ENERGYQUEST

esaa Domestic Gas Study Stage 2

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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

Section 1 Gas reserves and resources

- Australia is a gas-rich country, with substantial and growing reserves and resources of natural gas, both conventional and coal seam gas, with potential for further growth.
- Australia's gas reserves and resources are orders of magnitude greater than current domestic demand: currently 144 times domestic demand on the east coast and 385 times domestic demand in West Australia. Many resources are also remote from domestic gas markets. Accordingly these resources can only be fully monetised through exporting.

Section 2 Gas production costs

- Gas production costs vary significantly, depending on whether a project is onshore or offshore and also whether it utilises existing infrastructure (brownfield) or requires new infrastructure (greenfield).
- Costs of offshore developments have increased considerably. We estimate that production costs of Reindeer and Macedon, the new domestic gas developments, offshore Western Australia, will have a production cost (2010$, including capital and operating costs) of around $7.00/GJ. The production costs of domestic gas from the Gorgon and Wheatstone LNG projects may be somewhat lower at around $6.00/GJ but still expensive by historical standards.
- Offshore Victoria, the major uncommitted domestic gas resources are held by the Gippsland Joint Venture (GBJV), which has the Kipper and Turrum developments currently underway. BHP Billiton has recently disclosed major cost increases for these developments. Based on these disclosures, we estimate an average domestic gas production cost of $7.20/GJ from these developments. Other GBJV Contingent Resources are likely to be more expensive still and we estimate a possible production cost of over $9.00/GJ. While Victorian gas prices are currently low, these cost increases suggest that Victorian prices may increase significantly, not due to LNG developments but due to increased offshore development costs.
- The Cooper Basin has substantial Contingent Resources, comprising both conventional and unconventional gas. The conventional gas is estimated to have a production cost of $5.00/GJ and unconventional gas $8.00/GJ, with a likely time-frame of 5-10 years for commercialisation of large volumes of unconventional gas.
- Coal seam gas (CSG) is the largest source of gas on the east coast. The production cost from major new developments is estimated to be $4.00-5.00/GJ, above current costs of $3.00-4.00/GJ.

Section 3 LNG production outlook

- There are a large number of potential LNG projects in the Asia Pacific region which are chasing a limited volume of uncontracted LNG demand.
- While several Australian projects are close to taking Final Investment Decisions (FID), a number of other projects will probably not take FID on LNG in the near term. They have

a choice of either waiting for new opportunities to develop in the LNG market or to look to domestic gas customers to monetise their projects.

- The total uncontracted LNG market in the Asia Pacific region (demand not yet contracted under a binding sales agreement to a project that has taken FID) is around 25-40 Mtpa but is greatly dependent upon Chinese and Indian demand. In the last two years China has contracted an additional 28 Mtpa of LNG. Most analysts think that it is likely that China may have a total consumption of 40-50 Mtpa by 2020.
- Japan may contract part of its re-contracting volumes (LNG contracts totalling 25Mtpa that are expiring in the period 2011-18) to new Greenfield projects so as to promote supply growth as a security of supply and price stabilisation measure and as a result create an oversupply of LNG in the Asia Pacific.
- Korea has new demand growth potential but it looks as if it will satisfy this demand through new contracts with Gladstone LNG (GLNG), Donngi Sonoro and Prelude LNG in 2011. India will most likely source most of its new gas demand from indigenous supplies or by LNG from Qatar.
- Qatar, if it chooses to use its dominant position in the market, could easily prevent the construction of further new Australian LNG projects.
- Whilst the LNG market will be the most important factor in determining how many new Australian LNG projects are constructed, almost of equal importance is the capacity of the Australian construction industry to build multiple LNG projects within the same time frame. It is our belief that there is sufficient engineering and construction capacity in the Australian region to support at best six concurrent LNG projects.
- Market opportunities and construction capacity may limit growth in Australian LNG production this decade to around 48 Mtpa.
- If competing countries with available LNG capacity (Qatar, Indonesia, Malaysia, Brunei and Abu Dhabi) choose to compete vigorously for the Asian market, Australian growth in LNG projects will be slowed and or prices for LNG may be affected.
- We believe that there will be considerable growth in natural gas field development in both the east and west coasts, primarily to feed LNG plants. Given the nature of long term LNG contracts each of these projects will need to build redundancy into the whole of their gas delivery system. There will be opportunities for domestic gas buyers to tap this additional resource development.

Section 4 Asia-Pacific LNG price outlook

- Asian markets for LNG are based primarily on long term contracts and oil linked pricing. Natural gas markets in Europe and Great Britain have a mixture of long term contracts with oil linked pricing and spot contracts. Markets in the USA are primarily spot contracts with gas-on-gas pricing.
- Whilst Asian long term LNG prices may have the biggest influence on Australian domestic gas pricing if there is a large scale expansion of the Australian LNG business, the connection between the USA, EU and Asian markets cannot be ignored (and will add to the complexity).

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- In Asia there is a cyclical struggle between sellers and buyers over pricing depending on the perception of whether a buyers' or sellers' market exists. This leads to price variations in long term contracts but security of supply is of primary concern to Asian buyers. Spot contracts will remain only a small part of the LNG portfolio.
- It is clear that oil price is by far the biggest factor in the level of LNG price for any Asian contracts developed within the past few years and valid for the next 15-25 years. It is unlikely that new long term LNG contracts will be priced above the Japan standard price during the next 10 year period. There is likely to be some downward pressure on LNG prices for any new contracts concluded after the current array of greenfield LNG projects take FID (mid 2011).
- Domestic gas buyers will be competing with LNG buyers based on netbacks calculated primarily on long term Asian contracts. However there will be opportunities for domestic gas buyers based on built-in redundancy to LNG project supply capacity, on seasonality of LNG sales and on the additional supply capacity available during times of LNG plant routine maintenance shutdowns.
- Domestic gas purchasing strategies may need to be changed to reflect the availability of supply.

Section 5 Commercialisation for export or domestic sales?

- Production growth is the major strategic driver for oil and gas companies and LNG provides superior growth opportunities to Australian domestic gas. Australia's gas reserves and resources are orders of magnitude larger than domestic gas demand.
- LNG is also perceived to yield higher returns than domestic gas and/or to be the primary means of monetising large quantities of expensive or remote gas resources.
- Floating LNG is pushing down the minimum field size required for LNG development.
- Even though LNG may be the main driver for investment in Australian gas, there are still fields that are too small for LNG that are being developed for domestic gas.
- Also many projects that are developed for LNG will also produce domestic gas. As noted above, domestic gas capability allows LNG producers to better manage imbalances between LNG demands and gas supply. It also allows producers to optimise between domestic spot sales and LNG spot sales.

Section 6 Factors that may prevent gas prices moving to export parity

- Gas price netbacks at oil prices of US$80/bbl are estimated to be around $7.30/GJ at Gladstone and $6.90/GJ at Karratha. These estimates have fallen significantly over the last year as the Australian dollar has strengthened against the US dollar.
- In WA the netback estimates are of a similar order of magnitude to the production costs for new projects as estimated in Section 2. East coast netback estimates are higher than current domestic prices and estimated coal seam gas production costs.
- On the west coast there are limited impediments to gas price increases. Barriers to entry are high, development costs are high and competition from coal is limited.

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- On the east coast however, barriers to entry and costs are lower and coal provides strong competition. These factors may have the potential to limit price rises in long-term contracts.

Section 7 LNG projects and domestic gas contracts

- The domestic gas market is still dominated by long-term contracts.
- Notionally the east coast has substantial gas reserves and resources: over 100,000 PJ, compared with cumulative domestic demand over the next 20 years of around 24,000 PJ.
- However the feedback from market participants is that it is difficult to secure long-term gas contracts in Queensland. This reflects the drive for LNG volumes and reserves uncertainty.
- This suggests that the four major LNG proponents are unlikely to want to sign major long-term gas contracts while they have significant uncertainty about offtake agreements and the productivity of their fields.
- At the same time domestic gas contracts will be coming up for renewal and domestic demand as a whole is expected to grow.
- The options for any gas buyers seeking long-term contracts in Queensland, NSW or South Australia are fairly limited. The Cooper Basin is effectively fully contracted. While there are substantial uncontracted reserves at Moranbah, they are mostly 3P. Similarly while the smaller producers Bow Energy, WestSide and Molopo have significant 3P reserves and Contingent Resources, they have relatively small volumes of 2P at this stage. In some cases they are also planning their own power projects or considering LNG.
- Similar considerations apply in NSW in the case of Eastern Star and Metgasco.
- Over the period until start-up of the first Gladstone LNG projects (2014 and 2015) it is likely to be difficult to secure long-term gas contracts. Beyond this long-term contracts are likely to be available but at higher prices than currently.
- Long-term contracts are currently available in Victoria, but are likely to be at higher prices, reflecting increases in offshore development costs.
- Long-term contracts are available on the west coast, albeit at prices significantly higher than historically.

Section 8 WA gas reservation policy

- The North West Shelf (NWS) Project continues to dominate natural gas supply to WA domestic customers in 2010 supplying almost 600TJ/d (maximum sustainable capacity), which represents around 60% of total supply.
- There are concerns that with the expiry of the original NWS domestic gas contracts and the potential for reduced supply capacity out of the NWS project due to reserves depletion, WA natural gas supply will be constrained.
- However, exploration in the Carnarvon Basin continues to yield good results. Chevron, Apache, Hess and Santos have all had recent successes. Higher domestic gas prices

are likely to encourage further exploration and/or commercialisation of fields for domestic gas. There are also prospects for tight gas.

- The gas demand supply balance appears to be tight until the commencement of production from Macedon, Gorgon and Wheatstone between 2014 and 2016. Any significant slippage in these projects would intensify the tight situation.
- The market is also tight again from 2020 when NWS domestic gas production is assumed to commence declining. (The overall outlook is sensitive to NWS reserves and contract rollovers). The results are also sensitive to assumptions about the timing and volume of gas from Browse and Scarborough.
- If the policy settings are correct and the free market is permitted to work then there are ample reserves off the WA coast to meet the foreseeable future needs for natural gas supply in WA. The price for that gas has to be high enough to encourage the explorers to take the further financial risk on production of that resource.

Terms of reference

1. Provide a break-down of current estimates of remaining reserves and contingent resources for each basin.

2. Provide an indicative assessment of production costs for existing projects and new developments in each basin, including the development of contingent resources likely to become commercial in the period to 2030.

3. Provide an assessment of the likely timing and location of additions to LNG production capacity and estimates of annual LNG production for each basin to 2030.

4. Provide an assessment of the path for LNG prices in the Asia-Pacific region to 2030.

5. Identify what factors may prevent east or west coast prices moving to export parity/netback pricing.

6. Provide an assessment of the major financial/commercial drivers influencing the decision of east coast and west coast producers on whether to commercialise resources for supply to export markets or domestic customers.

> a. In the light of these drivers, evaluate the impact of large-scale export LNG projects on the availability of long term gas supply agreements in the east and west coast domestic markets over the short-term (1 to 2 years), medium term (3 to 6 years) and long-term (7 to 10 years).

7. Provide an assessment of the application of the gas reservation policy in Western Australia drawing on the experiences of recently approved LNG projects/expansions.

> a. Quantify the effect of this on the expected size and timing of domestic gas obligations on future proposed LNG projects/expansions in the state.
>
> b. Assess the risk to domestic supply in Western Australia of domestic obligations on LNG projects failing to materialise as anticipated, in terms of volume and timing. In assessing the risk, consider the prospects for additional resources coming on stream to service the domestic market.

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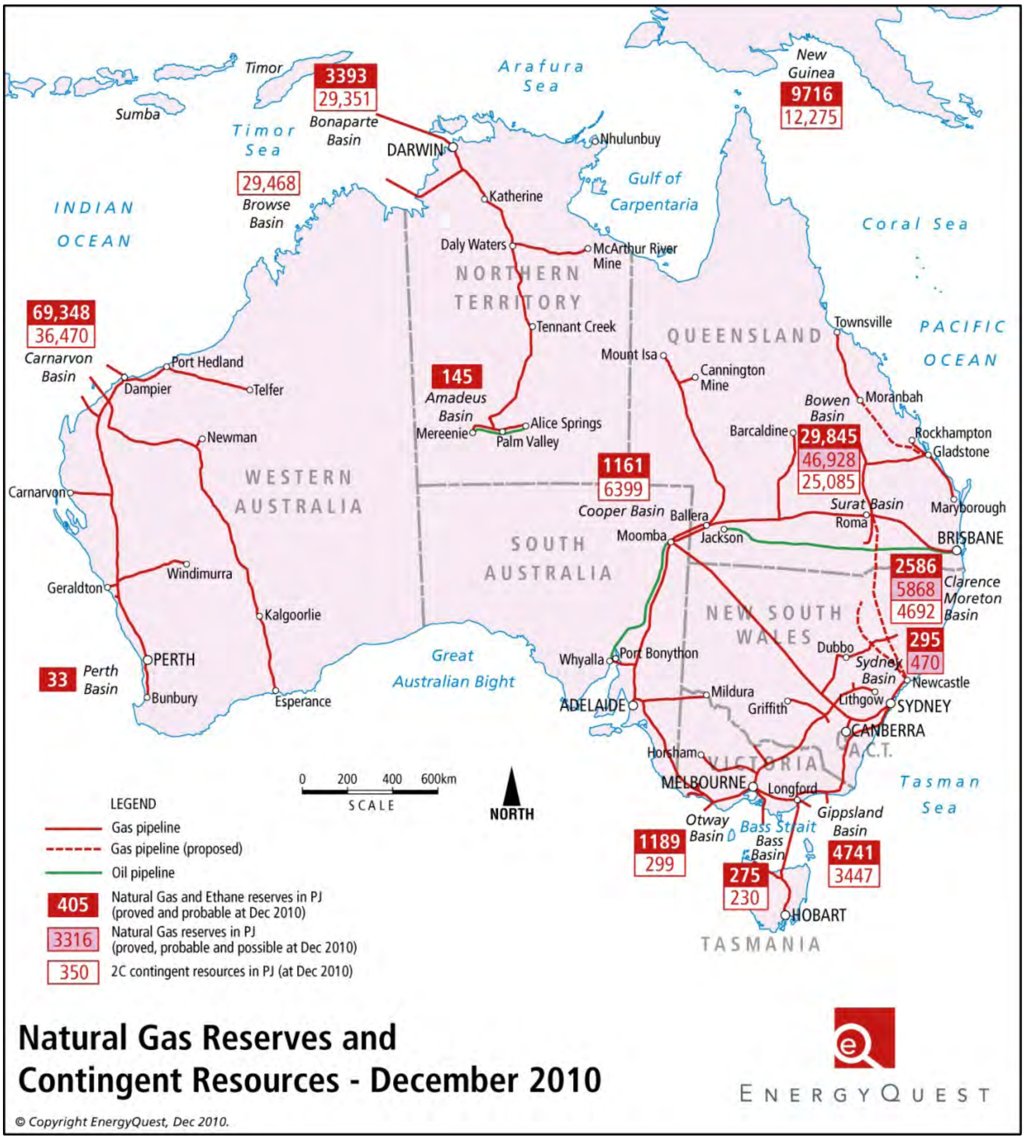
1. Gas reserves and resources

Australia has substantial and growing gas reserves and resources.[1] On the east coast, Queensland now has the largest volume of reserves and resources. These are primarily coal seam gas (CSG). There are also substantial reserves and resources of conventional gas offshore Victoria. New South Wales has growing CSG resources.

Figure 1 Australian natural gas reserves and resources December 2010



Cooper Basin reserves are declining but the basin is believed to have substantial Contingent Resources capable of being commercialised at higher gas prices.

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[1] References to Reserves and Contingent Resources in this report follow the definitions of the Society of Petroleum Engineers, which distinguishes the two categories and defines sub-categories. Reserves are commercial and Contingent Resources are sub-commercial. The different sub-categories denote different levels of technical risk. For Reserves the sub-categories are Proven, Probable and Possible. For Contingent Resources the sub-categories are Low, Best and High. See Appendix 1 for further details.

Estimates of reserves and resources by field are shown in Table 1, Table 2, Table 3 and Figure 1.

Table 1 Australian 2P natural gas reserves December 2010 (PJ)

	Latest %	31-Dec-09 %	Latest PJ	31-Dec-09 PJ	PJ change	% change
Western and northern Australia						
Amadeus	0.1%	0.2%	145	156	-11	-7%
Bonaparte						
Blacktip	0.9%	0.9%	954	954		
Bayu-Undan[1]	0.2%	0.2%	244	244		
Total Bonaparte	1.1%	1.2%	1 198	1 198		
Carnarvon						
NWS JV	16.6%	17.8%	18 439	18 439		
Carnarvon - Other						
Gorgon fields						
Gorgon	16.5%	17.6%	18 232	18 232		
Jansz	13.2%	14.2%	14 681	14 681		
Io	3.5%	3.7%	3 869	3 869		
Chrysaor	1.8%	1.9%	2 014	2 014		
Dionysius	1.4%	1.5%	1 590	1 590		
Eurytion	0.5%	0.6%	583	583		
Pluto	4.4%	4.7%	4 883	4 883		
Julimar-Brunello	2.0%	2.1%	2 226	2 226		
John Brookes	1.0%	1.1%	1 163	1 163		
Macedon	0.5%	0.0%	567	0	567	
Spar/Halyard	0.5%	0.1%	500	71	429	603%
Reindeer	0.4%	0.5%	485	485		
Harriet	0.1%	0.1%	116	116		
Total Other	45.9%	48.1%	50 909	49 913	996	2%
Total Carnarvon	62.6%	65.9%	69 348	68 353	996	1%
Perth	0.0%	0.0%	33	13	20	162%
Total western and northern Australia	**63.8%**	**67.2%**	**70 724**	**69 719**	**1 005**	**1%**
Eastern and southern Australia						
Cooper JV	1.0%	1.1%	1 161	1 151	10	1%
Gippsland						
Gippsland JV	3.4%	4.1%	3 736	4 229	-493	-12%
Kipper	0.6%	0.6%	654	654		
Longtom	0.3%	0.3%	350	350		
Total Gippsland	4.3%	5.0%	4 741	5 233	-493	-9%
Otway						
Thylacine/Geog	0.6%	0.6%	632	584	48	8%
Henry	0.2%	0.3%	270	350	-80	-23%
Minerva	0.2%	0.1%	177	149	28	19%
Casino	0.1%	0.1%	108	113	-4	-4%
Jacaranda Ridge	0.0%	0.0%	1	1		
Total Otway	1.1%	1.2%	1 189	1 197	-8	-1%
Bass						
Yolla	0.2%	0.3%	275	287	-12	-4%
Surat-Bowen Conventional	0.2%	0.2%	196	204	-8	-4%
Surat-Bowen CSG	26.8%	22.6%	29 649	23 458	6 191	26%
NSW CSG	2.6%	2.4%	2 881	2 466	415	17%
Total eastern and southern Australia	**36.2%**	**32.8%**	**40 091**	**33 997**	**6 095**	**18%**
Total	**100.0%**	**100.0%**	**110 816**	**103 716**	**7 100**	**7%**
1. Net entitlement to Australia.						
Gross reserves Bayu-Undan:			2 439	2 439	0	0%

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Table 2 Australian coal seam gas reserves and resources December 2010 (PJ)

Field	Basin	Net (N)/ Gross (G)	Production PJ year ended Sept 2010	Reserves/Resources PJ as at December 2010 1P	2P	3P	2C
Queensland							
Origin Energy fields							
APLNG	Surat-Bowen	N	19	1 527	10 099	14 538	4 844
Spring Gully (minority interests)	Bowen	G			48	60	
ATP788P (Ironbark)	Surat	G				1 003	
Total Origin Energy Fields				1 527	10 147	15 601	4 844
QGC and BG Group operated fields							
QCLNG (excl Woleebee Ck)	Surat-Bowen	N	14.9	727	7 420	7 420	10 730
Woleebee Creek	Surat	G		26	280	853	221
Total BG fields				753	7 700	8 273	10 951
Shell/PetroChina operated fields							
Surat	Surat	G	6.6	472	4 648	6 375	
PL 191 Moranbah Gas Project	Bowen	G	4	336	998	2 040	
ATP 364P North Goonyella	Bowen	G			492	2 614	
Total Shell/PetroChina fields				808	6 138	11 029	
Santos-operated fields							
GLNG	Bowen	N	14	1 427	5 005	7 737	3 732
Mahalo (ATP 337)	Bowen	G					553
Other Queensland	Surat/Bowen	N					
Total Santos fields				1 427	5 005	7 737	4 285
Molopo-operated fields							
Mungi, Harcourt	Bowen	G	0.2	34	250	628	789
Lilyvale and Oak Park	Bowen	G			65	242	166
Timmy	Bowen	G					371
Total Molopo fields				34	315	870	1 326
WestSide							
Meridian Seamgas	Bowen	G	0.9	58	184	334	
Tilbrook/Paranui	Bowen	G				422	
Total WestSide fields				58	184	756	
Bow Energy							
Don Juan	Surat	G			101	195	
Blackwater	Bowen	G			59	1 596	173
Comet	Bowen	G				871	439
Vermont	Bowen	G					1 402
Total Bow Energy fields					160	2 662	2 014
Icon Energy (Lydia)	Surat	G					1 115
Blue Energy (Monslatt)	Bowen	G					454
Comet Ridge (Gunn Project Area)	Galilee						67
Total Queensland			**59**	**4 607**	**29 649**	**46 928**	**25 055**
NSW							
Eastern Star Gas (Narrabri)	Gunnedah	G	0	115	1 520	2 797	3 515
AGL-operated fields							
Gloucester	Gloucester	G		15	669	832	
Camden	Sydney	G	1.4	60	153	199	
Hunter	Sydney	G			142	271	
Total AGL operated fields			1.4	75	964	1 302	
Metgasco (South Casino)	Clarence-Morton	G		3	397	2 239	1 177
Total NSW			**1.5**	**193**	**2 881**	**6 338**	**4 692**
Total			**60.4**	**4 801**	**32 530**	**53 266**	**29 748**

Table 3 Australian oil and gas resources December 2010 (PJ)

	Gas PJ	Oil/NGL MMbbls	Operator
Eastern and southern Australia			
Coal seam gas Queensland	10 951	0	BG Group
Coal seam gas Queensland	4 844	0	Origin Energy
Coal seam gas Queensland	4 285	0	Santos
Coal seam gas Queensland	2 014	0	Bow Energy
Coal seam gas Queensland	1 326	0	Molopo
Coal seam gas Queensland	1 115	0	Icon Energy
Coal seam gas Queensland	454	0	Blue Energy
Coal seam gas Queensland	67	0	Comet Ridge
Coal seam gas NSW (Narrabri)	3 515	0	Eastern Star Gas
Coal seam gas NSW (South Casino)	1 177	0	Metgasco
Cooper Basin JV	6 334	0	Santos
Gippsland JV	2 348	120	ExxonMobil
Wombat/Greater Trifon	834	0	Lakes Oil
Trefoil, White Ibis	207	12	Origin Energy
Judith	194	0	Bass Strait Oil
Thylacine South	100	0	Origin Energy
Martha	80	0	Santos
Longtom	71	1	Nexus
Cooper Basin Other	65	6	Beach
Netherby	64	0	Santos
Halladale/Black Watch	55	0	Origin Energy
Yolla	23	9	Origin Energy
Cooper Basin Other	0	5	Victoria Petroleum
West Seahorse	0	3	3D Oil
Total eastern and southern Australia	**40 123**	**156**	
Offshore western and northern Australia	**Bcf**	**MMbbls**	
Torosa, Calliance, Brecknock	14 000	370	Woodside
Ichthys	12 800	527	Inpex
Evans Shoal	8 000	0	Magellan
Scarborough	8 000	0	BHP Billiton
Caldita-Barossa	6 000	0	ConocoPhilllips
Sunrise	5 130	226	Woodside
Heron/Blackwood	4 960	0	MEO Australia
Wheatstone	4 000	25	Chevron
Clio	3 145	20	Chevron
Tidepole (NWS)	3 000	100	Woodside
Prelude	2 600	120	Shell
West Tryal Rocks	2 560	38	Chevron
Thebe	2 500	0	BHP Billiton
Geryon/Callirhoe	2 387	9	Chevron
Chandon	2 150	11	Chevron
Petrel Tern	2 100	0	Santos
Argus	1 500	0	BHP Billiton
Iago	1 066	11	Chevron
Concerto	1 000	0	Shell
Orthrus	852	2	Chevron
Pluto, Xena	500	6	Woodside
Lady Nora (NWS)	414	100	Woodside
Maitland	245	5	Apache
Prometheus/Rubicon	197	0	Eni
Urania	197	0	Chevron
Macedon	57	0	BHP Billiton
Perth	35	2	AWE
Greater Enfield	0	124	Woodside
Balnaves	0	16	Apache
Other	500	25	
Total western and northern Australia	**89 896**	**1 737**	
Total	**127 748**	**1 893**	

East coast reserves have grown substantially in recent years due to CSG[2]. There is believed to be further CSG potential. Geoscience Australia (Geoscience Australia, 2009) estimates total east coast CSG potential of 168 610 PJ, twice currently booked reserves and resources.

In addition there are resources of tight gas and potentially shale gas on the east coast. Tight gas exists in low permeability (poor quality) reservoirs and would generally require artificial stimulation (rock fracturing or "fraccing") to achieve commercial flow rates. This requires higher gas prices to be economically viable. 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 is gas still within the shale source rock. This also requires artificial stimulation. As Geoscience Australia notes, shale gas exploration is in its infancy in Australia and they do not attempt to estimate the likely potential. However a number of companies are actively assessing the potential of the Cooper Basin in particular for shale gas.

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.

On the west coast, the Carnarvon Basin has 69 348 PJ of 2P reserves plus another 36 470 PJ of Contingent Resources. Significant gas discoveries continue to be made in the basin.

The remote Browse Basin has 29 468 PJ of Contingent Resources. Exploration also continues to be successful in the Browse Basin. Geoscience Australia estimates that the Basin has a potential resource of around 36 000 PJ.

There are also large fields in the Bonaparte Basin.

Work is also underway to assess the potential for tight gas and shale gas onshore West Australia.

Australia's gas reserves and resources are orders of magnitude greater than current domestic demand: currently 144 times domestic demand on the east coast and 385 times domestic demand in West Australia.

[2] The EnergyQuest reserves estimates are based on company disclosures. The recent 2010 Gas Statement of Opportunities (AEMO, 2010) (GSOO) also has estimates of east coast gas reserves and resources, as of the end of 2009. Compared with the estimates above, the GSOO estimates of 2P reserves are somewhat lower (36,674 PJ versus 40,091 PJ above) and the GSOO estimates of 3P reserves are somewhat higher (67,077 PJ versus 60,828 above). However the GSOO estimates 2C resources of 81,394 PJ compared with the EnergyQuest estimate derived from company announcements of 40,123 PJ. Arrow Energy has never disclosed a verifiable 2C estimate and therefore EnergyQuest holds zero. The GSOO assumes 19,000 PJ of 2C resources for Arrow. The GSOO also estimates QGC 2C of 18,080 PJ..

2. Gas production costs

This section provides an indicative assessment of production costs for existing projects and new developments in each basin, including the development of contingent resources likely to become commercial in the period to 2030. It first discusses trends in development costs and then reviews each basin.

Development costs

Development costs are the major drivers of gas production costs. These include the cost of drilling and completing exploration, appraisal and development wells and building pipelines and gas processing plants.

Figure 2 shows development costs for conventional domestic gas developments offshore Australia. It represents the total announced capital cost for the project divided by 2P gas reserves, expressed as A$ per gigajoule (GJ) of reserves. The horizontal axis represents the first year of expected production.

There is clearly considerable variability in costs but also a clear pattern of substantial cost increases. East Spar, a project offshore Western Australia that came into production in 1996, cost $0.55/GJ of gas reserves. This included an innovative offshore development plus construction of a gas plant on Varanus Island. The Macedon project currently being developed by BHP Billiton and due to come into production in 2013 is expected to cost $2.82/GJ. The project involves four offshore wells and an onshore gas plant. BHP Billiton has also recently announced revised development costs for Kipper of $3.06/GJ, up from the initial estimate of $1.83/GJ.

Costs are also quite variable, depending on the scale of any required development and the existence or otherwise of existing infrastructure. For example development of the John Brookes field offshore WA utilised the East Spar gas plant, rather than building a new plant. Similarly, the development of Longtom in the Gippsland Basin uses the existing Orbost gas plant. Greenfield projects require the complete complement of wells, pipelines and processing facilities.

Cost estimates

The following sections provide estimates of break-even production costs for current producing projects and potential new developments. The estimates are based on a number of sources. For some existing projects, current gas prices, together with perceived profitability provides a guide. Discounted cash flows have also been estimated for some existing projects and a number of new projects, based on company announcements about production costs and other project parameters.

The general assumptions used in the discounted cash-flows are:

- The target internal rate of return is 12% after tax.
- Inflation is 3% per annum. (The Reserve Bank inflation target is 2-3% and the current long-term assumption from Westpac is 2.7-2.8%).
- Estimates are un-geared.

- Gas prices increase at 90% of inflation. (Historically prices under long-term Australian domestic gas contracts have increased at a percentage of inflation, typically 85-90%).
- Operating costs increase in line with inflation. (However, because of the potential for inflation in operating costs, some operating cost sensitivities are given below).
- Break-even gas prices are expressed in 2010 dollars.
- PRRT applies to offshore projects. PRRT calculations do not take account of past exploration costs or deductions arising from activities in other permits. (The results are not sensitive to the effective PRRT rate).
- Onshore projects are subject to royalties. The possible impact of applying PRRT to onshore projects as intended by the Federal Government is also discussed.
- All break-even prices are ex-plant.
- LNG projects are based on the life of contracts.
- For offshore domestic gas projects, full capital costs are assumed to be incurred up to first production. To the extent any capital costs are incurred later in the life of a field, this assumption may inflate estimated costs.
- Liquids revenue assumes a selling price of $75 per barrel and is assumed to partly offset gas production costs. (From a pure cost perspective production and treatment of liquids is an additional cost. However incorporating liquids revenue as a benefit provides an indication of fundamental field economics).
- Costs are the go-forward costs from the time of project sanction and do not include FEED or acquisition costs.

Due to the variability in the above assumptions, the cost estimates are indicative only but should provide a reasonable ranking of projects.

Gippsland Basin

The Gippsland Basin is the largest gas-producing basin on the east coast. Gas production occurs primarily from the ExxonMobil / BHP-Billiton Gippsland Basin Joint Venture, (GBJV), which comprises the Barracouta, Bream, Flounder, Marlin, Snapper and Tuna fields (Figure 3).

Current status

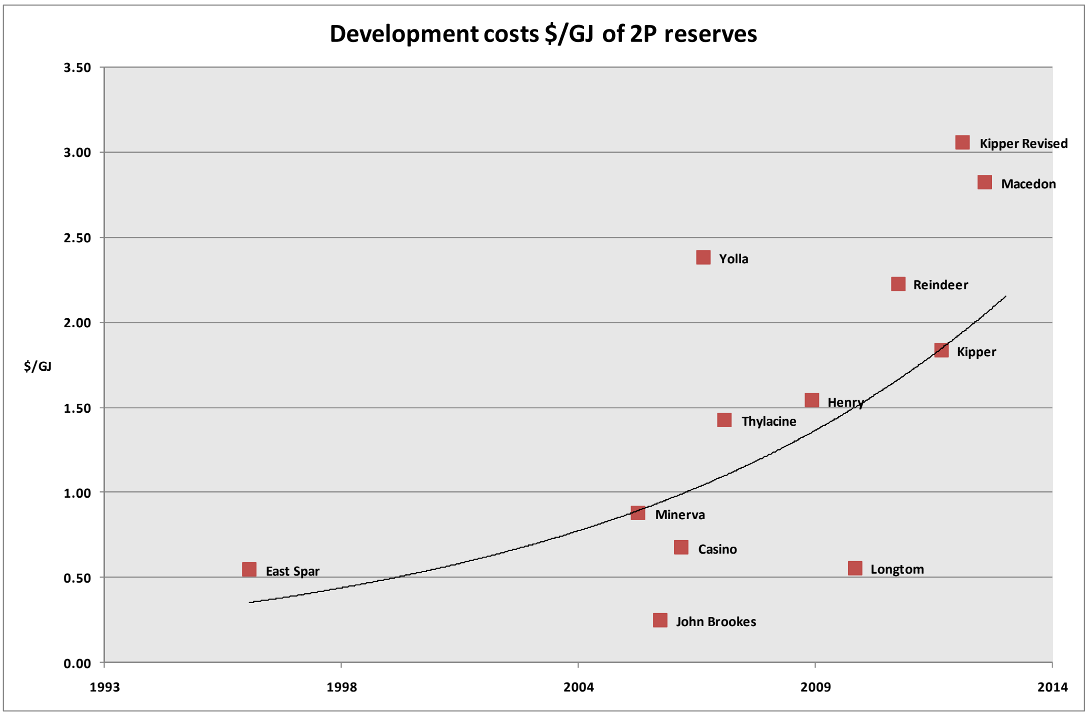
GBJV gas production was 221 PJ in 2009-10, down slightly from 229 PJ in 2008-09 and well below the 2007-08 record of 263 PJ. The Longford Gas Plant has three processing trains, with maximum capacity of 1,140 TJ/d. It often reaches full capacity in winter. Demand is heavily peaked, with the winter peak typically being close to capacity but summer demand being only 50% of winter demand. Any expansion of the Longford plant beyond its current maximum capacity is likely to require investment in an additional processing train.

Development of the Kipper gas field by the GBJV is underway. This is a 660 PJ field, with planned production of 75 TJ/d (27 PJ per annum), to be processed through the Longford plant. Production is expected to increase to 150 TJ/d (54 PJ per annum) from 2015, following completion of a CO_2 removal plant (with 374 TJ/d, 136 PJ per annum capacity).

BHP Billiton has announced a significant cost increase and delay in development of the Kipper field, associated with identification of mercury. Development is now expected to cost up to $2,000 million compared with $1,200 million originally envisaged.

The Turrum field, containing CO_2, is also being developed by the GBJV. Full field development is expected to recover approximately one trillion cubic feet of natural gas and 110 million barrels of oil and gas liquids. Turrum was expected to produce oil and gas liquids from 2011 or 2012 but this has now been pushed back to 2013. Initially gas will be injected back into the reservoir. Gas sales have been expected to commence in 2015 at approximately 200 TJ/d. The cost was originally expected to be approximately $1,400 million but has now been revised to up to $2,750 million.

Figure 2 Offshore gas project development costs (A$/GJ of 2P gas reserves)



Source: Company disclosures.

Figure 3 Gippsland Basin

The Longtom gas project in the Gippsland Basin (operated by Nexus Energy) began production in October 2009 and was producing 48 TJ/d in mid-March 2010. The field was subsequently shut-in to install mercury removal equipment but has recently re-commenced production.

Upside potential

The GBJV has recently drilled a successful exploration well, SE Remora-1.

Lakes Oil is actively pursuing tight gas opportunities onshore. The Wombat field has been assessed as having a contingent resource of 720 PJ. Beach Energy offshoot, Somerton Energy, has farmed-in to the field and a PetroChina subsidiary has a research agreement with Lakes Oil.

Geoscience Australia has quoted estimates of tight gas potential onshore Gippsland of 2,200 PJ.

Estimated production costs

Gippsland Basin 2P reserves are 4,741 PJ, of which approximately 2,250 PJ is contracted (comprising GBJV and Longtom contracts).

We believe the average weighted GBJV gas price ex-Longford under current contracts is around $3.80/GJ. This is likely to be well above the average cost of production. The GBJV has been producing for 40 years. Gas was originally a by-product from oil and liquids production and was sold very cheaply.

The gas price received by Nexus is approximately $3.40/GJ, prior to processing costs. This is probably close to production costs.

The remaining 2P reserves are mostly accounted for by Kipper and Turrum.

The original cost estimate for development of Kipper was approximately $1,200 million but BHP Billiton has recently disclosed that the total cost is now expected to be up to $2,000 million. Turrum has experienced similar cost increases.

Accordingly we estimate an ex-plant average production cost of $7.20/GJ for Kipper to achieve a 12% rate of return, assuming a total capital cost (Stages 1 and 2) of $2,000 million. This estimate takes account of liquids revenue. The production cost for Turrum would be similar.

The Gippsland Contingent Resources comprise:

- GBJV: 2348 PJ. This is most likely dry gas with CO_2. The production cost for a field like Kipper but without liquids is estimated to be $9.35/GJ, based on the latest costs for Kipper.
- Bass Strait Oil has a small field, Judith, of 194 PJ near Kipper, without liquids. The cost of a stand-alone development for a small dry field is likely to be over $9.00/GJ.
- Lakes Oil has a tight gas field called Wombat of 834 PJ onshore Gippsland. Production costs for this field are likely to be lower than offshore but still over $5.00/GJ.

Table 4 Gippsland Basin estimated production costs (2010$)

Field	Status	Size (PJ)	Estimated production cost
Gippsland JV	Contracted 2P	2 250	<$3.50/GJ
Gippsland JV	Uncontracted 2P	2 270	$7.20/GJ
Gippsland JV	Contingent resource	2 348	$9.35/GJ
Kipper	Uncontracted 2P (Santos share)	220	$7.20/GJ
Longtom	2P	421	$3.40/GJ
Longtom	Contingent resource	71	$3.40/GJ
Judith	Contingent resource	194	$9.35/GJ
Wombat	Contingent resource	834	>$5.00/GJ

Otway Basin

Current status

Minerva, Casino and Thylacine are the current producing fields in the Otway Basin. Total Otway production in 2009-10 was 105 PJ, down slightly from the previous year.

Santos has completed development of the Henry and Netherby offshore gas fields via a tieback to the nearby Casino project. The combined production from Henry and Casino is around 90 TJ/d.

Minerva and Thylacine have separate dedicated gas processing plants onshore whereas Casino gas is processed through the Iona plant. The Minerva plant has capacity of 94 TJ/d, the Iona plant capacity of 165 TJ/d and the Thylacine plant 206 TJ/d.

Estimated production cost

Otway Basin 2P reserves are 1,189 PJ and Contingent Resources are 299 PJ. Current 2P reserves are largely committed.

We believe the average weighted gas price from the Iona and Minerva plants is around $3.60/GJ and from Thylacine (which has liquids) is around $3.45/GJ. This is likely to be

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similar to average production costs. We estimate that the production cost from the tie-in of the Henry field to Casino is $3.60/GJ.

Contingent Resources at Thylacine South and Martha would most likely be developed by tying in to Thylacine and Casino respectively at a similar cost to the Henry tie-in.

Bass Basin

Current status

Production is from the Yolla field, which produced 12.3 PJ in 2009-10. Production is all contracted to the field operator, Origin Energy, and is processed at the Lang Lang plant, east of Melbourne, which has 70 TJ/d of capacity.

The project partners have committed to a mid-life enhancement program to extend the life of the field. The program includes drilling of two new development wells and the conversion of the remotely operated platform into a manned facility.

Estimated production cost

The original cost of Yolla, which commenced production in 2006, was $750 million. A further $345 million is currently being invested to drill more wells and upgrade production facilities. This is now being revised upwards by around $100 million. Altogether almost $1200 million will have been invested.

Reflecting the high level of expenditure, the estimated average production cost from Yolla is $5.50/GJ.

The Yolla field currently has 2P reserves of 275 PJ and 2C resources of 230 PJ.

The future production prospects for BassGas have been boosted by the successful appraisal of the southern extension of the Trefoil field and a new field oil and gas discovery at Rockhopper-1 in T/18P.The 2C resource of 230 PJ represents potential from the Rockhopper and Trefoil fields.

It may be possible to tie these fields in to Yolla. The cost would probably be similar to Henry, estimated to be $3.60/GJ plus processing costs.

Figure 4 Otway Basin

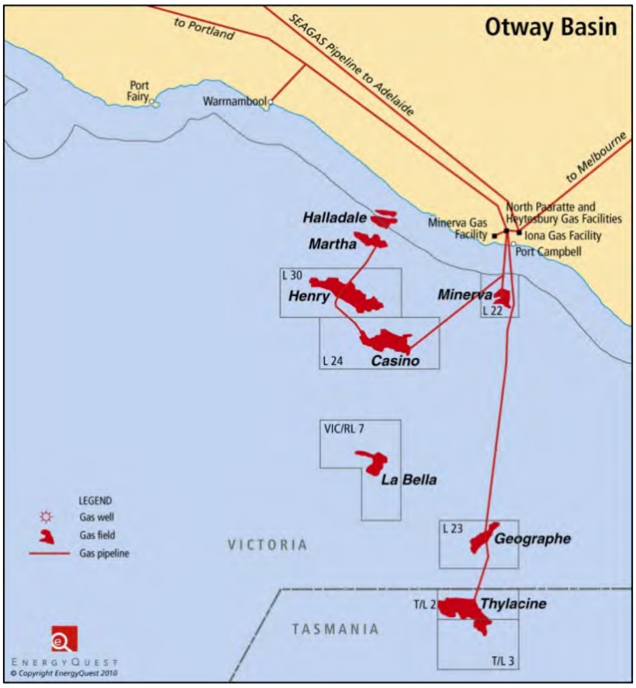
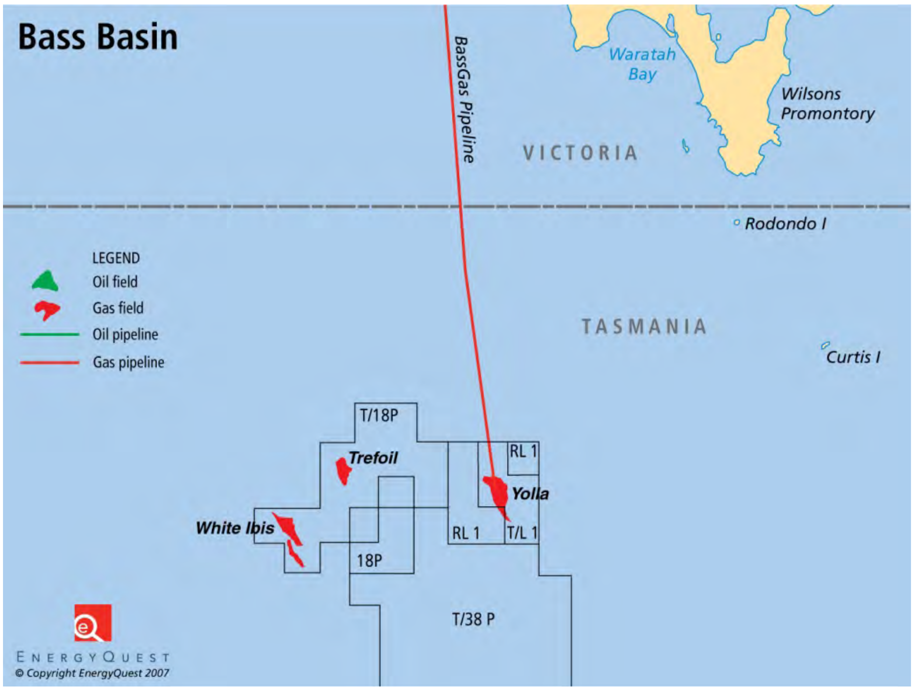


Table 5 Otway and Bass basins estimated production costs (2010$)

Basin	Status	Size (PJ)	Estimated production cost
Otway	2P (Contracted)	1 189	$3.45-$3.60/GJ
Otway	Contingent resource	299	$3.60/GJ (tie-in)
Bass	2P (Contracted)	275	$5.50/GJ
Bass	Contingent resource	230	$3.60/GJ (tie-in)

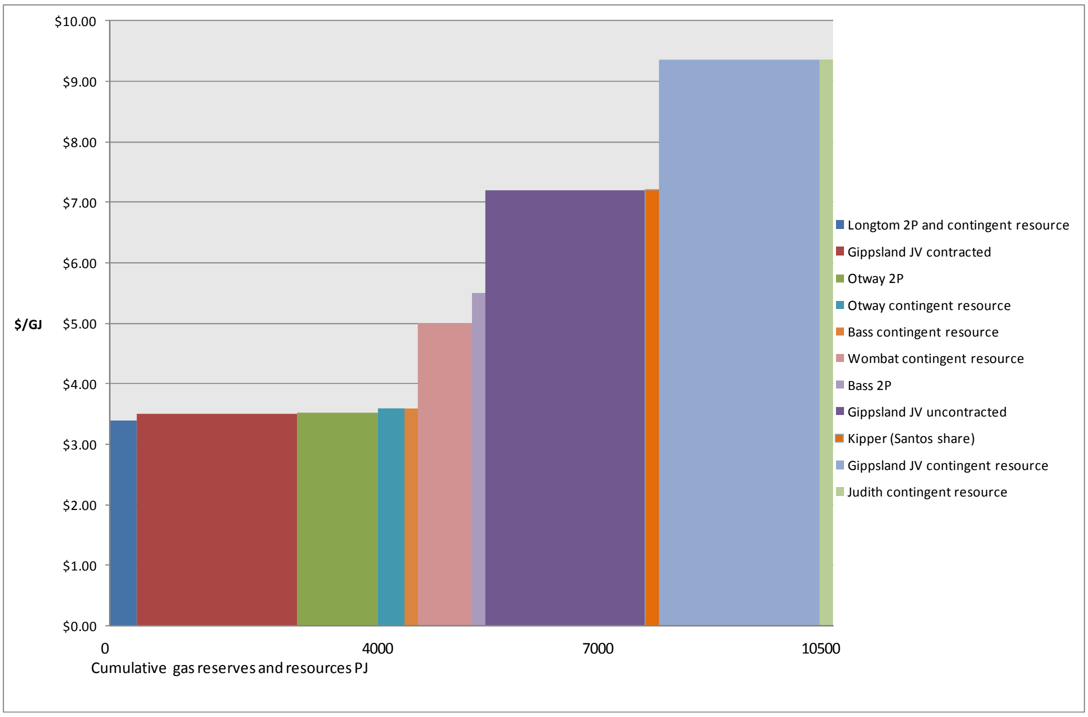
Figure 5 Bass Basin



Offshore Victoria production costs

Figure 6 shows estimated offshore Victorian production costs in the context of the relative size of each resource.

Figure 6 Offshore Victoria production costs (2010$)



Uncontracted gas is dominated by the GBJV. 'Gippsland JV uncontracted' is predominantly Kipper and Turrum. 'Gippsland JV contingent resource' is resources available for development after Kipper and Turrum, which are expected to be significantly more expensive to produce.

Cooper Basin

Current status

Annual Cooper Basin production reached a peak of 278 PJ in 2001 and has since declined, falling to 103 PJ in 2009-10. There are two major gas plants, Moomba in South Australia, with capacity of 430 TJ/d, and Ballera in Queensland, which has capacity of 150 TJ/d. Ballera is effectively mothballed. The immediate production outlook is for continuing decline.

The Cooper Basin Joint Venture (CBJV), of which Santos is the operator, has 2P reserves of 1,161 PJ. Reserves have been falling, but have begun to stabilise and are currently equal to 10 years of production cover.

Upside potential

Santos has identified 6,399 PJ (gross) of Contingent Resources. Around 1,600 PJ represents conventional gas potential from in-fill drilling in the Moomba, Big Lake, Tirrawarra, Cowralli, Nephrite and Tindilpie fields. The remainder represents unconventional gas potential from shale gas and tight gas.

Santos believes that lifting the average recovery factor for conventional gas from 50% to 75% would add 2,866 PJ to reserves and that there is unconventional resource potential of over 39,000 PJ in its acreage.

Beach Energy believes there is potential shale gas-in-place in their Nappamerri Trough acreage of over 200 trillion cubic feet (Tcf) (212,000 PJ).

Strike Oil believes there is a prospective CSG resource of 7,000-19,000 PJ in its PEL 96 acreage.

Stuart Petroleum believes that it has the potential to define 38-60 Tcf (40,300-63,600 PJ) of shale gas-in-place and 20 Tcf (21,200 PJ) of CSG-in-place in its acreage.

Estimated production cost

We understand that the average weighted gas price ex-Moomba is around \$3.70/GJ. Of the 1,161 PJ of 2P reserves, around 525 PJ is contracted. In addition, Santos has recently announced an agreement to sell 750 PJ of conventional gas to its Gladstone LNG (GLNG) project, mainly from the Cooper Basin. (Effectively this contracts all remaining 2P reserves). The gas will be sold under an oil-linked pricing formula at a higher price than domestic contracts. Cooper Basin development costs are high and liquids production is falling. Average production costs for 2P reserves are probably close to \$3.70/GJ.

Commercialisation of the Contingent Resources would require higher prices. We believe that the conventional Contingent Resource of around 1600 PJ could be commercialised at \$4-6/GJ. Production costs for the unconventional Contingent Resource are likely to be higher, potentially \$6-10/GJ.

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As indicated above, there are further large additional volumes of gas-in-place in acreage held by Santos, Beach Energy, Strike Oil and Stuart Petroleum.

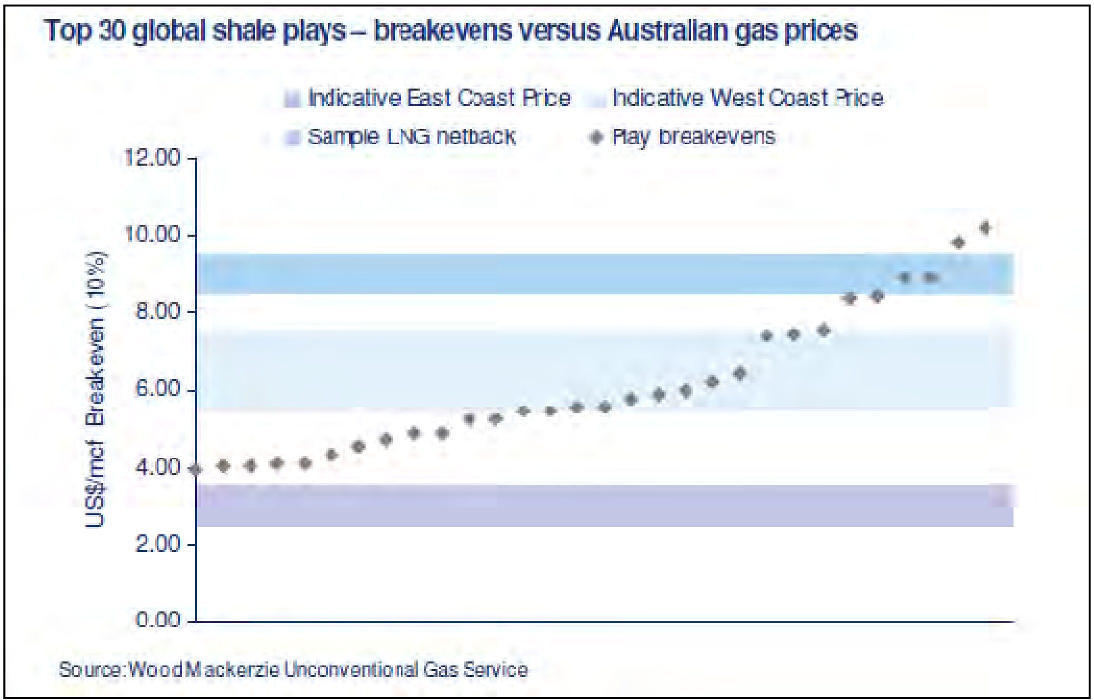
Drilling to confirm gas content and likely productivity of shale gas is only just commencing. At this stage drilling and completion is very expensive. According to Citigroup, the current Beach Energy two-well shale program is likely to cost $40-50 million to drill, case, fracture stimulate and tie-in the wells. Wood Mackenzie (Wood Mackenzie, 2010) believes that even if a substantial resource is confirmed, it will take many years to convert to commercial reserves. They cite evidence from the US that even the highest quality shale gas reserves are higher cost than most conventional and CSG plays in Australia, and above Australia's traditionally low domestic gas prices (Figure 7) and they believe that any Australian shale is likely to break-even at gas prices considerably higher than the leading US plays, which have taken 10-20 years to commercialise. They believe that shale gas is unlikely to be competitive in a 10-15 year time frame and over this period we would expect the cost of shale gas production to exceed $10/GJ.

However Beach Energy is aiming for first gas by 2015 and believes that shale gas should be commercial at oil-linked prices. For this reason they are considering contracting gas to Santos for GLNG and are exploring their own LNG options with Itochu.

Table 6 Cooper Basin estimated production cost (2010$)

Basin	Status	Size (PJ)	Estimated production cost
Cooper	2P (Contracted)	1,161	$3.70/GJ
Cooper	Contingent Resource (Conventional)	1,600	$5.00/GJ
Cooper	Contingent Resource (Unconventional)	5,238	$8.00/GJ

Figure 7 Top 30 global shale plays-breakeven versus Australian gas prices



Source: (Wood Mackenzie, 2010)

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Queensland Coal Seam Gas

Current status

Queensland CSG annual production reached 195 PJ in 2009-10, up from 151 PJ in 2008-09. The three largest fields (based on 2009-10 production) are Berwyndale South/Kenya (operated by QGC (part of the BG Group)), Spring Gully (operated by Australia Pacific LNG (APLNG), a joint venture of ConocoPhillips and Origin Energy) and Fairview (operated by Gladstone LNG (GLNG), a joint venture of Petronas, Santos and Total). Current reserves and resources are:

2P: 29,649 PJ

3P: 46,928 PJ

2C: 25,055 PJ

Reserves continue to increase.

Upside potential

There is considerable upside potential in CSG reserves and resources. Geoscience Australia (Geoscience Australia, 2009) estimates total east coast CSG potential of 168,610 PJ, twice currently booked reserves and resources.

Arrow claims 65,000 PJ of original gas in-place, which could significantly increase reserves.

In addition to exploration in the Bowen and Surat basins, exploration is also underway in Queensland's Galilee Basin.

Estimated production cost

In the September quarter 2010 the average price (ex-plant) of CSG sold by APLNG from their Queensland acreage (Spring Gully, Berwyndale South and Kenya/Argyle) was $3.18/GJ.

QGC's domestic gas is produced from the Berwyndale South and Kenya/Argyle fields at an estimated cost of $3.10/GJ. QGC has approximately 1,300 PJ contracted.

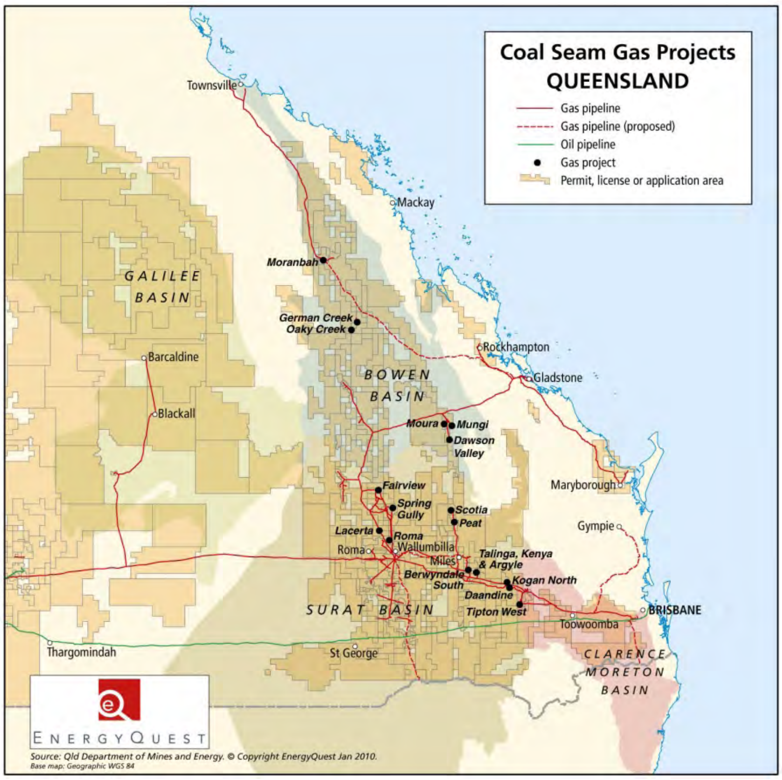
The effective cost of gas for the large-scale LNG developments (the most likely source of significant domestic gas volumes) appears to be higher than current costs. BG has recently announced that the cost to them to develop their 8.5 million tonne per annum (Mtpa) QCLNG project will be US$15 billion (net) to first LNG. The gas for this project will be supplied from their Surat Basin acreage, where they have 13,400 PJ of reserves and resources.

We have used the LNG development cost to back-out the effective gas cost, making the following assumptions:

- USD/AUD exchange rate:1.00
- gross project cost $16,000 million, reflecting the CNOOC and Tokyo Gas interests
- continuing capital expenditure to drill complete and connect 225 wells a year of $400 million from 2016, escalated at the inflation rate
- liquefaction plant cost of $1000 per tonne of capacity
- cost of gas pipeline to Gladstone $660 million

- total gas production of 550 PJ per annum
- operating costs $1.00/GJ in 2010, escalating at the 3% inflation rate.
- project life 20 years

Figure 8 Queensland coal seam gas projects



Based on these assumptions, the estimated production cost is $3.95/GJ, higher than our estimates of the current production cost of $3.10/GJ from Berwyndale South[3].

We believe this reflects a number of factors:

- the complexity of the large scale CSG field development required for LNG projects (effectively diseconomies of scale)
- higher costs outside sweet spots such as Berwyndale South
- possibly anticipated cost increases over the development period.

These estimates assume that a royalty fiscal regime applies for onshore projects. The Federal Government is in the process of introducing a PRRT system. Companies would still pay the state royalty but this will be credited against PRRT. The likely PRRT obligation will depend very much on the agreed starting value of each project. However, given the high prices paid for Queensland CSG resources, PRRT may not be paid for many years.

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[3] These results are sensitive to the target rate of return. Using 10% after tax rather than 12% would reduce the QCLNG break-even price to $3.65/GJ and the Berwyndale South break-even to $2.84/GJ. They are also sensitive to assumptions about escalation in operating costs. Inflating operating costs at 5% rather than 3% per annum increases the break-even gas price from $3.95/GJ to $4.26/GJ.

Accordingly the switch to PRRT may not have a material impact on the break-even gas cost.

QGC also has 4,524 PJ of uncontracted gas resources that are lower quality than their core LNG acreage but which are also likely to be destined for LNG. We expect that the average production cost of these resources would be around $5.00/GJ.

GLNG has 10,604 PJ of gas reserves and resources. We have assumed:

- a 7.8 Mtpa project
- capital cost of $16 billion
- continuing capital expenditure of $400 million (escalated with inflation) to drill 225 wells per annum.

The average implied production cost is $4.70/GJ. Again this is higher than the current production cost from Fairview, estimated to be $3.60/GJ, for similar reasons to the higher costs for QCLNG[4].

APLNG has some 1,800 PJ of gas contracted at an estimated cost of $3.10/GJ. It has an estimated 17,600 PJ available for LNG and domestic gas. This acreage is similar to that for QCLNG and is likely to have a similar cost of $3.95/GJ if developed for LNG.

Origin also has 1,000 PJ of CSG resources in the Surat Basin outside APLNG of potentially good quality. These are most likely to be developed for domestic gas, probably to meet Origin's own needs. We expect that this resource could be commercialised for $3.95/GJ.

The other major LNG proponent is Arrow Energy (now owned by Shell and PetroChina). They have 455 PJ contracted from their Surat acreage, at an estimated average cost of $3.60/GJ, and 430 PJ committed at Moranbah, at a lower cost (reflecting the earlier stage of development) estimated to be $2.75/GJ. They have 4224 PJ uncontracted at Moranbah which we believe could be commercialised at a $4.00/GJ gas price.

Arrow have Surat reserves and resources of 5,920 PJ targeted for LNG. These are lower quality than the QGC reserves and we estimate that the average production cost could be $5.00/GJ.

There are other CSG reserves and resources booked by companies in the Bowen and Surat basins. Bow Energy, Westside and Molopo have 7,887 PJ in the Bowen Basin. Icon Energy and Bow Energy have 1,310 PJ in the Surat basin. Indications from Bow Energy are that their reserves in the Bowen Basin could produce at around $4.00/GJ. Other smaller producers in the Bowen Basin appear to have higher costs. Costs in the Other Surat acreage (primarily Roma) are likely to be higher, estimated to be around $5.00/GJ.

Altogether there is over 8,000 PJ of gas resources in the Surat and Bowen basins operated by smaller companies that could potentially be commercialised for $4.00-5.00/GJ. However most of these companies are also hoping to commercialise their gas for LNG.

These cost estimates are summarised in Table 7, together with 3P reserves plus Contingent Resources.

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[4] The break-even gas price with a 10% target rate of return would be $4.30/GJ. With 5% operating cost inflation it would be $5.00/GJ.

Table 7 Queensland coal seam gas resources and production costs (2010$)

	3P Reserves plus Contingent Resources (PJ)	Cost ($/GJ)
QCLNG		
QGC contracted	1 300	$3.10
QCLNG (Surat)	13 400	$3.95
QGC uncontracted	4 524	$5.00
GLNG		
GLNG (Bowen)	11 469	$4.70
APLNG		
APLNG (contracted)	1 800	$3.10
APLNG (Surat)	17 600	$3.95
Origin uncontracted	1 000	$3.95
Arrow		
Arrow contracted (Surat)	455	$3.60
CILNG (Surat)	5 920	$5.00
Moranbah contracted	430	$2.75
Moranbah uncontracted	4 224	$4.00
Other Bowen	7 887	$4.00-5.00
Other Surat	1 310	$5.00

NSW Coal Seam Gas

Current status

Natural gas production in NSW was a modest 5.7 PJ in 2009-10, all from AGL's Camden project near Sydney. While NSW production is still modest, reserves and resources have been growing quickly. Current estimates are:

2P: 2,881 PJ

3P: 6,338 PJ

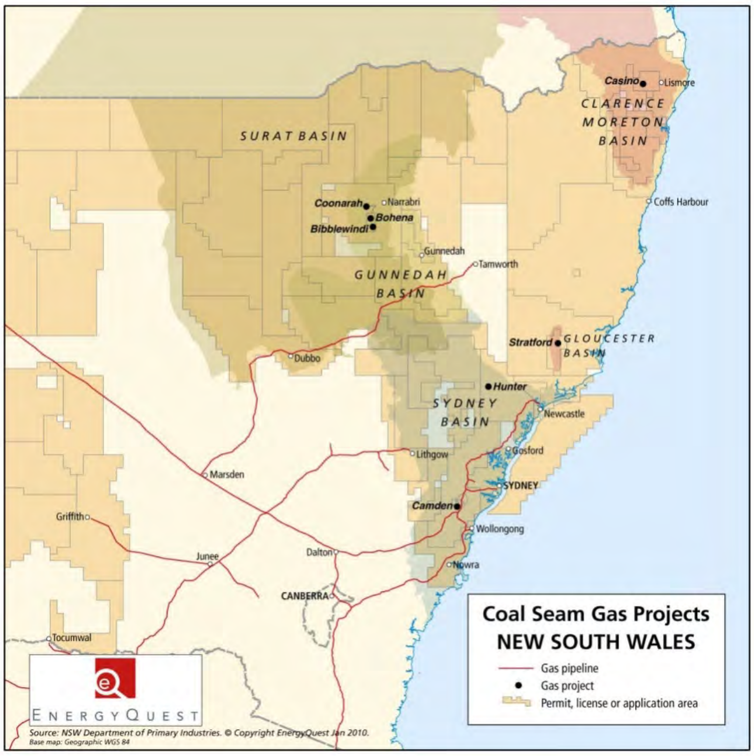
2C: 4,692 PJ

Eastern Star in the Gunnedah Basin has 2,797 PJ of 2P reserves and 3,515 PJ of Contingent Resources. The estimates for Metgasco in the Clarence Morton Basin are 2,239 PJ and 1,177 PJ respectively. AGL is also growing its reserves and resources in the Hunter area.

Upside potential

Santos believes there is over 50 trillion cubic feet (50,000 PJ) of prospective potential in the Gunnedah Basin.

Figure 9 NSW coal seam gas projects



Estimated production costs

The table below shows estimated NSW CSG production costs.

Table 8 NSW coal seam gas resources and production costs (2010$)

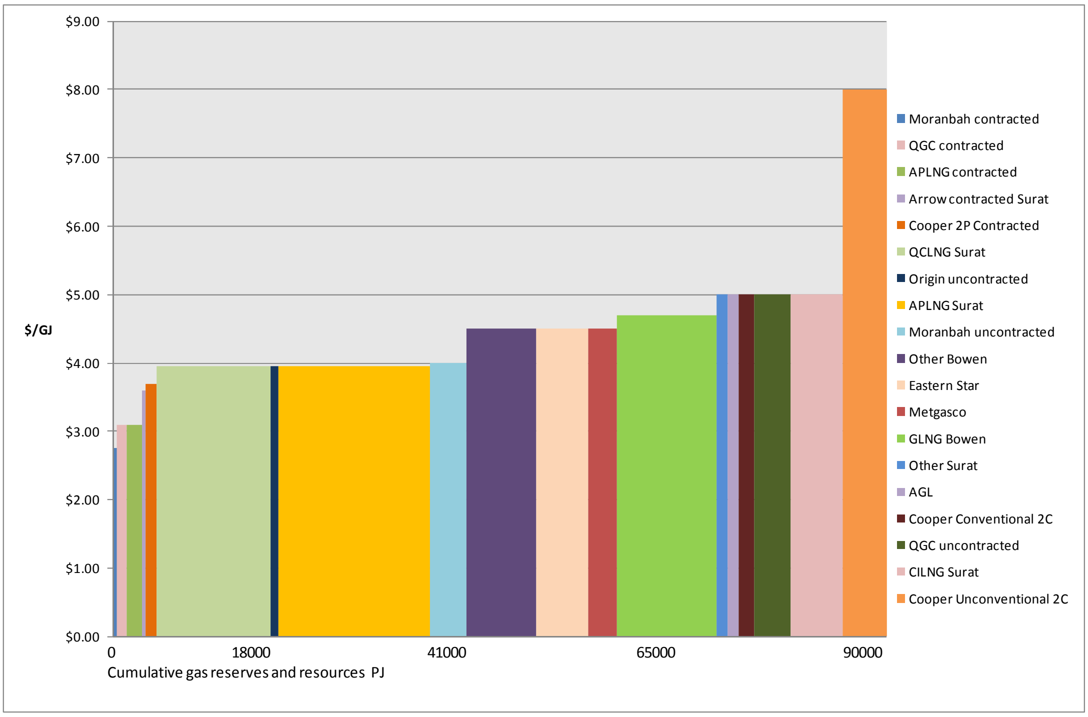
	3P Reserves plus Contingent Resources (PJ)	Cost ($/GJ)
Gunnedah		
Eastern Star	6 312	$4.00-5.00
Clarence-Morton		
Metgasco	3 416	$4.00-5.00
Sydney		
AGL	1 302	$5.00

There is little production history yet from either the Gunnedah or Clarence-Morton basins and what track record there is does not suggest that these are likely to be as productive for domestic gas as the prime Queensland areas. We estimate production costs of $4.00-5.00/GJ. Sydney Basin production is expensive and not expanding, despite being well located. The production cost is estimated to be similar to the delivered cost of gas from alternative sources.

Onshore Australia production costs

Figure 10 shows estimated production costs for the Cooper Basin and east coast coal seam gas. The first five categories on the left end of the horizontal axis all represent contracted gas. The next seven categories represent a large uncontracted gas resource (including substantial LNG resources) of around 34,000 PJ, with an estimated production cost of between $4.00 and $5.00/GJ. Moving to the right there are further volumes at higher estimated costs.

Figure 10 Onshore Australia production costs (2010$)



East coast summary

Figure 11 summarises the cost curve for east coast projects.

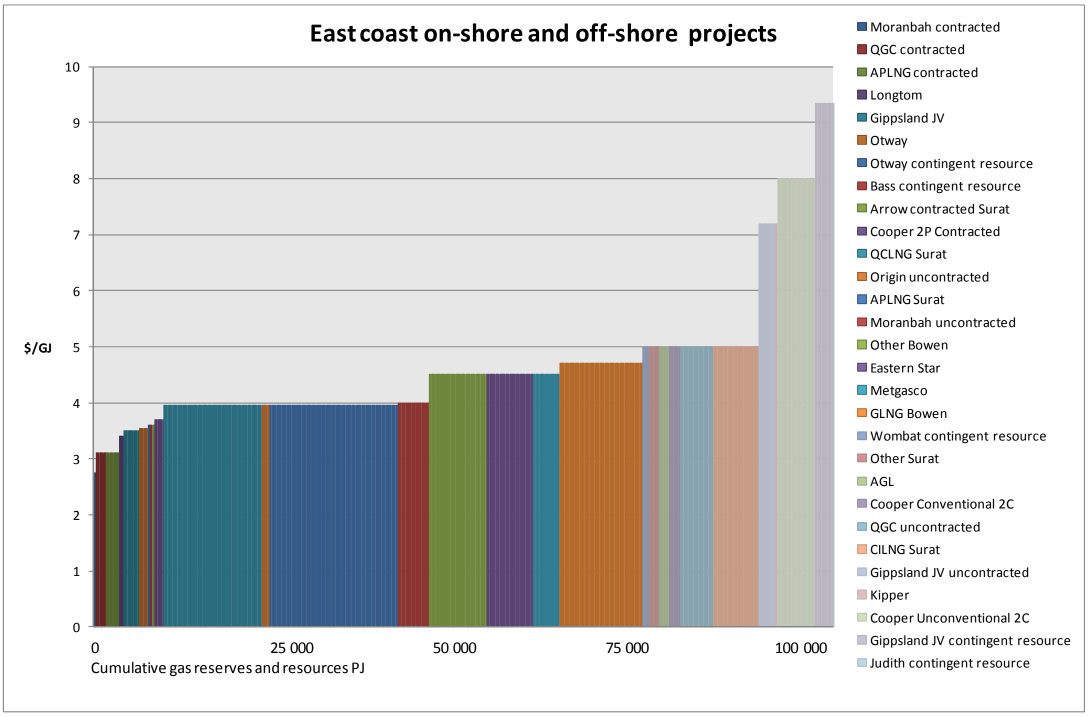
Carnarvon Basin

Current status

The Carnarvon basin supplies the bulk of WA domestic gas, with 2009-10 production of 354 PJ. Around 60% of supply comes from the North West Shelf, with almost all of the remainder from the John Brookes and Harriet fields operated by Apache Energy. The NWS domestic gas plant has capacity of 630 TJ/d and the Apache plant capacity of 360 TJ/d.

The NWS has been supplying domestic gas since 1984. Current NWS domestic contracts soon begin to tail off and conclude by late this decade. These contracts satisfy the NWS's obligations to supply domestic gas. However, the NWS is expected to continue supplying domestic gas beyond this date.

Figure 11 East coast onshore and offshore project production costs (2010$)



Domestic gas prices from the NWS have been around $3.20/GJ but have increased recently, following gas price arbitrations.

Harriet commenced gas production in 1992 and John Brookes in 2005. John Brookes and Harriet contracts extend into the 2020s. The price of John Brookes gas under long-term contracts is currently around $2.30/GJ. John Brookes also produces around 1 MMbbl/a of condensate.

There are a number of domestic gas developments underway in the Carnarvon Basin. Apache is developing a plant at Devil Creek to process gas from the Reindeer field. First gas is scheduled for November 2011. The field will initially produce 110 TJ/d of gas and 500 bbl/d of condensate a day, but has potential to double production.

Apache has also sanctioned development of its Halyard/Spar project, which is expected to begin producing in mid-2011, initially at 50 TJ/d and then ramping up to over 100 TJ/d by early 2013.

BHP Billiton has sanctioned development of the Macedon field, which is due to start production in 2013, with peak production of 75 PJ per annum.

Looking further ahead, the Gorgon and Wheatstone projects include domestic gas components, which will eventually increase the supply to Western Australia consumers. Gorgon has been approved for development with a domestic gas plant supplying up to 300 TJ/day or about one third of Western Australia's current domestic demand. Chevron also announced that Wheatstone would be planned with capacity to supply up to 200 TJ/day of domestic gas.

Figure 12 Carnarvon Basin

Upside potential

The Carnarvon Basin is a prolific gas basin, with a number of recent discoveries large enough to be considered for LNG. Onshore a number of companies are assessing potential for tight gas and shale gas. AWE believes its acreage in the Perth Basin could have gross shale gas-in-place of 13-20 Tcf (13,800-21,200 PJ).

Estimated production costs

The NWS domestic gas facilities cost over $3 billion at 2010 prices.

John Brookes has some very low gas prices. Apache has been realising prices of around $2.30/GJ for a considerable time. John Brookes benefitted from being tied into the processing facilities originally built for the East Spar field. Production costs are estimated to be $1.00-1.50/GJ. Although not all contracts are disclosed, the field may have up to 500 PJ uncontracted. Recent contracts are at high prices, up to $11.80/GJ.

However production costs are significantly higher for new developments. We estimate that the production costs for Macedon are $6.70/GJ and for Reindeer $7.00/GJ. Macedon is expected to cost $1.6 billion to commercialise 2P reserves of 570 PJ and Reindeer nearly $1.1 billion for reserves of 485 PJ. John Brookes cost $300 million with reserves of over 1000 PJ.

No cost estimates have been given for the Halyard/Spar development of around 500 PJ but this will be tied into John Brookes and the Varanus Island processing facilities and is therefore expected to be significantly cheaper than Macedon and Reindeer. If the cost was $300 million, the gas price required to achieve a 12% post tax return could be below $2.00/GJ.

The largest future source of domestic gas is likely to come from LNG plants. As noted above, the $43 billion Gorgon project will produce 15 Mtpa of LNG and up to 300 TJ/d of domestic gas.

In estimating the cost of domestic gas production from a project like this we have made the following assumptions:

- total LNG capacity 15 Mtpa from 2014 for 25 years
- domestic gas demand of 150 TJ/d for 5 years, followed by 300 TJ/d for 20 years
- total project cost $43 billion, liquefaction plant cost $15 billion ($1000 per tonne of capacity), and domestic gas plant cost $300 million[5].
- US$75/bbl oil price and peak liquids production of 4.5 MMbbl in 2015.
- 3% inflation
- 1,000 PJ per annum of feed-gas required to produce 15 Mtpa of LNG plus 300 TJ/d of domestic gas
- total operating costs of $1.00/GJ, escalated at 3% per annum.

The approach taken is to estimate the cost of gas production to the inlets of the LNG and domestic gas plants and then to estimate the cost of processing the domestic gas, including the plant investment.

Based on the above assumptions, the cost of gas at the domestic gas plant outlet would be $6.05/GJ. This estimate does not make any allowance for ongoing capital expenditure and may therefore be conservative.

These estimates are well above historical costs.

No cost estimates for Wheatstone have been released but the cost of producing domestic gas is likely to be similar to Gorgon.

For WA unconventional gas, the same comments apply as on the east coast.

Table 9 Carnarvon Basin domestic gas resources and production costs (2010$)

Field	Status	Size (PJ)	Estimated production cost
NWS	2P (Contracted)	1,400	$3.20/GJ
John Brookes	2P (part contracted)	1,160	$1.00-1.50/GJ
Macedon	2P (part contracted)	567	$6.70/GJ
Reindeer	2P (part contracted)	485	$7.00/GJ
Halyard/Spar	2P	500	<$2.00/GJ
Gorgon	2P	2,000	$6.05/GJ
Wheatstone	Contingent resource	2,000	$6.05/GJ

[5] John Holland won a $160 million contract to construct the Reindeer gas plant. Adding internal costs, we have assumed a total plant cost of $300 million.

Figure 13 Carnarvon Basin production costs (2010$)

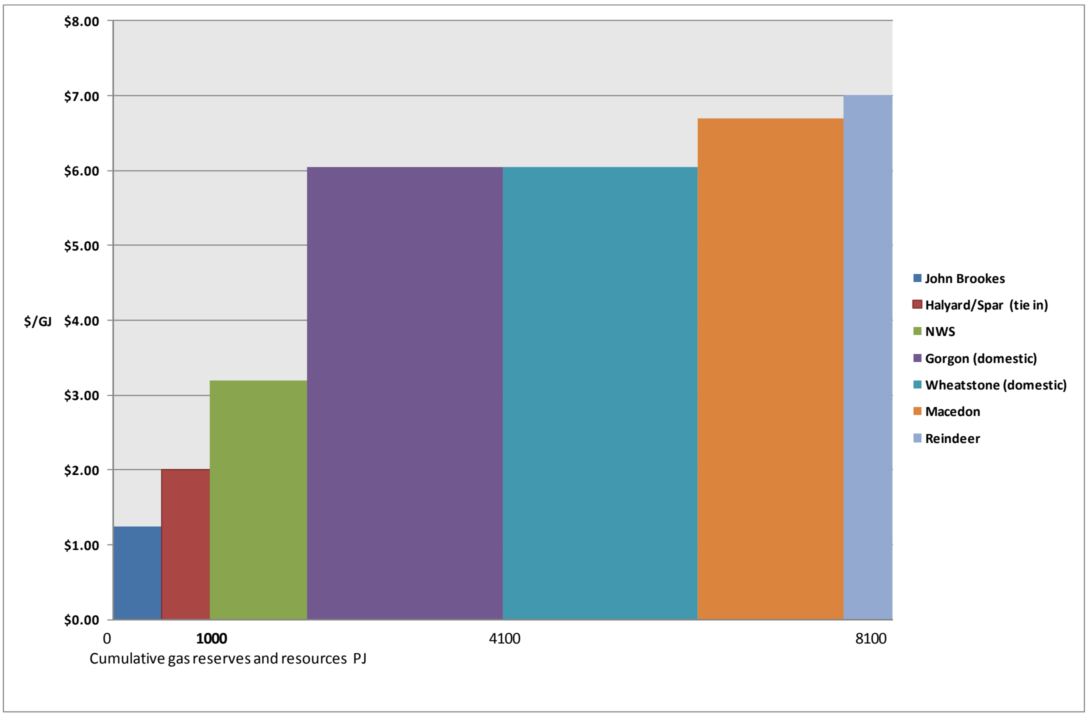


Figure 13 shows the schedule of estimated Carnarvon Basin production costs. Apart from the Halyard/Spar tie-in, all of the new supplies are significantly more costly than historic sources. In terms of volume, future supply is dominated by Gorgon and Wheatstone.

These estimates do not include possible Browse and Scarborough LNG projects. Browse would become relevant for domestic gas if it was piped to Karratha to the NWS plant rather than being processed at James Price Point (which is what is currently proposed) or if, under the WA gas reservation policy, the project partners are required to meet their obligations by buying gas from projects in the Carnarvon Basin. Scarborough is a deep, dry and remote resource. In either case the gas volumes involved would probably be similar to Wheatstone but at a higher cost.

3. LNG production outlook

This Section reviews all of the most credible LNG projects currently being promulgated in the Asia Pacific region.

There are several other projects proposed, including those in NSW (Eastern Star), South Australia (Beach Energy) and Queensland (EWC, Bow Energy and WestSide) that have a small chance of success but are not listed here given the overwhelming number of more advanced projects chasing a diminishing number of near term market opportunities.

Major Asian buyers are rather conservative when dealing with new entrants into the 'LNG club' and tend to look for proven ability to turn promises into reality. It usually takes 2-3 years of testing the waters before they will enter into meaningful negotiations with any new seller.

As such, most of the major projects rated with high probabilities have a better chance of securing the near term market along with a slot in the available construction schedules of the various LNG construction contractors.

Given that, small projects could slip under the radar of the bigger projects especially if they use modular construction techniques (fabrication offshore) and accept lower prices.

But it is clear to us that a number of proposed projects (both small and large) will probably not reach final investment decision (FID) in the near term and they have a choice of either waiting for new opportunities to develop in the LNG market or to look to domestic gas customers to monetise their projects.

Given the potential oversupply of LNG following the large increase in world LNG production materialising during the 2007-2016 period, new LNG opportunities may not be forthcoming until the latter stages of this decade.

LNG outlook

The total uncontracted LNG market in the Asia Pacific region (demand not yet contracted under a binding sales agreement to a project that has taken FID) is around 25-40 Mtpa but is greatly dependent upon Chinese and Indian demand. Both of these countries are developing alternate energy sources (pipeline natural gas, CSG, shale gas, coal) which may supplant LNG in the future even if there is significant near term growth.

China has in the last two years contracted an additional 28 Mtpa of LNG. Analysts are not agreed on what volume China may take but most think that total consumption in China is likely to be between 40-50 Mtpa by 2020.

Japan the largest consumer of LNG is unlikely to take significantly more than a modest increase over the 70 Mtpa it currently takes, due to a potential fall in population longer term. However Japan has been contracting to partially replace around 25 Mtpa of contracts that mature in the period to 2011-18. This is both a security of supply strategy and a longer term price control strategy since the projects with maturing contracts (Indonesia, Malaysia, Brunei, Abu Dhabi) will all have the capacity to produce a high proportion of their current production for many years beyond the end of these contracts.

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Figure 14 Location of LNG Projects in the Australian Region

Korea is still a rapidly growing market with a potential 1.0 Mtpa of unfilled capacity near term. It has been very active in the market securing in 2010 long term contracts for 1.5Mtpa from the Gorgon project and 2Mtpa from the Wheatstone project and a three year, 2.5Mt contract from GDF Suez. In January 2011 Kogas signed a 3.5 Mtpa contract with GLNG and a 0.7 Mtpa contract with Donggi Sonoro (Indonesia). This has enabled both of these projects to take FID.

APLNG, Prelude and PNG LNG are said to be competing for the remaining volumes but the main prizes seem to have been already awarded.

Table 10 shows both the potential total LNG growth and the risked growth. Figure 14 shows the location of projects in the Australian region. The risked growth in Australian projects alone is above the potential Asia Pacific demand. Some of the projects listed for other countries, notably the PNG LNG project, are actively marketing expansion volumes. If these projects act quickly to secure market they would have an advantage over greenfield Australian projects.

The risk analysis in Table 10 has been undertaken to try to rank the projects currently competing for Asian markets. It is mainly based on market risk given that the nature of LNG projects requires large, long term, high priced contracts for project financing. Each

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time a new project takes FID the market risk associated with the remaining projects is increased. It is not possible for all of these projects to be built in the timeframe to 2016.

Table 10 Asia Pacific LNG Projects

	Status	Probability	Start	Unrisked Capacity Mtpa	Risked Capacity Mtpa	POS	Comments
Australia							
Pluto T1	Construction		2011	4.8	4.3	FID 2007	Reserves constrained
Gorgon T1,2,3	Construction		2015	15	15	FID 2009	100% sold
Queensland Curtis (QCG)	Construction		2014	8.5	8.5	FID 2010	100% sold, T3 study
Gladstone T1 (Santos)	Construction		2014	3.9	3.9	FID 2011	3.9Mtpa sold
Gladstone T2 (Santos)	Construction		2014	3.9	3.9	FID 2011	3.6Mtpa sold
Wheatstone T1,2 (Chevron)	FEED	Probable	2015	8.6	5.16	0.6	75% sold under HOA contracts
Prelude FLNG (Shell)	FEED	Probable	2016	3.6	2.16	0.6	Technology risk
APLNG T1,2 (COP, Origin)	FEED	Possible	2015	8	3.2	0.4	No apparent buyers
Pluto T2	FEED	Possible	2015	4.3	1.72	0.4	Reserves constrained
Ichthys T1,2 (Inpex)	FEED	Possible	2016	8.4	2.52	0.3	Complex construction
Curtis Island T1,2 (Shell/PetroChina)		Possible	2016	8	2.4	0.3	JV will lift 100% of output
Fisherman's Landing T1,2 (LNG Ltd)	FEED	Speculative	2014	3.5	0.7	0.2	No CSM NG supply contract
Sunrise (Woodside)	FEED	Speculative	2016	3.6	0.72	0.2	Political issues with Timor-Leste
Pilbara (BHPB)		Speculative	2018	6	1.2	0.2	Cost, liquids poor, may join with Pluto 2
Browse (Woodside)	Pre-FEED	Speculative	2018	12	2.4	0.2	JV, cost, environmental issues
Australia Total				**102.1**	**57.78**		
Indonesia							
Donngi Sonoro	Construction		2014	2	2	FID 2011	100% of output sold
Tangguh T3	No project announced	Speculative	2016	3.8	0.76	0.2	T1,2 production issues
Sengkang	Modules constructed	Speculative	2014	2	0.4	0.2	Political issues
Indonesia Total				**7.8**	**3.16**		
PNG							
PNG LNG T1,2 (Exxon)	Construction		2014	6.6	6.6	FID 2010	100% sold, T3 study
Liquid Niugini Gas (Interoil)	FEED	Possible	2014	2	0.6	0.3	EWC modular technology
PNG Total				**8.6**	**7.2**		
Russia							
Sakhalin T3	No project announced	Possible	2016	4.9	1.47	0.3	Asian buyers eager for more, environmental issues
Asia Pacific Total				**123.4**	**69.61**		

The elephant in the room (not shown in this table) is Qatar. Qatar has 25-30 Mtpa of divertible LNG volume from its recently completed 77 Mtpa LNG complex. LNG can be diverted out of contracts sold into the EU, UK or USA (they have an unwind clause) allowing the LNG to be delivered into another market. Qatar has been promoting oil-parity pricing for LNG in Asia Pacific markets (whilst being prepared to sell into spot markets in the EU, UK and USA at one third to one half of the Asian price). This naturally has caused some resentment amongst Asian buyers which have looked to other (mainly Australian) sources of supply.

Qatar has effectively opened the door to many Australian projects that have been prepared to sell at around 85% of oil-parity. The mega trains in Qatar have an extremely low production cost to FOB (<US$3/MMBtu compared with about US$6-7/MMBtu for the CSG projects in Queensland). Qatar also has the potential to 'de-bottleneck' its facilities to yield another 12 Mtpa of LNG. If Qatar continues to sell into the Atlantic Basin the 'spare capacity' currently built into the Qatari projects may effectively prevent competing Atlantic Basin projects from securing markets at a price that supports their financing.

The Qatari approach to the Asian LNG market does not seem (to a westerner's eyes) to be a winning market strategy. If Qatar chooses to engage with Asia and contract at reasonable prices they could effectively stop *all* of the Asia Pacific projects that have not taken FID. The longer they leave this decision the more Australian projects that will take FID, ensuring a longer period of LNG oversupply and potentially creating a very competitive LNG market place.

This has obvious ramifications for Australian domestic gas prices in that the more the LNG market is oversupplied the greater the chance that spare capacity in Australian LNG projects will be competing in a competitive LNG spot market or alternatively supply into Australian short term natural gas markets.

Construction capacity

Whilst the LNG market will be the most important factor in determining how many new Australian LNG projects are constructed, almost of equal importance is the capacity of the Australian construction industry to build multiple LNG projects within the same time frame.

During the recent world LNG construction boom period there were up to 13 separate LNG trains being built globally in eight projects (Sakhalin 2 (T1,2), QatarGas 2 (T1,2), Yemen (T1,2), Tannguh (T1,2), RasGas 3 (T1,2), Peru, QatarGas 3, QatarGas 4.

The six additional Qatari LNG trains were effectively being managed as one construction project with materials, services and people skills being utilised to produce the best result. So effectively there were only five projects competing for people and materials.

Virtually every one of these projects was late in start up because of the lack of materials, (or supply of poor quality materials) and skilled labour. People shortages were evident in both engineering design and construction.

The Qatari projects (including chemicals plants, gas to liquids plants and aluminium smelter all located in an extended industrial complex) had 105,000 construction workers at their peak. The LNG projects are thought to have had 40-50,000 construction workers. The last four LNG trains were late (the last two up to a year late).

How many simultaneous projects can the Australian construction industry manage?

Firstly there is the problem of many different remote construction sites:

- The WA LNG projects have always had difficulty in attracting workers and have to pay amongst the highest construction salaries in the world. It is possible that Gorgon, Wheatstone, Pluto 2 and Browse projects (a total of 8 trains) could all be competing for construction labour at the same time. This could be a total of about 20,000 on site persons spread across the North West and Kimberley coasts.
- The Prelude Floating LNG project is also likely to be in construction during the same period but is different in that it will be largely constructed in Korea. It will still however require on-shore logistics.
- There are potentially four new projects in Gladstone Qld (QCLNG, GLNG, APLNG, CILNG) with potentially eight new trains being built in an overlapping time frame. Can Gladstone infrastructure handle the influx of about 20,000 people for this construction?
- Darwin would seem better placed to handle only one project (Ichthys Trains 1 and 2, ~5,000 persons). However if this project is built to its current timetable it will be competing with all of the other projects mentioned above.

Then there is the problem related to skilled project design and construction workers:

- Does Australia have 45,000 skilled project design and construction workers? What effect is the inevitable competition for workers likely to have on wage escalation?
- We believe that Australia does not have the numbers of skilled people required to managed this many projects simultaneously. Qatar utilised imported labour for virtually their entire construction workforce. Large scale immigration of skilled migrants into Australia to fill these positions is somewhat problematic given recent political debate.

Materials supply logistics is also a potential issue:

- Each of the current Australian LNG projects in construction (Pluto 1, Gorgon, QCLNG and GLNG) had to pre-order equipment and materials prior to taking FID in order to be placed in the queue for these items to be delivered to meet their start up schedules.
- Critical long lead items include specialised offshore pipeline materials, main cryogenic heat exchangers and large turbines used in compressors and power generation. Simultaneous orders from many competing LNG projects will lead to increasing item costs and delays in supply.

How many simultaneous LNG projects could be built in Australia?

- Given the events of the last few years we believe that about six geographically separate projects can be built worldwide at the same time without impinging on project schedules.
- With the Qatari building program effectively complete there are currently four LNG projects under construction (Pluto, Gorgon, PNG LNG and QCLNG) with GLNG about to commence. Pluto is almost complete and its construction workforce is winding down. The other four projects are in the early stages of construction.
- Hence there is only capacity for an additional two or perhaps three further projects spaced within the time frame 2011-16 based on the capacity of the material supply and construction industry.
- Those projects that secure LNG buyers are more likely to be able to take FID and will then effectively shut out additional projects due to market and construction bottlenecks.

If, for instance, Wheatstone (8.6 Mtpa), Prelude (3.6 Mtpa), APLNG (8 Mtpa) and Pluto 2 (4.3 Mtpa) were to take FID they would effectively fill all of the potential market demand until at least 2018.

There would be three additional LNG projects onshore Australia plus one FLNG unit built in Korea. The capacity of the Australian construction industry to construct all of these projects plus Gorgon, QCLNG and GLNG may be stretched.

Alternatively, other projects such as Curtis Island, PNG LNG T3 or Ichthys may be successful in place of some of these first mentioned projects.

Even three projects in Gladstone may stretch the capacity of local industry. Consolidation of separate project structures into one or two projects providing LNG production capacity for the other projects would enable better utilisation of infrastructure and construction workforce. That consolidation does not seem to be happening as yet.

Project outlook

Given the finite near term market capacity and the capacity of the construction industry a large number of these proposed projects are likely to be re-scheduled, some will be delayed and others cancelled.

In the following analysis shown in Figure 15 and Figure 16 the order of projects taking FID may change depending upon marketing success. Figure 15 shows information based on our current knowledge of the projects, the LNG market and potential construction bottlenecks. It is our belief that there is only sufficient engineering and construction capacity in the Australian region to support at best six concurrent LNG projects.

Figure 16 shows the Asia Pacific construction capacity implied by the two scenarios in Figure 15. In the Constrained Growth scenario additional LNG production builds rapidly to around 50 Mtpa by 2016. Growth is then tempered for up to three years by insufficient resources to build new projects.

These effects will act together since a fully utilised construction industry may result in higher construction cost inflation which in turn may make it more difficult to secure demand at reasonable prices.

The final constraint on Australian LNG production will come from competing LNG supply from Qatar, Indonesia, Malaysia and Brunei, which will all have potential spare capacity during the period under discussion. The 2 Mtpa Donngi Sonoro project in Indonesia took FID in January 2011. This will add further to the tightness of engineering and construction resources.

'Unconstrained Growth' represents the growth realised using the announced construction timetable of each of each of the LNG projects in the Asia Pacific region as represented in Table 10. It features rapid growth in the number of projects under construction and will inevitably result in intense competition for markets and construction resources.

'Constrained Growth' represents the best outcome achievable with marketing and construction constraints taken into account. The actual outcome may be even less favourable than this.

The projects scheduled post 2017 under the Constrained Growth scenario will be highly dependent upon market demand and hence may be further delayed if continued growth at current levels is not maintained.

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Figure 15 Schedule of potential additional LNG projects in Asia Pacific Region

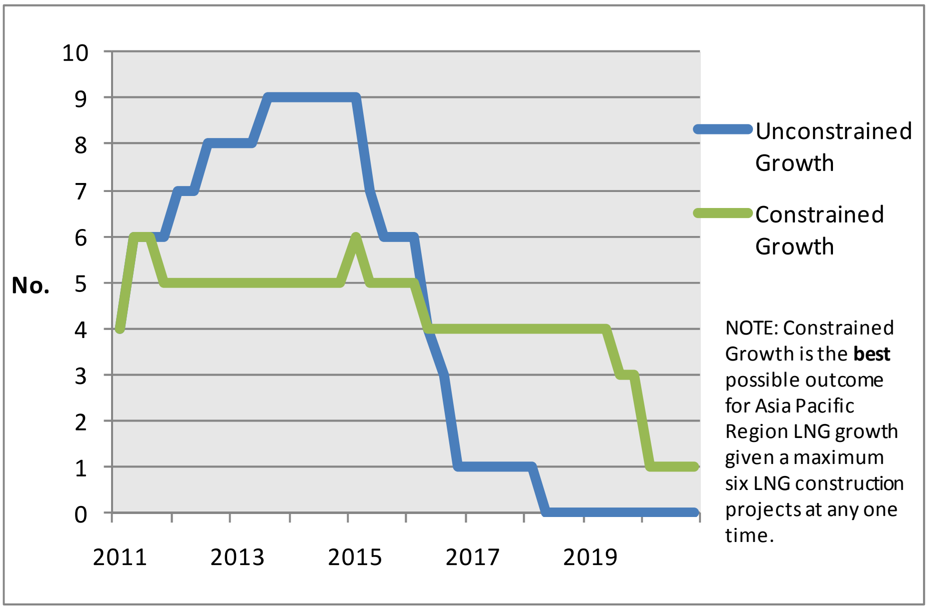


Figure 16 Potential LNG production increase for Asia Pacific Region LNG projects

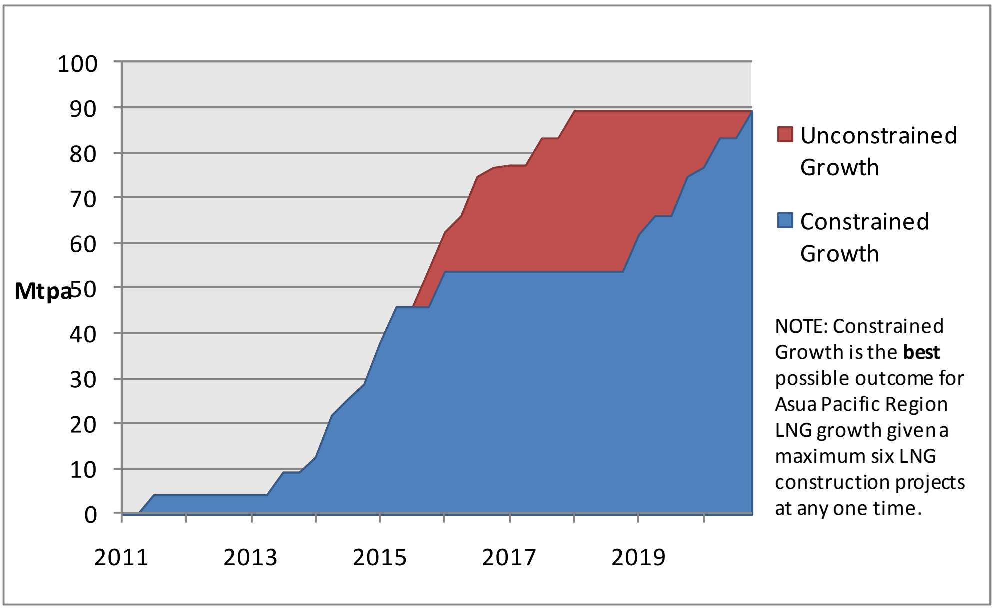
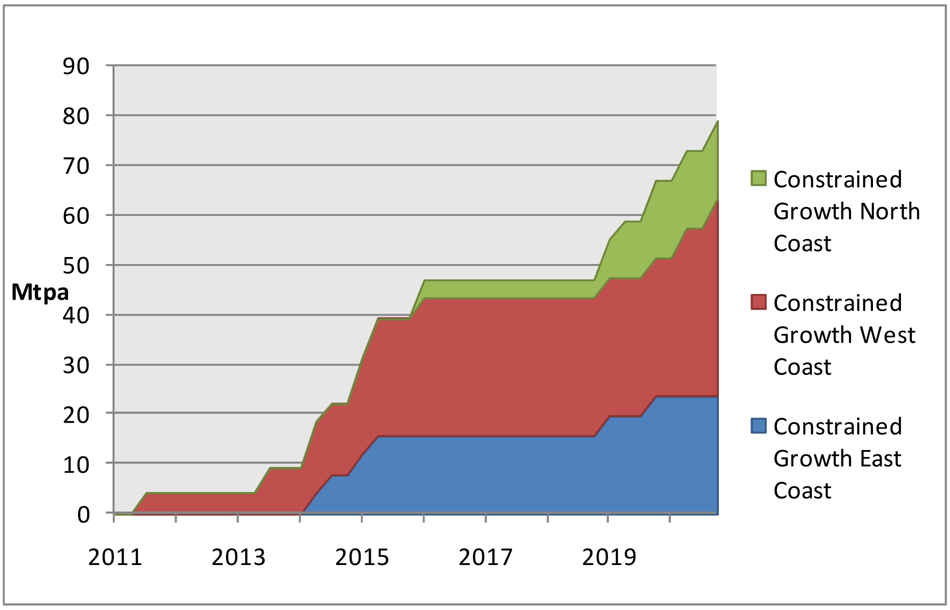


Figure 17 shows the Constrained Growth scenario for Australian projects by region. The Constrained Growth scenario as shown here is considered to be the best possible outcome for Australian LNG growth.

Figure 17 Australian LNG production increase - constrained growth



In this analysis North Coast refers to all projects located in Australian waters to the north of WA and the Northern Territory. These include Prelude, Ichthys, Sunrise and Browse. None of these projects are likely to deliver natural gas into the domestic gas systems of Western or Eastern Australia (perhaps with the exception of Browse which may eventually backfill the NWS Project rather than be developed as a separate project at James Price Point near Broome WA).

Given the forces at play in the world LNG market, the Australian LNG production increase could well be lower than the picture shown in Figure 17. In particular the large volume of divertible LNG supply that Qatar has developed, if successfully marketed into Asia, could easily inhibit the growth of Australian LNG beyond those projects in service and currently under construction (approx 39 Mtpa). The growth period following the predicted plateau from 2016-19 may not eventuate due to external competition or may be modified by market supply/demand balance.

We believe that by the end of 2020 additional production of LNG (over 2010 levels) will be between 28 and 40 Mtpa on the West Coast, between 16 and 24 Mtpa on the East Coast and between 4 and 16 Mtpa on the North Coast. This wide range of outcomes reflects the uncertainty about which projects will be successful in achieving FID through the securing of buyers at the right price and of a construction contractor capable of managing workforce resources in a tight market.

Between 44 and 64 Mtpa of this increase will be in projects that could also supply to domestic gas customers. Given the intense competition for resources to build these projects it is more likely that the increased supply will trend towards the low end of the ranges given.

We believe that there will be considerable growth in natural gas field development on both the east and west coasts, primarily to feed LNG plants. Given the nature of long-term LNG contracts each of these projects will need to build redundancy into the whole of their gas delivery system. There is limited flexibility on supply and receipt of LNG. Asian buyers demand stable consistent supply in return for the high prices that they pay.

This redundancy (which could be 5-8% higher than the required natural gas to meet plant demand) means that for most of the time there will be surplus natural gas production capability which could be utilised for domestic gas. For additional LNG supply of 28 Mtpa on the West Coast and 16 Mtpa on the East coast this could mean that at 5% surplus supply around 180 TJ/d and 120 TJ/d could be available on the West and East coasts respectively.

Gas contracts for domestic gas buyers may need to change to accommodate the broader spectrum of supply capability. There are opportunities emerging to re-frame conventional supply thinking.

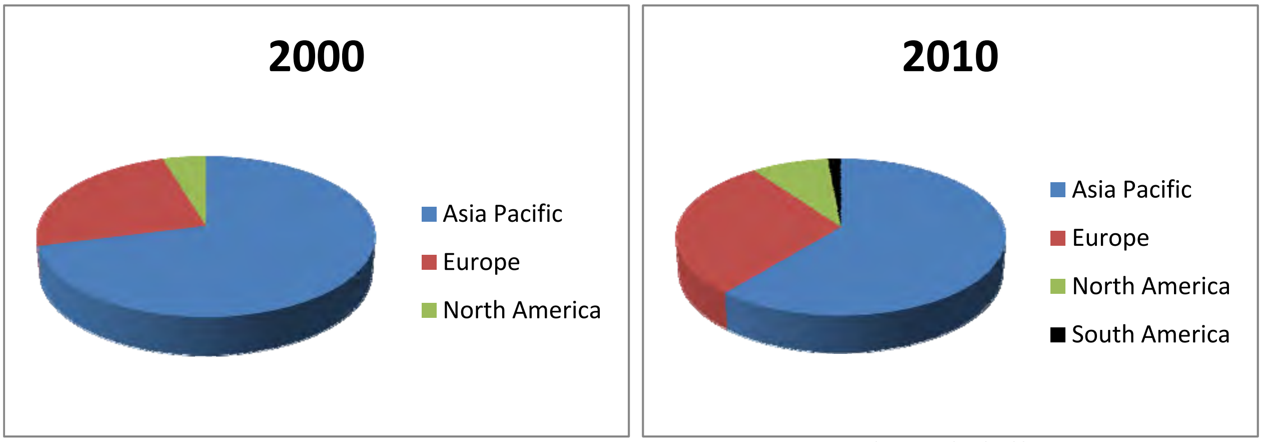
- Short term and spot supply may be more readily obtainable as a result of LNG supply system overcapacity.
- Spare natural gas capacity during periods of periodic LNG plant maintenance may be higher than the domestic gas market capability to utilise. (Natural gas supply to a 3.5 Mtpa LNG plant is about 600TJ/d. Even if the supply wells were turned down by 50% during the maintenance period, 300TJ/d capacity for three to four weeks of maintenance is still significant).

4. Asia Pacific LNG price outlook

The LNG industry has for a long time been mainly focussed on the Asia Pacific region. In recent years significant investments in import terminals have been made in Europe (EU) and America (US) driven by the perceived need to broaden the sources of supply for natural gas. This was accompanied by increased construction of new LNG production in the Atlantic Basin and the Middle East.

Total consumption of LNG in 2000 was 108 Mtpa. By 2010 this has risen to around 220 Mtpa. Figure 18 indicates the distribution of demand by region.

Figure 18 LNG Demand by Region



(source Wood Mackenzie)

Until the significant increases and diversification in LNG consumption (the EU from 2000, the US from 2006, India from 2004 and China from 2006) resulted in an increasing trend to shorter term LNG contracts, pricing for the majority of LNG contracts was typically linked to oil under long-term (20+ year) contracts with minimal price revision during the course of a contract. This arrangement benefitted both parties ensuring financeable projects and security of supply.

Spot and short term sales in Asia have put long-term pricing under some pressure but the nature of the LNG market is not conducive to significant commoditisation of LNG due to the cost of projects, security of supply concerns and need for dedicated shipping.

There have been long established spot natural gas sales in the EU and US pipeline markets. In the EU, natural gas spot markets work within an oil linked long-term gas contract market. The US gas market is predominantly spot trade. As deliveries of LNG into these markets increased, trade in spot LNG sales increased from ~5% of total LNG in 2000 to ~12% in 2010. World spot LNG trade is likely to peak at around 20% of the total LNG traded and hence oil linked contracts are likely to predominate for the foreseeable future.

Spot trade in the Atlantic Basin encouraged the development of a spot market in the Asia Pacific but the three markets are still fundamentally different in nature.

The founding Asia Pacific buyers (Japan, Korea and Taiwan) still rely on LNG for almost 100% of their reticulated gas supply. In 2010 these three countries account for around 50% of world LNG consumption. Security of supply is of utmost importance to these markets and they continue to sponsor new LNG projects and write new long-term LNG contracts with a high level of linkage to oil even when spot gas buyers in EU and US may be paying one third to one half the Asia Pacific price for their LNG supplies.

The new Asian buyers (China, India) have also been writing long-term oil linked contracts over the past few years but both have alternate pipeline supplies and are also engaging in the spot LNG market in a more strategic manner.

In the past five years there has been increasing evidence of transfer of LNG cargoes from the Atlantic to the Pacific or vice versa based on price signals and demand.

Thus, whilst Asian long-term LNG prices may have the biggest influence on Australian domestic gas pricing if there is a large scale expansion of the Australian LNG business, the connection between the USA, EU and Asian markets cannot be ignored (and will add to the complexity). For instance, in mid 2008 when the UK spot price (National Balancing Point) was at around US$10/MMBtu and the Louisiana Henry Hub (HH) around US$9/MMBtu, spot cargoes into Japan were fetching over US$20/MMBtu on security of supply fears. When all available Asian LNG supply had been taken, cargoes of LNG shifted out of the Atlantic into Asia.

Asia

Because most of the original Asian LNG buyers (Japan, Korea, Taiwan) had little in the way of alternative natural gas supplies, long term security of LNG supply was and still is their key criterion for new LNG contracts. Norms for long-term pricing were established early and have deviated little from the “Japan Custom Cleared” (JCC) oil related pricing basis for the past 25 years or so.

Newer Asian entrants into the LNG industry (India, China and Singapore) have also accepted the JCC formula for some contracts but have looked to de-link from oil in others. At this point in time all Asian long-term contracts are still linked to oil.

The supply/demand balance of LNG plays a critical role in price formulation. There is a cyclical struggle between seller and buyer over pricing depending on the perception of whether a buyer or seller market exists. Oversupply of LNG in the period 1997-2003 encouraged significant competition between suppliers of expansion LNG (Qatar, Australia, Indonesia, Malaysia, Russia) culminating in the very low long-term contract prices achieved by China in 2003-4. For example the NWS Project price into China is capped at around US$3.30/MMBtu delivered and the Indonesian and Malaysian contracts written a little later are not much higher than this.

Between 2004 and 2006 the market moved from a buyers’ to sellers’ market (as a result of insufficient construction of new LNG capacity in the previous five years to meet demand) and in 2010 it could be argued that a switch from a sellers’ to a buyers’ market is underway as a result of the LNG construction boom led by Qatar and now spilling over into Australia.

‘Standard’ Asian pricing is roughly 85% of oil parity. There are variations depending upon the timing that the contract was negotiated. The long established ‘S curve’ concept (which moderates LNG price above and below designated oil price ‘kink points’), designed to protect buyers and sellers from excessive movements in oil price, was out of favour during negotiations in the recent sellers’ market and many ‘straight line’ price formulae were agreed.

During the last buyers' market China, Japan, Korea and Taiwan achieved prices ranging from 30% to 65% of oil parity with S curves limiting the LNG price increases at oil prices above US$40/bbl. At the height of the sellers' market, just three years later in 2007-08, Qatar achieved contracts into Japan at 100% oil parity without S curves. Long-term LNG contracts negotiated in 2009 had reverted to 'standard' Asian pricing and by the second half of 2010 contracts are reported to have re-instated 'S curve' pricing principles.

A price formula for a Delivered Ex Ship (DES) contract is of the general format:

P = aX + b

where 'P' is LNG price in US$/MMBtu; 'a' is a multiplier representing the relationship between the oil price and LNG price; 'X' is the JCC price in US$/bbl; and, 'b' is a constant which usually is an allowance for shipping cost (plus or minus a margin depending upon the relative strength of the negotiating parties). Most sellers prefer contracts that are 'Delivered Ex-Ship' (DES) as it enables them to retain control over the destination of the LNG until it is unloaded. A typical formula may look like:

P = 0.1485X + 0.8.

The price formula for a Free On Board (FOB) contract is of the same general format as that for a DES sale. The constant 'b' is usually close to zero as shipping is provided by the buyer. A typical formula may look like:

P = 0.1485X + 0.03.

When an 'S curve' formula is used it has the same format as those above with the 'S curve' formula added on. During the 1990-2003 period LNG price formulae had S curve 'kink points' at around US$16.5/bbl and US$23.5/bbl. In the regions above and below the kink points the change in LNG price was around 35-45% of a change in oil price. A typical formula may look like:

P = 0.1485X + 0.8 + S

where 'S' is the S curve component. The S curve formula is of the form shown in Table 11.

Table 11 Typical Asian Long Term LNG Price Equations

X range (US$/bbl)	S	P
Below 16.5	1.361 – 0.0825X	0.066X + 2.161
16.5 to 23.5	0	0.1485X + 0.8
Above 23.5	1.641 – 0.0698X	0.0787X + 2.441

When X is between US$16.5/bbl and US$23.5/bbl then S = 0.

With the oil price rises in 2007-08 these formulae were out of date and newer price negotiations are reported to have kink points around US$70/bbl and US$105/bbl in one instance and in another contract around US$40/bbl and US$90/bbl.

The multiplier 'a' has in the past 10 years varied from 0.0525 (no price re-opener) for the NWS contract with China, up to 0.172 (oil parity) for a 5 year deal between Qatar and Chubu Electric. (The differences reflect the transition from buyers' to sellers' markets.) The vast majority of recent deals including those negotiated for the recent Pluto, Gorgon, QCLNG and GLNG projects are thought have multipliers in the range 0.13 to 0.152.

Europe

Since the 1970s most of EU pipeline gas has been supplied under long-term contracts linked to oil. Natural gas price formulae vary for different parts of EU. For example the North West EU is about P = 0.125 Brent – 0.2, whilst Spain is about P = 0.1 Brent + 1.0 (both in US$/MMBtu). Oil offered a transparent basis for buyers and sellers before natural gas became more of a global commodity through the growth of LNG trade. Gas-on-gas competition was also intensified through the opening up of new fields in Norway, the Balkans and new pipelines from Africa.

LNG now supplies around 15% of the EU gas market. In the UK LNG is now around 30% of supply and the spot market is of greater significance than long-term oil-linked gas contracts. The National Balancing Point (NBP) is a spot market located in the UK but this hub price is also used for EU trading as there is a physical connection for trading of gas between the UK and Europe. UK natural gas prices are written in pence per therm, which (for comparison with other prices in this study) equates to around P = 0.98 NBP - 0.6 (US$/MMBtu).

There are several other natural gas trading hubs in the EU (e.g. Title Transfer Facility (TTF) in the Netherlands, Zeebrugge in Belgium and Net Connect Germany (NCG) in Germany) but the NBP has a significantly larger traded volume than any of the EU hubs (NBP is about 60 times larger than all EU hubs combined).

LNG trade enhanced the effectiveness of established market hubs in the trade of both pipeline natural gas & natural gas derived from LNG. The global economic crisis of 2008-09 resulted in a marked reduction in oil prices, (and pipeline gas prices). Spot gas prices were further reduced by LNG imports. Buyers could buy even cheaper gas on the spot market and they sought to minimise contracted pipeline gas obligations.

This has put long-term contracts and the oil linkage relationship under stress in EU. Some long-term contracts are being re-negotiated by buyers seeking price formulae with part oil/ part NBP linkage. Supply security through a wider spread of supply options is also a driving factor. Russia has not helped its own position in its threats to withhold supply.

Of note for the Asian market is that transfers of LNG out of the UK and European destinations into Asia accelerated between 2006 and 2008 as a result of LNG shortages in Japan, Korea and Taiwan caused primarily by nuclear power plant shut downs. These cargoes were usually priced against NBP with an uplift factor to account for shipping and unwinding of the original contract (this uplift is usually about US$2.00/MMBtu). Regular diversions of LNG cargoes are also happening between the US and EU markets.

USA

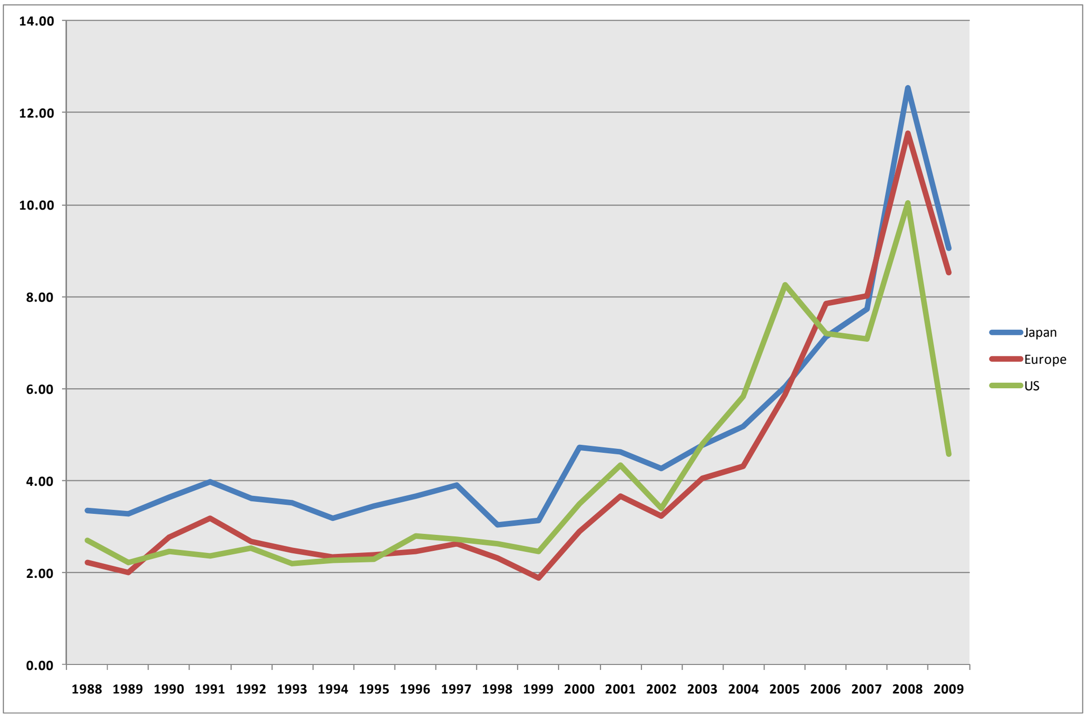
Although there are some long-term contracts for natural gas in the USA these are usually linked to forward pricing on natural gas hubs (the Henry Hub being the most traded) or to NYMEX gas futures. The US natural gas market is the largest in the world (around 23Tcf/a or ~63Bcf/d). This is equivalent to 460 Mtpa LNG (double the current world LNG market).

Although there is approximately 17.4Bcf/d of LNG import capacity in the US, Mexico and Canada, LNG imports only amounted to between 0.8 and 2 Bcf/d during the past couple of years. Winter peak imports have reached close to 4 Bcf/d based on the inability of the pipeline system to supply. LNG import capacity built in the 1970's was much underutilised until the early 2000's when it became apparent that conventional natural gas production was waning. Construction of new import terminals reached almost panic levels during the mid to late 2000's until another boom, shale gas, also took hold.

Shale gas production boomed from the late 2000's lowering gas prices from >US$10/MMBtu during the winter of 2007-08 to around US$4/MMBtu in late 2010. Plans for a massive increase in LNG imports (mainly from Qatar and mainly into the East and Gulf coasts of the USA) collapsed. Without a marked increase in price this will effectively push 15-20 Mtpa LNG into the EU and Asian markets thus also holding down spot prices in these markets.

Forward projections of US natural gas supply show that shale gas will continue to expand. However shale gas production costs are likely to increase and spot prices in the USA may slowly rise over the next 5 years to around US$7/MMBtu. This may have a small impact on Asia Pacific spot LNG pricing but as there is only one terminal on the North American west coast (Costa Azul) the impact is likely to be minimal.

Figure 19 Landed LNG prices, Japan, EU and USA (US$/MMBtu)



Source: BP, EIA.

Figure 19 shows that the relationship between landed LNG prices into Japan, Europe and the USA was more or less consistent throughout the late 1980s to the early 2000s.

The oil price increases from mid 2000s coupled with supply shortages of natural gas in Europe and the USA and of LNG in Asia saw natural gas prices increasing in all regions.

Natural gas shortages in the USA resulting from declining production from the Gulf of Mexico and a reduction in pipeline exports from Canada saw a strong growth in natural gas prices which sparked increased LNG imports and import terminal construction.

These shortages in the USA also triggered a boom in exploration for shale gas which quickly increased production from virtually zero to 4 Bcf/d in this period.

The global financial crisis and reduced natural gas consumption saw an equally spectacular fall in natural gas prices in the USA in the late 2000s. This was not nearly as pronounced in Asia or Europe with natural gas prices following the oil price reduction which occurred at the same time.

Figure 19 demonstrates that the market forces on natural gas pricing in each of the three regions are now only loosely linked and at various times local conditions do result in price imbalances between the markets.

In summary the three distinct LNG markets of Asia Pacific, EU and US are likely to continue with some narrowing of the difference in price but apart from exceptional circumstances (e.g. a shutdown of nuclear power stations in any of Japan, Korea or Taiwan) Asia Pacific spot LNG prices are unlikely to exceed the LT oil linked prices.

If the LNG market continues to be oversupplied for more than five years then spot prices are likely to have a dampening effect on long-term contract price renegotiations. History indicates that this effect will be at the margin. In the past price changes have been small even after protracted negotiations.

Thus, it is assumed that for the foreseeable time long-term oil related prices will dominate Asia Pacific LNG markets. Given that new LNG projects require high priced long term contracts to secure FID then it follows that for an Australian customer to secure a long term contract from a potential LNG project the price for that contract would need to be competitive with netbacks from long-term LNG prices. The biggest determinant of the level of pricing for future long term domestic gas contracts is therefore going to be the level of the oil price.

However, where an LNG producer has to make a market decision on the option of delivering into the spot LNG market or the short term domestic market, spot LNG prices should be used as the comparator. LNG spot prices are quite volatile and vary with season. Asian demand is highest during the period December through March. Most Asia-Pacific LNG producers are at capacity in this period and prices generally reflect long term contract prices. In the low season (April-May and September-October) LNG supply usually outstrips demand. Plant maintenance is carried out at these times.

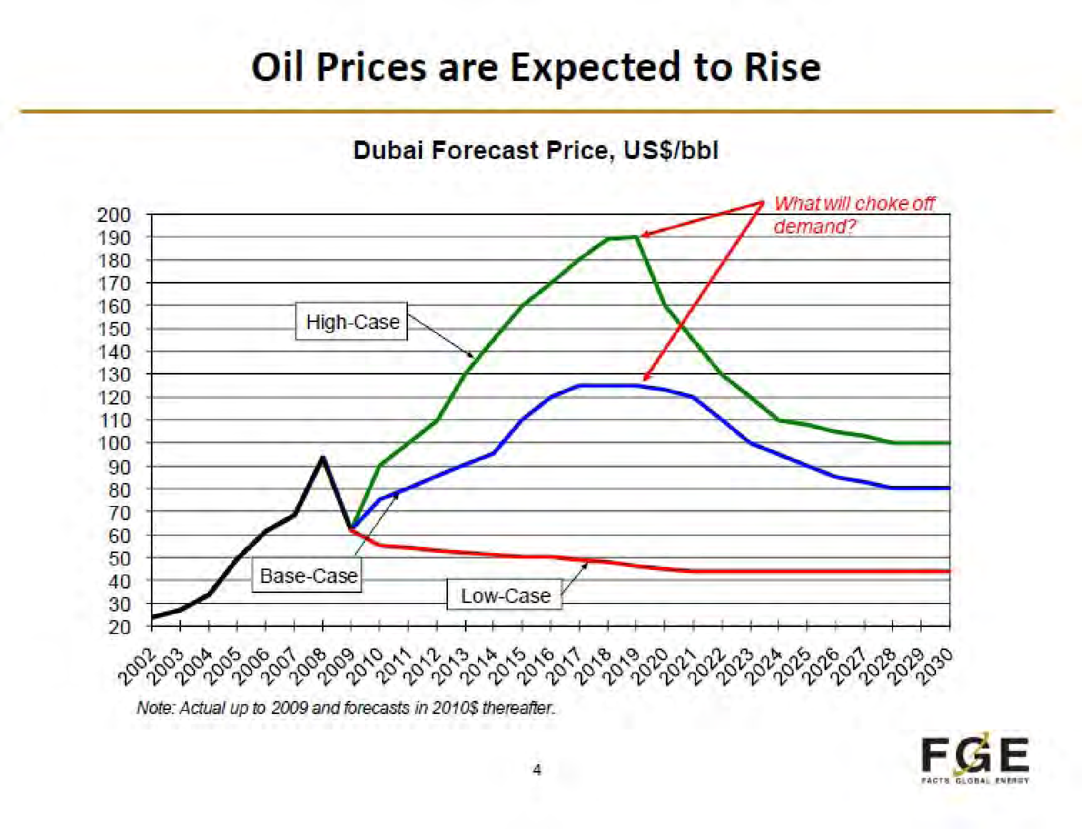
Path for LNG prices in the Asia-Pacific

Given that LNG prices in Asia are likely to remain linked with oil prices a review of current commentary on oil price forecasts is an important first step in the understanding of potential future LNG prices (and hence the potential future direction of Australian domestic gas prices).

Oil Price Forecast

There are potentially as many oil price forecasts as there are commentators and they have one thing in common - they will all be wrong to some degree. Hence one needs to be very careful about using future predictions of oil price. Recent oil price forecasts are shown in Figure 20 and Figure 21[6].

Figure 20 FACTS 2010 - Oil Price Forecast



Source: (FACTS Global Energy, 2010)

In the FACTS base case (Figure 20), oil prices rise to US$125/bbl in the period 2017-20 then drop back to US$80/bbl by 2030 (all in 2010$). The subsequent fall is due to demand destruction at higher prices and policies to limit oil-use.

The IEA gives three scenarios: growth to around US$140/bbl in 2030 with current policies (2009$), growth to around US$110/bbl if subsidies are removed (New Policies) and maintenance at around US$90 under a greenhouse constrained scenario (450 Scenario). The FACTS analysis can be interpreted as a possible time path through these scenarios.

That is, oil prices are likely to increase at a rate that falls somewhere between the IEA 'Current Policies' and 'New Policies' scenarios until there is a further oil price crunch which may occur as a combination of events that include declining oil production, economic recession or climate change imperatives.

[6] FACTS is a well-respected global oil and gas consultancy.

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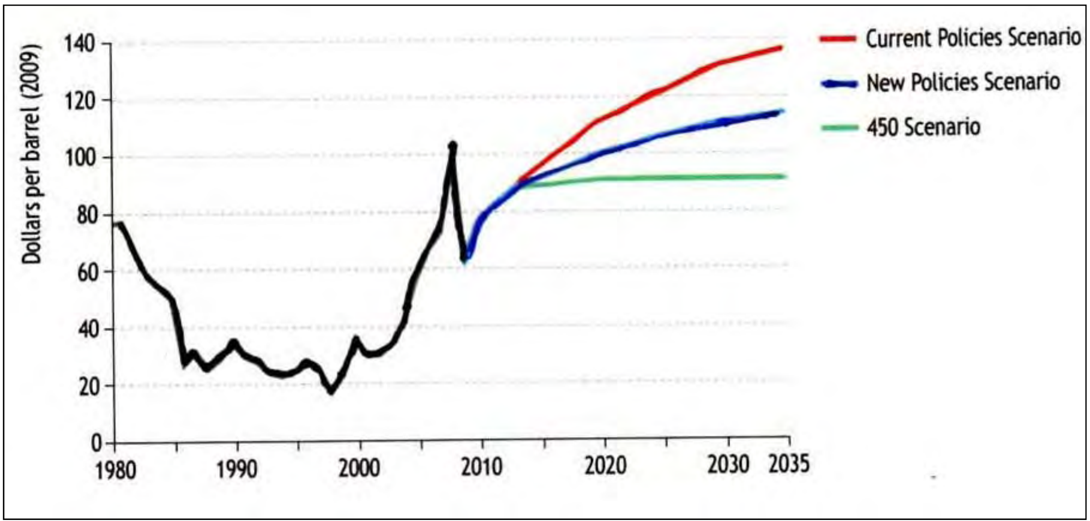
Figure 21 IEA World Energy Outlook 2010 - Oil Price Forecast



Source: (IEA, 2010)

Long-term LNG prices in the Asia Pacific region are likely to continue to be linked to oil for some time due to the absence of alternate competitive fuels to LNG in Japan, Korea and Taiwan. However the degree of oil-linkage will ebb and flow depending on the relative market power of buyers and sellers at any point of time. The emergence of powerhouses, China and India, which do have energy competitors to LNG may also moderate the linkage of LNG with oil through spot and short term trading of LNG. However this effect may take in excess of ten years to become apparent. With rapidly growing gas demand, both India and China are expected to continue to need to import significant volumes of LNG, even with the growth of indigenous gas supplies[7].

Natural Gas Price Forecast

The FACTS Global Energy view of the price path for world natural gas pricing is shown in Figure 22. We believe that this presents a more likely scenario than the one proposed by IEA 2010. As economic recovery gains pace the drivers for growth will once again accelerate the increase in oil prices taking long term oil linked LNG contract prices along for the ride.

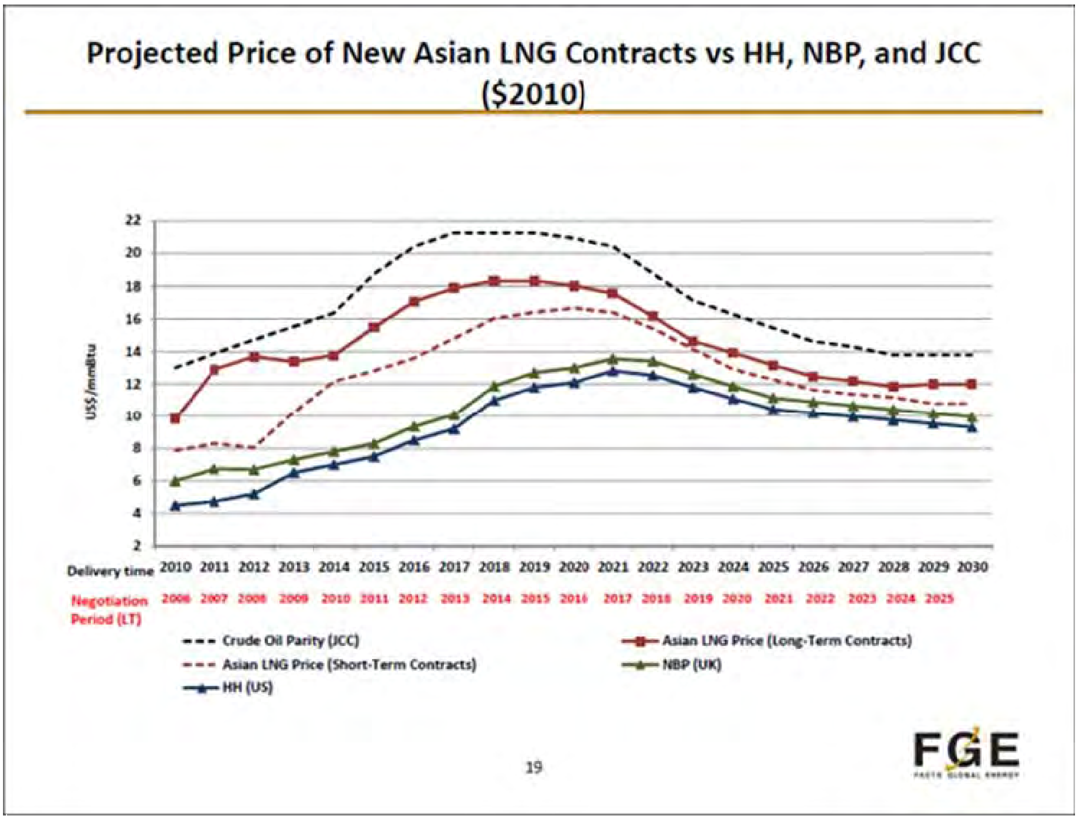
In the near term (to around 2016) surplus LNG will be sold into the spot market at a discount to the long term price. Where substitution of oil by natural gas is an option this may result in some fuel switching. Beyond that time frame, depending upon the quantity of new

[7] There are few drivers to encourage either producers or buyers to move away from oil linkage. Some traders (notably Enron) have attempted to set up positions in the middle of the buy/sell activity and have failed on complete lack of support from either buyers or sellers. It is unlikely that the countries reliant on LNG will be able to move completely away from oil linkage because they will not have new projects being built to supply them. There will probably be an increase in spot activity as all the new build LNG projects come on stream (Qatar projects now and Australian projects in 2015/16) and realise higher than name plate capacity production. But this will be at the margins. China may have greater ability to step away from the oil price linkage in its supply portfolio but it has locked itself into many 20-25 year oil linked contracts which will mean that whatever power they wield in the market to reduce prices will be tempered by the legacy contracts for many years to come.

LNG capacity installed, the long term and short term LNG price should track much closer to each other.

The ratio of the long-term LNG price to oil price implied is fairly constant (~80-87%) over the period to 2030. The analysis also suggests that there will be some narrowing of the gap between Henry Hub, NBP, Asian spot and Asian long-term LNG pricing.

Figure 22 FACTS 2010 - Projected price of natural gas



Source: FACTS Global Energy (2010)

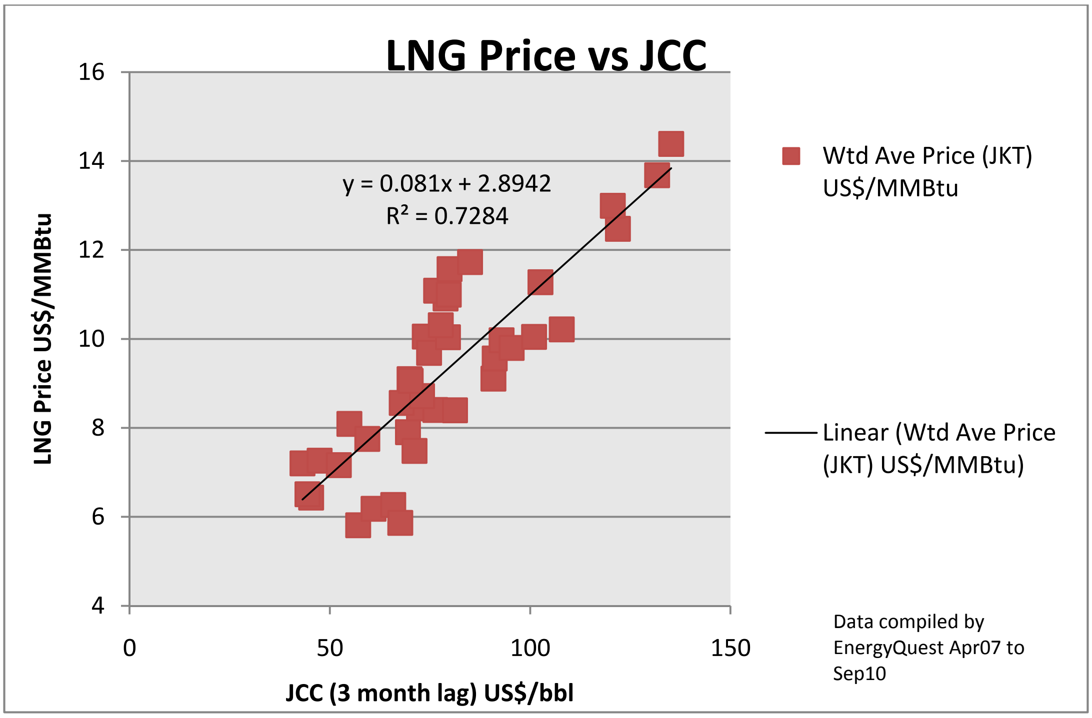
The estimates in Figure 22 reflect different assumptions used by FACTS for oil price increases and the ratio of natural gas prices to oil prices. However these prices are all above the average import price into Japan of ~US$10.80/MMBtu in 2010.

For LNG sellers the long-term LNG price formula is unlikely to vary much even though price review periods (usually every five years) are built in to these contracts. The LNG price will of course vary with the oil price variation. In other words the price formulae agreed in recent contracts are more or less locked in (unless there are exceptional circumstances).

The FACTS and IEA analysis does however assume that all long term contracts have straight line relationships between oil price and LNG price. This is clearly not the case for a large proportion of current LNG contracts which have S curves. Historical price import data for Japan, Korea and Taiwan imports from Australia for April 2007 to September 2010 is shown in Figure 23. China has been excluded from this analysis as it is an outlier contract (effectively a fixed price) agreed at the height of the last buyers' market.

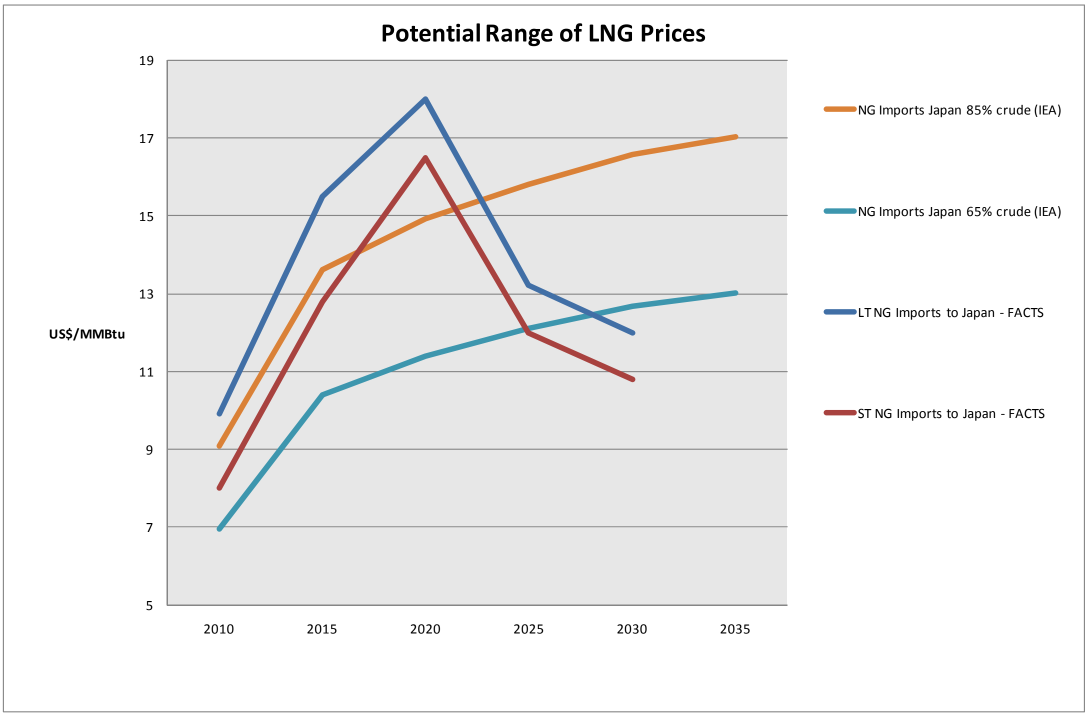
Figure 23 shows that at higher oil prices the effective slope of all the price formulae for long term contracts into Asia during the past four years was around 0.081 (47% of oil parity). What it does not show is that Australia's NWS project had a protracted dispute with Japan over price formulae which were considered to be 'outside the range' applicable to the contract. A settlement was eventually reached which recalibrated the applicable range and resulted in Japanese buyers paying several hundred million dollars to settle the price for the remainder of the inaugural contracts. These settlements are not shown in the statistics shown in Figure 23.

Figure 23 Historical LNG price vs JCC (Japan, Korea,Taiwan)



It is unlikely that there will be a significant change to the oil linked basis for these prices whilst Asia is dependent on LNG supply. If long term LNG contracts remain linked to oil at 65-85% of oil parity the implied long-term Asian market price for LNG is likely to be within the range shown in Figure 24.

Figure 24 Potential range of LNG prices



We believe that it is more likely that whilst headline price formulae for new contracts may continue to be agreed at around 85% of oil parity the actual LNG price will track closer to the 65% of oil parity line at oil prices above US$100/bbl taking into account the dampening effect of S curves.

Australian LNG export prices

Most recent (2006-10) LNG contracts for Australian projects have been negotiated at around the “standard Japan price” of P = 0.145JCC + 0.8 (US$/MMBtu), which is about 85% of oil parity. The slopes of the various price formulae for these contracts are thought to vary between 0.13 and 0.152.

In the period 1995-2006 most contracts were negotiated at about the standard Japan price. There were some contracts into China, Taiwan, Korea and Japan negotiated at levels which were 30 to 70% of oil parity but there were also contracts agreed (with Indonesia and Qatar) at above the standard Japan price. Most of the contracts in this period had kinks or ceilings set at very low oil prices (<US$40/bbl) making them effectively low slope (0.05-0.07) or fixed price contracts in today’s oil market. These contracts are now viewed as an anomaly but as they are long-term contracts are unlikely to be radically changed.

Figure 25 shows the potential range of prices agreed with Asian buyers by Australian projects during 2010. Note that these estimates are based on rumoured outcomes and may not be exactly correct but we believe that the outcomes are close enough to that shown to be able to draw general conclusions. The real outcomes are unlikely to be higher but could be marginally less than shown.

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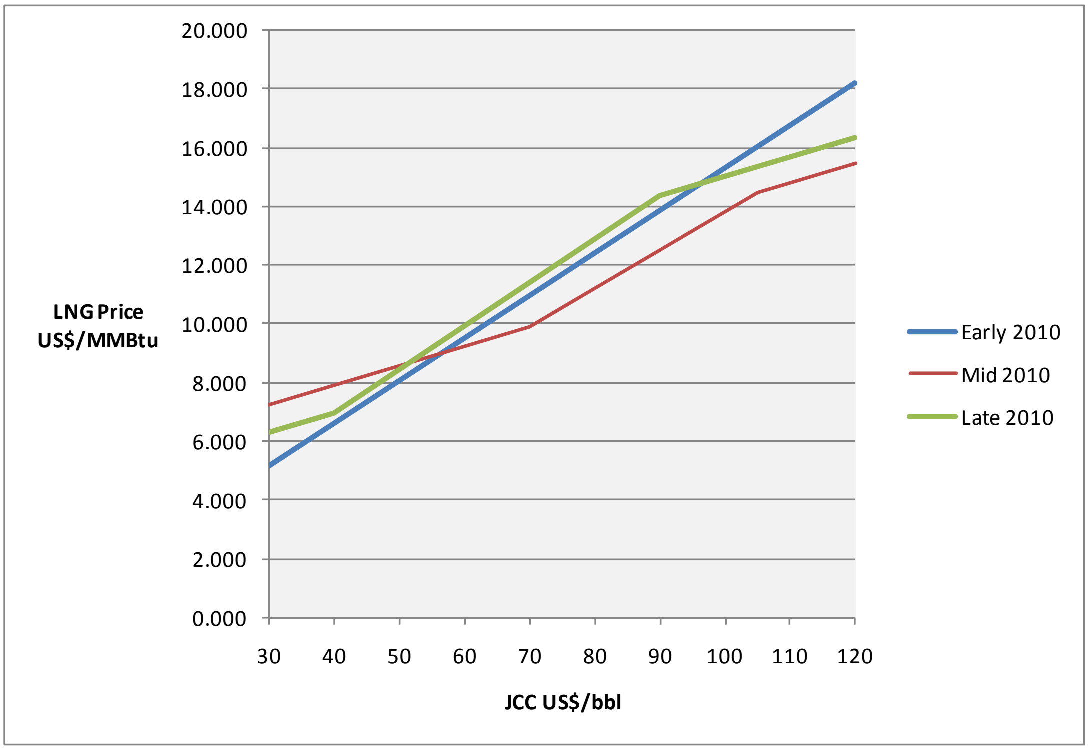
Figure 25 Range of recent Asian long term LNG price outcomes (2010 contracts)



Those contracts negotiated between 2007 and 09 (Gorgon, Wheatstone, PNG LNG) are thought to have straight line formulae. Some of these contracts are thought to contain floor prices to secure financing.

S curves are thought to be included in some of the contracts for QCLNG and GLNG negotiated during 2010. There is little concrete information on these price formulae but they are thought to have main slopes in the range 0.13 to 0.145 with kink points for one contract at around US$70/bbl and US$105/bbl and for another at around US$40/bbl and US$90/bbl. If the ‘S’ slopes are typical of previous formulae the slope will be around 0.066.

Comparing the outcomes of the straight line formula with those of the S curve formulae it is clear that oil price will be by far the biggest factor in the level of LNG price for any contracts developed within the past few years and valid for the next 15-25 years.

It is unlikely that during the coming period of world surplus of natural gas new long-term LNG contracts will be priced above the Japan standard price. There is likely to be some downward pressure on LNG prices for any new contracts concluded after the current array of greenfield LNG projects take FID (mid 2011). China and India are likely to try to push these prices down.

Brownfield LNG expansion projects may be able to support long-term LNG prices down to about 65% of oil parity although some buyers may decide not to support any further expansion of LNG supply whilst there is spare capacity available to the LNG spot market.

As new long term domestic contract outcomes will be compared with Asian long term contract outcomes there will be some pressure on Australian long term contract prices and these are likely to trend towards netback long term Asian LNG pricing.

5. Commercialisation for export or domestic sales?

This Section provides an assessment of the major financial and commercial drivers influencing the decision of east coast and west coast producers on whether to commercialise resources for supply to export markets or domestic customers.

Production growth

Production growth is the major strategic driver for oil and gas companies and LNG provides growth opportunities which Australian domestic gas does not.

Australia is a gas-rich OECD country in the Asia-Pacific region with a relatively small domestic gas market in relation to its gas resources and also abundant supplies of coal. These factors, together with the location of many of Australia's gas resources, make Australia an attractive place for LNG investment and less attractive for domestic gas.

Australia's gas reserves and resources are orders of magnitude greater than current domestic demand. East coast reserves and resources are currently 144 times annual domestic demand and WA resources are 385 times local demand. There continue to be good results from conventional gas exploration and further potential in development of unconventional gas.

At the same time Australia is relatively close to Asia, the world's largest LNG market, where gas prices are the highest in the world. Australia is also an OECD country with relatively low sovereign risk that encourages foreign investment.

These opportunities are large enough to attract some of the world's largest companies such as ExxonMobil, Shell, Chevron and ConocoPhillips. Gas and LNG are becoming increasingly important for the world's oil majors as oil becomes harder to find and is increasingly dominated by national oil companies such as Saudi Aramco.

Australian domestic gas does not provide growth opportunities in the same way as LNG. For international companies the Australian domestic market is too small to be material and, with competition from coal, domestic gas prices are also generally too low to be attractive. As we noted in Part 1, much of the expected growth in gas demand for minerals processing has not eventuated and expectations about gas demand for power generation have been affected by government mandating of renewables and uncertainty about carbon pricing.

Moreover, even if domestic gas grew quickly, the volume opportunities would still not match LNG. Chevron's share of output from Gorgon and Wheatstone will be 16.1 Mtpa, the equivalent of 870 PJ or about one-third larger than the east coast domestic gas market or two and a half times the WA market.

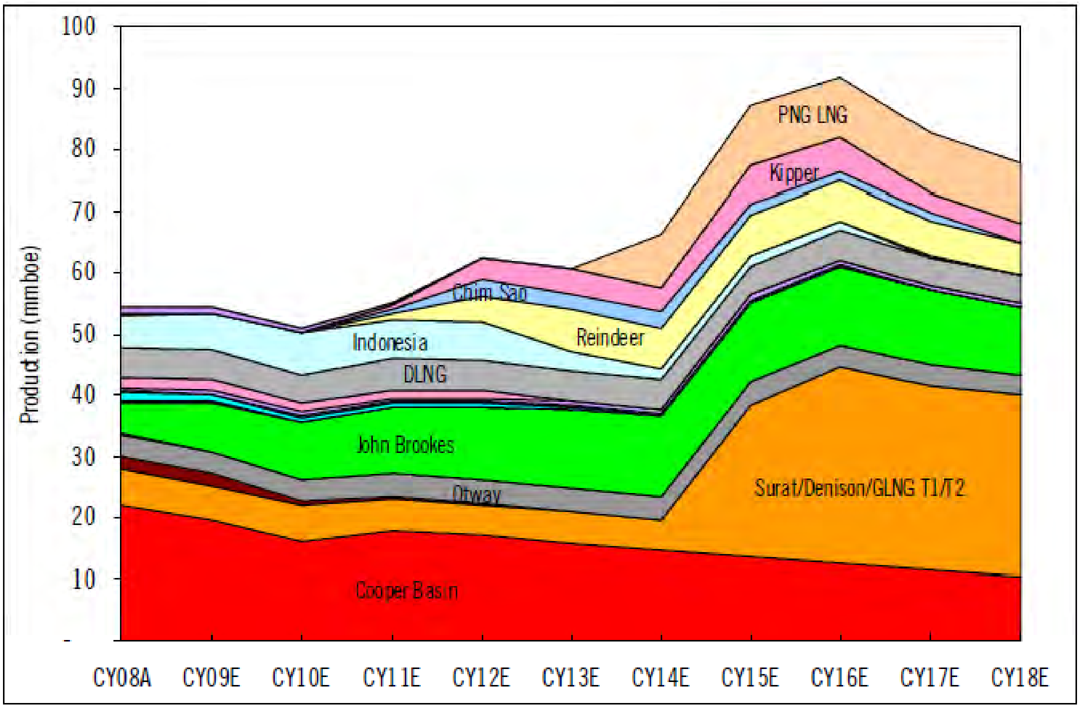
International companies have domestic gas interests in Australia but these reflect historical legacies rather than recent investments. ExxonMobil's interest in Victorian gas results from the discovery of Bass Strait oil in the 1960s. Exxon also had an interest in the Cooper Basin but sold down some years ago. Similarly, the interests of international companies in WA domestic gas mostly result from development of the NWS. Prior to the recent investments in Queensland, the only significant international companies with relatively recent and significant interests in Australian domestic gas were Apache and Mitsui.

Some of the international companies have now become significant participants in the east coast domestic gas market through their interests in Queensland CSG. However they are investing in Queensland as part of their global gas strategy and the domestic gas interest is a by-product of their investment.

Of the Australian companies, Woodside is also focussed on LNG for growth.

Historically Santos and Origin have been the major domestic companies producing gas on the east coast and growth is as important for them as for the international companies. For Santos, GLNG provides growth that domestic gas cannot. Figure 26 from Citigroup shows the importance of LNG for Santos's future growth.

Figure 26 Santos production outlook



Source: Citigroup

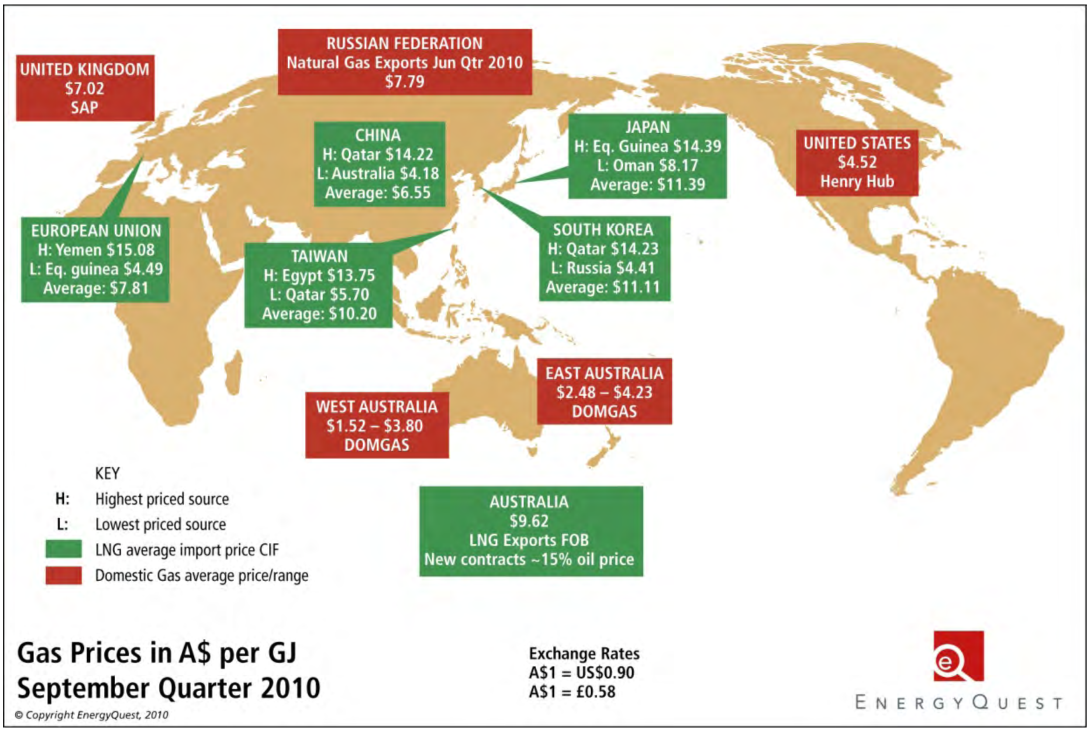
Origin came to LNG later than other companies but it also promises to provide superior growth opportunities.

Value, cost and location

LNG also has the potential to yield higher returns than domestic gas. Figure 27 shows world gas prices for the September quarter 2010. Average LNG import prices into Japan, Korea and Taiwan were all over $10/GJ compared with Australian domestic prices mostly under $4.00/GJ. It is natural therefore that domestic companies would also be keen to get into the LNG trade, both for production volume and also for perceived superior returns to domestic gas. (However, high costs mean that returns may not be as high as first thought.

Santos has recently disclosed that the rate of return on GLNG in US dollars is expected to be 11-14%.)

Figure 27 World gas prices, September 2010



Furthermore, large offshore gas fields like Gorgon are expensive to develop, as indicated by the earlier production cost estimates, much higher than historic domestic gas prices. Development is only viable if it is possible to sell the gas as LNG.

Location is also important. Some of Australia's major conventional gas resources are located in the remote Browse and Bonaparte basins, at great distance from domestic markets. The cost of supplying domestic gas from these remote fields would be significant in relation to domestic gas prices.

Technology

Historically there has been a minimum size at which a field can be developed for LNG, typically around 5,000 PJ. However, with floating LNG (FLNG) the minimum size is likely to be smaller. Shell's Prelude field, planned to be developed with FLNG, is around 2,500 PJ. GDF Suez has taken an interest in the Petrel-Tern field for possible FLNG. This is around 2,000 PJ.

Case studies

The considerations involved in decisions about developing a gas field for export or domestic use can be illustrated by a number of examples.

Bayu-Undan is a liquids-rich gas field, some 500 km offshore Darwin operated by ConocoPhillips. The gas is exported to Japan from Darwin as LNG. Prior to the development decision ConocoPhillips attempted to monetise the gas through sales to the east coast but the transmission costs and competition from CSG and coal meant that this was not viable.

Petrel-Tern is a medium size gas field offshore Darwin. Santos tried to develop the field for gas supply to Darwin but was beaten on price by ENI's Blacktip field. As noted above, Petrel-Tern is now being considered for FLNG in the absence of domestic demand.

Macedon is a 570 PJ field in the Carnarvon basin, operated by BHP Billiton. This field is too small for stand-alone LNG and BHP Billiton also has a natural demand for gas for its minerals business. Accordingly the field is being developed for domestic gas.

Julimar and Brunello are fields discovered recently by Apache in the Carnarvon Basin. The size of these fields is over 2,000 PJ, probably too small for stand-alone LNG but capable of making a contribution to another operator's project. Accordingly, after assessing LNG and domestic options, Apache decided to supply its gas to, and take an interest in, the Chevron-operated Wheatstone LNG project.

On the east coast LNG is also the preferred monetisation route, if possible, for both volume and value reasons. In addition to the larger companies like Santos, smaller companies like Eastern Star, Bow Energy and Beach Energy are all also pushing LNG, possibly with the hope of being taken over by an international player. However for some of the smaller companies development of domestic gas is also important to secure an early cash flow.

Domestic gas from LNG projects

Overall LNG is regarded as a superior investment option to Australian domestic gas and the first priority of the international and larger Australian companies is to aggregate sufficient gas to support LNG. We see this in WA where Woodside is trying to accumulate sufficient reserves for a second Pluto train and on the east coast where aggregating sufficient CSG reserves is the priority for companies like Santos.

However, while LNG may be the top priority, that does not necessarily preclude supply of domestic gas from LNG plants, as has happened for nearly 30 years from the NWS. There is also now a link between the Darwin LNG plant and the Channel Island power plant in Darwin.

The question then becomes, will companies include domestic gas supply capability in their LNG developments? Whether for commercial or political reasons, the answer in WA is clearly yes, with domestic gas plants included in both the Gorgon and Wheatstone projects.

In Queensland there will also be substantial domestic gas production capability from the LNG projects because gas will be treated to meet domestic specification at the field level before being piped to the LNG plants at Gladstone.

LNG plant operation

There are also likely to be domestic gas volumes resulting from LNG plant shut-downs.

LNG production requires steady operation. Although there are seasonal variations in off take to the different markets, operators endeavour to run the plant at a steady rate scheduling planned maintenance around train shutdowns. Most LNG plants have a turn-down rate of about 87-92% of design capacity. ConocoPhillips designed plant (all of the Queensland plants) can be operated at about 70% of design.

Most operators prefer to run facilities at close to maximum throughput, avoiding plant surges so as to protect the integrity of the Main Cryogenic Heat Exchangers (MCHE). (The MCHE can be subjected to extreme differences in temperature between the refrigerant and natural gas causing metal fatigue. Cracking and leaks in the MCHE can lead to extensive shut down for repairs.)

Deliveries to long-term buyers are scheduled a year in advance (the Annual Delivery Plan or ADP) locking in buyer, ship and loading/delivery dates. These plans are finetuned on a weekly basis as needed but usually run close to schedule with most plant achieving rates of 95%+ adherence to schedule.

Scheduled maintenance is planned a year in advance to coincide with the scheduled maintenance of long-term buyer facilities and is normally carried out during the low LNG demand season. For Asian customers this means that maintenance will usually be scheduled during April/May and September/October of each year.

Long-term buyers always want to have maximum LNG plant production capacity for heating demand during the winter months (December through March) although long-term buyers normally plan to start filling their large storage capacity during November. Kogas in particular has winter demand that is about three times higher than its average demand. There is a smaller summer peak period in July/August to accommodate power station demand (air conditioning).

LNG storage capacity is usually limited. There is little capacity for storing excess production against future delivery or for maintaining the shipping schedule if there is an unscheduled LNG plant shutdown or ship delay, either of which lasts for more than a couple of days. Any shut in of production will greatly increase the availability of gas for delivery into the domestic gas system.

Any shut in of LNG production capacity will inevitably lead to line pack of the supplying natural gas trunkline, followed by wind down of production out of wells, followed by shut in of wells. Shut in of either conventional or CSG production wells is not favoured by operators as it could affect the production capability of the wells on re-start leading to reduced production rates. (For conventional wells the concern is about stability of well sands and in CSG the concern is about water ingress and the requirement for subsequent de-watering.)

Any of the above issues relating to LNG production will provide opportunities for increased supply of natural gas for domestic gas. Unfortunately in most cases (except for LNG seasonality) they will be unplanned events. However, gas fired power stations that are well located in the natural gas and power supply grids may be able to take advantage of these short term events.

Spot LNG versus spot domestic gas

There are also likely to be opportunities for spot sales of domestic gas. Once an LNG project has been developed that has domestic gas capability, the LNG producer may find it advantageous from time to time to sell spot gas into the domestic market rather than into LNG.

Given the size of LNG plant throughput and the necessity of these plant to cater for buyer seasonality there is usually spare capacity built into the LNG plant. This gives the opportunity for LNG spot sales which may amount to 5-8% of total capacity. For an 8 Mtpa LNG plant spare capacity may amount to 0.4 to 0.6 Mtpa, the equivalent of 73 TJ/d LNG output or 80TJ/d gas supply to LNG plant gate. (This is a significant volume, close to 30 PJ/a or nearly 20% of the current Queensland market).

Hence an existing LNG seller will compare the opportunity to sell into the LNG spot market with supplying the domestic gas spot market.

6. Factors that may prevent gas prices moving to export parity

We have been asked to assess what factors may prevent domestic gas prices on the east and west coasts moving to export parity or LNG netbacks.

Export parity/LNG netback

Export parity or netback is defined as the landed LNG price in the importing country less shipping and liquefaction. This gives a measure of the value of the natural gas at the inlet to an LNG or domestic gas plant at a producing centre such as Karratha or Gladstone.

It is important to note that export parity is not the final LNG price as imported into a country such as Japan but also takes account of processing and transport costs.

We have estimated netbacks for new Australian LNG projects for various oil prices. In doing so we have made the following assumptions:

- Landed LNG price per million British thermal units (MMBtu) of 14.85% of the price of one barrel of oil at the Japan Crude Cocktail price.
- Liquefaction capital cost of US$1,000 per tonne of annual capacity, with an after-tax rate of return of 12%.
- US dollar/Australian dollar exchange rate equals parity.
- As discussed, there is assumed to be an S-curve arrangement that limits price increases at oil prices over US$100 per barrel. (While it is difficult to predict what will happen at very high oil prices there will be a significant part of the market that will be supplied with "S curve" contracts that will limit upside price growth. In addition there is likely to be extended "out of range" pricing discussions with buyers seeking to limit upside damage).

Export prices (ex-Australia) in USD are shown in Figure 28, together with netback estimates for Karratha and Gladstone based on these assumptions. At an oil price of US$80/bbl, the export price is US$11.88/MMBtu and the netbacks are A$7.33/GJ at Gladstone and A$6.91/GJ at Karratha.

The only difference between Gladstone and Karratha is that less gas is assumed to be lost in processing in the CSG case.

One important observation is that these estimates are sensitive to exchange rate assumptions. Twelve months ago it was reasonable to assume a 75 cent exchange rate. At an US$80/bbl oil price this gives a netback at Karratha of $9.21/GJ. Now, with exchange rate parity being a more reasonable assumption, the netback is $6.91/GJ.

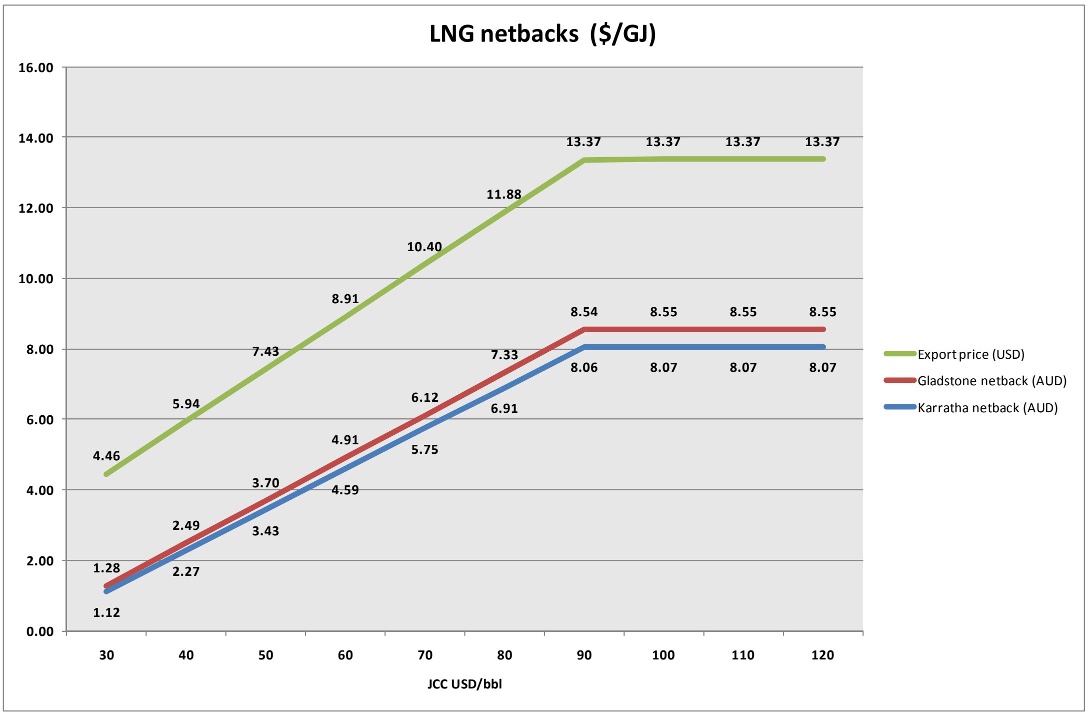
Overall, assuming a long-term oil price of US$80-90/bbl, west coast netbacks would be A$7.00-8.00/GJ and east coast netbacks A$7.50-8.50/GJ.

This type of calculation has been interpreted to imply that at an oil price of, for example, US$80 per barrel, producers would need to charge $6.91/GJ for gas at Karratha to earn the same return that they could earn from LNG exports.

However this is not necessarily the case. If returns to the project as a whole were over 12%, this calculation allocates all of the excess return to upstream production. This would not occur if, for example, the LNG facilities were under separate ownership. In that case the owners of the liquefaction plant would no doubt argue that all excess returns should accrue to them. Similarly, if the return to the project as a whole is less than 12%, the excess return would be being allocated to the liquefaction plant under this methodology, under-estimating the value of the upstream gas.

Other things being equal, LNG producers should be prepared to invest in domestic gas capacity if the returns to domestic gas are the same as those for the LNG projects as a whole.

Figure 28 Oil price and LNG netback Karratha and Gladstone ($/GJ)



Nonetheless netbacks are often used to gauge whether there is a significant difference between the value of gas exports and domestic gas and this is clearly the case in Australia.

Figure 29 West coast gas prices

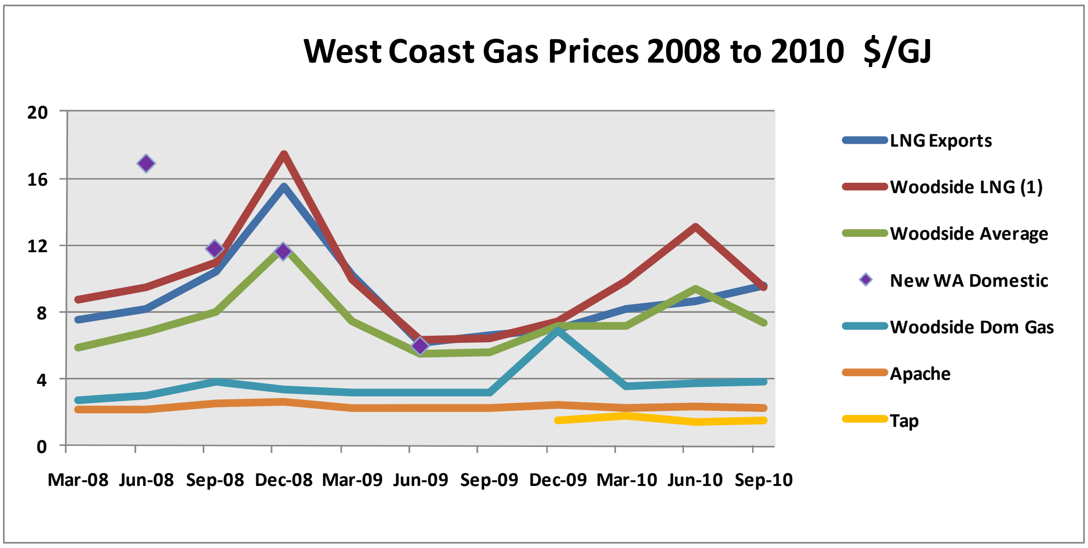


Figure 29 shows various indicators of WA gas prices. The top red line shows prices realised by Woodside for LNG sales (FOB Karratha). This reflects processed LNG so the netback line would be somewhat lower. The top blue line shows the average price of Australian LNG exports, including Darwin as well as the NWS. The bottom three lines show domestic gas prices realised by Woodside, Apache Energy and Tap Oil. The spike in the Woodside line reflects payments flowing from the Alinta gas price arbitration. The purple diamonds show new WA gas contracts, which are much closer to LNG prices. However, apart from the Alinta arbitration, there has been relatively little movement towards LNG netbacks in prices under existing domestic contracts. Perhaps these contracts do not typically have price-opening clauses.

Globalisation and gas prices

We have been asked to assess what factors may prevent domestic gas prices on the east and west coasts moving to export parity or LNG netbacks.

The focus here is assumed to be on long-term contract prices. On the east coast, ramp-up gas and possible project delays for the LNG projects are likely to mean relatively low short-term gas prices for a number of years.

Figure 30 is an adaptation of the familiar Porter Five Forces diagram, used to analyse rates of return in an industry. Prices reflect the balance of demand and supply generally and in particular:

- barriers to entry
- power of suppliers
- rivalry among industry producers
- power of buyers
- scope for using alternatives.

Export demand is only one factor driving domestic gas prices. We will now discuss these and other relevant factors in the context of both the east and west coast markets.

East coast

In terms of the Porter diagram, the direct impact of LNG on the east coast is to add additional buyers, paying higher prices, to the gas market, weakening the power of domestic buyers. The immediate impact is to quarantine large volumes of gas from the domestic long-term contract market as the LNG proponents prove up reserves for their LNG projects. As the LNG projects move into the development phase, development costs are also likely to increase for both export and domestic projects.

East coast gas production is also concentrated among a small number of producers, most of whom are involved in LNG projects.

These forces are likely to place upward pressure on long-term gas prices.

However there are also forces that may moderate upward pressure.

Figure 30 Domestic gas price determinants

	New Entrants • Ease of entry to new acreage and quality • Price elasticity of supply • Concentration of acreage ownership	
Supplier Power • Cost of development	**Competitive Rivalry** • Number of players and strength of rivalry	**Buyer Power** • Domestic buyers • LNG buyers
	Substitutes • Coal-fired electricity • Mandatory renewables	

As we saw in Section 2, there are now large volumes of uncontracted CSG held by smaller companies in Queensland and NSW and the indications are that while production costs are generally higher than historical east coast gas prices, they are probably $4.00-5.00/GJ.

These smaller companies are all keen to develop channels to LNG but they also need cash flow, necessitating domestic contracts. Factors that would assist in moderating domestic price rises would be if the smaller companies fail in their attempts to develop channels to LNG and if they are not acquired by the larger LNG players.

There is some interest by major LNG buyers in smaller projects but most of the interest revealed so far is from trading companies like Itochu, Marubeni, Mitsui and Sojitz. The smaller companies are likely to face a significant challenge entering LNG. Alternatively they may be acquired by a major LNG player but the smaller companies also provide opportunities for domestic gas buyers, through contracts or acquisition.

Barriers to entry into CSG have been relatively low and while there is variation in resource quality, supply appears to be relatively price elastic and there is considerable investment still underway in exploration and appraisal of unconventional gas on the east coast, both CSG and shale gas. The Galilee and Gunnedah basins both have exploration potential.

If gas prices rise, exploration offshore Victoria is also likely to become more attractive.

The east coast also has an extensive gas transmission network to facilitate monetisation of new gas discoveries.

Substitutes may also moderate gas price increases. Mandating renewables has reduced expected gas demand growth generally. Competition from coal-fired electricity is also likely to moderate gas price increases. The competitiveness of coal versus gas-fired generation will be affected by climate policies. However at moderate carbon prices coal is still likely to be competitive with gas for baseload generation. We already see electric pumping and compression being contemplated for the CSG LNG projects, which will reduce the amount of feedgas required. There are also long-standing proposals to link Mt Isa to the Queensland power grid, reducing gas demand by 20-30 PJ/a.

Successful development of competitive clean coal technology would also limit gas price increases.

Higher gas prices may also reduce industrial demand for gas, particularly in production of chemicals and alumina.

Overall, while there are pressures for real increases in long-term east coast gas contract prices, there are also a number of factors that may limit these increases.

West coast

The situation is different on the west coast, where barriers to entry are high, costs are high and the competition from substitutes is more limited.

We saw in Section 2 that WA has high offshore development costs. Barriers to entry are also high offshore and while there is scope for development of unconventional gas onshore, it is at an early stage. There is scope for coal competition and this is already in evidence but there is less scope than on the east coast. The domestic gas market is also dominated by a small number of producers and the bulk of future domestic gas is likely to come from LNG projects. The main factors able to limit domestic gas prices increases in WA are probably competition from liquid fuels like diesel and demand destruction.

7. LNG projects and domestic gas contracts

This Section evaluates the impact of large scale export LNG projects on the availability of long term gas supply arrangements in the east and west coast domestic markets over the short-term (1 to 2 years), medium term (3 to 6 years) and long-term (7 to 10 years). Specifically, it assesses the availability of long-term contracts now and the prospects for current contracts rolling over later this decade or for buyers seeking new contracts.

Long term contracts in the gas market

The domestic gas market is still dominated by long-term contracts, as is the LNG market. Long-term contracts have been necessary historically to underwrite new developments and provide security to buyers. Over time however the length of domestic gas contracts has shortened, from the original 30 year contracts that underwrote development of Bass Strait, the Cooper Basin and NWS domestic gas, to 10-15 years.

The two alternatives to long-term contracts are spot markets or vertical integration.

Spot markets are developing on the east coast and are likely to become more important as volatility grows in both gas demand (through increased peaking) and through the need to manage LNG plant operations.

Vertical integration is also growing as an alternative to third-party contracts. Australia's largest gas buyers, Origin and AGL, are increasingly self-sufficient in their gas needs. There is also an increasing trend for LNG buyers to take larger upstream equity in LNG projects. Similarly owners of gas reserves are moving into power generation. Vertical integration mitigates price and volume risk. It may also provide a significant competitive advantage over non-integrated gas users.

Nonetheless, long-term contracts are the overwhelming feature of the market.

East coast

What is the outlook for long-term gas supply agreements on the east coast and what has been the impact of the LNG projects? The east coast has substantial gas reserves and resources. Based on company disclosures, we estimate current resources as follows:

- Proved and Probable (2P): 40,091 PJ
- Proved, Probable and Possible (3P): 60,828 PJ
- Contingent Resources (2C): 40,123

The total of reserves plus resources is just over 100,000 PJ. Under the highest growth AEMO domestic gas demand scenario to 2030, total cumulative demand is projected to be 24,000 PJ (AEMO, 2010). This leaves substantial resources for LNG export[8].

However the feedback from market participants is that it is difficult to secure long-term gas contracts in Queensland. This reflects the drive for LNG volumes and reserves uncertainty.

QCLNG currently has 13,400 PJ of 3P reserves plus contingent resources, of which 2P represents 7,700 PJ. In addition they have 1,300 PJ for existing domestic contracts and 4,524 PJ uncontracted. They also have 640 PJ contracted from APLNG. They are currently proposing an 8.5 Mtpa two-train LNG project (requiring 10,000 PJ of reserves) but would desirably like to increase this to three trains (15,000 PJ). So at this point they have 7,700 PJ of low risk gas plus 640 PJ contracted plus 10,224 of higher risk gas. It is natural that they would want to hold enough gas in reserves to meet the need for three trains if it eventuates and to cover the risks of converting contingent resources to reserves.

The situation for the 7.8 Mtpa GLNG project is similar. The project will require around 8,500 PJ of gas reserves. It currently has 5,005 PJ of 2P reserves, 7,737 PJ of 3P reserves and 3,732 PJ of contingent resources plus 750 PJ of Cooper Basin gas. It needs a minimum of 8,000 PJ for a two-train development. It also needs to reduce the risk on its gas resource base for LNG. It would also like to have sufficient offtake agreements and gas resources to increase the project to 10 Mtpa.

Shell and PetroChina are planning an LNG project of up to 16 Mtpa. In the Surat Basin they have 4,600 PJ of 2P and 6,375 PJ of 3P reserves (5,920 PJ uncontracted). They have further reserves in the north Bowen Basin, but not sufficient total low risk reserves as yet to meet their needs.

APLNG has the largest quantum of low risk reserves, 10,099 PJ of 2P, of which 640 PJ is contracted to QCLNG and around 1,800 PJ committed to the domestic market. They plan an initial two-train project of 9 Mtpa, requiring around 10,600 PJ. While they have a good resource base, they would want to keep their options open for a large-scale development. Unlike the other LNG proponents, APLNG through Origin, has its own substantial channels into the domestic market to which it is likely to give preference over selling gas to other parties.

This suggests that the four major LNG proponents are unlikely to want to sign major long-term gas contracts while they have significant uncertainty about offtake agreements and the productivity of their fields.

At the same time domestic gas contracts will be coming up for renewal and domestic demand as a whole is expected to continue to grow.

Figure 31 shows our estimate of domestic gas contracts and commitments from fields in Queensland, NSW and South Australia (excluding gas for producers' own purposes such as their own power stations). We have also inserted a notional demand line representing

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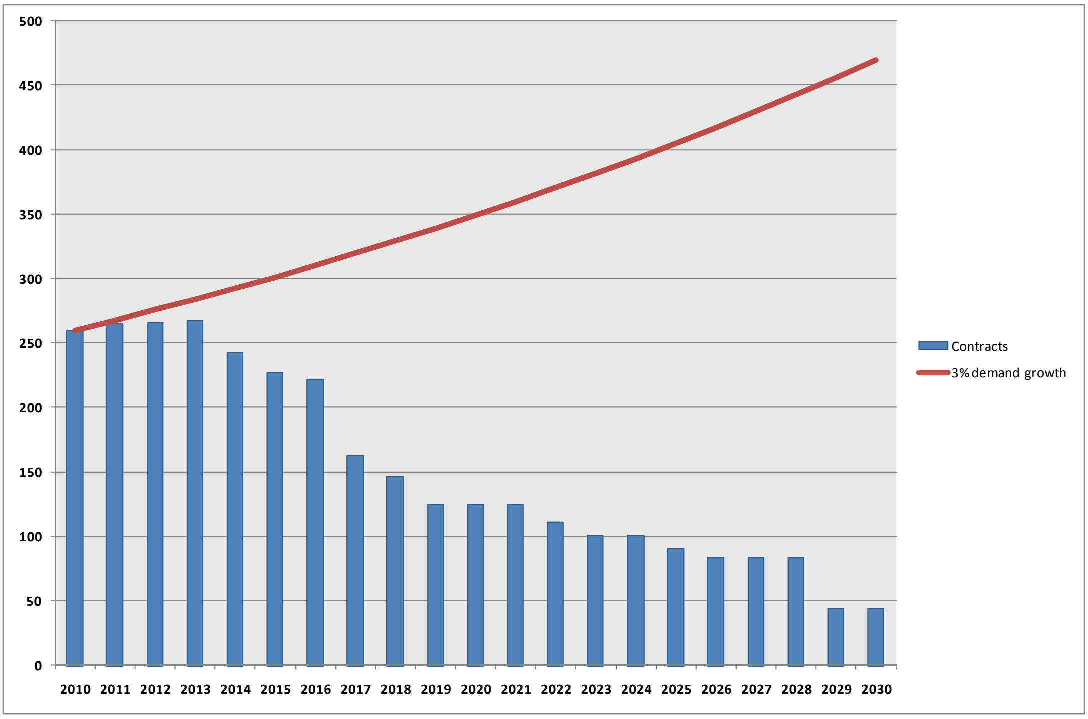
8 In the latest Gas Statement of Opportunities, AEMO (2010) concludes that east coast gas reserves are sufficient to meet annual demand projections and LNG export demand to year 2030. However they assume only 10.5 Mtpa of east coast LNG production by 2020 under their fast growth scenario but with the sanctioning of GLNG, 16.3 Mtpa is already under construction.

growth of 3% pa. Some contracts begin to expire over the next 3-5 years, with significant roll-off by 2020.

The options for any gas buyers seeking long-term contracts in Queensland, NSW or South Australia are fairly limited. The Cooper Basin is effectively fully contracted. While there are substantial uncontracted reserves at Moranbah, they are mostly 3P. Similarly the smaller producers Bow Energy, WestSide and Molopo have significant 3P and contingent resources but relatively small volumes of 2P at this stage. In some cases they are also planning their own power projects or considering LNG.

Similar considerations apply in NSW in the case of Eastern Star and Metgasco.

Figure 31 Domestic gas contracts, Queensland, NSW and SA fields (PJ/a)



Is it likely to be easier to secure long-term contracts 3-6 or 7-10 years from now? This depends on a number of considerations:

- Overall LNG demand.
- The production history of the fields dedicated to LNG. To the extent that uncertainty is reduced this may make it easier to contract.
- Developments with the smaller producers, how successful they are in converting resources to reserves, whether or not they are taken over by LNG proponents, whether or not they develop their own LNG options and the extent to which they develop their own power projects rather than selling gas on long-term contracts.
- Exploration success generally in the Galilee and Gunnedah basins and success with other types of unconventional gas.

Over this period LNG projects may be deferred but this is not likely to make it easier to secure contracts. Once they have accumulated a large volume of gas, companies are likely to want to hang on to it for eventual monetisation as LNG.

If one of the projects was abandoned it would be easier to execute long-term contracts but we would not give this a high probability.

Overall, while a substantial volume of gas reserves are likely to be quarantined from the domestic market, there is no doubt that the overall level of CSG reserves and resources is much greater than it would have been otherwise due to the prospects of LNG sales.

Political considerations are also relevant. Security of domestic gas supplies is an important political issue. The Queensland Government proposed a gas reservation policy, which it withdrew but the possibility of nominating dedicated domestic gas fields is still alive. The LNG proponents are sensitive to the political issues and if major generators or industrial buyers are not able to rollover gas contracts the producers are likely to come under political pressure.

Over the period until start-up of the first Gladstone LNG projects (2014 and 2015) it is likely to be difficult to secure long-term gas contracts in Queensland. Beyond this, long-term contracts are likely to be available. As discussed earlier, LNG projects are likely to have excess capacity and political considerations will also be relevant. However contract prices offered by LNG producers are likely to reflect LNG returns.

Long-term contracts are currently available in Victoria, but are likely to be at higher prices, reflecting increases in offshore development costs.

Western Australia

The situation in Western Australia is dealt with in detail in the next Section.

8. WA gas reservation policy

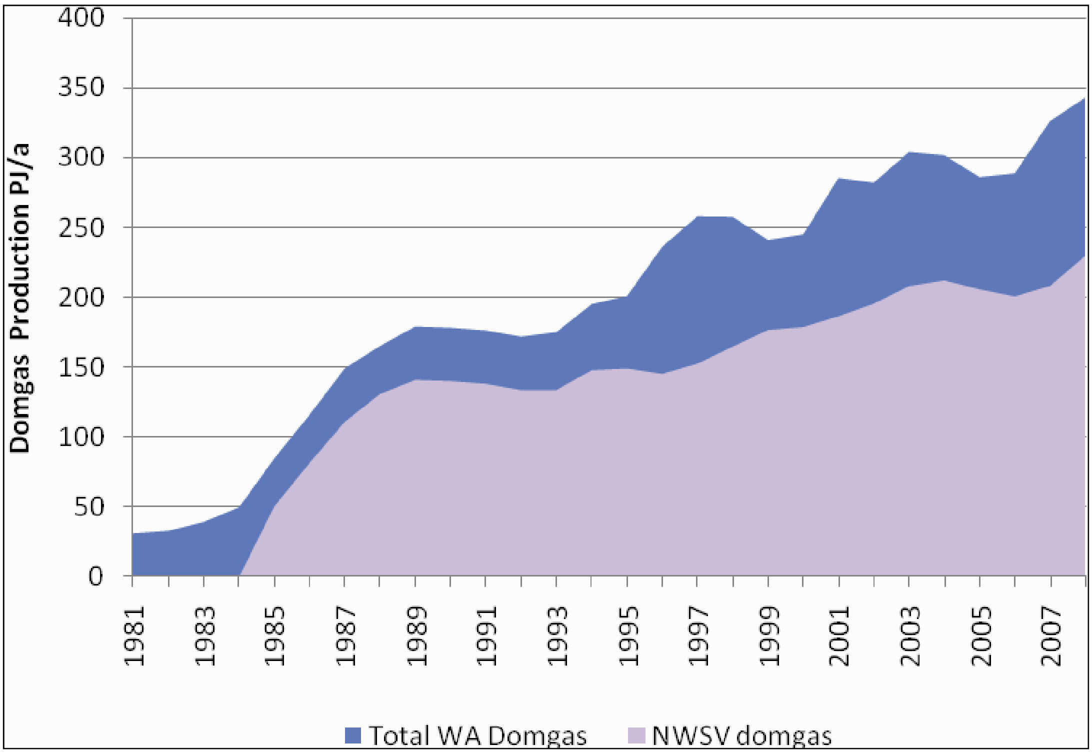
We have been asked to assess the application of the Western Australian gas reservation policy. In this Section domestic gas is referred to as Domgas in line with WA usage.

Background

The initial Domgas phase of the NWS Project was supported by a WA Government backed Take or Pay contract. The NWS Project committed to supply 414 TJ/d of Domgas for 20 years to various foundation buyers (3,023 PJ; First Priority Gas) plus a further 2,041 PJ to the WA Domgas market (Third Priority Gas), giving a total commitment of 5,064 PJ. (Second priority gas is entitled ‘Export Gas’ under the Act and relates to 198 billion cubic metres of gas reserved for LNG export.) Deliveries under this contract commenced in 1985 and the contract expires in its present form in 2014. However the NWS Project is ‘contractually obliged to continue supplying gas beyond that point and we will continue to do so.’ (Coetzer).

Figure 32 shows the growth in natural gas consumption in Western Australia from 1981 to 2008.

Figure 32 Natural gas consumption in WA



Following the inception of the NWS Project natural gas consumption increased rapidly to around 185 PJ/a in 1990 with the NWS Project supplying about 74% of all gas into the Domestic gas system. The NWS Project continues to dominate natural gas supply to WA domestic customers in 2010 supplying almost 600TJ/d (maximum sustainable capacity) and this represents around 60% of the total supply.

Development of alternative Domgas supply projects was slow due to the marginal economics of these projects based upon the low Domestic gas prices of the time (typical prices were in the range of A$2-3/GJ). Incremental demand for Domgas was beginning to put strains on the ability of the total natural gas supply system to maintain WA supply with a buffer.

The legacy contracts for Domgas supply backed by the WA Government's Take or Pay contract delivered low priced Domgas for the best part of 15 years. However, by the late 1990's it was clear that sustained low gas prices together with increasing development costs, made returns from investment in Domgas infrastructure uneconomic.

During the period 1997-2003 the world LNG market was in oversupply. This inhibited world LNG growth, put downward pressure on LNG prices and created great difficulties for the economic development of new greenfield LNG projects. It was even difficult during this period to make an economic case for the brownfield expansion (T4 and T5) of the NWS Project.

Woodside recently reported that development costs have increased by 18 per cent per annum over the past 10 years.

The development of new (much more capex intensive) gas reserves were needed to support an expansion of the NWS Project or the development of additional deepwater reserves for greenfield LNG projects and only the sales of large volumes of natural gas at Asian long-term LNG prices could create the economics to justify the investments needed.

Any disruptions to the supply chain (such as shut-in of NWS production due to a cyclone or equipment failure in its production system) or increased demands for natural gas resulting from, for instance, a failure of a coal fired power station, resulted in the phased reduction in gas supply to non-essential Domgas users.

In recent years Apache has supplied around 30% of WA's Domgas requirements from its Varanus Island Domgas plant. Shut down of this plant following a fire in June 2008 caused severe supply shortages in WA.

The supply of natural gas to the Domgas system in WA was, for most of the 1980's, in an oversupply situation. Domgas demand did not match contractual levels and the Take or Pay clause of the contract with the WA Government was invoked. By the late 1990's the lack of investment in new gas supply infrastructure by the NWS Project and other existing or potential new suppliers had resulted in a balanced supply system that looked to be headed towards a supply deficit. This created a strong push from producers and potential producers for an increase in Domgas prices that would encourage further development of smaller gas resource holdings. It was during this period that Apache's Varanus Island project was developed.

During the mid 2000's Santos developed the offshore John Brookes field which it processed on Varanus Island. Santos negotiated a series of contracts during the period 2008-10 at prices around A$8/GJ compared with the long term average of NWS Project Domgas pricing around A$3.50/GJ.

The Varanus Island incident, coupled with the perceived shortage of gas for domestic customers and new contract prices for Domgas that rivalled LNG netback pricing, triggered the previous WA Government to require new LNG projects to reserve 15% of their production for Domgas customers in exchange for permission to process LNG onshore. It also led to establishment of the current WA Government's 'Inquiry Into Domestic Gas Prices' during 2010.

What are the obligations of current and proposed LNG projects?

The obligations of the NWS Project under the original NWS Project Agreement expire with the completion of the contract in 2014. There has been some commentary in the WA Government 'Inquiry into the Price of Domestic Gas' (the Inquiry) which indicates that the WA Government could compel additional supply from the NWS Project if other supplies are not sufficient to meet the demand for Domgas.

Woodside recently made a statement to the Inquiry that, 'In relation to domestic gas, Woodside is absolutely committed to supplying the domestic gas market.'

The NWS Venture also commented as follows at the Inquiry:

- *'The real issue facing Western Australia is not a lack of gas, but the remoteness and difficulty of developing it commercially. While we have legacy contracts to 2020, we continue to market gas to new and existing customers in WA.'*
- *'We have made significant investment in our Domgas infrastructure and continue to maintain the facilities to ensure that capacity is available for ongoing competitive marketing. Ultimately, future supply will be contingent on genuine demand and market conditions.'*

However plans to upgrade the Domgas production facilities for the NWS project did not go ahead in 2007 following technical issues relating to the upgrade on the 630TJ/d plant. Plans to market an additional 100TJ/d were abandoned. No further reports on resolution of these technical issues have been made.

Table 12 Western Australian LNG projects

	Status	Probability	Start	Unrisked Capacity Mtpa	Risked Capacity Mtpa	POS	Comments
Western Australia							
NWS Project	Operation		1989	16.3	16.3	FID 1985	
Pluto T1	Construction		2011	4.8	4.3	FID 2007	Reserves constrained
Gorgon T1,2,3	Construction		2015	15	15	FID 2009	100% sold
Wheatstone T1,2 (Chevron)	FEED	Probable	2015	8.6	5.16	0.6	75% sold under HOA contracts
Prelude FLNG (Shell)	FEED	Probable	2016	3.6	2.16	0.6	Technology risk
Pluto T2	FEED	Possible	2015	4.3	1.72	0.4	Reserves constrained
Ichthys T1,2 (Inpex)	FEED	Possible	2016	8.4	2.52	0.3	Complex construction
Pilbara (BHPB)	Pre-FEED	Speculative	2018	6	1.2	0.2	Cost, liquids poor, may join with Pluto 2
Browse (Woodside)	Pre-FEED	Speculative	2018	12	2.4	0.2	JV, cost, environmental issues
WA Total				**79**	**50.8**		

Table 12 shows the existing and potential projects based in WA. (The Ichthys project is based in WA waters but is planning to build an LNG plant in Darwin.) Pluto 1 is almost completed and should start operation by mid 2011.

Whilst the risked capacity indicates significant growth potential in WA (>30 Mtpa higher than the NWS capacity) it is highly unlikely that all of this capacity will be developed in the time frame proposed by the project developers. Some of these projects may only be developed as back fill gas providers to other projects.

The key risks associated with these developments are:

- Market access and long term LNG sales at a price that support project economics.
- Project cost in remote locations.
- Competition for markets and resources required to build the projects from other projects in WA, Australia and other LNG producing nations in Asia Pacific and the Middle East.
- Securing reserves to back long term sales contracts prior to taking FID.

Large, offshore, deepwater reserves require huge LNG projects to justify their enormous capex requirements. The balancing of investment demands for Domgas and LNG will continue to test the financial capability of even the largest resource companies.

As a part of its agreement to develop the Pluto 1 LNG project, Woodside entered into an agreement with the government of Western Australia to market and make available for sale a quantity of domestic gas equal to 15 per cent of the quantity of LNG produced and exported from Pluto. This commitment begins to build five years after the date that LNG produced at Pluto is first exported, and is to be fulfilled if it is commercially viable for Woodside to do so.

Even though this commitment has been made it is not clear what 'commercially viable' means. Woodside has clearly indicated that it intends to build up to three LNG trains at Pluto. But Woodside has struggled to find sufficient reserves to enable FID to be taken on Pluto T2, let alone Pluto T3. It has offered the capability to process other resource holder gas through this facility.

When does the commercially viable test commence? At the completion of Pluto T1,2,3, or on indication of sufficient reserve to support Pluto T1,2 and a Domgas plant? Or is there some other test? If 5 Tcf (~5,800PJ) of reserves is required for each of Pluto T1 and T2 this would imply that Woodside may need to book about 11.5 Tcf (~13,360PJ) in order to supply LNG and Domgas.

If third parties utilise the Pluto facility to produce LNG are they also required to make available up to 15% of their reserves if it is commercially viable for them to do so? Is this the same as the test that Woodside must complete?

When asked at the Inquiry, 'What determines the commercial viability for the domestic reservation for the Pluto project?', Woodside's response was, 'Under the letter arrangement we have with the government of WA, that is something that needs to be agreed, but it will be an amalgam of a number of different features, I think, based on the marketability of the gas. I am sure that there will be financial-type metrics involved and general risk.'

From this interaction it is impossible to tell if or when Woodside will be providing Domgas from the Pluto project. Domgas supply out of Pluto T1 and T2 should be about 200TJ/d if 15% of LNG sales is used as the marker.

As for the Browse project Woodside has contended and the WA Government seem to agree (since they have insisted upon the Browse development being located in the Kimberley) that it would not be feasible to pipe Domgas into the WA west coast natural gas grid due to the 800km+ distance to Karratha. Small amounts of natural gas may be available for Broome or for local mining if the project proceeds at James Price Point. Other

Browse venturers however are more interested in using Browse reserves to backfill the NWS project at the completion of its reserves and thus ensure continued production for up to another 20 years. Such an outcome would also enable supply from Browse into the Domgas pipeline grid in WA.

There has been a suggestion that the WA Government would require Domgas supply from an alternative source to match the 15% obligation from Browse (or any other remote LNG project) but such a policy may be difficult to implement given the different ownership of different ventures.

Chevron reached agreement with the WA Government on the supply of 300 TJ/d from the Gorgon project and 200 TJ/d from the Wheatstone project. This represents an amount that is almost half of WA's current Domgas supply.

For Gorgon the agreed amount also had a financial viability clause and represented, at the time of agreement, about 5% of the Gorgon JV reserves. Since that time there has been an increase in reserves but the amount of natural gas dedicated to Domgas has not changed.

Chevron noted in their Environmental Scoping Document to the WA Environmental Protection Authority that Wheatstone's Domgas plant would represent about 15% of the LNG sales. Initial LNG production capacity is rated at 8.6 Mtpa (490PJ/a or 1330TJ/d) and hence a 200 TJ/d Domgas plant represents a 15% reservation.

The DomGas Alliance acting on behalf of the users of domestic gas in WA believes that, '... the reservation policy must be applied unequivocally. Domestic supply obligations must be made unconditional and not be subject to a commerciality escape clause'; and, '... the retention lease process must be transparent, must foster competition and must aim to stop producers warehousing gas'; plus, '... joint selling must end in five years' time to ensure that there are more sellers in the market to compete with each other'. Finally, '...the domestic price should reflect the cost of delivery into the processing plants'.

Whilst the arguments put forward by the producing companies for a continuation of joint selling should be strongly tested in a free market, on the whole the thrust of the submission of the Domgas Alliance to the Inquiry does not recognise the huge capital cost incurred by the various producers and the requirement of those businesses to make a profit on this capital expenditure to provide Domgas where (without LNG) there would only be a fraction of the Domgas that is available today.

It seems reasonable that Domgas should be made available to consumers in WA and that the price of that Domgas should reflect the cost to bring it ashore, process it and deliver it to market with a profit element that covers the capital risk.

Attempts at price regulation on Domgas or enforced reservation of reserves may result in less exploration, less development and a greater gap between perceived and fulfilled demand. It may also encourage more companies to take their processing offshore (as in the Prelude floating LNG project) where the jurisdiction is Federal and not State.

Recently the Australian Government has taken action on the warehousing of natural gas reserves putting the Browse Venturers on notice that a timetable to the FID decision must be accompanied by demonstrable action to complete FEED within a mid 2012 timeframe. It remains to be seen whether such action on other retention leases would actually encourage investment in Domgas infrastructure for supply of gas into a regulated Domgas market.

As Apache commented at the Inquiry, 'The issue is not finding more gas because we are running out; the issue is the correct economic and policy settings to allow people to bring that gas to the market.'

Apache, the second largest supplier of Domgas into WA has invested in Varanus, Devil Creek and Macedon to provide Domgas supply and are a part of the Wheatstone JV. They have said that, '...when customers are willing to pay prices that allow suppliers to develop gas reserves economically and under policy settings that allow the market to work as efficiently as possible, supplies will be adequate to satisfy the most optimistic demand projections.'

Apache summed up their investment strategy as, 'On a pre-tax basis, if the netback price is the same, we do not care—contractual obligations aside—which market we sell gas to.'

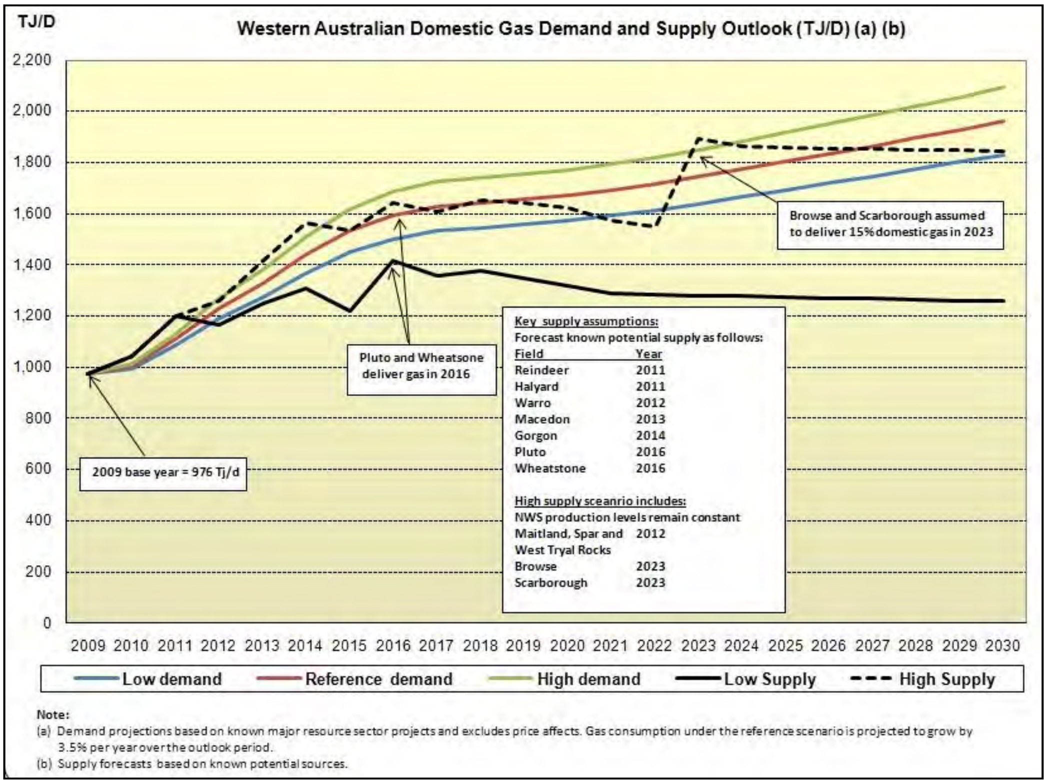
Size and timing of domgas supplies from LNG projects

Figure 33 shows WA domgas demand and supply scenarios prepared by the Department of Mines and Petroleum.

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: Model 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.

Figure 33 WA domgas demand and supply outlook

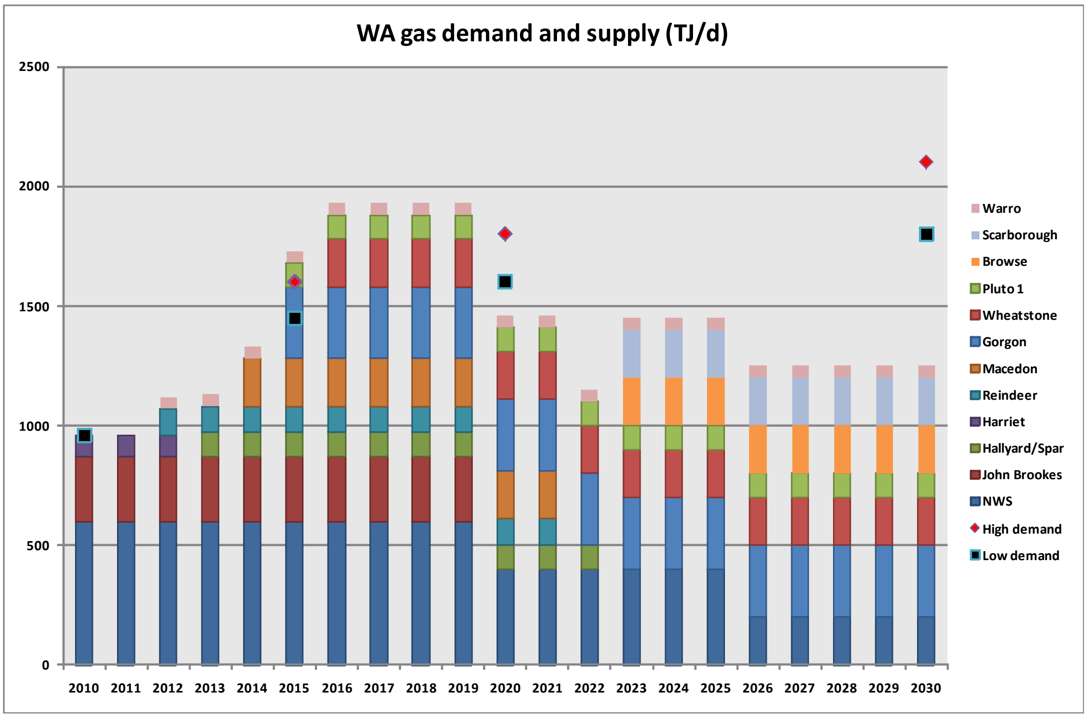


Source: (WA department of Mines and Petroleum, 2010)

Figure 34, prepared by EnergyQuest, builds up the supply side in detail. It assumes:

- NWS Domgas production is 600 TJ/d to 2019, then 400 TJ/d to 2025 and then 200 TJ/d to 2030.
- Harriet ceases production in 2012.
- Halyard/Spar commences production in 2013 and produces an average of 100 TJ/d for 10 years.
- John Brookes produces at an average rate of 270 TJ/d until 2019.
- Reindeer produces an average 110 TJ/d from 2012 for 10 years.
- Macedon commences production in 2014 and produces an average 200 TJ/d for 10 years.
- Gorgon commences Domgas production in 2015 at 300 TJ/d.
- Wheatstone commences Domgas production in 2016 at 200 TJ/d.

Figure 34 EnergyQuest WA domgas demand and supply



- Pluto 1 commences Domgas production in 2015 at 100 TJ/d.
- Browse commences Domgas production in 2023 at 200 TJ/d. This is a remote project so this either assumes that gas is piped to Karratha rather than being processed at James Price Point or that the Browse obligations are satisfied from another field.
- Scarborough commences Domgas production in 2023 at 200 TJ/d.
- Warro commences Domgas production in 2012 at 50 TJ/d.

The coloured diamonds and squares represent High and Low demand points from the DMP paper.

The gas demand supply balance under this scenario is tight until the commencement of production from Macedon, Gorgon and Wheatstone between 2014 and 2016. Any significant slippage in these projects would intensify the tight situation. The market is also tight again from 2020 when NWS domgas production is assumed to commence declining. (The overall outlook is sensitive to NWS reserves and contract rollovers). The results are also sensitive to assumptions about the timing and volume of gas from Browse and Scarborough.

Prospects for additional resources

Exploration in the Carnarvon Basin continues to yield good results. Chevron, Apache, Hess and Santos have all had recent successes. Higher domgas prices are likely to encourage further exploration and/or commercialisation of fields for domgas. There are also prospects for tight gas. The WA Department of Mines and Petroleum (DMP 2010) estimates that there are 9-12 Tcf of tight-gas-in-place onshore in the Perth Basin. There may also be shale gas potential.

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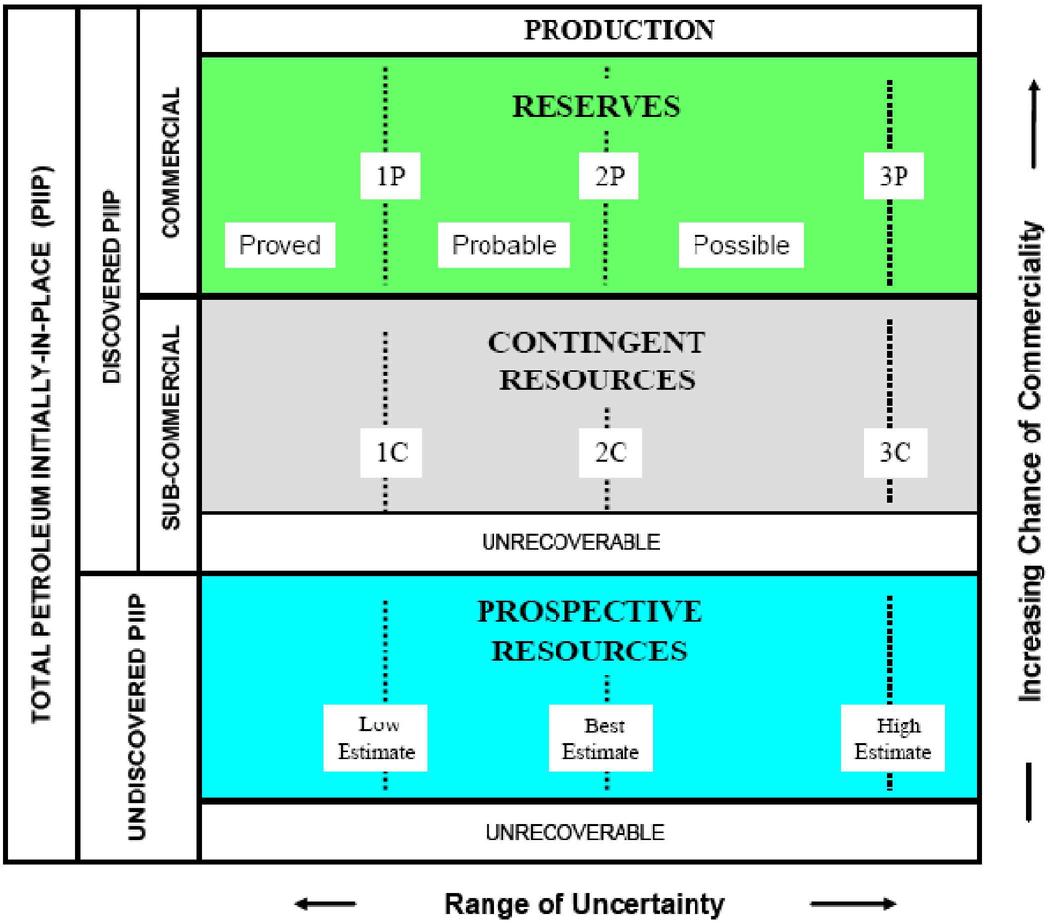
Appendix 1 Reserves and Resources

A new Petroleum Resources Management System (PRMS) was approved by the Society of Petroleum Engineers (SPE) in March 2007. The SPE's standards are recognized internationally and are widely adopted in Australia. Since 1 July 2007 Australian-listed oil and gas companies have been required to report to the ASX in accordance with the SPE or US Securities and Exchange Commission standards or to report what other standard they have used. Details of the PRMS are available at http://www.spe.org

The SPE classification system is as follows:



The SPE defines reserves as those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial and remaining.

All reserves estimates involve some degree uncertainty and are divided into three categories:

- **Proved:** those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations. If probabilistic methods are used for reserve estimation there should be at least a 90% probability that the quantities actually recovered will equal to or exceed the estimate. Proved reserves are also referred to as P90 or 1P and may be divided into developed and undeveloped reserves. Companies reporting in the US (including BHP Billiton) typically report on a Proved basis. An increasing number of other Australian companies also report their Proved reserves in varying degrees of detail.

- **Probable:** those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more likely to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater or less than the sum of the estimated Proved and Probable Reserves (2P). When probabilistic methods are used there should be at least a 50% probability that the quantities recovered will equal or exceed the sum of estimated proved plus probable reserves. The most common reserves benchmark in Australia is Proved plus Probable. This category is also commonly used for accounting purposes in Australia.
- **Possible:** those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. When probabilistic methods are used there should be at least a 10% probability that the quantities recovered will equal or exceed the sum of estimated Proved plus Probable plus Possible Reserves (also known as 3P or P10).

Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied projects are not yet considered mature enough for commercial development due to one or more contingencies such as lack of viable markets. Contingent Resources are typically measured at the Best Estimate level. Australian companies such as Woodside, Santos and Oil Search report their Contingent Resources.

Ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice. The SPE recommends that if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable timeframe (five years), the estimated recoverable volumes from the accumulation should be classified as Contingent Resources. Contingent Resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.

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Abbreviations

1P	proved reserves
2P	proved and probable reserves
3P	proved, probable and possible reserves
2C	best estimate contingent resources
3C	high estimate contingent resources
ACCC	Australian Competition and Consumer Commission
ADP	annual delivery plan
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
APPEA	Australian Petroleum Production and Exploration Association
bbl	barrel (159 litres or 35 imperial gallons)
bbl/d	barrels per day
Bcf	billion cubic feet (10^9 or a thousand million)
Bcf/d	billion cubic feet per day
boe	barrels of oil-equivalent
bopd	barrels of oil per day
Btu	British thermal unit (1.055 kilojoules)
CBJV	Cooper Basin Joint Venture
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
cf/d	cubic feet per day
CIF	cost, insurance and freight
Cl	chlorine
CILNG	Curtis Island LNG
CNOOC	China National Offshore Oil Corporation
CO_2	carbon dioxide
CSG	coal seam gas
CTL	coal to liquids
DES	delivered ex-ship
DEEDI	Queensland Department of Employment, Economic Development and Innovation
Domgas	domestic gas
DRET	Department of Resources, Energy and Tourism
DST	drill stem test
EIA	Energy Information Administration (US)
EIS	environmental impact statement
EU	European Union
FC	fixed carbon
FEED	front-end engineering and design
FID	final investment decision
FLLNG	Fisherman's Landing LNG
FLNG	floating liquefied natural gas
FOB	free on board
FPSO	floating production storage and offtake
GBJV	Gippsland Basin Joint Venture
GHG	greenhouse gas

GJ	gigajoule (1 billion joules or 10^9)
GL	gigalitre (1 billion litres or 10^9)
GLNG	Gladstone LNG
GSA	Gas sales agreement
GSOO	Gas Statement of Opportunities
GW	gigawatt
GWh	gigawatt hour
Ha	hectare
HGI	hardgrove grindability index
HH	Henry Hub
HOA	heads of agreement
Hp	horsepower
IEA	International Energy Agency
IPP	import parity price
JCC	Japanese crude cocktail
JV	joint venture
Kboe	thousand barrels of oil-equivalent
KJ	kilojoule (one thousand joules)
km	kilometre
kt	thousand tonnes
KTA	key terms agreement
LNG	liquefied natural gas
LPG	liquefied petroleum gas (propane and butane)
kbbl	thousand barrels
kbbl/d	thousand barrels per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MCHE	main cryogenic heat exchangers
MJ	million (10^6) joules
ML	million litres (6290 barrels or 796 tonnes)
mm	millimetre
MMbbl	million barrels
MMbbl/d	million barrels per day
MMboe	million barrels of oil-equivalent
MMboe/d	million barrels of oil-equivalent per day
MMBtu	million British thermal units
MMBtu/d	million British thermal units per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcm	million cubic metres (35.31 million cubic feet)
MMscf/d	million standard cubic feet per day
MOU	memorandum of understanding
MPa	megapascal
Mt	million tonnes
Mtpa	million tonnes a year
MW	megawatt
MWh	megawatt hour

Na	not available
NBP	National Balancing Point
NCG	Net Connect Germany
NEM	National Electricity Market
NGL	natural gas liquids (condensate and LPG)
NWS	North West Shelf
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OGIP	original gas in-place
OPEC	Organization of the Petroleum Exporting Countries
Pa	pascal
POS	probability of success
PJ	petajoule (one thousand terajoules)
PJ/a	petajoules a year
Ppm	parts per million
PRRT	Petroleum Resource Rent Tax
QCLNG	Queensland Curtis LNG
qoq	quarter on quarter
S	sulphur
SAP	system average price (UK)
SCLNG	see CILNG
SWQP	South West Queensland Pipeline
TIPS	Torrens Island Power Station
T	metric tonne
Tcf	trillion cubic feet (10^{12} or one thousand billion)
therm	100,000 Btu
TGP	terminal gate price
TJ	terajoule (one thousand gigajoules)
TJ/d	terajoules per day
TTF	Title Transfer Facility
VM	volatile matter
WTI	West Texas Intermediate oil
yoy	year on year

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, Eraring 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.

- 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.

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.

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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