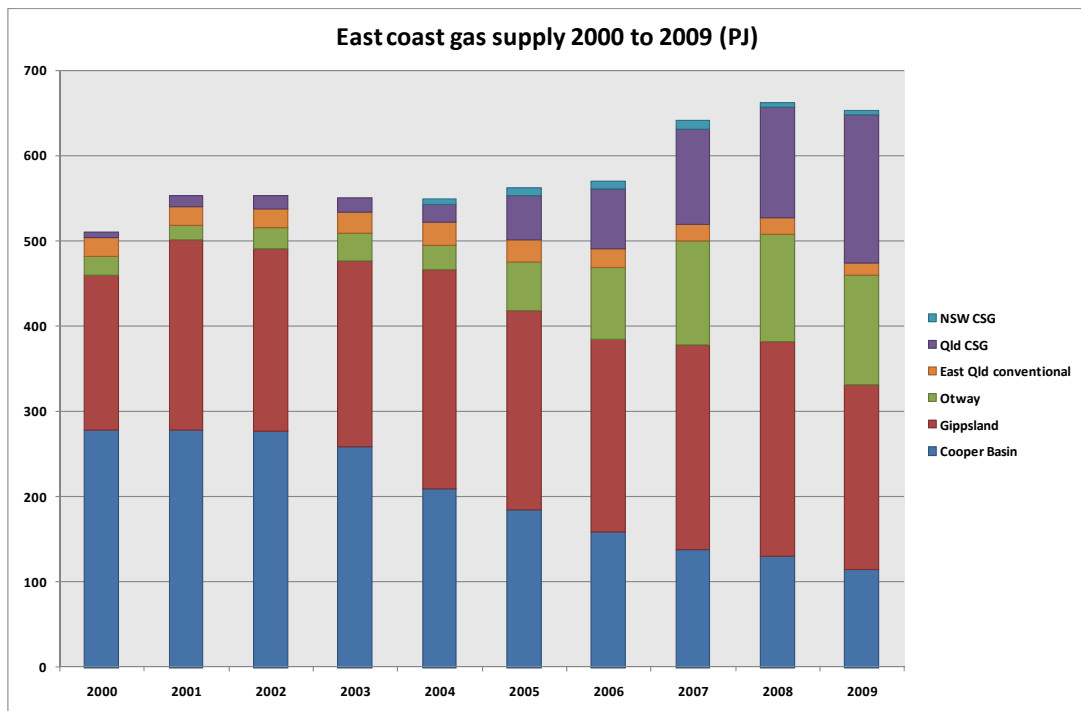
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In the Northern Territory gas is mostly used for power generation for towns and mines, although use has grown through the Darwin LNG plant.

Figure 5 shows the sources of supply on the east coast. Gas supply from the Cooper Basin has been declining, replaced by production from the Otway Basin, offshore Victoria, and Queensland coal seam gas (CSG).

Figure 5 East coast gas supply 2000 to 2009 (PJ)



Source: EnergyQuest

In WA around 60% of domestic gas is supplied from the North West Shelf (NWS), with most of the remainder supplied from the John Brookes and Harriet fields operated by Apache Energy.

Figure 6 shows indicators of east coast gas prices since 2006. The AEMO series is Victorian short-term prices. The Origin series is Origin's average price realised, mostly east coast and comprising both CSG and conventional gas. The APLNG series is the average price realised for CSG in Queensland. The Molopo series is the average price realised by Molopo, a small CSG producer in Queensland. The major trend has been the downward movement in Victorian short-term prices.

Figure 7 shows the average prices in WA under long-term contracts to the NWS and Apache and also some prices under recent contracts. Recent prices are considerably higher than historic contract prices.

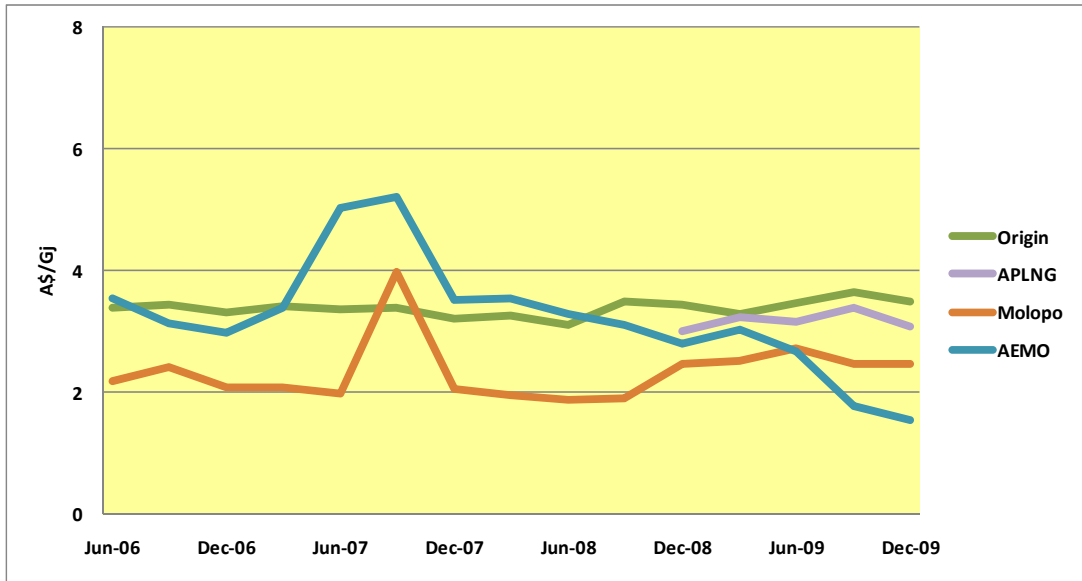
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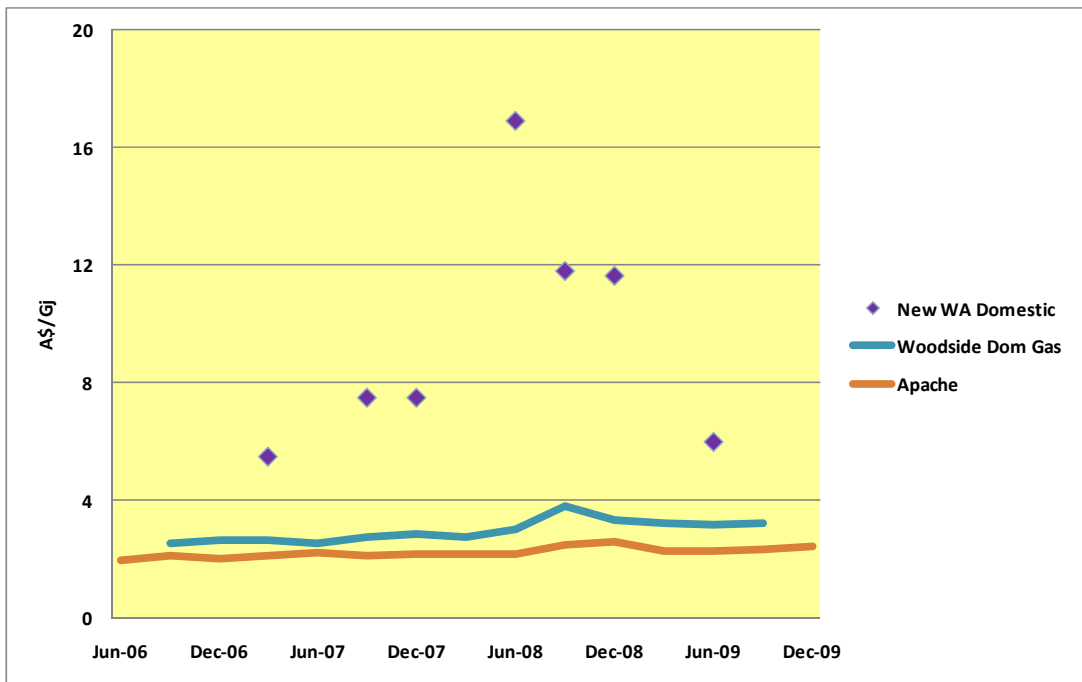
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Figure 6 East coast gas prices (\$/GJ)



Source: EnergyQuest

Figure 7 WA gas prices (\$/GJ)



Source: EnergyQuest

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## 2. Forecasts

Forecasts of natural gas demand, supply and prices are necessary for long-term investment decisions but are subject to considerable uncertainty. Twenty or thirty year forecasts can be dramatically revised within a relatively short period.

This section reviews a range of Australian gas forecasts and the following sections review the demand and supply side factors that determine the outcomes.

### Past forecasts

How have forecasts of gas demand and supply varied over the last decade?

ABARE has produced gas demand and supply projections for many years and these projections provide a useful historical record of how forecasts have changed over time<sup>1</sup>.

Generally demand projections depend heavily on assumptions about growth of gas-fired power generation (which depend in turn on assumptions about carbon prices, renewable energy policies, gas prices and competition from coal) and assumptions about growth of energy-intensive industries such as mining, aluminium, iron and steel and fertilisers.

Over the last decade assumptions about future growth of energy-intensive minerals processing projects have been scaled back while assumptions about gas-fired power generation and use of gas for LNG production have been increasing.

Figure 8 shows ABARE east coast (NSW, Victoria, Queensland, South Australia and Tasmania) demand projections since 2001 together with actual demand (shown by the black line)<sup>2</sup>.

Projections of future demand were continually revised downwards between 2001 and 2007. One source of change has been in assumptions about economic growth. Between 2001 and 2007 the assumed rates of real GDP growth for the projections were revised down from 3.8% to 2.6%, leading to slower growth in energy demand.

The 2001 projections also assumed strong growth in gas-use for east coast mining and manufacturing. In Queensland a range of greenfield and brownfield developments for aluminium, alumina, copper, silver, lead and zinc were assumed and a new 52 500 tonne a year magnesium smelter was assumed for South Australia. The Australian Magnesium Corporation was also assumed to build a 90 000 tonne a year plant in Queensland. A number of these developments failed to eventuate. Gas demand forecasts are very sensitive to assumptions about major energy-intensive development projects, which are difficult to forecast.

Projections of gas-use in power generation were revised upwards between 2001 and 2007. The 2001 projections forecast gas-use nationally in 2019-20 to be 452 PJ, increased to 629

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<sup>1</sup> A distinction is sometimes made between forecasts and projections. ABARE uses the term forecast for shorter-term predictions and projections for longer-term predictions, which by definition are less reliable. Both are predictions of future outcomes. The terms are used interchangeably in this report.

<sup>2</sup> The projections are published in (ABARE, 2001), (ABARE, 2004), (ABARE, 2005) and (ABARE, 2007).

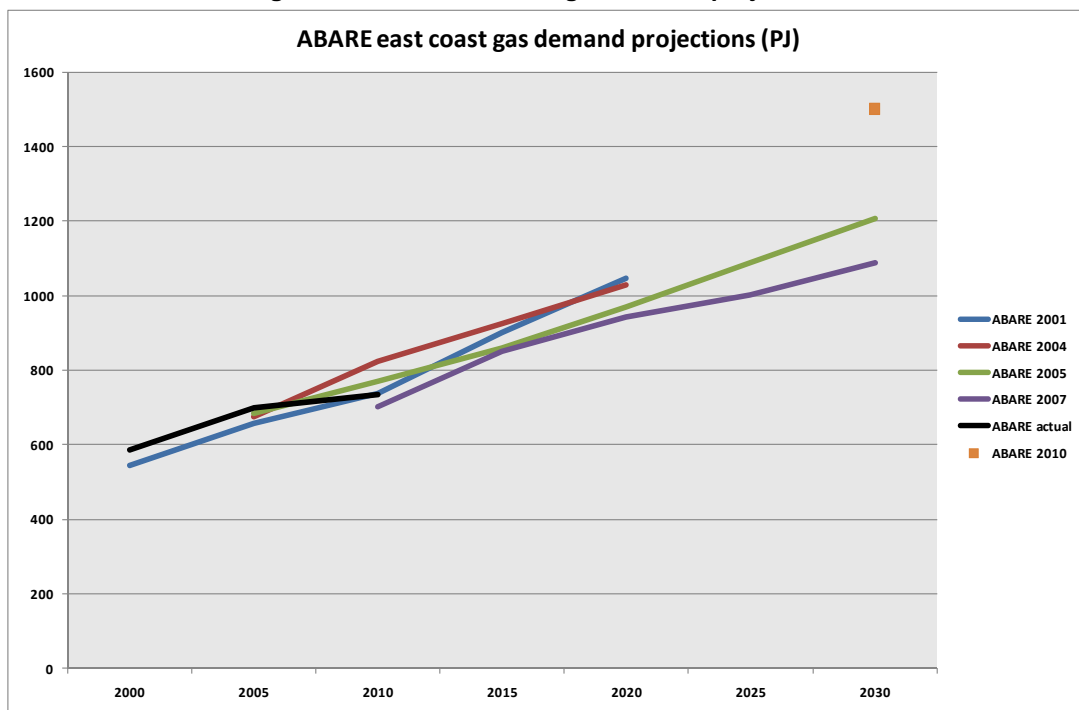
PJ in the 2007 projections. This reflected higher assumed electricity consumption plus a greater share for gas.

Actual demand has tended to be less than the earlier forecasts.

The latest (2010) projections now have a significantly higher level of demand (shown by the brown marker) (ABARE, 2010). These projections include renewable energy targets and assume a 5% reduction in carbon emissions below 2000 levels by 2020.

Unfortunately the latest projections do not provide the same statistical detail as earlier projections but the growth in demand appears to reflect faster growth in gas-fired power generation plus fuel used for 25 million tonnes of east coast LNG production by 2030 (possibly around 150 PJ).

**Figure 8 ABARE east coast gas demand projections**



Source: ABARE

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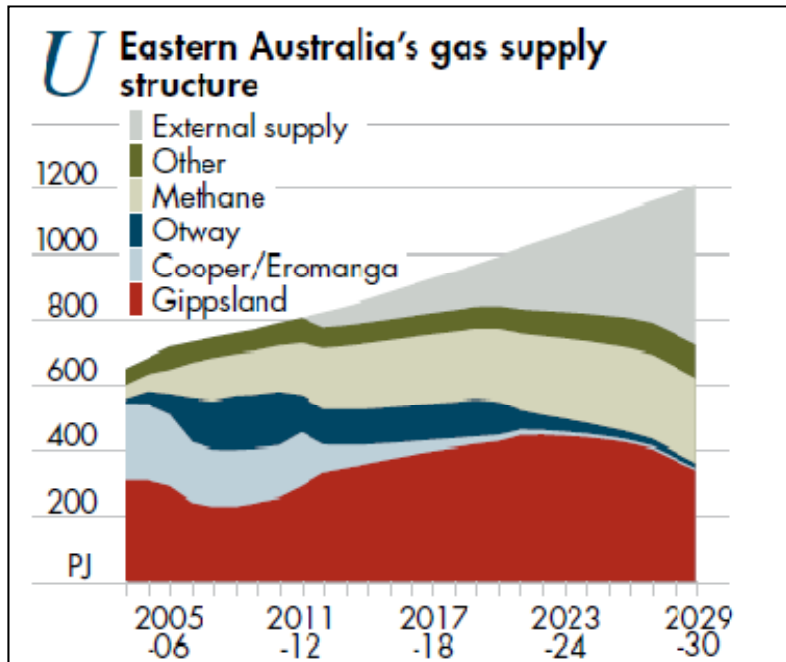
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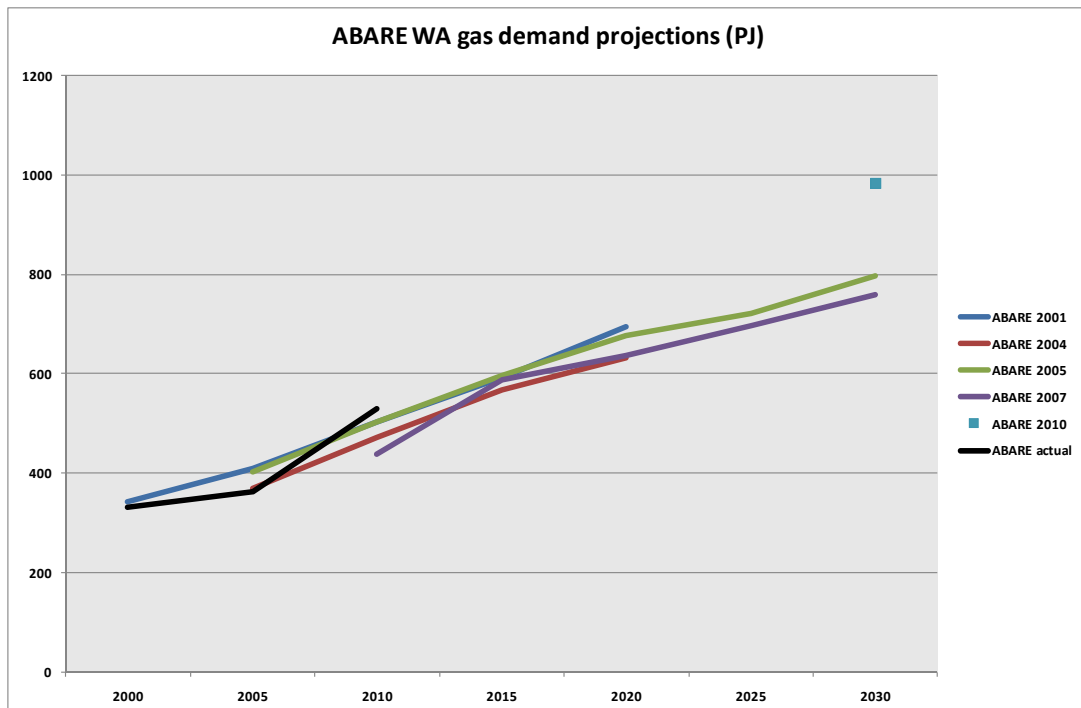


Figure 9 Eastern Australia's gas supply structure



Source: ABARE

Figure 10 ABARE WA gas demand projections



Source: ABARE

As recently as five years ago it was widely assumed that eastern Australia would need to import gas from PNG or northern Australia. Figure 9 shows a chart from the 2005 ABARE

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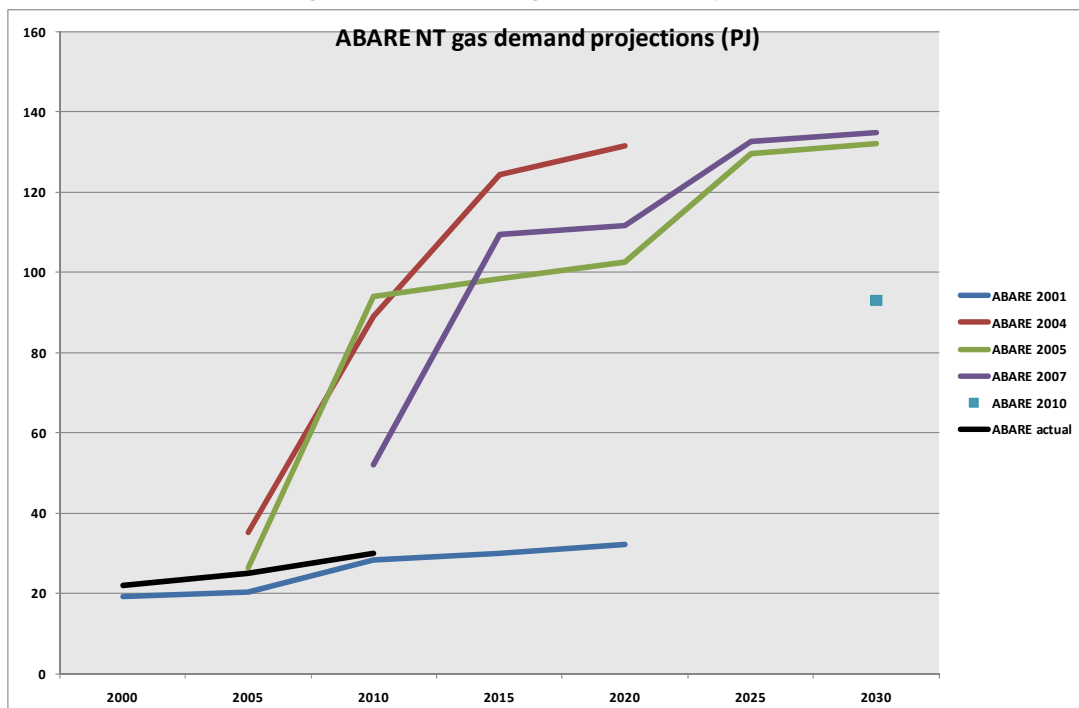


projections that forecast a requirement for around 500 PJ of gas imports by 2030. In reality eastern Australia is now expected to export LNG due to the growth of coal seam gas.

Unlike the situation on the east coast, gas demand in WA has tended to exceed projections (Figure 10), largely due to the greater than anticipated growth in LNG. The latest ABARE projections assume that LNG exports from the west coast will reach 73 million tonnes per annum by 2030. This could require around 400 PJ of gas for processing LNG. However the early ABARE projections assumed significant growth in direct reduced iron, which has not developed as anticipated.

Gas demand in the Northern Territory has failed to expand as expected and expectations have been revised down (Figure 11). Earlier projections assumed that the Gove alumina refinery would be converted to gas and other mining developments would occur which have not eventuated.

Figure 11 ABARE NT gas demand projections



Source: ABARE

## Current east coast demand forecasts

Figure 12 shows a number of more recent publicly available east coast gas demand forecasts.

The ACIL Tasman forecast is from their report for the ESAA in July 2008 on the impact of an ETS on the energy supply industry (ACIL Tasman, 2008).

The ABARE forecast is from their 2010 projections (ABARE, 2010).

The Core Energy forecast (medium) was quoted by Epic Energy at the UBS Utilities Conference in April 2010 (Epic Energy, 2010).

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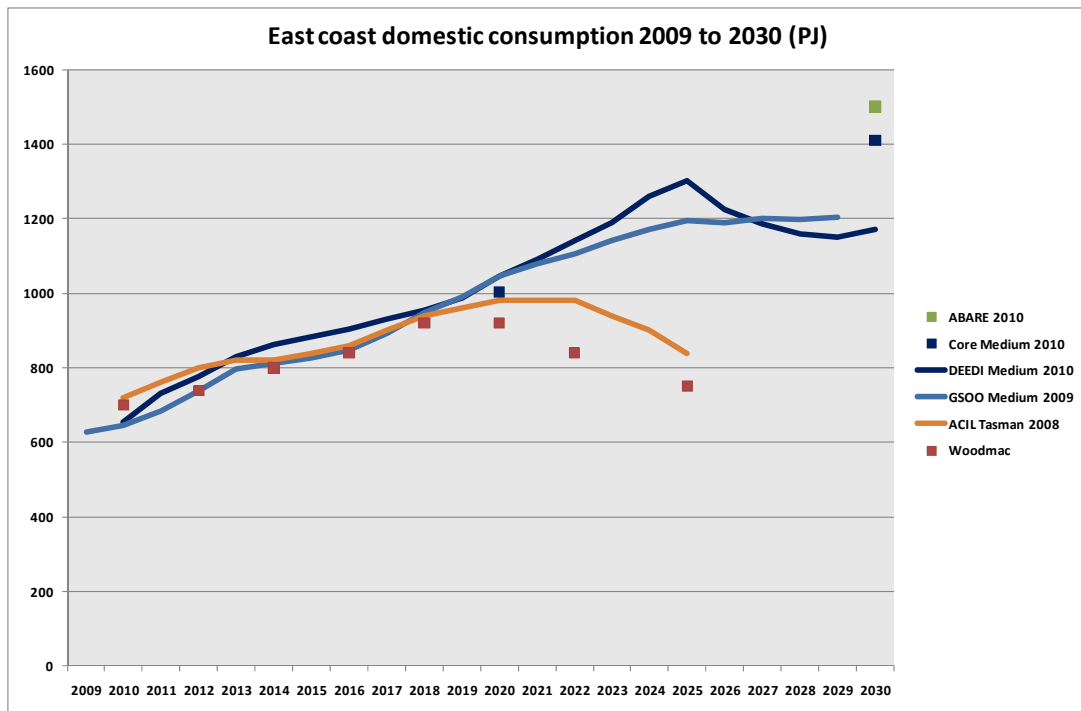


The medium growth GSOO forecast is from the AEMO 2009 Gas Statement of Opportunities released by AEMO in late 2009 (prepared by McLennan Magasanik (MMA) and Core Energy) (AEMO, 2009).

The DEEDI forecast is the medium scenario prepared by MMA for the 2010 Annual Gas Market Review for the Queensland Department of Employment, Economic Development and Innovation (DEEDI) (DEEDI, 2010).

The Wood Mackenzie forecast is from their Eastern Australia Gas and Power Outlook to 2025, as quoted by Eastern Star Gas<sup>3</sup>.

Figure 12 East coast domestic consumption 2009 to 2030



Source: EnergyQuest

## Assumptions

The assumptions behind each of the forecasts are listed below.

Reflecting when the forecasts were made, the assumptions about the CPRS and carbon pricing are now out of date following the decision by the Federal Government in April 2010 to defer the CPRS and subsequent political developments.

Most of the forecasts make assumptions about LNG exports and these are listed below. These assumptions are relevant to forecasts of gas supply and prices but not to domestic demand (which excludes LNG exports). However LNG assumptions are listed with the other assumptions for the convenience of listing all assumptions together.

<sup>3</sup> <http://www.easternstar.com.au/markets.html>



## E N E R G Y Q U E S T

As noted above, the ABARE demand forecast includes fuel gas used for gas production and processing (but not LNG exports). Excluding fuel gas, the ABARE 2030 forecast would be around 1350 PJ.

The other forecasts do not include fuel gas.

ABARE notes that its energy projections are highly sensitive to underlying assumptions about GDP growth. The projections assume GDP growth of 2.9% real (a reasonable medium growth scenario), continuing real growth in oil prices to around \$126 per barrel (in 2007-08 prices) by 2029-30 (with LNG prices following oil prices), Renewable Energy Targets (RET) and 25 million tonnes per annum (Mtpa) of LNG exports by 2030. East coast electricity generation is assumed to grow by 1.8% per annum. Gas-fired power generation is assumed to be cheaper than coal with carbon capture and storage (CCS) but gas with CCS is a similar cost to coal with CCS. The Carbon Pollution Reduction Scheme (CPRS) is assumed to commence in 2011-12 with a target of CPRS-5. Carbon prices (in 2007-08 dollars) commence at \$8.90 per tonne (\$8.90/t), increase to \$21.50 in 2012-13 and \$28.20 in 2019-20 and reach \$41.80 in 2029-30.

The Wood Mackenzie assumptions are not publicly available.

The ACIL Tasman forecast assumes commencement of emissions trading and LNG production from Gladstone at 4 Mtpa from 2014 (relevant to their supply and price forecasts).

The Core forecast assumes a CPRS-5 target and includes RET.

The GSOO medium economic growth scenario assumes a moderate global recovery over the next five years and stable growth thereafter; the CPRS is delayed to 1 July 2011, with a CPRS-5 target (the same as the Core assumption); the carbon price starts at \$10 per tonne (\$10/t), jumps to \$26/t and then grows at 4% real; assistance for Emissions Intensive Trade Exposed Industries (EITE) is as per the White Paper. The first 4 Mtpa of LNG is produced by 2015, with production reaching 24 Mtpa by 2030. The new contract gas price ex-plant is assumed to be \$4.00/GJ in 2010, growing to \$5.00/GJ by 2030 (in \$2009).

The DEEDI assumptions have some differences from the GSOO assumptions. Australian growth is assumed to be faster than global growth over the next two to three years; the CPRS starts in July 2012 rather than July 2011; carbon prices are set at \$10/t in 2012-13; the first 3.5 Mtpa LNG train commences production in 2014, with the second in 2015 and increasing by 3.5 Mtpa every two years (making 28 Mtpa by 2030); and ex-plant gas prices are assumed to be between \$4/GJ and \$6/GJ over the period (but with lower prices later). Non-power demand in states other than Queensland is assumed to be the same as in the GSOO.

In addition to the broad economic assumptions, forecasts have to make assumptions about major projects, the outcome of which is difficult to forecast but which can have a significant impact. For example, Mt Isa consumes around 30 PJ of gas per annum, nearly five percent of east coast consumption. There has been long-standing consideration of building a direct power link to Mt Isa. If this occurred it would have a material impact on gas consumption.

### **Comparisons**

Generally the forecasts are lower than those made two years ago. There are also significant differences between recent forecasts.

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## ENERGY QUEST

In the ABARE projection the share of gas in national primary energy consumption increases from 22% to 33%, with average growth of 3.4% per annum, driven by electricity generation and mining and reflecting a shift to less carbon-intensive fuels. The growth in gas consumption is expected to be stronger in the period to 2020, consistent with the emergence of technologies with a weaker carbon footprint after 2020. However CCS is not deployed to any significant extent due to its relative high cost. ABARE notes that the cost-competitiveness of gas for power generation depends on gas prices. The modelling undertaken by ABARE suggests that domestic gas prices are likely to increase but the results are not disclosed. Overall east coast gas consumption continues to grow to 2030, reaching around 1350 PJ by 2030 (excluding fuel gas used for gas production).

In the Core forecast, gas demand also continues to grow through to 2030, with growth in both gas-use for power generation (particularly in Victoria and Queensland) and other uses. East coast gas demand for power generation climbs from 200 PJ in 2010 to 700 PJ in 2030, with increasing demand in all states. Similarly demand for gas for other uses also increases to around 700 PJ by 2030, with total east coast gas consumption reaching 1400 PJ by 2030.

While these forecasts predict continuing growth in gas consumption, the other forecasts have gas demand flattening out next decade or falling. This is because carbon capture and storage (CCS) for coal-fired generation is assumed to become commercially viable.

In the GSOO medium growth scenario east coast gas consumption grows until 2025 when it reaches around 1200 PJ and then flattens out as a result of the assumed introduction of CCS technology. East coast demand grows at an average 3.3% per annum, faster in Queensland (5.2%), where gas-fired power generation grows at 7.1%, large industrial demand at 4.3% and retail demand at 2.2%. Demand for gas for power generation also grows strongly in Victoria at 11.1%.

In the DEEDI forecasts gas consumption is similar to the GSOO forecast to 2020 but then grows more strongly, reaching 1300 PJ by 2025 (630 PJ for power and 670 PJ for other uses) compared with 1200 PJ in the GSOO. Consumption then falls to around 1150 PJ, reflecting a fall in gas-use for power generation. This reflects the entry of CCS.

In the ACIL Tasman projection east coast gas consumption grows strongly until around 2020 when it reaches almost 1000 PJ (similar to the Core, GSOO and DEEDI forecasts) but then, rather than continuing to grow it begins to decline as supply-side constraints and rising gas prices see under-satisfaction of the market.

The Wood Mackenzie forecast has a dramatic fall in gas demand after 2020. This probably also reflects assumptions about entry of clean coal technologies.

Overall there is a range of 552 PJ between the highest and lowest forecasts for 2025, a range of 54% of the mean value of 1022 PJ.

### **Sensitivities**

Both the GSOO and DEEDI forecasts have High and Low economic growth scenarios.

Compared with the Medium scenario, the GSOO High scenario assumes a rapid global recovery from 2010, a CPRS-25 target from July 2016, carbon prices of \$50/t from July 2016 growing at 4% real, no EITE after five years, 36 Mtpa of LNG by 2030, higher ex-plant gas prices (\$6/GJ growing to \$8/GJ) and CCS from 2024.

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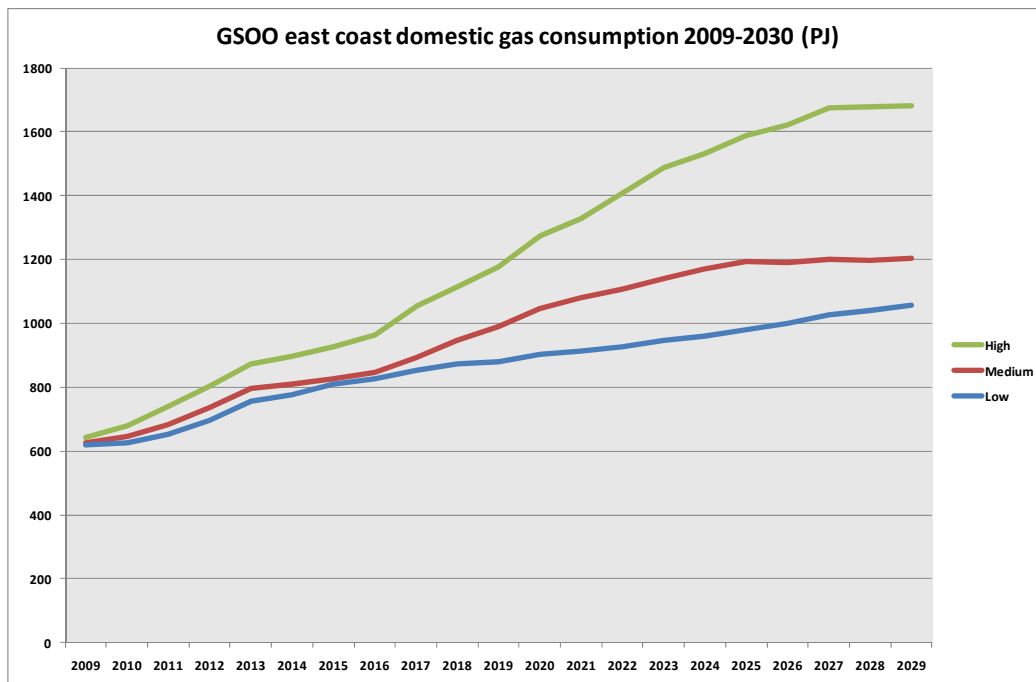


Under the High scenario east coast gas consumption in 2030 is 1680 PJ compared with 1200 PJ in the Medium scenario (Figure 13). Despite higher prices, gas demand is higher due to higher electricity demand, higher carbon prices stimulating gas-fired generation and higher demand for goods produced using gas-intensive processes. Gas demand flattens out due to introduction of CCS.

Compared with the Medium scenario, the Low scenario assumes a weak economic recovery, lower carbon prices (only grow by 2%), lower ex-plant gas prices (\$3.50 growing to \$4.00), lower LNG production (12 Mtpa by 2030) and CCS delayed to 2030.

East coast gas consumption under the Low scenario is similar to the Medium scenario to 2017 because the majority of electricity demand growth during this period will be met through renewable energy sources. In 2030 gas demand is 1050 PJ compared with 1200 PJ in the Medium scenario. Despite lower gas prices, gas demand is lower in the Low scenario due to lower electricity demand and lower carbon prices and lower demand for goods produced using gas-intensive processes.

Figure 13 GSOO east coast domestic gas consumption 2009 to 2030



Source: AEMO

Similarly DEEDI also has High and Low scenarios (Figure 14). The assumptions behind the High scenario are similar to those in the GSOO High scenario, except with higher LNG exports (49 Mtpa by 2030 compared with 28 Mtpa). The High scenario is greater than the Medium scenario but demand falls from 2025 due to entry of CCS.

The Low scenario forecasts are similar to the GSOO Low growth scenario.

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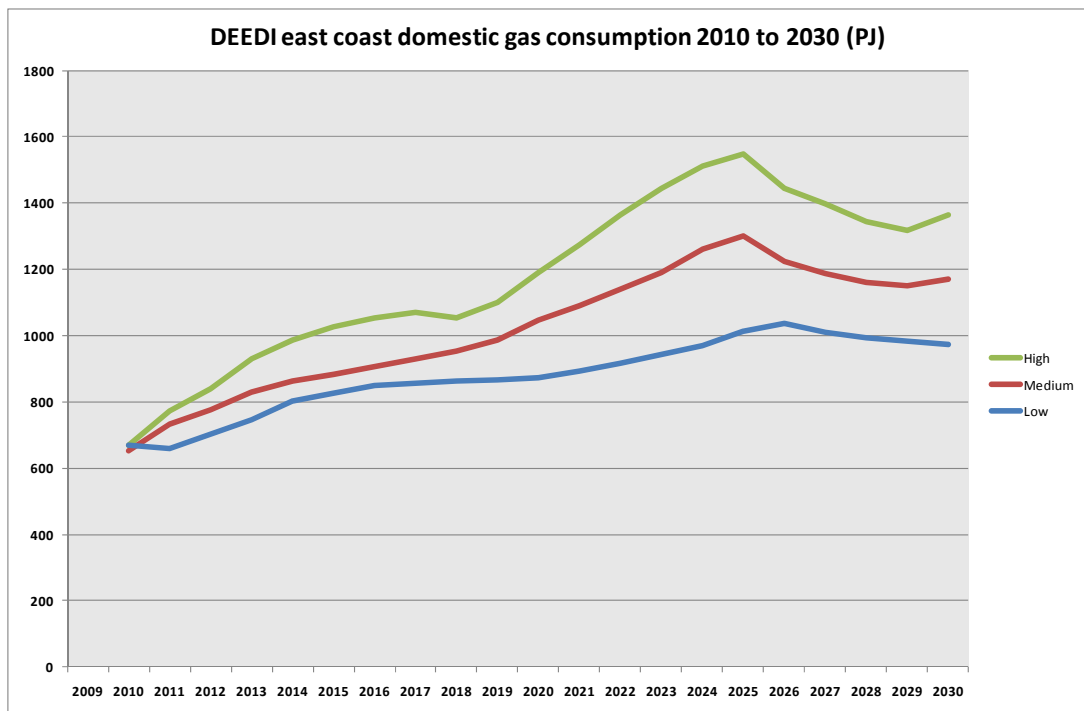
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Figure 15 and Figure 16 show the DEEDI forecasts broken down into utility (non-power) demand and power demand. Based on this modelling, utility demand increases with economic growth, notwithstanding higher gas prices and carbon prices.

In Figure 16 generation increases with economic growth and higher carbon prices but falls as CCS becomes competitive.

Overall there is a range of 389 PJ between the DEEDI High and Low forecasts, 33% of the Medium forecast.

**Figure 14 DEEDI east coast gas consumption 2010 to 2030**



Source: DEEDI

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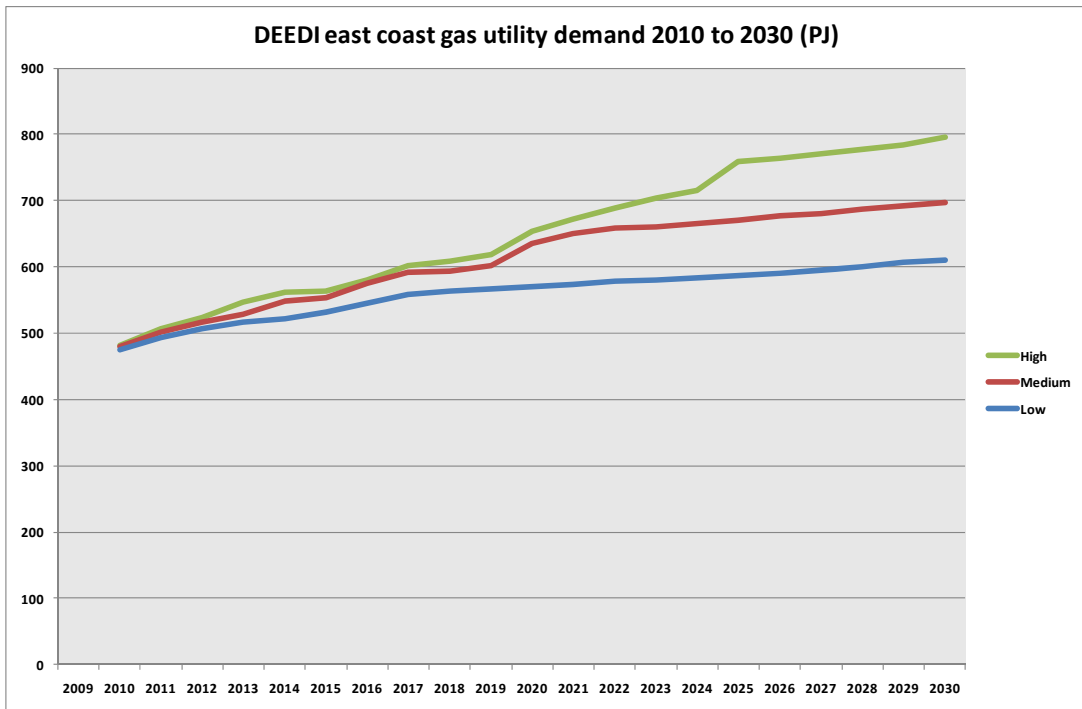
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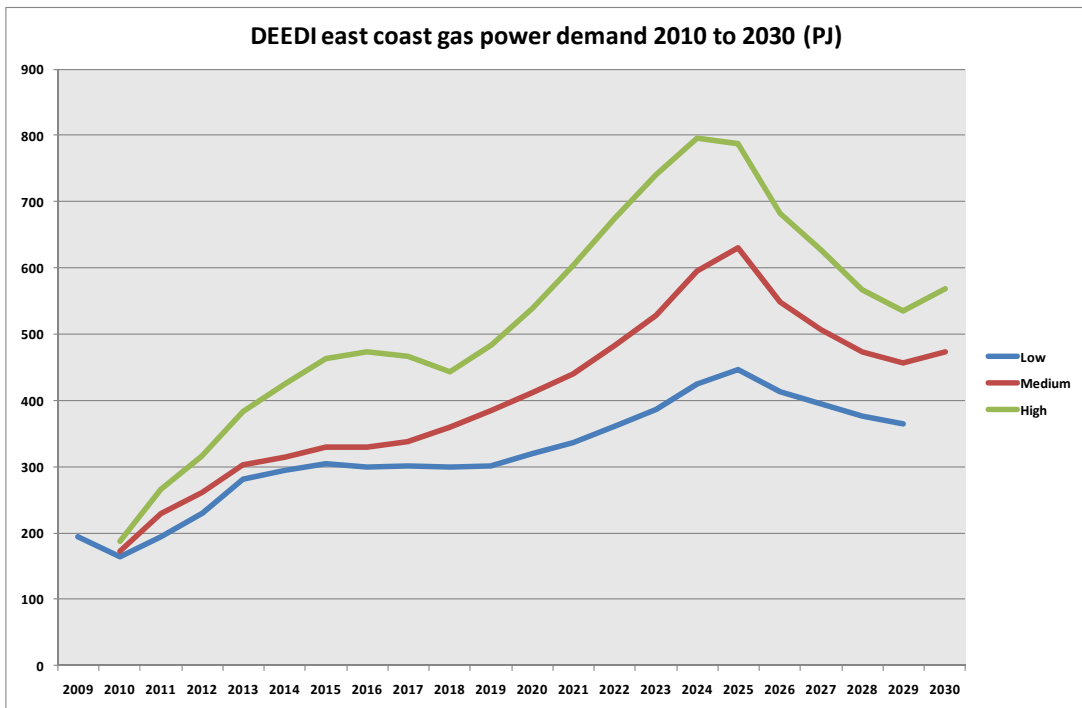


Figure 15 DEEDI east coast gas utility demand 2010 to 2030



Source: DEEDI (2010)

Figure 16 DEEDI east coast gas power demand 2010 to 2030



Source: DEEDI (2010)

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## Conclusions

The foregoing analysis suggests that there are significant uncertainties about future east coast gas demand, with fundamental questions of whether gas demand will continue to grow or not and, if it does not, when it will begin to decline. Critical uncertainties relate to:

- the rate of economic growth, commodity prices and oil prices
- carbon policies and prices (particularly as the proposed policies have changed significantly since many of these forecasts were undertaken)
- the level of LNG exports
- gas prices
- electricity demand
- competitiveness of coal and viability of CCS
- prospects for energy-intensive mineral-processing.

The results appear to be particularly sensitive to differences in assumptions about rates of economic growth and timing of CCS.

## East coast supply forecasts

As noted above, as recently as five years ago there was a general belief that east coast gas reserves were insufficient to meet demand and that imports from PNG or northern Australia would be necessary. This has turned around completely with the growth in CSG reserves sufficient for major export projects. Nonetheless, with ambitious LNG plans, concerns are still raised about reserves adequacy to meet both domestic demand and LNG exports.

The ACIL Tasman report completed in 2008 (ACIL Tasman, 2008) forecast a peak in gas production in 2020 due to resource constraints and higher production costs. This study had a relatively low LNG forecast of 4 Mtpa. On the supply-side the study assumed that gas fields offshore Victoria would begin to decline from around 2013 and fall steeply over the period beyond 2020, the contribution from the Cooper Basin would continue to decline, Queensland CSG would continue to grow strongly and there would be limited development of NSW CSG. These were reasonable assumptions at the time but there have since been substantial increases in Queensland CSG reserves and resources. Development is also proceeding with the Kipper and Turrum gas developments offshore Victoria.

ABARE (2010) concludes that the significant gas resource base in eastern Australia is capable of meeting both domestic and export demand over the next 20 years and beyond.

The GSOO (AEMO, 2009) contains a detailed analysis of current and projected east coast reserves. It concludes that projected gas reserves under the low, medium and high economic growth scenarios are sufficient to meet annual demand projections to 2029 including LNG exports of up to 36 Mtpa. However increasing demand for gas will place pressure on pipelines and production infrastructure, with the potential for both aggregate winter and summer peak demand to exceed production capacity under some scenarios (and in the absence of further investment).

Figure 17 reproduces Figure 6-1 from the report (DEEDI, 2010). Combined domestic and LNG reserves requirements are compared with projections based of reserves growth based

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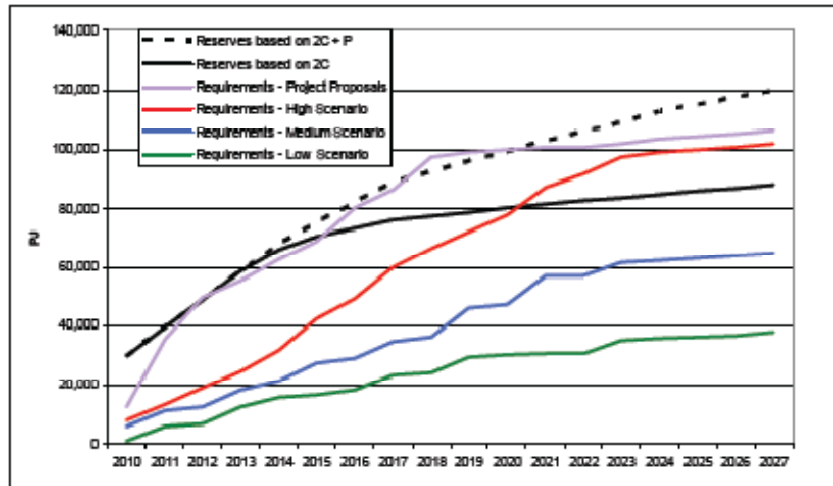
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on current reserves and contingent resources (Best Estimate Contingent Resources or 2C). A forecast of reserves growth that also takes account of Prospective Resources (P), which is an estimate of exploration potential, is also shown.

Figure 17 DEEDI forecast gas reserve growth 2010 to 2030



Source: DEEDI (2010)

The High demand scenario is as discussed above. The Project Proposals scenario shows what is planned by the LNG proponents (greater than in the High Scenario) plus High Scenario domestic requirements.

The report concludes that the reserve requirements of the Project Proposals scenario would severely test the industry's ability to develop reserves, particularly as some of the reserves, particularly those offshore Victoria, are not readily accessible to LNG developments in Gladstone.

The aggregate reserve requirements in the High Scenario however, which the report authors believe reflects the highest feasible LNG development rate for reasons other than reserve constraints, can be met more readily, with a steady buffer of over 20,000 PJ of uncontracted gas until 2020. This buffer will be maintained after 2020 only if there is continued growth of Prospective Resources feeding into Contingent Resources and Reserves, or if Prospective Resources in the Galilee Basin are developed into Contingent Resources and Reserves.

However the level and timing of LNG development is a significant uncertainty.

There are also uncertainties about CSG supply. Reserves and resources are categorised by levels of uncertainty and while CSG production has been growing quickly, it is as yet only a fraction of future requirements. There are significant uncertainties about future conversion of Contingent Resources to Reserves and 3P reserves to 2P reserves and 2P reserves to 1P reserves. In particular there are uncertainties about future outcomes in newer areas such as the Gunnedah basin in NSW and the Galilee Basin in Queensland.

## East coast price forecasts

Given the uncertainties about both demand and supply, it is not surprising that there are also uncertainties about future gas prices.

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The most recent publicly disclosed east coast gas price forecasts are those in the DEEDI report (Figure 18).

All prices are for gas delivered to zonal hubs (i.e. include transmission costs) and are expressed in real \$2010 terms. The prices shown here are the estimated price of new 15-year gas contracts starting in a particular year.

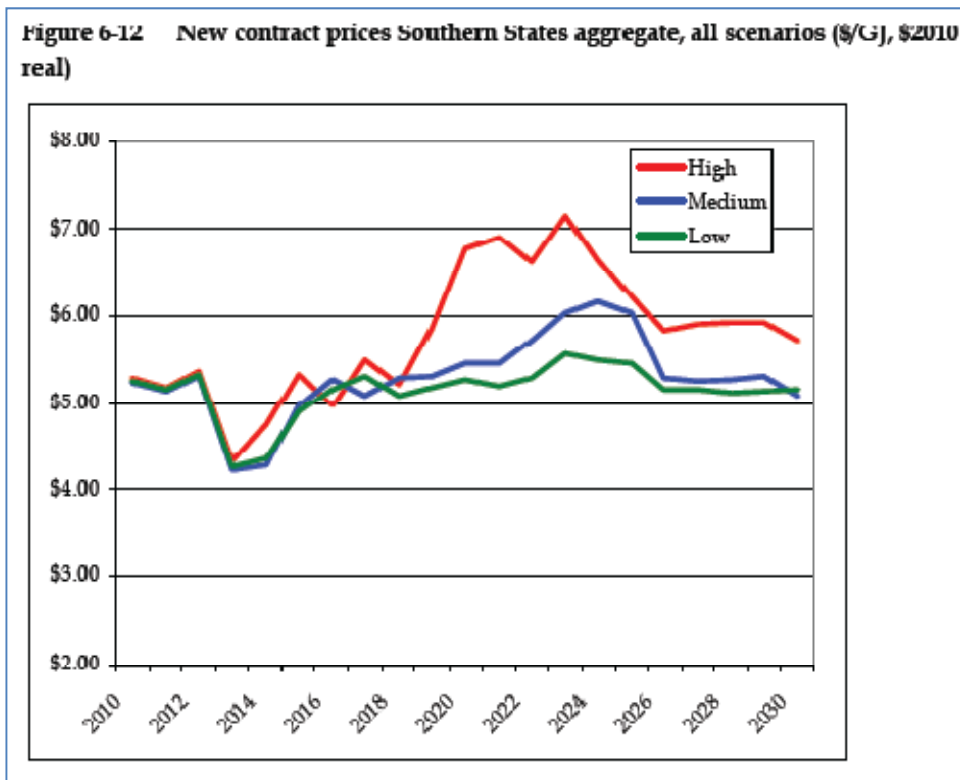
The prices do not take into account the possible availability of lower priced ramp-up gas in the period prior to LNG projects reaching full production.

New contract prices in southern states are projected to be relatively insensitive to the scale of LNG exports, largely due to the anticipated availability of NSW CSG from the Gunnedah and Gloucester Basins (matters of significant uncertainty), although delivered prices reach over \$7.00/GJ in the High case, prior to falling to around \$6.00 (Figure 18).

In contrast Queensland aggregate delivered prices are projected to be very sensitive to the scenarios (Figure 19). Across Queensland in aggregate:

- In the High scenario (with both high domestic demand and high exports) new contract prices are expected to rise substantially from 2013, to over \$7/GJ, and then to fall, to approximately \$6/GJ by 2030.
- In the Medium scenario (with medium domestic demand and medium exports) new contract prices are expected to rise initially to over \$6/GJ but then ease to \$5/GJ as reserves growth outpaces growth in exports.

**Figure 18 New contract prices, delivered Southern States aggregate 2010 to 2030**



Source: DEEDI (2010)

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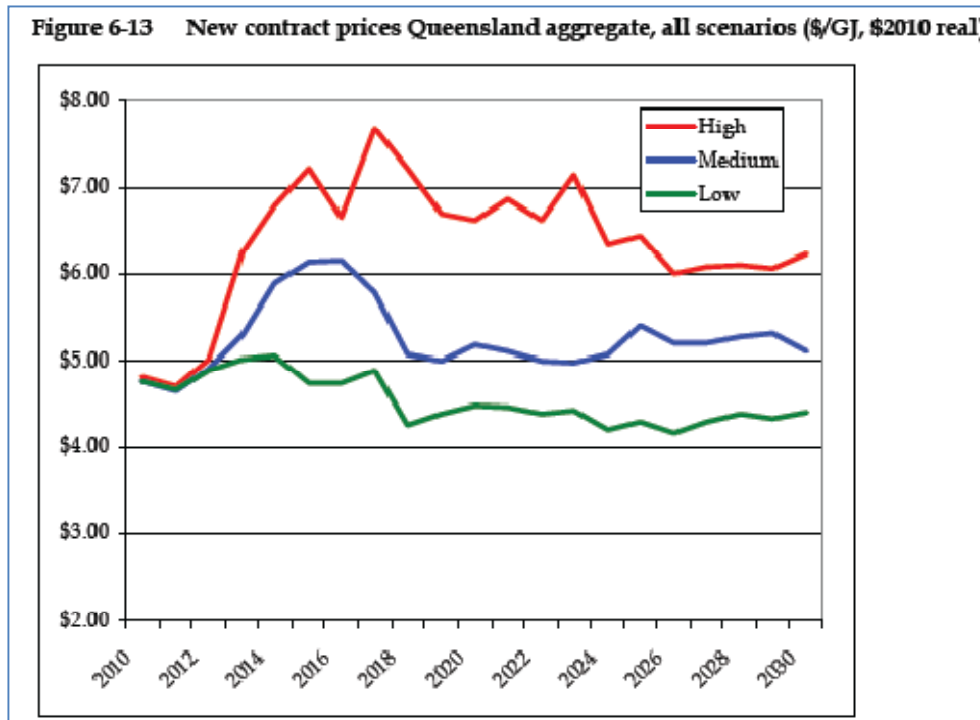
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**Figure 19 New contract prices delivered Queensland aggregate 2010 to 2030**



Source: DEEDI (2010)

- In the Low scenario (with low domestic demand and low exports) new contract prices are expected to barely increase, largely because the first exports are delayed until 2015 and the second train until 2017, significantly reducing the pressure on gas reserves relative to the Medium and High scenarios.

The other available forecasts are those by ACIL Tasman for AEMO (ACIL Tasman, 2009). These provide just one scenario and assume relatively low LNG development (8 Mtpa) and low growth in non-power gas demand.

As shown in Figure 20, delivered gas costs for new entrant CCGT plants in the southern states are forecast to gradually increase from \$4.81/GJ to \$6.85/GJ by 2029 delivered to Melbourne, \$5.81/GJ to \$6.64/GJ delivered to Sydney and \$5.44/GJ to \$7.41/GJ delivered to Adelaide. In the DEEDI report delivered prices in 2030 in the Low and Medium scenarios are around \$5.00/GJ and below \$6.00/GJ in the High scenario.

Prices delivered to Brisbane are forecast by ACIL Tasman to fall slightly from \$5.17/GJ to \$4.97/GJ (essentially to remain flat). No explanation is given for this. In contrast, the medium growth scenario in the DEEDI report has delivered prices in Brisbane increasing from around \$4.50/GJ to \$6.00 by 2014 and then falling to around \$5.00 and flattening out from 2020.

The DEEDI report has estimates of gas demand reductions due to the projected price increases, including a High scenario where 50% of reserve additions after 2010 can only be developed at \$5-6/GJ. The results are shown in Table 1.

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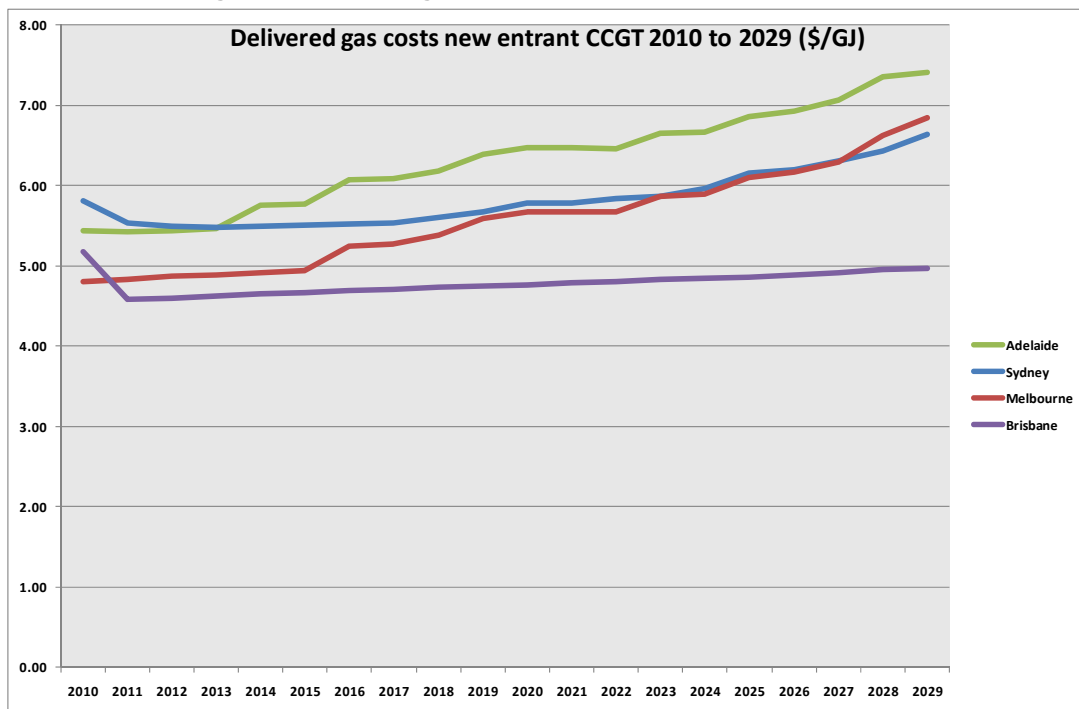
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**Table 1 Estimated demand reductions by 2025 due to price increases**

	Low scenario	Medium scenario	High scenario	High scenario with high cost
<b>Eastern Australia</b>	5%	8%	17%	21%
<b>Queensland</b>	6%	13%	28%	34%

**Figure 20 Delivered gas costs new entrant CCGT 2010 to 2029**



Source: ACIL Tasman (2009)

Overall, future gas prices are particularly uncertain, due to uncertainties about demand and supply and also future development costs.

## WA forecasts

WA gas demand is dominated by electricity generation, mining and minerals processing (manufacturing) primarily alumina and iron ore processing (Figure 21). Mining includes power generation at mine sites and fuel gas used in producing oil, gas and LNG.

Figure 22 shows recent forecasts of WA domestic gas demand and supply by the Department of Mines and Petroleum (DMP) (WA Department of Mines and Petroleum, 2010). The demand projections are based on known major resource sector projects and exclude price effects. Gas consumption under the Reference scenario is projected to grow

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## E N E R G Y Q U E S T

at 3.5% per annum. Consumption under the Low scenario grows at 3.0% and at 3.7% under the High scenario.

Figure 22 provides a range of notional demand and supply projections for the Western Australian economy from a bottom-up assessment of the energy needs of major projects and supply from existing or proposed gas developments. The three demand side projections aggregate the energy demands of projects which are under construction, committed or proposed during the period to 2030. The key assumptions underpinning the demand forecasts are:

- The Reference case captures advanced projects (construction, committed, planned) and takes into account projects identified as possibly occurring
- Resource project gas demand is assumed to grow at 4% per annum from 2020 to 2030.
- Energy consumption is assumed to grow at 3.5% per annum.
- Total gas demand is projected to double from 976 terajoules per day (TJ/d) in 2009 to 1,962 TJ/d in 2030 in the Reference case
- The low demand growth scenario only considers advanced projects. The High growth forecast assumes greater probability of potential projects proceeding.
- Demand scenarios exclude price effects.

The supply side has two scenarios:

- High Supply Case: assumes NWS production drops to 400TJ/d in 2016 and remains constant to 2030. Varanus Island production declines and is not replaced. 15% of Browse and Scarborough becomes available to the domestic market.
- Low Supply Case: assumes NWS production declines from current levels of approximately 600TJ/d to 200 TJ/d in 2020 and stays at that level to 2030. Varanus Island production declines and is not replaced.

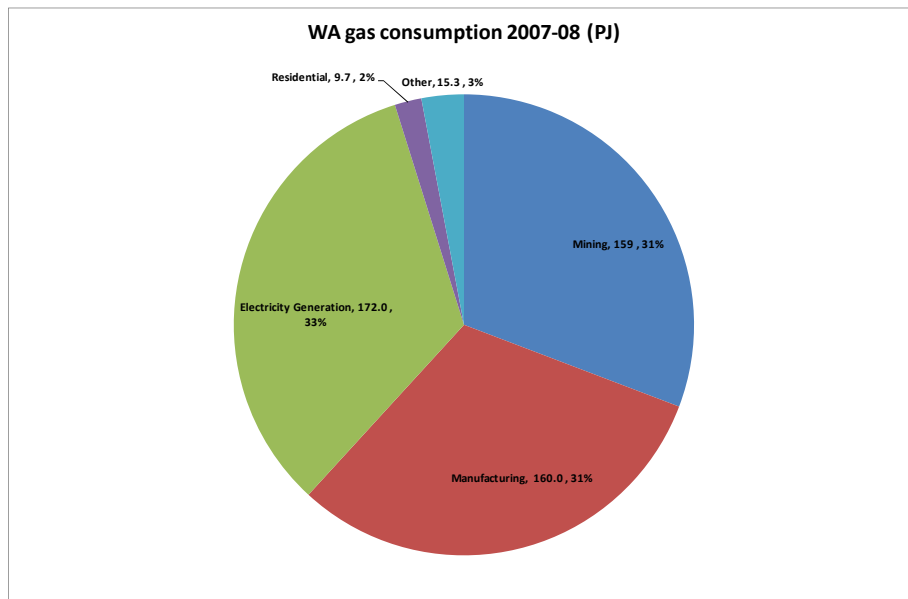
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**Figure 21 WA gas consumption 2007-08**



Source: ABARE

In the Low supply case, there will be a notional shortage of natural gas in all demand scenarios, which will drive up domestic gas prices. The higher prices will increase supply and ultimately choke off some of the domestic demand.

In the High supply case, supply is sufficient to meet demand in the Low and Medium demand cases in most years, although it is unable to meet demand in the High demand case in most years.

Ultimately, the level of prices will be determined by domestic gas supply and demand balance over those years. Critical to the future price path will be the availability of gas as assumed in the high supply case, especially the entry of Scarborough and Browse Basin fields early in the study period (2010 to 2030) with domestic gas deliveries commencing five years later by 2022.

There will be a need for additional pipeline capacity under all scenarios. The current combined capacity of the Dampier Bunbury, Goldfields and Pilbara pipelines is 1130 TJ/d.

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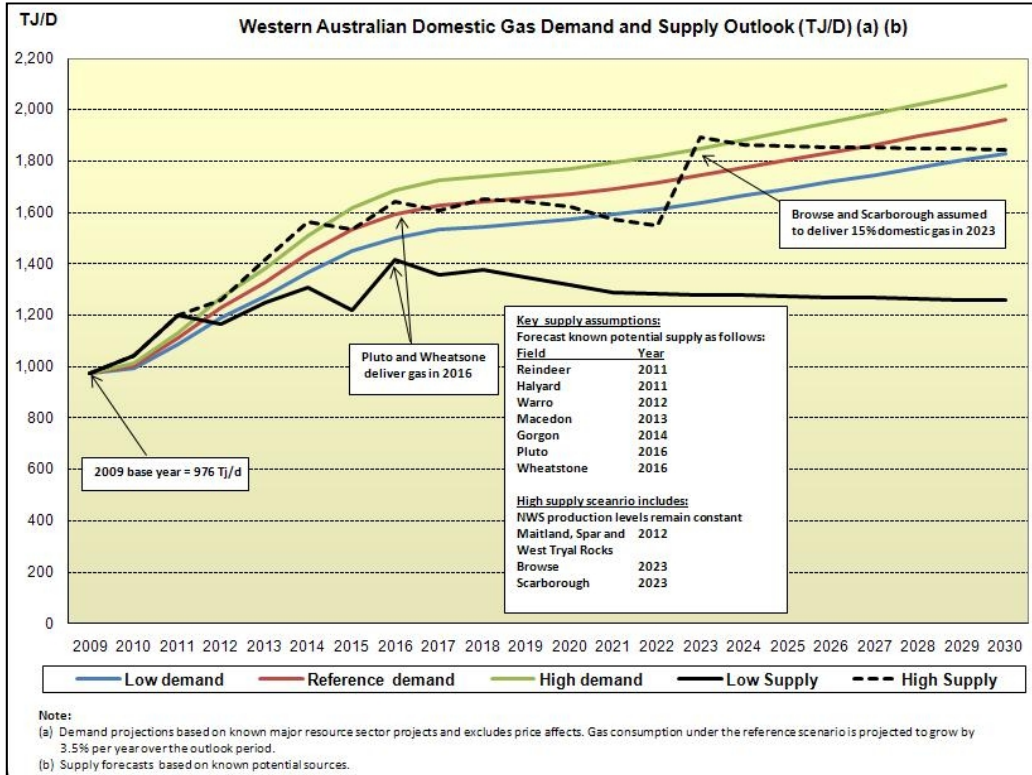
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Figure 22 WA Domestic Gas Demand and Supply Outlook (terajoules per day)



Source: WA Department of Mines and Petroleum (2010)

Figure 23 shows forecasts by ABARE and Economic Consulting Services (ECS, 2010). As noted above, the ABARE forecast includes gas used for LNG processing. The other forecast excludes this. We have provided an estimate of the ABARE forecast excluding fuel gas used for LNG processing (assuming this is 10% of LNG output) of 1600 TJ/d (585 PJ per annum). This is lower than the DMP projection.

The ECS forecast is sourced from a report prepared for the Domgas Alliance in June 2010 by. The ECS forecast assumes average 4% growth per annum to 2020. ECS estimates that total incremental demand for gas-fired power generation in the South West Integrated System (SWIS) will be 16.5 PJ per annum in 2015 and 24 PJ in 2020. Otherwise growth is likely to come from new mining and mineral processing projects.

Development of new projects is very difficult to forecast but ECS estimates that incremental demand could be nearly 160 PJ by 2015 and 226 PJ by 2020.

Overall, ECS forecasts total demand of 1600 TJ/d (585 PJ per annum) by 2020. This is similar to the DMP Low scenario for 2020.

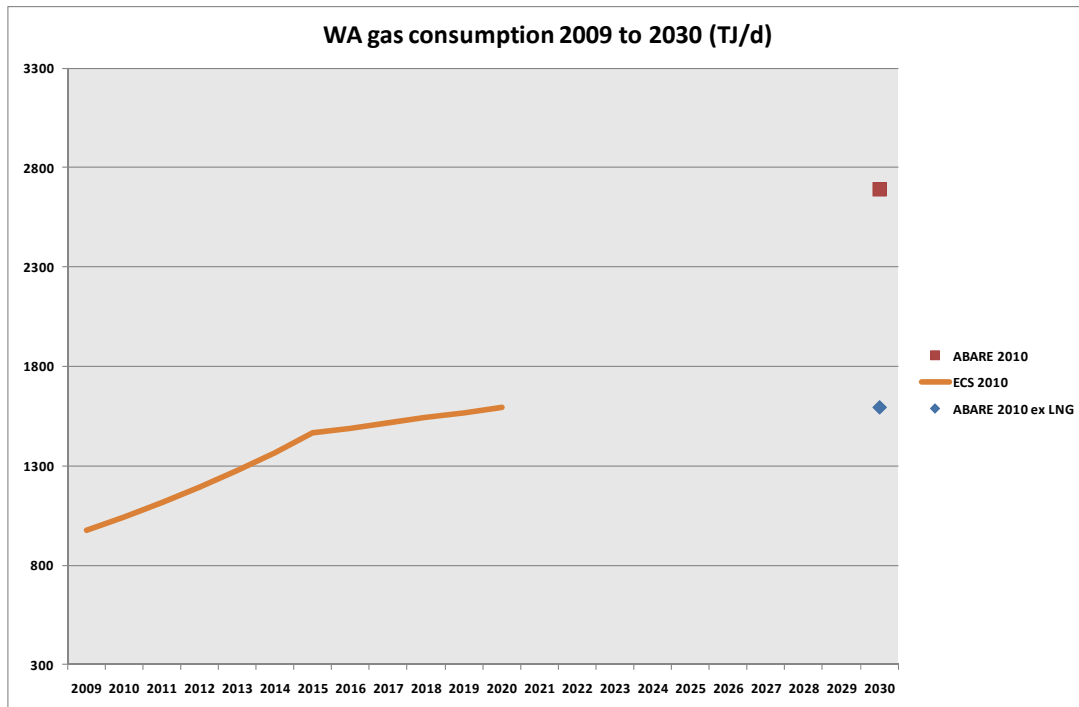
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Figure 23 WA gas consumption 2009 to 2030



Source: EnergyQuest

We are not aware of any publicly available forecasts of WA gas prices.

## Northern Territory forecasts

Figure 11 shows a range of ABARE gas demand forecasts for the NT. Most gas in the NT is used for power generation, either for principal generation or for power generation at mines. Gas (under the ABARE definition) is also consumed in production of LNG. Apart from this component, gas demand has been fairly flat at around 20 PJ per annum. All gas currently comes from the Blacktip field offshore Darwin, which has replaced the Amadeus Basin, which now has surplus gas. Historically there have been some major gas development proposals, such as converting the Gove Alumina Refinery to gas. However so far these have not eventuated. We expect gas demand to remain flat. Blacktip appears to have adequate reserves to supply gas for many years. Gas prices in the NT are confidential

## LNG forecasts

LNG demand is one of the critical factors affecting the domestic gas market. On the east coast, potential LNG demand could dwarf the domestic market and not only are major gas producers like Origin and Santos actively engaged in developing LNG projects but many smaller players are also attempting to be involved in export projects. In WA some fields that may have added to domestic supply are now earmarked for LNG. On the other hand the Gorgon and Wheatstone LNG projects are also expected to be major suppliers of domestic gas; up to 300 TJ/d in the case of Gorgon and 230 TJ/d in the case of Wheatstone or about 30% of projected demand in 2020.

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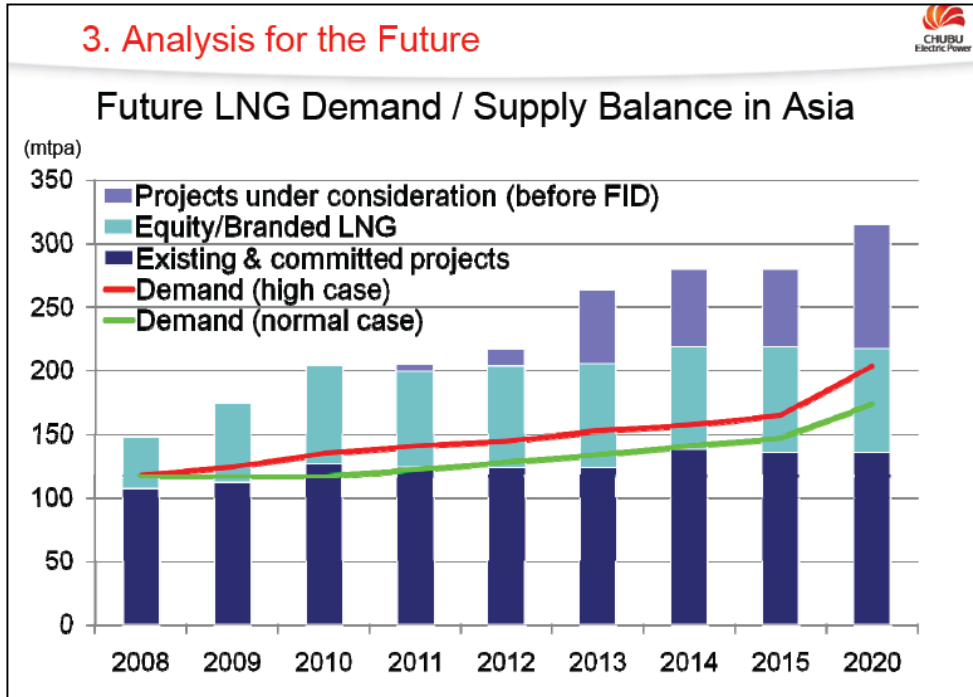
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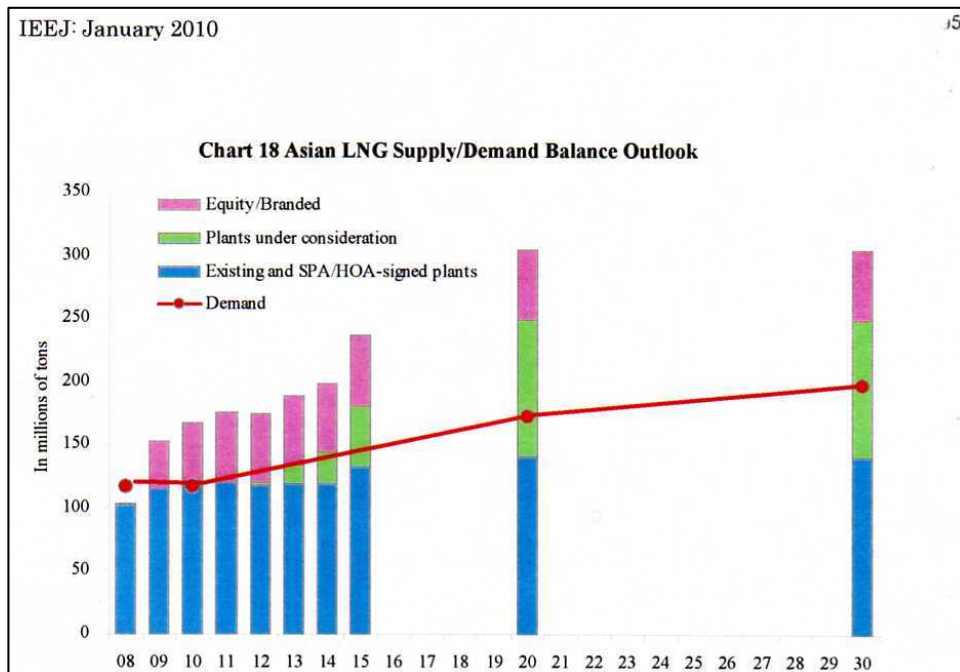
Projections of LNG demand depend on assumptions about growth in energy demand in importing countries, the fuel split and the outcome of competition between different sources of gas. There are uncertainties in all of these factors.

Figure 24 Future LNG demand/supply balance in Asia



Source: Sato ( 2009)

Figure 25 IEEJ Asian LNG supply/demand balance outlook



Source: Kobayashi (2010)

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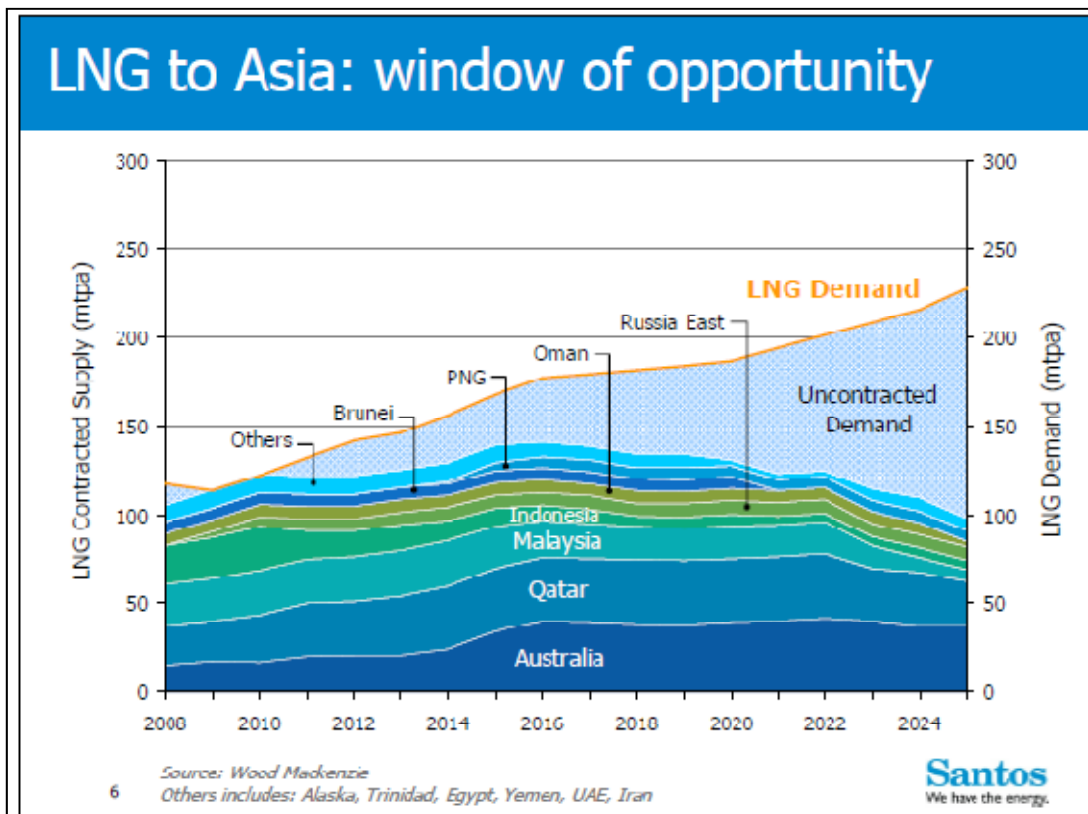
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There is a general view that there are more LNG projects proposed for the Asia-Pacific region than the market can accommodate. Figure 24 and Figure 25 give two Japanese perspectives, one from Chubu Electric and the other from the Japanese Institute of Energy Economics (IEEJ).

Chubu projects Asia-Pacific demand of 175-200 Mtpa by 2020 but over 300 Mtpa of existing and proposed LNG projects to meet this demand. The IEEJ paints a similar picture, but with demand only reaching 200 Mtpa by 2030. Wood Mackenzie has a higher demand forecast (Figure 26).

Figure 26 LNG to Asia: window of opportunity



Source: Santos (2010)

Incremental demand is not the only uncertainty. As Figure 26 highlights, the other uncertainty is to what degree contracts from existing suppliers will be rolled over or whether buyers will contract with new projects instead.

This appears to have been happening with Australian projects so that, despite a projected LNG oversupply, buyers have been active in contracting gas from new Australian and PNG projects (Figure 27). However there are still many proposed Australian projects seeking contracts, with fierce competition between them. This accounts for the widely varying assumptions for example, about how much LNG might be exported from Gladstone within any particular time-frame.

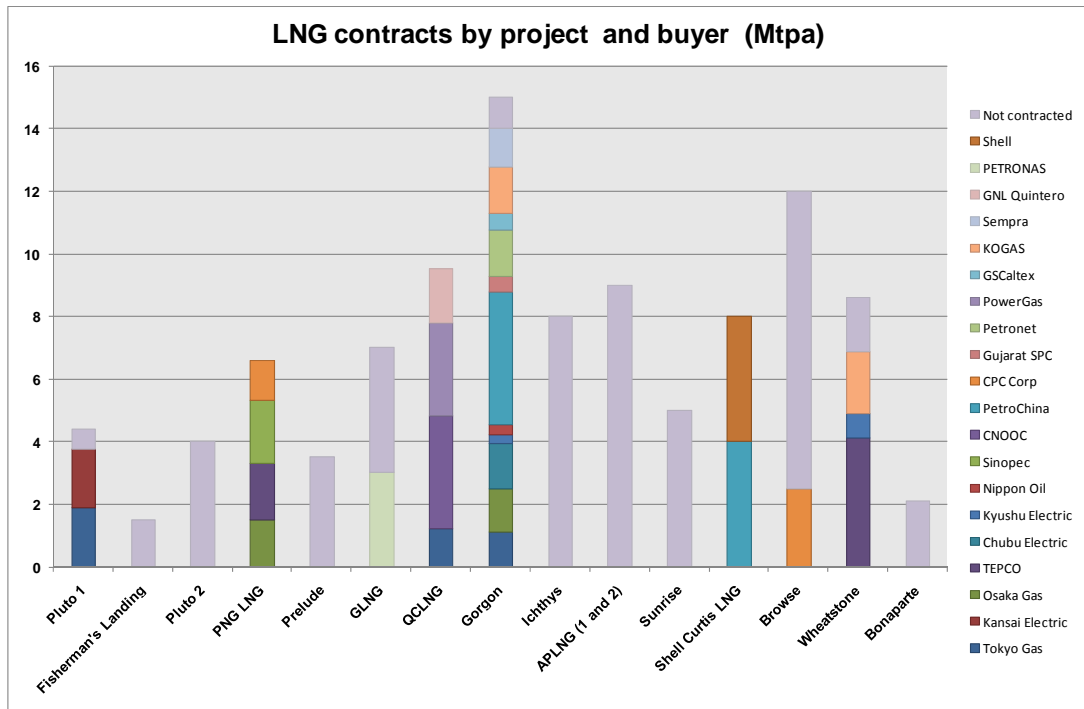
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Figure 27 LNG contracts by project and buyer, July 2010



Source: EnergyQuest

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### 3. Factors affecting gas markets

This section provides an overview of the main current commercial and regulatory environments facing Australia's major gas markets and an assessment of possible future developments.

#### Demand-side issues

Many of the demand-side issues have been referred to above.

The state of the global economy, growth in Australia's major trading partners and Australian economic growth all have an impact on Australian gas demand. Increasingly the growth in demand for Australian gas is coming from export demand and gas-use for domestic electricity generation, rather than from mineral processing or manufacturing.

With relatively high oil prices and emphasis on reducing greenhouse emissions, there is increasing interest in use of gas for domestic transportation but this is unlikely to have a major impact on total gas consumption in the near future.

There are also changes occurring in the nature of gas consumption for power generation, from baseload to providing gas for peaking generation. This has significant cost implications arising from amortising fixed costs of transportation and storage across small volumes.

More generally also changing weather patterns are affecting gas consumption, with warmer and drier weather reducing growth in retail demand but increasing demand for gas-fired generation.

#### Supply-side issues

##### Geology and technology

The gas-supply situation on the east coast has undergone a paradigm shift over the last five years due to CSG. The growth of CSG reflects a number of factors:

- market demand due to the decline of the Cooper Basin
- Queensland Government encouragement through targets for gas-fired generation
- successful exploration, identifying "sweet spots"
- successful identification of appropriate technology.

A similar unconventional gas revolution occurred in the US with shale gas, which is likely to enable the US to avoid becoming a major gas importer.

Although there are estimates of how much CSG may be commercially recovered in Australia (260 000 to 300 000 PJ), the ultimate potential is still highly uncertain. The uncertainties include:

- the ultimate potential of the Bowen and Surat basins outside the areas that are currently most productive
- the potential of the Galilee Basin, which is at an early stage of exploration

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- the ultimate potential of CSG in NSW, where significant reserves have been booked but significant production is yet to be demonstrated.

In addition there are resources of tight gas and potentially shale gas. Tight gas exists in low permeability (poor quality) reservoirs and would generally require artificial stimulation to achieve commercial flow rates. This requires higher gas prices to be economically viable. Shale gas is gas still within the shale source rock. This also requires artificial stimulation.

Geoscience Australia quotes estimates of tight gas of 8,800 PJ in the Cooper Basin and 2,200 PJ onshore the Gippsland Basin in Victoria.

Shale gas exploration is in its infancy in Australia and a number of companies are actively assessing the potential of the Cooper Basin in particular for shale gas.

Companies are also assessing the potential of tight gas and shale gas in WA.

Both tight gas and shale gas are likely to require higher gas prices, possibly twice to three times current east coast levels to be commercially viable.

There is also potential for unconventional gas to impact on Australian LNG exports.

Wood Mackenzie has recently said that unconventional gas, particularly shale, will increase significantly to help meet China's strong gas demand growth. China's LNG import growth will be mitigated by the emergence of indigenous unconventional gas.

### **Costs**

Recent years have seen significant increases in costs for all types of gas projects, including upstream developments and the cost of gas transmission pipelines and LNG plants. The global financial crisis was expected to take the pressure off costs and may have done so to a small extent but costs are still significantly higher than five years ago.

For example, the Minerva gas field offshore Victoria, which commenced production in 2005, cost \$0.88/GJ of reserves to develop. Thylacine, also offshore Victoria, cost \$1.43/GJ.

The Eastern Gas Pipeline cost \$450 million in 2000 or \$31 500 per kilometre inch. Pipelines now typically cost over \$50 000 per kilometre inch.

Greenfield LNG liquefaction projects used to cost around US\$300 per tonne of capacity but now cost over \$1000.

There is particular cost uncertainty in relation to CSG, both the supply curve generally as new areas are developed and the cost of large-scale upstream development for LNG projects.

## **Government policy settings**

### **Climate Change Policies**

As illustrated earlier, climate change is clearly a major area of uncertainty for the energy industry, and the broader economic and industrial development of Australia. The significance of this issue is symbolised by the extent of analysis and modelling conducted largely for the Department of Climate Change and Federal Treasury.

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The major significance of this issue to the energy industry is the extent to which any such policies could impact the demand for gas, particularly for electricity generation if a carbon cost is imposed.

The gas demand forecasts presented earlier illustrate the varying impact on gas demand for new electricity generation due to carbon pricing and therefore the relative competitiveness of gas-fired electricity generation versus coal fired generation.

An issue as significant and important as the extent of additional gas-fired electricity generation, and which contributes to the uncertainty of future gas demands, is the extent to which existing coal-fired generation will be displaced. In principle this will be determined by any carbon pricing (both in its quantum and timing). This is obviously a critical political issue, particularly for generation based on the extensive Latrobe Valley coal resources and generation infrastructure, and therefore difficult to predict at this stage. The Victorian Government has said that it will seek the staged closure of the Hazelwood Power Station.

Following the change in leadership, recent announcements from the Federal Government have placed greater emphasis on “direct action” (energy efficiency) in the shorter term, with the implication that a carbon pricing regime may be further deferred. The Opposition also has expressed its preference for “direct action”. Clearly, with a Federal election imminent, this subject will be highly political, resulting in further uncertainty in an industry which requires long term certainty of investment to ensure reliability of supply.

This situation will lead to the tension between ensuring that any climate change policies are effective and viable and doing so in a timely manner to provide the policy certainty necessary for the necessary medium and long term investments in the electricity and gas industries.

Close monitoring of any climate change policy developments and associated implications, and influencing any developments will continue to be a key activity for the ESAA.

### **Renewable Energy Policies**

While, in principle, climate change policies have the potential to increase gas demand significantly by replacing coal-fired generation, renewable energy policies such as embodied in the Federal Government Renewable Energy Target (RET) Scheme, in which 20% of Australia’s electricity demand must be met by renewable energies by 2020, are likely to decrease the annual demand for gas for electricity generation below what otherwise would have been the case.

However, another major implication of the RET is the potential to significantly increase the demand for gas to meet variable and peak electricity demands due to the variability of renewable generation which is expected to be dominated by wind power until at least 2020. It is expected that to meet the RET, approximately 7,000MW of wind capacity would need to be built by 2020. To back-up the intermittent nature of wind generation, (estimates vary between only 5% and 8% of wind power capacity will contribute to meeting peak electricity capacity demands), it is expected that approximately 5,000MW to 6,000MW of gas-fired peaking plant will also need to be built to meet electricity reliability requirements during low wind periods. This situation raises the critical issue of what gas production and transmission infrastructure will be required to meet such intermittent demands, and its associated costs. Also, an outstanding question is whether the NEM, which does not

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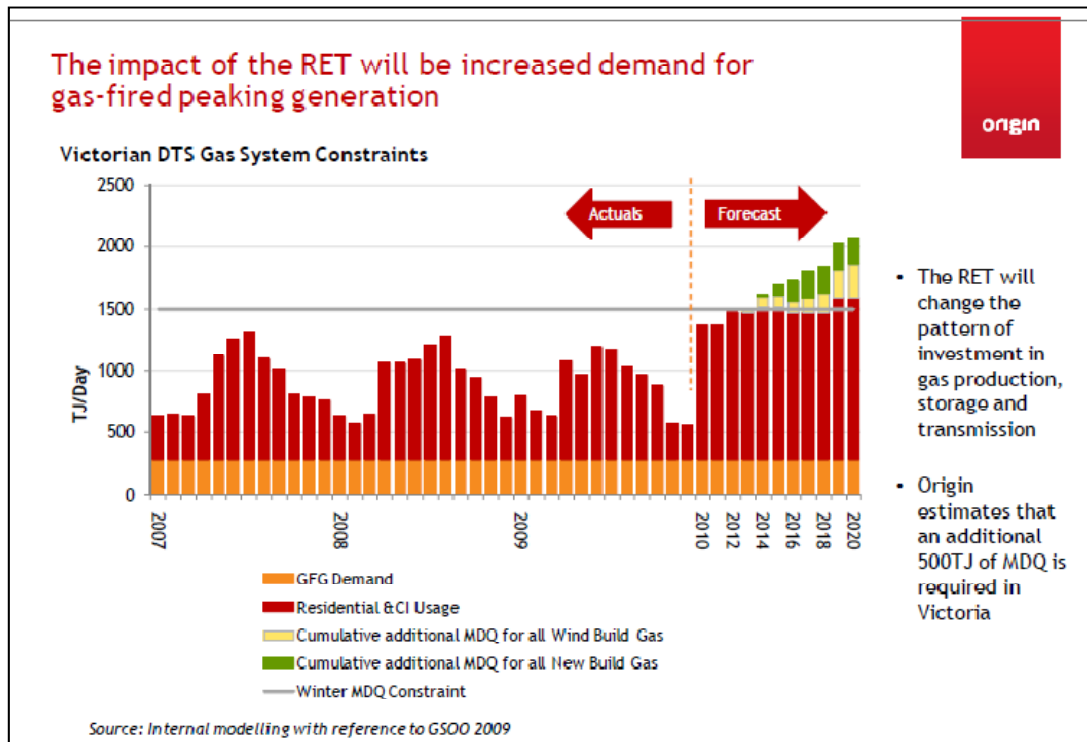
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directly reward capacity investment, will provide the adequate and timely signals to ensure the necessary investment in such low capacity factor generating plant.

As an indication of the significance of this issue, in a presentation to the APPEA Conference on 18 May 2010, Grant King, CEO Origin Energy, presented Figure 28, which shows that an additional 500 TJ/d of gas capacity will be required in the Victorian gas system by 2020.

Figure 28 Victorian gas-fired peaking generation



Source: Origin Energy

The above comments are based on the majority of renewable energy being supplied by wind power by 2020. Geothermal energy has the potential to provide base-load renewable energy and ameliorate the peaking issue described above, but there is much speculation as to what extent geothermal will contribute by 2020.

It is recommended that these issues should be subject to more detailed analysis during Phase 2 of this Project.

All States are currently experiencing increasing peakiness of their electricity supplies as climate change has increased the peak summer electricity demands due to air-conditioning loads. A focus on any “direct action”/energy efficiency initiatives related to reducing peak electricity demands as an integral part of climate change policy has the potential to ameliorate the economic inefficiencies inherent in the current demand patterns to the benefit of the energy industry and therefore to the Australian economy, and the ESAA may consider it appropriate to pursue this issue as part of its input to the climate change scheme debate.

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A solution to the increasing demand for peaking supplies is gas storage. The current major storage facilities in the eastern States are at Moomba and the TRUenergy facilities at Iona. While these can provide substantial peaking gas supplies, they are relatively remote from the likely demand sites and therefore also require peaking gas transportation with its associated issues related to capacity, and the cost of that capacity, which will be required relatively infrequently (i.e. low utilisation factor).

Obviously the ideal storage is that which is very close to the demand site.

This issue is being addressed by some companies such as AGL Energy. On 1 July 2010, AGL Energy announced an unconditional proposal to acquire Mosaic Oil, including the gas storage facility at Silver Springs. Importantly, AGL stated "...the underpinning rationale for this investment is the creation of a gas storage business as part of AGL's integrated strategy...". Also when announcing their intention to install 700MW of gas-fired peaking plant at Torrens Island, AGL Energy announced that it was investigating the potential for peak gas supplies to be provided to that peaking plant by an LNG facility. This presumably would be similar to that used in the Victorian system at Dandenong during high winter demand periods.

Another interesting solution to this issue is the installation of a "large fat pipe" storage system on the Colongra Power Station site in NSW. This pipeline, comprising of approx 9km of 42inch diameter pipeline, will supply up to 5 hours of peaking gas supplies for the 660MW peaking generation plant.

We expect that as this issue becomes more widely recognised there will be further innovative and creative solutions developed.

### **Royalties and taxation**

The Australian fiscal system as it applies to oil and gas has been stable since the 1980s, with the federal Petroleum Resource Rent Tax (PRRT) applying in Commonwealth waters and state royalties applying elsewhere. This changed in May with the announcement and subsequent modifications to the Resource Super Profits Tax. The current proposal is that PRRT will apply to onshore oil and gas (and the NWS) but there is still considerable uncertainty about how the tax is to apply and even whether the current proposal will survive, depending on the election outcome.

### **Gas reservation**

In recent years the WA Government has implemented a Domestic Gas Policy, intended to provide a buffer between the large supply volumes brought on by LNG developments and the more continuous and smaller demands of the domestic market. The Policy is not designed to constrain price, but to ensure availability, with the price and terms to be negotiated between producers and consumers on commercial terms.

Key elements of the policy are:

- The Government negotiates with proponents of LNG projects to include a domestic gas supply commitment as a condition of access to Western Australia's land for locating processing facilities.
- The Government's objective is to secure domestic gas commitments up to the equivalent of 15 per cent of LNG production from new export gas projects. This target reflects current estimates of future domestic gas needs, estimated gas reserves and

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forecast LNG production. As these estimates could change over time the target is subject to periodic review.

- The Government does not intervene in commercial negotiations between gas producers and consumers regarding the price at which gas will be supplied to the domestic market.

The Queensland Government considered a similar policy but has instead opted to monitor the market. If necessary, the Government has proposed reserving specific exploration leases for domestic gas.

### **Acreage Management**

Policies on granting and renewing retention leases in relation to offshore gas discoveries have been a matter of concern for WA gas buyers.

The Commonwealth Government released a discussion paper in June 2009 to consider changes to the retention lease system. The paper was broadly supportive of taking a more stringent approach to the management of retention leases ('Use it or Lose it' policy). However, a final policy has not yet been released by the Commonwealth. The delay appears to have been required to allow time for the recommendations of the Productivity Commission's Review of the Upstream Regulatory Burden on the Petroleum (Oil and Gas) Sector to be considered. The Productivity Commission Review was completed in April 2009 and included findings on the management of Retention leases. These findings do not appear to be generally supportive of a 'use it or lose it' approach, publicly supported by Commonwealth Minister for Resources and Energy.

### **Joint marketing**

From time to time domestic gas buyers have been critical of the joint marketing of domestic gas by upstream joint ventures. The WA Domgas Alliance has recently argued against the ACCC authorising joint marketing of domestic gas by the Gorgon joint venture. The Alliance's arguments were not accepted and joint marketing has been authorised.

## **Market issues**

### **Gas supply contracting**

Traditionally gas was contracted between producers and customers on a relatively long term basis. This was inherent in the establishment phase of the industry during which producers (and gas transmission companies) were seeking reassurance of long term revenue streams to underpin their major infrastructure investments, primarily in circumstances of one production source to one demand centre through one pipeline (e.g. SA Cooper Basin to Sydney; SA Cooper Basin to Adelaide; South West Queensland Cooper Basin to Brisbane and Mount Isa).

As the gas industry has evolved to the point where the major production source infrastructures are well established and a network of interconnected gas transmission pipelines now allows supplies to demand centres to be satisfied from different sources (e.g. Otway Basin gas to Adelaide; eastern Queensland CSG to Adelaide and Sydney; Gippsland Basin gas to Sydney) there has generally been a gradual shift to shorter term contracting.

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This seems to have been largely due to customers becoming more confident that the potential supplies from multiple sources of gas, and the associated increased competition between those sources does not require the certainty of long term supplies from a single source as in the past, and, in fact, more frequent contracting for gas supplies provides an on-going competitive environment. Perhaps the most outstanding example of this multiple source, competitive sourcing was in 2003 when AGL secured gas supplies from the Cooper Basin, Gippsland Basin and Queensland CSG at the one time.

Reinforcing this shorter term trend in the case of retailers is the introduction of greater retail competition and potential churn, leading to greater uncertainty of their future gas demands in each of their load centres (as many of them operate across the eastern States), thus appropriately resulting in them entering shorter term commitments.

Over the past 12 months we have also seen a trend for producers (primarily those with potential to provide gas to the LNG export projects in Queensland) to not commit any long term gas supplies as they husband gas which may be required for those projects. Further, because of the difficulties in managing the build up of gas supplies from CSG wells with their turndown limitations (generally referred to as the ramp gas problem), producers are actively seeking short term contracts to their advantage.

Another contracting trend which we have observed is the willingness of producers to contract gas closer to the annual daily demand profile requirements of various customers rather than the traditional approach of selling a "block of gas" (e.g. a fixed maximum daily quantity for each day of the year regardless of seasonal or other reasons for variable demand). While this variability may appear to come at a higher direct price to the customer, it is preferable to the indirect cost of a customer effectively committing to a higher take-or-pay type commitment for gas not required.

Another trend which we have observed is the willingness of producers to move away from the traditional approach of annual escalation of gas price in accordance with Consumer Price Index. While this willingness is still limited, we think that it is an important and emerging trend. We are aware of gas prices becoming linked to varying degrees with electricity prices, and we expect this trend to increase as the extent of gas-fired generation increases. (In the UK we understand that electricity prices may be linked to gas prices). In WA it is understood that there is at least one recent contract where the gas-price is linked to oil.

Another trend, although admittedly variable across the industry, is the increased separate marketing from joint ventures. Primarily this appears to result from the relatively recently established joint ventures, while the older joint ventures appear to be maintaining their joint marketing. We suspect that the differences in approach is largely due to the specific nature of the joint ventures/operating agreements, and the complexities of separately disposing of gas on a daily basis within common production stream arrangements.

Although there are individual examples of these developments, they are not yet common or widespread.

The commentary above relates primarily to the east coast. In WA the major development in contracting appears to be some cases of indexing gas contracts to oil prices. The issue of whether joint marketing limits competition causes great contention in WA. The ACCC has authorised joint marketing by the Gorgon partners (as noted above) and it recently issued a

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draft ruling that authorises the North West Shelf partners to continue to jointly market domestic gas.

### **Market structure**

The most significant trend which we have observed in relation to the structure of the energy industry has been both the horizontal integration (i.e. electricity and gas) and the vertical integration (i.e. ownership of production and generation, gas transmission and retailing) amongst the energy retailers over the past few years.

With regard to horizontal integration, this has primarily been driven by retailers wanting to be able to offer their customers a total energy service, whether it be for supply of electricity or gas (or a combination of both), often complemented by energy efficiency and other advisory services. This is consistent with the experience overseas as energy markets are liberalised.

With regard to vertical integration, we have seen Origin Energy, who have been gas producers for a long time in the Cooper Basin, extend their gas production into the Otway Basin, Bass Basin and most notably Queensland CSG. At the same time, Origin have been developing major power stations such as Darling Downs and Mortlake Power Stations.

Over the past few years, AGL has purchased gas production reserves in PNG (now disposed) and Moranbah, and exploration interests in the Galilee Basin. AGL has also invested in gas pipelines in Queensland, but once established have sold these assets to pipeline companies. AGL has also invested in power stations such as Torrens Island Power Stations, and a proposed Tarrone Power Station in Victoria, and is developing major wind power projects in various states.

In our view, the primary driver for such vertical integration is risk management. As both of these companies are primarily gas and electricity retailers, increasingly in many States, their major risk is their ability to meet their customer demand and at a price which they can recover from their customer contracts. These risks are obviously at their highest during periods of high demand (e.g. peak electricity demand periods during summer and peak gas demands during winter). There have been examples in which the retailer has incurred tens of millions of dollars in one day due to inadequate coverage of their retail loads.

While theoretically these risks can be covered by entering insurance contracts with electricity generators in summer and gas producers in winter, this interface results in an insurance premium cost with the contracting party. In principle, having their own electricity generation facilities, or own gas production or storage facilities, enables them to minimise or ideally avoid these interface costs. For example, AGL has announced plans to add 700MW gas-fired peaking plant at Torrens Island, and Origin has peaking plant at the Quarantine Power Station on Torrens Island.

Another motivation for energy retailers to move into renewable energy production facilities such as wind farms, is the requirement for them to source 20% of their electricity demand from renewable energy production. Again, while such renewable energy can be purchased from other companies, the lack of an interface minimises cost and can provide operational responsiveness and efficiencies. In AGL Energy's case, ownership of the Torrens Island Power Station, with its ability to load follow complements the intermittent nature of their wind farm generation in South Australia.

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### **Transportation contracting**

Frustration is often expressed about the lack of access to gas transmission pipeline capacity, particularly in circumstances in which pipelines may be fully contracted but underutilised.

The context in which this issue needs to be considered is the substantial investment required by pipeliners to install any transmission capacity (either new or expansions), and the nature of these pipeline companies generally being funds in which investors (such as superannuation funds) are seeking relatively long term low risk, stable returns.

Accordingly, investment in pipeline capacity is normally under-pinned by shippers committing to the majority of any capacity created under long term contracts.

A good example of this is the recent Stage 3 expansion of the Epic Energy (owned by Hastings Fund Management) South West Queensland Pipeline (SWQP) capacity by approximately 380TJ/day. This project has a total project cost (including financing during construction) of \$858m and is under-pinned by long term transportation agreements for over 90% of the capacity created with AGL Energy and Origin Energy until 2028 and 2034 respectively.

The commercial reality is that such investments are unlikely to proceed without these long term agreements. This low risk appetite is reinforced by the potential for any uncontracted pipeline capacity to be stranded by alternative pipelines. For example, Epic Energy would be appropriately concerned with the potential for the SWQP capacity to be stranded by a Hunter Gas Pipeline delivering gas from Queensland CSG to the Hunter Valley, or pipelines delivering NSW CSG to Brisbane or Wallumbilla.

A similar approach is taken with smaller capacity expansions (e.g. Eastern Gas Pipeline), although due to the smaller scale of any such expansions, and presumably based on a view about prospective future capacity demand assessments, there is a greater willingness to build capacity without necessarily fully under-pinning it with long term transportation agreements.

In relation to the level of utilisation of contracted capacities, there are many pipelines in the eastern States which are well underutilised for a wide range of reasons such as seasonality of demand, and the ability of producers and customers to source gas from alternative sources through the interconnected transmission network.

As an example of the levels of utilisation the following load factors applied for 2009: Moomba to Adelaide Pipeline: 50%; SEAGas Pipeline: 50%; Eastern Gas Pipeline: 70%; Moomba to Sydney Pipeline: 41%; SWQP: 76%; Roma to Brisbane Pipeline: 80%; Carpentaria Pipeline: 73%.

While superficially this may indicate that there is capacity which could be more fully utilised by others, generally most of the capacity is contracted to shippers and the pipeliner is not prepared to take the risk in providing such capacity to another shipper on a firm basis to the contractual and commercial detriment of the contracted shipper. Pipeliners are prepared to offer any spare capacity to shippers on an "as available" and short term basis (i.e. effectively interruptible at relatively short notice). However, this generally does not meet the firm supply requirements of the potential additional shippers.

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While theoretically a contracted shipper could itself offer to on-sell any unutilised capacity (assuming that it has this entitlement in its transportation agreement with the pipeliner), this would require a rare match of user's capacity requirements. One possibility is for a retailer with a high capacity demand in winter for heating on-selling its capacity in summer to a peaking electricity generator. One of the motivations for the horizontal and vertical integration of retailers as discussed above is to maximise the utilisation of any contracted transmission capacity in such a way.

With the commencement of the Blacktip gas supplies to Darwin replacing the historical gas supplies from Mereenie and Palm Valley, the majority of the pipeline capacity to Darwin will be well underutilised and could provide potential gas supplies to any potential customers in the Northern Territory south of Darwin.

With the development of the integrated gas transmission network in the eastern States, and with the potential for users to utilise gas from alternative sources, an emerging trend is the requirement of users and the willingness of pipeliners to negotiate back haul arrangements. Back-haul is a situation in which, without the backhaul requirement, a pipeliner on a day would be transporting gas for a shipper, say from west to east. Assuming that another shipper wishes to transport a lesser quantity of gas from east to west, this can be commercially achieved with the result that the physical flow of gas in the pipeline is lower than it would have been on that day. This is one way of effectively increasing the utilisation of the existing pipeline capacity. Although back-haul tariffs obviously vary between specific circumstances, the back-haul tariffs typically are approximately half of the forward haul tariffs.

### **Wholesale gas markets**

A significant recent gas industry development is the proposed establishment of Short Term Trading Markets (STTM) at hubs in Sydney and Adelaide by the Australian Energy Market Operator.

These are mandatory wholesale gas markets in which all gas transmitted through a hub, including gas which is supplied under long term gas supply contracts, is bought from, and sold to, the STTM. While it has many similar characteristics, objectives and outcomes, it is conceptually different from the existing Victorian Wholesale Gas market in that the Victorian Market is a net pool arrangement which does not include contractual supplies (i.e. its primary purpose is to balance the principal transmission and distribution systems by injections and withdrawals).

While the intention was to commence operation of the Sydney and Adelaide STTMs in June 2010, trials have been conducted since March 2010 and based on the progress and feedback, the commencement has been delayed until September 2010. AEMO's intention is to review the necessity or otherwise of additional hubs in 2011.

The stated objectives of the STTM are to:

"..help facilitate the development of economically efficient gas markets through:

- providing transparent price signals for gas delivered and withdrawn from defined market hubs
- enabling the participation of all major gas users, including direct transmission customers (wherever practicable)

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- efficiently pricing congestion on the system(including facilitating a market based solution to emergencies if possible)
- facilitating secondary trading (including demand side response) from short term market prices.

The basic mechanism is to establish a single daily market-clearing hub price before each gas day by matching supply and demand through offers and bids to deliver gas to, or to take gas from, each hub. In many ways it is similar to the National Electricity Market although cleared and settled on a daily basis rather than half-hourly.

While the establishment of the STTMs is still in its infancy, and a range of issues may emerge from their application, we consider that there is no doubt that the Ministerial Council of Energy will wish to pursue their establishment. In 2011 it is planned to extend the market to Queensland.

We recommend that this is a subject which ESAA may wish to be expanded in Stage 2.

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## EnergyQuest

### About EnergyQuest

EnergyQuest is an energy consulting company established by Dr Graeme Bethune in 2005 to provide strategic analysis on Australian oil, gas and unconventional energy sources. It produces regular multi-client reports and undertakes specific consulting assignments.

EnergyQuest is increasingly recognised as an authoritative source of data and analysis on Australian energy and its reports on energy trends are regularly quoted by the major international news services such as Bloomberg, Platts and Dow Jones, as well as by the Australian media. The Australian Energy Regulator has made extensive use of EnergyQuest data in their State of the Energy Market Reports since 2007. The 2009 report contained a lead essay on Australian gas markets by Graeme Bethune.

EnergyQuest's clients include most major Australian energy companies, most Australian governments, institutional investors and a number of international companies.

Many EnergyQuest clients are members of the ESAA: AGL, ATCO Power, CS Energy, Delta Electricity, Energy Australia, Envestra, Earing Energy, ERM Power, Jemena, Origin Energy, Snowy Hydro, Stanwell, Synergy and Tarong Energy.

EnergyQuest is a member of the Australian Petroleum Production and Exploration Association, the Australian upstream oil industry association, and the Australian Pipeline Industry Association.

### Research and Analysis

EnergyQuest produces the *EnergyQuarterly*, which provides comprehensive and timely statistical analysis of oil and gas production, reserves, development projects, gas contracts and prices in Australia.

EnergyQuest has also produced a major 180 page multi-client study, *Australian Coal Seam Gas 2010: CSG Meets LNG* and, a comprehensive review of Australian biofuels, *Australian Biofuels 2009*.

### Consulting

#### **Energy Supply**

EnergyQuest has undertaken assignments for major energy producers, buyers and government agencies on the future energy supply and cost outlook and strategic options.

#### **Natural Gas**

EnergyQuest has undertaken many assignments on Australian gas, including:

- Independent report on gas reserves for a proposed pipeline acquisition.
- Independent report on gas deliverability for a major gas user.
- Advice for a NSW power generator on gas supply options.
- Advice on gas supply options for the Mt Isa minerals province.
- Gas price forecasts by Australian state to 2030.

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- Advice for an infrastructure provider on east coast gas storage options.
- Advice for a major oil and gas company on potential Australian LNG projects.
- Independent expert report for an east coast gas price arbitration in 2008.
- Projections of future Australian coal seam gas demand and supply for a major resources company.
- Report on coal seam gas for a potential major customer.
- Advice on east coast gas supply options for a major industrial customer.
- Advice on gas marketing and price options for a potential gas field development.
- Advice on the outlook for Australian gas (domestic and LNG) for a major resources company.
- Advice on gas transmission pipelines for an institutional investor.
- Advice on gas commercialization outlook and options for a proposed east coast gas development.

### **LNG**

EnergyQuest undertakes assignments on LNG marketing and shipping:

- Facilitation of large LNG projects (producers or receiving terminals) by connecting projects with potential suppliers /customers.
- Negotiation of contracts for sale or purchase of LNG.
- World LNG market supply/demand (with a particular focus on Asia/Pacific).
- World LNG market strategic direction (i.e. how and where to secure sales or purchase of LNG given the risk factors associated with various LNG suppliers or consumers).
- The interplay between pipeline and LNG supply in world markets (with a particular focus on Asia/Pacific).
- LNG spot trading.
- Facilitation of commercial activities relating to LNG shipping (ship charters, ship purchase).

### **EnergyQuest Team**

- Dr Graeme Bethune, CEO, with 30 years experience in economic and financial analysis, 10 years in senior business development and finance roles with Santos and founder of EnergyQuest in 2005. Graeme ranks in the top 5% of experts in the Gerson Lehrman Energy and Industrials Council, a global network of over 30,000 experts in the energy, transport and industrials sectors, providing advice to investors, professional services firms and companies.
- Graeme Atwell, Senior Associate, with 40 years experience in power generation and gas contracting and trading with ETSA and Santos. Working with EnergyQuest since 2007. Gas supply and marketing specialist.

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- Mike Cochran, Senior Associate, with 30 years experience in oil and petroleum marketing with Santos and mineral marketing with Rio Tinto. Working with EnergyQuest since 2005. Specialist in conventional and alternative liquid fuels.
- Greg Veitch, Senior Associate, 28 years with Shell, with senior roles in LNG marketing, commercial and shipping.
- Susan Bethune, Executive Manager and co-founder of EnergyQuest, specialist in economic, financial and statistical analysis.

### ***Dr Graeme Bethune Chief Executive***

Graeme Bethune is CEO of EnergyQuest, which he established in 2005 to provide strategic research and analysis on Australian oil, gas and other energy sources.

Graeme is author of *Australia's Natural Gas Markets: Connecting With the World*, the lead essay in the *State of the Energy Market 2009* report published by the Australian Energy Regulator.

He is a board member of the Australian Gas Industry Trust and in this capacity was a member of the Australian delegation to the World Gas Conference in 2009.

He contributes to a number of study groups of the International Gas Union on international gas strategy, gas markets and LNG.

He is a technical editor of the SPE Economics and Management Journal and is rated in the top 5% of analysts in the Gerson Lehrman global network of energy experts.

Prior to establishing EnergyQuest, Graeme had 30 years in senior finance and corporate affairs roles, including 10 years in senior executive positions with Santos.

Graeme is Chair of the Australian Institute of Energy in South Australia, a member of the University of Adelaide Business School Advisory Board and assists the Australian School of Petroleum at the University of Adelaide in supervision of doctoral candidates. In the not-for-profit sector, he is Chairman of the Phoenix Society.

Graeme has a first-class honours degree in economics from Monash University and a PhD from the Australian National University. He has undertaken the executive program at the Graduate School of Business at Stanford University, is a fellow of the Australian Institute of Company Directors and the Australian Society of Certified Practising Accountants and is a member of the US Society of Petroleum Engineers (SPE) and the Petroleum Exploration Society of Australia.

### ***Graeme Atwell Senior Associate***

Graeme is an engineer with over 40 years of experience in the energy industry in Australia, primarily in gas and power.

Since joining EnergyQuest in 2007, Graeme has advised both gas users and producers on strategic and commercial issues. He has also acted as an independent expert in gas price arbitrations.

For over 30 years, Graeme operated in a diverse range of roles in the electricity generation industry in South Australia. This included power station design, operation and maintenance, coal mining and purchasing and trading of gas for electricity generation.

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## E N E R G Y Q U E S T

Between 2001 and 2007, Graeme was employed by Santos in key commercial roles.

This included marketing and commercialisation of gas from the Cooper Basin, including the sale of 500PJ of gas (over \$2 billion) to AGL in 2002, major ethane sales to Qenos in Sydney, and negotiation and establishment of Australia's first major gas swap agreement which enabled Queensland CSM to be contractually supplied to Sydney markets.

Within Santos, Graeme was also responsible for commercialisation of Santos' Timor Sea assets and played a key role in the project to bring PNG gas to Australia.

In support of Graeme's commercial and contractual responsibilities he also completed a Professional Certificate in Arbitration and Mediation.

Graeme is a member of the Australian Institute of Energy, and the Institute of Arbitrators and Mediators.

### ***Mike Cochran Senior Associate***

Mike Cochran has been working with EnergyQuest since 2005 and specialises in conventional and alternative liquid fuels.

Previously Mike held senior commercial and marketing positions with some of the world's largest resource and petroleum organisations, Santos Ltd, Rio Tinto and, BHP.

During 22 years with Santos, Mike was responsible for marketing Santos' petroleum liquids, crude oil, LPG, condensate and naphtha, in international markets. He was also responsible for business improvement initiatives such as splitting condensate/naphtha for the Asian petrochemical and Hong Kong town gas markets and, inland production of diesel fuel.

Mike has a Bachelor's degree in Economics from Sydney University and post graduate Diploma of Oil Supply and Refining (University of Oxford). Over the past eight years, Mike has presented at national and international forums on condensate, naphtha, LPG and biofuels.

### ***Greg Veitch Senior Associate***

Greg Veitch is a leading expert in LNG marketing, commercial and shipping.

He worked in the Shell organization for 28 years and was a Director of four Shell or Shell joint venture companies and Chairman of the North West Shelf Shipping Services Company.

He has extensive experience in LNG marketing, leading negotiations for several long-term contracts in Asia and numerous spot contracts in Asia and the USA. He has purchased LNG from Asian and Middle East suppliers.

Greg was also involved in North West Shelf, Gorgon and Sunrise project developments.

Since January 2007 Greg has been an independent consultant. In this role he was Vice President LNG Supply at NorthernStar NG between February 2007 and April 2010, for whom developed LNG supply opportunities for the proposed Bradwood Landing LNG terminal in Oregon in the United States. Greg has also recently consulted to Silver Metals Pty Ltd., Credit Suisse and Goldman Sachs.

Outside of the oil and gas industry Greg has had extensive experience in project development for Shell Metals (Worsley Alumina) and in business planning for Shell Coal.

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He has also been involved in Shell Corporate activities (human resources). Prior to Shell Greg worked with Nabalco Alumina Pty Ltd in a technical role.

***Susan Bethune Executive Manager***

Susan Bethune is a partner in EnergyQuest, responsible for market data and analysis.

She is an expert on energy market data and modelling, including energy prices, production and reserves. Susan has created and maintains the data bases used in EnergyQuest's EnergyQuarterly reports and has undertaken numerous projects for clients wanting customised data series.

Susan has 35 years experience in economic and financial analysis with the Australian government (Australian Bureau of Statistics and Productivity Commission), the corporate and finance sectors and the tertiary education sector (University of Adelaide and University of South Australia). She has a Bachelor of Arts with Honours from Macquarie University and a Masters of Economics from ANU.

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