WA GAS
SUPPLY & DEMAND

The Need for Policy Intervention

July 2007

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DISCLAIMER

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GAS CONVERSION FACTORS

In general this report uses Peta Joules (PJ) as the principal gas unit. For the purposes of converting between different gas units the following conversion factors have been used.

1 PJ = 0.943 Trillion cubic feet (Tcf)

1 PJ = 26.7 Million cubic meters (Mm^3)

1 PJ = 18,041 tonnes of LNG

EXECUTIVE SUMMARY

KEY FINDINGS

- The WA economy has the highest energy dependence on natural gas of any state in Australia.
- Natural gas accounts for 51% of WA primary energy consumption and this dependence is expected to increase in the future.
- WA's continued economic growth is critically dependent on access to competitive and reliable energy.
- Climate change policy initiatives are likely to increase domestic and international demand given natural gas is a relatively clean and low carbon fuel.
- Access to natural gas will play a critical role in Western Australia and indeed Australia's ability to meet greenhouse gas reduction targets.
- WA economic growth is likely to be maximised by downstream investment in mineral processing rather than relying solely on upstream petroleum and mineral production.
- There is compelling evidence that the WA gas market suffers from market failure.
- Existing and potential gas users have reported significant challenges in securing additional or new supplies of gas.
- The WA gas supply market is highly concentrated. Two operating entities hold close to 100% of gas reserves in developed fields.
- The current joint marketing arrangements for the North West Shelf joint venture significantly reduce competition by reducing the number of independent producers selling into the domestic market.
- There is a need for urgent policy intervention by government to ensure continued supply of competitively priced gas to the domestic market.

RECOMMENDED POLICY OPTIONS

- Given the need for urgent action, recommended options include:
  > Removing anti-competitive joint selling arrangements for domestic gas in WA.
  > Addressing possible impediments associated with Retention Lease arrangements by:
  – strengthening the commerciality test used in assessing whether to extend a retention lease; and
  – improving the transparency of the process through which the commerciality test is applied.
  > Facilitating independent third party ownership of upstream infrastructure servicing the domestic gas market to enhance the commerciality of domestic gas supply; and/or providing the opportunity for third parties to gain access to natural monopoly upstream gas gathering and processing facilities on terms and conditions that recognise the risk associated with the investment in such facilities.
  > Requiring producers to reserve a given proportion of gas for sale to the domestic market; and/or limit the proportion of gas that could be offered in the WA domestic market under joint marketing arrangements.
- These policy options are proposed in addition to the State Government's gas reservation policy and not in place of it.
- There is a need for immediate action given the potential delay between when a policy is implemented and its effect on actual market conditions. Targeted government action now will have the immediate effect of sending appropriate signals to the supply side. This will expedite needed corrections to the market.

SUMMARY

PURPOSE OF THE REPORT

The DomGas Alliance was established to ensure the long term availability and competitiveness of gas to meet the requirements of the WA domestic market. The Alliance considers that the WA domestic gas market has experienced serious market failure with insufficient supply to meet emerging domestic demand and a lack of competition on the supply side.

This report provides an assessment of the WA gas market covering issues in gas supply and demand, types of policy and market failures likely to be present given the structural characteristics of the WA gas market, assessing the efficacy of policy responses that have been mooted. The report is based on publicly available information.

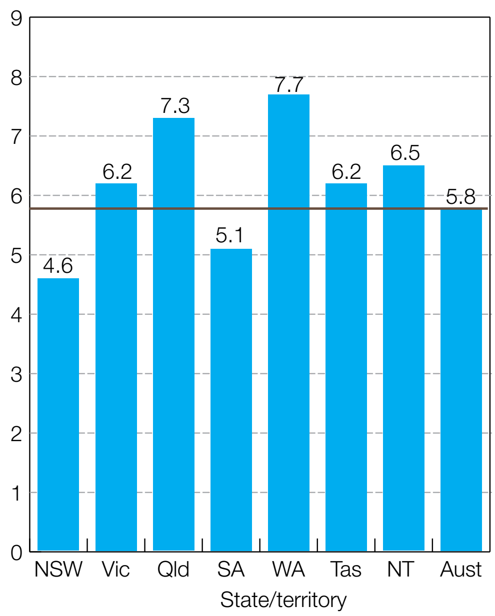
IMPORTANCE OF GAS

WA has the highest energy consumption per dollar of GSP of any State or Territory with WA using some 33% more energy (7.7PJ/$Billion GSP) to generate a dollar of GSP compared to the national average (5.8PJ/$Billion GSP).

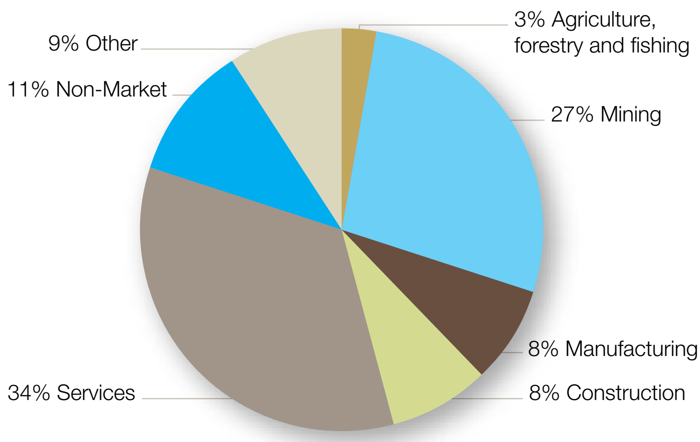
The energy intensity of the WA economy is a direct reflection of its resource base and the extent of value added processing undertaken in WA. The contribution of mining to the WA economy is by far the highest of any Australian State (around 27% of GSP in 2005-06).

The WA economy is the most reliant on gas of any Australian jurisdiction (gas accounts for 51% of primary energy consumption in WA). ABARE have forecast this reliance to increase over the medium to long term.

Energy Consumption per Billion Dollars of GSP 2005/06



Industry Contribution to WA Total Factor Income (2005-06)



In addition, the fact that natural gas is a relatively clean and low carbon fuel means that climate change policy initiatives are likely to increase the demand for gas both domestically and internationally.

Given the structure of the WA economy, it is clear that continued economic growth is critically dependent on access to reliable sources of energy and in particular, natural gas. Further, access to natural gas will play a critical role in Western Australia and indeed Australia's ability to meet greenhouse gas reduction targets.

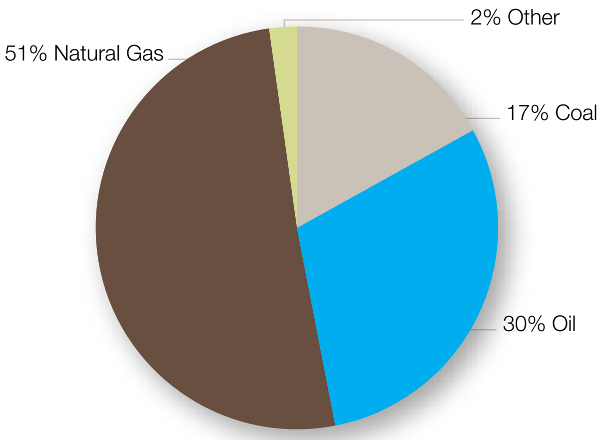
Economic modelling undertaken by the ERC at the University of Western Australia using the WAG computable general equilibrium model indicates that WA GSP growth is likely to be maximised where downstream investment in mineral processing can be undertaken viably rather than simply relying on upstream petroleum and mineral production.

Indeed, the estimate of the impact on private consumption of a specific investment in mineral production is a net benefit equal to 17% of the investment with this benefit increasing to some 22% of the investment where it is related to mineral processing investment.

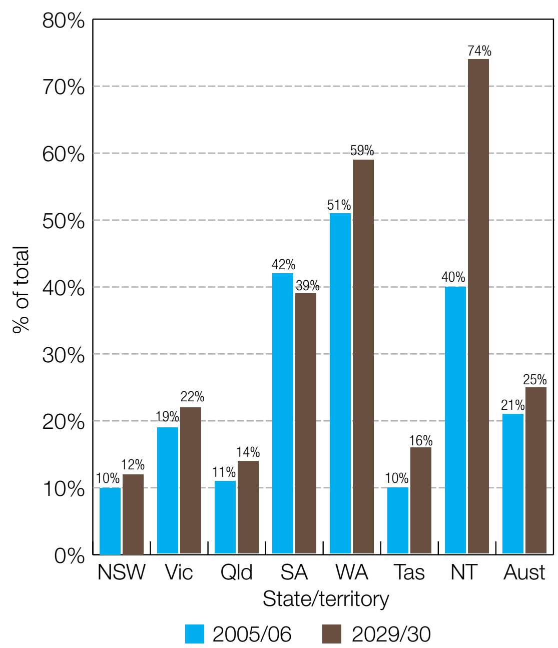
That is, this economic modelling suggests that in a constrained economy (such as the current situation where the economy is operating at close to capacity) the benefit from downstream investment will significantly exceed the benefit associated with the same level of investment in primary mineral production.

This finding suggests that a focus on facilitating downstream investment is likely to generate a significant positive benefit. This facilitation would include the removal of structural impediments, including any impediments to the domestic supply of natural gas.

Primary Energy Consumption 2005/06



Gas as % of Total Primary Energy



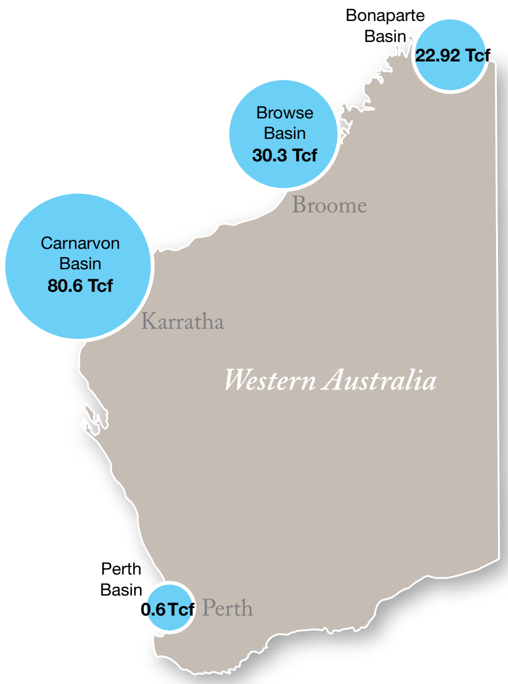
HISTORY OF GAS DEVELOPMENT

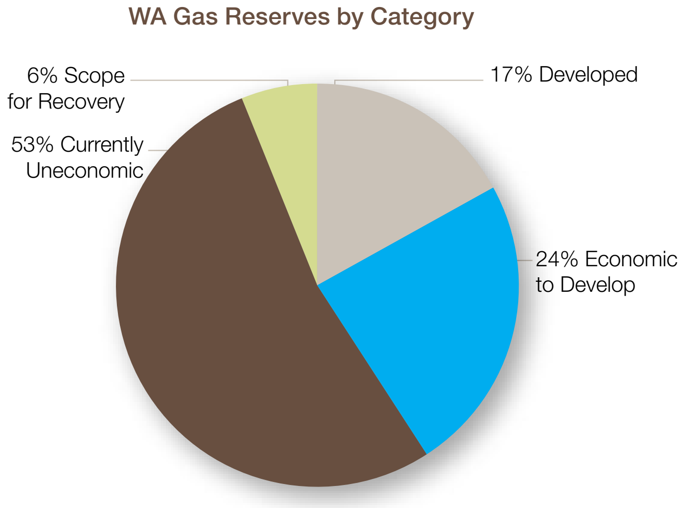
Major gas development in WA is directly attributable to the role of government and government owned entities in underpinning the North West Shelf development through the willingness in 1975 to commit to long term (20 year) take or pay contracts for large volumes of gas (over 400 TJ/day) and to construct the 1,600 km Dampier to Bunbury Pipeline to deliver that gas to prospective domestic markets. This was followed by the finalisation of LNG contractual arrangements with Japanese customers in 1985. This initial government action has underpinned the current situation where WA hosts a world class LNG export industry and where the domestic economy is heavily reliant on access to natural as a principal source of energy.

OUTLINE OF REGULATORY/ LICENSING

Offshore gas reserves such as those in the Carnarvon and Browse Basins may be subject to a range of Commonwealth and State regulation depending on their location.

While current LNG technology uses land based processing facilities the use of floating facilities has been mooted and such facilities may result in LNG production being subject only to Commonwealth regulation. At present, the use of land based facilities potentially brings such developments under state based approvals arrangements. The requirement for state based approvals underpins the WA government's reservations policy.





Key elements of the regulatory/licensing arrangements include:

- the use of retention leases to enable exploration firms to retain control of gas reserves demonstrated to be currently uneconomic without the need for immediate development of the reserves. While such leases provide an incentive for exploration by reducing exploration risk, they have the potential, where not subject to rigorous assessment, to delay the commercialisation of gas reserves; and
- the continued presence of joint marketing arrangements authorised by the ACCC for the North West Shelf joint venture. Such arrangements reduce competition in the gas supply to the domestic market. Corresponding arrangements have either never existed or have been unwound in jurisdictions such as the USA and Europe.

GAS RESERVES

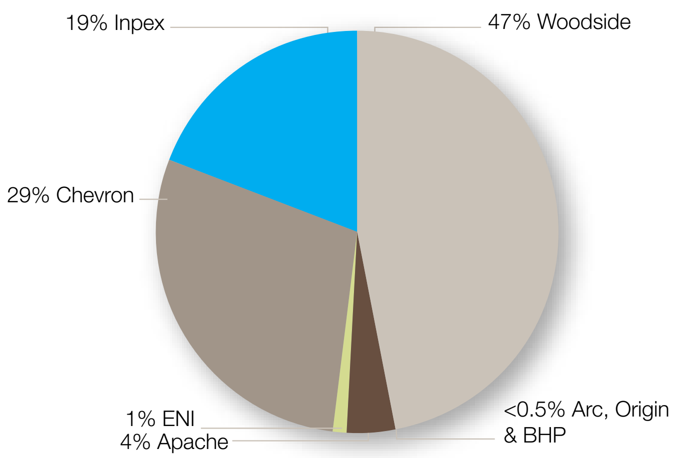
WA gas P50 reserves currently stand at some 126,000 PJ (~120Tcf). This represents less than 2% of total world gas reserves.

Virtually all of WA's gas reserves are located in three major basins (Carnarvon, Browse and Bonaparte basins) off the north west and north of WA.

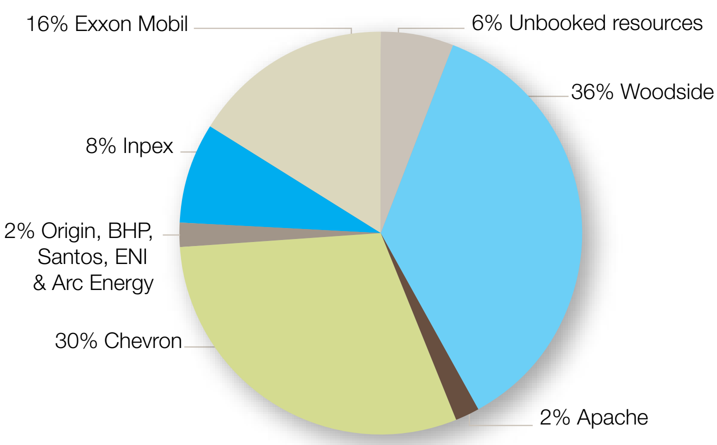
Around 17% of WA reserves are in currently developed fields with a further 24% being in fields operators consider economic to develop. The majority of reserves (some 53%) are in fields deemed currently uneconomic to develop and therefore held under Retention Leases.

The vast majority of WA gas reserves are controlled by a small number of parties. From the current fields providing gas that is marketed as part of domestic gas projects, over 92% of the remaining gas resource is contained in fields held by partners in the North West Shelf Joint Venture with another 7.4% located in fields operated by Apache meaning

WA Developed and Economic to Develop Reserves by Operator



WA Total Gas Reserves by Operator



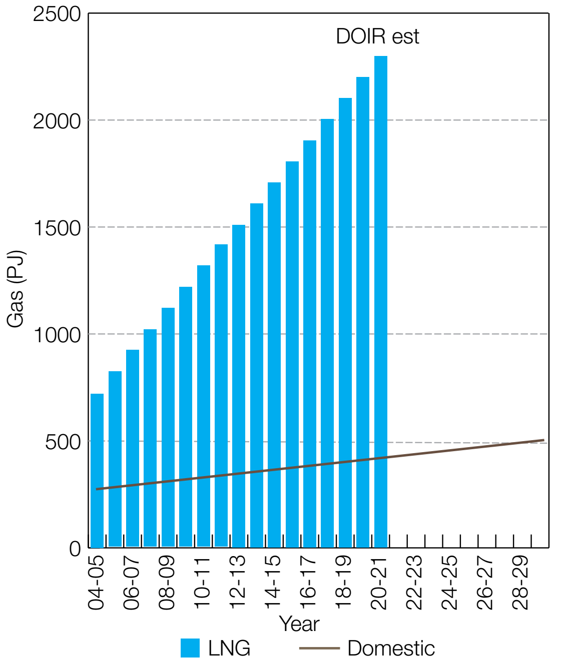
that the two operating entities hold close to 100% of the gas reserves in developed fields.

Removal of the domestic joint marketing arrangements would increase the number of suppliers from two to seven – promising to potentially dramatically increase supply competition.

Over two thirds of total (including currently non-economic) reserves are controlled by two operators (Woodside – either on its own or as the NWS operator and Chevron). This increases to around 83% with the inclusion of Exxon Mobil and over 90% when Inpex is included.

This is unlikely to change as a result of additional companies making major gas discoveries and current evidence suggests that there is limited likelihood of major increases in WA gas reserves.

WA Forecast Natural Gas Consumption



Note: LNG growth is based on interpolation from current actual LNG production to the DOIR estimate for 2020/21 and as such does not reflect the timing of capacity increases

The offshore, deepwater nature of WA's most significant undeveloped gas reserves contributes to high development costs. Commercialisation of major reserves is likely to require access to large, long-term contracts. The scale of development required for commercial feasibility is likely to be associated with international LNG sales.

DEMAND

Current natural gas sales in WA (domestic and export) are in excess of 1,000 PJ/yr. Of this total, around 70% is LNG related with LNG's relative share of total WA gas sales forecast to increase over time.

Domestic gas consumption is primarily associated with minerals processing, electricity generation and mining which together account for around 95% of domestic gas consumption.

ABARE have forecast domestic demand to approximately double to around 570PJ per annum by 2029/30 while production and export of LNG is forecast to increase even more rapidly. Forecasts for LNG production vary widely with the highest estimate being that of the WA government which has indicated that LNG production is expected to reach some 50mt (or 2,770 PJ) per annum by 2015.

THE GAS MARKET

The WA gas market exhibits very high levels of concentration on the supply side with significantly less concentration on the demand side. This is in contrast to international gas markets in Europe and America which exhibit much greater diversity on both the demand and supply sides and operate as mature commodity markets.

The WA reticulated gas market is considered to be a distinct product market as the quantum of gas demand that can switch to alternative fuels in the short term is unlikely to be sufficient to discipline gas prices. Further, the long-term response (the time frame under which substantial new investment is likely) to gas price changes is also likely to be insufficiently large and timely to discipline price increases.

This contrasts with the international LNG market which exhibits much greater liquidity although not yet exhibiting the single transparent reference prices (with differences related to transport costs) seen in fully competitive markets. Nevertheless, international trade in LNG is growing rapidly with a much larger number of market participants.

Compared to international demand, domestic demand growth is incremental. The greater liquidity and larger size of the international gas market allows it to absorb increases in supply or demand relatively easily and provides a stable and predictable base against which to make long-run investment decisions.

In contrast, the WA gas market is characterised by a small number of large customers giving rise to large (relative to underlying demand) step changes in consumption. One potential advantage of these large step changes is the ability for the domestic gas market to underpin quite significant new gas field development.

Notwithstanding the size and relative liquidity of the international gas market, there is still no recognised single international price for natural gas. Gas prices internationally exhibit much greater variance across regional markets than oil prices.

EVIDENCE OF MARKET FAILURE

The following factors provide evidence that the WA gas commodity market suffers from market failure:

- concentration in supply:
  - the effect of the authorised joint marketing arrangements for the NWS producers is to dramatically reduce the number of independent producers selling gas into the domestic market; and
  - this effect is not offset by any concentration on the demand side of the WA domestic gas market because current and prospective domestic gas customers have no reasonable fuel alternatives that can be accessed quickly at prices close to the prevailing prices of gas, while new field producers do have a profitable alternative in LNG exports; and
- a lack of liquidity arising from:
  - transactions between buyers and sellers that are bespoke and long term; and
  - the absence of secondary markets, spot markets or market makers; and
  - the joint marketing arrangements leading to a lack of diversity of risk preferences across upstream suppliers

In addition, existing and potential gas users have reported significant challenges in securing additional or new supplies of gas.

There is therefore a need for urgent policy intervention by government to ensure continued supply of competitively priced gas to the domestic market.

The presence of market failure is likely to lead to significant efficiency losses within the economy resulting in a reduction in income compared to a situation where no market failure exists.

BENEFIT OF ACTION

The presence of market failure in one form or another often leads to the conclusion that a government policy response is desirable to correct the failure, thereby resulting in greater economic efficiency.

In WA, economic modelling has indicated that the economic impact of disinvestment within the existing mineral processing sector due to inability to access competitively priced gas supplies will be a significant reduction in private consumption estimated at 22% of the disinvestment. That is, if the lack of competitively priced gas supplies results in an existing billion dollar mineral processing investment closing down, there would be a net impact on private consumption of around $220 million.

However, policy responses to market failures can also be costly, particularly where regulation is misapplied or when it is poorly designed.

Applying some form of regulation or policy response to a perceived market failure where, in fact no such failure exists, can result in regulation where it is not appropriate. In these circumstances, the cost of intervention will exceed the benefits. Even in the presence of market failure, regulation can impose net social costs, for example if the efficiency consequences of market failure are small, or if regulation is poorly applied.

The converse problem also arises: not intervening where there are socially costly market failures will potentially result in economic costs.

For example, there would be the economic cost to society from failing to regulate monopoly pricing of infrastructure assets such as gas or electricity transmission networks.

The WA economy relies heavily on competitively priced energy resources, and based on the observations of domestic gas users, the balance of the evidence points to a market failure in the provision of domestic gas as evidenced by the lack of gas supply offers to domestic users even at prices equivalent to the LNG net back price or higher.

There is therefore a need for urgent intervention to ensure a continued supply of competitively priced gas to domestic users. Such intervention should aim to avoid being excessively costly, and be the minimum necessary to correct the failure.

While the relative costs and benefits of possible interventions to secure long term domestic gas supplies are difficult to estimate precisely, there is an economic case for 'no regrets' or near 'no regrets' interventions that are likely to result in efficiency improvements in the domestic market.

The most fruitful targets for such intervention are likely to be removal of unnecessary joint selling arrangements such as the domestic market joint selling arrangements in WA and in terms of a potential policy response to support domestic gas supplies, addressing possible impediments associated with the current nature of Retention Lease arrangements possibly through an enhanced role for information disclosure about exploration activities and a strengthening of the commerciality test used in assessing whether to allow a retention lease to be extended and the transparency in which that test is applied.

RECOMMENDED POLICY OPTIONS

Given the need for urgent intervention, recommended policy options include:

- removing unnecessary joint selling arrangements such as the domestic market joint selling arrangements in WA. To be effective this needs to also ensure that the supply of gas to domestic markets is not disadvantaged relative to LNG;
- addressing possible impediments associated with the current nature of Retention Lease arrangements by:
  - strengthening of the commerciality test used in assessing whether to extend a retention lease and
  - improving the transparency of the process through which the commerciality test is applied;
- providing the opportunity for third parties to gain access to natural monopoly upstream gas gathering and processing facilities on terms and conditions that recognise the risk associated with the investment in such facilities or facilitating independent third party ownership of upstream infrastructure servicing the domestic gas market may enhance the commerciality of domestic gas supply;

In addition, a possible policy option aimed at increasing diversity of suppliers to the domestic gas market would be to require producers to reserve a given proportion of gas for sale to the domestic market. However, it is not enough to simply have more supply: preferably that supply should be offered independently by different suppliers if a meaningful reduction in supply concentration is to be achieved. An alternative, possibly superior option, would be to limit the proportion of gas that could be offered in the WA domestic market under joint marketing arrangements.

The above policy options are proposed in addition to the State Government's gas reservation policy and not in place of it.

There is a need for immediate action given the potential delay between when a policy is implemented and its effect on actual market conditions. Targeted government action now will have the immediate effect of sending appropriate signals to the supply side. This will expedite needed corrections to the market.

1 PURPOSE OF THE REPORT

The DomGas Alliance (the Alliance) is comprised of:

- Alcoa of Australia;
- Alinta;
- Synergy;
- Dampier Bunbury Pipeline;
- ERM Power/NewGen Power;
- Newmont Australia Ltd;
- Fortescue Metals Group; and
- Perth Energy;

all of which are major gas users, prospective users or gas infrastructure investors in Western Australia. They account for over 80% of the State's gas transmission capacity and domestic gas consumption. The Alliance was established to ensure the long term availability and competitiveness of gas to meet the requirements of the WA domestic market.

The Alliance considers that the WA domestic gas market has experienced serious market failure. They contend that:

- gas suppliers are unable to meet their existing contracted supply obligations and one supplier, Tap Oil has issued a notice of force majeure in relation to its contract with Burrup Fertilisers;
- there is no uncommitted gas supply capacity currently available – irrespective of price – to meet the growth requirements of existing gas purchasers;
- there are no new developments which would provide additional domestic gas to underpin new projects or to replace existing long term contracts as they expire;
- gas purchasers have been unable to engage with existing or prospective gas suppliers regarding supplies of new gas;
- there is currently no evidence of competition within the domestic gas supply market; and
- the market has become distorted — the main gas supplier to the state remains a joint venture which is allowed to collectively market gas, whereas there has been significant splintering of gas purchasing following the disaggregation of the SECWA contract and the deregulation of the gas and electricity markets. This has resulted in a significant number of gas users (20 – 30) purchasing their gas directly from the producers. An additional – and much larger number – purchase their gas via aggregators like Alinta, for reasons of convenience, but could if they chose purchase directly.

The Alliance members believe that these contentions are supported by their own individual experiences in the market – which they are unable to make public for reasons of confidentiality – and by the following:

- the current WA 400MW electricity generation tender is unlikely to include a gas option;
- the Gindalbie Karara iron ore project has had to rely solely on long term contracts with coal fired generation, as this is the only feasible option;
- Newmont has chosen coal fired power for its Boddington gold project despite the fact that gas would, assuming reasonable prices, be a more attractive option;

- tenders conducted by Alliance members during 2006 for new gas supplies failed to elicit competitive gas supply offers;
- DBP was required to significantly downsize an expansion of the DBNGP in 2006 (from 300 to 100 TJ/day) as a number of prospective projects were unable to secure gas supplies;
- the Alliance has recently been approached by a number of new project developers seeking membership on the basis that they have been unable to secure gas supplies;
- DBP tenders for compressor gas failed when the prospective supplier withdrew its offer;
- there is little or no competition for supply of gas into the WA market – Apache Energy, which has been responsible for the main competition with NWSG in the WA gas market, is fully sold, so supply in the short-term can only come from NWSG; and
- development has focused solely on LNG, meaning that the supply of significant volumes of gas has become dependent on the timing and economics of LNG developments:
  - Gorgon LNG project is now unlikely to develop LNG before 2012 with domestic gas being developed some time after this date;
  - Pluto LNG project has devoted its available gas reserves for LNG and is unlikely to deliver any gas domestically before 2016; and
  - Browse LNG projects at present are unlikely to be brought into operation before 2016 and at present are isolated from necessary infrastructure to bring gas into the WA market.

In light of these concerns, the Alliance has engaged Synergies Economic Consulting (Synergies) to provide an assessment of the WA gas market covering the issues in gas supply and demand in Western Australia, types of market failure likely to be seen given the structural characteristics of the WA gas market, possible policy responses that have been mooted, and possible alternative responses consistent with an efficient economic outcome. The report is based on publicly available information.

2 IMPORTANCE OF GAS

The contribution of mining to the WA economy in 2005-06 amounted to some 27% of GSP, by far the highest proportion of any Australian State.

The WA economy also has the highest reliance on gas as a primary energy source of any state in Australia. ABARE have forecast this reliance to increase over the medium to long term.

The fact that natural gas is a relatively clean and low carbon fuel means that current environmental policy initiatives are likely to increase the demand for gas both domestically and internationally.

WA's continued economic growth is critically reliant on access to reliable sources of energy and in particular, natural gas.

Economic modelling indicates that WA GSP growth is likely to be maximised where downstream investment in mineral processing can be undertaken viably rather than simply relying on upstream petroleum and mineral production. This facilitation would include the removal of structural impediments, including any impediments to the domestic supply of natural gas.

2.1 ECONOMIC

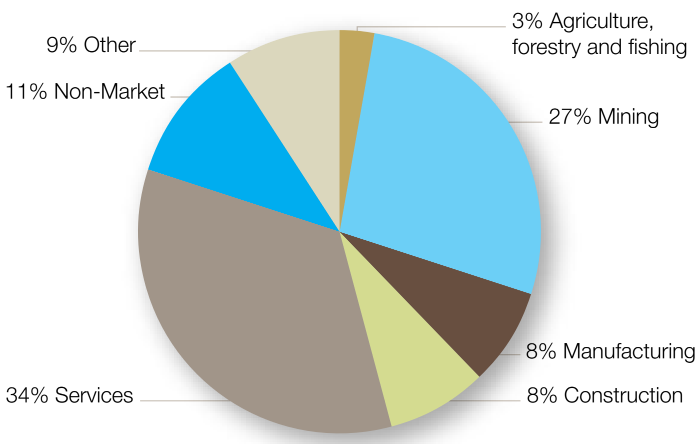
2.1.1 WA Economic Structure

Western Australia (together with Queensland) is exhibiting the most rapid growth of any state in Australia with figures showing that the WA economy grew by 4.9% in 2005/06. The most recent forecasts predict growth of around 5.75% in 2006/07. This has also been reflected in WA's historically low unemployment rate of 3.0% – the lowest level in Australia and the lowest since current labour force participation rate figures have been collected (1978).

The Western Australian economy has benefited from strong international commodity prices in recent years with forecasts of continuing strong demand for commodities suggesting the likelihood of continued rapid growth.

The reliance of the WA economy on internationally traded commodities is reflected in the fact that the mining industry is the State's single largest

Figure 1 Industry Contribution to WA Total Factor Income (2005-06)[1]



Data source: ABS Australian National Accounts: State Accounts 2005-06 Cat No. 5220.0

[1] The ABS data has been aggregated into economic categories consistent with those used by the WA Department of Treasury and Finance in its report on The Structure of the WA Economy August 2005. The data is merely updated to reflect the most recently available information.

industry accounting for over one-quarter of Gross State Product (GSP) with manufacturing (including downstream mineral processing and energy resources) accounting for a further 8% of GSP and construction activity including mineral projects and processing facilities accounting for a further 8% of GSP (Figure 1).

The majority of manufacturing activity in WA is comprised of value added mineral processing (refer Table 1). These activities are very significant employers in the WA economy and are export oriented. They are energy intensive and hence crucially dependent on a reliable and cost effective energy source.

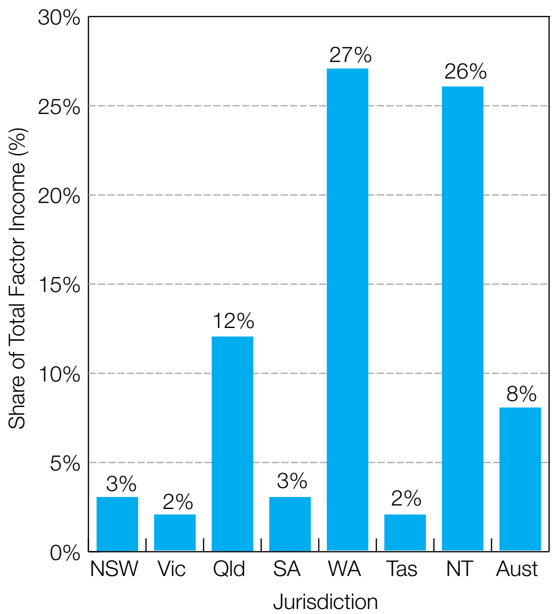
Table 1 Mineral Processing in WA

Bauxite to alumina processing
Cement and lime production
Fused alumina and fused zirconia
Lithium and tantalum chemicals
Production of Silicon
Gold / Sodium cyanide
Alumina chemicals
Synthetic rutile to titanium dioxide pigments
Zircon refractories
Ammonia and ammonium nitrate
Phosphate Fertilisers
Direct reduced iron (HIsmelt)

The significance of this is highlighted by the fact the equivalent share of GSP for mining in Queensland which is also considered to be a beneficiary of the commodity boom (and which has a much larger and more broadly balanced economy than the Northern Territory, the jurisdiction where mining has the next largest share of total factor income) is only 12%, with the Australia wide share being only 8% (refer Figure 2).

The WA economy is therefore highly energy dependent as a consequence of its underlying structure. Total primary energy consumption in WA was estimated to be approximately 804 PJ in 2005/06.[2] This gives a per capita energy use of some 406 PJ per million population compared with the lowest per capita consumption of 220 PJ per million population in NSW and SA. WA's per capita energy consumption is some 43% higher than the national average of 285 PJ per million population.

Figure 2 Mining Share of Total Factor Income (2005-06)



Data source: ABS Australian National Accounts: State Accounts 2005-06 Cat No. 5220.0

[2] Australian Energy National and state projections to 2029-30. ABARE December 2006. p 75

WA has the highest energy consumption per dollar of GSP of any State or Territory (Figure 3). WA uses some 33% more energy to generate a dollar of GSP compared to the national average. The energy intensity of the WA economy is a direct reflection of its resource base and the extent of value added processing undertaken in WA.

This together with the extent of value added processing highlights the importance of having competitively priced reliable sources of energy if WA's recent record of sustained growth is to be maintained into the future and if WA is not to become just an extractive industry economy.

WA's current energy requirements are satisfied by a range of fuel sources but principally natural gas, oil and coal, which together account for 98% of primary energy. Gas is the largest energy source, representing some 51% of 2005/06 consumption (Table 2).

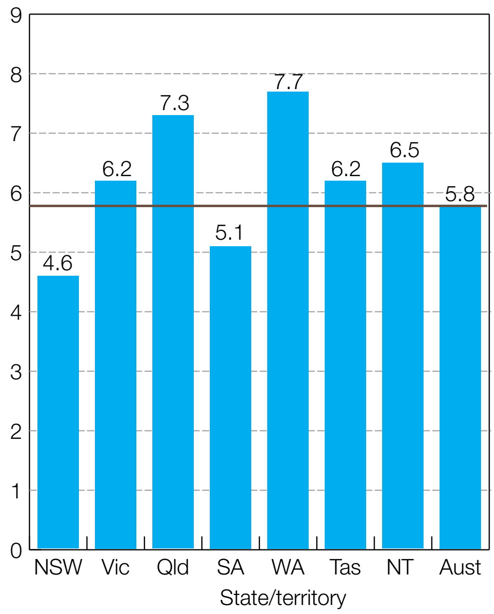
Table 2 Energy Consumption per Billion Dollars of GSP 2005/06

Primary Energy Source	PJ	% of Total
Coal	140	17
Oil	237	30
Natural Gas*	411	51

Source: ABARE Australian Energy Projections 06.26 Table E2

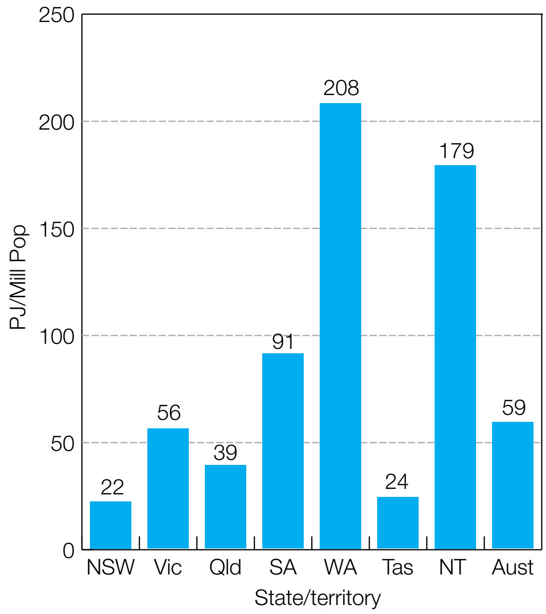
Note: Domestic natural gas consumption includes gas used for LNG processing, in field use, LPG and refinery use.

Figure 3 Energy Consumption per Billion Dollars of GSP 2005/06



Data source: ABARE Australian Energy Projections 06.26 Table E2 and ABS Australian National Accounts 5206.0 Table 21

Figure 4 Per Capita Gas Use 2005/06 (PJ per Million Population)



Western Australia has the highest consumption of natural gas per capita of any Australian state or territory at some 208 PJ per million population. This is more than nine times higher than the lowest per capita gas use State (NSW) and some 3.5 times higher than the national average.

ABARE forecasts that WA will increase its reliance on natural gas for primary energy supply with the percentage increasing to 59% or some 815 PJ by 2029/30 (Table 3). This represents an approximate doubling of gas use over the 24 year period from 2005/06 to 2029/30.[3]

Table 3 WA Primary Energy Sources – 2029/30

Primary Energy Source	PJ	% of Total
Coal	179	13
Oil	362	26
Natural Gas*	815	59

Source: ABARE Australian Energy Projections 06.26 Table E2

Note: Domestic natural gas consumption includes gas used for LNG processing, in field use, LPG and refinery use.

The foregoing clearly indicates the high degree of dependence of the WA economy on access to reliable sources of energy generally and gas specifically.[4]

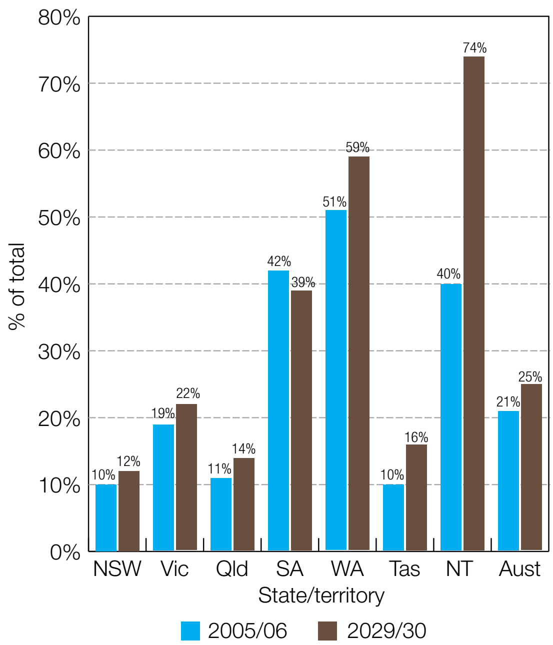
2.1.2 Australian energy use

In terms of reliance on natural gas for primary energy, the rest of Australia provides an interesting contrast to Western Australia. Only SA has a significant current dependence on natural gas (at some 42% of primary energy) although this dependence is forecast to decrease over the period to 2029/30. On average, gas as a percentage of total Australian primary energy consumption is forecast to increase from the current level of around 21% of Australia's primary energy in 2005/06 to around 25% by 2029/30.

2.1.3 International – increasing reliance on gas (and in particular LNG)

Natural gas provides approximately 21% of primary energy worldwide. In 2004, 37% of global gas production was used for heat and power, 26% for residential and commercial uses and 24% for industry applications. Internationally there is an increasing reliance on gas and

Figure 5 Gas as a Percentage of Total Primary Energy 2005/06 and 2029/30 (est)



Data source: ABARE Australian Energy Projections 06.26 Table E2

[3] We understand that this growth in gas use is based on current relative prices. That is, a change in relative price in which gas became significantly more expensive could be expected to impact on gas use.

[4] The use of this gas in WA is discussed in Section 6 and Attachment C.

in particular LNG as an energy source. Between 2005 and 2010 the production of LNG is expected to nearly double, while global gas demand increases by 2.4% per year over the same period.[5] The IEA has reported that the largest contributor to increased gas demand growth will be electricity generators, and that the increasing share of gas generation as a proportion of total generation capacity is likely to reduce the ability to switch to alternative forms of generation during peak gas price period suggesting that demand may become less price responsive in certain uses.[6]

Global natural gas consumption is expected to reach 134 Tcf per annum by 2015 and 182 Tcf per annum in 2030[7]. Natural gas consumption is expected to increase by 2.4% per year to 2030. In the International Energy Outlook, the EIA has stated that for the period to 2030 coal will be a more economical fuel source due to an increase in demand for gas driving the price higher. Over the period to 2030, demand for coal is expected to increase by 2.5% per year and oil by 1.4% per year.[8]

The forecast strong growth in international demand for gas and in particular for LNG can be expected to further increase the attractiveness of supply from politically stable countries such as Australia and therefore to underpin further rapid expansion of WA LNG production.

2.2 ENVIRONMENTAL/ CLIMATE CHANGE

Australia has recently experienced an upsurge in policy discussion on climate change, emissions trading and the impact of carbon based fuels. Internationally significant documents including the Stern Report and the release of the first stage of the IPCC Climate Change 2007 report have highlighted the potential costs of climate change and the increasing certainty within the scientific community of the causes of climate change. Against this background, during 2007 there has been extensive debate on policy directions relating to energy sources and emissions.

On May 6 2007, the WA Premier released a Climate Change Action Statement calling for a reduction in WA greenhouse emissions by 60% of 2000 levels by 2050. This Statement noted the important role played by natural gas in ensuring that WA has lower emissions per kWh of electricity generated than any mainland state. The Statement also sets a cleaner energy target for the SWIS of 60% of energy being generated by cleaner means – specifically noting the importance of access to sufficient natural gas for domestic use.

The Federal Government's Taskforce on Emissions Trading released its report to the Prime Minister at the end of May 2007. This recommends the establishment of national greenhouse emission reduction targets for post-2012,

5 International Energy Agency, 'Natural Gas Market Review 2006' p31,55.

6 International Energy Agency, 'Natural Gas Market Review 2006' p33-34.

7 By contrast Western Australia's total gas reserves at a 50% chance of recovery are only in the order of 120 Tcf – less than 1 years world demand.

8 Energy Information Administration, 'International Energy Outlook 2006' June 2006, p37.

and a national emissions trading scheme. The Report recognises that natural gas can make a major contribution to global efforts to reduce greenhouse gas emissions if used to generate electricity instead of coal. The report also recognised the need to ensure continued supply of low emission resources to both world and Australian markets.

In February 2007 the Australian state premiers indicated their intention to implement some form of emissions trading scheme by 2010, even if the Federal Government does not participate in the initiative.[9] In Western Australia, the Greenhouse and Energy Taskforce has released a report outlining strategies to reduce greenhouse gas emissions. The report stated that a carbon price of $25/t was likely by 2020.[10]

The National Generators Forum has recently undertaken a study into policy scenarios relating to greenhouse gas emissions and electricity supply in Australia.[11] Reports such as this undertaken by industry bodies demonstrate the growing awareness that government policy developments may be likely and demonstrate the concern on the part of these bodies to be prepared for such developments.

The impact of these carbon trading initiatives will further increase the demand for gas as an energy source, in addition to other low emissions energy sources or renewables. The chief benefit of the use of gas – especially compared to coal use as a source of primary energy – is its relatively low CO_2 output per unit of energy (with coal producing in the order of 1.6 times the CO_2 of gas when used for electricity generation) as well as its generally cleaner burning characteristics.[12]

In the WA context, the 2005 electricity generation tender resulted in the construction of around 300 MW of combined cycle base load generation capacity being constructed which is expected to produce only 50% of the CO_2 of comparable coal fired generation.

In addition the development of cogeneration capability – with steam production for alumina refining in conjunction with the generation of power – offers very significant greenhouse savings if applied to its fullest extent across all four WA alumina refineries. Cogeneration plants can achieve 75% energy efficiency, compared with 30-50% for comparable coal fired generation.

Furthermore, the capital costs of gas fired power generation facilities, and the associated gas supply infrastructure are considerably lower than the coal equivalents. While nuclear power also satisfies emissions reduction policies, the technology is undeveloped in Australia and consequently lead times for operational implementation are

9 See newspaper articles from 9-10 February 2007, available online including: http://www.smh.com.au/news/environment/states-sign-on-to-carbon-trading-scheme/2007/02/09/1170524303964.html and http://www.theage.com.au/news/National/Australia-must-transfer-to-renewables/2007/02/09/1170524270104.html.

10 Greenhouse and Energy Taskforce 'Strategies to reduce greenhouse gas emissions from the Western Australian stationary energy sector' December 2006, p2.

11 CRA International, 'Analysis of Greenhouse Gas Policies for the Australian Electricity Sector'.

12 The relative CO_2 output will vary with the quality of the coal used and is likely to be higher for WA coal.

significant. In addition, gas is already a publicly accepted, uncontroversial energy source.

In the present political environment governments have only committed to implement greenhouse initiatives to the extent that they do not create job losses or result in detriment to the Australian economy. However, were Australia to participate in a global emissions trading scheme, the extent to which the Australian economy would suffer is entirely uncertain. The extent of a global initiative may be greater than the measures currently being proposed within Australia, requiring even heavier reliance on renewables and gas, and potentially the use of nuclear power plants to meet Australia's energy demands.

Although an exact timeframe for implementation of these greenhouse policy initiatives is not certain, during the time period over which we have considered domestic gas supply and demand, some form of trading or tax is highly likely to be put in place. An emissions trading or carbon tax is likely to increase pressure for the use of natural gas, both domestically and internationally, at the expense of more carbon intensive energy sources.

2.3 INVESTMENT BENEFITS TO WA ECONOMY

Expanding the extent of minerals processing is often seen as a key value-adding strategy for the Australian Mining Industry[13]. This is particularly true in Western Australia where, historically, there has been continuing tension between the maximisation of minerals extraction versus minerals processing with WA being relatively successful in promoting value added processing with, for example, all bauxite processed to alumina; all nickel and mineral sands processed to higher valued products.[14]

Despite the efforts of successive governments to promote the benefits of vertical integration within the minerals industry, relatively little research has been undertaken into the economics of minerals processing and, in particular, into quantifying the size of the benefits that flow from increased mineral processing activity.

However, research undertaken at the University of Western Australia using the University's WAG computable general equilibrium model and the WA input-output table provides some indication of the magnitude of potential benefits.[15] It should be noted that while this represents the latest research, it was undertaken between 1995 and 2001 and as such is somewhat dated and could benefit from new research using the 2006 Census data when this becomes available.

[13] For example, see CSIRO (2005) "Minerals Processing- The Trillion Dollar Target: Process, Oct.

[14] See, Midwest Development Corporation (2004) "Opportunities in Minerals Processing and Mining Services" www.dlgrd.wa.gov.au.

[15] For a good overview of this research see, Ahammad, H. (2001) "The Economics of the WA Minerals Sector : An Overview of ERC Research, Economic Research Centre University of Western Australia.

2.3.1 Modelling the Impact of Minerals and Minerals Processing

The ERC at the University of Western Australia has been at the forefront of attempts to model the Western Australian Mining Industry, in particular the downstream and upstream linkages between the mining sector and the rest of the WA economy. It is in this context of quantifying economic linkages that the significance of economic activity in minerals processing becomes apparent.[16]

Clements, Ahammad and Ye (1996) produced the first estimates of the relative significance of Minerals and Minerals Processing in terms of output, income and employment generation with respect to the All Industries averages.[17] These estimates are still used in the WAG system of CGE equations which currently models the WA economy.

Table 4 Type II Multipliers – WA Economy

Minerals	Output	Income	Employment
Metallic Minerals	2.1	3.0	4.1
Coal, Oil and Gas	1.8	2.2	3.6
Minerals, NEC	1.8	2.6	2.9
Mineral Processing			
Base Metal products	2.3	3.4	4.7
Chemicals, petroleum etc	1.9	3.8	4.3
Non-Metallic minerals	2.2	2.7	2.9
All Industries	2.2	2.4	2.6

Note: Type II multipliers include consumption effects

Source: Ahammad (2001)

Table 5 Net Impact of a $1 Million Investment in Mining and Mineral Processing

	Mining – construction phase	Mineral processing construction phase	Mining – operational phase	Mineral processing – operational phase
Employment(jobs)	10.4	10.1	5.4	7.4
Gross State Product($m)	0.34	0.34	0.31	0.38
Private Consumption ($m)	0.26	0.24	0.17	0.22
Consumer Price index	.06	0.05	0.02	0.01
Total exports ($m)	-0.63	-0.48	0.19	0.24

Source: Ahammad (2001)

[16] Part of the difficulty in establishing the true value of minerals processing has been the fact that minerals processing is grouped by the Australian Bureau of Statistics with the Manufacturing industry, which hinders development of models to examine its interaction with the Minerals industry itself.

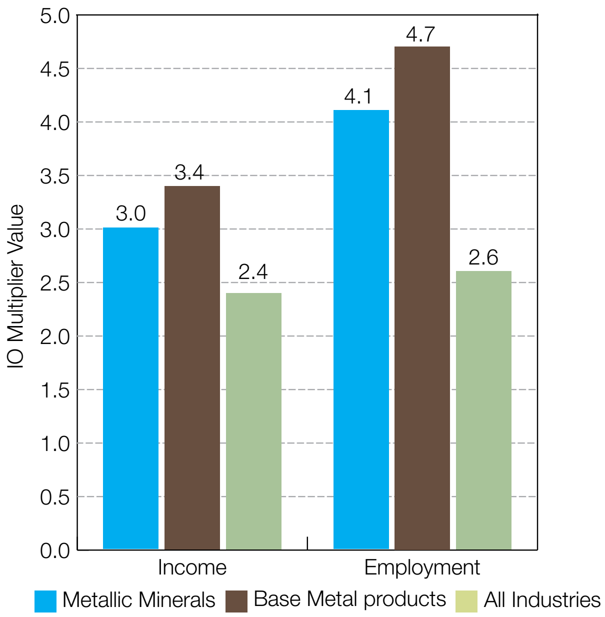
[17] Clements, K and Ahammad, H and Ye, Qiang (1996) "Economic Impact of Expanding the Minerals and Energy Industry", Perth Chamber of Commerce, May.

What is clear from Table 4 is that while comparable in terms of output impacts, the Mining and Minerals processing industries in WA have a considerably higher impact on employment and factor income than the All Industries average.

2.3.2 Minerals Processing just as important as Mineral Extraction

In order to better estimate these impacts, Clements and Ahammad examine the value adding properties that would flow from the investment of $1 million dollars in either Mining or Mineral Processing within the Western Australian Economy using the WAG computable general equilibrium model. Note that while IO modelling and CGE modelling have some similar properties, the CGE estimates are generally lower because they take into account potential losses in other sectors from expanding one particular sector.

Figure 6 Selected Type II Multipliers – WA Economy



This is generally important but especially important during times of capacity constraint such as those currently being experienced.

The most relevant impact normally presented for general equilibrium modelling is the impact on private consumption. From the above table it can be seen that the estimate of the impact on private consumption of a specific investment in mineral production is a net benefit equal to 17% of the investment. This benefit is estimated to increase to some 22% of the investment where it is related to mineral processing investment.

That is, this economic modelling suggests that in a constrained economy the benefit from downstream investment will significantly exceed the benefit associated with the same level of investment in primary mineral production.

Conversely, the economic impact of disinvestment within the existing mineral processing sector due to inability to access competitively priced gas supplies will be a significant reduction in private consumption.

3 HISTORY OF GAS DEVELOPMENT

The current production and marketing arrangements for WA gas reflect historic development patterns and in particular the key role of long-term domestic gas contracts in underpinning the development of offshore gas reserves and their role in addressing demand risk issues at the time North West Shelf gas was initially commercialised.

3.1 WESTERN AUSTRALIA

WA has had a gas industry (initially based on coal gas) since the 19th century, indeed the City of Perth Gas Company was formed in 1882. During the first half of the 20th century electricity was the prevalent source of energy supply, based on a combination of coal and liquid fuels, with an increasing reliance on coal fired generation after the oil price shock of 1974. During the late 1960s there were a number of natural gas discoveries in Western Australia, with gas from the Dongara field in the Perth Basin piped to Perth in 1971.

In 1971, the first of the major gas discoveries – North Rankin, Angel and Goodwyn – were made on the North West Shelf, providing early insight into the extent of Western Australian natural gas endowments.[18] This led to several years of investigations and feasibility assessment work in an attempt to find a viable framework for development.

Early work focused heavily on the development of a major LNG facility, associated with some production for the domestic gas market. Unfortunately the size of the task, from a technical, financing and marketing standpoint proved extremely challenging and the North West Shelf joint venture partners agreed to concentrate initial efforts on a domestic gas only venture.

In 1975 SECWA (State Energy Commission of WA) was formed from an amalgamation of the former State Electricity Commission and the Fuel and Power Commission. It assumed State-wide responsibilities for electricity and gas supply and for energy industry regulation. The formation of SECWA facilitated the negotiation of a long-term gas supply agreement between the State and North West Shelf joint venture.

Under this arrangement, SECWA (backed by the State Government) agreed to financially underpin the development of a domestic gas only project with a 20 year take-or-pay contract for over 400 TJ/day of gas, and a commitment to construct the 1,600 km Dampier to Bunbury Natural Gas Pipeline (DBNGP) so that the gas could be delivered to prospective markets. The State's commitment – which was finally signed in 1980 – was supported by Alcoa, the State's largest consumer of gas, which undertook to purchase approximately 50% of the contracted gas. These long-term supply arrangements were immensely beneficial to both the State and the NWS participants because they provided low-risk returns to allow the development of the industry.[19]

[18] http://www.energysafety.wa.gov.au/EnergySafety/resources/pages/history.html.

[19] http://www.energysafety.wa.gov.au/EnergySafety/resources/pages/history.html.

The domestic gas phase of the project involved the construction of:

- the North Rankin A platform in 140 metres of water;
- the laying of a 40 inch pipeline from the platform to shore;
- the domestic gas processing plant on the Burrup Peninsula; and
- the DBNGP through to Perth

These facilities were all commissioned in time for the delivery of first gas in 1984.

Meanwhile, in 1981 eight Japanese utilities signed a Memorandum of Intent for the supply of LNG from the North West Shelf project; however it took until 1985 for completion of the final contractual arrangements for the construction of the LNG facilities. First LNG was not delivered until 1989, five years after completion of the Domgas phase of the project.

During the early 1990s some competition began to emerge in domestic gas supply with the development of the Tubridgi and subsequently the Harriet fields on the North West Shelf. The development of these fields was followed by a number of additional fields centred around the Varanus and Thevenard Island processing hubs. None of these fields was of sufficient size to support an LNG scale development and were, therefore, totally reliant on the domestic market for gas sales [they also export oil and condensate].

In 1995 SECWA was restructured into separate gas and electricity businesses – Western Power and AlintaGas (Alinta) respectively. At the same time the single SECWA contract with the North West Shelf Gas joint venture was disaggregated into five separate purchase contracts, and a third party access framework was introduced for the DBNGP which separated gas purchase from transportation. A separate government body, the Office of Energy was formed to assume responsibility for energy advisory and regulatory activities.[20]

In 1998 the government decided to privatise Alinta's gas transmission business and the DBNGP was sold to Epic Energy. In 1999-2000 the balance of Alinta was privatised and Alinta became a publicly listed corporation.[21]

The addition of new gas suppliers and the development of the further gas production capacity feeding through the Varanus and Thevenard Island processing hubs brought supplier competition to the domestic market as well as further production capacity. The needs of the domestic gas market were adequately met – both in terms of capacity and price – until the position was reached in early 2006 when the reserves of these additional fields were fully committed under long-term contract.

[20] http://www.energysafety.wa.gov.au/EnergySafety/resources/pages/history.html.

[21] http://www.alintagas.com.au/company/history/.

The fact that the bulk of the remaining reserves on the North West Shelf are in very large fields has presented the producers with the option of pursuing massive LNG export opportunities or smaller scale developments focused on the domestic market. The isolation of Western Australia from the other states and the high cost of gas transmission pipelines has precluded the sale of gas to other Australian markets, particularly in light of the rapid growth of coal seam methane in the eastern states markets.

The apparent preoccupation of the producers with LNG export projects and the clear indications of a shortfall in the domestic gas market led the WA Government to seek to ensure long-term domestic gas supplies through the introduction of a "Gas Reservation" policy. That is, a policy of reserving a proportion of available gas reserves for domestic use.

The Government has used the precedent of the North West Shelf project to defend its reservations policy. As part of the original North West Shelf negotiations, agreement was reached to prioritise the allocation of reserves. First priority gas was committed to the SECWA take-or-pay contract; second priority gas was to support the original LNG export project; and third priority gas was to provide for some domestic gas market growth.

It is understood that all the original domestic gas reservations have now been committed under long-term contracts. No further reservation arrangements were imposed by the State until negotiations began for the State Agreement Act covering the Gorgon project.

Negotiations for the proposed Gorgon LNG project in 1999 concluded with the Barrow Island Agreement Act in 2003. The preamble to the Agreement Act clearly sets out the State government's desire to promote industrial development in Western Australia and to supply gas to the domestic market. The Agreement Act requires the delivery of 2,000 PJ (approximately 2 of the 40+Tcf of gas available to the Gorgon partners) to the mainland (close to that agreed between the State and the NWS joint venture in 1977). Schedule 1 to the Barrow Island Agreement Act (the Gorgon Gas Processing and Infrastructure Project Agreement) requires the partners to submit studies on commercial viability to the government until daily deliveries exceed 300 TJ.

Gas reservations under the Act include a requirement that a domestic gas capability will only be developed where it is commercial to do so. However, the recent willingness of the WA Government to act proactively to ensure domestic gas supply together with the need for additional State approvals for any project expansion suggests that there is likely to be ongoing pressure to ensure domestic supply from the Gorgon project. Notwithstanding the Gorgon domestic supply obligation, the viability and timing of the Gorgon LNG project – and the development of any domestic supply capability – remains uncertain. Contracts for Gorgon LNG offtake have been secured and publicly announced however to date there have been no such arrangements for Gorgon Domestic offtake.

In late 2006, Woodside agreed, subject to commercial viability, to market the equivalent of 15% of the LNG from a new project based on the Pluto fields to the domestic energy market. Woodside and the State are to negotiate in good faith on commercial viability with the commencement date of the first commitment to be five years after the date that LNG is first exported from Pluto (first exports are not expected until 2012 or later), or the date on which the 30 millionth tonne (approximately 1.5 Tcf) of LNG is produced at Pluto, whichever is the earliest. It is understood that the Pluto project will not be covered by a State Agreement.[22]

With the exception of North West Shelf and Gorgon, all other producing natural gas projects in Western Australia operate under petroleum industry legislation without any specific State Agreement Acts. There are no reservation arrangements in general petroleum industry legislation. The second largest gas supplier, Apache, is not affected by the reservation policy as none of its fields are of sufficient scale to support an LNG development. Over time as new LNG projects come on-line it is likely that smaller fields able to access LNG infrastructure will potentially be capable of being diverted from domestic gas to LNG. The reservation policy is linked to LNG export and so even these smaller fields will be subject to the reservations policy should they wish to export LNG.

3.1.1 North West Shelf Agreement

The desire of the State government to ensure domestic gas supplies first surfaced in the negotiations with the North West Shelf Joint Venture partners around 1977. Gas production prior to those negotiations was based on modest Perth Basin reserves with nowhere near the scale to support an export project. The prospect of massive LNG exports from the North West Shelf changed this situation.

The first petroleum State Agreement Act negotiated with the North West Shelf Joint Venture partners (NWS) required them to retain sufficient gas to ensure they met the delivery requirement under the contract entered into by the State government energy utility, namely more than 400 TJ per day for 20 years or 2,920 PJ (~2.6 Tcf) in total.

The 1979 Agreement Act did not contain specific reservation sections for other gas sources that might be discovered, but required that the JV partners discuss with the government the possible development of a petrochemical industry *if* they discovered additional commercial gas resources in the Dampier region (section 20). This reflected the government thinking that with domestic gas supplies and LNG commitments of 6.5 million tonnes (~0.3 Tcf) per annum assured for 20 years (~6.5 Tcf over 20 years), any new gas discoveries could be used to establish a secondary processing industry.

[22] See comments of Premier Carpenter in WA Parliamentary Questions, 12 December 2006, available from http://www.parliament.wa.gov.au/pq/qsearch.nsf/49a9e326e1c1a39848256d870006cd8a/c76bf52d04f7e064c825724500761b43?OpenDocument.

While any new discoveries were to be subject to a commercial viability test, the inclusion of this requirement within the Act suggests that the company and the government supported such use for future discoveries.

Amendments made in 1985 at the time of the commitment to the LNG phase of the project specifically required that the Joint Venture partners discuss with the State government their plans for any new export contracts. The State government would then be able to use such an opportunity to determine if there was enough gas available to meet domestic demand before such approval was given. Interestingly there have been recent announcements of existing LNG contracts being extended well beyond 2010. For example, Kyushu Electric[23] and Kogas contracts were previously scheduled to expire in 2009 and 2010 respectively and have been extended to 2017. This would imply that the State Government has determined there is sufficient gas to meet domestic demand.

Renegotiation of the Agreement Act in 1994, just prior to the disaggregation of the SECWA contract led to the first specific volume gas commitment.

In that Act, the concept of *third priority gas* was introduced, defined as:

> "….such quantities as are commercially producible, shall be reserved for and sold, used or supplied only for consumption in Western Australia".

The volume of third priority gas was set at 2,041 PJ (~2 Tcf) and was additional to the first priority gas which is that volume set aside for the initial contract with the government utility.

Reservation gas currently negotiated and expected to be negotiated is shown below. Figures are included for those fields that the WA Government Policy on Securing Natural Gas Supplies considered big enough to support LNG production. Being big enough to support LNG production, and given the likelihood that if developed they will be used to produce LNG, these fields are likely to be subject to reservations. This of course assumes that the gas will be processed on-shore rather than off-shore and, therefore, be subject to the state governments reservation policy.

[23] See Woodside website Media Announcements http://www.woodside.com.au/Media/Announcements/.

Table 6 Reservations in WA

Field/ Project	Remaining Reservations (PJ) either negotiated or based on 15% of total reserve (1000PJ is approximately 1 Tcf)	Additional Comments
North West Shelf	2,750	These NWS reservations have been fully contracted.
Gorgon	2,000	As under the Gorgon Agreement Act, supply of this gas must be commercially viable.
Pluto	573	Woodside and the WA Government have agreed to a reservation of 15% of LNG produced. Supplying the domestic gas must be commercially viable.
Ichthys	1,511	This gas is subject to the project being developed and supplying the reserved gas being commercially viable.
Torosa	1,829	This gas is subject to the project being developed and supplying the reserved gas being commercially viable.
Brecknock	843	This gas is subject to the project being developed and supplying the reserved gas being commercially viable.
Scarborough	826	This gas is subject to the project being developed and supplying the reserved gas being commercially viable.
Total	**10,332**	

4 OUTLINE OF REGULATORY/ LICENSING

Offshore gas reserves may be subject to a range of Commonwealth and State regulation depending on their location.

Current LNG technology uses land based processing facilities although the use of floating facilities has been mooted.

The use of land based facilities potentially brings such developments under state based approvals arrangements. This is the basis of the WA government's reservations policy.

Key elements of the regulatory/licensing arrangements include:

- **the use of retention leases to enable companies to retain control of gas reserves considered to be currently uneconomic without the need to invest in the development of the reserves. While such leases can have the effect of reducing exploration risk and therefore providing an incentive for exploration, they also have the potential, where not subject to rigorous assessment, to delay the commercialisation of gas reserves; and**
- **the continued presence of joint marketing arrangements authorised by the ACCC for the North West Shelf joint venture. Such arrangements have the effect of reducing competition in the market and either never existed or have been unwound in other jurisdictions such as the USA and Europe.**

Regulatory and licensing issues have the potential to either encourage or hinder petroleum exploration and development activities. This section briefly outlines the key characteristics of the regulatory and licensing regime in Western Australia and associated offshore waters. Additional details are provided in Attachment A.

4.1 STATE/COMMONWEALTH INTERACTION

Oil and gas resources may be governed by either Commonwealth or State legislation, depending on the location of the resource.

In Western Australia, onshore activities are governed by state legislation.[24] Offshore resources may be under State or Commonwealth legislative regimes, depending on the location of the resource with respect to the territorial sea baseline (TSB). In relation to oil and gas reserves, an attempt has been made to develop a uniform regulatory approach whether the resource is located within Commonwealth or State jurisdiction by virtue of the *Petroleum (Submerged Lands) Act 1982* (WA) *Schedule Specific Requirements as to Offshore Petroleum Exploration and Production* 1995.[25]

[24] The *Petroleum Act 1967* (WA), *Petroleum Act 1967* (WA) Schedule of Onshore Petroleum Exploration and Production Requirements 1991 (WA) and the *Petroleum Pipelines Act 1969* (WA).

[25] DOIR, http://www.doir.wa.gov.au/environment/D284DE0313FE4072AB76BACF0365F56C.asp.

The importance of Commonwealth and State jurisdictional issues must be understood against the background of the WA Government Policy on Securing Domestic Gas Supplies. The policy states:[26]

> In order to provide continued certainty that Western Australian consumers will have ongoing access to supplies of natural gas, the WA Government will negotiate with proponents of export gas (LNG) projects to include a domestic gas supply commitment as a condition of access to Western Australian land for the location of processing facilities.

Current technology allows oil to be recovered and transported directly from offshore waters but virtually all gas projects worldwide involve processing on land. A floating LNG plant has been under consideration in Nigeria for at least five years but development appears to have stalled.

The current enforceability of the 15% domestic gas policy relies on the need to locate processing facilities either onshore, or within WA territorial waters.[27] Offshore processing facilities in Commonwealth jurisdiction may allow a project to be developed without having to observe the 15% reservation policy.

4.2 ROYALTY ARRANGEMENTS

In WA, all minerals in their natural form are owned by the State unless the land on which the minerals are found was granted freehold title before January 1899. Royalties paid to the State by a resource developer are effectively the purchase price of the resource.[28] In 2005 mineral and petroleum royalties collected by the state amounted to $1.513 billion, an increase of $372 million from 2004.

4.3 LICENSING AND REGULATION

The right to explore for petroleum across all legal jurisdictions in Western Australia is on the basis of a competitive work program bid. Exploration titles can generally be renewed after six years, provided the company has met its work program obligations but the area that can be held is reduced at each renewal.

Having discovered oil or gas, a company has the right to convert the exploration permit to a Production Licence subject to defined conditions; however this carries with it an obligation to develop the field. Alternatively, where the discoverer believes the resource is presently uncommercial but is expected to become commercial within a fifteen year period, it can apply for a Retention Lease. In this event the company must demonstrate to the relevant authority (State or Commonwealth depending on the location of the field) that the discovery is in fact uncommercial. The initial term of a Retention Lease is 5 years, but it can be renewed if it still meets the required commerciality criteria.

There do not appear to be any examples in Western Australia of Retention Leases that have not been approved or Leases that have been cancelled.

4.4 ROLE OF JOINT MARKETING ARRANGEMENTS

The role of joint marketing arrangements can be seen against the background set out above. An argument which has been advanced in favour of such agreements is that they can support capital provision

[26] WA Government Policy on Securing Domestic Gas Supplies, October 2006, see Key Points section.

[27] Refer to the quote from the Policy document above.

[28] DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/936F48C0800744BFA92040ECE9085832.asp.

from firms that otherwise compete, which may be important in securing sufficient investment for very large projects. They may also ensure the best mix of skills are brought to bear. But more importantly, they could help limit the competition that might arise between joint venturers competing to market resource from the same field, expectations of which might, *ex ante*, prevent the resource from being developed.

Joint marketing arrangements have been approved for use in Australia by the ACCC in a number of areas. In providing these approvals, the ACCC has expressed concern over indefinitely authorising joint marketing, preferring to authorise joint marketing for a fixed period of time. In time-limiting these arrangements, the ACCC has sought to minimise the detrimental effect joint marketing may have on the development of the gas industry,[29] but allow sufficient time for the development of uneconomic fields that might not be viable if there were *ex ante* expectations of immediate vigorous competition.

The original authorisation for the North West Shelf project was granted in 1977 and does not have a specific termination or review date. A separate authorisation which was sought by the North West Shelf joint venturers in 1998 for the "Incremental Joint Venture" had a seven year review period. The parties did not seek to extend this authorisation in 2005 and it has subsequently lapsed. Domestic gas marketing on behalf of the North West Shelf joint venture is still undertaken jointly, but no authorisation is in place for the current arrangements.[30] The marketing representative, North West Shelf Gas Pty Ltd has stated its commitment to comply with TPA requirements, notwithstanding the lack of authorisation.

This can be contrasted with the international situation. For example, the EU now looks unfavourably upon joint marketing arrangements for gas. A recent example is the DONG/DUC case concerning Danish natural gas. The joint marketing arrangement was considered a horizontal restraint on competition. The choice of customers as to gas supplier is reduced when the joint marketing arrangement occurs. In addition to breaking up the joint marketing arrangements, in this case it was also agreed that a portion of the gas be reserved for supply to new customers to further increase competition.[31]

Joint marketing is not a feature of the US natural gas market. Natural gas in the US is now heavily traded, and exhibits all the hallmarks of a major commodity market. By way of example, there are spot and futures markets for natural gas trading on the New York Mercantile Exchange which show considerable depth, liquidity and diverse participation.

[29] ACCC, North West Shelf Project Determination, 29 July 1998, vii.

[30] The 1977 authorisation had no 'sunset clause' and continues in force until revoked. However, the immunity under this authorisation applies only to the joint venture parties as they existed in 1977, undertaking the joint actions outlined in the authorisation decision. The addition of a joint venture party necessitated the 1998 authorisation, and the participation of this party did not cease following the lapse of immunity. Although it remains in force, the 1977 authorisation is unlikely to be considered to provide immunity to the joint venture parties with respect to joint marketing as these marketing arrangements currently stand. Testing any immunity enjoyed by the joint venturer, or whether their conduct contravenes the TPA is a legal enquiry and such matters lie outside the scope of this report.

[31] Philip Lowe, 'Applying EU Competition Law To The Newly Liberalised Energy Markets' 13 May 2003, p5-6.

5 GAS RESERVES

WA gas reserves currently stand at some 126,000 PJ (~120Tcf). This represents a relatively small share of total world gas reserves (less than 1.9%).

Around 17% of WA reserves are in currently developed fields with a further 24% being in fields considered economic to develop. The majority of reserves (some 53%) are in fields deemed currently uneconomic to develop and therefore are held under Retention Leases.

The vast majority of WA gas reserves are controlled by a small number of parties.

Around 94% of reserves in developed fields or fields economic to develop are operated by only three parties – Woodside (47%), Chevron (29%) and Inpex (19%).

Over two thirds of total (including currently non-economic) reserves are controlled by two operators (Woodside and Chevron). This increases to around 83% with the inclusion of Exxon Mobil and over 90% when Inpex is included.

There appears limited likelihood of major increases in WA gas reserves.

The offshore, deepwater nature of WA's main gas reserves contributes to high development costs. Commercialisation of major reserves is likely to require access to large, long-term contracts. The scale of development required for commercial feasibility is likely to be associated with international LNG sales.

It is important to determine whether the current paucity of long-term contracts for domestic gas is a result of some form of market or regulatory failure, or whether it results from a more fundamental problem, namely a shortage of viable sources of upstream supply, and a preference to divert that supply to high value LNG projects. An examination of reserves is helpful in clarifying this question. This section provides a brief summary of the status of reserves. Additional details are found in Attachment B.

Overall Western Australian gas reserves as at 31 December 2005 were estimated at 119.1 Tcf (126,300 PJ).[32] These have been estimated at the P50 level of recovery probability. Given forecasts of increasing production, DOIR has estimated that WA has sufficient gas reserves to meet international and domestic demand until 2053.[33] Synergies' calculations indicate the WA domestic gas reserves could be exhausted as early as 2027 under worst case scenario analysis, or more feasibly by 2050. This disregards infrastructure constraints that may limit the domestic

[32] Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75. Energy value estimated based on sales gas, not LNG. Conversion from cubic metres in DOIR report to TJ using 26,700 m^3 per TJ.

[33] Department of Industry and Resources, 'WA Government Policy on Securing Domestic Gas Supplies Consultation Paper', February 2006, 5.

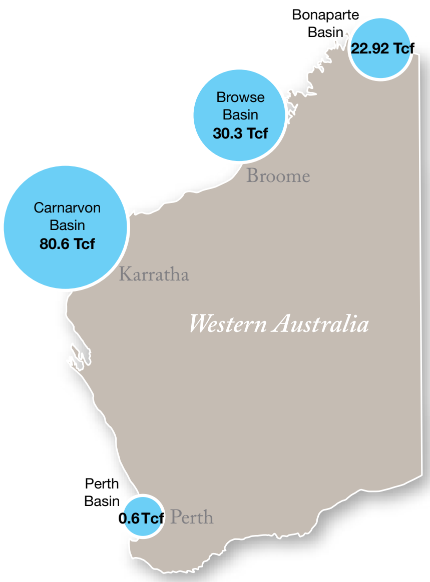
availability of gas from remote reserves.[34] The location of WA gas reserves is highlighted in the following Figure.

At the 50% recovery probability (P50), only around 17% of the overall WA gas endowment relates to developed fields.[35] Figure 8 provides a picture of the total WA gas reserves.

Total gas consumption in WA is forecast to rise from 760 PJ in 2004-05 to 965 in 2010-11, 1,196 PJ in 2019-20 and 1,385 PJ in 2029-30.[36]

From the current fields providing gas that is marketed as part of domestic gas projects, over 92% of the remaining gas resource is contained in fields held by partners in the North West Shelf Joint Venture.[37]

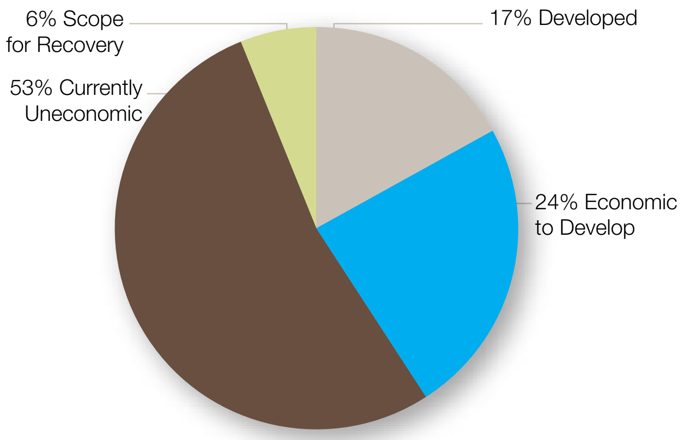
Figure 7 Location of WA Gas Reserves



Note: WA share of Bonaparte Basin is 1.43 Tcf. These volumes exclude unbooked resources

Data source: DOIR 'Western Australian Oil and Gas Review 2006' p7

Figure 8 WA Gas Reserves by Category



Note: Scope for recovery refers to discoveries or fields which may or may not eventually prove technically viable and are therefore unbooked

Data source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75.

[34] Gas reserve estimates are calculated based upon probability. A greater probability of successful realisation of a reserve results in a higher probability rating. Common ratings are P90 or 90% and P50 or 50%. A probability rating of 50% indicates 50% certainty that the volume of gas stated (X Tcf) will be recovered. A reserve at a 90% probability rating is consequently different to a reserve at the less certain 50% level. All reserve figures quoted in this report are on a P50 basis. Other factors are also important in the development of a field other than the size of the reserve. These issues include matters like gas quality, location, ownership arrangements, infrastructure and access issues and other characteristics of the reserve that decrease ease of recovery.

[35] Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75.

[36] ABARE, 'Australian energy national and state projections to 2029-30', December 2006, p26.

[37] NWS joint venture is comprised of six members each with an equal share. They are Woodside Petroleum Ltd; BP Developments Australia Pty Ltd; Chevron Australia Pty Ltd; Shell Development (Australia) Pty Ltd; BHP Petroleum (NWS) Pty Ltd; Japan Australia LNG (MIMI) Pty Ltd. Woodside is the operator for the NWS joint venture.

Another 7.4% is located in fields operated by Apache meaning that the two operating entities hold close to 100% of the gas reserves in developed fields (Figure 9). Clearly, removing the joint marketing arrangements would increase the number of operating entities controlling developed gas fields to seven.

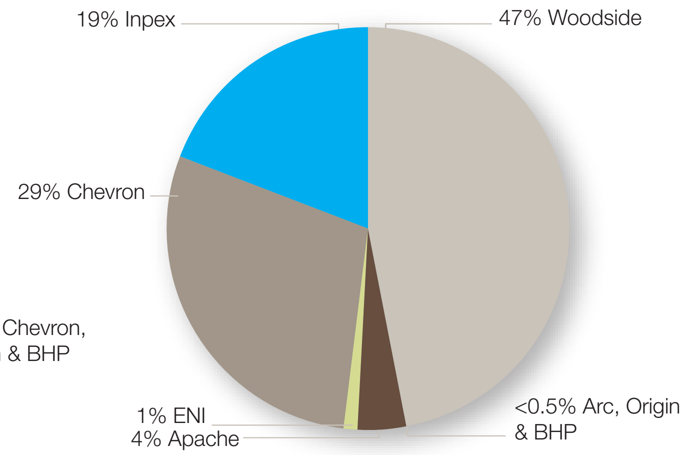
Undeveloped gas fields that have been discovered can be categorised into those with commercial potential in the short to medium term and those held under Retention Leases. Gas reserves that are either currently developed or under consideration for development (summarised by operator) are shown below.

Total gas reserves by operator (developed, undeveloped commercial and non-commercial) are highlighted in Figure 11.

5.1.1 Impact of development issues on supply

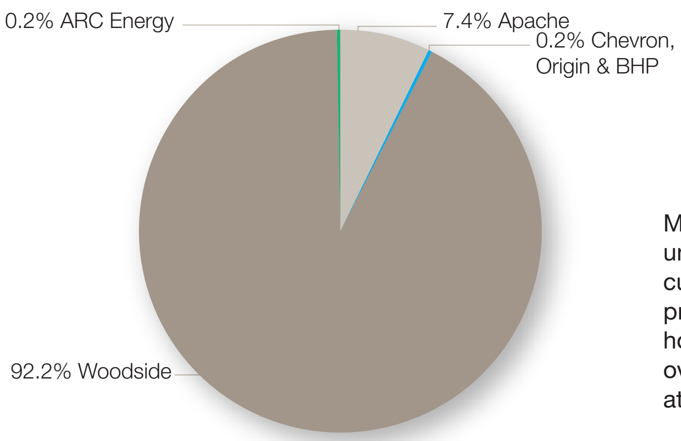
The vast majority of WA's undeveloped gas reserves are held under Retention Leases on the basis that these reserves are currently uneconomic to develop. The characteristics of these reserves that contribute to their current uneconomic nature are not generally related to the size of the field, that is, that the reserves are too small, rather, they are related to the offshore nature of the reserves, quality characteristics of the gas, the size of the development required to achieve economies of scale and the significant capital investment required to bring them to market. This is particularly the case given the increase in costs of developments experienced world wide in recent years.

Figure 10 WA Developed and Economic to Develop Reserves by Operator



Most of Western Australia's gas reserves are held under retention leases and, by definition, are not currently considered commercial by potential producers or the WA Government. Six operators hold gas reserves, but three hold the overwhelming majority of total gas reserves at the 50% level of probability.

Figure 9 Developed Reserves by Operator



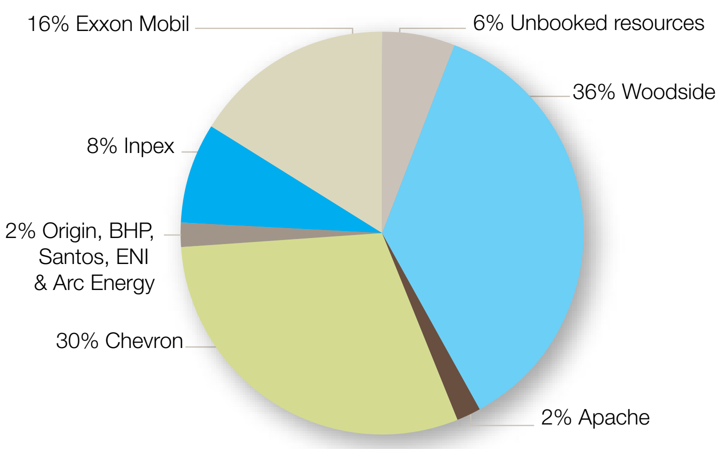
Large infrastructure investments to increase supply of gas – whether for domestic gas or LNG – require significant capital expenditure. Gas field location significantly influences the cost of developing reserves.

Domestic gas projects face capital expenditure costs relating to pipeline development to connect a development with established infrastructure. This is particularly the case when a field is located in a remote offshore region or there is no established infrastructure near a reserve, even if located close to shore. Sub-sea pipelines required for the development of offshore reserves require larger capital expenditure than pipelines located on land, with water depth having a major impact on the cost of a sub-sea pipeline.

Gas used for domestic gas supply may have less stringent quality specifications than gas for export and, therefore, be less expensive to develop.

The fact remains that on the East Coast of Australia suppliers are willing to develop offshore gas fields with delivered domestic gas prices in the region of $3.00.

Figure 11 WA Total Gas Reserves by Operator



6 DEMAND

Current natural gas sales in WA are in excess of 1,000 PJ/yr (~1 Tcf/yr). Of this total, around 70% is LNG related.

LNG's relative share of total WA gas sales is forecast to increase over time.

Domestic gas consumption is primarily associated with minerals processing, electricity generation and mining which together account for around 95% of domestic gas consumption.

ABARE forecast domestic demand to approximately double to around 570PJ per annum by 2029/30.

Production and export of LNG is forecast to increase even more rapidly. The WA government has indicated that LNG production is expected to reach some 50mt (or 2,770 PJ) per annum by 2015.

The pattern of demand for gas in WA is critical to establishing the adequacy of existing reserves and the relative future significance of domestic consumption compared to export consumption. This section presents a high level profile of historic and forecast demand for WA gas. Additional discussion is found in Attachment C.

6.1 WESTERN AUSTRALIAN GAS DEMAND

Western Australia is the largest natural gas consuming state in Australia, representing around one third of Australia's total consumption. Consumption increased by an average 9.1% per annum over the 25 years to 2005.

Of the total gas production in WA, LNG sales far exceed domestic natural gas sales. Approximately 0.604 TCF (720 PJ)[38] of LNG is shipped overseas, compared to 0.272 TCF (290 PJ) of gas supplied domestically.[39] Despite strong domestic demand growth, this excess of LNG sales over domestic sales is forecast to increase.

6.1.1 Domestic demand for gas

Gas usage in Western Australia is dominated by a small number of industrial sectors and individual organisations. This concentration of demand in a relatively small number of major projects can act to make demand for gas lumpy, as entry or exit of a large industrial user can significantly alter the demand profile for gas. Notwithstanding the impact of major projects there continues to be a steady growth in demand from smaller users.

The minerals processing (manufacturing) sector consumes about 40% of the gas with most used to produce alumina from bauxite. Nickel and mineral sands processing are also important sectors making mineral processing the dominant part of gas use in the State.

Natural gas is also used as a chemical feedstock for ammonia, sodium cyanide and fertiliser production.

[38] DOIR reported figures for LNG exports are 9Mt (500 PJ).

[39] Chamber of Commerce and Industry Western Australia, 'Meeting the Future Gas Needs for Western Australia A Report to the Western Australian Government' Draft Report, February 2007.

Electricity generation is the second largest use accounting for around 30% of the total. Historically, a primary concern in relation to the use of gas for base load generation is the higher fuel cost associated with gas use. Peaking plant which is only used during periods of higher electricity prices is able to profitably operate with higher fuel costs. As peaking plant requires rapid start ability such as that provided by gas turbines, gas is generally the fuel of choice. However, gas fired generation was successful in the WA 2005 base load generation tender resulting in around 300 MW of gas fired base load generation being constructed.

Gas-fired plants now provide around 60% of the electricity generation capacity in the State, compared to approximately 35% of generation from coal-fired plants.[40]

Gas use in the commercial and residential sectors is a small proportion of the total. While most households in the State access a reticulated gas supply, the milder climate means a relatively low space heating requirement with most gas used to provide hot water.

A recent WA policy document on greenhouse gas emissions indicates that for emissions in WA to be cut further, there may be increased reliance on gas and renewable energy sources to provide for the state's energy consumption. In addition, some form of emissions abatement is finding increasing State and Federal support Australia wide. More rather than less reliance on gas as an energy source for domestic WA energy consumption is likely.[41]

Future growth in domestic demand for gas

Domestic demand for gas will depend on the availability and competitiveness of supply. A major new base-load electricity generation plant will be commissioned in 2008; however it appears likely that the next station currently out to tender will be fired by coal. Alinta has committed to construct two cogeneration plants at Alcoa's Wagerup refinery. In the short term these will be open-cycle plants fired by liquid fuels and conversion will depend on a number of factors including the availability of gas as will the associated expansion of the Wagerup alumina refinery. Offsetting some of the growth in generation capacity will be the retirement of existing plants reaching the end of their economic or engineering lives.

Other major projects understood to require gas include the Worsley alumina refinery expansion; a number of iron ore developments in the mid-west; prospective iron ore processing developments in the Pilbara; and a variety of mining and power generation projects along the route of the Goldfields Gas Pipeline.

Replacement gas for supply contracts which are due to expire in the short to medium term are also an important consideration.

Estimated forecasts of domestic natural gas consumption in Western Australia are shown in the following figure together with current and estimated LNG sales.

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[40] Office of Energy (WA), 'Electricity Generation from Renewable Energy' available from http://www.energy.wa.gov.au/cproot/799/5305/RenewableEnergyFactSheetAug2006FINAL.pdf.

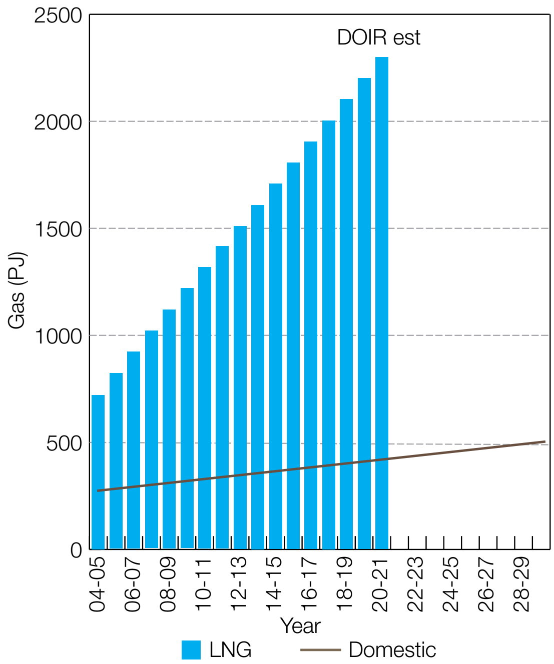
[41] Greenhouse and Energy Taskforce 'Strategies to reduce greenhouse gas emissions from the Western Australian stationary energy sector' December 2006.

6.1.2 Export demand for WA gas (LNG)

Export demand for LNG is expected to continue to be the dominant market for WA gas. By 2005-06, close to 70% of the gas produced was exported from the North West Shelf project as LNG.

LNG export predictions are uncertain and there are a range of forecasts as to the likely magnitude of increases in LNG production and export. However, there is an overwhelming consensus that growth in LNG production will be strong and sustained.

Figure 12 WA Forecast Natural Gas Consumption (2004/05 to 2029/30)



Note: Domestic gas usage excludes field use, pipeline energy, LNG production use, LPG and refinery. LNG growth is based on interpolation from current actual LNG production to the DOIR estimate for 2020/21 and as such does not reflect the timing of capacity increases

Data source: ABARE, 'Australian energy national and state projections to 2029-30', December 2006, p74.

Gas fields in the Browse Basin are located significant distances from suitable pipelines to transport gas for domestic consumption. Therefore Woodside and Inpex's fields in the Browse Basin would require a lengthy extension of the gas transmission system in order to contribute significantly to supplies of domestic gas. The alternative for such projects to satisfy domestic gas supply obligations under the State's reservations policy, is for these producers to reach agreement to supply the domestic market with explorers and operators of smaller fields unsuitable for LNG export, which are closer to existing transmission systems.

The Scarborough field is located a great distance offshore and viability may be reliant on technology allowing offshore processing which is yet to be proven. The remoteness of the Scarborough field would suggest that the cost of bringing the gas ashore for onshore processing is likely to be significant.

The DOIR has estimated that annual LNG exports will rise to 41.9 Mt (2,300 PJ or 2 Tcf) by 2020 and domestic gas production will rise to 0.51 Tcf (540 PJ) by 2020. Current levels are 9Mt (500 PJ or 0.4 Tcf) and 0.27 Tcf (286 PJ) respectively.[42]

The WA Government has been even more positive about the growth prospects for LNG in its policy document relating to securing domestic gas supplies[43] which stated that the natural gas industry had set a target level of LNG production of 50 Mt per year, approximately 2,770 PJ (2.3 Tcf), by 2015.

[42] Department of Industry and Resources, 'WA Government Policy on Securing Domestic Gas Supplies Consultation Paper', February 2006, 5.

[43] WA Government Policy on Securing Domestic Gas Supplies, October 2006.

6.2 INTERNATIONAL

World gas reserves are estimated at 6,360 Tcf or 6,740,676 PJ.[44] On this basis Western Australia has approximately 1.9% of proven global gas reserves.

The OECD has estimated that global gas consumption has increased at a rate of 2.6% per year from 2000 to 2005 and will increase at 2.4% per year for the 5 years to 2010. In 2005 global gas production was 2.8 trillion cubic metres (99 Tcf or 104 855 PJ). Global gas consumption is expected to increase to 3.2 trillion cubic metres per annum (113 Tcf or 119,834 PJ) by 2010.

The most significant global gas reserves are found in the Middle East and former USSR. Russia, Iran and Qatar hold 57% of total natural gas reserves.[45] Although Australia's total known gas reserves represent little more than one year of total world gas consumption, Australian gas production is highly valued because of the stable political climate and associated certainty of contracting and supply.

In an environment of increasing global gas consumption it is likely that demand for Australian LNG production will increase in the foreseeable future. It is noteworthy that LNG prices (delivered) tend to bear a high degree of relationship to crude oil costs usually with some discount.

The OECD has also indicated it believes that Australian LNG production and export is likely to increase in coming years[46]. This increase in production will more rapidly deplete WA gas reserves and potentially impact on domestic supply.

[44] International Energy Agency, 'Natural Gas Market Review 2006' 31.

[45] International Energy Agency, 'Natural Gas Market Review 2006' 31.

[46] International Energy Agency, 'Natural Gas Market Review 2006'.

7 THE GAS MARKET

The WA gas market exhibits very high levels of concentration in supply and to a lesser extent demand.

International gas markets in Europe and America exhibit much greater diversity on both the demand and supply sides and operate as mature commodity markets.

The WA reticulated gas market is considered to be a distinct energy market as the quantum of gas demand that can switch, in the short term to alternative fuels, is unlikely to be sufficient to discipline gas prices at current relative fuel prices. Further, the long-term response (the time frame under which substantial new investment is likely) to gas price changes is also considered likely to be insufficiently large and timely to discipline price increase.

This contrasts with the international LNG market. International trade in LNG is growing rapidly with a much larger number of market participants. Some 11% of total LNG flows occurs under spot LNG trades and other short-term transactions.

Compared to international demand, domestic demand growth is incremental. The liquidity and size of the international gas market allows it to absorb increases in supply relatively easily and provides a stable and predictable base against which to make long-run investment decisions.

In contrast, the characteristics of the WA gas market comprise a relatively small number of large customers and give rise to large (relative to underlying demand) step changes in consumption. One potential advantage of these large step changes is the ability for the domestic gas market to underpin quite significant new gas field development.

There is no recognised single international price for natural gas, rather, internationally gas prices exhibit much greater variance across regional markets than oil prices. In recent years in the US, gas prices have tended to range between US$6.00 and US$8.00 per ‘000cf (exhibiting a winter price peak) with the EIA forecasting a continuation of this price range. Similarly, forward contracts out to 2012 for gas sales ex-Henry Hub as at February 2007, exhibited a generally declining price trend in the range of US$6.00 to US$8.00 per GJ. LNG prices are not published and given that they are in the main fixed under long-term contract, depend on the climate when the arrangements were entered into.

Australian domestic gas prices published by Vencorp for calendar 2006 indicate a weighted average settlement price of $3.16/GJ.

WA ex-plant gas prices in 2004 were estimated to be in the order of $2.10 to $2.30/GJ. By 2007, WA ex-plant prices for new gas supply had been estimated to have increased to more than $5.00/GJ.

7.1 GAS MARKET CHARACTERISTICS

7.1.1 Western Australia market characteristics

Western Australia exhibits a very high degree of concentration in terms of domestic gas supply. Given the ACCC authorisation of the NWS joint marketing arrangements, over 90% of proven developed reserves that currently service domestic demand are held by the NWS joint venture, with another 7% held by Apache. In effect, close to 98% of gas reserves currently available to the domestic market are held by two operators.

In terms of gas users in total, mineral processing, mining and electricity generation account for over 90% of natural gas use in Western Australia. The six leading gas users are: Alcoa (alumina processing), BHP Billiton (mining and mineral processing), Alinta (gas supply to industrial and domestic users and electricity generation), Verve Energy (electricity generation), Burrup Fertilisers (chemical manufacturing) and Wesfarmers (LPG extraction, fertiliser and chemicals production).

In all, a total of around 20 – 30 customers in these sectors contract directly with upstream gas suppliers. This represents substantially less concentration than on the supply side.

Commercial and residential use represents only a small proportion of total gas consumption in Western Australia.

7.1.2 Comparison with Eastern Australia and US/EU

The gas market in Western Australia contrasts with markets in the United States and the European Union, and even with the market in eastern Australia. The US and EU markets are much larger and much more competitive than any of the Australian gas markets. They are characterised by extensive pipeline networks (when compared with Australia) often supporting multiple delivery paths, and by a diversity of buyers and sellers (as noted above). Australia is a net exporter by virtue of its supply of LNG to the world market whereas the US consumes most of the gas it produces, and the EU is a net gas importer.

Eastern Australia

Until gas market liberalisation policies were implemented in the early 1990s, Australian gas markets were typically regional markets, with a single joint venture producer supplying a single government owned retailer under long term take or pay arrangements.[47] The current Australian gas market is more consistent with a project or contract market than a fully functioning commodity market.[48] The Australian gas market is commonly referred to as immature and distinguished from United States and European markets that are typically characterised as mature commodity markets.

Eastern Australian markets are highly concentrated. BHP Billiton, Exxon Mobil, Santos and Origin Energy

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[47] Julie Harman, ABARE, 'Gas market development and regional gas flows in eastern Australia' June 2000, p2-4.

[48] The ACCC has commented on the difference between a project or contract market and a commodity market. See ACCC, Applications for Authorisation Mereenie Producers – Gasgo Sales Agreement, 7 April 1999, 32.

account for 93% of the eastern Australia upstream gas supply.[49] Indeed ERIG has commented:[50]

> The Eastern gas market has three major retailers, few major transmission pipeline providers and limited gas storage facilities. It has three major gas producers.

Eastern Australia is likely to be increasingly reliant on coal seam methane (CSM) gas in future years. In addition to coal seam methane, eastern Australia is likely to require either imported natural gas or newly discovered reserves in coming years to offset supply shortages.[51] Indeed, the concerns over long term domestic supply shortages in WA are mirrored Australia wide, although caused by different issues. CSM reserves are not currently suitable for LNG production, so it is unlikely that eastern Australian gas reserves will be exhausted supplying international regions.

United States and European Union

The ACCC has said of the US and UK gas markets that:[52]

> The physical production and delivery of gas is separated from the contractual sales, with a variety of trading, swapping and hedging practices helping to achieve a more efficient allocation of the gas supplied to the various end customers.

The maturity, size and well-developed trade focus of these markets contrasts with the current Australian gas market that has little trading and relatively few market participants.

The well developed trading arrangements in both the US and Europe reflect the diversity of buyers and sellers, consumers and producers. Trading arrangements have evolved to serve their interests, and once evolved, have supported the range of intermediaries that are so useful in ensuring liquidity, arbitrage and efficient risk management.

Installing trading arrangements in Australia will not, in the absence of upstream and downstream diversity, result in competitive outcomes.

United States

For most of the 20th century the US gas market was heavily regulated, with prices determined by external regulation at many points in the gas supply chain. Supply shortages in the 1970s and surpluses in the 1980s made poignant examples of the deficiencies of the US system, leading to deregulation of the natural gas industry, which has proven to be highly successful by most measures.

In the current deregulated US market, natural gas marketers play a critical role serving different industry groups or operating independently, or in an aggregating or brokering role. This indicates both the size of the market, and its maturity given the variety of trading arrangements.

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[49] Energy Reform Implementation Group, Discussion Papers, November 2006, 207-208.

[50] Energy Reform Implementation Group, Discussion Papers, November 2006, 205.

[51] One such source, the proposed PNG gas pipeline, appears to have been shelved.

[52] ACCC, Applications for Authorisation Mereenie Producers – Gasgo Sales Agreement, 7 April 1999, 32.

The US market is significantly larger than the Australian market. In 2005 there were approximately 69 million natural gas consumers, comprising 63.5 million residential (compared with circa 500,000 residential customers in WA), 5 million commercial and 200,000 industrial consumers. At the end of 2005 there were 425,303 gas and gas condensate wells. Total gas consumption was 22 Tcf and total gas delivered to consumers was 20.5 Tcf. LNG exports were 0.065 Tcf and pipeline exports were 0.66 Tcf. LNG imports were 0.63 Tcf and pipeline imports were 3.7 Tcf.[53]

In the US there are more than 8,000 producers of natural gas and 580 processing plants. There are 160 pipeline companies operating 285,000 miles of pipelines including 180,000 miles of interstate pipeline. The capacity of this pipeline network is 0.12 Tcf per day. Total storage facilities have a capacity of 3.9 Tcf, enough to store over 4 years of total WA gas production and over 14 years of WA domestic gas consumption.[54]

European Union

The European Union has been undertaking gas market liberalisation in order to realise a common market for gas. Western Europe has limited gas reserves, estimated at approximately 5% of total world reserves. The Netherlands, Norway and the United Kingdom are the main gas producers within the region, but the majority of gas consumed within western Europe must be imported, with the majority being sourced from Russia, which has significant reserves.[55]

Primary energy consumption in the EU25 was 73,420 PJ in 2005. Natural gas provides approximately 25% of primary energy consumption in the European Union (18,200 PJ). 41% of EU natural gas supplies were met by domestic production in 2005. In addition Russia (24%), Norway (15%), Algeria (11%), Libya, Nigeria, Egypt and Qatar all supplied gas to the European Union. In 2005, LNG imports for the EU25 were 1,761 PJ. The EU25 has 102 million gas customers (comprising domestic, commercial and industrial usage) and employed 208,700 people. There is 1,812,067 km of natural gas pipelines in the EU.[56]

When reporting statistics for the EU, it is important to note that there is often significant variation between different regions within the EU.

7.2 MARKET DEFINITION ISSUES

In assessing whether there is evidence of potential market failure in terms of the supply of gas for domestic use in Western Australia it is not sufficient to simply look at supply and demand issues related to natural gas itself. Rather, it is important to first have an understanding of the market in which gas is sold within the State. This requires at least a high level consideration of market definition.

[53] Energy Information Administration Office of Oil and Gas, 'Natural Gas Annual 2005', November 2006, p 1, 3, 10, 18.

[54] http://www.naturalgas.org/business/industry.asp.

[55] http://www.unctad.org/infocomm/anglais/gas/market.htm#consumption.

[56] Eurogas, 'Statistics 2005 – EU25: Natural Gas Trends 2004-2005 Statistical Data & Taxes'. Eurogas has stated that the market characteristics of the EU now make accurate data collection difficult.

This report is not intended to provide a formal analysis of the market or an assessment of whether there is prima facie evidence of technical breaches of the Trade Practices Act but rather whether there is evidence of potential market related issues sufficient to justify some form of policy (rather than legal) response. As such, market definition comments are limited to a high level consideration. None the less, it is not economically meaningful to suggest that a market has 'failed' unless there is a clear understanding of the relevant market.

Market definition is not an end in itself but a key step in identifying the competitive constraints acting on a supplier of a given product or service. Market definition provides a framework for competition analysis. For example, market shares can be calculated only after the market has been defined and, when considering the potential for new entry, it is necessary to identify the market that might be entered. Market definition is usually the first step in the assessment of market power.

The concept of a 'market' is defined by the TPA in s4E:

> 'market' means a market in Australia and, when used in relation to any goods or services, includes a market for those goods or services and other goods or services that are substitutable for, or otherwise competitive with, the first-mentioned goods or services.

It was noted by Burchett J in *News Ltd v Australian Rugby Football League Ltd*[57] that the words 'or otherwise with' in s4E suggest that a wider rather than narrower specification of a market is appropriate[58] but s4E still requires close substitutability because, when viewed broadly, most products are to some limited degree substitutes for one another.[59]

The most important matter to defining the market is the extent of substitutability or the cross-price elasticity of demand. In general it is argued that the price elasticity of demand for gas is relatively low, that is that the demand for gas is inelastic. For example, the Australian Competition Tribunal noted:[60]

> The available evidence indicates that the price elasticity of demand for gas is low, and that gas prices have little influence on the demand for electricity (cross price elasticity). The elasticities were estimated using data which pre-dates the reforms in the gas industry so they are likely to be underestimates of the actual position today. In the future, changes in technology and the use of gas to generate electricity from 2006 onwards could be expected to lead to a more integrated energy market.

WA is somewhat unusual in having some dual fuel power generators. To some extent this is an accident of history whereby a number of generators which were originally constructed to burn oil were subsequently converted to burn coal and can now burn gas or coal.

[57] *News Ltd v Australian Rugby Football League Ltd* (1996) 58 FCR 447.

[58] Russell Miller, *'Miller's Annotated Trade Practices Act 1974'* (24th ed, 2003) 94.

[59] SG Corones, *'Competition Law in Australia'* (3rd ed, 2004) 52 citing *Boral Case* (2003) 195 ALR 609.

[60] Australian Competition Tribunal EGP Decision ACompT2 2001 para 79.

Other peaking generation plant can burn gas or – in time of high demand when gas transmission capacity is fully committed – can burn liquids. This gives some WA generators that are large gas consumers the ability to switch relatively easily to an alternative fuel in the face of gas supply shortages (the differential between alternative fuel cost and gas cost is so great that switching is generally not done for reasons of price). Accordingly, the price elasticity of demand for gas (and the cross price elasticity between gas and the alternative fuels) is potentially higher in WA than elsewhere in Australia.

However, the potential for a higher demand elasticity may not be reflected in an actual demand response unless there is a sufficiently large relative price change. In addition, the rapidly increasing demand for electricity in WA and the optimisation of new base load generators for use with gas only, are likely to significantly diminish the scope for substitution for gas in the future.

Similarly, a number of downstream mineral processing industries are likely to be unable to switch fuels, as the nature of their processes or the amount of capital invested makes it either not possible or not viable to switch to an alternative fuel source.

However, as a general proposition, demand generally becomes more elastic over time as progressive replacement of plant enables users to move away from reliance on gas. That is, long-run price elasticity of demand is greater than short-run elasticity.

Potential substitutes for natural gas in WA are likely to include liquid fuels, coal and potentially to some extent alternative energy sources such as wind power. The coal market in WA currently comprises only two production companies and given the relatively limited commercial coal reserves in WA there is unlikely to be significant new entry and therefore the continuation of the current concentrated supply is probable. Under these circumstances it could be expected that in the long-run coal prices will not exert a strong independent influence on competing fuel prices (principally gas) and coal prices would tend to move broadly in line with competing fuel prices.

Even so, it is not considered that the quantum of gas demand that can switch is sufficient to discipline gas prices at current relative fuel prices and that long-term response to gas price changes would also be insufficiently large and timely to discipline price increase.[61] Accordingly, we concur with most prevailing analysis in Australia, that reticulated gas in WA forms a distinct market.

In contrast, even if international LNG forms a distinct market it is likely to be a competitive market. A hypothetical LNG monopolist seeking to increase prices could well be defeated by customers switching to alternative fuel imports (predominantly coal, liquids and local natural gas resources) in the event of a small but significant non-transitory increase in price. Furthermore it is considered likely that WA LNG exports are part of the international LNG market which is itself competitive.

[61] Readers may recognise the linkage to one classical indicia of a distinct market, whether a hypothetical monopolist of the gas market could profitably enact a small but significant non-transitory increase in price (the SSNIP test).

7.3 DOMESTIC VERSUS INTERNATIONALLY TRADED GAS

The domestic gas market is very small when compared to the international market for LNG. WA gas reserves are only 1.9% of proven global gas reserves. Growth in world demand is forecast to grow at 2.6% per year to 2010. Currently, annual WA gas production is less than 1% of global gas production.[62]

The domestic market is characterised by long term contracts and a limited number of large scale buyers and sellers, while international trade in LNG is growing much more rapidly and with a much larger number of market participants. Some 2.5% of the international gas trade and 11% of total LNG flows occurs under spot LNG trades and other short-term transactions. In 2005 LNG trade reached 6.8 Tcf. The increased trading focus of the international LNG market is shown by the fact that by 2010 international LNG trade is expected to be in the range of 10.6 Tcf to 12.4 Tcf.[63]

Compared to international demand, domestic demand growth is in incremental steps, and is influenced by the consumption behaviour of individual market participants. The liquidity and size of the international gas market allows it to absorb increases in supply relatively easily and provides a stable and predictable base against which to make long-run investment decisions. In contrast, the characteristics of the WA gas market, particularly the small number of large customers and the nature of their businesses, give rise to large (relative to underlying demand) step changes in consumption, more easily dealt with under long-term contracts for supply and transmission.

7.4 RELATIVE GAS PRICES

As noted by the UNCTAD:[64]

> As the world market for natural gas is fragmented in different regional markets, it is not possible to talk about a world price for natural gas. Although there is a market liberalization trend all over the world, in many countries natural gas markets are still highly regulated. As a result of different degrees of market regulation, natural gas prices differ among countries. In North America, for example, where the market is highly liberalized, prices are very competitive and respond to demand and supply forces.

The result of this is that prices are likely to vary significantly in different countries or geographic regions and often may lack transparency. One source of information on international gas prices is provided by the EIA in the US. Data collected by the EIA indicate that prices are likely to vary dramatically across countries. The following table reproduces the EIA data for gas prices (converted to AUD[65]/GJ) for those counties with price data in 2004 or 2005.

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[62] International Energy Agency, 'Natural Gas Market Review 2006' p35-36.

[63] International Energy Agency, 'Natural Gas Market Review 2006' p35-36.

[64] http://www.unctad.org/infocomm/anglais/gas/prices.htm.

[65] Assumed an AUD:US exchange rate of 1.00 A$ to 0.75 US$. While this is lower than the current rate as at May 2007 or around 0.82US$, it is considered representative of a medium term average exchange rate.

The highest price in 2004 ($25.76) is some 56 times higher than the lowest price ($0.46) while for the more limited data reported for 2005, the highest price of ($12.74) is some 8.5 times higher than the lowest price ($1.50).

Interpretation of gas pricing can sometimes be misleading as knowledge of the gas supply chain needs to be used when making a comparison. For example Henry Hub gas pricing includes not only the well head pricing but also the cost of transport. To the extent that LNG pricing has any meaningful impact on Hub pricing, then the cost of processing and transport also form part of the gas supply price. [see this table to get an idea of well-head gas pricing in the US http://www.eia.doe.gov/emeu/aer/pdf/pages/sec6_17.pdf]

Table 7 Comparison of International Gas Prices Paid by Industry – 2004 or 2005

Country	2004 AUD/GJ	2005 AUD/GJ
Argentina	1.50	
Barbados	25.76	
Bolivia	2.29	
Brazil	12.75	
Canada	7.09	9.34
Chile	6.74	
Chinese Taipei (Taiwan)	10.68	12.38
Colombia	7.75	
Cuba	4.20	
Czech Republic	6.89	9.27
Finland	5.40	6.03
France	8.31	10.47
Greece	7.36	9.90
Hungary	9.12	10.99
Ireland	9.25	11.86
Japan	12.44	
Kazakhstan	1.44	1.50
Korea, South	10.84	12.44
Mexico	9.53	11.32
New Zealand	3.86	5.11
Peru	5.13	
Poland	5.69	7.12
Portugal	9.06	10.79
Russia	1.05	
Slovak Republic (Slovakia)	7.70	9.11
Spain	6.83	8.06
Switzerland	11.17	12.74
Turkey	7.30	9.66
United Kingdom	6.42	9.47
United States	7.99	10.32
Venezuela	0.46	

Note: Includes taxes
Source: http://www.eia.doe.gov/emeu/international/gasprice.html

In the US there is a well developed, liquid and transparent spot market for gas traded at the Henry Hub in Louisiana.[66] Historic and forecast prices have been prepared by the EIA and are reproduced in the following figure. It is interesting to note that excluding the period following Hurricane Katrina, when significant interruption occurred to US gas production, prices in recent years

[66] Historically the volume of gas traded on spot markets as a proportion of total demand has varied dramatically, from virtually zero in the early 1980s to over 80% in the late 1980s and since declining again. Most gas is now sold under long term contracts although these normally provide for some form of price indexing generally to the spot gas market. See for example commentary by the New York Mercantile Exchange "Risk Management with Natural Gas Futures and Options". The result is that Henry Hub spot prices are routinely reported as the market clearing price.

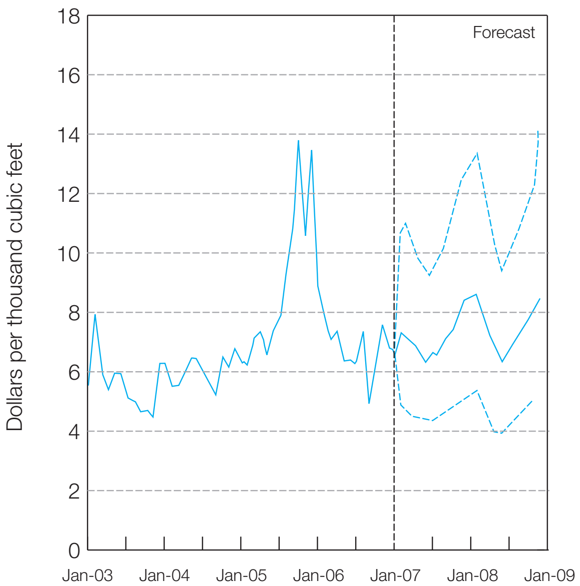
have tended to range (and are forecast to continue to range) between USD 6.00 (AUD 8.00) and USD 8.00 (AUD 10.66) per '000cf.

The above EIA forecast for Henry Hub prices can be compared with Henry Hub futures which, in February 2007, exhibit a general declining price trend with increasing length till maturity. This is highlighted in the following graph.

Almost all gas is traded at hub prices in the US (either directly through the spot market or alternatively through long term contracts with price linkages to hub prices), so there is no clear notion of well head price (although clearly this must be lower than hub price as it will reflect the incremental transport cost from well head to hub). There is also a well established transmission market from the hub to the point of consumption, sufficient to provide a basis for a liquid market in delivered gas.[67]

Gas sales contracts in Australia are generally bi-lateral contracts between producers and purchasers and as such are treated as commercial in confidence. The result of this is that there is very little transparency in terms of Australian domestic gas prices. The only indicative price publicly available is the VenCorp spot price which is the daily settlement price in the Victorian gas market. Over calendar 2006, the volume weighted average Vencorp settlement price was AUD 3.16/GJ with a minimum price of AUD 2.21/GJ and a maximum price of AUD 6.04/GJ. The daily settlement prices are presented in the following chart.

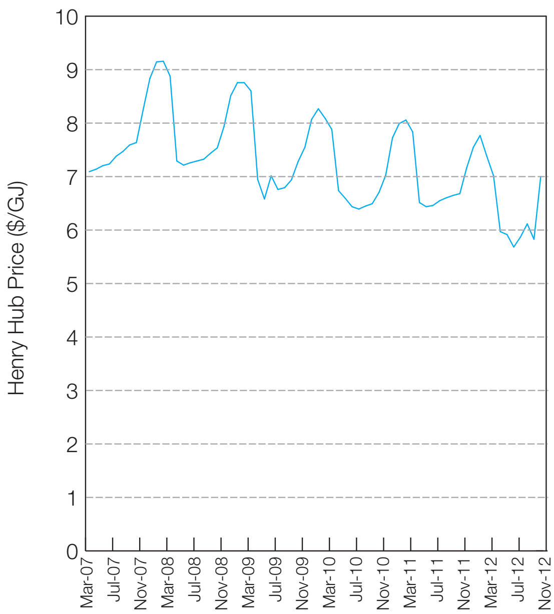
Figure 13 US Henry Hub Gas Spot Price 2003 to 2009 (forecast) USD/'000cf



* The confidence intervals show +/– 2 standard errors based on the properties of the model.

Data source: EIA Short Term Energy Outlook, February 2007

Figure 14 NYMEX Henry Hub Natural Gas Futures (converted to USD/GJ)



Data source: http://data.tradingcharts.com/futures/quotes/NG.html February 16 2007

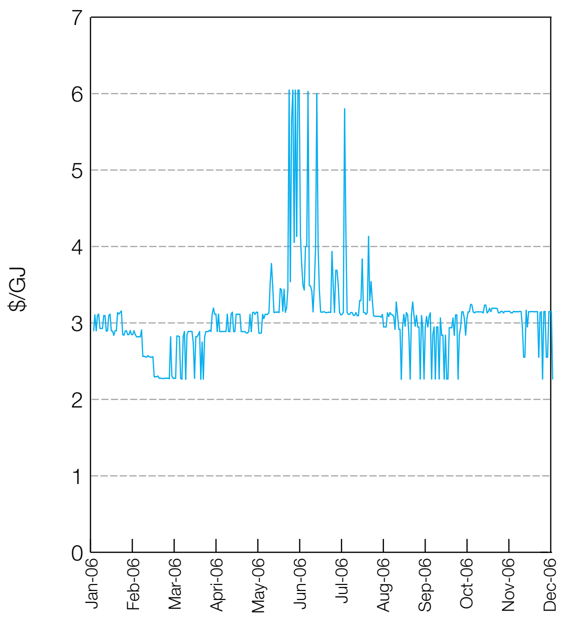
[67] As a result, city gate prices are widely reported.

In 2004, ex-plant prices required to support new gas fields in WA were estimated to range from $2.50/GJ to $3.70/GJ with then prevailing prices for existing fields (excluding transmission) reportedly in the range of $2.10 to $2.30/GJ.[68]

WA gas users are reported to have indicated that the limited supplies of new gas that have been made available to the Domestic Market recently have been priced at above $5/GJ.[69]

The DomGas Alliance has reported a doubling in WA gas prices in the last 12 months, with delivered prices now approximately double that in the Eastern States.

Figure 15 VENCorp 2006 Daily Market Price ($/GJ)



Data source: VENCorp

7.5 WA ENERGY INTENSITY AND GAS USE

The defining characteristic of the WA domestic gas market is that gas is supplied under bilateral contracts. Many of these contracts are long-term in nature; usually with a 10-20 year term. Unless contracts have the flexibility for price renegotiation during the contract term contract pricing is usually fixed and escalated as a percentage of the Consumer Price Index. As a result gas prices in WA do not have the pricing volatility of gas markets which are more closely linked to the oil price.
There is also no formalised gas spot market in WA.

The long-term bilateral contracting nature of the WA gas market has stemmed from the producers desire to have certainty about a revenue stream to underpin the large capital costs associated with gas field development and the consumers desire to have certainty of supply for the term of their project. This is in contrast to the US market in which there is significant liquidity with multiple producers and multiple consumers significantly reducing revenue and supply risk.

The forecast growth in WA domestic gas demand is likely to be largely associated with major project development such as gas fired electricity generation and mineral processing developments.
The 2004 WA Government sponsored report titled Energy for Minerals Development in the South West Region of WA suggested that Bauxite/Alumina,

[68] Sleeman Consulting, Energy for Minerals Development in the South West Region of WA, December 2004, 22-23.

[69] See for example “WA Under Pressure as Gas Pries Double” Article in The Australian 27 February 2007.

Titanium pigment and Nickel Smelter expansion projects would require a maximum gas price of $2.80/GJ while DRI/HBI/Pig-Iron and Magnetite Pellets projects would require a maximum gas price of $3.50/GJ in order to be commercial.[70]

In the short term, the recent resources boom and associated high commodity prices is likely to have increased the gas price (and development cost) at which such projects are viable. However, most projects are evaluated on a long range commodity price which would not necessarily mirror current commodity prices. Nevertheless, there is some level of relative gas price increase which will ultimately result in some projects being deferred or cancelled. This would have an adverse impact both on the level of economic activity and the total domestic demand for gas.

7.6 ROLE OF GAS EXPORTS IN WA COMPARED TO EASTERN AUSTRALIA

Gas reserves of sufficient scale to support LNG production are only located in northern and western regions of Australia's territorial sea. The majority of potential reserves in Eastern Australia are CSM and are suited only to domestic production given current technology. Currently, gas exports in the form of LNG come from the North West Shelf and ConocoPhillips Darwin LNG plant.

LNG exports appear to be profitable at currently prevailing world LNG prices for large scale offshore sources such as the North West Shelf. Given the size and buoyancy of the world market, and the relative appeal of LNG from Australia given the stable political climate and advantageous extraction costs, WA LNG exporters face few concerns of failing to find markets for their products.

While reserves in the Eastern States are used solely to supply domestic demand, a strong international LNG market dictates that in WA, natural gas for LNG export far outstrips natural gas for domestic supply. Currently more than twice the supply of domestic gas within WA is exported as LNG. The North West Shelf project provides approximately 65% of domestic gas in WA, however, almost 70% of production from the North West Shelf project is exported as LNG. Gas exports play a significant role in the WA economy.

[70] Sleeman Consulting, Energy for Minerals Development in the South West Region of WA, December 2004, 125-152.

8 EVIDENCE OF POTENTIAL FOR MARKET FAILURE

There is evidence that the WA gas commodity market suffers from significant market failure arising from:

- concentration in supply
- transactions between buyers and sellers that are bespoke and long term; and
- the absence of secondary markets, spot markets or market makers acting to increase liquidity.

The concentration on both the supply and demand side of the WA domestic gas market will not offset each other. That is because current and prospective domestic gas customers have no reasonable alternatives that can be accessed quickly at prices close to the prevailing prices of gas, while producers do have a profitable alternative in LNG exports.

The effect of the authorised joint marketing arrangements for the NWS producers is to dramatically reduce the number of independent producers selling gas into the domestic market.

The most important contributor to market failure in WA is upstream concentration as this may:

- lead to monopolisation of the WA domestic gas market by restricting availability of gas to the domestic market; and
- limit the scope for contract and secondary markets to develop because the joint marketing arrangements lead to a lack of diversity of risk preferences across upstream suppliers.

As a result, there is a need for urgent policy intervention by government to ensure continued supply of competitively priced gas to the domestic market.

8.1 IMPACT OF JOINT MARKETING

8.1.1 Nature of joint marketing arrangements

Joint marketing of gas by joint venture partners has been a hallmark of the gas industry in Australia, and has been the subject of authorisation applications before regulators since competition legislation was introduced. Joint marketing may contravene the Trade Practices Act and in an authorisation context joint marketing by joint venture parties must be capable of showing that the benefits from the conduct outweigh any anti-competitive detriment.

Joint marketing increases industry concentration. In traditional antitrust analysis, a significant increase in concentration is viewed with concern as it normally gives rise to market power and a concomitant risk of increased prices, above competitive levels, through misuse of that market power. Under a typical antitrust analysis, it can be said that all other things being equal a gas market with separate marketing will be less prone to anti-competitive pricing than the same market if joint marketing were allowed. It is, of course, a question of fact as to whether the offsetting efficiency advantages that come from joint marketing are sufficient to overcome any adverse efficiency consequences from potential anti-competitive behaviour.

A considerable efficiency gain may be realised by separate marketing as it will increase intra-basin competition, even between joint venture partners. Separate marketing bestows the benefit of decreasing the concentration of gas suppliers, which may make substitution between suppliers relatively easier for customers, and will introduce greater diversity of supplier risk preferences.

The majority of argument in an Australian context is whether or not separate marketing is feasible for a particular market. Joint marketing is seen as preferable where it supports projects that, with separate marketing, would not be developed. That is, there are cases where no gas would be produced in the absence of a joint marketing arrangement, so anti-competitive effects are moot. No efficiency gains can be realised from separate sales arrangements if the effect of such arrangements is the abandonment of the market. In these circumstances, joint marketing results in an increase in production or output: it is very unlikely that any arrangement that increases output in a distinct market could be considered inefficient.

There are clearly circumstances in which separate marketing can increase costs. Separate arrangements may increase transaction costs and marketing costs, which are likely to increase ultimate downstream gas prices as these higher costs are passed on to final consumers.[71] But perhaps the most compelling cost associated with separate selling arrangements is that they increase the prospect of *ex post* competition (between the gas producers), and the resultant price competition has the potential to force the gas price below the level needed to make the project viable. In this case, an *ex ante* agreement to fix prices, that prevents this *ex post* competition, is needed to attract investment (or to reduce the investment risk and hence equivalently the required return on investment).

Another possible benefit of joint marketing is demonstrated by the Irish case study outlined in Attachment A. A strong customer coalition can in effect create an inefficient monopsony. In these circumstances, allowing joint marketing may increase the negotiation power of gas producers compared to the dominant monopsony creating a more efficient outcome for the wholesale gas supply market.

Despite this relative customer concentration in WA, one should be careful in drawing parallels with Ireland. WA customers are unlikely to exert any countervailing power against the upstream suppliers. The extent of countervailing power by buyers and sellers depends crucially on their next best alternative in the event of failing to agree terms. As a practical matter,

[71] ACCC, North West Shelf Project Determination, 29 July 1998, iii – viii.

current and prospective domestic gas customers have no reasonable alternatives that can be accessed quickly at prices close to the prevailing prices of gas. On the other hand, producers do have a reasonable alternative, namely LNG exports. Hence concentration in demand is unlikely to help resolve any market failure in gas supply.

While not relevant to the NWS case, a joint marketing arrangement also allows a mix of small and large partners to exploit a resource, and this may be important in bringing the requisite skills to a development consortium, and minimising the risk to any one producer. Under a diverse ownership structure, joint marketing allows smaller joint venture partners with a commensurately small share of gas production to market more easily, by jointly marketing with one or more of the larger joint venture partners which in turn may help them to develop their marketing and overall operations. But in any event, many small producers will commonly sell their gas to a larger producer in the joint venture if joint marketing were prohibited, achieving a similar result with respect to competition under either approach.

Accordingly, there are circumstances where joint marketing will lower the costs of developing and marketing the field amongst the joint venture parties, thereby lowering costs to downstream gas users.

Of course, joint marketing arrangements come with the attendant risk that firms will use them to stymie the development of a competitive market. In doing so, they may seek to limit production from new fields or existing fields. To the extent that they serve distinct markets (e.g. international LNG and domestic gas) in which they have different levels of market power, they may be selective about how they supply and price in different markets.

The extent of potential harm that can arise from joint market arrangements depends on the relative size of the joint marketing venture and the relevant gas market that it serves. Were they to exist, joint marketing arrangements in the North American and European markets would not be likely to give rise to problems because of the size of the markets and the diversity of buyers and sellers. Joint marketing arrangements in the international LNG market are similarly unlikely to result in competition concerns. Similarly, joint marketing arrangements in markets where there are a range of alternative fuel sources (oil, coal etc.) with similar effective costs are unlikely to be an issue.[72] But joint marketing arrangements that are suited (and efficiency enhancing) for the international LNG market are unlikely to be suited to the small domestic WA gas market.

Furthermore, the case for joint marketing arrangements is likely to differ substantially across the life-cycle of a gas market. In the early stages of development (such as development of Moomba, Bass Strait, North West Shelf) when huge investments are needed to develop fields and the markets in which the gas will be sold are relatively

[72] Of course, the gas market would not be a distinct market in the economic sense where such alternatives exist.

new,[73] the risks imposed on investors from *ex post* competition are large: so joint marketing can be essential for investment to take place. In the mature stages of the market, where extensive infrastructure is in place and new demand is met through incremental development of fields, processing facilities and transmission infrastructure, investment risks are much more manageable. It is in these later stages of the market that the anti-competitive effects of joint marketing arrangements are likely to be detrimental.

ABARE has identified that joint marketing allows upstream gas companies to develop market power, potentially to the detriment of the greater economy.

> In the gas market, market power may a llow current producers to capture some of the cost savings generated by downstream reforms:[74]

8.1.2 Measures of market concentration

Recently, the ERIG Discussion Papers have commented on the pervasiveness of joint ventures and joint marketing in Australia. For eastern Australia, this compounds very high market concentration because BHP Billiton, Exxon Mobil, Santos and Origin Energy account for 93% of the Eastern Australia upstream gas market.[75] ERIG states that joint marketing is associated with market imbalances and inefficiency.[76]

In anti-trust analysis, the Herfindahl-Hirschman Index (HHI)[77] is a commonly used measure of market concentration. The Federal Trade Commission and Department of Justice, the US Federal agencies that engage in the analysis of mergers and acquisition, routinely scrutinize any merger that has an HHI score in excess of 2,000 — this equates to a market with 5 equal sized players. It is not unusual to investigate cases that equate to 6 equal sized players (which yields an HHI score of 1,667). The HHI for the West Australia gas market is in excess of 8,000 (a monopoly market has an HHI score of 10,000).

When assessing competition in the gas market, it is important to recognise that in the long term gas is also in competition with other energy sources like electricity generated from non-gas fuel and other hydrocarbons. A significant increase in the price of gas would be expected to shift demand towards these other fuel sources. For gas price rises that are not significant, price movements are likely to be absorbed, as substituting energy sources for some customers may involve large capital expenditure during the adoption of an alternative energy source.[78] In a market that is increasingly aware of emissions, gas demand is very strong and may become less price

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73 Indeed, there may be no pre-existing market for the gas, as was the case for the Bass Strait development.

74 Julie Harman, ABARE, 'Gas market development and regional gas flows in eastern Australia' June 2000, p4.

75 Energy Reform Implementation Group, Discussion Papers, November 2006, 207-208.

76 Energy Reform Implementation Group, Discussion Papers, November 2006, 208.

77 The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. For example, for a market consisting of four firms with shares of thirty, thirty, twenty and twenty percent, the HHI is 2600 ($30^2 + 30^2 + 20^2 + 20^2 = 2600$).

elastic as heavily polluting fuel sources are avoided, whether by choice or more likely by policy direction.

8.1.3 ACCC Position on Marketing

As a general position, the ACCC has historically accepted that although separate marketing of gas may be preferable, it has not been feasible for the Australian gas market, at least in some areas.

The general tenor of several ACCC decisions since the late 1990s has been that the real question is whether separate marketing is feasible, and that if it is then separate marketing should be the preferred approach. The ACCC has adopted the comparison of commodity markets (where separate marketing is feasible) with project or contract markets (where separate marketing is not feasible) when characterising the Northern Territory gas market as small, immature and unsuited to separate marketing.[79]

There are two limbs to the ACCC's consideration of authorisation:

(i) The arrangements must result in a benefit to the public; and

(ii) That benefit outweighs any detriment from lessening competition.

In authorising the original joint marketing arrangements for the North West Shelf project, the ACCC made the following important observations:[80]

> While it is impossible to be prescriptive about exactly what market features need to develop before separate marketing will become viable in WA, the greater the number of the following list of market developments that are introduced, the greater the likelihood that separate marketing will be viable:
>
> – a significant increase in the number of customers;
> – the entry of new competitive suppliers;
> – additional transportation options;
> – storage;
> – the entry of brokers/ aggregators;
> – the creation of gas-related financial markets; and
> – the development of significant short term and spot markets.

We believe that the ACCC is too pessimistic in establishing this list. Short-term/spot markets, financial markets, the entry of brokers etc are all outcomes that can be expected to arise *when* a market is reasonably competitive. Putting them in place (or more realistically, seeking to do so) will not create a competitive market when underlying structural

[78] By way of a simple example, if the effective cost of gas for electricity generation is $3/GJ, and the cost of oil is $5/GJ, the gas price could rise by $2/GJ before the generator would substitute. For this reason, relative price is relevant in defining a market. Ford Falcons and Bentleys reside in different markets. Both are cars, but it is inconceivable that a buyer of a Ford Falcon would substitute to a Bentley if Ford increased the price of the Falcon.

[79] ACCC, Applications for Authorisation Mereenie Producers – Gasgo Sales Agreement, 7 April 1999, 32.

[80] ACCC, North West Shelf Project Determination, 29 July 1998, v.

characteristics will not support it.[81] The key to the success of separate marketing lies more in the structural factors that the ACCC identifies.

The ACCC has clearly stated that it sees no impediment to joint production of gas occurring where there is separate marketing undertaken.[82]

The ACCC has expressed concern over indefinitely authorising joint marketing, instead preferring to authorise joint marketing for a fixed period of time in order to minimise the detrimental effect it may have on the development of the gas industry.[83] By authorising the joint marketing only for a limited period the benefits of allowing other uneconomic fields to be developed may be realised, but the risk of long term collusion detrimentally influencing market outcomes is limited.

It is not apparent that any authorisation is in place for the current North West Shelf domestic gas marketing arrangements, though the joint venture has stated its commitment to complying with the TPA. The number of independent producers selling gas into the domestic market is greatly reduced by these joint marketing arrangements. As outlined in Section 5, two operating entities (NWS and Apache) hold close to 100% of the gas reserves in developed fields that currently service the domestic market. That is, absent the joint marketing arrangements, there would be seven independent producers potentially marketing gas for domestic use.

This increase in entities potentially supplying gas for domestic use could be expected to increase the diversity of supply offers available. That is, the risk preferences of the six members of the NWS joint venture are likely to differ. The risk preference of the joint venture therefore represents some form of average of the risk preference of the individual members which by its nature must reduce the diversity of acceptable supply options available in the market.

The practical implication of this is likely to be that in order for requests for domestic supply to be commercially acceptable to the NWS joint venture they will have to satisfy a relatively narrow range of characteristics. Indeed, these characteristics may reflect the NWS's experience with LNG contracts so that the only attractive domestic supply contract going forwards may be one for very large gas volumes delivered over long contract periods (perhaps as long as twenty years).[84]

8.2 MARKET STRUCTURE AND INVESTMENT DYNAMICS

This report has identified that the WA market for domestic natural gas sales is characterised by extreme concentration on the supply side with possible future gas supplies also tightly held

[81] Equally, if the structural features of the market support competition, mechanisms that improve the operation of the market — such as spot markets — are very likely to arise anyway (albeit at a slower pace than might be the case if governments put them in place, as was the case with the National Electricity Market).

[82] ACCC, Applications for Authorisation Mereenie Producers – Gasgo Sales Agreement, 7 April 1999, 33.

[83] ACCC, North West Shelf Project Determination, 29 July 1998, vii.

[84] The nature of LNG contracts is often one whereby a number of gas buyers pool their demand in order to, aggregate and underpin a major LNG project rather than an individual purchaser contracting for the entire volume.

under Retention Lease arrangements. This suggests that under current arrangements, there is little prospect for a substantial reduction in supply concentration in the foreseeable future.

As the vast majority of existing known WA gas reserves are located in offshore fields, development costs are likely to be very high and as such, commercialisation of these reserves is only likely to occur where long term contracts are able to be negotiated for sufficiently large volumes of gas to underwrite the project. For example, the Gorgon gas field is being developed on the basis of a 10 million tonne per annum LNG project. Such a project will require in the order of 500 PJ per annum of gas, an amount materially in excess of the current total WA gas market.[85]

In addition, the difficulty in getting agreement to share existing facilities or sites is likely to increase the cost of developing new fields and therefore either delay or stop commercialisation of some fields.

While exploration and development of on-shore gas fields promises to be significantly cheaper than for off-shore fields, the prospect of massive discoveries off-shore has meant that there has been limited exploration attention given to WA on-shore sedimentary basins.

The Western Australian domestic gas market, while exhibiting the highest per capita and the highest total gas consumption of any Australian State or territory is still a relatively small market in international terms at around 290 PJ per annum excluding gas used for LNG production, LPG and refinery gas.

Demand for gas in Western Australia is primarily driven by electricity generation and industrial use and as such, incremental demand is likely to be relatively lumpy as it will be related to the development of new industrial facilities or generation plant or roll-off of existing contracts.

While the scale of investment for LNG may necessitate joint marketing arrangements, the domestic gas market is distinct from the LNG market. Specifically, it is unlikely that these fields would be developed solely to serve the domestic gas market, but given that the LNG market exists, producers should be willing to make incremental investments to supply the WA domestic gas market. There are no compelling grounds for believing that the conditions that predispose joint marketing to develop fields for LNG also apply to the incremental investment needed to also support the domestic market.

8.3 JUSTIFICATION FOR A POLICY RESPONSE

A government policy response in the form of an intervention in a particular market is usually justified on the grounds of addressing market failure, addressing some form of policy failure, or of achieving a more equitable distribution of income. In each case, there is a rebuttable presumption that the costs of intervening are less than the benefits of so doing.

[85] This is in contrast to the situation applying at the commencement of the NWS project where aggregation of domestic demand was the critical factor in underpinning development of the resource.

Market failure can arise from a number of causes. The intention of policy responses to market failure is to 'correct' for the market failure and to consequently achieve an improvement in overall economic efficiency i.e. take action that leads to a net public benefit. Increasing competition is commonly associated with increasing economic efficiency, although it will not always do so. Examples of measures to increase competition within a market in order to 'correct' market failure are as follows:

- anti-trust authorities routinely prevent mergers and acquisitions that would reduce competition between firms. Alternatively, they may seek safeguards to mitigate such an outcome;
- there has been a widespread move towards open access networks in telecommunications, gas, electricity and ports to ensure that firms are not prevented from competing because they cannot get their products to market; and
- anti-trust or government authorities have sometimes resorted to divestiture to foster competition (the separation of AT&T from the Bell operating companies in the US is one example, breaking up of the SECV generation and transmission assets is a local example).

A general introduction to the concept of market failure is provided in the following box.

Box 1 Market Failure

Market failure occurs when resource allocation is not efficient; that is when someone can be made better off without making someone else worse off.

An economically efficient resource allocation occurs when cost of producing the marginal unit of a good or service is equal to consumer's willingness to pay for that unit of the good or service.

Economic theory shows that perfectly competitive markets will produce an allocation of resources that attains economic efficiency.

The most common types of market failure are:

- Incomplete property rights;
- market power;
- incomplete information; and
- missing and incomplete markets.

Incomplete property rights – efficiency requires that all goods and services can be produced and exchanged to the benefit of the parties to the transaction. A property right provides the owner of the good with an exclusive right to consume or sell a good or service.

There are many goods and services for which this assumption does not hold. Without well-defined property rights goods and services will be under or over-priced compared to an efficient price. The outcome is that economic well-being is less than it might otherwise have been.

Box 1 Market Failure (continued)

The terms externalities and public goods are used to describe particular examples of this market failure:

- Externalities describe a situation where one or more parties incur a benefit or cost from the actions of another person that is not the subject of a market transaction. An example is the upstream factory that pollutes water needed by downstream firms. The absence of a property right for the right to pollute imposes uncompensated costs on the downstream firms. In some cases the existence of property rights will not guarantee an efficient outcome. This is because transaction costs of bargaining or enforcing property rights outweigh an individuals gain.
- Public goods describe goods for which it is very difficult to exclude people outside the transaction and the good can be consumed simultaneously by more than one user. Defence expenditure is an example of a public good.

Market power – a perfectly competitive market assumes a firm has no ability to influence the price of a good or service. However, in some markets firms can raise the price of their good without being disciplined by the actions of rivals. Market power can result in higher prices and reduced output compared to a competitive market. Market power can be temporary or enduring and it is usually the latter that is of concern to policy makers. Market power generally arises because rivals are faced with barriers which prevent them from imposing competitive discipline.

Incomplete information – A perfectly competitive market assumes that all agents are fully informed when transacting. In most cases, agents will have incomplete information when entering transactions mainly because there is a cost of gathering and evaluating information. Incomplete information can result in market failure when one party to a transaction has information relevant to the transaction that the other party does not have access to. In the extreme, it can cause markets to cease to exist. This type of market failure is often associated with insurance markets and markets where quality of a good affects its price.

Missing and incomplete markets – Efficient outcome assumes a full set of markets in which to exchange goods and services. When markets are missing needs are unmet and so a potentially better allocation of resources would be available if the market existed.

Government policy responses do not always achieve an increase in economic efficiency as they too are also prone to government or regulatory failure. This may occur because of poorly designed or implemented policy responses. The interaction and balance between market failures and regulatory failures need to be carefully considered in assessing whether a policy response is justified. A brief discussion concerning potential for government policy failure is provided in the following box.

Box 2 Government Failure

The potential to improve economic welfare provides a strong rationale for governments to intervene in markets. Governments use a variety of methods to correct market failure, that is to restore the competitive market outcomes, including:

- Regulation;
- Taxation;
- Delivering services;
- Defining property rights; and
- Providing information.

Government failure describes circumstances where an intervention aimed at correcting market failure fails to achieve its intended outcomes or does so at excessive cost so that there is a net public detriment. There are five reasons why this can occur:

- Government has limited information and fails to predict or anticipate the consequences of its interventions. With incomplete information a government may not properly anticipate the response of agents to its interventions and as a result the desired outcomes are not achieved or there may be unintended consequences from government action;
- Government has limited control over the actions of private market agents. This is a particular problem in regulation and taxation where agents find ways of adapting their behaviour to limit the impact of taxes and regulation;
- Failure of the bureaucracy to implement policy;
- Limitations of a political process resulting in outcomes that may harm particular groups; and
- The direct administrative costs and indirect costs of raising revenue to finance the intervention may be too high.

The following section outlines: the possible types of market failures; an assessment of the possible presence of market or regulatory failures in the WA gas market; and an assessment of whether there is a case for a regulatory response.

8.3.1 Types of market failure

Economic welfare is maximised when certain conditions (ie. technical, allocative and dynamic efficiency) are met. However, there are a number of circumstances under which these conditions will not be met. These circumstances are market failures, and they form the rationale for government intervention in the market. Market failures include:[86]

- failure of competition;[87]
- public goods;[88]
- externalities;[89]
- incomplete markets;[90] and
- incomplete information.[91]

Market failures are not mutually exclusive, with more than one of the above failures potentially applying in a particular market. For example, information problems often partially explain incomplete or missing markets. Many market failures arise because transactions costs are too high for the particular weakness to be addressed effectively.

[86] Stiglitz, J.E. (1986) Economics of the Public Sector, 2nd edition, pp. 71-79.

[87] There is a lack of competition when, in a particular industry, there are relatively few firms or when a small number of firms have a large share of the market. Barriers to entry may arise from increasing returns to scale – typically the case in infrastructure industries, resulting in these industries being natural monopolies. However, the presence of only a few firms in itself does not necessarily imply the firms are not acting competitively. If there are a large number of potential entrants, existing firms may not be able to act monopolistically and it is possible for firms to be rivals in relatively concentrated markets. The definition of the market is also important in ascertaining whether a market is competitive.

[88] Public goods have two critical properties: firstly, there is no additional cost for an additional individual to use the good; and secondly, it is generally not possible to exclude individuals from enjoying the good. Defence is a classic example of a public good. The provision of lighthouses represents a celebrated debate as to the bounds of public goods. Coase showed that lighthouses need not involve non-excludability where a fee could be charged for the service that was provided (such as where it guided entry into a harbour. Coase's examination of the provision of light houses in Britian found that "contrary to the belief of many economists, a lighthouse service can be provided by private enterprise... The lighthouses were built, operated, financed and owned by private individuals, who could sell a lighthouse or dispose of it by bequest. The role of the government was limited to the establishment and enforcement of property rights in the lighthouse." (Coase, Ronald. 1974. "The Lighthouse in Economics." Journal of Law and Economics 17 (October): 357-76. [Reprinted 1990 in The Firm, the Market and the Law, Chicago: University of Chicago Press]).

[89] Externalities occur where the actions of one individual or firm affect others, but the effect is not captured by prices in the market. These effects can be either positive or negative. For example, an enterprise which discharges pollutants into a river may impose a cost on other users of the river, but this cost is not reflected in the firm's cost of production. An example of a positive externality is where there may be social benefits from conserving a natural habitat, such as a wetland, but this is not taken into account in the private decisions of owners of this resource.

Where there are such externalities, the resource allocation provided by the market may not be efficient. As individuals do not bear the full cost of the negative externalities they generate, they will undertake an excessive amount of such activities (from a social point of view). Conversely, where individuals do not capture the full benefit of activities that generate positive externalities, they will engage in too little of these.

[90] Where private markets fail to provide a good or service, even though the cost of providing it is less than what individuals are willing to pay, there is a market failure due to incomplete markets. Insurance markets have often been cited as an example of an incomplete market. The planning and coordination role of government in urban development provides another example of where markets alone may not generate a socially optimal outcome. Generally a full set of markets over time and state of nature is needed to ensure economic efficiency.

[91] An efficient competitive market assumes that all participants are well informed. However, in reality this is frequently not the case, as consumers do not always have full information regarding the products/services they may purchase. Government responses to this type of market failure include mandating disclosure of certain information, such as through labelling or setting minimum quality standards. Public disclosure of reference tariffs in regulated monopoly infrastructure industries is another example of where, in the absence of mandated information disclosure, consumers may not have sufficient information to make a decision that is in their best interests.

Other than to achieve social equity goals through income redistribution, a government policy response is typically justified on the grounds that it will correct for a particular market failure, provided the social benefits of correction exceed the social costs of intervention and does not have unintended consequences.

However, a policy response to a market failure does not necessarily lead to an improvement in societal welfare. There are also costs associated with government intervention, including administrative costs and the risk of regulation being inappropriately applied. This may occur because of poorly specified or designed programs or policies. For example, third party access regulation is intended to counteract the efficiency losses arising from monopoly pricing of infrastructure but care needs to be taken in its design and implementation to ensure it is effective and does not have adverse unintended consequences (such as delaying or distorting incentives to invest in infrastructure).

Any assessment of whether a policy response is justified will need to consider the existence and extent of any market failures, and whether a policy response is justified. Even where regulation will have benefits, it will only be warranted when the benefits of regulation exceed the costs.

8.3.2 Risk of market failure

There is clear evidence that the WA gas commodity[92] market suffers from significant market failure, arising from a number of its structural features:

- the WA gas market is a distinct market in that there are insufficient substitute sources of supply of alternative fuels;
- in the absence of reasonable substitutes, upstream supply is highly concentrated, with nearly 100% of supply deriving from two marketers, one of which is a joint marketing arrangement of NWS producers;
- the downstream market is also somewhat concentrated comprising a few large buyers. With the exception of gas for domestic and small business consumption, growth in demand (and associated infrastructure) tends to be large and infrequent. However, this concentration does not offset the market power of the upstream suppliers because buyers lack alternatives to gas. In contrast, producers have profitable alternatives, namely LNG sales. Accordingly, buyers do not have monopsony power sufficient to compel producers to sell gas at a competitive price;
- transactions between buyers and sellers tend to be bespoke and long-term. This is necessary because there is no liquidity in the contract market, and accordingly, no ability for buyers and sellers to manage their risks outside of the bilateral contracts; and
- there are no secondary markets, spot markets, intermediaries (market makers and brokers) operating in the market to increase liquidity.
  This results in an additional problem related to information dissemination that is important in the timely matching of supply and demand. These mechanisms are not likely to develop

[92] The discussion not address the question of regulating the gas transmission and distribution networks, although clearly they are monopolies and capable of misusing their market power in the absence of effective regulation.

given current modes of transacting gas. And it is doubtful whether artificially creating these would deliver substantial benefits.[93]

The extent of harm that arises from these market failures is difficult to assess, since it is difficult to determine what a notional workably competitive WA gas market might look like. However, there is clearly concern over the availability of gas for domestic use even at prices equivalent to the LNG net back price or higher, despite the fact that there are large reserves, and this tends to suggest that the costs of market failure are significant.

As noted in Section 1, recent tenders for new gas have failed to elicit competitive offers for new gas supply. In 2006 a project to increase the capacity of the DBNGP had to be reduced from approximately 300 TJ/d to less than 100 TJ/d substantially because prospective shippers were unable to secure gas supply. The recent tender for a 400 MW base load power station is understood not to have attracted one gas-fired proposal, notwithstanding the fact that at the previous tender a gas-fired proposal was successful and significantly below the cost of coal generation.

Of the foregoing, the most important contributor to market failure in WA is upstream concentration. This could manifest itself in three ways:

- monopolisation of the WA gas market by restricting the availability of gas to the domestic market — i.e. the type of anti-competitive behaviour described earlier over which the ACCC has expressed some concern;
- increase the barrier for new entrants as smaller suppliers perceive that the market is already captive;
- limit the scope for contract and secondary markets to develop because the joint marketing arrangements lead to a lack of diversity of risk preferences across upstream suppliers.

The latter point requires some elaboration. Diversity of risk preferences in upstream suppliers is fundamental to the operation of competitive commodity markets. That diversity gives rise to producers offering a range of different contract prices and terms. In turn, that range of contracts allows downstream consumers a greater selection of contract offerings.

Furthermore, this diversity then tends to foster the development of associated trading forums and mechanisms (spot markets and the like) which further increase the diversity of offerings. All of these mechanisms allow buyers and sellers to manage their risks at least cost. Furthermore, given the distinct nature of the LNG and domestic gas markets, there is no reason why the former cannot be supported through

93 Generally speaking, efforts to establish these types of trading systems will only be beneficial if the underlying structural features of the market mean that buyers and sellers have incentives to use them. In WA as it currently stands, this is unlikely. Accordingly, the presence of these types of arrangements will have little impact on the competitiveness of the market if the underlying structure of supply does not support competition. In addition secondary markets need to have considerable depth with frequent trading opportunities and this is considered unlikely for the WA domestic gas market in the foreseeable future.

joint marketing arrangements, which arrangements are not allowed to operate in the WA gas market.

Finally, it is possible that the current problems in the WA gas market are simply a temporary mismatch between supply and demand. However, while demand for gas for generation may have risen more quickly than participants had expected, the growth in the overall domestic gas market has showed steady growth for many years. This leads one to ask why the imbalance has arisen given that there is no obvious shortage of potential upstream supply, why there is no evidence of new domestic gas projects in the feasibility or development phase, and why the consumers are maintaining that they are unable to even engage with producers over new gas supplies. It is reasonable to infer that some market failure must have contributed to this state of affairs (as it suggests that the concentration has contributed to a situation where what would normally be mutually beneficial trades are simply not being made).

It is considered that the key issue is the extent of upstream concentration with only two entities controlling nearly all existing developed gas reserves and with only limited likelihood of a significant new entrant entering the domestic gas supply market. This high degree of concentration is also likely to contribute to the lack of liquidity in the [forward] markets which means that there is no effective signal to indicate the expectation of buyers that future demand (and hence prices) will increase.

It seems clear, then, that there is a compelling case for alleviating the market failure in WA gas, and one way to do this could be by modifying the operation of the joint marketing arrangements.

8.3.3 No regrets interventions

The NWS gas project is well established in terms of supply to the WA domestic gas market, but it also serves the LNG market. The case for joint marketing arrangements is more compelling from the perspective of the international LNG market than it is from the domestic perspective.

In addition, in developing policy responses, it is important not to harm the prospects of meeting LNG demand in the process of improving the WA gas market, given the disparity in relative size and value of the two different markets.

This highlights the importance of framing policy as ‘no regrets’ or ‘first, do no harm’ or ‘limit interventions to those that cause least harm’.

9 POLICY OPTIONS

Seven principal policy options have been suggested in response to the presence of, or potential for, market failure in the WA gas market. These are:

- removing anti-competitive joint selling arrangements such as the domestic market joint selling arrangements in WA. To be effective this needs to also ensure that the supply of gas to domestic markets is not disadvantaged relative to LNG;
- addressing possible impediments associated with the current nature of Retention Lease arrangements. Retention Leases are a policy response to the public good nature of exploration which aims to enable a firm to capture the benefits of exploration activity. However, they come at an economic cost in terms of tying up reserves that might otherwise be developed. Rebalancing these conflicting aims may involve an enhanced role for information disclosure about exploration activities and a strengthening of the commerciality test used in assessing whether to allow a retention lease to be extended;
- requiring producers to reserve a given proportion of gas for sale to the domestic market. However, it is not enough to have simply more supply: preferably that supply should be offered independently by different suppliers if a meaningful reduction in supply concentration is to be achieved with the associated potential for greater competition in supply. An alternative, possibly superior option, would be to limit the proportion of gas that could be offered in the WA domestic market under joint marketing arrangements;
- providing enhanced access to upstream gas gathering and processing facilities. Facilitating independent third party ownership of upstream infrastructure servicing the domestic gas market may enhance the commerciality of domestic gas supply;
- aggregation of demand. This offers the potential to enhance the countervailing negotiating power of major consumers. However, the countervailing power of large customers is limited due to the lack of alternative economic energy sources;
- revising taxation/royalty arrangements applicable to domestic gas supply projects. However, it is not clear whether this would be a cost effective means of improving the market;
- providing enhanced incentives for exploration – specifically aimed at resources more suited to domestic gas supply. It is important to ensure that the regulatory framework supports willing explorers/producers to access prospective ground through ensuring that retention leases are only granted where absolutely justified and ensuring maximum exploration information transparency.

This section briefly outlines possible arguments applicable to the main policy options that have been advanced to date to address perceptions of market failure.

9.1 JOINT SELLING ARRANGEMENTS

The existing joint selling arrangements as they apply to the marketing of domestic gas are likely to be the single largest contributing factor to market failure in the WA domestic gas market due to the upstream concentration associated with the current arrangements. This in turn significantly decreases supply competition and is likely to result in a lack of diversity of risk preferences across upstream suppliers potentially leading to circumstances where the competitive supply of domestic gas is compromised.

The approval process for joint selling arrangements under the TPA provides a mechanism for an interested party to challenge the continued approval of such arrangements. It is questionable whether the existing joint selling arrangements applying to the sale of domestic gas in WA can be justified in a public policy context and it is recommended that a review of the approval should be sought.

However, to be effective this must be associated with mechanisms ensuring that the supply of gas to domestic markets is not disadvantaged relative to LNG sales as discussed above.

9.2 RETENTION LEASES

As noted in Attachment A, some 53% of current WA gas reserves are held under Retention Leases.

Exploration Permits (which entitle a company to explore for oil or gas in a particular area) may, on discovery of oil or gas, be converted to a production licence. Where the discovered oil or gas is presently uneconomic to develop, a Retention Lease may be appropriate, provided the resource is expected to become economic within a fifteen year period.

Retention Leases and Production Licences are a policy response to the public good nature of exploration. Unless a company can capture the benefits of a discovery, it will face little incentive to undertake exploration investment. This is similar to the economic problem with some forms of research. Without a mechanism, such as a property right, to 'internalise' the benefits associated with exploration or research, a socially sub-optimal amount of this activity will be undertaken.

Retention Leases also impose some economic costs in terms of tying up gas fields in leases held by particular companies when other companies may in fact be willing and capable of undertaking their commercial development. Although the lessee is obliged to undertake periodic studies on the commercial viability of the discovery, this process is likely to be imperfect and, consequently, may not result in all economically viable gas sources being developed. This reasoning implies that potential sources of gas for domestic supply are not being developed which, in the absence of the Retention Lease (or greater scrutiny of the allowance of retention leases), may in fact become commercially viable operations.

There is most likely to be a trade-off between retaining an incentive to invest in gas exploration and the cost of commercial opportunities foregone where potential gas supply projects do not proceed due to the Retention Leases.

Another option may be an enhanced role for information provision to facilitate the efficient operation of the market. Mandated disclosure of more detailed information relating to gas discoveries will facilitate the alignment of commercial opportunities for project development with firms willing to undertake such development; and should not negatively impact on exploration incentives as it does not alter the property rights enjoyed by the exploration company.

An associated option would be to strengthen the commerciality test[94] used in assessing whether to allow or extend a Retention Lease so as to encourage firms to provide evidence that they have approached potential purchasers to establish whether commercial impediments can be overcome.[95]

When coupled with enhanced information disclosure, this offers the potential to ensure that previously non-commercial reserves are brought into production at the earliest opportunity. An example of how this might work would be where a potential major domestic gas user is able to indicate interest in gas supplies across a certain price range which would suggest the reserves are commercially viable. Alternative producers could also flag their interest in developing the reserves given the prospective demand and the information on the nature of the reserves.

Allowance for immediate review of selected Retention Leases would maximise the effectiveness of this policy option. Leases for review could be selected on the basis of likely suitability for provision of gas to the domestic market.

9.3 RESERVATIONS

The WA state government policy on gas reservations is designed to act as a ‘safety net’, by providing long-term certainty for domestic consumers that if no new domestic supplies of gas become available, reserves can’t be consumed in export production to the exclusion of domestic gas supply.

[94] As noted in Attachment A Section 3.2, the assessment of the commerciality of off-shore gas projects is likely to be complex due to the uncertainties over technical issues as well marketing issues. However, the key issue with respect to commerciality is likely to be whether a market for sufficient gas exists at a price high enough to ensure the hurdle rate of return is achieved.

[95] It should be noted that the responsible jurisdiction for the reassessment of retention leases will vary depending on the location of the lease (that is, whether it is in Commonwealth controlled waters or State controlled waters). However, this does not alter the nature of the argument with respect to scrutiny of retention leases at time of granting and renewal.

An alternative option (or variation) which will have the added effect of delivering greater diversity in supply options would be to limit the total share of gas that could be offered under joint marketing arrangements to X% with remaining gas (1-X%) required to be offered to the domestic gas market outside any joint marketing arrangements. Under such an arrangement, where the WA Government reserves 15% of gas for domestic use, that gas could be required to be supplied outside of any joint marketing arrangements.

In addition, it is important that the structure of any production agreement between the parties is not overly restrictive (that is, does not serve to effectively preferentially favour diversion to LNG).

To achieve a policy goal of enhancing local energy security, reservations can clearly play a useful part in ensuring downstream gas supplies for the domestic market. The effectiveness of the policy might be further enhanced by structuring it in a way that fosters some upstream diversity and a willingness to trade gas into the WA gas market. Hence, for example, JV partners might be precluded from selling more than 85% of their production entitlements through the JV. They might be required to offer the remaining 15% into the WA gas market (and in the absence of buyers, default to the JV arrangement). Supply being offered independently by different suppliers will have the effect of producing a meaningful reduction in supply concentration with the associated potential for greater competition in supply.

This option is not a no regrets response (because it may harm the JV profits) but in reality is unlikely to substantially undermine the profitability of the JV (85% can still be jointly sold as LNG or potentially into the domestic market if that is the most attractive option) while definitely improving WA gas supply and marketing conditions.

9.4 ACCESS TO UPSTREAM INFRASTRUCTURE AND GAS QUALITY

The costs of building pipeline and other gas processing infrastructure necessary to ensure sales quality gas is delivered from offshore fields to the mainland for domestic supply can be a significant impediment to the timely development of new gas fields. While this is not necessarily a market failure, it raises the question of whether other ways of providing necessary infrastructure, or gaining access to existing infrastructure, might be appropriate.

For example, the establishment of offshore gas gathering and processing facilities as common user infrastructure may be one means of reducing delivered gas costs, ensuring connection to onshore transmission infrastructure such as the DBNGP is economic. The ability for third parties to have an absolute right of access to upstream facilities, although presently not allowed under the Trade Practices Act, would possibly be another avenue for opening up upstream infrastructure for the potential supply of domestic gas.

One mechanism for delivering such an outcome would be through encouraging exploration and development companies to focus purely on exploration and extraction and to allow specialised infrastructure companies (such as gas pipeline companies that are not vertically integrated into gas sales), to take on ownership and operation of offshore gas gathering and processing facilities, especially those servicing domestic markets.

The range of gas quality allowed to enter pipelines has been cited as an impediment to gas supplies being made available domestically. Gas quality can be dealt with in two ways. At the supply end, gas can be treated to ensure that it meets the specification for the gas transmission system (prior to transmission) usually through carbon dioxide and nitrogen removal or enhanced heating value through the addition of LPG. This has an associated cost. Alternatively, gas transmission systems can be built to cater for different gas quality, this too has an associated cost and in the case of regulated pipelines has an associated regulatory risk. Resolution of these issues is primarily a commercial matter to be negotiated between producers, consumers and pipeline operators. Ultimately a cost-benefit analysis should be undertaken to determine the most economically efficient way to allow changes in gas quality to be managed.

9.5 AGGREGATION OF SMALL USERS

In theory the problems arising from a small number of gas producers with a commercial preference for very large, long term supply contracts can potentially be mitigated to some degree by the operations of aggregators such as Alinta. This was recognised by the ACCC in its authorisation of joint marketing arrangements when it noted that the further development of brokers and aggregators in the gas industry would, among other things, assist in making separate marketing viable. Aggregation allows for a number of smaller loads to be combined to make a more commercially attractive offer.

However, given the scale of production required to underwrite new gas field developments aggregation of smaller loads in their own right may not be sufficient without aggregation with some of the larger customer loads also. Also, the structure of the WA domestic market probably means that any countervailing power by large customers is limited since they do not have a meaningful alternative. Accordingly, aggregation is unlikely to significantly reduce the adverse consequences of market failure.

9.6 TAXATION/ROYALTY TREATMENT

The possibility of altering the level of government imposts applying to gas projects directed at domestic gas markets has been raised. This might take the form of some generic rebate proportional to domestic gas supply or could be targeted at development of fields considered more suitable for domestic supply (for example, onshore gas fields).[96]

However, it is not clear whether this would actually be a cost effective means of improving the market and may in fact simply entrench an (expensive) distortion within the market. Moreover, to the extent that a market failure exists (as we believe is likely to be the case), a measure such as this does not directly address the cause of that failure and as a result is less likely to be as effective as other measures and more likely to introduce unintended consequences.

9.7 INCENTIVES FOR EXPLORATION

Direct investment by government in exploration is unlikely to be efficient or effective and is not considered to be an appropriate role for government in the context of the market failures being considered here. Petroleum and natural gas exploration is a high risk commercial business. While it is almost certain that spending more on exploration will deliver greater gas discoveries, marginal exploration expenditure is likely to be less productive as it will be applied to less prospective areas or less commercial areas. In addition government would not have the appropriate incentives or experience to be involved in direct investment in gas exploration.

The result is at best simply likely to be growth in non-commercial reserves held under Retention Lease. At issue is whether the regulatory framework is suitable in terms of willing explorers/producers being able to access prospective ground for example through ensuring Retention Leases are only granted where absolutely justified.

Similarly, there may be a role for government in ensuring maximum transparency in the availability of information on gas prospectivity within WA noting that there is currently no mechanism to require exploration companies to disclose underlying data with respect to relinquished exploration blocks.

[96] It is considered that any form of subsidy to domestic gas would be inappropriate and economically irresponsible as it would be likely to result in significant adverse economic efficiency impacts.

10 CONCLUSION – BENEFIT OF ACTION

The presence of market failure in one form or another often leads to the conclusion that a government policy response is desirable to correct the failure, thereby resulting in greater economic efficiency. However, policy responses to market failures can also be costly, particularly where regulation is misapplied or when it is poorly designed.

Applying some form of regulation or policy response to a perceived market failure where, in fact no such failure exists, can result in regulation where it is not appropriate. In these circumstances, the cost of regulation will exceed the benefits. Even in the presence of market failure, regulation can impose net social costs, for example if the efficiency consequences of market failure are small, or if regulation is poorly conducted.

The converse problem also arises: not intervening where there are socially costly market failures will potentially result in economic costs. For example, there would be the economic cost to society from failing to regulate monopoly pricing of infrastructure assets such as gas or electricity transmission networks.

The WA economy relies heavily on efficiently priced energy resources, and the balance of the evidence points to a market failure in the provision of domestic gas as evidenced by the lack of gas supply offers to domestic users at virtually any price.

There is therefore a need for urgent intervention to ensure a continued supply of competitively priced gas to domestic users. Such intervention should aim to avoid being excessively costly, and should be the minimum necessary to correct the failure.

While the relative costs and benefits of possible interventions to secure long term domestic gas supplies are hard to estimate precisely, there is an economic case for 'no regrets' or near 'no regrets' interventions that are likely to result in efficiency improvements in the domestic market. The most fruitful targets for such intervention are fundamental changes to joint marketing arrangements and to the evaluation of retention leases.

A OUTLINE OF REGULATORY/ LICENSING

Regulatory and licensing issues have the potential to either encourage or hinder petroleum exploration and development activities. This section outlines the key characteristics of the regulatory and licensing regime in Western Australia and associated offshore waters.

A.1 STATE/COMMONWEALTH INTERACTION

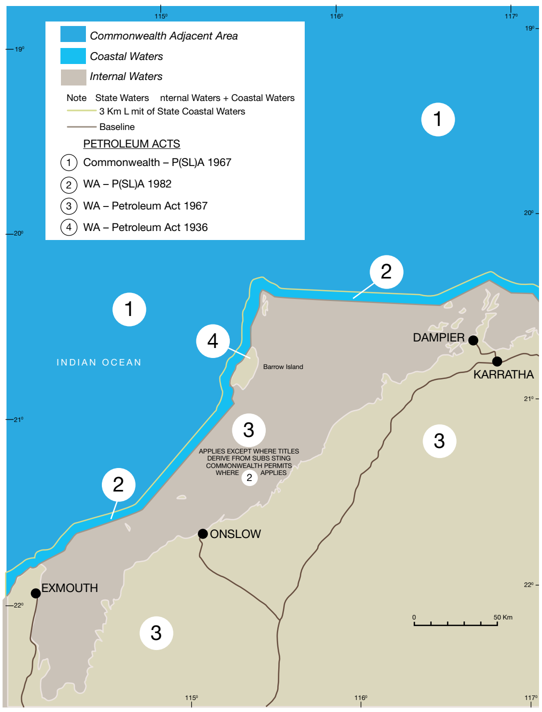
Oil and gas resources may be governed by either Commonwealth or State legislation, depending on the location of the resource. In Western Australia, onshore activities are governed by state legislation.[97] Offshore resources may be under State or Commonwealth legislative regimes, depending on the location of the resource with respect to the territorial sea baseline (TSB). Under the Offshore Constitutional Settlement, Western Australia has jurisdiction over the first 3 nautical miles (nm) seaward of the TSB. Where straight baselines are drawn, as in the North West Shelf region of WA, this extends the jurisdiction of the state substantially further than 3nm from the coastline. Areas beyond the 3nm limit within Australia's jurisdiction (as determined by international treaties) are within Commonwealth jurisdiction. In relation to oil and gas reserves, an attempt has been made to develop a uniform regulatory approach whether the resource is located within Commonwealth or State jurisdiction by virtue of the *Petroleum (Submerged Lands) Act 1982* (WA) *Schedule Specific Requirements as to Offshore Petroleum Exploration and Production* 1995.[98]

The importance of Commonwealth and State jurisdictional issues must be understood against the background of the WA Government Policy on Securing Domestic Gas Supplies. This document outlines that the State intends to:

> …secure domestic gas commitments up to the equivalent of 15 percent of LNG production from each export gas project.[99]

Particularly important is the basis upon which the WA Government may enforce its policy.

Figure 16 Example of Commonwealth – State Jurisdiction



Data source: DOIR

[97] The *Petroleum Act 1967* (WA), *Petroleum Act 1967* (WA) Schedule of Onshore Petroleum Exploration and Production Requirements 1991 (WA) and the *Petroleum Pipelines Act 1969* (WA).

[98] DOIR, http://www.doir.wa.gov.au/environment/D284DE0313FE4072AB76BACF0365F56C.asp.

[99] WA Government Policy on Securing Domestic Gas Supplies, October 2006, see Key Points section.

[100] WA Government Policy on Securing Domestic Gas Supplies, October 2006, see Key Points section.

The policy states:[100]

> In order to provide continued certainty that Western Australian consumers will have ongoing access to supplies of natural gas, the WA Government will negotiate with proponents of export gas (LNG) projects to include a domestic gas supply commitment as a condition of access to Western Australian land for the location of processing facilities.

Current technology allows oil to be recovered and transported directly from offshore waters but virtually all gas projects worldwide involve processing on land. A floating LNG plant has been under consideration in Nigeria for at least five years but development appears to have stalled.

Large gas projects classified as having potential for development or held under retention leases are almost all located within Commonwealth jurisdiction. These large gas projects have reserves capable of supplying significant amounts of domestic gas, but the operation of the WA government's 15% reservation policy is contingent on these projects having onshore processing facilities. The WA government has exhibited a willingness to implement legislation enforcing the 15% reservation policy where operators of gas fields have been reticent in agreeing to the policy requirements.

Jurisdictional issues, should offshore processing of LNG be realised, may prevent even a legislative approach being effective. The current enforceability of the 15% domestic gas policy seems to be due to the location of processing facilities either onshore, or within WA territorial waters.[101] Offshore processing facilities in Commonwealth jurisdiction may allow a project to be developed without having to observe the 15% reservation policy.

The reservation policy's effectiveness is contingent on the continued status of floating LNG processing as uneconomic. In the medium term it is likely that offshore LNG processing technology will not be developed, and therefore the reservation policy will continue to be an effective means of securing WA's gas requirements.

The reservation policy may also have the unintended effect of shifting the balance of investment towards offshore (the reservation policy is rendered irrelevant by processing facilities being located entirely outside WA jurisdiction) and away from onshore processing, because the latter are not encumbered with reservations that likely have the effect of lowering financial returns.[102] To the extent that capital is the constraint on total development this may drive earlier development of offshore processing technology in Australia. An offshore processing facility would allow all gas produced to be sold on the world LNG market without the project having to meet domestic gas policy reservations, either from reserves within the LNG field or development of a smaller field with which to satisfy its domestic gas requirements.

The additional value to the firm of offshore processing relative to onshore processing under the reservations policy environment

[101] Refer to the quote from the Policy document above.

[102] If suppliers could earn higher risk adjusted returns from domestic gas, reservations would not be required.

would be the difference between the profits accruing from supplying 15% of the field as domestic gas and profits realised by sale of international LNG, which currently trades at a higher price than the domestic gas market.

A.2 ROYALTY ARRANGEMENTS

In WA, all minerals in their natural form are owned by the State unless the land on which the minerals are found was granted freehold title before January 1899. Royalties paid by a resource developer are effectively the purchase price of the resource.[103] In 2005 mineral and petroleum royalties collected by the state amounted to $1.513 billion, an increase of $372 million from 2004. Major contributors to Royalties received by the WA Government in 2005 (those contributing more than $10 million) were:[104]

– Alumina	$57m
– Copper	$11m
– Coal	$15m
– Diamonds	$50m
– Gold	$74m
– Zircon	$15m
– Iron Ore	$535m
– Nickel	$88m
– Condensate	$150m
– LNG	$228m
– LPG – Butane	$16m
– LPG – Propane	$13m
– Natural Gas	$42m
– Crude Oil	$176m

The main commodities by royalty share are Petroleum (41%), Iron Ore (35%), Nickel (6%), Gold (5%), Alumina (4%) and Diamonds (3%)[105].

In respect of sub-seas resources, inshore royalties are collected solely for the WA Government, while offshore royalties are collected in accordance with legislation enacting the agreements made under the Offshore Constitutional Settlement. Barrow Island royalties are also shared between the Commonwealth and the State.[106]

Mineral Royalties

Mineral royalties are payable under either the *Mining Regulations 1981* (WA) or State Agreement Acts.[107]

There are 3 systems of mineral royalty collection used:

- Specific rate[108]

  Specific rate royalties are generally only used for low value construction minerals. The rate is based on tonnes produced.

  Rates per tonne are now indexed to the ABS Non-Metallic Mineral Products Price Index.

- Ad Valorem[109]

  An ad valorem royalty is calculated as a proportion of the royalty value, which comprises the gross invoice value of the mineral minus any permissible deductions.

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103 DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/936F48C0800744BFA92040ECE9085832.asp.

104 DOIR, http://www.doir.wa.gov.au/documents/mineralsandpetroleum/StatsDigest/royalties05.xls.

105 DOIR, http://www.doir.wa.gov.au/documents/mineralsandpetroleum/StatsDigest/royalties05.xls.

106 DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/69AEF0AB0263463295F7BB9A95F0F3AB.asp.

107 DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/0A3F7FC391AA4CC08487D56234500D7C.asp.

108 DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/E16218E473524201B51E183A5F373BEE.asp.

109 DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/C6127BDB955E4962B29FF40208ADC408.asp.

Table 8 Ad Valorem Royalty Rates

Type of material	Rate of Royalty as a percentage of Royalty Value
Bulk Material	7.5%
Concentrate Material	5.0%
Metal	2.5%

Source: http://www.doir.wa.gov.au/mineralsandpetroleum/C6127BDB955E4962B29FF40208ADC408.asp.

- Profit Based[110]

  Royalties are calculated by obtaining project revenues and deducting allowable amounts to ascertain mine profit. The profit based approach attempts to deliver a return of 22.5% over the life of the project while ensuring a minimum ad valorem payment of 7.5% per year.

Mineral royalties are specified in detail in the *Mining Regulations 1981* (WA) Part V, Div 5, Regs 86 and 86AA.

Petroleum Royalties

Three systems are used for collection of petroleum royalties:

- Well-head royalty

  The well-head royalty is calculated by taking the gross value of petroleum recovered and making allowable deductions up to the deduction limits of 50% of gross value for oil projects and 90% of gross value for gas projects. The allowable deductions are: post well-head operating costs; depreciation on commissioned post well-head assets; cost of borrowing on commissioned post well-head assets.[111] A permittee must nominate a block for the purposes of declaring a location once it is established that a commercial discovery has been made. The permittee then has 2 years to apply for a primary production licence. The number of blocks that may be included in a primary licence is limited. The permittee may apply for less production licences than the limit and subsequently add blocks to their primary entitlement over the two year period. Alternately, if the permittee applies for a production licence of the maximum number of blocks they may make one application within the 2 year period for some or all of the remaining blocks in the location. The subsequent production licences for additional blocks are secondary licences.[112]

  For primary licences, a royalty rate of 10% generally applies, while for secondary licences a royalty rate of 12.5% will generally be applied. Upon invoking a secondary licence, the 12.5% rate applies to both the primary and secondary licences.[113]

- Resource rent royalty

  Resource rent royalty is charged at a rate of 40% of income over a threshold rate. Allowable expenditure is deducted and any excess of costs over revenue is carried forward at the threshold rate. The Commonwealth receives 75% of the royalty payments compared to the State's 25% but the State remains responsible for all administration. The resource rent royalty is applied before income tax and is deductible for income tax purposes.[114]

[110] DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/95F1DB34DDD744E9A258757557B5792C.asp.

[111] DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/6B7F91DC544B486EA4B89BBA4E8CE74F.asp.

[112] DOIR, http://www.doir.wa.gov.au/documents/mineralsandpetroleum/pag53.pdf.

[113] DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/5DBE888D49FC481F98FC1D34C9519E5F.asp.

[114] DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/ED7D42F2C3E345508A44CC10547708B2.asp.

- Petroleum Resource Rent Tax

  The Petroleum Resource Rent Tax (PRRT) is a Commonwealth tax on petroleum production levied according to project cash flows. The PRRT is not the same thing as the resource rent royalty. Royalties are not applicable to fields paying the petroleum resource rent tax. The tax is deductible for income tax purposes.[115]

A.3 LICENSING AND REGULATION

A.3.1 Exploration rights

The right to explore for petroleum across all legal jurisdictions in Western Australia is on the basis of a competitive work program bid. Areas available for exploration are released by the government under a tender process in which exploration companies are asked to bid a program of work. Such work can include research programs, seismic and other surveys and drilling activities. Exploration titles are awarded to the company which proposes the most comprehensive work program and is both financially and technically able to undertake the work.

Titles can generally be renewed after six years, provided the company has met their work program obligations but the area that can be held is reduced at each renewal.

A.3.2 Retention Leases

Having discovered oil or gas, a company has the right to convert the exploration licence to a production licence subject to defined conditions. This can be a Production Title or, where the resource is presently uneconomic but is expected to become economic within a fifteen year period, a Retention Lease.

Retention Leases are granted over the blocks comprising a discovery which, generally, is a substantially smaller area than the Exploration License. Depending on the circumstances further exploration work may be undertaken. The lessee is obliged to undertake re-evaluation studies on the commercial viability of the discovery to retain it. Renewals occur every five years.

The aim of the Retention Lease is to reduce exploration risk by providing an option on currently uneconomic resources, thereby encouraging more exploration. It does this by allowing the explorer to defer production for a period of time, subject to appropriate safeguards requiring them to continually re-assess the factors that are inhibiting the development.

A company has two years from the date of discovery to apply for a Retention Lease with the first retention lease expiring after five years. The company is required to set out their case for such a lease and to address the steps that will be taken to overcome any commercial impediments.

There do not appear to be any examples in Western Australia of Retention Leases that have not been approved or Leases that have been cancelled.

Gas projects pose particular problems in the evaluation of Retention Lease applications. Offshore projects generally require substantial investment in processing infrastructure and pipelines

[115] DOIR, http://www.doir.wa.gov.au/mineralsandpetroleum/EED6F2644F0F4FBDB7D50013F2C2B8A5.asp.

to shore. The large investment is likely to necessitate either long term gas sale contracts or third party access to the infrastructure of any nearby gas projects and pipelines. While there appears to be a reported increase in trading of LNG (Section 7.3), industry participants such as Woodside still suggest that the traditional approach of long term partnerships and long term take or pay contracts for large LNG volumes are likely to remain dominant in underpinning new developments.[116]

That is, these large investments will only take place if the investment environment is appropriate. For example, if there are stable, reliable and liquid commodity markets, and if the producer can secure access to these markets, then this may be a sufficient basis for investment. However, in the absence of these — for example, if there is no reliable third party access to gas pipelines or if access requires negotiation with competitors, or if there are no liquid spot and contract markets — then investors will need alternative mechanisms for managing their investment, namely secure long-term contracts.

In this context, contract and infrastructure access markets in WA are best described as rudimentary, and are not likely to provide sufficient investor confidence to underpin major investment in the absence of tailored long-term contracts.

In terms of access to infrastructure such as gas gathering systems and domestic gas processing facilities, it is notable that there are only two large gas producers in Western Australia, so there is a high probability that necessary infrastructure will belong to a close competitor. Further, there is no offshore infrastructure that is owned by companies who are not in the gas production business.

The only realistic source of long term contracts in WA that could support investment are new power stations, large mineral processing projects, or the renewal of aggregator supply contracts. These contracts are few in number, and individually small in comparison with the typical LNG contract.

A.3.3 Production Leases

Production Licences are granted over the blocks comprising a commercial discovery and usually emanate from an Exploration Permit. They are often issued for 21 year terms with a right of renewal. The Production Licence is subject to conditions imposed on the title covering issues such as health and safety, the management of extraction and operational practices, environmental management and the payment of royalties.

If petroleum is not being recovered in a production licence area and the government believes that petroleum exists there, it may direct the licensee to take all necessary and practical steps to recover the petroleum. The government may also direct the licensee to take all necessary and practical steps to increase or decrease the rate of recovery. In determining whether to give such a direction, the regulator may take into account the effects on government revenue of the proposed direction but such directions can not run counter to good oilfield management practices.

[116] The Australian 19 February 2007.

Generally, pipeline licenses are also required to operate an oil or gas project. For gas projects, these will generally include components located within 3 nautical miles of the TSB providing the State with an opportunity to influence development.

A.4 ROLE OF JOINT MARKETING ARRANGEMENTS

The role of joint marketing arrangements can be seen against the background set out above. At one level, such agreements support capital provision from firms that otherwise compete, which may be important in securing sufficient investment for very large projects. They may also ensure the best mix of skills are brought to bear. But more importantly, they help limit intense competition that might arise between several firms exploiting the same resource, expectations of which would, *ex ante*, prevent the resource from being developed.

A.4.1 Australia

Joint marketing arrangements have been approved for use in Australia by the ACCC in a number of areas. In providing these approvals, the ACCC has expressed concern over indefinitely authorising joint marketing, preferring to authorise joint marketing for a fixed period of time. In time limiting these arrangements, the ACCC has sought to minimise the detrimental effect joint marketing may have on the development of the gas industry,[117] but allow sufficient time for the development of uneconomic fields that might not be viable if there were *ex ante* expectations of immediate vigorous competition. Examples of ACCC approved joint marketing arrangements are provided below.

Otway Basin LPG

Separate marketing exists in the Otway basin in Australia.[118] Woodside and Origin are the major gas companies involved in the project. Two small companies Benaris and CalEnergy are also involved. While natural gas is separately marketed, Woodside, Benaris and CalEnergy jointly market the LPG produced while Origin markets its LPG separately.

The Otway Project is an unincorporated joint venture by the four companies to develop the Thylacine and Geographe fields. The interests of the companies are shown in the following table.

Table 9 Joint Venture Interests – Otway Gas Project

Joint Venture Partner	Interest
Woodside	51.55%
Origin	30.75%
Benaris	12.70%
CalEnergy	5.00%

Source: ACCC, Draft Determination Application for Authorisation lodged by Woodside Energy Ltd, Benaris International Pty Ltd and CalEnergy Gas (Australia) Ltd, 15 February 2006.

[117] ACCC, North West Shelf Project Determination, 29 July 1998, vii.

[118] Anna McKinlay, Separate Marketing of Natural Gas Australian Experience Report to NGC, May 2003, pp18-19.

The ACCC considered that little anti-competitive detriment would result from the joint marketing arrangement because wholesale gas customers would need to negotiate their arrangements with either Woodside or Origin whether or not the authorisation was granted because if the authorisation were not granted Benaris and CalEnergy would simply sell their gas to Woodside or Origin.[119]

It was found that:

> Even if Benaris and CalEnergy were to independently market their LPG absent authorisation, the separate marketing of Origin's LPG and the competitive constraint provided by LPG producers from other gas fields and refineries would limit the anticompetitive detriment generated by the proposed arrangement.[120]

It was decided to authorise the joint marketing for three years.[121]

The following table shows the LPG production from the Otway Gas Project.

Table 10 Otway Gas Project LPG Production

Joint Venture Partner	2006 gas production	Future gas production
Woodside	25.78 kt/yr	56.71 kt/yr
Benaris	6.35 kt/yr	13.97 kt/yr
CalEnergy	2.5 kt/yr	5.5 kt/yr
Joint marketing total production	34.63 kt/yr (69.25% of Otway Gas LPG production)	76.18 kt/yr (69.25% of Otway Gas LPG production)
Origin	15.38 kt/yr (30.75% of Otway Gas LPG production)	33.83 kt/yr (30.75% of Otway Gas LPG production)
Total Production	50.01 kt/yr	110.01 kt/yr

Source: ACCC, Determination Application for Authorisation lodged by Woodside Energy Ltd, Benaris International Pty Ltd and CalEnergy Gas (Australia) Ltd, 29 March 2006, 11.

BassGas Project

The Bass Project is concerned with developing the Yolla gas field in Bass Strait. LPG production is expected to be 55kt in 2006 increasing to 80kt thereafter. The ownership structure is as follows (but soon Calenergy will sell 5% of its entitlement to Origin).

[119] ACCC, Determination Application for Authorisation lodged by Woodside Energy Ltd, Benaris International Pty Ltd and CalEnergy Gas (Australia) Ltd, 29 March 2006, i.

[120] ACCC, Determination Application for Authorisation lodged by Woodside Energy Ltd, Benaris International Pty Ltd and CalEnergy Gas (Australia) Ltd, 29 March 2006, i.

[121] ACCC, Determination Application for Authorisation lodged by Woodside Energy Ltd, Benaris International Pty Ltd and CalEnergy Gas (Australia) Ltd, 29 March 2006, ii.

Table 11 Joint Venture Interests – BassGas Project

Joint Venture Partner	Interest
Origin Energy	37.5%
Origin Energy Northwest Limited	5%
Australian Worldwide Exploration Ltd (AWE)	30%
Calenergy	15%
Wandoo	12.5%

Source: ACCC, Determination Application for Authorisation lodged by Woodside Energy Ltd, Benaris International Pty Ltd and CalEnergy Gas (Australia) Ltd, 29 March 2006, 12.

Elgas, in its submission to the ACCC relating to the Otway Gas Project authorisation stated that it had reached separate contractual arrangements with AWE, Calenergy and Wandoo, three of the joint venture participants.[122]

The marketing arrangements for the gas produced by the BassGas Project are that Origin acquire all natural gas production, Shell acquire all condensates and each joint venture party separately market their LPG.[123]

Cooper Basin

Applications for authorisation by Delhi Petroleum and Santos were withdrawn on 28 February 2006 (Delhi Petroleum) and 1 March 2006 (Santos). These applications had been granted interim authorisation. The gas contracts and sales arrangements to which they applied are no longer in place and for this reason when contacted by the ACCC in November 2005 both Delhi Petroleum and Santos advised that they had no concern with the applications being withdrawn.[124]

A.4.2 Internationally

Denmark

The EU now looks unfavourably upon joint marketing arrangements for gas. A recent example is the DONG/DUC case concerning Danish natural gas. The European Commission's Competition Directorate-General and the Danish Competition Authority acted together to remove anti-competitive arrangements in re-notified agreements concerning the sale of gas by the partners of Dansk Undergrunds Consortium (DUC) and Dong Naturgas A/S (DONG). The actions of the EC and the Danish Competition Authority ended DONG's position as the sole buyer of gas from the North Sea.[125]

The DONG/DUC case did not only concern joint marketing of gas. Other arrangements in place in the Danish natural gas market were that the members of DUC offer all their gas first to DONG. DUC provides 90% of Danish gas production. The members of DUC were Shell (46%), AP Møller (39%) and Chevron Texaco (15%).[126]

DUC had believed that the joint marketing arrangements were exempted under EU Regulation 2658/2000 which allows certain forms of joint distribution. Under the agreement with the regulators, Shell, AP Møller and Chevron Texaco agreed to market their gas separately.[127]

122 Elgas, Submission to ACCC, 10 November 2005, 2.

123 http://www.originenergy.com.au/news/news_detail.php?pageid=82&newsid=711.

124 See Santos and Delhi Petroleum withdrawal letters, available from ACCC website, http://www.accc.gov.au/content/index.phtml/itemId/278015/fromItemId/3879.

125 http://www.ks.dk/english/competition/national/before04/dong-duc/.

126 http://ec.europa.eu/comm/competition/antitrust/cases/index/by_nr_76.html#i38_187.

127 http://ec.europa.eu/comm/competition/antitrust/cases/index/by_nr_76.html#i38_187.

The joint marketing arrangement was considered a horizontal restraint on competition. The choice of customers as to gas supplier is reduced when the joint marketing arrangement occurs. In addition to breaking up the joint marketing arrangements, in this case it was also agreed that a portion of the gas be reserved for supply to new customers to further increase competition.[128]

Norway

The presence of significant amounts of gas in Norway was first realised and extraction commenced in the late 1960s and early 1970s. In 1986 sales agreements were developed for the Troll gas fields in the North Sea with major European energy companies. Following this, Norway established the GFU (Gas Negotiating Committee) to be responsible for marketing and selling all Norwegian gas. No companies could sell their own reserves. The GFU negotiated field independent contracts and the government then decided which field would supply the particular contract in a heavily centralised process.[129]

EU Directive 98/30/EC related to the single gas market, requiring access to gas infrastructure in the gas supply chain.

This led to Norway winding up its 'single desk' marketing and selling arrangements and the GFU was dissolved from 1 January 2002. This allowed companies to sell their own gas.[130]

Under the settlement reached the Norwegian gas producers on the continental shelf agreed to individual marketing and Statoil and Norsk Hydro reserved 15.2 bcm (0.54 Tcf) of gas for new customers over four years.[131]

The arrangements reached by the GFU were criticised by the EC for being restrictive and "led to a significant rigidity and lack of liquidity in the European gas markets."[132] The EC also stated:[133]

> it is of paramount importance that producers sell their gas individually so that those customers that can already choose their supplier benefit from real choice and competitive prices"

Ireland

Enterprise Oil, Statoil and Marathon made an application to jointly market gas produced at the Corrib field for five years. Following discussions between the companies and the European Commission's Competition Directorate-General, the application was withdrawn.[134]

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[128] Philip Lowe, 'Applying EU Competition Law To The Newly Liberalised Energy Markets' 13 May 2003, p5-6.

[129] Morten Pedersen and Havard Nygard, Putting the pipelines in place, Norwegian Continental Shelf, 2005:2, 10 – 14.

[130] Morten Pedersen and Havard Nygard, Putting the pipelines in place, Norwegian Continental Shelf, 2005:2, 10 – 14.

[131] GFU (IP/02/1084 of 17 July 2002) http://europa.eu/rapid/pressReleasesAction.do?reference=MEMO/03/89&format=HTML&aged=0&language=EN&guiLanguage=en.

[132] http://ec.europa.eu/comm/competition/antitrust/cases/index/by_nr_72.html#i36_072.

[133] http://ec.europa.eu/comm/competition/antitrust/cases/index/by_nr_72.html#i36_072.

[134] Corrib (IP/01/578 of 20 April 2001) http://europa.eu/rapid/pressReleasesAction.do?reference=MEMO/03/89&format=HTML&aged=0&language=EN&guiLanguage=en.

The application was lodged because the companies perceived that the purchasing power of Irish energy companies was significant. The EC questioned whether joint marketing actually brings about economic benefits. It also noted that increasing liberalisation would allow greater choice of supplier by those on the demand side. For this reason the application was withdrawn.[135]

United States and North America

For many years, extensive price regulation of the entire gas supply chain in the United States limited the potential role of gas marketing. Under regulation, there was no need for marketing by sellers to buyers because prices were determined by interactions between the firm and the regulator. Therefore, natural gas marketing was not a pressing issue until the gas market was deregulated.

United States gas market deregulation began in the mid 1980s and was firmly entrenched in a number of initiatives by the early 90s. From the mid 1990s the changes that these initiatives wrought on the gas industry were clear and the market had evolved considerably from its previous behaviour when the industry was heavily regulated.[136]

FERC Order 436 in 1985 enabled the unbundling of gas and transportation by allowing consumers to own gas, and make separate arrangements for its transportation by buying pipeline services. In 1989 the Decontrol Act allowed price controls of wellhead sales to be removed. The removal of price controls occurred in January 1993. FERC Order 636 in 1992 furthered the regulatory reform by requiring interstate pipelines to offer transportation services only.[137]

Marketing is now a necessary hallmark of the US gas market. Natural gas in the US is now a heavily traded commodity, and exhibits all the hallmarks of a major market for a commodity. There is a spot and futures market for natural gas trading on the New York Mercantile Exchange. In the US there is physical and financial trading of natural gas. The physical trading is natural gas trading in a more traditional sense where contracts for the sale of gas are negotiated between parties. Financial trading is primarily concerned with risk and price volatility and hedging.[138]

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135 http://europa.eu/rapid/pressReleasesAction.do?reference=IP/01/578&format=HTML&aged=0&language=EN&guiLanguage=en.

136 Paul W. MacAvoy, 'The Natural Gas Market Sixty Yeats of Regulation and Deregulation' 2000, p16-17.

137 Paul W. MacAvoy, 'The Natural Gas Market Sixty Yeats of Regulation and Deregulation' 2000, p16-17.

138 www.naturalgas.org/naturalgas/marketing.asp.

But the most important feature of the North American gas market is the huge diversity of buyers and sellers and the extensive nature of gas transmission infrastructure. In 2005 there were some 68 million natural gas consumers and more than 8,000 producers of natural gas with some 160 pipeline companies operating 285,000 miles of pipelines.[139]

This diversity has led to the development of a liquid and highly competitive trading market, and the proliferation of trading mechanisms noted above is both a consequence and symptom of that diversity.

Marketing of natural gas in the US is undertaken by a range of firms. The Natural Gas Supply Association on naturalgas.org develops five classifications of marketing companies:

- Major nationally integrated marketers;
- Producer marketers;
- Small geographically focused marketers;
- Aggregators; and
- Brokers.[140]

[139] http://www.naturalgas.org/business/industry.asp.

[140] www.naturalgas.org/naturalgas/marketing.asp.

B GAS RESERVES

It is important to determine whether the current paucity of long-term contracts for domestic gas is a result of some form of market or regulatory failure, or whether it results from a more fundamental problem, namely a shortage of upstream supply, and a preference to divert that supply to high value LNG projects. An examination of reserves is helpful in clarifying this question.

In presenting data on reserves, it should be noted that the summary reflects current knowledge. As a general matter, we tend to find that the extent of reserves tends to rise with the level of exploration.[141]

B.1 WESTERN AUSTRALIA

Overall Western Australian gas reserves as at 31 December 2005 have been estimated at 119.1 Tcf (126,300 PJ)[142]. Of this, 2005 annual production was 0.935 Tcf (990 PJ), or less than 0.8% of estimated current reserves. Given forecasts of increasing production, DOIR has estimated that WA has sufficient gas reserves to meet international and domestic demand until 2053.[143] Synergies calculations indicate the WA domestic gas reserves could be exhausted as early as 2027 under worst case scenario analysis, and more feasibly by 2050, disregarding infrastructure constraints that may limit the domestic availability of gas from remote reserves.[144]

Of the five significant gas basins located in WA, the Perth Basin is relatively small, and the Browse and Bonaparte Basins are located in remote regions that make domestic gas supply problematic without investment in major pipeline infrastructure. The onshore Canning Basin is still relatively unexplored, though oil was discovered in the area in the 1980s. The lack of exploration of the Canning Basin, given it is an onshore basin, may reflect the fact that the Canning Basin has relatively low prospectivity.

Over the past thirty-six years only 8% of potential production has been extracted. Though the low utilisation of gas to date suggests there is abundant gas available for future domestic consumption, this oversimplifies the situation as domestic market potential depends on the location of reserves, ownership and future commitments.

At the 50% recovery probability, only around 17% of the overall WA gas endowment relates to developed fields.[145] Table 12 provides a summary of the total WA gas reserves.

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[141] The IEA has reported (International Energy Agency, 'Natural Gas Market Review 2006' 31) that global gas reserves have increased 15% since 2000 indicating ongoing success at expanding reserves.

[142] Energy value estimated based on sales gas, not LNG.

[143] Department of Industry and Resources, 'WA Government Policy on Securing Domestic Gas Supplies Consultation Paper', February 2006, 5.

[144] Gas reserve estimates are calculated based upon probability. A greater probability of successful realisation of a reserve results in a higher probability rating. Common ratings are P90 or 90% and P50 or 50%. A probability rating of 50% indicates 50% certainty that the volume of gas stated (X Tcf) will be recovered. A reserve at a 90% probability rating is consequently different to a reserve at the less certain 50% level. Other factors are also important in the development of a field other than the size of the reserve. These issues include matters like gas quality, location, ownership arrangements, infrastructure and access issues and other characteristics of the reserve that decrease ease of recovery.

[145] Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75.

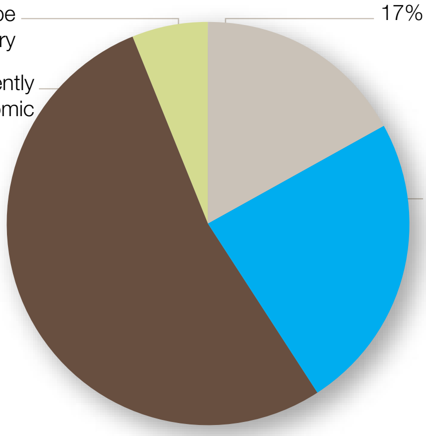
Table 12 Summary of WA Gas Reserves

Category of Gas Reserve	Reserves of Gas (PJ)		% of total gas reserves	
	90%	50%	90%	50%
Developed Fields	16,811	21,729	21.7%	17.2%
Potential for Development	20,760	30,341	26.8%	24.0%
Held under Retention Lease	39,011	67,076	50.4%	53.1%
Unbooked Resources – scope for recovery	854	7,104	1.1%	5.6%
Total	77,436	126,250		

Note: % measures refer to probability of recovery level, that is, 50% probability of recovery and 90% probability of recovery.

Source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75.

Figure 17 WA Gas Reserves by Category



Data source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75.

Table 13 shows the quantity of gas produced from WA since 1996-97.

Table 13 Quantity of Gas Production in WA

Year	LNG (PJ)	LPG Butane and Propane (kt)	Natural Gas (PJ)
1996-97	393	395.43	258
1997-98	402	639.35	258
1998-99	416	647.90	241
1999-00	417	778.15	245
2000-01	455	762.37	286
2001-02	409	856.52	282
2002-03	428	807.07	304
2003-04	429	695.27	302
2004-05	612	777.17	286
2005-06	647	871.98	289

Note: Natural gas converted to PJ based on general energy for natural gas, not LNG. LNG figures for 2004-05 and 2005-06 converted from Mt to PJ and previous years converted from billion BTUs to PJ, based on typical LNG energy conversion values. The step jump from 2003-04 to 2004-05 is attributable to the fourth train of the NWS coming online in mid 2004.

Source: DOIR, 'Western Australian Mineral and Petroleum Statistics Digest 2005-06' p34-35.

Total energy consumption in WA is forecast to rise from 760 PJ in 2004-05 to 965 in 2010-11, 1,196 PJ in 2019-20 and 1,385 PJ in 2029-30.[146]

From the current fields providing gas that is marketed as part of domestic gas projects, over 90% of the remaining gas resource is contained in three fields held by partners in the North West Shelf Joint Venture:

- Perseus field – 8.8 Tcf;
- North Rankin – 5.3 Tcf; and
- Goodwyn fields – 4.1 Tcf.

The following table identifies developed reserves by operator and this information is used to develop Figure 18.

Table 14 Developed Fields

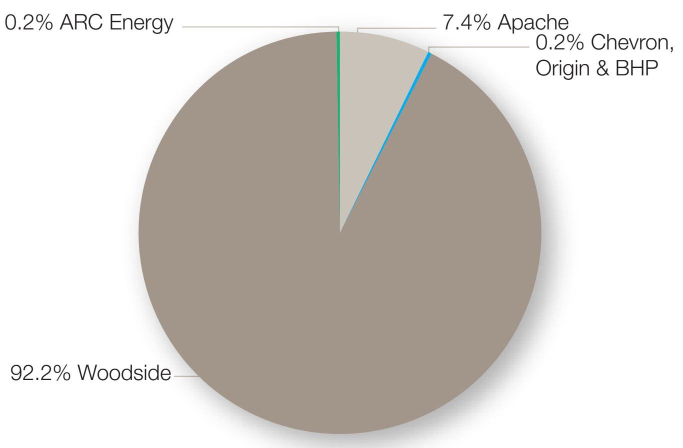
Operator	Annual Production MMCF	Reserves Tcf (50%)
Woodside	838,528	18.88
Apache	71,836	1.51
BHP Billiton	7,229	0.01
ARC Energy	7,060	0.03
Chevron	3,683	0.03
Origin	3,008	0.02
Vermilion Energy	2,485	
ENI	1,038	
Santos	194	0.01
Total	935,062	20.49

Source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 73.

The above figure clearly shows that the North West Shelf operator (Woodside) under the joint domestic marketing operations controls some 93% of developed gas reserves. Another 7.4% is located in the John Brookes field operated by Apache meaning that the two operating entities hold close to 100% of the gas reserves in developed fields.

Undeveloped gas fields that have been discovered can be categorised into those with commercial potential in the short to medium term and those held under retention leases. Fields under consideration for development (summarised by operator) are shown below, with reserves of approximately 28.6 Tcf or some 30,000 PJ.

Figure 18 Developed Reserves by Operator



[146] ABARE, 'Australian energy national and state projections to 2029-30', December 2006, p26.

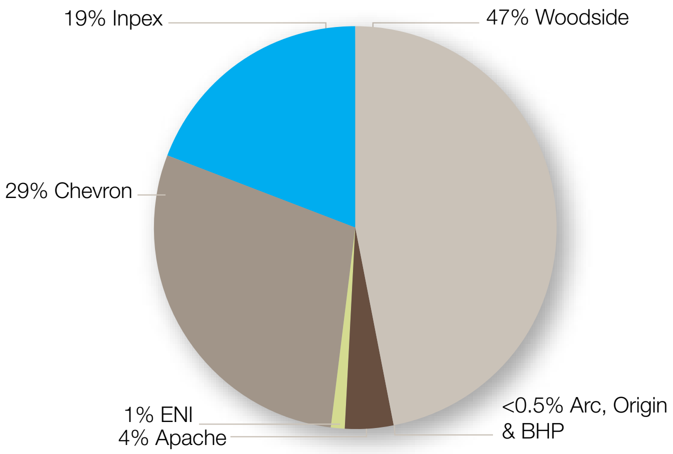
Table 15 Undeveloped – Potential for Development

Operator	Reserves of Gas (Tcf) 90%	50%
Woodside	2.390	3.739
Arc	0.003	0.003
Apache	0.430	0.698
ENI	0.478	0.642
Chevron	10.590	14.030
Inpex	5.685	9.499
Total	19.577	28.611

Note: Although not classified as a project with potential for development by DOIR, the Pluto gas field will have a final investment decision during 2007 and first production may occur from late 2010 – Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 62.

Source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 74.

Figure 19 WA Developed and Economic to Develop Reserves by Operator



Undeveloped gas fields that have been discovered but remain undeveloped can be categorised into:

(i) those with commercial potential in the short to medium term; and

(ii) and those held under retention leases.

Fields with potential for development are shown in Table 15 above, with reserves of approximately 28.6 Tcf or 30,341 PJ.

Some of these fields lie in existing petroleum production license areas and hence can be brought into production relatively easily in that they lie close to infrastructure and government approvals are likely to be relatively straightforward. These fields are all in Woodside operated production areas and include 3.7 Tcf or 3,965 PJ. Other fields currently under consideration but which are not in existing licence areas, such as Blacktip, are remote from Western Australian infrastructure and are not likely to be marketed in this state. The Ichthys project is being investigated as a new LNG project with all production destined for Japanese markets, reducing reserves available for the domestic market by 9.5 Tcf.

The largest gas resources are found in the fields associated with the Gorgon project operated by Chevron Texaco. The Joint Venture owners are seeking to develop this as an export LNG project but have undertaken to market up to 2 Tcf of gas in Western Australia.[147] This will require a pipeline from Barrow Island to the mainland and connection to the DBNGP transmission pipeline. As Barrow Island lies some 70 km off the WA coast, the distance involved is significant and the

[147] The Barrow Island Act 2003 requires the Joint Ventures to "actively and diligently undertake" to market gas domestically. Schedule 1, 17(3)(a).

cost will be substantial. For example, the development of the Otway gas project in Victoria is estimated to cost some $1.1 billion. This project involves construction of a remotely operated platform, a 70 km sub-sea pipeline and a land based gas processing plant. Initial production is forecast to be around 60PJ/yr.

As the requirement to market in Western Australia includes a provision that it be commercial to do so, there must be some doubt as to the future availability of this gas. It should however be noted that the WA government's reservation policy provides for meeting the domestic gas commitments of an LNG project from a different source, allowing an operator of a small field suited to domestic gas development to negotiate with an operator of a large LNG field so that domestic gas commitments of an export project are satisfied.

Only two other significant fields remain and both are operated by Apache: Reindeer and Corvus. These fields collectively contain 0.49 Tcf (523 PJ) of gas, an amount that would satisfy domestic demand for less than two years. With the exception of the two current dominant operators, the only real potential for more domestic gas supply options currently considered commercial is the Gorgon project.

Most of Western Australia's gas reserves are held under retention leases and, by definition, are not currently considered commercial by potential producers or the WA Government. Six operators hold gas reserves, but three hold the overwhelming majority of total gas reserves at the 50% level of probability. The largest field, Jansz, is held by Exxon Mobil but is likely to be part of a greater Gorgon project in the future and is best regarded as part of that development (Table 17).

Table 16 Gas Reserves by Operator – Held under Retention Lease

Operator	Reserves of Gas (Tcf)	
	90%	50%
Apache	0.075	0.180
Woodside	12.917	21.667
Chevron	13.564	21.272
BHP Billiton	0.350	0.696
Mobil	9.249	18.649
Santos	0.634	0.789
Total	36.787	63.252

Source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 75.

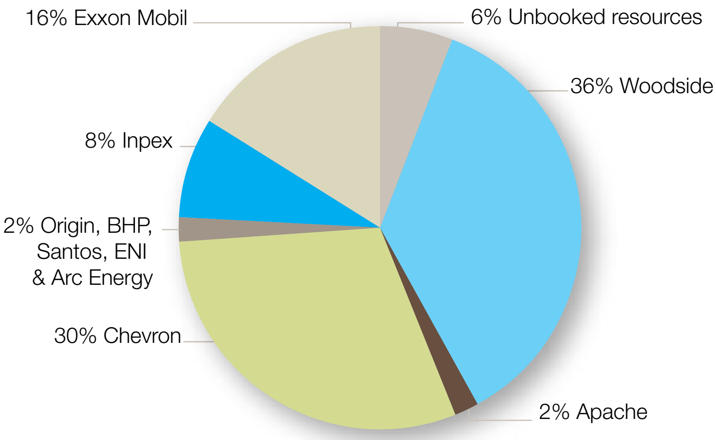
Total gas reserves by operator (developed, undeveloped commercial and non-commercial) are summarised in Table 17.

Table 17 WA Total Gas Reserves by Operator

Operator	Reserves Tcf		Share of total (50% level)
	90%	50%	
Woodside	16.145	44.291	37.2
Apache	0.577	2.388	2.0
Chevron	24.158	35.333	29.7
Origin	0.003	0.015	0.0
BHP	0.357	0.709	0.6
ARC Energy	0.010	0.033	0.0
Santos	0.634	0.796	0.7
ENI	0.479	0.642	0.5
Inpex	5.685	9.499	8.0
Mobil	9.249	18.649	15.7
Unbooked resources	0.810	6.700	5.6
Total	58.106	119.054	

Source: Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 72-75.

Figure 20 WA Total Gas Reserves by Operator



B.1.1 Impact of development issues on supply

The vast majority of WA's undeveloped gas reserves are held under retention leases on the basis that these reserves are currently uneconomic to develop. The characteristics of these reserves that contribute to their current uneconomic nature are not generally related to scale, that is, that the reserves are too small, rather, they are related to the offshore nature of the reserves, quality characteristics of the gas, the size of the development required to achieve economies of scale and the significant capital investment required to bring them to market. This is particularly the case given the increase in costs of infrastructure developments experienced world wide in recent years.

An example of such a previously uneconomic reserve is the Greater Gorgon project being developed by Chevron in a joint venture with Exxon Mobil. The Greater Gorgon area is estimated to have gas reserves exceeding 20,000 PJ (possible reserves are 21.5 Tcf).[148] However, the development partners have faced a number of critical development issues that have delayed commencement of the project. These included the fact that the fields lie some 130 km off the coast and the fact that the raw gas contains 12 to 15% carbon dioxide which they have undertaken to sequester within the depleted Barrow Island oil field.

The most recent public statements by the project proponents indicate they are currently planning to spend $11 billion on commercialising these gas reserves

[148] Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 59.

with the establishment of two 5 million tonne LNG processing trains on Barrow Island and associated gas gathering pipelines and processing plants. However, it is entirely possible that this cost estimate will be further increased as has happened with other major infrastructure projects in recent years.

The cost of developing the project purely to service the WA domestic gas market was considered to be prohibitive given the long payback time associated with such a small market, judged relative to international LNG trade. In December 2004, DOIR published a study report titled “Energy for Minerals Development in the South West Coast Region of Western Australia”. This document included an appendix 5 titled “LNG and Gorgon Pricing Considerations”. While the data in this study is now dated (it estimated a project cost of USD5 billion (AUD 6.7 billion assuming 0.75 USD/AUD) compared to the current estimate of AUD11 billion), it does provide a picture on the share of costs related to production and gathering systems which would be required to support domestic supply of gas.

The capital costs excluding liquefaction were estimated to be around USD 2 billion (AUD 2.7 billion) to produce 1,500TJ/day (sufficient for a 10Mtpa LNG facility). While current total domestic demand is currently only around 800TJ/day, the large scale economies associated with such projects mean it is unlikely that capital costs would decrease in a linear relationship with reductions in demand. Indeed, given the rapid increase in estimated project costs, it may be reasonable to assume that there would be no reductions in capital costs associated with matching production to meet domestic demand or a substantial proportion thereof.

Even in the absence of any market failure, supporting such a large scale investment purely to service the domestic market would be likely to require some aggregation of demand or at least contractual commitment to substantial purchase over an extended period of time. For the initial NWS development, this role was satisfied by government.

Large infrastructure investments to increase supply of domestic gas require significant capital expenditure, as do all gas developments, including LNG. Gas reserve location significantly influences the cost of developing reserves, whether for domestic or export use.

Gas projects for domestic gas supply face capital expenditure costs relating to pipeline development, particularly when a field is located in a remote offshore region or there is no established infrastructure near a reserve if the reserve is located close to shore. Sub-sea pipelines required for the development of offshore reserves require larger capital expenditure than pipelines located on land while the water depth will also impact on the cost of a sub-sea pipeline.

Gas used for domestic gas supply may be less expensive to develop as quality specifications are less stringent.

A notable benefit of gas projects for domestic supply in Australia is the relatively low risk environment in which the development operates. Once built, the risk to a pipeline of failing to receive the anticipated return is relatively low compared to LNG development. Risk to a natural gas pipeline for domestic gas supply is normally due to the fact that development of the pipeline must precede development of the field from which it will receive supply. Though international LNG trade is presently characterised by strong demand, which is expected to continue for the foreseeable future, such a development does face a greater risk, which must be offset by the higher price realised by fields producing LNG.

B.1.2 Outline of possible prospects for additional gas reserves in WA

Assessment of the potential for growth in reserves of natural gas is extremely difficult. In assessing the potential for growth in reserves within the Exmouth Basin, Geoscience Australia indicated that they had applied a reserves growth model which suggested that from the date of discovery, both oil and gas in already discovered accumulations could increase by about 25% in the next fifteen years. For the Exmouth basin this is significantly more than what has been modelled to be discovered.[149]

Geoscience Australia noted that this phenomenon of reserves growth contributing more than new discoveries has been seen elsewhere in Australia and should always be considered when determining opportunities for growth in reserves.

They also noted that despite the number of discoveries in 2004, there had been an overall decrease in crude oil and gas reserves for identified fields in the year to 1 January 2005.[150]

As such, while it is reasonable to expect some level of new gas discoveries in Western Australia, it is possible that these will not be significant in terms of extending reserves. However, coupled with growth in existing reserves, it may be reasonable to expect an increase in total reserves of up to one third.

B.2 REST OF AUSTRALIA – HIGH LEVEL SUMMARY

While there is no significant interaction between the gas markets in WA and the rest of Australia, it is useful to summarise gas reserves elsewhere in Australia, if nothing else to highlight the uniquely large WA endowments.

Of Australia's current total gas reserves, the Carnarvon, Browse and Bonaparte Basins together account for over 90% as highlighted in the following figure.

Continued exploration activity, changes in exploration and extraction technology and changes in market characteristics, will lead to both an increase in total reserves and a change in the mix of those reserves (with a greater proportion of existing reserves becoming commercial over time). While the majority of growth in reserves is expected in the Carnarvon, Browse and Bonaparte basins, reserves in eastern Australian basins are also likely to increase. For example, Geoscience Australia noted that:[151]

[149] Geoscience Australia Oil and Gas Resources of Australia 2004 p 38.

[150] Geoscience Australia Oil and Gas Resources of Australia 2004 p 2.

[151] Geoscience Australia. Oil and Gas Resources of Australia 2002. p.26.

> The Casino gas discovery has confirmed the presence of an active petroleum system in this part of the offshore Otway Basin and has enhanced the prospectivity of a number of additional prospects which have a seismic response similar to that present over the Casino gas field…

As such, the above reserve estimates represent the lower limit of expected reserves.

Indeed, the rapid commercialisation of coal seam methane (CSM) reserves in recent years suggests and increasing role for CSM in augmenting gas supplies in the eastern states. ABARE noted that Dickson and Noble had estimated potential CSM resources in the Sydney, Gunnedah and Clarence-Moreton basins in NSW at about 97,000 PJ with a further 152,000 PJ in the Bowen basin in Queensland.[152]

Further CSM has relatively low upfront capital requirements and therefore provides a real opportunity for new entrants, especially in light of the relatively high degree of knowledge (mapping) of Australia's coal reserves.

Figure 21 Australian Natural Gas Reserves and Gas Transmission Pipeline Infrastructure

Data source: Dickson and Noble 2003. Eastern Australia's Gas Supply and Demand Balance. APPEA Journal 2003 p 136

[152] ABARE Australian Energy national and state projections to 2029-30 October 2005 p41.

C DEMAND

The pattern of demand for gas in WA is critical to establishing the adequacy of existing reserves and the relative future significance of domestic consumption compared to export consumption. This section presents a high level profile of historic and forecast demand for WA gas.

C.1 WESTERN AUSTRALIAN GAS DEMAND

Western Australia is the largest natural gas consuming state in Australia, representing around one third of Australia's total consumption. Consumption increased by an average 9.1% per annum over the 20 years to 2004-05.

While Western Australia's gas consumption is significant compared to the rest of Australia, it accounts for only 14% of total energy consumed in Australia. As noted above, gas is a very important source of energy in WA representing some 51% of WA's 2005/06 primary energy consumption.

Of the total gas production in WA, LNG sales far exceed domestic natural gas sales. Approximately 0.604 TCF (720 PJ)[153] of LNG is shipped overseas, compared to 0.272 TCF (290 PJ) of gas supplied domestically.[154] Despite strong domestic demand growth, this excess of LNG sales over domestic sales is forecast to increase.

C.1.1 Domestic demand for gas

Gas usage in Western Australia is dominated by a small number of industrial sectors and individual organisations. This can act to make demand for gas lumpy, as entry or exit of a large industrial user can significantly alter the demand profile for gas.

The manufacturing sector consumes about 40% of the gas with most used to produce alumina from bauxite. Nickel and mineral sand processing are also important sectors making mineral processing the dominant part of gas use in the State.

Natural gas is also used as a chemical feedstock for ammonia, cyanide and fertiliser production.

Most industrial sectors have steadily increased gas use although the closure of a large iron ore processing plant in the Pilbara reduced the use of gas significantly in the iron processing sector.

Electricity generation is the second dominant industry use accounting for around 30% of the total. Base load power generation has historically been dominated by coal-fired plants in Western Australia A primary concern in relation to the use of gas for base load generation is the higher fuel cost associated with gas use. However, gas fired generation was successful in the WA 2005 base load generation tender resulting in around 300 MW of gas fired base load generation being constructed.

Gas use in cogeneration plants providing heating and electricity has been a rapidly growing sector in recent years.

Use of gas for electricity generation has grown rapidly over the last decades with annual increases of 7 to 8% over extended periods. Gas plants now

[153] DOIR reported figures for LNG exports are 9Mt (500 PJ).

[154] Chamber of Commerce and Industry Western Australia, 'Meeting the Future Gas Needs for Western Australia A Report to the Western Australian Government' Draft Report, February 2007.

provide around 60% of the electricity generated in the State, compared to approximately 35% of generation from coal-fired plants.[155] They increasingly compete with coal for base load electricity and with diesel in mine sites. Power stations remote from the large integrated electricity networks rely heavily upon gas for fuel.

The mining sector is a large consumer of natural gas for electricity generation with some mineral extraction processing. Annual consumption has risen by an average of 3.2 % each year over the past decade with this sector now accounting for about 25% of the total.

In summary, mineral processing, mining and electricity generation account for over 90% of natural gas use in Western Australia. Use in the commercial and residential sectors is a small proportion of the total. While most households in the State access a reticulated gas supply, the milder climate means a relatively low heating requirement with most gas used to provide hot water.

The dominance of the mining and mineral processing and electricity generation sectors in gas use and the concentration of these industries in the hands of a few large companies means that a large proportion of consumption is made up by only five entities – Alcoa (alumina manufacturing), BHP Billiton (mining and mineral processing), Alinta (gas supply), Verve Energy (electricity generation) and Burrup Fertilisers (chemical manufacturing).

A recent WA policy document on greenhouse gas emissions indicates that for emissions in WA to be cut further, there may be increased reliance on gas and renewable energy sources to provide for the state's energy consumption. In addition, some form of emissions abatement is finding increasing State and Federal support Australia wide. More rather than less reliance on gas as an energy source for domestic WA energy consumption is likely.[156]

Future growth in domestic demand for gas

Domestic demand for gas will be bolstered by new electricity generation projects that rely on gas. These committed projects as at 2006 are shown on the following page.

[155] Office of Energy (WA), 'Electricity Generation from Renewable Energy' available from http://www.energy.wa.gov.au/cproot/799/5305/RenewableEnergyFactSheetAug2006FINAL.pdf.

[156] Greenhouse and Energy Taskforce 'Strategies to reduce greenhouse gas emissions from the Western Australian stationary energy sector' December 2006.

Table 18 New Generation Projects as at 2006

Location	Owner	Fuel	Capacity (MW)
Broome (March/April 2007)	Energy Developments Ltd	Natural Gas/ Distillate	47
Derby (April 2007)	Energy Developments Ltd	Natural Gas/ Distillate	13
Fitzroy Crossing (June 2007)	Energy Developments Ltd	Natural Gas/ Distillate	4.8
Halls Creek (July 2007)	Energy Developments Ltd	Natural Gas/ Distillate	3.9
Kwinana (2008)	NewGen Kwinana Partnership	Natural Gas	320
Pinjarra Unit 2 (2007)	Alinta Cogeneration (Alcoa Pinjarra)	Natural Gas	140
Wagerup (Stage 1; October 2007)	Alinta Cogeneration (Alcoa Wagerup)	Natural Gas/ Distillate	350
Total			878.7

Source: WA Office of Energy, http://www.energy.wa.gov.au/cproot/802/5379/2006%20Final%20Generation%20Table.pdf.

Offsetting some of the above growth in generation capacity will be the retirement of existing plants reaching the end of their economic or engineering lives. The natural gas electricity generators that are scheduled to be retired as at 2006 are shown below.

Table 19 Electricity Generation Plant Scheduled to Close

Location	Owner	Fuel	Capacity (MW)
Kwinana Stage B (August 2008)	Verve Energy (Kwinana Power Station)	Natural Gas/Fuel Oil	240 (out of 901)
Kwinana Stage A (August 2009)	Verve Energy (Kwinana Power Station)	Coal/Natural Gas/ Fuel Oil	240 (out of 901)
Total			480

Source: WA Office of Energy, http://www.energy.wa.gov.au/cproot/802/5379/2006%20Final%20Generation%20Table.pdf

Estimated forecasts of natural gas consumption in Western Australia are shown in the table below.

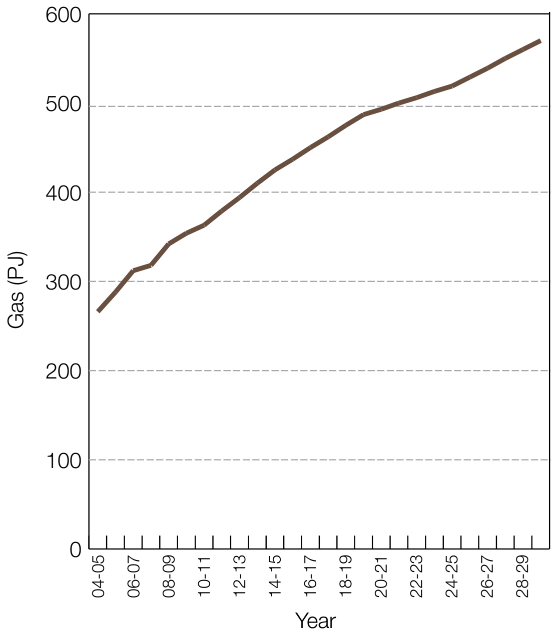
Table 20 Forecast WA Domestic Gas Consumption (2004/05 to 2029/30)

Year	Daily Consumption (TJD)	Annual Consumption (PJ)	Annual Consumption (TCF)
2004-05	784	286	0.27
2005-06	792	289	0.27
2006-07	858	313	0.30
2007-08	874	319	0.30
2008-09	940	343	0.32
2009-10	973	355	0.33
2010-11	1000	365	0.34
2014-15	1167	426	0.40
2019-20	1340	489	0.46
2024-25	1430	522	0.49
2029-30	1570	573	0.54

Source: DOIR, ABARE.

It is important to note that the eastern states of Australia cannot provide gas to Western Australia in the event of a shortfall in domestic supply. The eastern states are also facing a potential local supply shortage from 2012-13 unless gas is imported from other regions.[157] Alternately, the eastern states will have to rely much more heavily on Coal Seam Methane (CSM) production.

Figure 22 WA Forecast Natural Gas Consumption (2004/05 to 2029/30)



Note: Domestic gas usage excludes field use, pipeline energy, LNG production use, LPG and refinery.

Data source: ABARE, 'Australian energy national and state projections to 2029-30', December 2006, p74.

[157] ABARE, 'Australian energy national and state projections to 2029-30', December 2006, p5.

C.1.2 Export demand for WA gas (LNG)

Export demand for LNG is expected to be the dominant market for WA gas. By 2005-06, close to 70% of the gas produced was exported from the North West Shelf project as LNG. The volume was equivalent to about 1,780 TJ/d (650 PJ/yr) compared with about 800 TJ/d (290 PJ/yr) for domestic sales.

Production of LNG has grown by 5.8% each year in the past ten years, and by 9% in the past five years. This growth reflects the strong demand for natural gas from consumers in Asia.

LNG production from the North West Shelf Gas project will increase to 16.3Mt (903 PJ) per year from Q4 2008. This will occur with the commissioning of a fifth LNG processing train with a capacity of 4.4Mt (244 PJ) of LNG per year. Current capacity is 11.7Mt, comprising three 2.5Mt (139 PJ) trains and one 4.2Mt (233 PJ) train.[158] The current domestic gas processing plant for the NWS project has a daily capacity of 600 MMCF or 0.22 Tcf/yr (637 TJ/d or 233 PJ/yr). In 2005 production was already 0.19 Tcf (197 PJ) per year, giving an average daily production of 510 MMCF (541 TJ/d). With this processing capacity domestic gas supply can only increase by 15.1% while with new LNG capacity, LNG production is forecast to increase 37.6%.

This indicates that gas production is likely to increase, but production of LNG to international markets is likely to increase far more significantly than production of gas for the WA domestic market.[159]

LNG production is expected to be around 15.9Mt (881 PJ) per year from Q4 2008 when the fifth processing train has been commissioned.[160] [161]

LNG export predictions are uncertain and there are a range of forecasts as to the likely magnitude of increases in LNG production and export. However, there is an overwhelming consensus that growth in LNG production will be strong and sustained.

[158] http://www.australialng.com.au/website.aspx?mp=3&pn=302 and Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 46.

[159] http://www.australialng.com.au/website.aspx?mp=3&pn=306 and Department of Industry and Resources, 'Western Australian Oil and Gas Review 2006', 46.

[160] http://www.australialng.com.au/newsItem.aspx?id=17.

[161] According to DOIR, 'Western Australian Mineral and Petroleum Statistics Digest 2005-06' p13, other LNG projects are currently being considered around Australia and in Western Australia. These projects include:

- expansion of the ConocoPhillips Darwin LNG plant by commissioning a second production train;
- Woodside's Pluto gas field, expected to produce 5-7Mt (277 – 388 PJ) per annum from a reserve of 3.5Tcf;
- Woodside's fields in the Browse Basin. Woodside's reserves in the Browse Basin are estimated to be 20 Tcf (23,908 PJ), a final decision is to be made around 2008-2010, and if approved the first cargo could be delivered between 2012/14;
- Chevron's Barrow Island, Gorgon and Jansz fields, with a potential of 10Mt per annum;
- Inpex's Browse Basin; and
- BHP Billiton-Exxon Mobil's Scarborough LNG project.

Gas fields in the Browse Basin are located significant distances from suitable pipelines to transport gas for domestic consumption. Therefore Woodside and Inpex's fields in the Browse Basin would require the costly extension of the gas transmission system in order to contribute significantly to supplies of domestic gas. Instead these fields may rely upon agreements with explorers and operators of smaller fields unsuitable for LNG export. The Scarborough field is also located a great distance offshore. Technology allowing offshore processing has not yet been developed, but the remoteness of the Scarborough field would suggest that the costs of onshore processing would be significant.

The table below shows ABARE's forecast LNG exports from Australia to 2029-30.

Table 21 ABARE Forecast LNG Exports

Year	LNG export (PJ)	Change from previous period
2004-05	576	
2010-11	1,061	485 PJ (84% increase)
2014-15	1,948	887 PJ (84% increase)
2019-20	2,856	908 PJ (47% increase)
2024-25	3,204	348 PJ (12% increase)
2029-30	3,650	446 PJ (14% increase)

Source: ABARE, 'Australian energy national and state projections to 2029-30', December 2006, p40.

The DOIR has estimated that annual LNG exports will rise to 41.9 Mt (2,300 PJ or 2 Tcf) by 2020 and domestic gas production will rise to 0.51 Tcf (540 PJ) by 2020. Current levels are 9Mt (500 PJ or 0.4 Tcf) and 0.27 Tcf (286 PJ) respectively.[162]

In its policy document relating to securing domestic gas supplies[163] the WA government stated that the natural gas industry had set a target level of LNG production of 50 Mt per year, approximately 2,770 PJ (2.3 Tcf), by 2015.

[162] Department of Industry and Resources, 'WA Government Policy on Securing Domestic Gas Supplies Consultation Paper', February 2006, 5.

[163] WA Government Policy on Securing Domestic Gas Supplies, October 2006.