SUBMISSION TO SENATE ECONOMICS COMMITTEE INQUIRING INTO MATTERS RELATING TO THE GAS EXPLOSION AT VARANUS ISLAND, WESTERN AUSTRALIA

November 2008

INTRODUCTION
On 28 August 2008, the Senate referred the following matters to the Senate Standing Committee on Economics:

a. the economic impact of the Western Australian gas crisis, including but not limited to:
   i. the extent of losses faced by business and industry failing to meet production targets due to the lack of gas supplies,
   ii. the disproportionate disruption to industry in the south west of Western Australia, and
   iii. the nature of contractual arrangements forced on business and industry during the gas crisis and their status since the resumption of gas supplies from Varanus Island; and

b. the government response to the Western Australian gas crisis, including but not limited to:
   i. the adequacy of the crisis management response,
   ii. the adequacy of reliance on one source of supply of gas for domestic markets,
   iii. the provision of reliable and affordable supplies of alternative energy,
   iv. the feasibility of developing emergency storage facilities of gas in depleted reservoirs or other repositories, and
   v. the justification for any refusals to release relevant facts and documents publicly.

BACKGROUND
Synergy is Western Australia's largest electricity retailer with over 970,000 industrial, commercial and residential electricity customers. Synergy supplies electricity customers connected to the South West Interconnected System (SWIS) covering the area from Kalbarri in the north down to Albany in the south and east to Kalgoorlie. Synergy procures electricity through competitive tenders on a regular basis, incorporating alternative fuel sources to address the issues of security, price and sustainability.

Synergy commenced selling gas in October 2003, and is an active player in the industrial and commercial market. Synergy does not retail to residential or very small businesses. In order to service its industrial and commercial customers, Synergy has developed a diverse and flexible gas supply portfolio and complementing transport entitlements.

Synergy estimates it services approximately three percent of the market and on average sells less than 25 TJ of gas per day. Currently, Synergy has approximately 200 customers in a market of 6,000.

VARANUS ISLAND GAS EXPLOSION
As a result of an explosion at Apache Energy's Varanus Island facility on 3 June 2008, 30 per cent of the State's gas supplies were reduced by approximately 350 TJ per day. Notwithstanding its small participation in the gas market in Western Australia, Synergy responded to customer requests to assist, where it could, during this period.

Synergy procures its gas supplies from a variety of sources, including a small amount of gas via Varanus Island which was cut as a result of the explosion and has still not fully recovered.

However, Synergy was able to leverage its diverse and flexible gas portfolio, where it could, to ensure it was not required to curtail any of its own customers throughout the gas shortage and could maintain all its contractual obligations. Synergy also did what it could to assist businesses who were not existing Synergy customers who were otherwise facing decreased or no gas supply, which ultimately enabled a number of businesses to continue operations and protected the jobs of many Western Australians.

> "Simcoa was very pleased with the support which we received from both Verve and Synergy in terms of obtaining sufficient gas to restart our charcoal plant as if we had not been able to do so we would have also been obliged to shut down our furnaces with a forced stand down of our workforce."
>
> *(Mr Jim Brosnan, Vice President, Simcoa, 20 October 2008)*

Synergy made alternative arrangements to ensure it was able to continue to supply gas to its customers. For example, Synergy negotiated with a customer to bring forward maintenance outages and compensated the customer for the foregone gas. This entitlement was used in conjunction with gas procured from secondary market industrial customers, at the then prevailing market prices to facilitate sales through the Gas Bulletin Board (GBB) (refer to "Short Term Trades").

STATE GOVERNMENT WORKING GROUP

A working group was established comprising representatives of the Premier's Office, the Energy Minister's Office, Office of Energy, Western Power, Alinta, Synergy, Verve Energy, the Dampier to Bunbury Gas Pipeline, the Chamber of Minerals and Energy and the Chamber of Commerce and Industry and was chaired by the Coordinator of Energy.

Guiding principles were established for the allocation of available energy.

The following principles were established for the priority allocation of limited energy resources:
1. protect the health, safety and property of the community;
2. minimise broad community disruption; and
3. minimise economic impact.

The priority schedule would not override contractual arrangements. To ensure the allocation of limited energy supply was in the public interest and consistent with the above principles, the following was the agreed priority schedule:

1. Energy infrastructure was to be given top priority to maintain the State's capability to supply gas and electricity to users.

2. Essential Services were defined as those critical services that had the potential to seriously impact on the health and safety of the community and included essential public transport and communications.

3. Essential Supply to Residential Customers would minimise the potential for health impacts and disruption to the community. Consumers were encouraged to reduce energy consumption. Synergy also took steps to reduce energy consumption within its own offices.

4. Industries providing essential goods and services to the WA community will have a higher priority in the allocation of energy than those that do not. This is to minimise disruption to the community and recognise the important services that these industries provide.

5. For all other industries, every effort will be made to maximise the availability of supply, recognising their importance to the State and National economy.

GAS SUPPLY MARKET

Western Australia's gas supplies, in the main, is concentrated with a few operators providing gas from the North West. Two operators, representing the interests of a number of joint venture parties, account for 98% of total gas production (both LNG and domestic gas) (Source: Argonaut Securities).

Wholesale bilateral supply contracts are generally signed for terms of five to seven years with these operators. The pricing related to these bilateral contracts have generally been confidential and therefore price disclosure has been infrequent with the result the market has not fully understood the price trends. This makes contracting in the market difficult for both buyers and sellers.

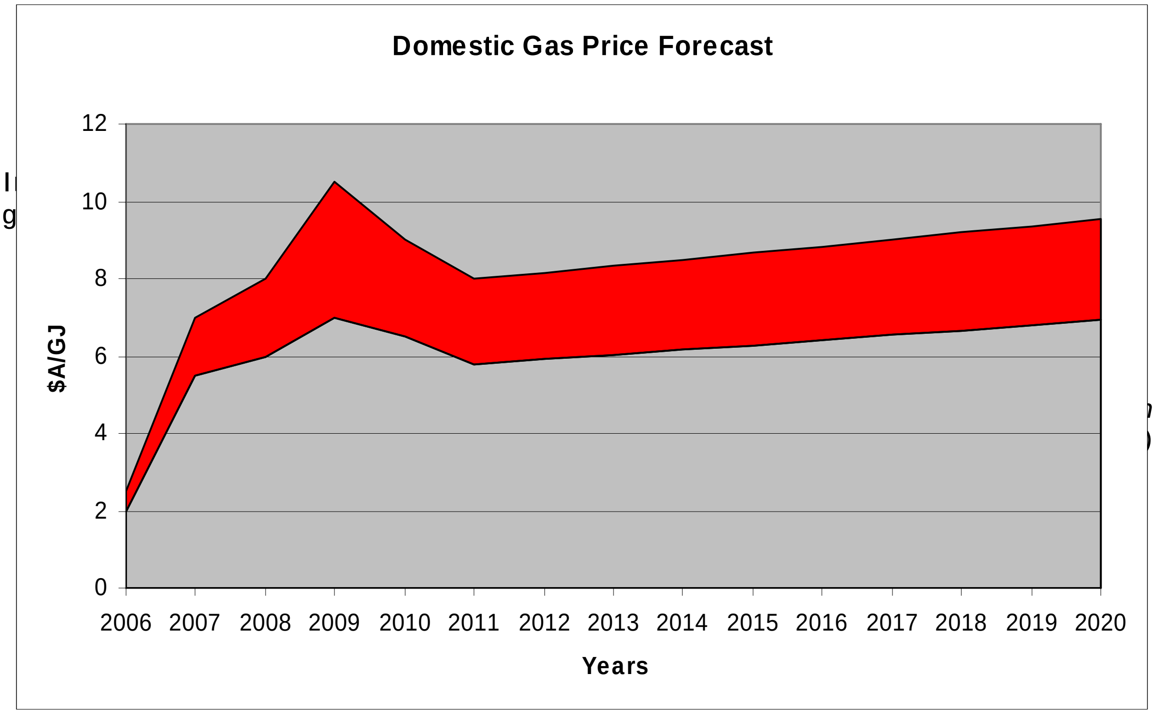
The secondary gas market is also small with a number of gas trades occurring annually between large industrials that have a requirement to adjust their supply position and counterparties such as Synergy, Verve Energy and Alinta. Typically these are shorter term trades at prices exceeding long term contract prices.

Historically, the large quantity of cheap gas has been an important driver of WA growth over the last few decades. Demand of gas through the 1990's was satisfied through strong supply, and prices were constrained over this period. In the early 2000's, prices remained constrained at around $2.50 GJ. Prices have increased significantly since 2005 due to a number of factors including:

- Strong growth in energy demand over a number of years for both domestic gas and LNG
- Facilities and pipeline capacity constraints limiting supply
- Dramatic rising exploration and development costs
- The widening gap between local and international prices
- Insufficient reserves earmarked for domestic gas sales, which point to continued shortages (in the absence of a strong price signal).

This shortage of supply has culminated in substantial price increases in the wholesale market and consequently increasing prices for new retail contracts, which has been validated by independent market observers.

Argonaut Securities, for example, projected in September 2007 wholesale domestic supply prices would continue to rise to peak price of around $11/GJ, as highlighted in the following diagram. Argonaut's forecasts are proving accurate, although slightly conservative.



Source: Argonaut Securities P/L – Equity Research Sep07

> "Information from stakeholders indicates that domestic gas prices have more than doubled in the 12 month period since early 2006 to a current level of around $5.50 to $6/GJ. This compares with $2 to $2.50/GJ in early 2006."
> *(Mr Lyndon Rowe, Chairman, Economic Regulation Authority, 13 June 2007)*

Evidence of the market price of gas rising significantly is also highlighted by the recent reporting of a contract between Santos and Moly Mines.

The Australian of 9 October 2008 reported Santos had "signed the highest-priced domestic gas contract yet, charging Moly Mines four times the average for other contracts."

The report added:

> "Santos also signalled a change to the way it sells its West Australian gas, linking the contract to global oil prices -- a feature previously only seen in liquefied natural gas export contracts.
>
> Santos has agreed to supply Moly Mines' planned Spinifex Ridge molybdenum and copper project with gas at $US11.50 (AUD$16.21) a gigajoule at current oil prices, making the contract four times as valuable as the $4 a gigajoule Santos averaged for its domestic gas in the second quarter. "

The report quoted BBY analyst Scott Ashton as saying: "Gone are the days of $2 to $3 in WA -- it's trending toward LNG prices."

It is clear gas prices have been increasing significantly, and there is no sign of gas prices falling.

Consequently, customers coming out of contract previously on these base price contracts, are experiencing shock by these market price signals.

SYNERGY'S GAS PRICING AND SUPPLY

Synergy's gas pricing approach for long term retail customer contracts remained unchanged throughout the Varanus Island gas crisis and continues to apply today.

The pricing framework adopted for Synergy's retail customers applies a commodity benchmark which is regularly aligned to changes in wholesale prices. The commodity benchmark price of gas charged by Synergy remained unchanged from July 2007 to May 2008. As a result of commodity price increases, the commodity benchmark price was increased in May 2008, prior to the Varanus Island gas explosion. This price was maintained through to 7 July 2008, some 36 days after the explosion.

Seven new contracts, which commenced in June/July, were being negotiated by Synergy prior to the Varanus Island gas explosion. The prices for these contracts were quoted prior to the Varanus Island gas explosion, and did not change.

Synergy also renewed 13 existing contracts, which commenced in June/July. Again, these prices were established prior to the Varanus Island gas explosion, and the prices did not change as a result of the explosion.

Synergy commenced negotiations for five new long term retail contracts, with a daily combined consumption of less than 1 TJ, following the Varanus Island gas explosion. These customers would have been out of contract in order to enter into their agreement with Synergy. The prices for these contracts were consistent with Synergy's normal business rules and based on the 6 May 2008 commodity benchmark price.

All 25 contracts referred above were priced using the commodity benchmark price of 6 May 2008 or prior. Synergy did not price gouge as it honoured the commodity benchmark pricing determined prior to the Varanus Island gas explosion.

During the Varanus Gas Crisis, Synergy tendered for additional short term supplies of gas to service the GBB and also to assist a number of competitor customers without gas who sought Synergy's assistance. Unfortunately Synergy was unsuccessful in securing material quantities from this market through these tender processes because other participants were prepared to pay significantly higher prices. Minor amounts of gas were accessed through the secondary market. These quantities were used to support our activities on the GBB, however prices were close to 80 to 100% higher than our long term commodity benchmark price.

With regard to the short term, such as the GBB and related activities, Synergy's trades reflected the then current market prices, as evidenced by the publicly available pricing on the GBB.

Synergy management provided guidance to operational staff to ensure Synergy did not engage in price gouging.

At the public hearing held on 2 October 2008, it was suggested Synergy may have had excess gas available:

> **Senator JOHNSTON**—But you cite this particular example:
> ... Synergy, a State Government owned entity, could redistribute apparent 'spare gas' to new customers under new contracts, reportedly at substantially higher prices and for periods or terms expanding out well over the estimated expected time of the disruption.
> **Mr Lock**—Correct.

(Senate Committee on Economics, Hansard, 2 October 2008)

Synergy does not carry "spare" gas, nor does it carry "spare" transport capacity. However, at the time of the incident Synergy had a small amount of headroom so was able to assist a limited number of customers. Synergy's normal business practice is to maintain some flexibility in its gas headroom to allow for opportunities to grow new business or to meet unexpected existing customer demand or to deal with other unforseen events. Accordingly, Synergy followed the same policies and methodologies applicable before the incident and were consistently applied following the incident.

In the days following the Varanus Island explosion, Synergy was approached by in excess of fifty businesses of varying sizes, and major mining customers, seeking gas supplies which their current retailer or supplier was unable to provide. Most of these businesses did not have alternative or emergency gas or energy supply arrangements in place.

Synergy could not initially assist those customers as all available gas was being made available to generation in support of the electricity network until after mid June.

TWO TO THREE YEAR CONTRACTS

The following comments were made at the public hearing of the Estimates Committee on 2 October 2008:

> **Senator JOHNSTON**—So Synergy were effectively taking advantage of the vulnerability of businesses to enhance their commercial position by writing two- to three-year contracts at inflated prices?
> **Mr Lock**—That is what we understand.
> *(Senate Committee on Economics, Hansard, 2 October 2008)*

and

> **Senator JOHNSTON**—Were you aware that Synergy ultimately was in fact rewriting two and three-year term contracts arising from the incident with people who were not previously customers or who could not access gas but, to get Synergy gas, were being asked to write new contracts at substantially increased prices?
> *(Senate Committee on Economics, Hansard, 2 October 2008)*

Synergy was very conscious of <u>not</u> acting in a way that knowingly took advantage of the crisis, and, after seeking legal advice, took active steps to ensure this including:

- not changing the price or the terms or conditions in which Synergy offered to supply gas to prospective customers (in this respect Synergy's usual contract period offering is two to three years and Synergy continued to offer these contractual terms after the commencement of the crisis); and
- not seeking to do anything that would cause another retailer's customers to breach their contracts with that retailer.

A number of customers approached Synergy at that time seeking side deals to their Alinta contracts and Synergy expressly stated to those customers it could not offer any special deals whilst they were under contract with their existing retailer. Synergy was aware the Independent Market Operator (IMO) was developing the GBB which would offer a mechanism by which short term transactions could be completed without breaching market rules and customers' existing contracts. Accordingly, Synergy provided the IMO with technical advice during the design phase to ensure the success of the GBB.

Synergy did not take advantage of the Varanus Island gas explosion to force customers to enter into contracts for two to three years. Further, Synergy did not approach any businesses to offer two and three year contracts as result of the Varanus Island gas explosion. Synergy did not seek to take advantage of the crisis to charge inflated or substantially increased prices. Neither did Synergy change any of its standard terms and conditions of contracts. Where any terms or conditions were adjusted, it was at the customer's request.

Synergy was explicit with potential customers that it could only contract with customers that were either out of, or about to be out of, contract with their retailer or who were free to do so under the terms of their existing contracts. Once this was confirmed Synergy only made offers under Synergy's normal business rules.

Where Synergy entered into contracts of two or three years, it was as a result of those businesses approaching Synergy and the prices offered to those businesses were the same as prices quoted in the weeks leading up to the Varanus Island explosion.

SHORT TERM TRADES

Synergy provided technical assistance to the Independent Market Operator in establishing the GBB. Once a mechanism and process was available, Synergy was prepared to trade, and conducted trades on a short term basis, either through the GBB or subsequent short term bilateral trades.

The GBB enabled allocation of gas on market principles and freed Synergy from making deliberate decisions about allocating small amounts of gas. The new market and rules for short term contracts dealt through this market reflected the commercial risks for Synergy and counter-parties.

The volumes of gas supplied through these arrangements were not substantial however Synergy's actions did have a tangible impact on the ongoing operations of a range of businesses, and protected the jobs of many Western Australians.

Synergy was the only party offering gas for sale on the GBB that was matched during the crisis. Synergy responded to requests for prices on a day-ahead basis and for slightly longer-period supplies of one to four weeks.

Synergy sold gas via the GBB, however, some customers either missed the matchup or wanted different quantities or terms to those offered under the GBB. In particular, some customers wanted more certainty than day-ahead allocation, hence, to the extent it could, Synergy used subsequent bilateral sales to ensure they could get gas.

In addition, Synergy was operating under pipeline transport constraints. This impacted Synergy's ability to provide offers on the firm terms and conditions sought by many parties wanting to contract via the GBB.

Trades on the GBB were at higher prices than the market standard two and three year contracts due to a number of factors, including the fact that the price of the gas source for supply was higher and to the nature of the contracts. They were short term contracts at spot prices and with unknown counter-parties.

Synergy undertook 63 trades with ten customers via the GBB and subsequent bilateral trades. The average price of these trades was reflective of the current market price and was approximately 50 per cent of the diesel substitute price.

Synergy refutes any suggestion it has priced customers at the diesel substitute price.

Synergy has received positive feedback from counter-parties with which it did business, including customers with whom it did business for only a very short period of time.

For example, Mr Martin Taylor, General Manager of GMA Garnet Pty Ltd indicated the gas available via the GBB was preferable to no gas supply at all:

> "Although the price of gas negotiated via GBB, plus delivery charges, was in the order of double our normal price GMA was well aware that under the supply/demand circumstances at the time the price could have been substantially higher and still been a better alternative than lost production. Overall, GMA was satisfied with the even-handed and fair treatment by Synergy during this period.

(Email to Synergy, 20 October 2008)

EXPEDITING CUSTOMER TRANSFERS

At the hearing held on 3 October 2008, the following comment was made by Mr John Scolaro, of Harvey Fresh:

> We said to Synergy, 'Yes, we will contract with you and yes we can contract with you.' We put that in writing. It then was revealed to us that it takes five days for suppliers to take on board a new customer from an existing supplier. That is to do with new rules from an organisation with the acronym REMCO—I am not sure what it stands for. It was told to me, but I cannot recall it—and the Office of Energy. REMCO is federal; the Office of Energy is state. We were that in an effort to protect customers this five-day cooling off period was insisted on. I do not know if it is correct that it was there to protect the customer. I guess it is like a cooling off period in any contract. Before supply starts, a five-day period has to ensue after the signing of the contract. Then supply starts. We said, 'We can dispense with the cooling off period,' and we were told that we did not have a choice; it has to exist.

(Senate Committee on Economics, Hansard, 3 October 2008)

Synergy sought to assist customers in desperate need of gas supplies as quickly as possible. Under the market rules which are governed by the Market Administrator, Retail Energy Market Company (REMCo), transfers are conducted via the market IT system. The system has been designed to automatically prevent any transfers taking place during an initial minimum five business day period. This is for the benefit of REMCo to ensure that in times of normal market activity, high volumes of transfers can be administered properly by the market system and are conducted in accordance with prudent business practices.

Synergy was instrumental in changing the transfer provisions to a new process, endorsed by REMCo and the market participants early in the crisis, by seeking an urgent REMCo Board meeting to amend the five day transfer period. This new process enabled next-day transfers for a small volume of customer churns to be completed outside the market system.

As Mr Scolaro indicated:

> It was through some great effort on the part of Synergy, which I admire them for. They did their very best to speed it up.

(Senate Committee on Economics, Hansard, 3 October 2008)

Similar rules apply to the electricity market in Western Australia which prescribe a five day notice period. Synergy facilitated an urgent electricity transfer, irrespective of these rules, to enable a customer, Doral Minerals Ltd, which had electricity curtailed through the declaration of Force Majeure, to continue to receive supplies in order to maintain business operations. We advised the regulator we would be breaching the rule to save jobs. This was despite the fact Synergy would not benefit in the long term from this transaction.

> "The flexibility and willingness that Synergy showed in diverting power to us late on a Sunday afternoon to cover our short term needs was noticeable and highly appreciated, especially given there was no long term benefit to Synergy and limited short term benefit (as we churned the same day and we could terminate the temporary arrangement with only a few days notice)."
>
> *(Mr Colin Bwye, Managing Director, Doral Mineral Industries Ltd, 20 October 2008)*

HARVEY FRESH

Synergy welcomed the input of Mr John Scolaro, of Harvey Fresh, as it highlighted the impact of the volatility of commodity prices in Western Australia, and the concern this has for Western Australian businesses, and enables Synergy to provide context and background to information to this specific contract.

Mr Scolaro referred to differential prices quoted at different times between March 2008 and 19 June 2008.

Synergy's commodity price remained the same between 27 July 2007 and 6 May 2008, at which time it increased reflecting changes in the market price of gas. Synergy's commodity price remained at the 6 May 2008 price until 7 July 2008.

Harvey Fresh's first offer was made based on the 27 July 2007 commodity price. On 15 May 2008, Harvey Fresh advised Synergy they would not contract with Synergy.

Synergy was contacted by Harvey Fresh on 17 June 2008 – fourteen days after the Varanus Island gas explosion – requesting gas supply. Synergy's quote for this request was based on the 6 May 2008 commodity price.

The second offer Synergy made on 17 June reflected the 6 May 2008 commodity price, and in the case of the additional site, an increased cost of transport was passed through as capacity booked by Synergy was exceeded for which Synergy is subject to penalty costs. The commodity pricing on the second site was still based on the 6 May 2008 pricing.

The delay in accepting Synergy's original offer did not deliver benefits due to rising commodity costs, and was not due to the Varanus Island gas explosion.

Finally, it is important to respond to an apparent concern expressed by Mr Scolaro to the public hearing, in which he stated, "my guess is that Synergy and Alinta kept talking to each other". Synergy categorically refutes any implication it engages in, or has ever engaged in, collusion with Alinta or any other competitor in the electricity or gas markets in contravention of any legal, regulatory or moral obligations. Synergy urges the Committee to raise any evidence that the Committee believes constitutes contravention of any legal obligation with the appropriate authorities including the Australian Competition and Consumer Commission.

CONCLUSION

Synergy refutes any suggestion it acted improperly following the Varanus Island gas explosion, or at all. Synergy acted as a responsible corporate citizen and within its limited capacity to respond and assist impacted parties. Synergy has well documented policies and procedures that determine its business practices including procurement and pricing.

APPENDIX ONE

ARGONAUT
SECURITIES PTY LIMITED

THE WESTERN AUSTRALIAN GAS MARKET

Goodwyn Platform, North West Shelf Venture (Source: Woodside Petroleum)

September 2007

Ian Christie

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ARGONAUT
SECURITIES PTY LIMITED

The Western Australian Gas Market

Equities Research

Date: September 2007

Ian Christie (08) 9224 6872

Executive Summary

- WA is well endowed with around 118tcf in reserves of natural gas, primarily in the Carnarvon and Browse Basins. Only 17% of these reserves have been developed.

- About 70% of the gas produced in Western Australia (WA) is exported in the form of LNG, with the balance sold into the domestic market. To date the supply of natural gas to the local market has been underpinned by WA's gas reservations policy, which essentially ensures that a portion of gas produced has to be sold locally.

- Future LNG projects (such as Pluto and Gorgon) will likely be subject to similar reservations policies through the approval process for onshore facilities. However these will be agreed on a case by case basis, and sales will need to be on "commercial" terms.

- The natural gas is delivered to the energy-hungry southwest portion of the State through three main independently owned pipelines – the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the Goldfields Gas Pipeline (GGP) and the Parmelia Pipeline (PGP). The DBNGP currently has no spare un-contracted capacity.

- A plentiful and cheap supply of natural gas has been a major driver behind the WA economy over the last few decades, and the State continues, on a per capita basis, to be the most energy hungry in Australia. Over half of the energy consumed in WA is provided by natural gas.

- 95% of gas demand comes from the minerals processing, electricity generation and mining sectors, with only 5% provided to households. The biggest users are Alcoa, BHP, Alinta, Verve, Burrup Fertilisers and Wesfarmers.

- Ample supply and competition has ensured that domestic gas prices in WA have traditionally been low (around $2/GJ) in comparison to international prices. However, this has changed dramatically over the last couple of years and we understand new contracts are being negotiated at prices in excess of $7/GJ.

- This has been driven by a rapid growth in demand as a result of the resources-led mining boom in WA, pipeline capacity constraints, dramatically increasing costs of gas development and production, moves to bring local gas prices closer to regional prices and LNG, and a readily apparent imminent gap in supply.

- With continued demand growth **Argonaut expects a dramatic shortfall of supply** for the next 2 to 3 years until some larger projects (Reindeer, Macedon) come on-stream in 2010 / 2011 (at the earliest).

- As a result we expect a **spike in prices** over the next couple of years until supply catches up with demand. Thereafter, as domestic gas sales have to be "commercial" for LNG producers we expect **LNG development and production costs to underpin domestic gas prices**. Prices around $2/GJ will not be seen again.

- The main **winners from this will be lower-cost producers of domestic gas** (not necessarily LNG projects – although they will do well from strong international LNG markets). Onshore project development and proximity to pipelines / markets will be key drivers of margins.

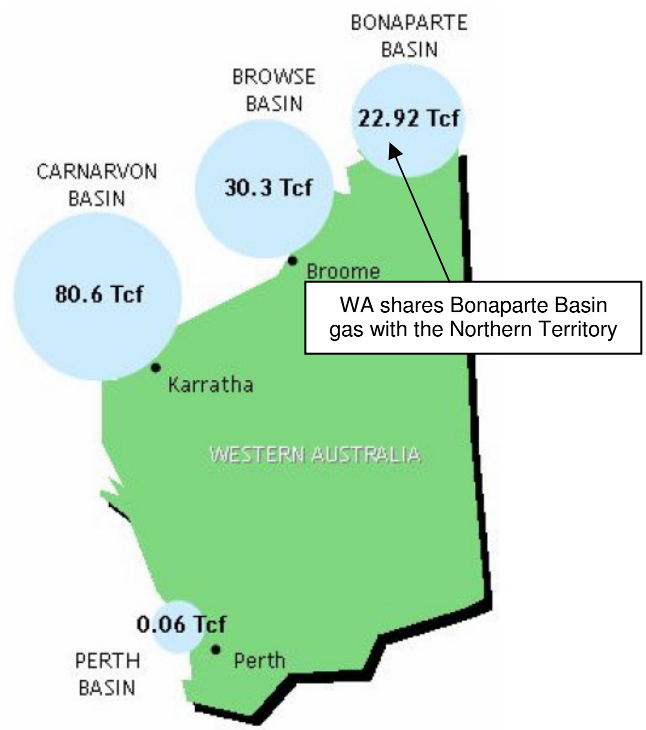
- The main **losers in the short-term will be large commercial consumers, such as mining projects, that have not tied down and / or fixed their energy requirements**. Short-term price spikes could render projects unviable and / or a lack of supply could potentially prevent development.

WA – WELL ENDOWED

WA is well endowed with 80% of Australia's gas reserves ……

- Western Australia holds 80% of Australia's natural gas reserves and produces 66% of the nation's natural gas. Mid-case (P50) gas reserves are around 118tcf located primarily in the Carnarvon, Browse and Bonaparte Basins.

Figure 1: WA Gas Reserves

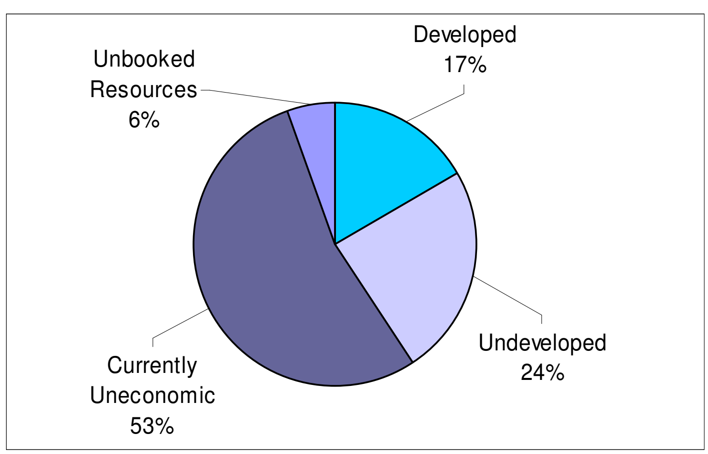


Source: Office of Energy, Dept of Industry & Resources

…… although only a fifth of these are currently developed.

- Less than a fifth of these reserves are currently developed and the majority is currently classified uneconomic (although this could be adjusted in the future to reflect increasing LNG and domestic gas prices).

Figure 2: WA Gas Reserves Breakdown

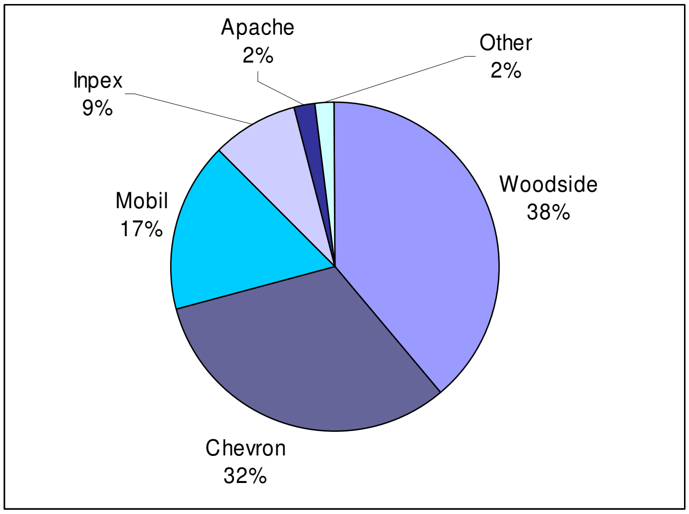


Source: Office of Energy, Dept of Industry & Resources

- Woodside and Chevron are the operators on fields which contain the bulk of total reserves, with Mobil, Inpex and Apache operators across other substantial fields.

Split by operator, Woodside and Chevron dominate WA gas reserves,

Figure 3: WA Gas Reserves Split by Operator



Source: Office of Energy, Dept of Industry & Resources

Table 1: Reserves for Larger WA Gas Fields

Field	Operator	Reserves (P50, tcf)
Developed Fields		
Goodwyn	Woodside	3.79
John Brookes	Apache	1.27
North Rankin	Woodside	5.57
Perseus	Woodside	8.50
Undeveloped Fields		
Angel	Woodside	1.85
Blacktip	ENI	0.64
Dockrell	Woodside	0.61
Gorgon	Chevron	14.03
Ichthys	Inpex	9.50
Reindeer	Apache	0.37
Tidepole	Woodside	0.52
Retention Lease (Currently Uneconomic)		
Brecknock	Woodside	5.30
Io	Chevron	6.27
Jansz	Mobil	13.46
Scarborough	Mobil	5.19
Torosa	Woodside	11.50
Wheatstone	Chevron	3.97

Source: Office of Energy, Dept of Industry & Resources

although net equity reserves positions differ.

- Note that the companies' net reserves positions should not be inferred from this data, as being an operator on a field does not reflect the ownership interests of JV parties.

- For example Woodside appears to dominate reserves and production data. This is largely because it is operator at the North West Shelf Venture (NWSV). Its actual ownership interest in the NWSV ranges between 12.50% and 50.00%.

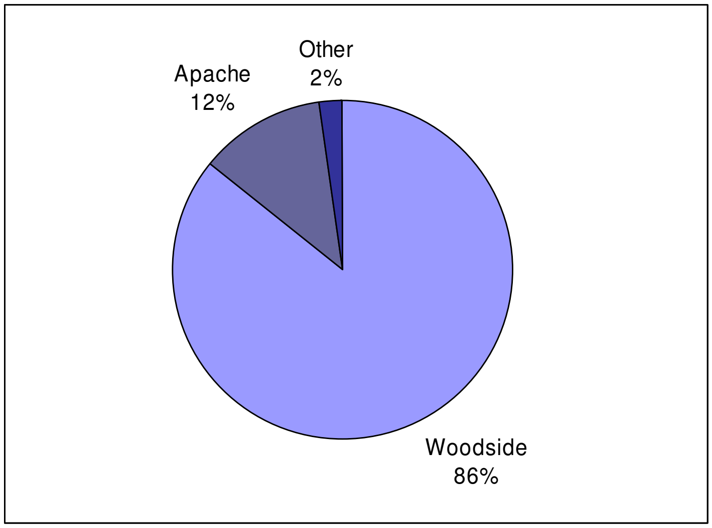
PRODUCTION

WA currently produces close on 1tcf of natural gas p.a., 70% of which is exported as LNG.

- Total natural gas production in 2006 was 0.98tcf (DOIR, 2007). The bulk of this (0.68tcf, or 69%) was exported in the form of LNG. The remaining 0.30tcf was sold under contract into the domestic market.

- Two operators, representing the interests of a number of JV parties, account for 98% of total production (both LNG and domestic gas) although the operator of the NWSV represents the JV interests of 6 companies.

Figure 4: WA Gas Production Split by Operator



Source: Office of Energy, Dept of Industry & Resources

The North West Shelf Venture dominates gas production …..

- The NWSV is Australia's largest resource development project and has invested more than $14b since 1984. There are three offshore facilities in use – the North Rankin A Platform, the Goodwyn A Platform and the Cossack Pioneer Floating Production, Storage and Offtake (FPSO) facility.

- Natural gas is converted to LNG onshore, with the 5th LNG train currently under construction.

Table 2: NWSJV Participants

Company
Woodside
BP
Chevron
Japan Australia LNG
Shell
BHP

Source: www.nwsg.com.au

…… and supplies around $^2/_3$ of the natural gas sold to the domestic market.

- The NWSV supplies around $^2/_3$ of the natural gas sold to the domestic market (domgas), with the Harriet Joint Venture (HJV), East Spar, John Brookes, Griffin and Perth Basin Producers supplying the balance.

- At the HJV, Apache represents the interests of Kufpec and Tap Oil.

RESERVATIONS

Domestic supply has been underpinned by gas reservations with the North West Shelf ……

- To date the supply of gas to the local market has been underwritten by the State's Gas Reservation Policy with the NWS. This has essentially ensured a proportion of the gas produced is available for domestic use.

…… and it is understood that all of these original reservations have been fully committed under long-term contracts.

- It is understood that all original domgas reservations have been fully committed under long-term contracts. Future agreements are likely to be decided on a case by case basis. The table below provides an indication of potential reservations, but is still subject to negotiation. The term "must be commercially viable" introduces a further grey area.

Table 3: Reservations in WA

Field / Project	Remaining Reservations (PJ) either negotiated or based on 15% of total reserves	Comments
NWSV	2,750	Has been fully contracted
Gorgon	2,000	Must be commercially viable
Pluto	573	Must be commercially viable
Ichthys	1,511	Subject to project development and must be commercially viable
Torosa	1,829	Subject to project development and must be commercially viable
Brecknock	843	Subject to project development and must be commercially viable
Scarborough	826	Subject to project development and must be commercially viable
Total	**10,332**	

Source: Synergies Economic Consulting

Note: 1,000PJ is approximately 1tcf

Future agreements will be negotiated on a case by case basis, with a commerciality clause another grey area.

- While the bulk of offshore gas fields lie in Commonwealth as opposed to State waters, WA has been able to implement the reservations policy through the approvals process for the construction and operation of onshore LNG facilities.
- Offshore floating LNG facilities have been mooted, but until this happens the WA Government retains the ability to negotiate gas reservations.
- The WA Government points out that the currently contracted NWSV reservation plus existing contracts from domgas only projects will supply less than $^2/_3$ of the projected domgas requirements between now and 2020.
- To ensure local supply of gas, current WA Government policy is to secure domestic gas commitments up to 15% of LNG production from new export gas projects.

Gas reservations policy is a hot topic at present, with pricing likely to emerge as the key issue.

- This (or perhaps more pertinently the consequent pricing of the domgas) is the subject of debate at present, with gas producers querying why they should subsidise the margins of commodity producers (who themselves have seen significant increases in the sales prices of their exports).

PIPELINES

Getting gas from Dampier to the south-west involves 3 major pipelines and vast distances.

- WA's major gas fields lie in the offshore Carnarvon Basin (the North West Shelf) and to get it to the energy hungry south-west and the goldfields, gas has to be transported the same distance as Moscow is from London. There are three major gas transmission pipelines in WA.

Table 4: Major Gas Transmission Pipelines

Pipeline	Owners	Average Installed Capacity
Dampier to Bunbury Natural Gas Pipeline (DBNGP)	DUET (60%), Alcoa (20%), Alinta (20%)	710TJ/d
Goldfields Gas Pipeline (GGP)	Australian Pipeline Trust (88%), Alinta (12%)	130TJ/d
Parmelia Gas Pipeline (PGP)	Australian Pipeline Trust (100%)	65TJ/d

Source: Office of Energy

- The DBNGP and GGP are covered by independent economic regulation of third party access to their pipelines. The regulator is the Economic Regulation Authority (ERA) and all pipelines are licensed by the Department of Industry and Resources (DOIR).

DBNGP

The Dampier to Bunbury Pipeline has no un-contracted capacity at present (but will be increasing capacity in the near term).

- The DBNGP currently has no un-contracted forward haul capacity, but was committed under agreements in 2004 to expand the capacity of the pipeline by at least 100TJ/d.
- In late 2006 the DBP announced Stage 5 expansion of the DBNGP, with the first component adding about half the mainline length (570km) and adding 100TJ/d capacity. This will cost about $660m and is expected to be completed in March 2008.
- A further expansion, expected to be commissioned much later in 2010, will add another 40TJ/d to the pipeline's capacity.

GGP and PGP

- The GGP has long term contracts in place with major mining companies including Nickel West and Newmont. The Australian Pipeline Trust reports that current contracts account for total reserved capacity of approximately 38PJ/annum, which implies un-contracted capacity of around 20TJ/d.
- Industry sources suggest that the PGP has un-contracted capacity of around 40TJ/d.

DEMAND

WA uses more gas per capita than any other State …….

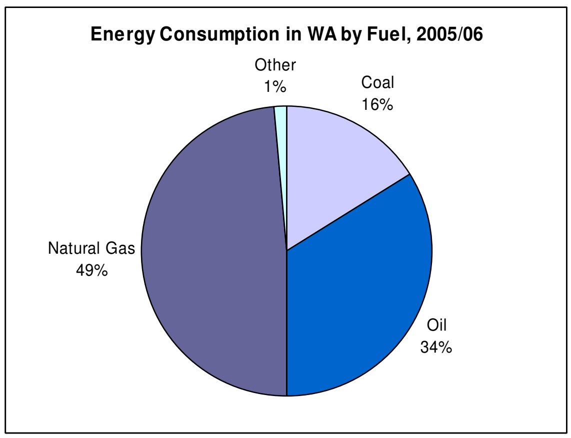
- The large quantity of cheap gas has been an important driver of WA growth over the last few decades. The development of the North West Shelf and the construction of the 1,600km DBNGP in the early '80's, followed by further development and competition, has underpinned an economy where energy-intensive mining and mineral processing activities predominate.

- Of all the states and territories in Australia, mining in WA has the largest slice of Gross State Product (GSP), energy consumption per unit of GSP is the greatest, and WA uses the most energy per capita (Synergies Economic Consulting, 2007).

……. accounting for nearly 50% of primary energy consumption …….

- Gas accounts for close to 50% of primary energy consumption in WA (ABARE, 2007). This is the highest in any state and is expected to increase further. As such, future growth in the WA economy will remain very reliant on the domestic availability of natural gas.

Figure 5: Energy Consumption in WA



Source: ABARE

….. and is far cleaner than coal.

- Contributing to the increasing share of natural gas in the State's energy mix is the issue of climate change with Policy likely to encourage even further use of natural gas (it is far cleaner than coal).

Within the natural gas market, 95% is consumed by the mining, mineral processing and electricity generating sectors …….

- Demand primarily from minerals processing, electricity generation and mining accounts for around 95% of domestic gas consumption. Households and small business accounts for the remaining 5% of demand.

…….. although the remaining 5% (households) has a significant political voice.

The Six Leading Gas Consumers in WA
Alcoa (alumina processing)
BHP Billiton (mining & mineral processing)
Alinta (gas supply and electricity generation)
Verve Energy (electricity generation)
Burrup Fertilisers (chemical manufacturing)
Wesfarmers (LPG extraction, fertiliser and chemicals)

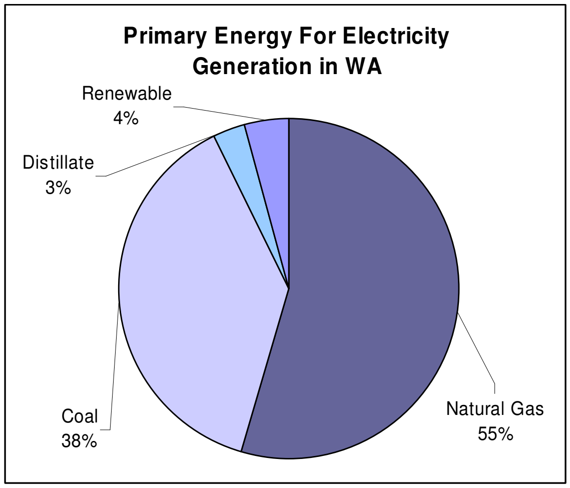
- In total, around 20-30 customers contract directly with upstream gas suppliers. These gas sales contracts are treated as commercial in confidence and there is therefore very little transparency in terms of domestic gas prices. Wholesale gas pricing is discussed in more detail in a later section.

Electricity Generation

The bulk of energy for electricity generation in WA comes from gas.

- Over half of the primary energy for electricity generation in WA comes from natural gas, with coal-fired generation making up the bulk of the balance.

Figure 6: Primary Energy for Electricity Generation



Source: Office of Energy, Dept of Industry & Resources

- Excluding generation from plants of less than 10MW that do not supply either Verve or Horizon, at August 2006 WA had:
  - 6,192MW installed capacity (95.5% non-renewable, 4.5% renewable)
  - 1,100MW capacity committed or under construction to 2008 (99.3% non-renewable, 0.7% renewable)
  - 762MW capacity (all non-renewable) scheduled to retire in 2009

Although some plants can switch between energy sources, oil is expensive, while coal is limited and "dirtier".

- It is interesting to note that a number of these plants can switch between sources of energy. For example, of the 3,420MW of plant capacity that runs off natural gas, over half can be switched to distillate / diesel in need. Of course there is a substantial cost in doing so with the latter delivered at over $40/GJ (prior to any rebate).
- Apart from some regional Electricity Supply Authorities there are three major electricity networks in WA:
  - The South West Interconnected System (SWIS)
  - The North West Interconnected System
  - The Esperance System
- Western Power Corporation was recently restructured into 4 divisions:
  - Within the SWIS:
    - Verve Energy is responsible for power generation
    - Western Power Networks is responsible for transmission and distribution
    - Synergy is responsible for retail
  - Outside the SWIS Horizon Power is responsible for generation, transmission and retail.

Table 5: Major WA Electricity Generation Stations

Some Major WA Electricity Generation Stations (>100MW Installed Capacity)			
Location	**Owner**	**Primary Fuel**	**Capacity (MW)**
Operating			
Muja	Verve	Coal	1,040
Kwinana	Verve	Coal	901
Pinjar	Verve	Natural Gas	581
Collie	Verve	Coal	330
Kemerton	Transfield	Natural Gas	240
Kwinana	Verve	Natural Gas	240
Telfer	Newcrest	Natural Gas	161
Pinjarra Unit 1	Alinta Cogen (Alcoa)	Natural Gas	140
Burrup Peninsula	Woodside	Natural Gas	120
Dampier	Pilbara Iron (HI)	Natural Gas	120
Worsley	SW Cogen JV	Natural Gas	120
Worsley Alumina	Worsley	Coal	120
Kwinana	Perth Power Partnership	Natural Gas	116
Mt Keith Nickel	Southern Cross Energy	Natural Gas	114
Mungarra	Verve	Natural Gas	112
Kalgoorlie	Newmont / TransAlta	Natural Gas	110
Cape Lambert	Pilbara Iron	Natural Gas	105
Planned			
Wagerup Stage 1	Alinta Cogen (Alcoa)	Natural Gas	350
Kwinana	Newgen	Natural Gas	320
Collie (Bluewaters 1)	Griffin	Coal	208
Pinjarra Unit 2	Alinta Cogen (Alcoa)	Natural Gas	140

Source: Office of Energy, Dept of Industry & Resources

Retail Gas Sales

Competition and tariff caps help control prices for retail customers.

- On the retail side, full contestability has been in place in WA gas markets since June 2004. This means that new gas companies can enter the market and provide greater retail choice. Government imposed tariff caps are imposed in most markets.

Table 6: Current Gas Market Operators in WA

Licence Area	Network Operator	Retailers
SW Coastal Area (Geraldton to Busselton)	AlintaGas Networks	Alinta Synergy
Kalgoorlie-Boulder	AlintaGas Networks	Alinta
Albany	AlintaGas Networks	Alinta
Margaret River	Wesfarmers Kleenheat	Wesfarmers Kleenheat
Leinster	Wesfarmers Kleenheat	Wesfarmers Kleenheat
Esperance	Burns Roe Worley	Burns Roe Worley

Source: Office of Energy, Dept of Industry & Resources

GAS PRICES – THE PAST

WA gas prices have lagged oil, LNG and gas price trends, internationally and regionally, for a number of years ……

- The chart below shows provides a history of domestic gas prices along with international comparables (Brent crude, Henry Hub gas, and LNG) over the last 12 years.

Figure 5: Comparative International Gas Prices

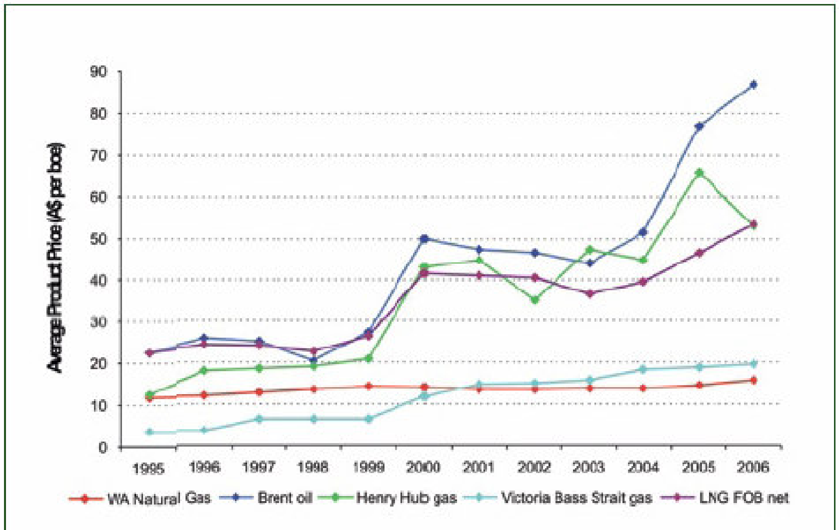


Figure 4. Australian gas price - international comparison 1995-2006

Source: DOIR Petroleum in WA (April 2007)

- With significant development and competition emerging in the 1990's and a reservations policy that ensured demand was more than sufficient to meet supply, prices were kept well in check over the period.

- This situation was maintained into the early 2000's, culminating in the HJV contract with Burrup Fertilizers at probably never to be repeated prices (we understand nearer to $1/GJ than $2/GJ).

- More recently the DOIR has indicated that domestic sales in 2006 increased by 13% on 2005 to 318PJ and the value of this gas increased by 23% to $811m (Petroleum in WA, April 2007). This works out to an average WA gas sales price of $2.55/GJ.

…… but this has changed dramatically in recent months for a number of reasons.

- However, this number largely reflects historic contracts and masks some significant underlying changes. Newer contracts are currently being negotiated at significantly higher prices – above $7/GJ.

- We believe there are a number of reasons for this:

  - Strong growth in energy demand arising from a number of years of above trend growth in WA

  - Facilities and pipeline capacity constraints limiting supply even if offshore producers diverted production to domgas

  - Dramatically rising exploration and development costs

  - The widening gap between local and international prices

  - Insufficient reserves earmarked for domgas sales, which point to looming shortages (in the absence of a strong price signal)

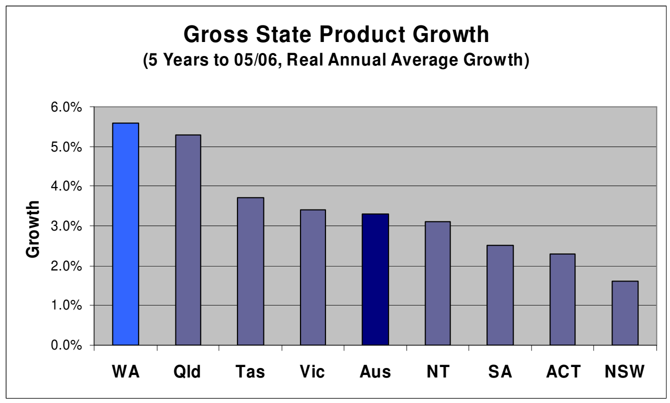
FUTURE DRIVERS

Demand

WA has grown faster than any State in Australia over the last 5 years …..

- Fueled by the rapid growth in China and a strong global economy, WA has experienced an exceptional few years. Only Queensland, which is also benefiting from the mining boom, has come close to matching WA's growth over the last 5 years.

Figure 6: GSP Growth Compared

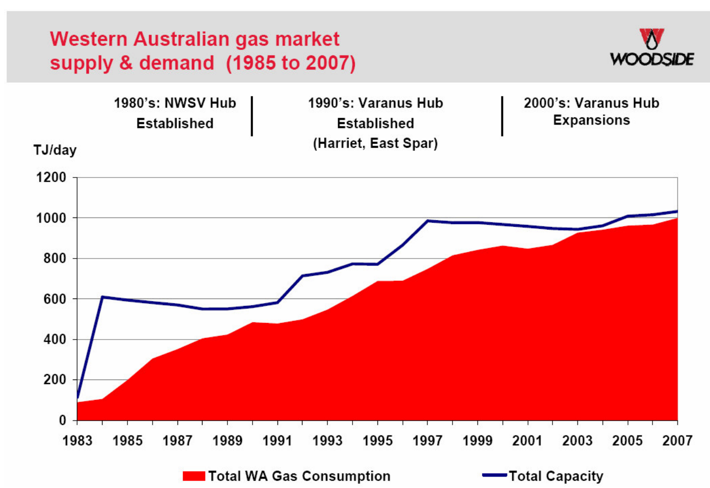


Source: WA Dept. of Treasury & Finance, ABS

……. resulting in the gap between gas availability and demand being steadily eroded.

- This growth has required energy, and as shown in Figure 7 the gap between capacity and demand has been steadily eroded.

Figure 7: WA Gas Consumption and Capacity



Source: Woodside

- With continued investment expected in the energy-hungry resources sector (particularly mining projects), energy requirements are only going to grow further.

This demand growth is unlikely to falter in the near future with nearly 60% of advanced mining projects based in WA ……..

- Table 7 shows that 26 of the 46 (57%) advanced resources projects nationwide are based in WA. It is questionable whether the proponents of these projects have not only adequately assessed the energy cost, but also its physical availability.

- It is a similar situation to the hard rock drilling rig market, where available drilling rigs are unlikely to be sufficient to meet the combined drilling expectations of numerous exploration companies.

Table 7: Advanced Resources Projects by State

…… requiring $19.4b (or nearly 90%) of the earmarked capital.

Advanced Projects by State, April 2007								
	Energy Projects		Mining Projects		Minerals Processing		Total	
	No.	$m	No.	$m	No.	$m	No.	$m
NSW	4	601	3	259	2	460	**9**	**1,320**
Vic	4	1,402	1	120	0	0	**5**	**1,522**
Qld	17	5,914	7	975	3	799	**27**	**7,688**
WA	10	8,531	26	19,367	0	0	**36**	**27,898**
SA	1	55	5	1,325	0	0	**6**	**1,380**
Tas	0	0	1	77	0	0	**1**	**77**
NT	3	262	3	245	1	3,000	**7**	**3,508**
Aus	**39**	**16,766**	**46**	**22,368**	**6**	**4,259**	**91**	**43,393**

Source: ABARE

Pipelines

There is another question mark over pipeline capacities, and higher than expected demand or delays in pipeline expansion capacity could result in physical constraints.

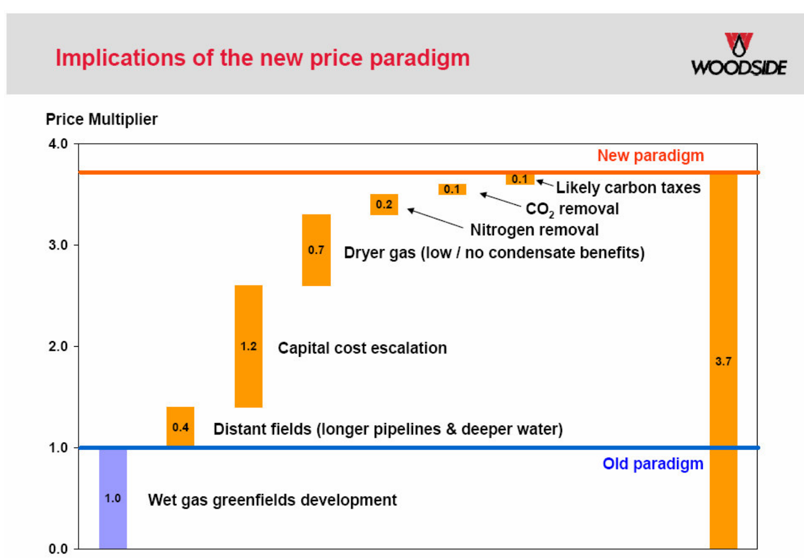
- Over 70% of domgas is sold in the southwest (primarily to Alcoa, Alinta and Verve Energy). There is therefore a heavy reliance on the DBNGP. This pipeline has no un-contracted forward haul capacity.
- So even if there was a concomitant increase in supply to meet new demand, there is a question over whether the DBNGP is capable of handling the extra volume.
- The pipeline capacity is being increased by 100TJ/d from early next year and by another 40TJ/d in 2010, which appears to be just sufficient to meet requirements.
- However, more than anticipated demand and/or delays to pipeline expansion could result in physical capacity constraints. Future energy policy in WA must therefore address capacity as well as supply issues.

Costs

Developers highlight the significant increases in both capital and operating costs ………

- Woodside included a figure in a recent presentation highlighting the significant increases in offshore development costs.

Figure 8: A New Paradigm



Source: Woodside

…… the 4 D's …… with gas now more likely to be distant, deep, drier and dirtier.

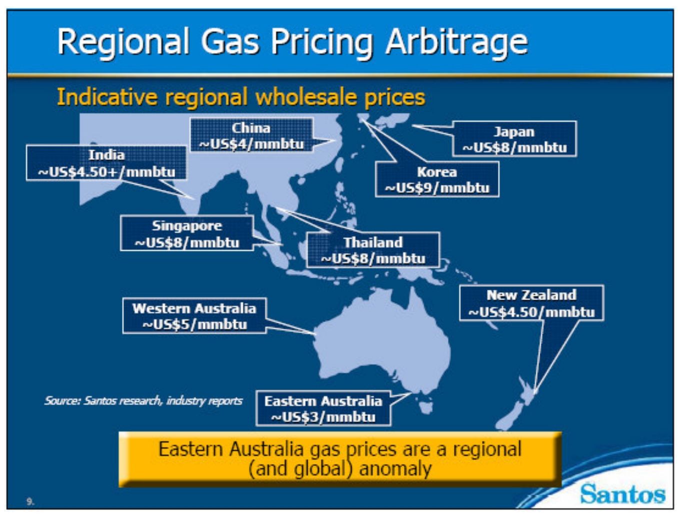
- It is not only the escalation in capital costs that has to be considered. Gas E&P companies need to take into account the 4 D's – gas is now more likely to be distant, deep, dry (i.e. lower associated valuable liquids production), and dirty (i.e. needs further cleaning to remove higher percentages of nitrogen and CO_2).
- Based on Woodside's numbers in Figure 8, if gas used to be produced for $1.00/GJ, the new paradigm implies a sales price of at least $3.70/GJ simply to cover the cost escalation.
- It must be remembered that the WA Government's gas reservation policy stipulates that any gas sold into the domestic market must be commercially viable.

International Comparisons

WA gas prices have been, until recently, way out of line with prices on international and regional markets ………

- A recent Santos comparison of gas prices on regional markets is instructive, showing that prices range between US$4/GJ and US$9/GJ and that WA gas in June was selling for US$5/GJ (A$6/GJ).
- This shows that the old selling prices of $2/GJ are out of line with regional markets, and suggests that new contracts are being negotiated at much higher prices.

Figure 9: Regional Gas Pricing Arbitrage

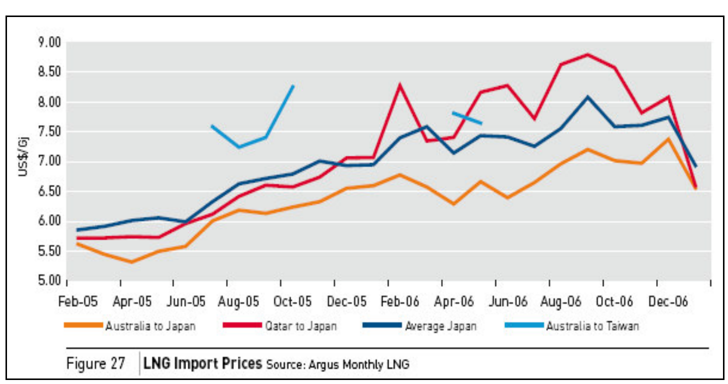


Source: STO Presentation (June 2007)

Note: 1mmBtu is approx. 1GJ which is approx. 1mcf

- Most of WA's gas is sold into international LNG markets, where strong demand has caused an increase in the price of LNG over the last few years (see Figure 10 below).

Figure 10: LNG Import Prices



Source: DOIR: WA Mineral & Petroleum Statistics Digest 2006

……. and developers like Woodside expect internationally competitive prices where it comes from an export facility.

- At Woodside's AGM earlier in the year, the Chairman stated that the "nature and location of Western Australia's gas resources means that further development of gas supplies for the state is dependent on large scale LNG export projects. The gas industry expects to receive an internationally competitive price for its gas where that comes from an export facility".

Local Supply and Timing

A major issue is the timing of future domestic gas supplies – with domestic gas from LNG projects only becoming available well into the next decade.

- Despite the uncertainty over the pricing of future domgas sales, we believe the strong market for LNG will result in ongoing project development. For example, in July 2007 Woodside approved development of the Pluto LNG Project, signing an export agreement with Japanese companies in August.

- Assuming no delays, first LNG from Pluto will be delivered in late 2010. However, what is critical to note is that the commitment to reserve 15% gas for the domestic market only begins 5 years after first production. This implies first domgas sales from Pluto in 2015 at the earliest.

- This story of a significant time-lag to local gas sales is likely to be repeated with other large LNG developments such as Chevron's Gorgon project. In line with other agreements, the gas only has to be supplied locally if "commercially viable".

Even the smaller projects take a number of years to develop.

- Even the smaller projects that are only targeting local sales will take years to develop. Santos and Apache recently announced the commencement of front-end engineering and design (FEED) studies for the Reindeer Gas Field in the Carnarvon Basin:

  - Gross recoverable resource range of 410-640PJ

  - Production capacity of 110TJ/d, with first gas for the domestic market in mid 2010

  - The Santos Managing Director commented that the "booming minerals industry in WA has given us the confidence to move forward" and that "recent higher gas prices will help to facilitate significant investments in long term gas supply for WA"

- Development planning for BHP's Macedon field (150TJ/d) is progressing with a start-up targeted for 2011.

The bottom line is that there is at least a 3 year lag before significant new supply comes on stream.

- The key takeaways from the above are that:

  - Even if the go ahead is given today, it will take at least 3 years for new developments supplying natural gas to the local market to get up and running

  - Proposed and potential LNG projects could provide significant quantities of gas for the domestic market through reservations, but only from well into the next decade

- Another factor to take into account is that given the size and cost of field development and capacity upgrades, supply will only react if underwritten by significant step changes in demand. There are therefore likely to be periods of shortages followed later by dramatic surges in supply as producers react to price signals.

FORECASTS

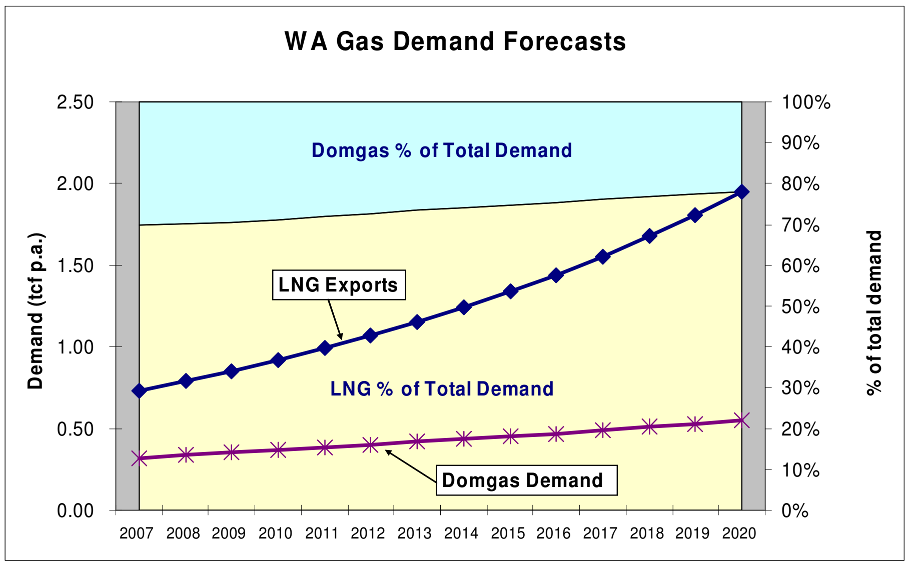
Demand and Supply

Over the next 13 years, we expect steady growth in domestic gas demand, and an even larger growth in LNG production.

- We have forecast anticipated trends in gas and LNG sales as shown in Figure 11. This shows LNG production and domestic gas sales increasing to around 2.0tcf p.a. and 0.55tcf p.a. respectively by 2020.

- For domestic gas, this assumes a base of 0.32tcf domgas demand in 2007 and a 6% p.a. growth in demand over the next two years (in line with a significant number of near-term mining projects and strong State growth). Thereafter, growth is assumed to be 4.0% p.a. for the remainder of the period.

Figure 11: Projected Demand



Source: Argonaut forecasts, various industry sources

However, with limited spare domestic gas capacity at present …….

- On the supply side, we assume there is only limited spare capacity at this point. This is consistent with anecdotal evidence indicating challenges in securing new or additional supplies of gas. Further backup for this assumption comes from Woodside, who in a recent presentation indicated only around 30TJ/d spare capacity at this point.

……. and a lag until new development projects come on stream ……...

- Looking forward, we assume that the 110TJ/d Reindeer and 150TJ/d Macedon projects come on stream as anticipated in 2010 and 2011. However, we should note that it has been rare to see any resources project completed on time for the last couple of years.

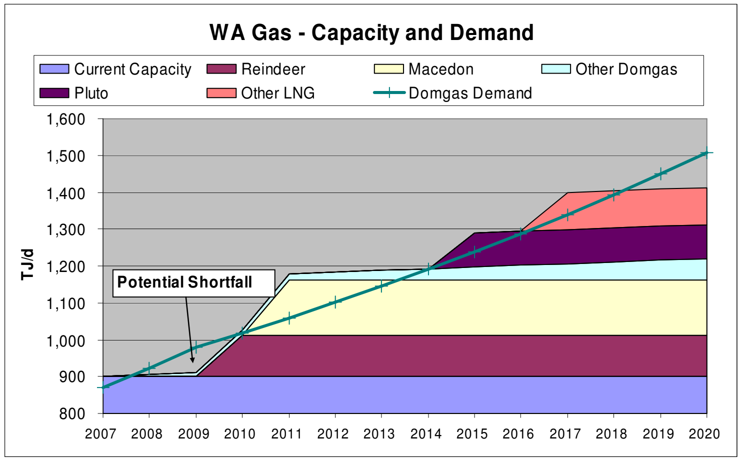
- In the longer term, we believe that the international market for LNG will remain strong and LNG prices high, resulting in the development of major LNG projects (like Pluto, Gorgon and Scarborough). Reservations will ensure substantial increases in domgas supply, but only from well into the next decade.

- We also have added in some incremental growth from smaller offshore and onshore fields that are likely to be developed on an ongoing basis over the next few years. The impetus to do so will be strengthened by an increasing domestic gas price.

……. we anticipate a short-term gap where supply will not be able to meet demand.

- The following figure overlays the forecast demand with these anticipated additions to supply. Readily apparent is a likely short-term "gap" where supply will not be able to match demand.

Figure 12: Demand and the Supply Gap



Source: Argonaut forecasts, various industry sources

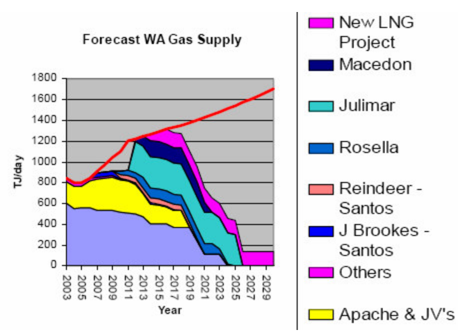
This gap will be most noticeable in 2008 and 2009 ……

- On these assumptions, this "gap" amounts to around 20TJ/d in 2008 and 70TJ/d in 2009. Reindeer, in 2009 brings the market back into balance, but if this project were to be delayed by a year, the deficit in 2010 would escalate to in excess of 100TJ/d. The timely success of these projects is critical in order to prevent even more serious short-term supply problems.

….. and follows similar analysis and conclusions from the two largest operators in WA.

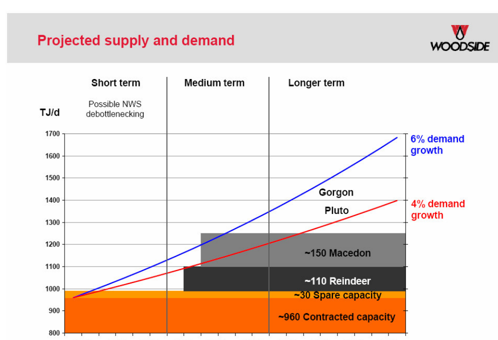
- Apache and Woodside have recently highlighted the same short-term issues via the following graphics:

Figure 13a: Forecast WA Gas Supply – Apache



Source: Apache Energy (Houston Investor Conference, June 2007)

Figure 13b: Forecast WA Gas Supply – Woodside



Source: Woodside

- In the longer term we anticipate further LNG developments to fill in the gap that becomes evident from the latter part of the next decade.

Prices

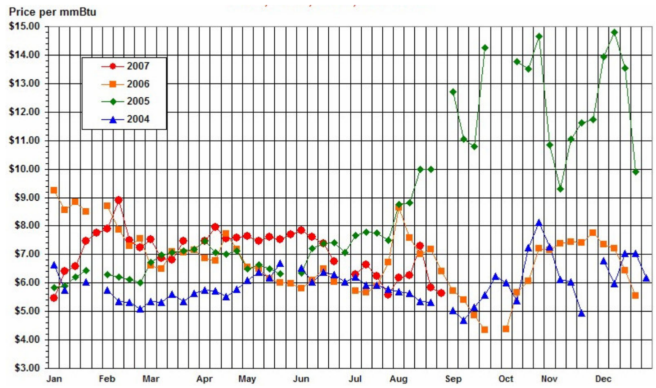
As a result we expect a spike in prices over the next couple of years ……..

- We expect prices are set to spike sharply over the next couple of years as the strong growth in demand results in a supply shortfall. It is difficult to put exact numbers on prices, but we are influenced by:
  - International comparative prices
  - Experiences in other markets
  - LNG production costs

……. with Henry Hub prices in 2005 demonstrating what can happen to prices when supply does not meet demand.

- Movements in the Henry Hub natural gas price in the US over the last few years shows what can happen to prices when there are supply problems. Gas prices had been trending upwards, but spiked significantly when Hurricanes Katrina and Rita caused major production problems in the Gulf of Mexico in 2005.

Figure 14: Henry Hub Natural Gas Price (US)



Source: Nebraska Energy Office

- Prices in the US have since fallen back, but the Henry Hub futures market suggests prices trending up from around US$7/mcf (~A$8.50/GJ) for the foreseeable future.

Longer term we expect domestic gas prices to be underpinned by LNG costs of production ……

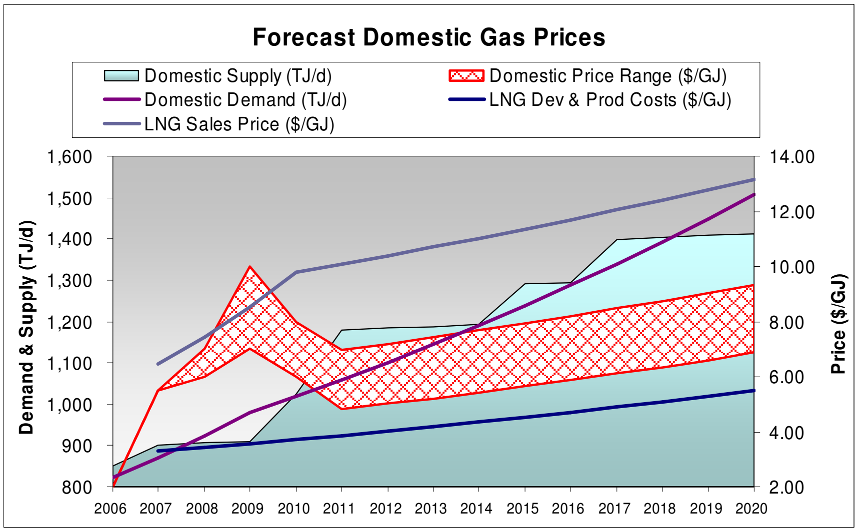
- Locally, after a short-term spike in prices, we expect longer-term domestic gas prices to be underpinned by LNG costs of production plus a margin as under reservations rules the sales must be "commercial". We do not expect domgas prices to ever fall back to historical levels of $2/GJ.

Figure 15: WA Natural Gas Forecasts

……. and trade in a range that also takes into account the international price of LNG.

2008/09 should see prices in the $7/GJ to $10/GJ range.

The days of $2 gas are gone.



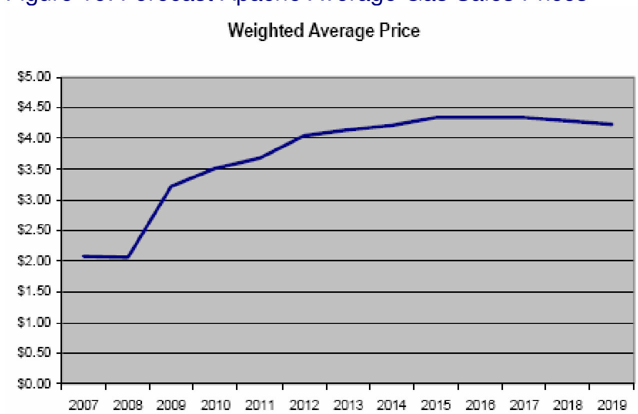
Source: Argonaut

- We have based our assumptions for LNG costs of production on the Pluto development, which according to Woodside will cost:
  - More than $12b to develop 5tcf
  - Between $4 and $5 per boe in operating costs

This new pricing paradigm for natural gas in WA is reflected in recent comments from major gas producers.

- A number of companies back the view that there is a new paradigm for domestic gas prices:
  - Woodside recently announced that the "easy gas is gone" and the days of cheap gas are over.
  - Apache have noted that their average sales prices are forecast to increase to US$3.25/mcf (~A$4.00/GJ) by 2010 and US$4.00/mcf (~A$4.50/GJ) by 2016. It must be remembered that this is an "average" so includes contracts at low historic prices. New contracts would need to be at significantly higher prices to bring the average up.

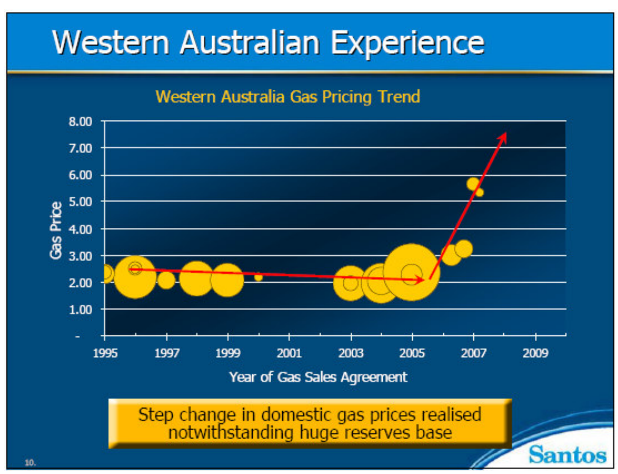
Figure 16: Forecast Apache Average Gas Sales Prices



Source: Apache Energy (Houston Investor Conference, June 2007)

  - Santos also noted the change in WA gas pricing in a recent presentation.

Figure 17: Gas Prices in WA



Source: Santos Presentation (June 2007)

With domestic gas prices being out of line with international prices for far too long, a sharp realignment was always a likelihood.

- Anecdotal evidence suggests that Santos, as one of the few current sellers of uncontracted gas, is able to dictate its terms on new contracts at prices above $7/GJ.

WINNERS & LOSERS

Winners

- We believe that LNG projects will prove to be robust for WA producers based on our expectation of strong global demand.

- However, domgas sales from LNG producers are unlikely to be particularly attractive. While domgas sales will be "commercial", we expect the WA Government will do all it can to keep the price down, limiting margins.

The main winners will be less costly producers of currently un-contracted domestic gas ……

- However, the LNG producers' costs will provide a floor for domestic gas prices and we therefore believe the primary winners will be:

  - Less costly producers of currently un-contracted domestic gas. Margins will be directly related to costs, with better performers being those:

    - Closer to the energy hungry south-west

    - Onshore rather than offshore

…… but service companies and pipeline owners also stand to benefit.

  - Companies providing drilling and other services to the upstream domestic gas market.

  - Pipeline owners, as they expand pipeline capacities

  - Governments through increasing royalties and taxes

- More specifically:

We understand Santos is the only company with un-contracted gas available at present ……

  - Argonaut understands that **Santos** (STO) is currently the only company with un-contracted gas to market. It is therefore in a strong position to negotiate considerably higher prices for its gas. At a recent presentation, STO highlighted:

    - That at its 45% owned John Brookes field, there is around 160bcf of net un-contracted 2P reserves and that several new contracts have been "signed at higher gas prices"

    - These higher prices have facilitated the development of Reindeer

…… while Tap Oil will have gas available to it over the coming years that it states can be sold into the domestic market …..

  - **Tap Oil** (TAP) has indicated that it has 33PJ of un-contracted gas available to it under agreements with the John Brookes and East Spar JV's. This is available to TAP at historic prices and Argonaut understands from TAP can be sold over the next 10 years to the domestic market at new contract prices.

…… and ARC Energy is embarking on a higher risk, but major exploration programme across the onshore Canning Basin.

  - On the higher-risk exploration front, **ARC Energy** (ARQ) recently kicked of its onshore Canning Basin exploration with the Valentine-1 well. ARQ has gross exposure to 140,000 square kilometres in this Basin, which has been under-explored in recent times due to its distance from markets and perceived technical difficulties. The dramatic changes to WA gas prices in recent times have changed this view and improved the chances of commercial development of discoveries.

Losers

- Retail consumers:

Over a longer period of time, retail consumers may start to feel the impact of higher prices ……

  - The WA Government puts a limit on the price that gas companies can charge to retail customers. This tariff cap protects consumers from unfair gas prices or large changes. These caps apply in the SW Coastal Area, Kalgoorlie-Boulder and Albany, but do not apply in Margaret River, Leinster or Esperance.

  - Over time, retail customers will need to pay prices reflecting the increased costs of exploration, development, production and transportation. This may take years due to the existence of long term contracts, but it is inevitable, no matter how politically unpalatable this may be.

- Large commercial consumers:

……. but we believe the issue for large commercial consumers who do not as yet have long-term supply contracts in place to be more serious.

  - We believe the issues here are more serious in the short term, primarily for those potential large commercial customers who do not as yet have long-term supply contracts. In this case:

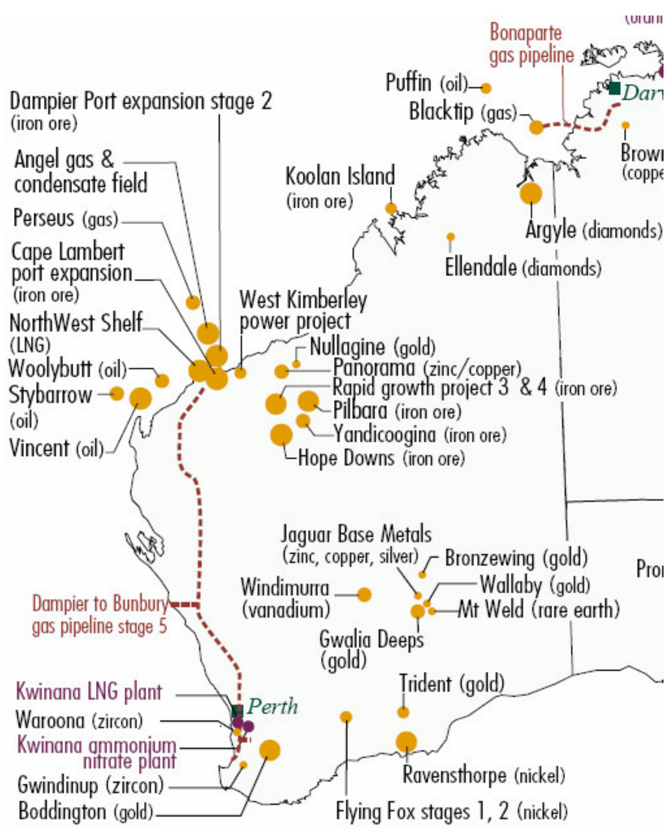
    - Adequate supply may be unobtainable in the short-term

    - Even if it is available, the gas could be prohibitively expensive

While a good percentage of projects are likely to have agreements and contracts in place ……

- A lot of the future energy demand will come from the mining sector in WA. ABARE data in April 2007 shows that there are 26 advanced mining projects in this State, with an estimated capital cost of $19.4b. This accounts for nearly 90% of all the capex committed to mining projects in Australia.

Figure 18: Advanced Minerals and Energy Projects



Source: ABARE

- A significant amount of the total capex (nearly $12b) will be spent on iron ore expansion and infrastructure by BHP, RIO and Fortescue.

- The largest advanced gold project is the Newmont / AngloGold Ashanti $2b redevelopment of Boddington, while BHP's Ravensthorpe nickel project is expected to cost close to $3b.

- We assume that the owners of projects of this size would have assessed and tied down the necessary energy contracts (which may not require natural gas, such as Boddington which will run on coal-fired energy).

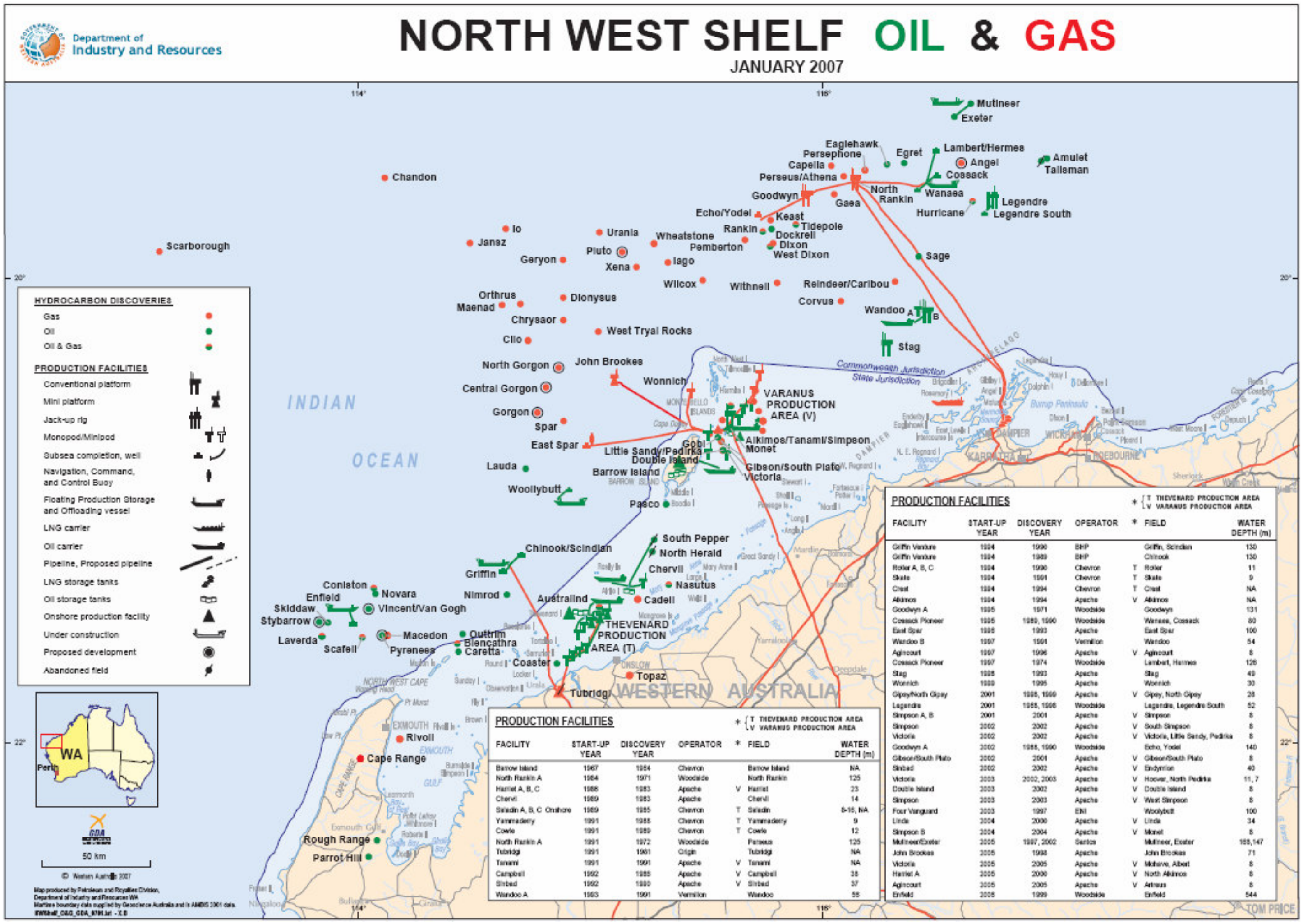
……. there may be projects that have not tied down their energy needs and could find the economics of their projects significantly altered.

- However, there could be a number of smaller projects that have not yet finalised their energy / gas requirements or have not fixed prices. In this case the economics may be significantly negatively altered.

- In recent news as an example, following a delay in obtaining funding, Precious Metals Australia (PMA) announced that Santos has offered a revised agreement on terms "unacceptable to PMA". Alternatives are being sought by PMA.

- This is just the start. Over the next couple of years we expect that we will see more mining projects facing altered economics as a result of the changing face of the WA gas market.

APPENDIX



Source: Department of Industry & Resources

Common Abbreviations and Their Metric Equivalents		
m = thousand	= 10^3	= k (kilo)
mm = million	= 10^6	= M (mega)
b = billion	= 10^9	= G (giga)
t = trillion	= 10^{12}	= T (tera)
	= 10^{15}	= P (peta)
	= 10^{18}	= E (exa)

Source: BHP Billiton Petroleum

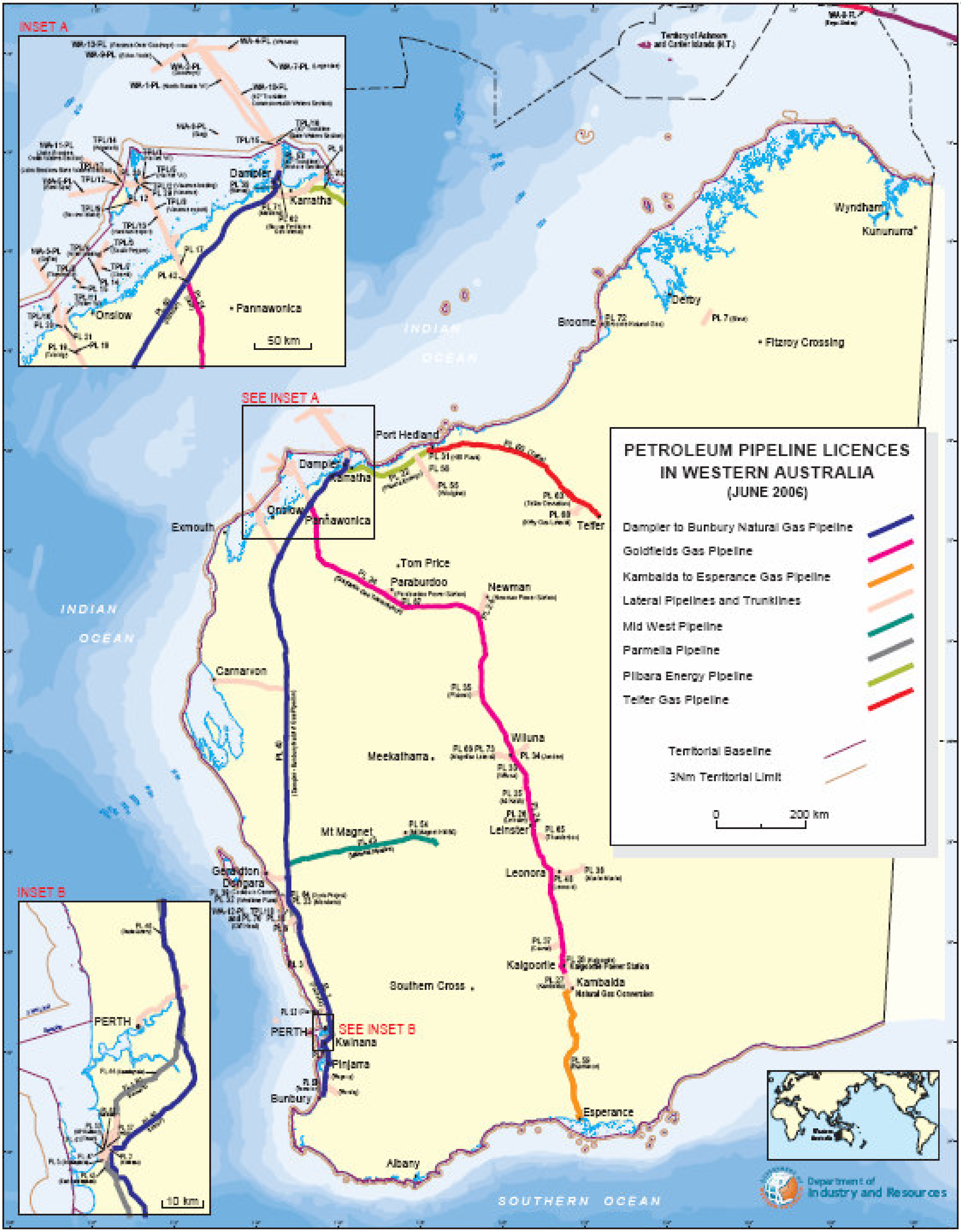
Equivalents	
1mcf	1.05GJ
1mmcf	1.05TJ
1bcf	1.05PJ
1tcf	1.05EJ
1m^3	35.32cf
1mcf	1.03mmBtu

Where:

"cf" stands for "cubic feet"

Btu stands for "British Thermal Units"

ARGONAUT



Source: Dept. of Industry & Resources

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APPENDIX TWO

Discussion Paper:
Gas Issues in Western Australia

June 2007

Economic Regulation Authority
WESTERN AUSTRALIA

A full copy of this document is available from the Economic Regulation Authority web site at www.era.wa.gov.au.

For further information, contact:

Economic Regulation Authority
Perth, Western Australia
Phone: (08) 9213 1900

CONTENTS

Overview

This paper presents a summary of the findings drawn from a consultation process undertaken by the Authority in late 2006 and early 2007 involving a number of significant gas users, shippers, producers, pipeline owners and relevant government agencies. These findings raise issues relevant to the Western Australian energy market which the Authority considers to be important in the context of its administration of the national third party gas access regime.

Introduction

In late 2006, the Authority decided that in view of the time which had elapsed since the introduction of the national third party gas access legislation, it would be worthwhile to undertake discussions with key stakeholders to determine their views on the effectiveness of the access regime. The purpose of this consultation was to assist the Authority in its future decision making process by providing a better understanding of whether the gas regulatory regime in Western Australian is meeting its primary objectives.

It was recognised, at the time the consultation program was being considered by the Authority, that proposed changes to the existing gas access legislation were being finalised at the national level. However, the Authority considered that stakeholder consultation based on the existing regime was still of value as the proposed new legislation and rules were not substantially different from the existing legislative arrangements.

Forty one organisations consisting of gas users, shippers, producers and pipeline owners together with relevant government agencies were proposed to be included in the Authority's consultation program. Thirty ultimately agreed to be included in this program.

The Authority appreciates the effort taken by those stakeholders who participated in this program and the frankness of these stakeholders in conveying their views to the Authority. This discussion paper seeks to respect the confidentiality of these discussions, while at the same time conveying the overall concerns expressed to the Authority.

Individual meetings with these stakeholders were undertaken by Russell Dumas (Director, Gas and Rail Access) and Peter Rixson (Manager Projects, Gas and Rail Access) over a four month period, from 26 October 2006 to 16 February 2007.

The key areas covered in these meetings were:

- Are the objectives of the national third party gas access regime being met?
- Is the Authority administering the gas access regime in an appropriate manner?
- Are there any other comments stakeholders wish to bring to the attention of the Authority in relation to their particular circumstances?

As set out in the preamble of the Gas Pipelines (Western Australia) Act 1998, the key objectives of the existing national gas access regime are to:

- facilitate the development and operation of a national market for natural gas;
- prevent abuse of monopoly power;

- promote a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders;
- provide rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users; and
- provide for resolution of disputes.

Results of Consultation

Natural gas is a fundamental part of Western Australia's energy market and the ability of energy suppliers and major energy users to obtain a gas supply and transport that gas to where it is needed is a key requirement for this State.

The findings from the Authority's stakeholder consultation program indicate that stakeholders have significant concerns in relation both to upstream (gas supply) and gas transport issues. Both gas supply and gas transport issues have the potential to adversely impact on the downstream (gas retailing and trading) markets. As the Authority's functions only relate to gas transportation, it is keen to understand, appreciate and separate the gas supply and transport issues in relation to their impact on downstream markets. The principal concerns expressed to the Authority are outlined below.

Upstream (Gas Supply) Issues

Many stakeholders expressed concerns about the gas supply situation. These concerns were that the gas supply market is very tight and that gas supply contracts are difficult to secure and that long term contracts are no longer available. In some cases, companies noted that they have been unable to obtain gas supply contracts because the gas producers are not interested in small contracts. If users or energy retailers cannot obtain appropriate gas supplies from gas producers then the ability to develop a competitive market for gas is significantly impeded.

It appears from the comments provided by stakeholders that there has been a considerable change in the gas supply situation in the WA market since around mid-2006. Prior to this time, long term contracts (20 to 25 years) for gas supply were available. However, since this time the maximum contract term offered by gas producers has reduced significantly. It is understood that currently, the maximum term available in the market is generally about 5 years. It is also understood that it is not currently possible to obtain gas supply contacts under about 10 TJ/day.

Gas producers commented that they were no longer offering long term contracts due to uncertainty about future gas field development costs in light of the large cost increases currently being experienced. Some of the producers also mentioned that uncertainties in relation to future gas prices and the Government's domestic gas reservation policy were additional considerations.

A number of shippers also commented that it was no longer possible to negotiate better terms and conditions for gas supply contracts with gas producers based on larger volumes, as had been the case in the past.

Some of the stakeholders mentioned that the declaration of force majeure on 28 December 2006 by the Harriet Joint Venture partners (Apache, Tap Oil and Kufpec) in relation to their 20 year, 66 TJ/day gas supply contract with Burrup Fertilisers, was a significant factor in the tightening of the gas supply market. It is understood that the force majeure related to a suspension of a requirement in the sale agreement to demonstrate reserves sufficient to meet a 20 year supply and resulted from well failures in the Harriet gas fields.

It is also understood from stakeholder comments that the Varanus Island gas supply capacity is now close to being fully committed and that little additional capacity is currently available from gas producers using the Varanus Island hub. In these circumstances, it appears that the supply of gas to the Western Australian market is likely to depend largely on NWSG for the next few years, until additional gas fields are discovered, and brought to production, around the Varanus Island hub or elsewhere.

NWSG recently advised the Authority that the upgrading program currently being undertaken on its two domestic gas processing trains had run into technical difficulties. The upgrading program had been intended to increase the capacity of these trains by circa 100 TJ/day to accommodate growing demand and align with pipeline expansions. There is restricted capability to further upgrade these trains once this expansion is completed. The North West Shelf Venture (NWSV), the owner of the gas processing facilities, would require an additional domestic gas processing train to meet any further demand for gas.

As a consequence of the technical problems experienced by NWSV during the upgrading program, further work on the upgrading program has been halted until a detailed diagnostic and technical evaluation of the problem is undertaken. NWSG has suspended marketing of domestic gas and has withdrawn from gas contract negotiations underway at that time. NWSG expects that it is likely to be some months before the technical problems can be identified and a technical solution recommended. No decision will be made until this diagnostic work is completed and assessed, which is expected to occur by about mid-2007. If, after the diagnostic work is completed, the plant's capacity is able to be increased, NWSG will engage with potential gas buyers. Subject to the technical recommendation and financial approval, the upgrading of NWSG's domestic gas processing trains is unlikely to be completed until late 2008.

Should the upgrading of NWSV's gas processing trains proceed, it is estimated that the 100 TJ/day of capacity resulting from the upgrading program will have been taken up by about mid- 2009, beyond which time no more gas will be available from NWSV and companies requiring gas will be dependent on gas from Varanus Island. Given it is currently believed that there is little new gas capacity available from the Varanus Island producers, this has the potential to lead to supply problems in the WA gas market.

It could take up to five years for the NWSV to develop a new domestic gas processing train once the upgraded trains reach capacity, given the time needed to identify sufficient demand to underpin a new train and make a decision on the substantial investment required to design and build the new train. A further constraint could arise in regard to capacity of offshore infrastructure required to provide the additional gas required for a new domestic gas processing train.

Three known potential new sources of gas which may come into the WA market at some stage in the future are the Macedon, Gorgon and Pluto gas fields. However, there is no definitive domestic gas production development timetable for these projects.

The development of Macedon is, at least in part, dependent on BHPBilliton reaching a satisfactory agreement with DBP to put this gas into the DBNGP as the Higher Heating Value (HHV) of Macedon gas does not meet the inlet gas specification under either DBP's

Standard Shipper Contract or the DBNGP access arrangement. Given the agreement required with DBP, the need for BHPBilliton to then make the decision to proceed and a three year construction period to build the infrastructure required, it is unlikely that domestic gas will be available from Macedon within the next four to five years.

Gorgon's construction timetable is uncertain with recent approval delays and cost blowouts affecting the planning for this project. It is doubtful that the earliest timeframe for domestic gas production of end 2012, as outlined in the State Agreement (and subject to a positive economic evaluation by Gorgon in 2010), is now achievable.

While the NWSG and proposed Gorgon LNG projects are both subject to State Agreements, which set out arrangements for domestic gas production, the third proposed LNG gas project off the State's North-West coast (Woodside's Pluto project) does not have a State Agreement but rather has committed to comply with the State's new domestic gas reservation policy. The cornerstone of this policy is to reserve for domestic use the equivalent of 15 percent of gas available from any future offshore development subject to commercial viability. It is understood, that under the arrangement agreed between the Government and Woodside, the Pluto field will be able to export LNG for 5 years (from the time of its first LNG exports expected to begin in late 2010) before Woodside has to carry out an economic evaluation of domestic gas production. The earliest start date for domestic gas production from Pluto (subject to a positive economic evaluation in 2015) would therefore appear to be around 2018 unless Woodside decides to develop Pluto's domestic gas earlier.

It should also be noted that another factor, which could further delay any domestic gas development from the above three potential projects, is the requirement for the DBNGP to be significantly expanded to accommodate these projects. Additional pipeline capacity in the order of 100 to 300 TJ/day would be required for each of these projects. Such expansions will require the DBP Board to come to a commercial decision to proceed with the expansions at the time they are required. Based on experience with the stage 5 expansion, it may take some time for such decisions to be made and DBP may require the Authority to undertake section 8.21 (pre-approval) determinations prior to making such decisions.

It is likely, therefore, that there could be potential problems looming in the supply of domestic gas to the WA market at various periods over the next five to seven years. Beyond 2014, it is probable that either the NWSV would have built a new domestic gas processing train (up to 300TJ/day) and/or Macedon would have been developed (up to 150TJ/day) and/or Gorgon would have developed its domestic gas processing facilities (up to 300TJ/day). Prior to this time, there are likely to be gas supply difficulties from now to late 2008 (when the NWSV's domestic gas processing train upgrading program is completed subject to overcoming the current technical difficulties) and from around mid-2009 until sometime in 2010 (between the additional capacity of 100TJ/day from the NWSV's upgrading being taken up and the Varanus Island producers bringing on stream their current known undeveloped gas fields around the Varanus Island hub (such as the Reindeer gas field owned by Santos)).

It is not known as to whether the undeveloped gas fields around Varanus will be sufficient to provide the gas market requirements over the 2010 to 2014 period or when the gas processing trains on Varanus will reach capacity and require upgrading or additions. Further, it would be expected that any new gas discoveries by Apache would need first to be allocated against its Burrup Fertilisers supply contract reserves. It is also possible that sizable new gas fields could be found onshore or close offshore in the Perth Basin. Such fields could be developed relatively quickly. Alternatively, 'greenfield' areas such as the onshore Canning Basin (in the Kimberley) might yield new large gas fields. However, it would take some time to develop the infrastructure (such as pipelines) required to support the development of such fields.

It is also possible that coal seam methane fields (CSM) could be in production in Western Australia in five years time. CSM has become a large part of the gas market in the Eastern States with its share of this market expected to reach 20% by the end of this year. Companies have recently started exploration work to investigate areas prospective for CSM production within Western Australia (presumably in response to higher domestic gas prices as discussed below).

Associated with concerns about the gas supply, stakeholders in the Authority's consultation process expressed considerable concern about the steep rise in the gas price for new gas contracts over the period since mid-2006.

A rising gas price has the potential to impact on the State's energy market in the following ways:

- On the positive side, a higher gas price encourages potential gas producers (including potential CMS producers) to undertake exploration and develop projects to supply gas to the domestic market. It was noted by at least one of the potential gas producers involved in the Authority's consultation that good returns appeared to be available from domestic gas based on the level to which gas prices had risen. Santos, in its 2006 annual report, mentioned that the sharply higher gas prices in WA will support further gas developments in that State.
- On the negative side, a higher gas price could:
  - Make Western Australia less attractive for industries with high gas usage, resulting in such industries switching investments from WA to the Eastern States (where gas prices are significantly lower) or to overseas locations where gas prices are lower.
  - Make the use of alternative fuels for base load power generation, such as coal, more attractive. This may impact on greenhouse gas emission targets and be impacted on by any carbon trading arrangement introduced in Australia.
  - Put newer energy retailers at a commercial disadvantage in the marketplace in competing against existing retailers having long term gas supply contracts at 'old prices'.

In relation to the gas price, it was evident from the discussions with stakeholders that the gas price had risen significantly over the period of the consultation (October 2006 to February 2007). In particular, there appeared to have been a large rise over the November/December 2006 period.

Information from stakeholders indicates that gas prices in the Western Australian market have more than doubled in the 12 month period since early 2006 to a current level of around $5.50 to $6/GJ. This compares with $2 to $2.50/GJ in early 2006. By contrast, on the East Coast the availability of coal seam methane has driven gas prices down from around $3.50/GJ to about $3/GJ in Victoria and NSW and about $2.50 /GJ in Queensland.

One of the stakeholders consulted estimated that the netback price of domestic gas, based on LNG prices at that time, was about $5.80/GJ. The netback price represents the price at which LNG producers would be getting a similar return on domestic gas and LNG taking into account the relevant infrastructure required to produce these two products. If

LNG prices rise then the netback price would also rise. Over the long term, the ceiling price for domestic gas would be expected to be around the netback price level.

Pipeline Issues

The principal pipelines regulated by the Authority are the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the Goldfields Gas Pipeline (GGP) and the Mid-West and South-West Gas Distribution System.

The key issues of concern raised by stakeholders, in relation to each of these pipelines, are outlined below.

DBNGP

There was a consistent concern expressed by a number of shippers and potential shippers that Alinta's position as a part owner of the DBNGP would enable it, in conjunction with DBP, to inhibit competition in the downstream energy market in order to protect its position as a major energy retailer. No specific examples were provided to support this concern and the Authority is not in a position to comment on the validity of the concerns expressed.

A significant degree of concern was also expressed by shippers and potential shippers over the Standard Shipper Contract (SSC) under which all shippers on the DBNGP operate. The main concerns were that:

- the minimum 15 year contract period under the SSC constrained the ability for energy sellers to buy gas and on-sell energy to businesses when energy sale contracts were generally only up to 5 years;
- the financial hurdles (such as bank guarantees and credit rating) set by DBP to obtain a SSC were difficult for small to medium sized companies to meet;
- administration of the SSC was complex and difficult to manage; and
- DBP could be difficult to deal with in relation to SSC issues, there was little give-and-take in negotiations with DBP and DBP appeared to be under-resourced which made negotiations protracted.

A number of shippers and potential shippers also commented on the absence of a significant gas aggregator in the Western Australian gas market to allow small to medium sized energy retailers or users to readily obtain a gas supply. As noted above, such firms have difficulty in the current market in both obtaining a gas supply contract from the gas producers and a gas transportation contract on the DBNGP and would be assisted by an aggregator able to purchase gas and transport the gas on the DBNGP for on-sale to small energy retailers or users. It was evident from stakeholder comments that those parties which had undertaken some aggregation activities in the past were reducing or discontinuing such activities.

A further concern outlined by shippers and potential shippers was the lack of spare capacity on the DBNGP. This lack of spare capacity forced new shippers onto the SSC, made administration of the SSC more difficult and prevented shippers from readily obtaining additional firm capacity, forcing a wait of up to 30 months for such capacity under the terms of the SSC.

On the possible Alinta influence issue, the Code requires ringfencing arrangements to be in place between DBP and Alinta and the Authority recently exercised its discretion under the Code to require DBP to provide an annual report, from an independent auditor, outlining its compliance with the Code's ringfencing provisions. The Authority approved DBP's 2006 report and is due to receive DBP's next report in October this year. However, shippers and potential shippers expressed the view that the Code's ring-fencing arrangements may not be adequate to prevent Alinta influencing the operation of the DBNGP if it wished to do so.

The other issues outlined above are all commercial matters on which the Authority has no role or influence. In regard to the SSC, the Authority will not have any direct role until 2016 when the SSC tariffs reduce to the access arrangement tariffs and then later in 2019 when the SSC terms and conditions revert to the access arrangement terms and conditions.

Is the Authority making a difference?

If the concerns in relation to the DBNGP as discussed above are valid, it would appear that the Authority is making little difference so far as the operation of this pipeline is concerned at this point in time.

GGP

Shippers and potential shippers were generally satisfied with the operation of the GGP.

All shippers on the GGP have commercially negotiated individual shipper contracts. A number of shippers commented that GGT displayed flexibility and "give-and-take" in negotiations on these contracts.

Is the Authority making a difference?

As for the DBNGP, the Authority has no role in relation to the commercially negotiated shipper contracts. However, a number of shippers on the GGP commented that they had been able to renegotiate or were currently renegotiating their tariffs downwards in light of the access arrangement tariffs put in place by the Authority in 2005. On this basis, it could be said that the Authority has had an impact.

Mid-West and South-West Gas Distribution System

Shippers and potential shippers were generally satisfied with the operation of the Mid-West and South-West Gas Distribution System. All shippers using the Gas Distribution System have shipper contracts based on the access arrangement and the view was that the Code was working for this pipeline system.

Is the Authority making a difference?

In the case of this distribution system, the Authority is playing a direct role in ensuring the pipeline operates in accordance with the Code objectives through the access arrangement.

Transmission Pipeline Owners

An issue of concern, expressed by the transmission pipeline owners was the lack of certainty under the Code in the recovery of capital invested in expanding a pipeline.

These parties considered that there were problems with the new facilities investment section of the Code as the tests under this section did not take into account all the factors relevant to an expansion, such as demand. As a result, these parties considered that the Code failed to facilitate investment in pipeline expansions as there was no certainty that all the capital invested in the expansion could be rolled into the pipeline's capital base.

The Authority is currently preparing a paper on the new facilities investment section of the Code to be considered by the Australian Energy Regulator (AER) and other regulators which is intended to be issued as a discussion paper. While the interpretation of the new facilities investment section of the Code could be improved by having regulators agree on a more consistent approach to its application, the Authority sees merit in the economic principles underlying this section.

If it is found that changes are required to the new facilities investment section, policy makers may in future utilise the rule change process proposed under the new gas law, following appropriate consultation.

Authority's Administration of the Code

Stakeholders were generally satisfied with the Authority's administration of the Code noting that they appreciated the accessibility of the Authority and the level of consultation and discussion with stakeholders carried out by the Authority during the access arrangement assessment processes. A number of stakeholders also specifically mentioned the roundtable discussions that the Authority organised with key stakeholders at the end of last year and said that this was very useful.

A number of stakeholders also expressed support for a front-end consultative approach to future access arrangements processes with early (pre-lodgement) consideration of the information requirements for these access arrangements. The Authority will be developing, in conjunction with the AER, an early consultation program involving both service providers and the public prior to the next round of gas and electricity access arrangements.

Interestingly, some stakeholders considered that the Authority provided too much detail in decisions relating to the approval of access arrangements whereas others considered that too little detail was provided.

The Authority has received some useful suggestions from stakeholders and will take on board those ideas which have the potential to improve the way in which the Authority carries out its regulatory functions and consults with stakeholders in the future.