ECONOMICS AND INDUSTRY STANDING COMMITTEE

INQUIRY INTO DOMESTIC GAS PRICES

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Inquiry into Domestic Gas Prices

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ECONOMICS AND INDUSTRY STANDING COMMITTEE

INQUIRY INTO DOMESTIC GAS PRICES

Report No. 6

Presented by:
Dr M.D. Nahan, MLA

Laid on the Table of the Legislative Assembly
on 24 March 2011

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TABLE OF CONTENTS

COMMITTEE'S FUNCTIONS AND POWERS

The functions of the Committee are to review and report to the Assembly on: -

(a) the outcomes and administration of the departments within the Committee's portfolio responsibilities;

(b) annual reports of government departments laid on the Table of the House;

(c) the adequacy of legislation and regulations within its jurisdiction; and

(d) any matters referred to it by the Assembly including a bill, motion, petition, vote or expenditure, other financial matter, report or paper.

At the commencement of each Parliament and as often thereafter as the Speaker considers necessary, the Speaker will determine and table a schedule showing the portfolio responsibilities for each committee. Annual reports of government departments and authorities tabled in the Assembly will stand referred to the relevant committee for any inquiry the committee may make.

Whenever a committee receives or determines for itself fresh or amended terms of reference, the committee will forward them to each standing and select committee of the Assembly and Joint Committee of the Assembly and Council. The Speaker will announce them to the Assembly at the next opportunity and arrange for them to be placed on the notice boards of the Assembly.

INQUIRY TERMS OF REFERENCE

On 20 April 2010, the Legislative Assembly referred the following terms of reference to the Economics and Industry Standing Committee:

(1) That the House refer the issue of domestic gas prices for industry and consumers to the Economics and Industry Standing Committee for investigation.

(2) That the Committee specifically investigate:

(a) the price of gas for customers throughout Western Australia;

(b) the comparison of the price of gas with other states, especially Victoria, and whether there is a significant price differential and, if so, why; and

(c) the contrast between domestic gas prices in Western Australia and international LNG prices and the LNG contracts that govern these international prices.

(3) That the Committee make recommendations on any measures that could be implemented to reduce the price of gas in Western Australia.

(4) That the Committee report by 30 September 2010 (extension granted by Legislative Assembly to 24 March 2011).

CHAIR'S FOREWORD

Western Australia's economic future is inexorably tied to the development and use of the state's large reserves of natural gas.

Since gas first flowed from the North West Shelf Project over 25 years ago, the state has become highly reliant on the use of gas as a fuel source. Indeed, the intensity of gas use in Western Australia is double the level of other states.

Aside from abundant supplies, the use of gas in the state has historically been encouraged by competitive domestic prices on a national and global basis.

The state's large gas reserves have also been the foundation for the development of a large and now rapidly expanding Liquefied Natural Gas (LNG) industry exporting gas to Asian markets. The LNG sector is not just generating thousands of high paying jobs and billions of dollars in investment, export income, royalties and tax receipts: it is also greatly expanding the stock of known gas reserves.

Western Australia is now one of the world's most prospective and largest gas regions.

Despite the large expansion in reserves and investment in LNG production, domestic gas prices have risen sharply in recent years.

Indeed, there have been reports that prices on some new domestic contracts have exceeded LNG contract prices (in netback terms after processing and shipping costs are removed). In other words, some domestic prices are being set at levels reflecting or exceeding that of high priced Asian LNG markets.

The concern is that the recent high gas prices are seriously undermining the state's competitiveness and imposing high and excessive costs on businesses and households. There is also a related concern that export markets are getting a preference over the domestic market in terms of access to the state's gas reserves.

In response to this concern, the Legislative Assembly, with all party support, instructed the Economics and Industry Standing Committee to inquire into domestic gas prices, including the current level and trends, and to suggest recommendations to address the rising gas price.

This was not an easy task. Gas in Western Australia is sold via contracts with limited market data available on price and quantity. Moreover, most gas contracts are commercially confidential with published information around any details scarce. LNG is also sold via commercially confidential contracts. Gas markets are highly complex and the task given to the Committee required a great deal of expert knowledge and skills.

Nonetheless I believe the Committee has done an excellent job of overcoming these information barriers and identifying price levels and trends. The report presents the first authoritative review of gas pricing in the state and the first detailed analysis of the relationship between the domestic and LNG export sector and the state of play of unconventional gas resources in Western Australia.

The report also provides a comprehensive set of recommendations designed to ensure that the domestic market receives an adequate supply of gas at lower prices—substantially below LNG net back prices.

The Committee received a large amount of detailed information in confidence. While the confidential information is not referred to in the report, it has been taken into consideration by the committee in making its conclusions.

The Committee was also given funding to contract-in specialist advice from Mr Peter Kolf, formerly Executive Director of the Economic Regulation Authority and an authority on energy pricing and modelling. I thank Peter for his invaluable support.

I would like to thank my fellow Committee members who worked in a very constructive and collaborative manner.

On behalf of the Committee I would like to offer special thanks to Mr Tim Hughes, the Committee's Principal Research Officer. Tim performed above and beyond the call of duty. I would also like to thank Mrs Kristy Bryden, the Committee's Research Officer for her contribution.

I urge the Government to act on this important report.

Mike Nahan

DR M.D. NAHAN, MLA
CHAIR

ABBREVIATIONS AND ACRONYMS

ABARE	Australian Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APPEA	Australian Petroleum Production and Exploration Association
BCF	billion cubic feet
BOE	barrel of oil equivalent
CME	Chamber of Minerals and Energy WA
CPI	Consumer Price Index
CSG	coal seam gas
CSM	coal seam methane
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DBP	DBP Transmission (owner and operator of the Dampier to Bunbury Natural Gas Pipeline)
DEEDI	Queensland Department of Environment, Economic Development and Innovation
DES	delivered ex-ship
DMP	Department of Mines and Petroleum (WA)
DRET	(Commonwealth) Department of Resources, Energy and Tourism
DSD	Department of State Development
ECS	Economic Consulting Services
EISC	Economics and Industry Standing Committee

ERA	Economic Regulation Authority
ERAA	Energy Retailers Association of Australia
esaa	Energy Supply Association of Australia
ESCOSA	Essential Services Commission of South Australia
FID	Final Investment Decision
FLNG	Floating Liquefied Natural Gas
FOB	free on board
FRC	Full retail contestability
GBA	Gas balancing arrangement
GGP	Goldfields Gas Pipeline
GJ	gigajoule
GMDWG	Gas Market Development Working Group
GMLG	Gas Market Leaders Group
GSEMC	Gas Supply Emergency Management Committee
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
HUGS	Hardship Utilities Grant Scheme
IBT	Inclining Block Tariff
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal of NSW
JV	joint venture
JWG	Joint Working Group on Natural Gas Supply
LNG	Liquefied Natural Gas
MCE	Ministerial Council on Energy
MCF	thousand cubic feet

MDQ	maximum daily quantity
MJ	megajoule
mmBTU	million British Thermal Units
MOS	market operator service
mtpa	million tonnes per annum
NGA	National Gas Access (Western Australia) Act 2009
NWS	North West Shelf
NWSG	North West Shelf Gas
PGPLR	Prospective Gas Production Land Reserve policy (Queensland)
PJ	petajoule
REMCo	Retail Energy Market Company Limited
SECWA	State Energy Commission of Western Australia
STTM	Short Term Trading Market
SWIS	South West Interconnected System
TCF	trillion cubic feet
TJ	terajoule
UK	United Kingdom
US	United States
WA	Western Australia
WACOSS	Western Australia Council of Social Service Inc
WAGN	WA Gas Networks

GLOSSARY

1P reserves[+]	1P (proved) reserves are shown by geoscience and engineering research to have a reasonable certainty of being recoverable. There is a 90% probability that the quantities recovered will be 90% or more of what is estimated (taking into account production methods, operating conditions, prices and costs).
2P reserves[+]	2P (probable and proved) reserves are shown by geoscience and engineering research to have an even (50%) likelihood of being recoverable. 2P reserves estimates show that reserves recovered will exceed expectations.
boe[+]	Barrel of oil equivalent. A commercial unit of energy, notionally equivalent to the energy content of one barrel of oil, used to convert volumes of different hydrocarbon production to a standard measure. 1 boe = 6.119 gigajoules = 5.800 million BTU (@ 15°C).
delivered	The price charged by a producer when the producer organises the transmission of the gas contracted for sale. Different from the ex-plant price [see below].
delivered (ex ship)[#]	The delivery basis for most traditional long-term LNG contracts. Agreed price includes cost of freight and insurance for transporting the LNG by tanker to buyers' facilities. Usually contrasted with Free On Board (FOB).
downstream[+]	Downstream refers to all petroleum operations occurring after delivery of crude oil or gas to refinery or fractionation plant.
ex-plant	The wholesale gas price that producers charge for supplying gas to their juncture of the transmission pipeline. A gas purchaser paying an ex-plant price needs to negotiate a separate contract for transmission with the pipeline operator.
feedstock[*]	Raw material required for an industrial process as opposed to fuel burnt or altered obtaining energy.
free on board[#]	Delivery, inspection and loading costs involved in putting LNG on a tanker at sellers' facilities are included in agreed price. Buyer pays all additional costs to transport and unload the cargo.
joule	Unit of energy used for measuring gas volumes.

LNG+	Liquefied natural gas. Natural gas that has been liquefied by refrigeration or pressure in order to store or transport it. Generally, LNG comprises mainly methane.
LNG train*	A term used to describe the liquefaction and purification facilities in a liquefied natural gas plant.
LPG+	Liquefied petroleum gas, sometimes known as condensate. A mixture of light hydrocarbons derived from oil-bearing strata which is gaseous at normal temperatures but which has been liquefied by refrigeration or pressure to store or transport it. Generally, LPG comprises mainly propane and butane. 1 tonne = 8.458 boe.
reservoir+	A rock or formation which holds hydrocarbons.
take-or-pay	A clause applying to the quantity of contracted volume that the purchaser agrees to pay for regardless of whether they take delivery.
well+	A hole drilled to test an unknown reservoir or to produce from a known reservoir.

Key to Sources (where used)

* AEMO, *2009 Gas Statement of Opportunities for Eastern and Southern Australia*, 2009, (Glossary), pp. 4-5. Available at: www.aemo.com.au/planning/0415-0005.pdf . Accessed on 21 March 2011.

\# LNGpedia, 'Glossary of LNG Terms,' n.d. Available at: www.lngpedia.com/resources/glossary-of-lng-terms/. Accessed on 22 March 2011.

\+ Santos, 'Gas Industry Terminology,' 13 April 2010. Available at: www.santos.com/exploration-acreage/gunnedah-basin-gas/gas-industry-terminology.aspx. Accessed on 22 March 2011.

EXECUTIVE SUMMARY

Western Australia is the base of Australia's lucrative LNG export industry and has historically been promoted as an economy with domestic gas in plentiful supply at comparatively low prices. Industrial consumers have long been drawn to the benefits of the state's abundance of gas resources, with over 90 per cent of local demand for domestic gas coming from the manufacturing, construction, utilities, mining, agricultural and transport sectors.

There is increasing concern among Western Australia's gas consumers that unacceptably high prices are now eroding the competitive advantage that the state has traditionally enjoyed as a result of its natural endowment of gas reserves. Of particular concern is the prospect that Western Australian wholesale gas customers may be paying more for new supplies of gas than overseas recipients of the state's LNG cargoes.

The Economics and Industry Standing Committee has been asked to investigate the issue of domestic gas prices for industry and consumers throughout Western Australia. The Committee has been directed to compare the prices paid on domestic natural gas and LNG contracts in this state and to explain the reasons for any differences observed. The Committee was also asked to compare local domestic gas prices with those in other Australian jurisdictions: most notably Victoria, which is cited as an exemplar of efficient gas markets. Finally, the Committee was to make recommendations on any measures that could be implemented to reduce the price of gas in Western Australia.

Chapter One provides a background to the Western Australian gas market and the factors that have precipitated this Inquiry. A striking feature of the domestic gas market in this state is its high level of concentration. Three joint venture projects (the Woodside-operated North West Shelf and the Apache-operated John Brookes and Harriet projects) supply over 97 per cent of the state's local gas. On the buyer's side, over 90 per cent of demand is represented by five major consumers: Alcoa, Alinta Sales, BHP Billiton, Burrup Fertilisers and Verve Energy.

For several decades, there appears to have been an oversupply of gas relative to local demand requirements. To underpin the original development of the North West Shelf gas project, the joint venture agreed to supply more than 5,000 petajoules to the local market over a minimum 20-year period. In return, the government-owned State Energy Commission of Western Australia (SECWA) purchased a substantial proportion of this gas. Whilst considered expensive at the time, this "legacy contract" and others that emanated from that period have forged the state's reputation as a relatively cheap venue for domestic gas supplies.

Local buyers are now confronted with higher prices as contracts from this legacy period approach maturity at a time when demand, driven by unprecedented growth from the resources sector, is extremely strong. That prices in the Western Australian domestic gas market have increased is not in dispute. Where contributors to this Inquiry differ is over the causal factors.

The state's peak energy user group claims that the current period of undersupply has been contrived and that an upstream duopoly enables incumbent producers to "keep their foot on the hose." It is also suggested that major producers are "warehousing" fields for potential development as part of LNG projects.

The counter argument from the peak national body representing gas producers is that the market is "healthy" and "functioning" and that the recent price rises have generated an unprecedented supply response that will, over time, alleviate price pressures by bringing new supply sources to market.

The purpose of this Report is to wherever possible, quantify the magnitude of the recent price increases and identify their true cause in order to consider what corrective policy responses may be required. Robust forecast data is critical as it forms the basis of any market-driven or government-initiated response to correct supply and demand imbalances.

Chapter Two evaluates several prominent natural gas supply and demand forecasts for Western Australia. The Department of Mines and Petroleum (DMP) forecast, published in September 2010, has fuelled further debate amongst local gas market participants after suggesting there may be a substantial shortfall in supply by 2020. This is based largely on the assumption that volumes from the North West Shelf would reduce by two-thirds from current levels.

The Committee acknowledges that forecasting is an inherently complex practice, but feels that the veracity of future projections will be enhanced if an attempt is made to take price sensitivity into account. Based on the evidence it received, the Committee considers that the low supply scenario projected by DMP is unlikely to materialise and that the demand for gas in Western Australia will likely continue along its historic trend.

In addition, this chapter identifies several important factors that have impacted on the price of domestic natural gas in Western Australia. These include the watering out of Apache Energy's East Spar field earlier than expected in 2005, the short-term spike in prices attributable to the explosion at Apache's Varanus Island gas processing facility in 2008 and sharp increases in upstream industry costs over the last six years.

However, the state has also witnessed a tightening of domestic gas processing capacity since around 2004. Given the historic rate of growth in demand for domestic gas, it should have been fairly obvious to market participants that extra processing capacity would be required from around 2007—even in the absence of a global commodities boom.

The Committee notes that commitments have been made to establish new domestic gas processing plants (Devil Creek, Macedon and Gorgon). These facilities will increase the supply of domestic gas significantly and should, if historic rates of demand growth are maintained, alleviate the price pressures that are associated with current capacity constraints.

Despite this, the Committee remains concerned that the lack of new capacity since around 2007 is inconsistent with a well functioning market. As it stands, only Devil Creek and Macedon can be considered a supply response attributable to market signals. The Gorgon processing facility, which represents over 40 per cent of this new committed capacity, is only being constructed as part of an obligation to supply the domestic market that was written into the State Agreement underpinning the Gorgon LNG project.

Chapter Three attempts to ascertain where local domestic gas prices sit in comparison to prices paid by interstate customers and those offshore who purchase LNG from Western Australia. There are a variety of factors that complicate any attempts to make a genuine "apples with apples" comparison. Nevertheless, the Committee is comfortable with the following conclusions that it has drawn:

- The average price of all wholesale domestic gas contracts in Western Australia as at 2009/2010 is calculated to be around $3.70 per gigajoule.
- More recently, prices on new wholesale domestic gas contracts in Western Australia have been struck in a reported range of approximately $5.55 to $9.25 per gigajoule.[1]
- Prices on new wholesale domestic gas contracts in Western Australia are at least double those of recent prices in the eastern states.
- It is now highly likely that the recent rise in local gas prices has created an environment where—for certain contracts—domestic prices will exceed LNG netback equivalent levels.

The Committee has identified a range of structural differences in interstate domestic gas markets that would be problematic or impossible to replicate in Western Australia. Interstate gas reserves are located across multiple basins that are generally much closer to the centres of demand and transmission pipeline infrastructure. Moreover, with a fully integrated transmission system, gas producers from four states must compete with each other to supply the local market. Furthermore, demand for domestic gas in other states is tempered by a far greater reliance on coal-fired power generation.

There are, however, some structural advantages evident in the eastern states that could be pursued in Western Australia. Interstate domestic gas markets enjoy comparatively greater levels of liquidity, competition and transparency courtesy of mechanisms such as official secondary trading markets, gas market bulletin boards and formal "statement of opportunities" publications.

A critical difference observed with interstate domestic gas markets is that producers have not historically had an alternative (LNG) market in which to sell their gas (although this is likely to change as Queensland's Coal Seam Gas to LNG industry develops).

Chapter Three concludes that the LNG market in Western Australia does impact the price of local domestic gas. It has been recently reported that domestic gas prices now tend to be linked to oil prices in US dollars. This marks a departure from historical domestic gas contract pricing, which has traditionally been indexed to local inflation indicators, and can be attributed to the current lack of competition amongst upstream gas producers. Moreover, there is an unprecedented level of demand from resource companies, many of whom can absorb higher oil-linked prices as their alternative fuel is diesel (which has reached energy equivalent prices of $20 per gigajoule).

[1] Refer to footnote no. 155 on page 51.

The Committee has strong concerns about the impact that such pricing will have on the competitive position of the state and in particular the ongoing viability of domestically focused businesses, including utilities, that are predominantly reliant on gas-fired power.

The Committee agrees that a rise in domestic gas prices from the $2 to $3 per gigajoule range of the legacy contract period is inevitable with production costs increasing as new gas supplies are sourced from deeper and more remote fields. However, insufficient competition amongst upstream producers is currently generating excessive price outcomes. Prices that persistently reach or exceed an LNG netback equivalent reflect an absence of competition and are inconsistent with a well functioning market. Under such circumstances, some form of policy intervention in the market is appropriate.

The ultimate aim of any policy intervention should be to ensure that domestic gas prices can settle at levels substantially below LNG netback values, whilst offering producers returns that encourage further exploration and development.

The second half of the report considers the policy responses available to government. **Chapter Four** examines the two policy levers directed towards LNG producers that were brought most regularly to the Committee's attention by advocates of lower domestic gas prices: domestic gas reservation obligations and retention lease arrangements.

Under the state government's Domestic Gas Reservation Policy each LNG project is required to reserve up to 15 per cent of its LNG production for supply to the domestic market, subject to commercial viability parameters. These agreements are reached as a pre-condition for allowing on-shore processing facilities on state land. In the absence of a formal reservation policy, it is unlikely that LNG producers would commit to providing the level of domestic gas processing capacity needed to produce volumes and prices more consistent with a well functioning local market.

The Committee strongly supports the Reservation Policy, but argues that it needs to be delicately handled to ensure the state derives the optimal economic benefit from its gas resources. The current flexibility in the policy is endorsed to ensure that there remains adequate incentive to encourage further exploration and development. This will lead to a greater diversity of supply, more upstream competition and lower prices.

To ensure the appropriate amount of gas is supplied to the market under domestic reservation obligations, and to improve the current operation of the domestic market, the Committee recommends the establishment of an independent Gas Market Monitor. Based on the concept of the recently appointed Gas Market Commissioner in Queensland, this position would:

- continually monitor the supply/demand balance and requirements in the Western Australian gas market;
- identify deficiencies or failings across the gas supply chain and facilitate discussion between government and market participants on corrective measures; and,

- provide advice to the Minister on appropriate volumes and processing capacity requirements under future domestic reservation agreements.

This chapter contains other recommendations aimed at further improving the management of future reservation policies and commitments under existing State Agreements.

Chapter Five examines and endorses the mechanisms used to improve transparency, competition and liquidity in the wholesale gas markets of the eastern states. The Committee urges the expeditious implementation of an official Short Term Trading Market, Gas Market Bulletin Board and Gas Statement of Opportunities in Western Australia.

With these mechanisms in place, there is a strong case for the government to pursue the unwinding of the joint-marketing authority currently granted by the ACCC to the North West Shelf and Gorgon joint ventures when applications come up for renewal again in 2015. The Committee has considered the issue of joint marketing and finds that whilst there are arguments supporting the practice at this time, there is concern that it reduces the competitive tension amongst producers in the local market.

Chapter Six describes the operation and regulation of the gas transmission sector in Western Australia. Unlike the eastern states, Western Australia's domestic gas supplies are heavily reliant on one major pipeline for shipment. The potential for greater competition is limited given the prohibitive capital costs facing new entrants. Improvements therefore need to be made to the transparency of this sector and the manner in which incremental expansions in capacity can be added. These initiatives, along with the augmentation of storage facilities, could underpin the development of a Short Term Trading Market and improve the ease with which gas producers can increase supplies in a timely manner.

Chapter Seven focuses on retail gas prices. This sector comprises mainly small businesses and householders and represents around 4 per cent of the state's overall gas consumption. Whilst a small figure in terms of total demand, it still represents 600,000 households connected to mains gas. Retail gas prices in Western Australia have increased sharply since 2007/2008 and are among the highest in the country. This has coincided with the increase in wholesale gas prices (representing around 30 per cent of a residential retail bill) and a series of regulated tariff increases from the state's only household retailer, Alinta. These tariff increases have been recommended by the Office of Energy as part of a move towards cost-reflectivity that is designed to promote a greater level of competition in the retail gas sector. While Alinta remains the only service provider for Western Australian householders, all other states have multiple retailers.

While the majority of the evidence received throughout the Inquiry pertained to the wholesale gas market, the Committee has examined some of the programs currently available to mitigate the impact of retail gas tariff increases on householders. This is an area where the government will need to give further consideration to appropriately targeted policy responses.

The report concludes in **Chapter Eight** with a look at how latent unconventional gas deposits may fundamentally change the gas supply picture in Western Australia, placing significant downward pressure on wholesale and, to some extent, retail prices. There appears to be substantial unconventional gas deposits located on-shore and quite close to Perth. Along with the obvious increase in supply, these deposits could be cheaper to transmit due to their proximity to consumers and could offer the state economy additional royalty-based income streams.

Notably, with the proliferation of unconventional (shale) gas in the United States the wholesale price of gas fell by over two-thirds between 2008 and 2010. This final chapter examines the prospectivity and viability of unconventional gas in Western Australia. These resources look to have considerable potential, but there are lessons to be learned from recent experiences in the U.S. regarding environmentally responsible development practices.

FINDINGS

Page 22

Finding 1

Differences in historical information on the demand for natural gas in Western Australia as between the main providers of such information are of concern. There is a need for demand, supply and price information to be of good quality and a review of the methodology, assumptions and historical database would appear to be warranted.

Page 24

Finding 2

In recent years, the production side of the Western Australian domestic gas market has become highly concentrated. Such concentration raises legitimate concerns about the level of competition and effectiveness of this market.

Page 25

Finding 3

The demand for natural gas for use in Western Australia has expanded annually by an average of around 30 terajoules per day since the first year of recorded sales (1977) on the APPEA data base.

Page 30

Finding 4

Some factors that drive domestic gas prices are self-correcting. The rapid economic growth recently witnessed in this state, largely as a result of demand from the mining sector, has produced increases in energy prices that to some extent, will in turn dampen the future demand for domestic natural gas. This will have some flow-on effect on prices.

Page 33

Finding 5

On the balance of the evidence received and the economic and other forecasts available, the Committee considers that demand for natural gas in Western Australia will, over the next few years continue along its historic upward trend implying an annual compound growth in demand of 2.6 per cent to 2030. This figure is in contrast to 3.5 per cent annual compound growth projected by the Department of Mines and Petroleum. The difference between the historic upward trend and the DMP forecast accumulates to approximately 279 terajoules per day by 2030.

Page 35

Finding 6

The low supply scenario included in the Department of Mines and Petroleum's 2010 gas supply and demand outlook is unlikely to materialise. Western Australia is adequately endowed with a gas resource sufficient to satisfy domestic demand and any supply shortages are not likely to be caused by a lack of accessible reserves.

Page 41

Finding 7

Although proposed future expansions of effective gas processing capacity are evidence of suppliers responding to market signals, the lack of new capacity since around 2007 has put the adequacy of gas processing capacity of the state at risk. This lack of new capacity is inconsistent with a well functioning market and is a significant contributing factor to recent price rises

Page 42

Finding 8

The commitments to establish domestic gas processing facilities at the Gorgon, Macedon and Devil Creek projects will increase the supply of domestic gas. If historic rates of demand growth are maintained, this should ease the current capacity constraints that have contributed to recent price prises.

Page 44

Finding 9

The government needs to consider measures that will improve liquidity, transparency and competition in the Western Australian domestic gas market. There is also a need to consider other measures including the ongoing role of the state's gas reservation policy so as to ensure that adequate supplies of gas are available to the domestic market.

Page 54

Finding 10

Based on data published by the Department of Mines and Petroleum, the average price of all domestic gas contracts in Western Australia in 2009/2010 is calculated to be $3.70 per GJ. However, prices for gas under new contracts have recently been reported to be in a range of approximately $5.55 to $9.25 per GJ.

Page 55

Finding 11

Based on data published by the Department of Mines and Petroleum, the growth in total value of gas sold in the domestic market has exceeded the growth in quantity sold. This means that the average price of gas is increasing. This Committee has estimated that the *incremental value* of gas (value of the additional gas sold) in 2009/10 was in the order of $13.80 per gigajoule.

This figure is greater than the prices seen for new gas contracts because total value also reflects income earned from increases in the prices and a tightening in terms and conditions of existing contracts.

Page 56

Finding 12

The prices of new domestic gas contracts in Western Australia are at least double those of the eastern states.

Page 61

Finding 13

Structural differences exist between the eastern states' and Western Australian domestic gas markets, which need to be considered when comparing price differences across jurisdictions.

Page 61

Finding 14

Some of the structural differences that contribute to lower gas prices in the eastern states would be difficult or impossible to replicate in the Western Australian market. These include:

- multiple sources of supply much closer to major centres of demand and pipeline infrastructure;
- an integrated transmission pipeline sector that enables competition between four gas producing states;
- oil fields (particularly in Victoria) that are still rich in associated gas;
- a significantly greater reliance upon coal-fired power generation;
- the absence of an alternative (LNG export) market for gas.

Page 61

Finding 15

There are a number of structural advantages currently enjoyed by eastern states' gas markets that the Western Australian government should pursue. These include:

- mechanisms that promote greater liquidity and transparency, such as official secondary trading markets; and
- the facilitation of greater competition among producers through the development of new supply sources including unconventional gas deposits.

Page 63

Finding 16

An increase in domestic gas prices from historical levels is inevitable given the recent surge in production costs. Even so, insufficient competition amongst upstream producers is currently generating excessive prices.

Page 73

Finding 17

Despite the inherent differences in the respective markets, LNG prices do impact domestic gas prices in Western Australia. It is now highly likely that the recent rise in local gas prices has created an environment where—for certain contracts—domestic prices will trade at or above LNG netback equivalent levels.

Page 76

Finding 18

Prices that persistently reach or exceed LNG netback values reflect an absence of adequate competition and are inconsistent with a well functioning domgas market. Under such circumstances, some form of policy intervention in the market is appropriate

Page 76

Finding 19

The Domestic Gas Reservation Policy is an essential policy instrument for ensuring that an appropriate level of gas is supplied into the local market to achieve reasonable price outcomes.

This instrument should be part of a suite of policy responses, the primary aim of which should be to improve the overall level of liquidity, competition and transparency in the Western Australian domestic gas market.

Page 84

Finding 20

In the absence of a gas reservation policy it is unlikely that LNG producers would develop adequate domestic gas processing facilities.

Page 84

Finding 21

There is no evidence to suggest that the state's current approach to domestic gas reservation obligations has deterred LNG producers from pursuing development opportunities in Western Australia.

Page 84

Finding 22

Domestic gas reservation obligations remain a valuable tool for policy makers to ensure that a proportion of the state's gas reserves are supplied to local consumers in volumes and at prices that are consistent with a well functioning market.

However, this policy requires delicate handling to ensure that market outcomes reflect those of a well functioning competitive market.

Page 97

Finding 23

Floating LNG (FLNG) technology enables project proponents to conduct all aspects of production at sea in commonwealth waters. This greatly reduces the formal powers of the state government to negotiate a domestic gas supply commitment under the state's reservation policy.

Page 99

Finding 24

The parameters for commercial viability, as it pertains to the supply of gas reserved from LNG projects for the domestic market, need to be clarified. Acceptable parameters for commercial viability might include, but not be restricted to:

- a price that covers the cost of production and provides an industry-recognised reasonable rate of return.

Page 105

Finding 25

If the gas reservation policy does not lead to a reduction in domestic gas price beyond LNG netback, the government should consider additional options to create a functioning market for gas-on-gas competition in Western Australia, including a regulated auction or limiting specific fields to domestic use (as per Queensland’s Prospective Gas Production Land Reserve policy)

Page 109

Finding 26

The current process underpinning the application for and renewal of retention leases lacks sufficient rigour and enables the stockpiling of gas reserves by incumbent producers. These reserves may include fields that are suitable for the development of domestic supplies.

Page 117

Finding 27

While arguments can be made in support of the continuation of joint marketing in the current Western Australian domestic gas market, it is plausible to claim that the practice has facilitated a reduction in competitive tension between gas producers.

This may have contributed to the increasingly stringent contractual terms and conditions that some gas buyers have been reportedly facing and the higher prices being realised in this state.

Page 123

Finding 28

The introduction of a Short Term Trading Market (STTM) will improve the efficiency of the Western Australian wholesale gas market by promoting a level of transparency, competition and liquidity currently lacking.

Whilst there are challenges facing the establishment of a STTM in Western Australia, these should not be seen as insurmountable

Page 127

Finding 29

The establishment of a Gas Market Bulletin Board and Gas Statement of Opportunities (GSOO) is likely to enhance the efficient operation of the Western Australian wholesale gas market.

The Committee supports the introduction of these measures and urges the Minister for Energy to expedite the implementation process for each.

Page 138

Finding 30

The Committee finds that gas storage is important to the development of a more liquid and mature gas market in Western Australia and strongly supports the Gas Supply Emergency Management Committee's recommendations relating to gas storage.

Page 146

Finding 31

The distribution sector is a natural monopoly and usually requires ongoing regulatory oversight.

The Committee is satisfied with the current regulatory regime for distribution networks in Western Australia.

Page 153

Finding 32

The government needs to consider policies that will mitigate the impact on retail residential gas bills that will emanate from the recent increases in the wholesale price of gas and from any move towards cost-reflective tariffs in gas and electricity.

Page 174

Finding 33

Unconventional gas developments have the potential to significantly improve the level of upstream competition in the domestic gas market.

Page 174

Finding 34

While tight and shale gas have fundamentally altered the supply and demand balance in the U.S., the production process has generated environmental concerns regarding water use and treatment methods.

RECOMMENDATIONS

Page 22

Recommendation 1

That the Department of Mines and Petroleum review the methodology, assumptions and historical database of natural gas supply and demand (including average price information) for Western Australia to confirm the veracity of this information.

Page 27

Recommendation 2

The Office of Energy expedites the introduction of more reliable gas demand and supply forecasts for Western Australia that take price sensitivity and trends into account.

Page 87

Recommendation 3

The flexibility within the state's domestic gas reservation policy should be maintained unless an independent cost-benefit analysis demonstrates that a strict reservation of 15 per cent of the gas from each LNG project for the domestic market represents a more valuable and efficient use of the resource.

Page 90

Recommendation 4

The government establishes an independent Gas Market Monitor to oversee the operation of the local wholesale gas market. Modelled on the Queensland Gas Commissioner and reporting to the Minister for Energy, the Gas Market Monitor's primary duties would be to:

- publish an annual gas market review that includes price-sensitive supply/demand forecasts and identifies deficiencies in the operation of the market;
- facilitate discussion between government and market participants on how to address identified market inefficiencies; and
- provide the basis for ministerial and departmental discussions with LNG producers before future domestic reservation obligations are finalised.

Page 93

Recommendation 5

The Department of State Development commence discussions with the North West Shelf Joint Venture to obtain a commitment from the joint venturers that production capacity at the Karratha Domestic Gas Plant will continue at current levels, as per the terms of the existing State Agreement, until at least 2025.

Scope should remain open within the agreement to allow third party gas processing at the Karratha Gas Plant should North West Shelf reserves prevent full production capacity from being maintained after 2020.

Page 95

Recommendation 6

Under the terms of the State Agreement, the Minister for State Development confirm with the Gorgon joint venturers and advise Parliament on:

- the current date by which the Barrow Island domestic gas processing plant is expected to be built to its full 300 terajoules per day capacity; and
- the potential of this facility to process third party gas as an interim measure.

Page 97

Recommendation 7

Even with reduced formal powers, the state government should do all it can to obtain a commitment to the domestic gas market, including from developments using Floating Liquefied Natural Gas (FLNG) technology.

The government should encourage the promotion of third party gas processing to meet such commitments.

Page 100

Recommendation 8

Department of State Development refine, and publish a list of, any general parameters that are deemed to satisfy "commercial viability" as it pertains to domestic gas reservation obligations.

Page 101

Recommendation 9

The review mechanism articulated in Clause 17 (Schedule 1) of the *Barrow Island Act 2003* should be regularly enforced until the Gorgon Joint Venturer's full domestic gas production capacity is contracted.

Page 101

Recommendation 10

To ensure that commerciality provisions applicable to domestic gas reservations are used appropriately, a register of all independent assessments of commercial viability claims should be maintained by the Department of State Development.

Whilst commercially sensitive material should remain confidential, a detailed explanation of the reasoning behind each assessment should be published.

Page 104

Recommendation 11

All future domestic gas reservation agreements should include a review mechanism, similar to that contained in Clause 17 of the *Barrow Island Act* 2003, which obliges producers to actively and diligently test the market and be subject to independent assessment.

If prices are deemed by such an independent assessor to be commercially viable, producers should be further obliged to enter into contractual arrangements at the most attractive terms available to the producer.

Page 110

Recommendation 12

The Department of Mines and Petroleum should request that the Commonwealth Department of Resources, Energy and Tourism (DRET) respond urgently regarding:

- A detailed update on the status of the 2009 “Review of Policy relating to the Grant and Renewal of Retention Leases”.
- DRET’s current position on retention lease management processes.
- The merit of subjecting all retention leases with no development plans in place within the next five years to a re-evaluation of commercial viability by the Joint Authority.
- Ensuring that the supply of gas to the domestic market is included as a priority in the process of renewing or issuing a retention lease.

Page 117

Recommendation 13

The government should vigorously pursue the elimination of the joint marketing authority currently granted to the North West Shelf and Gorgon joint venturers when the applications come up for renewal in 2015.

Page 123

Recommendation 14

The Minister for Energy proceed with the introduction of a Short Term Trading Market in Western Australia as a matter of priority.

Page 127

Recommendation 15

The Minister for Energy expedite the introduction of a Gas Market Bulletin Board and Gas Statement of Opportunities in Western Australia.

Page 142

Recommendation 16

That the Minister for Energy arrange for a review to be undertaken of identified shortcomings in Western Australia's regulated gas transmission sector with a view to urgently progressing reforms that will overcome the need for gas market participants to trade in gas without first or separately having to enter into long-term transmission contracts.

Page 157

Recommendation 17

That the Office of Energy extends the planned Tariff and Concession Framework Review to cover the retail gas market.

Page 174

Recommendation 18

To encourage the development of unconventional gas, and to ensure it is undertaken in a responsible and environmentally sustainable manner, the Department of Mines and Petroleum should:

- work with all stakeholders to promptly resolve issues in the regulatory, environmental and native title approvals process; and
- ensure that Environment Management Plan compliance audits and reviews are undertaken regularly in order to identify and act upon any practices that demonstrate improper or unsafe water management processes.

MINISTERIAL RESPONSE

In accordance with Standing Order 277(1) of the Standing Orders of the Legislative Assembly, the Economics and Industry Standing Committee directs that the Minister for State Development, the Minister for Energy and the Minister for Mines and Petroleum report to the Assembly as to the action, if any, proposed to be taken by the Government with respect to the recommendations of the Committee.

CHAPTER 1 INTRODUCTION

1.1 Background

1. No Australian state is as abundant in natural gas as Western Australia. Of Australia's 200,000 petajoules (PJ) of conventional gas resources, 92 per cent are located in the Carnarvon and Browse basins, off the state's north-west coast, and in the Bonaparte Basin, off the north Kimberley coast.[2]

2. As at June 2010, about 106,000 PJ of gas reserves in Australia were considered to be "proved and probable" (2P).[3] Over 64 per cent of these reserves were located in the Carnarvon Basin off the Pilbara coastline.[4]

3. Of the 1,911 PJ of gas produced in Australia in the year to June 2010, 54 per cent (1,036 PJ) went to the domestic market, with the balance exported as Liquefied Natural Gas (LNG). Significantly, the Carnarvon Basin produced just over one-third of the gas sold on the domestic market and 862 PJ of the total (874 PJ) exported.[5]

(a) The Importance of Gas to WA

4. Given the extent of its local reserves, it is hardly surprising that Western Australia is the nation's largest consumer of gas. Table 1 below shows relative consumption rates, expressed in petajoules, for 2009.

Table 1 Consumption of Natural Gas by State 2009.[6]

QLD	NSW/ACT	VIC	TAS	SA	WA	NT
164	**140**	**227**	**8**	**105**	**355**	**21**

[2] Geoscience Australia and ABARE, *Australian Energy Resource Assessment*, Government of Australia, Canberra, ACT, 2010, pp. 83-84.

[3] Proved reserves have a 90 per cent likelihood of being commercially recoverable. Probable reserves have a 50 per cent probability. AER, *State of the Energy Market 2010*, ACCC, Canberra, 2009, p. 226.

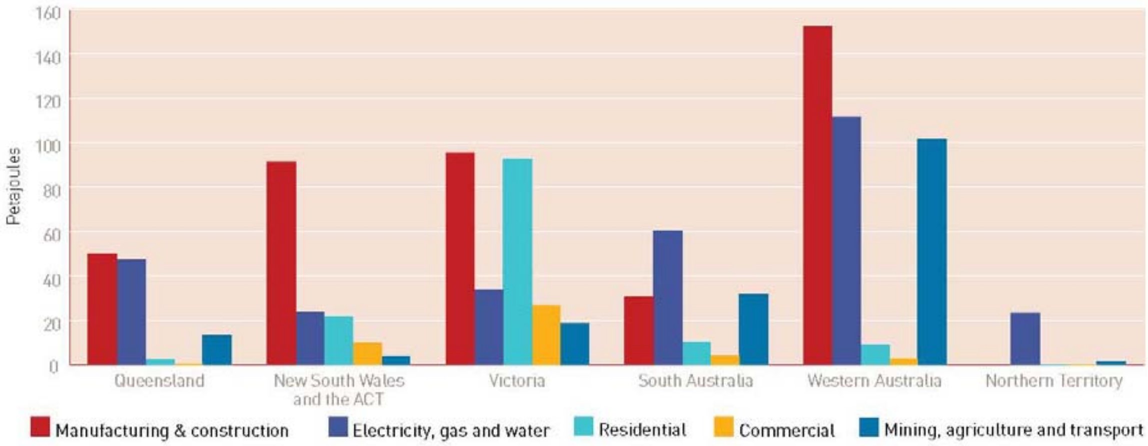
[4] AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 71.

[5] ibid.

[6] Figures for WA, See Submission 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 6 October 2010, p. 6. Figures for NSW, VIC, SA, TAS and QLD, See McLennan Magasanik Associates, "Report to DEEDI: Annual Gas Market Review", 23 June 2010, p. 10. Available at: www.dme.qld.gov.au. Accessed on 18 January 2011. Figures for NT based on 2008 data in AER, *State of the Energy Market 2008*, ACCC, Canberra,, 2008, p. 28.

5. A sectoral breakdown of domestic gas (hereafter domestic gas or "domgas") consumption in the Figure 1 below shows that the manufacturing and construction industries are the largest consumers in each state bar South Australia. Utilities, along with the mining, agriculture and transport sectors are also large consumers. Victoria, for reasons that will be explained in later chapters, has a notably higher demand for gas for household use. While somewhat dated (2005), the trends in Figure 1 (below) remain largely consistent with current patterns of consumption across each state and territory—particularly the higher level of usage in Western Australia.

Figure 1 Domestic Gas Consumption by Sector 2005[7]



6. Western Australia's energy intensity is underlined by the fact that the state consumes 6.28 terajoules (TJ) of energy for every million dollars of Gross State Product generated. This compares with a national figure of 5.32 TJ for every million dollars of Gross Domestic Product.[8]

7. More recent analysis (2007-2008) from ABARE confirms that gas represents 56 per cent of the primary energy fuel source in Western Australia. In the other states and territories, where coal and hydro-electricity are often readily available, gas averages just over 20 per cent of the energy mix.[9] The Western Australian figure is also high by international standards outstripping the US (26 per cent) and the UK (40 per cent).[10]

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7 ABARE data as displayed in, AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 232.

8 Energy Supply Association of Australia (esaa), 'Western Australian Energy Market Study', November 2009, p. 42. Available at: www.esaa.com.au. Accessed on 27 December 2010.

9 ABARE, *Energy in Australia 2010*, ACCC, Canberra, 2010, p. 12. See also, AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 22.

10 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 42.

(b) Consumers' Profile

8. Ninety per cent of the domgas purchases in Western Australia are shared between five large customers: Alcoa, Alinta Sales, BHP Billiton, Burrup Fertilisers and Verve Energy. Of all the gas purchased in this state, over 80 per cent is used for power generation, alumina refining and resource processing and manufacturing in the South West.[11]

9. Alcoa confirmed to the Committee that it makes up one-quarter of the state's gas consumption for its alumina production and is '100 per cent reliant on natural gas'[12] to fuel its refineries. Two-thirds of its gas is used for independent power generation.

10. BHP Billiton advised that its Iron Ore, Nickel West and Worsley Alumina refinery businesses account for approximately 15 per cent of total gas demand in the state.[13] Again, much of the gas consumed on these projects is for the purpose of generating power on sites not connected to the electricity grid.

11. Verve Energy supplies over 60 per cent of the power that goes into the electricity grid known as the South West Interconnected System (SWIS). While two-thirds of the energy Verve sells is coal-fired, its generation capacity is two-thirds gas-fired and is used to manage the extremely peaky patterns of local electricity consumption.[14]

12. Burrup Fertilisers differs in its use of gas. The 85 TJ a day it typically consumes, represents just under 10 per cent of the state's daily contracted demand and is used as a feedstock to produce ammonia.[15]

13. As Figure 1 shows, the household and commercial sector represents a negligible portion of the total gas consumed in Western Australia. One of the latest estimates puts the combined figure at 4 per cent of total domestic consumption.[16] Whilst representing a fraction of overall gas usage, the

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11 ACIL Tasman, *Gas Prices in Western Australia: Review of inputs to the WA Wholesale Energy Market*, May 2010, pp. 4-5. Available at: www.imowa.com.au/f2138,484255/ACIL_Tasman_Final_Report_-_Updated.pdf. Accessed on 27 December 2010.

12 Mr Michael Parker, Director, Business Development and Marketing, Alcoa of Australia, *Transcript of Evidence*, 17 November 2010, pp. 1, 3.

13 Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 23 July 2010, p. 7.

14 Mr Jason Waters, General Manager, Trading and Fuel, Verve Energy, *Transcript of Evidence*, 20 October 2010, p. 2.

15 Mr Basil Lenzo, Solicitor/General Counsel, Burrup Fertilisers Pty Ltd, *Transcript of Evidence*, 17 November 2010, pp. 1-2.

16 ACIL Tasman, *Gas Prices in Western Australia: Review of inputs to the WA Wholesale Energy Market*, May 2010, p. 5. www.imowa.com.au/f2138,484255/ACIL_Tasman_Final_Report_-_Updated.pdf. Accessed on 27 December 2010.

household sector nonetheless comprises around 600,000 dwellings with 46 per cent using gas as their main form of heating.[17]

(c) Suppliers' Profile

14. The Department of Mines and Petroleum advised that for 2009, 1304 PJ of gas was produced in Western Australia. DMP estimate that the majority of this (68 per cent) was converted to LNG for export and 27 per cent was sold to the domestic market. Of the balance, 3 per cent was converted to Liquefied Petroleum Gas (LPG), 1 to 2 per cent was flared during production and 1 to 1.5 per cent was reinjected into reservoirs.[18]

15. The major suppliers of gas to the Western Australian domestic market operate in joint venture (JV) partnerships. The most prominent is led by Woodside, whose North West Shelf JV supplies 66.2 per cent of the local market. Apache Energy Limited operates two other JVs, which supply 31.3 per cent of the market. Both Apache's and Woodside's operations produce gas from the Carnarvon Basin. The balance of domestic gas comes from a range of smaller projects in the Perth Basin, a predominantly on-shore strip of hydrocarbon resource running from Geraldton to Cape Leeuwin. Table 2 shows the breakdown of current producers.

Table 2 Joint Venture Projects as a Percentage of 2009 Domestic Sales[19]

Joint Venture	Participants (% Share)	Basin	Share of 2009 WA Market
NWS Gas Project[20]	BHP Billiton (8.33%) BP (16.67%) Chevron (16.67%) MIMI (0%) Shell (8.33%) Woodside Petroleum (50%)	Carnarvon	66.2 %
John Brookes	Apache (55%) Santos (45%)	Carnarvon	22.9%
Harriet Area	Apache (69%) KUFPEC (19%) Tap Oil (12%)	Carnarvon	8.4%

17 Australian Bureau of Statistics, *4656.5 - Household Choices Related to Water and Energy, WA October 2009*, 16 June 2010, pp. 10-12. Available at: www.abs.gov.au. Accessed on 28 December 2010.

18 Submission No. 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 6 October 2010, p. 6.

19 Wood Mackenzie, *Western Australia Gas Market Study*, 26 March 2010, pp. 21-22. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/application. Accessed on 23 March 2011.

20 NWS sales up to 550 TJ/d Woodside retains 50% share. For incremental sales above the threshold all partners (including MIMI) will have an equal 16.67% share. The threshold volume was reduced to 414 TJ/d effective from 1 July 2005. Wood Mackenzie, *Western Australia Gas Market Study*, 26 March 2010, p. 22. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/application. Accessed on 23 March 2011.

East Spar	Apache (55%) Santos (45%)	Carnarvon	Depleted
Griffin	BHP Billiton (45%) ExxonMobil (35%) INPEX Corporation (20%)	Carnarvon	Depleted
Beharra Springs	AWE (33%) Origin Energy (67%)	Perth	1.3%
Dongara Area	AWE (100%)	Perth	0.6%
Hovea Area	AWE (50%) Origin Energy (50%)	Perth	0.4%
Woodada	AWE (100%)	Perth	0.2%

(d) Development of Gas Market in Western Australia

16. The development of the Western Australian gas market was predominantly underpinned by an agreement entered into between the then State Energy Commission of Western Australia (SECWA) and the original North West Shelf JV partners.

17. In 1977 the government of Sir Charles Court negotiated an arrangement with the North West Shelf JV partners that was later (1979) ratified via a State Agreement.[21] The agreement was designed to develop the export potential of the vast hydrocarbon resources off the north-west coast and to support local industry with long-term supplies of gas. As part of the agreement, the joint venture committed to delivering a significant volume of gas to the local market over a period covering at least 20 years (under subsequent revisions to the State Agreement, this commitment has reached 5,064 PJ).[22]

18. To underwrite the development, SECWA, a government-owned entity responsible for the supply of gas and electricity to the state, entered into a contract with the joint venture in September 1980 to purchase approximately 414 TJ/day of gas for 20 years (3,020 PJ in total) commencing in 1985.[23] SECWA also funded the construction of a gas transmission pipeline extending from Dampier through to Bunbury.[24]

19. The contracted price of the gas under this “legacy contract” was around $2.50 per gigajoule (GJ). Whilst this appears cheap by today’s standards, the contract was expensive for the government of

21 North West Gas Development (Woodside) Agreement Act *1979* (Western Australia).

22 Submission No. 19 from Department of State Development, 30 June 2010, p. 6.

23 ACCC Determination (Final) in respect of joint marketing activities for the sale of domgas in Western Australia from the North West Shelf Project and to administer existing gas supply contracts [hereafter, ACCC Final Determination - NWS Project], 8 September 2010, s. 3.104.

24 DBP, ‘Pipeline History’, 2010. Available at: www.dbp.net.au/the-pipeline/history.aspx. Accessed on 28 December 2010.

the day because under the agreed 100 per cent "take-or-pay" provisions, SECWA paid for its allotted daily commitment regardless of whether it took delivery of the full balance. During the early years of the legacy contract, the government paid for a lot of gas that it did not need.[25]

20. On the back of the North West Shelf development, consecutive state governments promoted Western Australia as an economy with low prices and plentiful gas. Alcoa was a foundation customer, taking the first gas that flowed from the Dampier to Bunbury Natural Gas Pipeline (DBNGP) into its refineries at Kwinana, Pinjarra and Wagerup. Prior to this, Alcoa sourced small amounts of gas from a number of fields in the Perth Basin and relied mainly on oil for its power needs.[26]

21. When SECWA was disaggregated in 1995, the subsequent gas and electricity providers (AlintaGas and Western Power respectively) assumed independent legacy contracts with greater flexibility in the terms and conditions. Verve Energy then assumed responsibility for Western Power's legacy contract when the latter was disaggregated in 2006.

22. With the main pipeline infrastructure in place, several lateral pipelines (Griffin, Harriet, and Thevenard Island and Tubridgi) were established by other producers to supply gas to the local market from other areas of the Carnarvon Basin. The largest of these other producers was Apache Energy Limited (Apache). By the late 1990s, domestic gas was being supplied from nine separate sources (six in the Carnarvon Basin and three in the Perth Basin) and gas prices were reportedly in the range of $1.50 to $2.50 per gigajoule (GJ) at the field gate.[27]

23. By 2009, several of the smaller fields had been depleted and the production side of the local market had become highly concentrated and dominated by two producers, Apache and Woodside, leading joint venture operations.

24. With two major producers and five large customers representing 90 per cent of demand, the Western Australian gas market has been invariably described as 'lumpy' and 'project driven'.[28] For much of the last 25 years, with legacy contracts dominating the market place, such labels have been of little consequence with gas in abundant supply at prices low by interstate and international standards.

25. However, with new sources of demand emerging at a time when legacy contracts are due for renewal and the North West Shelf's 5,064 PJ domestic supply obligation is nearing fulfilment, the state's gas consumers have become increasingly concerned about the rising prices of gas.

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25 Mr Lyndon Rowe, Chairman, Economic Regulation Authority, *Transcript of Evidence*, 13 September 2010, p. 11.

26 Submission No. 24 from Alcoa of Australia, 30 July 2010, p. 6.

27 Submission No. 13 from Economic Regulation Authority, 1 July 2010, pp. 3-5.

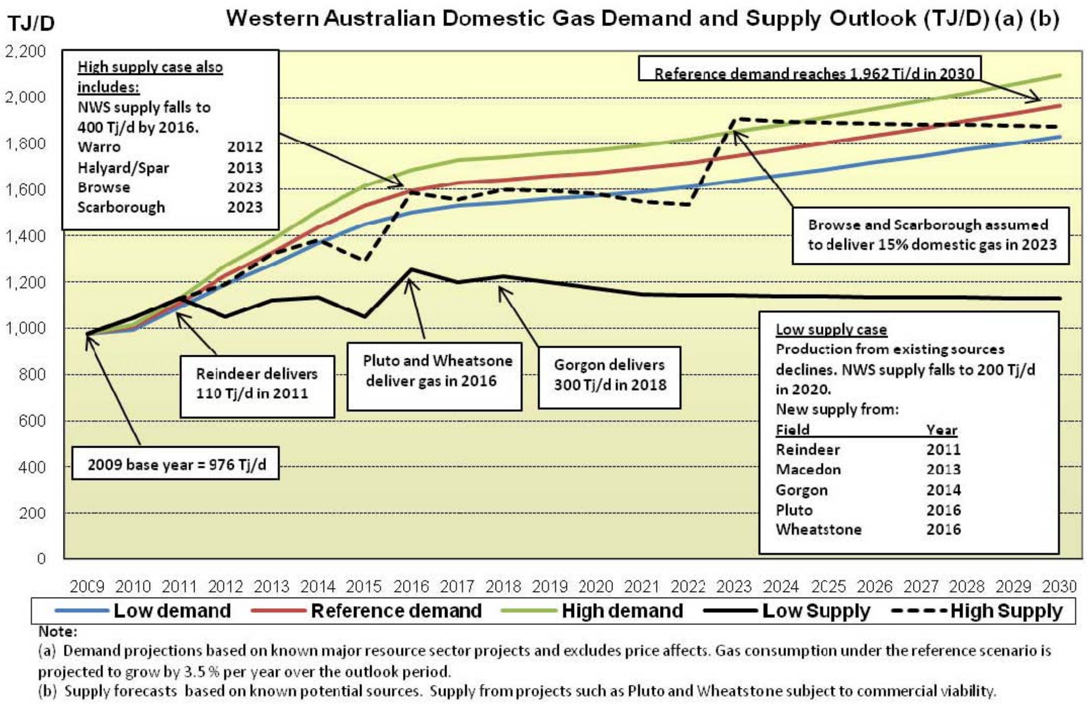
28 See, for instance, John Boardman, Independent Consultant, *Transcript of Evidence*, 11 October 2010, p. 3; ACCC Final Determination - NWS Project, 8 September 2010, s. 5.55.

1.2 The Gas Market Debate

26. This Inquiry has been motivated by the concern that the Western Australian domestic gas market faces an ongoing lack of supply that is leading to unacceptably high prices for local consumers. Speculation over current prices and the factors underpinning their upward movement has generated spirited debate among major stakeholders.

27. This debate gained momentum after the Department of Mines and Petroleum (DMP) published a domestic gas supply and demand forecast which, under one scenario, suggested that the supply of gas currently coming from the North West Shelf might drop by two-thirds by 2020 (see Figure 2). (Note: a revised supply and demand forecast from DMP has been released in March 2011 - see Figure 11 below).

Figure 2 Domestic Gas Supply and Demand Outlook (DMP September 2010)[29]



28. It is commonly accepted that Western Australia has enjoyed comparatively low wholesale gas prices over the last decade. Energy Quest states that:

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[29] Mr William Tinapple, Executive Director, Petroleum Division, Department of Mines and Petroleum, 'New Initiatives for Energy Resources in Western Australia', Presentation at the Petroleum and Geothermal Open Day, 9 September 2010. Available at: www.dmp.wa.gov.au/10686.aspx. Accessed on 15 February 2011.

Until recently, upstream prices were around $2-3 per gigajoule in Western Australia and $3-4 per gigajoule in the east coast. In contrast, US gas prices (an indicator of gas prices globally) peaked at over US$12 per gigajoule in mid-2008[30]

29. However, the landscape has clearly changed. In July 2010 the *Australian Financial Review* reported that: 'WA businesses coming off contracts are now routinely paying between $8 and $9 a gigajoule, although some are understood to be paying double-digit prices.'[31]

30. The Australian Energy Regulator confirmed that short-term wholesale prices reached almost $17 per gigajoule after an explosion at Apache Energy's Varanus Island processing facility reduced the supply of domestic gas by 30 per cent for two months from June 2008.[32]

31. The Office of Energy advised that '…new supply contracts have been quoted as having reached levels of up to $14-$16 per gigajoule.'[33] In support, they cited a lower volume contract that Moly Metals signed with Santos in October 2008 at a reported price of $16.20 per GJ.

32. The DomGas Alliance, Western Australia's peak energy user group, argue that prices in this state are now three times that in Victoria and are more reflective of prices in energy poor nations like China and Japan.[34]

33. The Premier expressed his concern in April 2010 that domestic gas prices were '…probably 30 to 50 per cent above what world prices are now.' [35] Whilst conceding that there were some mitigating factors, Mr Barnett added that, '…for the long term we cannot have that persist.'[36]

34. When considering the reasons for the reported price increases, the Department of Mines and Petroleum argue that the primary issue facing the local market is a lack of supply leading on to higher prices although they also concede that newer contracts are moving closer towards LNG "netback"[37] equivalent prices.[38]

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30 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 28.

31 Kerr, P., & Barrett, J., 'WA businesses hit by gas attack', *Australian Financial Review*, 20 July 2010, p. 3.

32 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, pp. 233, 245.

33 Office of Energy, *Energy 2030: Strategic Energy Initiative Issues Paper*, Perth, December 2009, p. 6.

34 Mr Gavin Goh, Executive Director, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 2. See also, Submission No. 3 from DomGas Alliance, 24 June 2010, p. 1.

35 Hon. C Barnett, MLA, (Premier), *Transcript of Interview - 6PR*, Media Monitoring Unit, Department of Premier and Cabinet, 16 April 2010, p. 4.

36 ibid.

37 The netback price can be calculated in a variety of ways but is commonly considered to be the delivered price of an LNG cargo less the costs of transport, liquefaction and marketing.

38 Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, pp. 4, 9.

35. The Office of Energy concurs with the supply shortage thesis, but attributes this to the 'pendulum' nature of the Western Australian market. As a project-driven market, the state is prone to periods of oversupply and undersupply.[39]

36. For the DomGas Alliance, this period of undersupply has been contrived. The Alliance argues that producers are able to 'keep their foot on the hose' allowing only small volumes to be sold for short terms at high prices. Moreover, they claim that LNG producers are 'warehousing' gas fields that could be developed to supply the domestic market in order to boost their exportable reserves. This, DomGas Alliance argues, is a consequence of a lack of competition in the upstream gas sector.[40]

37. Alcoa is also concerned by the lack of upstream competition suggesting that supply will always be constrained while production remains highly concentrated.[41]

38. Responding on behalf of the upstream producers, the Australian Petroleum Production and Exploration Association (APPEA) argues that despite the short-term lack of supply, the market is healthy and functional. Recent higher prices have generated an unprecedented response in the way of new projects that will increase production capacity and alleviate the supply situation over the next five years.[42]

39. The North West Shelf concedes that domestic gas prices (hereafter "domgas prices") had risen, but adds that '…under the cover of speaking up for mums and dads…industrial gas users continue to argue for subsidised prices to benefit their bottom line.'[43]

40. As to the argument that LNG producers warehouse reserves for export markets, the North West Shelf counters that LNG projects are actually "enablers" of domestic supplies. Many offshore fields that supply the local market have only been developed because the large volumes of gas sought by international customers have made the projects viable.[44]

41. Apache assured the Committee that 'the gas is there in abundance.'[45] However, customers had to be realistic with their expectations of the price at which new reserves can be commercially developed.

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39 Ms Anne Hill, A/Coordinator, Office of Energy, *Transcript of Evidence*, 11 October 2010, p. 6.

40 Submission No. 3 from DomGas Alliance, 24 June 2010, pp. 4-5.

41 Mr Michael Parker, Director, Business Development and Marketing, Alcoa of Australia, *Transcript of Evidence*, 17 November 2010, p. 2.

42 Mr Tom Baddeley, Director (WA), APPEA, *Transcript of Evidence*, 20 September 2010, p. 2.

43 Mr Kevin Gallagher, Chief Eexecutive Officer, North West Shelf, *Transcript of Evidence*, 18 October 2010, p. 2. See also, Submission No. 16 from NWS Project Participants, 2 July 2010, p. 8.

44 Submission No. 16 from NWS Project Participants, 2 July 2010, p. 11.

45 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy Limited, *Transcript of Evidence*, 20 September 2010, p. 2.

(a) Impact of Higher Gas Prices

(i) Industry

42. The importance of a reliable and competitively priced gas supply was evident during the period that the Varanus Island processing facility was out of commission following the June 2008 explosion. The combination of diminished supply and higher prices for emergency tranches that were made available from other sources (see 30 above) is reported to have cost the state's economy $2 billion.[46]

43. Alcoa argued that access to competitively priced gas has '…been a source of competitive advantage for exporting industries in Western Australia and one of the reasons for locating their businesses in the region.'[47] In addition to undermining this advantage, price increases of the magnitude being witnessed will affect the cost of living and of conducting business in the state.[48]

44. Alcoa contends that Western Australia's ability to compete in the global alumina industry is contingent upon 'certainty over **long-term competitively priced energy supply**.'[49] Already Alcoa's decision to postpone its expansion of the Wagerup refinery was partly attributable to 'the lack of long-term domestic gas supplies.'[50] With LNG producers looking to link domestic gas contracts to oil indexes, Alcoa argues it will have to consider increasing its reliance on coal as a substitute fuel for its power generation if gas prices settle between A$8-$16 GJ.[51]

45. Burrup Fertilisers was the recipient of very cheap gas when constructing its ammonia processing facility in 2003[52]. The company advised the Committee that any expansion plans it has considered would be shelved unless it could obtain $5 per GJ gas.[53]

46. Companies like Burrup Fertilisers are almost exclusively reliant on gas as a feedstock in its manufacturing process and, unlike Alcoa, do not have the option of switching to cheaper substitutes such as coal. As Anne Nolan, Director General of the Department of State

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46 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 251.

47 Submission No. 24 from Alcoa of Australia, July 2010, p. 2.

48 ibid. See also, Submission No. 8 from Verve Energy, 25 June 2010, p. 8.

49 Alcoa's emphasis. Submission No. 24 from Alcoa of Australia, July 2010, p. 9.

50 Submission No. 24 from Alcoa of Australia, July 2010, p. 6.

51 ibid., p. 3.

52 This 25 year contract to supply 707PJ was signed in December 2001. Mr Basil Lenzo, Solicitor/General Counsel, Burrup Fertilisers Pty Ltd, *Transcript of Evidence*, 17 November 2010, pp. 1, 4. The price on the contract was reported to be in the vicinity of $0.86 to $1.60 per gigajoule. See Submission No. 19 from Department of State Development, 30 June 2010, p. 10.

53 Mr Basil Lenzo, Solicitor/General Counsel, Burrup Fertilisers Pty Ltd, *Transcript of Evidence*, 17 November 2010, p. 5.

Development (DSD), told the Committee: 'I think it would be a reasonable expectation to say that if gas is your feedstock, at $8 a gigajoule, you might find alternative options in the world.'[54]

47. Interestingly, APPEA challenges the claims of exporters such as Alcoa and Burrup Fertilisers, arguing that these companies could absorb the rise in gas prices as the commodities they sell enjoy exposure to international market prices.[55]

48. The state's power generators and retailers expressed concern about their ongoing ability to procure gas for reasonable periods at sustainable prices. Verve Energy said that it was budgeting for higher wholesale gas prices into the future. The South West Interconnected System (SWIS) is predicted to nearly double its 5000 megawatt capacity over the next 10 to 20 years. During this time Verve is hoping to have its current 3,000 megawatt capacity limit increased allowing it to build an extra 2,000 megawatts of plant.[56] However, at $8 - $10 per gigajoule, '[gas]…is completely priced out of the market.'[57] If high gas prices endure '…we may have no option but to essentially continue to build coal plant to our current standard.'[58]

49. Electricity retailer Synergy agreed with Verve Energy's prognosis, adding that despite the likely switch to coal, the cost of maintaining the substantial level of gas-fired generation capacity to manage peaks in the system will still result in increased electricity prices.[59]

50. Horizon Power is a government trading enterprise that generates power and retails gas and electricity in areas that fall outside the SWIS. It advised the Committee that, 'Access to cheap, secure and reliable energy is something that is important to the development of regional WA.'[60]

51. Horizon receives a subsidy through a "tariff equalisation fund", which enables it to supply electricity at cost to small towns in regional areas. When the expiry of older contracts sees it re-enter the market, Horizon expects that any steep price increases it is exposed to will ultimately be borne by the government via the tariff equalisation process.[61]

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54 Ms Anne Nolan, Director General, Department of State Development, *Transcript of Evidence*, 13 September 2010, p. 6.

55 Submission No. 10 from APPEA, 25 June 2010, p. 8.

56 Mr Jason Waters, General Manager, Trading and Fuel, Verve Energy, Transcript of Evidence, 20 October 2010, p. 2

57 ibid., p. 7.

58 ibid., pp. 3-4.

59 Mr James Mitchell, Managing Director, Synergy, *Transcript of Evidence*, 20 October 2010, p. 2.

60 Mr Frank Tudor, General Manager, Strategy and Business Development, Horizon Power, *Transcript of Evidence*, 13 October 2010, p. 3.

61 ibid., p. 6.

(ii) Household

52. While representing a fraction of overall consumption, the household sector has still been affected by increasing power costs. It is important to note that the wholesale price of gas only represents up to 30 per cent of the final retail price paid for gas[62] and an even lower portion of an electricity bill. Even so, the Office of Energy confirmed that the '…wholesale price of gas has had a significant impact on the regulated gas tariffs'[63] facing householders.

53. The Committee was advised that regulated gas retail tariffs for the 'median customer' were increased on three occasions between 2008 and 2010 by a total of between 27 to 32 per cent above CPI.[64] During a cold snap in Perth on 7 July 2010, various media outlets[65] reported that:

- household power costs (gas and electricity) had risen by 40 per cent since April 2009;
- amounts outstanding on bills increased from $1 to $9 million over the past year; and
- pensioners and low income earners were foregoing heating their homes due to the expense of their power bills.

54. The Office of Energy confirmed that '…there had been a significant increase in the number of gas customers who are subject to an instalment plan'[66] and that 20 per cent of Synergy's retail customers [electricity] had been given payment extensions. There had also been a doubling in the number of Synergy customers who received assistance via the Hardship Utility Grants Scheme.[67] Similarly, after Alinta made the scheme available to its retail gas customers in 2009-2010, 1,641 applicants received assistance.[68]

1.3 The Inquiry into Domestic Gas Prices

55. Since 2009, two papers have been commissioned to examine various aspects of the domestic gas market in Western Australia.

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62 Submission No. 12 (A) from Office of Energy - Response to Question on Notice, 3 November 2010, p. 6.

63 ibid.

64 ibid., p. 3.

65 *ABC Television News (7.00pm)*, 2010, television program, Perth, 7 July. See also, *Channel Ten News (5.00pm)*, 2010, television program, Perth, 7 July.

66 Submission No. 12 (A) from Office of Energy - Response to Question on Notice, 3 November 2010, p. 10.

67 The Hardship Utility Grants Scheme is operated by the Department of Child Protection. It will be discussed in more detail in Chapter 7.

68 Submission No. 12 (A) from Office of Energy - Response to Question on Notice, 3 November 2010, pp. 10-11.

56. The government formed the Gas Supply Emergency Management Committee (GSEMC) to review the security of the state's gas supplies after the Varanus Island explosion in June 2008 and a 53-hour total shut down of the North West Shelf JV's Karratha Gas Plant six months earlier. The GSEMC presented its final report to government in September 2009.[69]

57. The Office of Energy, which coordinated the GSEMC project, is now in the midst of compiling an overview of the state's entire energy sector. The *Strategic Energy Initiative* will '…outline the plans, strategies, policies and regulatory frameworks needed to ensure a range of energy supply options are available to meet our future needs under various scenarios.'[70] The *Strategic Energy Initiative* is due to be completed by mid-2011.

58. Where this new Inquiry of the Economics and Industry Standing Committee (EISC) differs is with its specific focus on the price of gas. On 20 April 2010, the Legislative Assembly referred 'the issue of domestic gas prices for industry and consumers'[71] to the Committee.

59. Given the state's abundance of natural gas reserves, both sides of the House echoed the earlier concern of the Premier (see 33 above) that domestic consumers may be paying more than overseas customers for locally produced gas.[72]

60. Accordingly, the referred terms (see (1) on page vii) have asked the Committee to compare the prices paid for domestic natural gas and LNG in this state and to explain the reasons for any differences observed.

61. A similar comparison is to be undertaken between local domgas prices and those paid in other Australian jurisdictions: most notably Victoria, which is cited as an exemplar of efficient gas markets.

62. Finally, the Committee has been asked to make recommendations on any measures that could be implemented to reduce the price of gas in Western Australia.

63. As part of its research, the Committee called for submissions throughout May and June 2010 and received a total of 27 formal responses. Between June and November, the Committee then held 36 formal hearings and four private briefings.

64. At the beginning of September, the Committee undertook a week of investigative travel to Brisbane, Sydney and Melbourne where it received a further 14 briefings. Several members of the Committee then travelled to Texas in November to attend the World Shale Gas Conference. During this trip another two private briefings were held. Full lists of those who provided a

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69 Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009.

70 Office of Energy, *Energy 2030: Strategic Energy Initiative - Issues Paper*, Perth, December 2009, p. 2.

71 Hon. G Woodhams, MLA, Speaker, WA, Legislative Assembly, *Parliamentary Debates* (Hansard), 20 April 2010, p. 1504.

72 See Mr. M McGowan, MLA, WA, Legislative Assembly and Hon. Dr. K Hames, MLA, Deputy Premier, WA, Legislative Assembly, *Parliamentary Debates* (Hansard), 20 April 2010, pp. 1505-1507.

submission and appeared before or met with the Committee are included in Appendices 1 and 2 at the back of the report.

65. The Committee has attempted to obtain input from a representative sample of the parties who are involved in the gas supply chain. This includes explorers; LNG and domgas producers; major domgas customers; transmission and distribution network operators; retailers; regulators and consumer advocates.

66. The information received has given the Committee greater insight into a market that is shrouded in secrecy and dominated by highly confidential bilateral contracts. In the domgas market, these contracts are valued at over $1.3 billion dollars a year whilst LNG projects are valued in the tens of billions of dollars. The lack of transparency in the market is understandable to some extent, given the value of the commercial negotiations being undertaken. Nonetheless it is still problematic, as it lends itself to constant speculation around the level of prices and the terms and conditions that underpin them. This leads to an important caveat that the Committee wishes to place at the outset of this report.

67. It is critical that the findings and recommendations of the Committee—which can influence subsequent government policy—are based on the most accurate information available. For this Inquiry, much of the most pertinent information required is commercially sensitive and highly confidential. When requesting such material, the Committee has given regular undertakings that the information received would be treated as *in camera* evidence. Under Standing Order 271(3) of the Legislative Assembly, a Committee can not publish or disclose evidence taken *in camera* unless it receives the written approval of the witness. *In camera* status was afforded to all or part of 16 of the Committee's formal hearings and to the sample of contract data it summonsed from nine commercial entities.

68. While the Committee can not refer directly to any material it has taken *in camera*, readers should be aware that this information has, in many instances, influenced the findings and recommendations that follow.

69. An additional caveat is offered regarding the theoretical framework that has shaped this report. Members of the Gas Supply Emergency Management Committee—many of whom contributed to both sides of the debate during this current Inquiry—endorsed in 2009:

> *Support for markets as the preferred mechanism to manage the balance between demand and supply*[73]

70. While the Committee supports this principle, it is also aware that a degree of regulation is required occasionally to ensure that markets are operating with maximum efficiency and effectiveness. Determining the appropriate balance is crucial.

[73] Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009, p. 7.

71. The findings and recommendations that follow aim to ensure that the market is developed to operate as efficiently and effectively as possible.

72. The Committee would like to thank all witnesses and contributors to the Inquiry for their cooperation, but particularly all those who were asked to provide commercially sensitive material.

CHAPTER 2 FUTURE DEMAND AND SUPPLY OF NATURAL GAS IN WA

73. The demand and supply of natural gas is important to this inquiry because the interaction between the two determines the price of new supplies coming into the market.

2.1 Natural Gas Forecasts

74. The Committee is aware of natural gas forecasts produced by the Chamber of Minerals and Energy (CME), the WA Department of Mines and Petroleum (DMP), Economic Consulting Services (ECS) and the Australian Bureau of Agricultural and Resource Economics (ABARE).

75. The general tenor of the first three of the forecasts referred to in paragraph 74 above is that Western Australia faces future supply shortfalls that will put upward pressure on natural gas prices which, given the importance of natural gas to the Western Australian economy, will adversely impact economic activity.

76. Future domestic demand for natural gas will depend on a range of factors including the general level of economic activity; the demand for commodities, especially those produced for export; population growth; the price of natural gas into the domestic market; and the price of natural gas relative to other fuels. Some factors such as price are interdependent in that increased demand will tend to put upward pressure on price which in turn would be expected to moderate the increase in demand.

77. The CME forecast, published in November 2009, projected an upper level compound annual growth in demand for natural gas (state-wide and for all industries) of 5.3 per cent. Scenarios for moderate and constrained growth in demand produced lower average annual growth rates.[74]

78. A recent natural gas forecast published by DMP projects gas demand for a reference case scenario to grow at a rate of 3.5 per cent per annum. Low and high growth demand scenarios are also provided.[75]

79. Similar to DMP, the ECS forecast also uses a project-based analysis and estimates gas demand to increase above 2009 levels by 490 TJ/d in 2015 and 620 TJ/d in 2020.[76] The 2020 estimate implies a cumulative annual growth in demand of 4.6 per cent to 2020.

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74 For further information see The Chamber of Minerals & Energy Western Australia, *Developing a Growth Outlook for WA's Minerals & Energy Industry*, 18 December 2008. Available at: www.cmewa.com/UserDir/CMEPublications/090324-MEM-Developing%20a%20Growth%20Outlook%20for%20WA's%20Minerals%20and%20Energy%20Industry-v179.pdf

75 See: Department of Mines and Petroluem, *Petroleum in Western Australia September 2010*, September 2010, p. 21. Available at: www.dmp.wa.gov.au/documents/Petroleum_in_WA_magazine_09_10.pdf,. See also, Figure 2 above.

80. It is important to ascertain the veracity of these forecasts in order to determine the true magnitude of any ongoing and future supply crisis so that subsequent policy responses will not inadvertently distort the market.

(a) Historical Demand

81. As a starting point for determining for determining a robust forecast, it is useful to compare demand projections against historical information to assess whether they are generally consistent with what has happened in the past. While forecasts may depart from historical trends, it is important to understand why such departures are anticipated. The following paragraphs therefore look at the historical information available on the demand for natural gas in Western Australia.

82. Again, there are various sources of historical information covering the production of and demand for natural gas. As discussed below, there are differences between these sources of information, which in some cases are quite significant.

83. The main providers of natural gas production, sales and demand information are DMP[77], the Australian Petroleum Production and Exploration Association Ltd (APPEA)[78] and ABARE[79].

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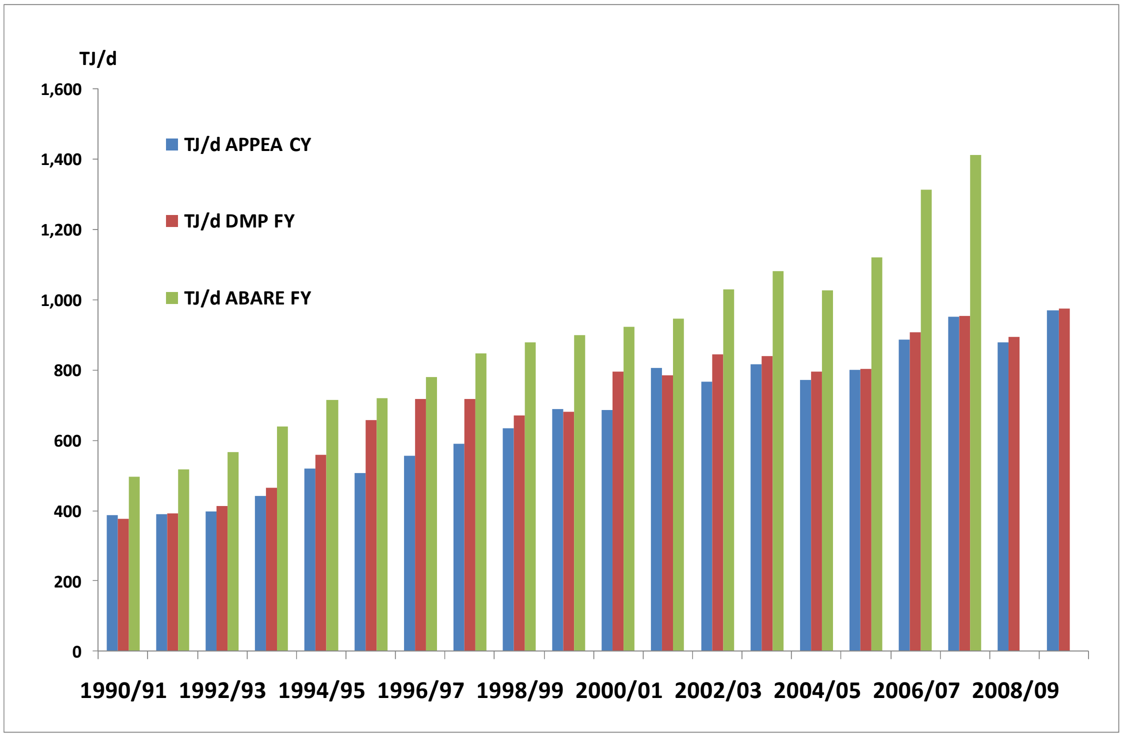
76 The ECS forecast is published on the Domgas Alliance website. Domgas Alliance, *Western Australia Natural Gas Demand and Supply - A Forecast*, report prepared by Economics Consulting Services, Perth, June 2010. Available at: www.domgas.com.au/pdf/Media_releases/2010/A%20-%20Domgas%20demand%20report%20-%20REVISED%20FINAL%20-%2025June10.pdf. Accessed on 19 March 2011.

77 DMP regularly publishes information on the quantity and value of minerals and petroleum produced in Western Australia..Department of Mines and Petroleum, *Western Australian Mineral and Petroleum Statistics Digest 2009*, Government of Western Australia, April 2010. Available at: www.dmp.wa.gov.au/documents/Western_Australian_Mineral_and_Petroleum_Statistic_Digest_2009.pdf. Accessed on 19 March 2011. In addition, statistical reports are published on the DMP website. Department of Mines and Petroleum, 'Production Statistics'. Available at: www.dmp.wa.gov.au/1938.aspx. Accessed on 1 9 March 2011.

78 APPEA, 'Statistics'. Available at: www.appea.com.au/index.php?option=com_content&view=section&layout=blog&id=53&Itemid=600003. Accessed on 19 March 2011.

79 ABARE, 'ABARE Data'. Available at: www.abare.gov.au/publications_html/data/data/data.html. Accessed on 19 March 2011.

Figure 3 Production of Natural Gas, Western Australia 1990/91 to 2009/10, TJ/d



Note: The data for APPEA is for calendar years (CY) ending 2009 whereas the others are financial years as shown (FY).

84. As shown in Figure 3, the series by ABARE is consistently above those of the other two. It is understood that ABARE's definition of domestic consumption differs from the "sales gas" concept used by DMP and APPEA in that ABARE includes, among other things, gas used in the production of LNG (excluding feedstock gas) as part of the domestic stream whereas DMP and APPEA do not.[80]

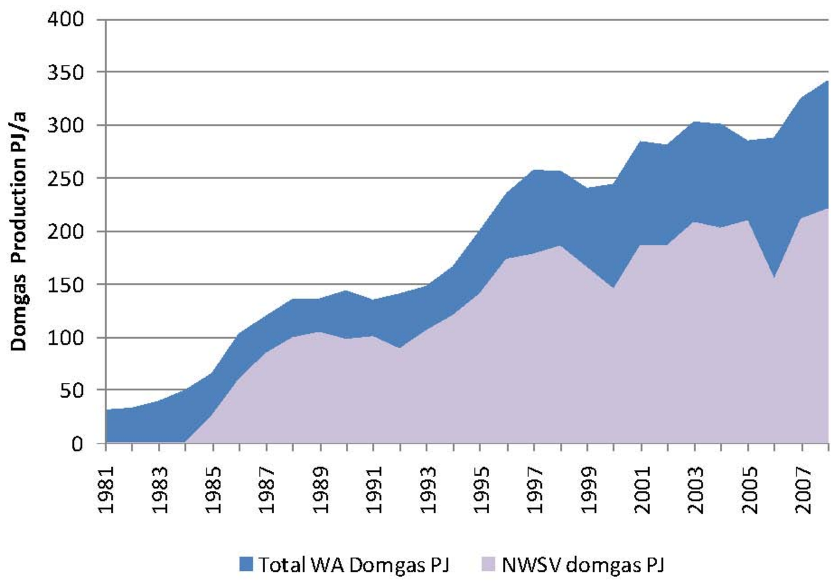
85. The series by DMP and APPEA are closely correlated, particularly in more recent years, even though the series for APPEA is in calendar year terms ending six months before that of DMP. The series by DMP is in financial year terms. The two series, however, diverge significantly in the three years 1995/6 to 1998/9. Inspection of Figure 3 suggests that the APPEA data is likely to be a better estimate for the three years in question for the reason that its relativity to the ABARE series is more constant.[81]

[80] Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 21.

[81] APPEA sources its sales gas data directly from its members on gas production supplied directly to market. Submission No. 10 (A) from APPEA - Response to Question on Notice, 13 October 2010, p. 6. Also refer to Submission No. 10 (A), from APPEA - Response to Question on Notice, 13 October 2010, footnote 4.

86. The Committee is aware of two other historic gas consumption series which were brought to its attention in submissions. One raised in the submission by the Economic Regulation Authority provides a chart prepared by ACIL Tasman (Figure 4) which shows Western Australia's domgas production for the period 1980 to 2008. This chart, which is expressed in petajoules (PJ) per annum, is broadly consistent with information provided by DMP.

Figure 4 Western Australian Domgas Production 1980 - 2008[82]



87. The other historic series was presented by Wood Mackenzie in its report "Western Australian Gas Market Study" published on the Australian Competition and Consumer Commission's (ACCC) website (Figure 5).[83] The report was submitted to the ACCC as Attachment 1 by Freehills in a submission on behalf of the North West Shelf Project participants as part of an application for authorisation of joint marketing.[84] The Wood Mackenzie report was referenced by the North West Shelf Project partners in its submission to this inquiry.[85]

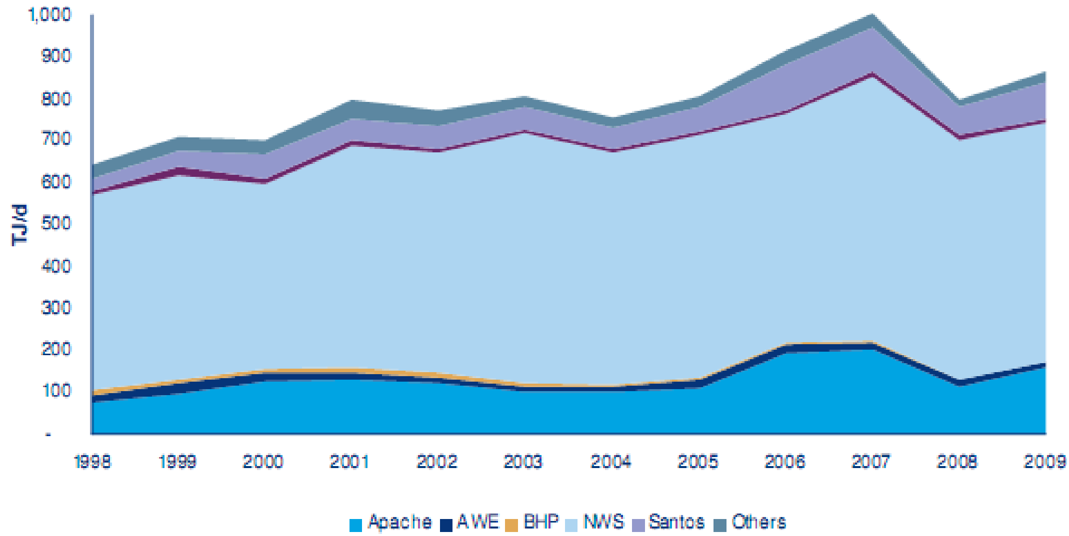
82 ACIL Tasman, *Gas Prices in Western Australia: Review of inputs to the WA Wholesale Energy Market*, May 2010, p. 3. Available at: www.imowa.com.au/f2138,484255/ACIL_Tasman_Final_Report_-_Updated.pdf. Accessed on 27 December 2010. Citing Western Australian Department of Industry and Resources and ACIL Tasman estimates.

83 Wood Mackenzie, *Western Australia Gas Market Study*, 26 March 2010. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/application. Accessed on 23 March 2011. Discussion on Wood Mackenzie's historic gas sales series is at pages 19 to 22 of this report.

84 Application and submission lodged on 31 March 2010, ACCC authorisations A91220 to A91223.

85 Submission No. 16 from North West Shelf Project Participants, footnote 11, p. 6.

Figure 5 WA Domestic Market Gas Sales Volumes – By Seller



Source: Wood Mackenzie

88. Except for the last three years, the Wood Mackenzie series appears to be reasonably consistent with that produced by APPEA. For 2007, the Wood Mackenzie data appears to be well above that of APPEA and DMP whereas for 2008 and 2009 it appears to be well below.

89. Differences between the various sources of historical information raise questions about the definitions used in compiling historical gas demand and average price data.

90. In response to a question from the Committee on its definition of "sales gas" DMP responded that, 'This value is based on the summation of total domestic gas sales values at the point of entry into the Dampier to Bunbury natural gas pipeline (DBNGP), or where applicable, the Parmelia Pipeline.'[86] In response to a further question from the Committee, the department advised that:

> *The Goldfields Gas Pipeline licence was granted in August 1995 to connect with the DBNGP. Prior to connection to the DBNGP sales gas was valued as per the dollar value on audited sales invoices as per contract prices submitted to DMP by the producer. Gas coming from Commonwealth waters would have been estimated at the average sales price of natural gas into the DBNGP.*[87]

91. DMP also confirmed that:

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86 Submission No. 18(B) from Department of Mines and Petroleum - Response to Question on Notice, 23 December 2010, p. 1.

87 Submission No. 18(C) from Department of Mines and Petroleum - Response to Question on Notice, 1 February 2011, p. 1.

> *As Griffin is in Commonwealth waters, sales gas was values [sic] were estimated at the average sales price of natural gas into the DBNGP. Sales quantities were derived from monthly reports submitted to DMP complying with petroleum legislation.*[88]

92. In addition, DMP advised that, 'As Blacktip is in Commonwealth waters and all sales gas is sold through a pipeline to the Northern Territory it was not included in the Western Australian figures.'[89]

93. The information provided by DMP concerning the definitions used in compiling historical gas demand and average price data indicates that a degree of estimation is involved in the compilation of this data. In making use of this data for the purposes of:

- projecting demand, as discussed in this section of the report; and
- analysing average price, discussion of which commences at paragraph 178 below,

there is a need to be cautious in interpreting the outcomes of any such analysis.

94. The Committee also has concerns relating to the assumptions that have been made about the future supply of natural gas to the Western Australian domestic gas market. The Committee's consideration of issues concerning supply commences at section 2.1(c) below.

Finding 1

Differences in historical information on the demand for natural gas in Western Australia as between the main providers of such information are of concern. There is a need for demand, supply and price information to be of good quality and a review of the methodology, assumptions and historical database would appear to be warranted.

Recommendation 1

That the Department of Mines and Petroleum review the methodology, assumptions and historical database of natural gas supply and demand (including average price information) for Western Australia to confirm the veracity of this information.

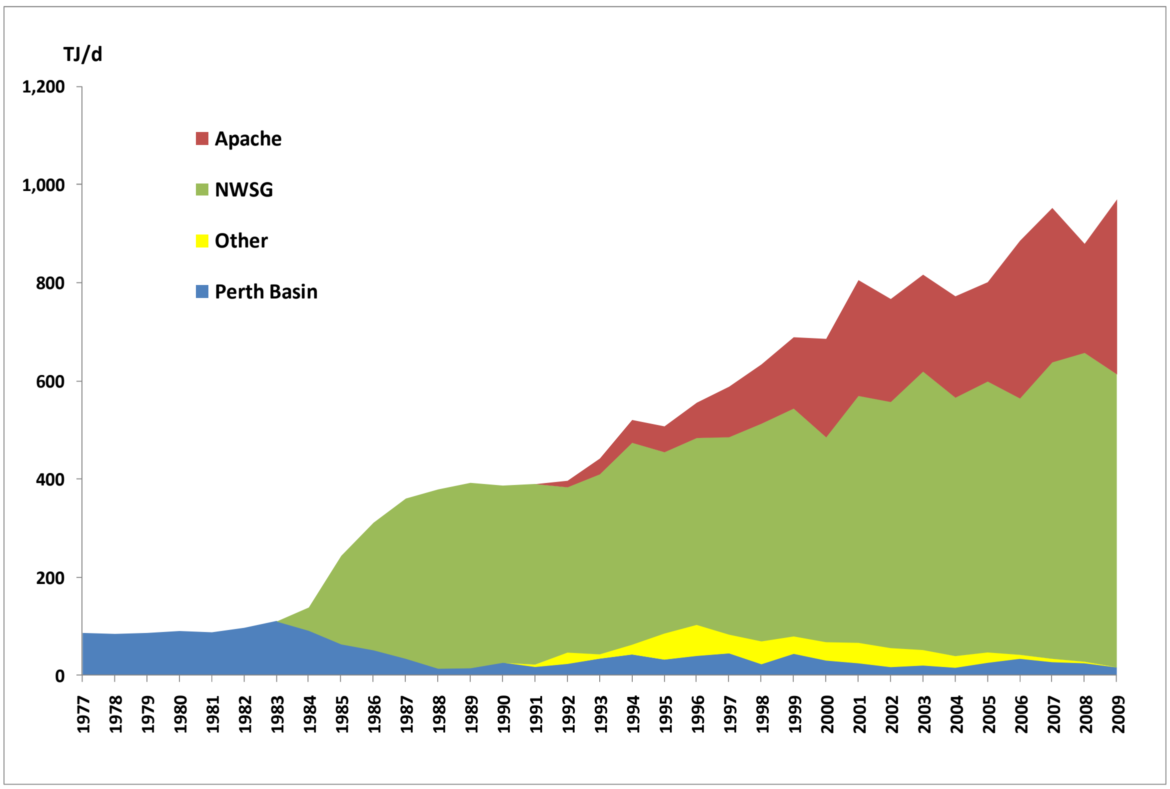
88 Submission No. 18(C) from Department of Mines and Petroleum - Response to Question on Notice, 1 February 2011, p. 1.

89 ibid.

95. The following analysis of historical data is, for the reasons set out in paragraph 85 above, based on the information published by APPEA.

96. Figure 6 below illustrates historical sales gas data for Western Australia grouped into four main categories. Apache includes the Harriet group and those supplying gas via Varanus Island. NWSG refers to production from the North West Shelf Gas joint venture on the Burrup Peninsula. The Perth Basin includes all production from that basin in the years shown. The “Other” category includes production from Tubridgi, Griffin and Thevenard Island. It should be noted that a small amount of gas (6 TJ/d) produced in the Bonaparte Basin from the Blacktip field in 2009, and presumably shipped to the Northern Territory, is excluded.

Figure 6 Sales Gas Western Australia 1977 to 2009 Calendar Years



Committee’s calculations in Figure 6 are based on APPEA Production Statistics, Sales Gas Western Australia. http://www.appea.com.au/index.php?option=com_content&view=section&layout=blog&id=53&Itemid=600003

97. In line with comments made in submissions[90], Figure 6 shows the increased concentration of upstream sales to two producer groups labelled Apache and NWSG. The figure shows this concentration to have occurred over the past 13 years. In 2009, the Perth Basin is shown to have produced only 17 TJ/d of sales gas while there was no production from the “Other” category.

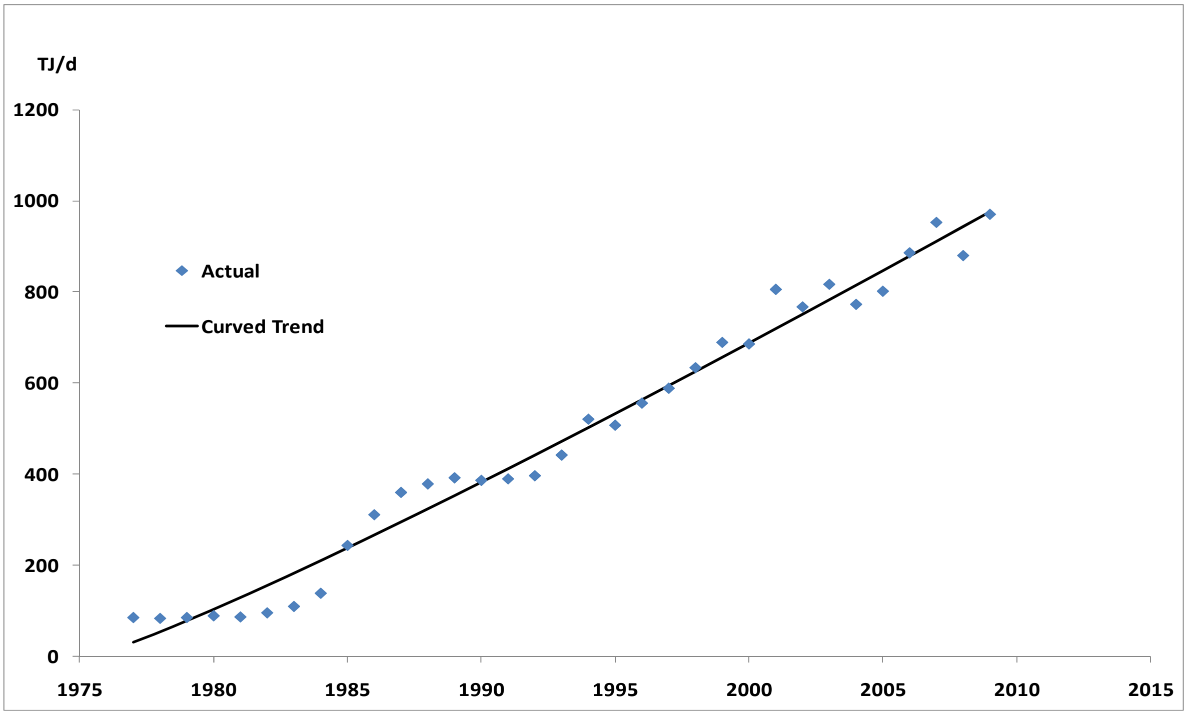
90 For example, Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 34.

98. Concentration in the upstream domgas market raises legitimate concerns about competition in that market. Without gas on gas competition, suppliers have the opportunity to drive prices up to the cost of alternative fuels, which in the case of distillate is estimated at around $20 per GJ.[91] Issues concerning competition and pricing are discussed in more detail in 3.2 below.

Finding 2

In recent years, the production side of the Western Australian domestic gas market has become highly concentrated. Such concentration raises legitimate concerns about the level of competition and effectiveness of this market.

Figure 7 Sales Gas Trend Western Australia 1977 to 2009 Calendar Years



Committee's calculations in Figure 6 are based on APPEA Production Statistics, Sales Gas Western Australia http://www.appea.com.au/index.php?option=com_content&view=section&layout=blog&id=53&Itemid=600003

[91] Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 34.

99. While various forms of trend analysis were examined, Figure 7 shows that there is a clear near straight line trend in sales gas over the period 1977 to 2009.[92] As shown in the figure, Western Australia has experienced some periods of strong growth. However, over the period since the first recorded sales on the APPEA data base (1977), the market has expanded annually by around 30 TJ/d. With the trend being close to a straight line, the rate of growth in demand has therefore declined over time. For example, the average annual rate of growth has declined from around 8.8 per cent for the thirty year period 1979 to 2009 to around 4.1 per cent over the last ten year period 1999 to 2009.

Finding 3

The demand for natural gas for use in Western Australia has expanded annually by an average of around 30 terajoules per day since the first year of recorded sales (1977) on the APPEA data base.

(b) Future Demand

100. Looking forward, there are many uncertainties that will have a bearing on the future domestic demand for natural gas. There are also other factors that will shape future demand about which the Committee can be more confident. The Committee has examined these both by reference to the forecasts that have been cited in submissions and by examining other available forecasts relating to energy and economic activity more generally.

101. Major uncertainties include the future price of crude oil, the price of carbon and the timing of a carbon abatement program in Australia, future growth in the world economy and the impact of this on the demand for resources related commodities. Other matters on which well researched information is available include short to medium term projections of future economic growth in the state, population growth projections and utility expansion programs.

102. As discussed in paragraphs 77 to 79 above, the three main forecasts made known to the Committee through submissions provide projections of demand for natural gas in Western Australia ranging from a low of around 3 per cent per annum to a high of 5.3 per cent per annum. If, however, the near straight line trend illustrated in Figure 7 above were to continue until 2030, which is the period of the DMP forecast, this would be equivalent to an average compound annual growth of 2.6 per cent over the 21 years.

92 A least squares time series trend of the form Sales=a+b(Time)^k showed a slight improvement on a simple straight line estimate. Parameter values are: a=10.9315 (14.1769); b=19.5951 (0.5046); k=1.1147; R^2=0.9799; numbers in parenthesis are standard errors. The value "k" is a constant determined using a methodology that further minimises the residual sum of squares.

103. It is therefore useful to ask what factors would be likely to cause the demand for natural gas in the state to increase at rates above or below those of past trends. The following discussion is focussed on those factors.

104. Forecasts by CME, DMP and ECS, referred to in paragraph 74 above, envisage considerable expansion in demand for natural gas in Western Australia. The projected growth in demand for natural gas by CME, DMP and ECS is well above the trend defined by the near straight line shown in Figure 7 above. The expansion in demand is attributed to a booming resources sector responding to strong overseas demand, particularly from China.

105. While actual demand has tracked the long-term trend quite closely for most of the last 15 years, it is clearly possible that, looking forward, demand will move above and perhaps well above the trend shown in Figure 7.

106. The studies undertaken by DMP and ECS, which are more recent than that by CME, have mainly relied on aggregating the projected energy demands of known proposed resource projects over time. ECS, in its report, also presents a trend analysis but does not draw attention to the near straight line nature of historic demand.

107. The difficulties associated with aggregating demand on a project by project basis are well recognised and acknowledged in the reports. Among the difficulties is the need to make judgements or assumptions such as which projects are likely to proceed and which are not. This is further exacerbated by the studies not directly taking into account the impact that changes in gas prices would have.

108. The Committee sought information from both DMP and the Domgas Alliance on the price sensitivity of the prospective energy using projects that accounted for the significant demand for natural gas in the scenarios presented. Unfortunately, neither DMP[93] nor the Domgas Alliance[94] were able provide this information.

109. Historically, Western Australia has not experienced a great deal of volatility in its domestic gas price, limiting the ability to assess how gas demand (and supply) in the state will respond to higher prices. Nonetheless, the Committee is of the view that the development of methodologies that take price sensitivity into account is an important step towards producing more reliable forecasts. The Office of Energy has now commissioned an economic analysis of the price responsiveness of gas demand (and supply) in Western Australia as part of its Strategic Energy Initiative.[95] The Committee endorses this approach and recommends that it become a regular component of future forecasting practices.[96]

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93 DMP did, however, provide a list of the committed and proposed projects that were incorporated into its demand forecast. Submission No. 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 6 October 2010, pp. 6, 10-12.

94 Mr Tony Petersen, Chairman, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 14.

95 Office of Energy, '*Energy 2031 - Strategic Energy Initiative: Directions Paper*', Perth, March 2011, p. 21.

96 Gas supply is discussed in more detail in section 2.12.1(c) below.

Recommendation 2

The Office of Energy expedites the introduction of more reliable gas demand and supply forecasts for Western Australia that take price sensitivity and trends into account.

110. Until relatively recently, Western Australia was fortunate to have natural gas prices among the lowest in the world.[97] This situation changed quite markedly following a series of events that came together in the period leading up to the global financial crisis in 2008.

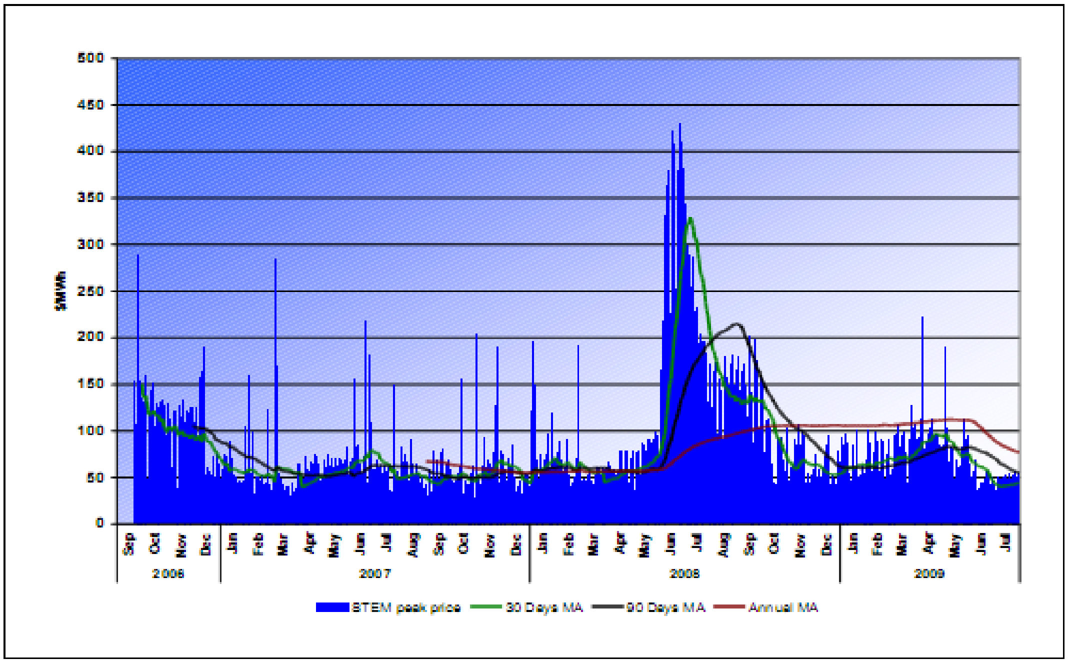
111. Western Australia's natural gas supply appears to have first showed signs of shortage with the sudden and unexpected watering out of Apache's East Spar field in 2003, with production ceasing at this field in 2005. Until then, adequate supplies of natural gas at relatively low prices appear to have been available. This event was exacerbated by a commodity boom which was well progressed by 2006 that saw the price of crude oil increase, peaking in July 2008 at a price around US$130 per barrel.

112. Western Australia's natural gas shortage was compounded further by an explosion at the Varanus Island gas processing plant on 3 June 2008 that saw the state's gas supplies cut by around 30 per cent.

113. As there is no transparent gas market in Western Australia, the impact of the Varanus Island disruption cannot be illustrated directly by reference to gas prices. However, as the electricity market in this state is closely linked to the gas market, the impact of the Varanus Island disruption can be illustrated indirectly by reference to prices in the short term electricity market (Figure 8).

97 Whilst Western Australian prices have been low, they have not been as low as those available in countries such as Qatar.

Figure 8 Average Daily Short Term Electricity Market Peak Period Clearing Prices



Source: Figure 2, 2009 Annual Wholesale Electricity Market Report for the Minister for Energy, Refer: http://www.erawa.com.au/2/532/42/annual_wholesale_electricity_market_report_to_the_.pm

114. The impact of the Varanus Island disruption is indicated by short term electricity market peak prices increasing to around $430 per MWh. Figure 8 suggests that the impact of the disruption continued to be reflected in the market until around June 2009.

115. Other factors that have impacted on the price of domestic natural gas in Western Australia include:

- Supplies of natural gas associated with the production of crude oil, condensate and other liquids tapering off.
- The domgas facility at the Burrup Peninsula reaching its production capacity.
- Supplies of onshore natural gas from the Perth Basin tapering off and production ceasing at the Tubridgi field.
- Increases in the cost of producing natural gas attributable to two main causes:

  1. After decades of production, with low cost fields having been developed, new supplies of gas are more costly to produce because they are further away, in

deeper water offshore or need to be sourced from costly unconventional sources such as tight or shale deposits.[98]

2. The other cost driver being increased demand for resources and commodities, particularly from China, which has put pressure on the price of crude oil and oil industry costs more generally. Information available indicates that upstream industry costs increased by around 120 per cent in the period since 2005, although these costs have recovered by about 20 per cent following the global financial crisis (Figure 9).

Figure 9 Upstream Capital Costs Index - IHS CERA

Source: http://ihsindexes.com/ucci-graph.htm[99]

116. As a consequence of the matters discussed in paragraphs 104 to 115 above, it is now reasonably well accepted that natural gas prices will be higher in Western Australia than in the past. Higher prices would naturally be expected to dampen the demand for gas in the state.

98 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 10.

99 IHS (NYSE: IHS) is a global source of critical information and insight dedicated to providing information and expertise. IHS product and service solutions span four areas of information: Energy, Product Lifecycle, Security, and Environment covering more than 180 countries.

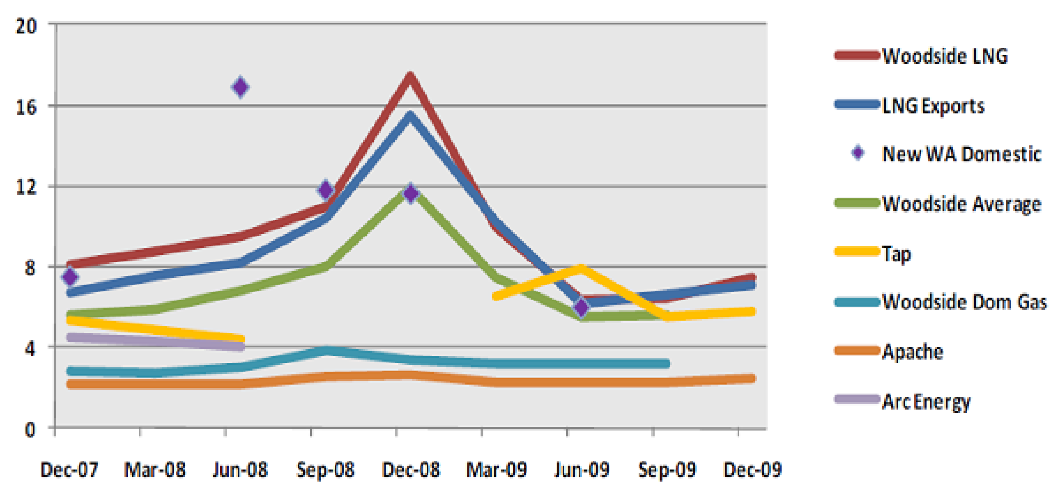
Finding 4

Some factors that drive domestic gas prices are self-correcting. The rapid economic growth recently witnessed in this state, largely as a result of demand from the mining sector, has produced increases in energy prices that to some extent, will in turn dampen the future demand for domestic natural gas. This will have some flow-on effect on prices.

117. The extent to which higher gas prices dampen demand will in turn depend on a range of factors including the magnitude of the increase in price, the price sensitivity of gas use in its various applications, the relative price of gas as compared to other fuels and the ability to switch from one fuel to another.

118. Figure 10 shows estimated gas prices for Western Australia including LNG which is exported. Of particular relevance are the “New WA Domestic” prices which reached exceptionally high levels at the time of the Varanus Island disruption but are shown—in one instance—to have traded back around the $6/GJ mark following the global financial crisis.

Figure 10 West Coast Gas Prices 2007 to 2009 $/GJ[100]



Source: EnergyQuest, Energy Quarterly, Feb 2010, Figure 18.

119. Interestingly, Western Australia’s Independent Market Operator (IMO) has recently had cause to undertake a review of gas prices for the purpose of setting wholesale electricity market energy price limits. With the assistance of ACIL Tasman, the IMO concluded that at an 80 per cent

100 As cited in Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 8.

confidence interval the spot market commodity cost of natural gas was in the range \$5 and \$12 per GJ, with a skew-normal mode of \$8 per GJ.

120. Recognising that natural gas prices depend on the terms and conditions including contract duration, allowance needs to be made for the spot market nature of the IMO's natural gas price estimate. It is therefore likely that the spot prices estimated in the IMO's review will be at the higher end of the price range as compared with prices negotiated for firm contracts extending over a period of time.

121. With domgas prices for new contracts reportedly at around twice the current average price of gas (\$3.50/GJ)[101], it seems likely that the demand for natural gas may well be constrained to its historic trend in spite of strong demand coming from the resources sector which is experiencing high levels of activity, particularly from China.

122. The higher gas prices are also likely to advantage coal-fired generation of electricity, especially for base load applications. This advantage will be further enhanced with the completion of a 330 kV line from Neerabup to Karara (via Eneabba and Three Springs).[102] The proposed construction of such a line for completion by 2013 will greatly enhance the opportunity for coal-fired generation to be transmitted into the Mid-West, which together with the Pilbara are the main areas experiencing strong growth in the resources area.

123. A major uncertainty concerning coal-fired generation of electricity relates to the introduction of a carbon abatement program in Australia. Such a program will increase the cost of coal relative to natural gas and thereby stimulate the demand for natural gas.

124. It is noted that the demand for gas transmission and distribution on the state's main gas pipeline systems is expected to expand at only modest rates over the next four to five years and not at all in the case of the Goldfields Gas Pipeline. Information on this is provided in revisions to access arrangements regulated by the Economic Regulation Authority. For example:

- Information submitted by Dampier to Bunbury Pipeline (DBP) shows that the average full-haul throughput for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) is expected to grow by only around 1 per cent per annum over the period to 2015.[103]

- Information submitted by Goldfields Gas Pipeline (GGP) and the access arrangement information approved by the Economic Regulation Authority shows no growth in either throughput or forecast contracted capacity for the period to 2014.[104]

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101 Submission No. 18 from Department of Mines and Petroleum, 6 July 2010, p. 3

102 For details of the Neerabup - Karara 330 kV line see: Western Power, 'Mid West Energy Project'. Available at: www.westernpower.com.au/networkprojects/substationPowerlineProjects/Mid_West_Energy_Project.html.

103 DBNGP (WA) Transmission Pty Ltd (DBP), *Revised Access Arrangement Information*, 1 April 2010, Table 17, p. 18. Available at: www.erawa.com.au/cproot/8466/2/20100415%20DBNGP%20-%20REVISED%20AAI%20-%20PUBLIC%20VERSION%20-%20Date%20Submitted%201%20April%202010.pdf. Accessed on 18 March 2011.

- Information submitted to the Economic Regulation Authority shows that the average daily quantity of gas delivered via the gas distribution system has declined from around 86 TJ/d in 2005 to 76 TJ/d in 2009.[105] Further, Western Australian Gas Network's (WAGN) amended forecast for its gas distribution systems shows only a modest increase in average daily quantity to around 82 TJ/d in 2013/14 or about 1.6 per cent per annum growth over this period.[106]

125. The proposed Oakajee port and rail development will be important for the development of iron ore mining in the mid-west region of Western Australia. While a short delay of six months has been announced, the proponents of the rail and port development seem intent on achieving project go ahead by the end of 2011 or early 2012.[107] The timing of the Oakajee project will almost certainly have important implications for the demand of natural gas in that region.

126. Western Australian Treasury forecasts of economic activity in the last budget projected that the state's economy would grow by 3.75 per cent in 2009-10, driven mainly by growth in household consumption and exports, as well as stronger dwelling investment. Growth in real Gross State Product (GSP) was then expected to accelerate to 4.5 per cent in 2010-11 and 4.75 per cent in 2011-12, above the long-run average rate of growth of 4.1 per cent.[108]

127. While the performance of the mining industry continues to be particularly robust, underpinned by sustained strength in global commodity markets, Treasury's mid-year review projects that economic growth is likely to be slightly lower in 2010-11 at 4.0 per cent, compared to 4.5 per cent forecast at budget-time. Treasury attributes this downward adjustment in expected economic activity to relatively subdued activity in both the property market and growth in household spending up to the time of the 2010-11 mid-year review, reflecting higher interest rates and the withdrawal of stimulus spending.[109] Looking forward, Treasury now expects GSP to grow at 4.5

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104 Goldfields Gas Transmission, *Goldfields Gas Pipeline Revised Access Information*, 5 August 2010, Table 12, p. 13. Available at: www.erawa.com.au/cproot/8796/2/20100909%20D49960%20Goldfields%20Gas%20Transmission%20Pty%20Ltd%20-%20GGP%20-%20Revised%20AAI.PDF. Accessed on 18 March 2011.

105 WA Gas Networks Pty Ltd, *Amended Access Arrangement Information for the WA Gas Networks Gas Distribution Systems*, 8 October 2010, p. 5. Available at: www.erawa.com.au/cproot/8939/2/20101015%20WA%20Gas%20Networks%20Pty%20Ltd%20-%20AA%20AAI%20for%20the%20WA%20Gas%20Networks%20GDS.pdf. Accessed on 22 March 2011.

106 Using data from WA Gas Networks Pty Ltd, *Amended Access Arrangement Information for the WA Gas Networks Gas Distribution Systems*, 8 October 2010, Table 17, p. 18. Available at: www.erawa.com.au/cproot/8939/2/20101015%20WA%20Gas%20Networks%20Pty%20Ltd%20-%20AA%20AAI%20for%20the%20WA%20Gas%20Networks%20GDS.pdf. Accessed on 22 March 2011.

107 Oakajee Port and Rail, *Oakajee Quarter*, Issue 4, November 2010, p. 1. Available at: www.opandr.com/images/opandr---neiwi.pdf. Accessed on 18 March 2011.

108 Department of Treasury and Finance, *2010-11 Budget Economic and Fiscal Outlook, Budget Paper No.* 3, Government of Western Australia, 20 May 2010, p. 9.

109 Department of Treasury and Finance, *2010-11 Government Mid-year Financial Projections Statement*, Government of Western Australia, December 2010, p. 1.

per cent in 2012-13 and 4.0 per cent in 2013-14 as compared with 3.0 per cent for each of these years in the last budget.[110]

128. Other relevant key economic indicators projected in the mid-year review include employment growth which is forecast to remain steady at 2.5 per cent per annum over the period 2011-12 to 2013-14; the Perth Consumer Price Index which is forecast to increase to 3.25 per cent in 2012-13 and remain at that rate in 2013-14; and population growth which is forecast to decline slightly in 2013-14 to 2.1 per cent per annum from 2.2 per cent in 2011-12 and 2012-13.[111]

129. The mid-year review also projects the crude oil price and the Australian exchange rate, which impact on the demand for natural gas in the state. The crude oil price is projected to further increase reaching US$89 in 2013-14, while the Australian dollar is expected to decline to 79.6 cents in 2013-14.[112]

130. On the balance of the evidence received and the economic and other forecasts available, the Committee considers that demand for natural gas in Western Australia will, over the next few years continue along its historic upward trend. While strong demand will continue to be seen from the resources sector, this will be offset to an extent by the shelving of more marginal project proposals—either in response to the higher cost of gas or to other unrelated factors.

Finding 5

On the balance of the evidence received and the economic and other forecasts available, the Committee considers that demand for natural gas in Western Australia will, over the next few years continue along its historic upward trend implying an annual compound growth in demand of 2.6 per cent to 2030. This figure is in contrast to 3.5 per cent annual compound growth projected by the Department of Mines and Petroleum. The difference between the historic upward trend and the DMP forecast accumulates to approximately 279 terajoules per day by 2030.

(c) Supply of Natural Gas

131. Gas supplies can be adversely impacted by one or more of the following:[113]

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110 Department of Treasury and Finance, *2010-11 Government Mid-year Financial Projections Statement*, Government of Western Australia, December 2010, Table 2, p. 3.

111 ibid.

112 ibid.

113 For a discussion on supply side considerations see Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 4.

- the lack of an adequate gas resource;
- insufficient capacity to process gas for domestic use; or
- inadequate pipeline transmission capacity.

(i) Gas Resources

132. The domgas forecast supplied by DMP (refer to paragraph 78 above) included a low supply scenario which suggested a reduction in the delivered volumes from the North West Shelf of up to two-thirds of its current 600 TJ/day capacity by 2020 as its existing fields deplete. Naturally, this forecast has caused consternation amongst Western Australia's major gas consumers. This alarm was exacerbated after Wood Mackenzie, in a report prepared on behalf of the North West Shelf, confirmed that the failure of the joint venture to continue its local sales, '…in whole or in part, would have a profound impact on the WA domestic gas situation.'[114]

133. The North West Shelf joint venture rejected the DMP scenario when questioned by the Committee:

> *They* [DMP] *make a very simple assumption that as contracts come to their natural end, we will simply not replace them; and that is not the truth*[115]

134. The joint venture partners stressed that they were confident of being able to supply sufficient gas to continue operating their domgas facility on the Burrup Peninsula after existing contracts roll off. Indeed, they expressed the view that it would be contrary to their commercial interests to do otherwise.[116] Apache also argued that reserves in the region are sufficient to meet domestic demand subject to it being economically viable for the suppliers to bring the resource to the market.[117]

135. Given these public assurances of the current major producers, the Committee considers that the key assumption underpinning the DMP low supply scenario is unlikely to materialise. DMP appears to have acknowledged this point in a revised forecast that has been released in March 2011 (see Figure 11 below). Under the revised low supply scenario, the North West Shelf is expected to maintain a 600 TJ/d supply until 2020, declining to 300 TJ/d by 2030. It seems to the Committee that Western Australia is adequately endowed with a gas resource sufficient to satisfy domestic demand and that a lack of an adequate gas resource is not likely to be the cause of a

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114 Wood Mackenzie, *Western Australia Gas Market Study*, 26 March 2010, p. 48. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/application. Accessed on 23 March 2011.

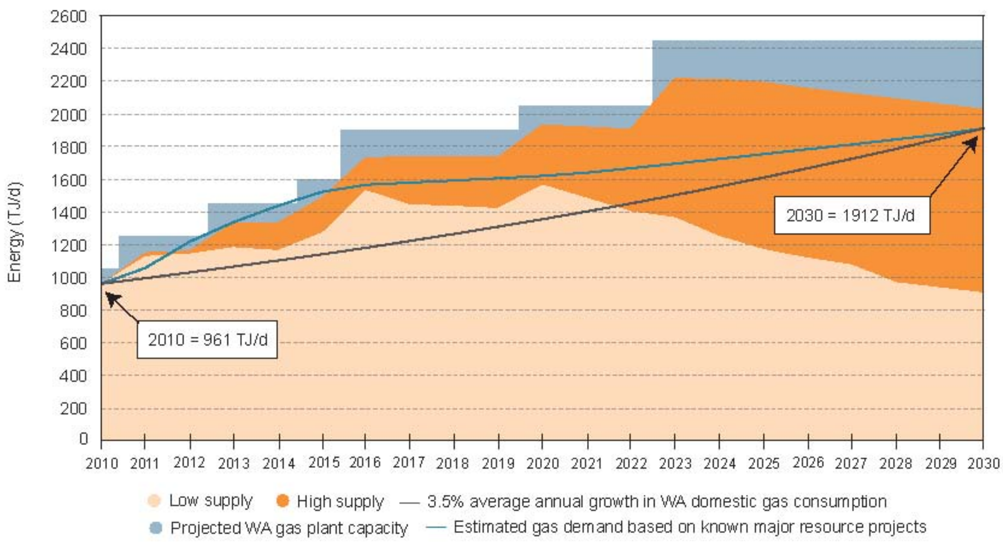
115 Mr Ben Coetzer, General Manager, North West Shelf Gas Pty Ltd, *Transcript of Evidence*, 18 October 2010, p. 6.

116 ibid., p. 8. See also, Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 11.

117 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy, *Transcript of Evidence*, 20 September 2010, p. 2.

supply shortage. Producers advised the Committee that there was between 130 and 160 trillion cubic feet (TCF) of gas reserves off the Western Australian coast with new discoveries still being made.[118] This equates to between 140,000 to 173,000 petajoules (PJ).The tight gas supply situation, which the state is still experiencing, is therefore attributable to other factors. These other factors include production capacity constraints and market participants being unable to agree on price associated with suitable terms and conditions.

Figure 11 Domestic gas supply and demand forecast, 2010-2030 (DMP, March 2011)[119]



Finding 6

The low supply scenario included in the Department of Mines and Petroleum's 2010 gas supply and demand outlook is unlikely to materialise. Western Australia is adequately endowed with a gas resource sufficient to satisfy domestic demand and any supply shortages are not likely to be caused by a lack of accessible reserves.

136. Prospective buyers have not been able to reach agreement on terms and conditions, including price, for the purchase of gas from producers. In part, this may be because buyers have been taken aback by the magnitude of price increases having enjoyed relatively low cost gas supplies under long-term legacy contracts entered into in the early 1980s when circumstances, particularly relating to cost of supply, were significantly different. With the relatively more easily accessed gas resources and those offering associated liquids having been developed, new supplies must be

118 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy, *Transcript of Evidence*, 20 September 2010, p. 5; Mr Tom Baddeley, Director (WA), APPEA, *Transcript of Evidence*, 20 September 2010, p. 2.

119 Office of Energy, *Energy 2031 - Strategic Energy Initiative: Directions Paper*, Perth, March 2011, p. 20.

sourced from fields that are either further away, in deeper water or are otherwise more costly to produce.

137. Furthermore, the economic development of many gas fields off the Western Australian north-west coast relies on them being developed as part of a larger LNG development. The location of these fields, their water depth and processing requirements, which in the case of Gorgon includes geosequestration, requires a scale of operation in excess of that needed to satisfy domestic demand. It is argued that the state's future needs for natural gas are therefore linked to LNG developments whose scale of operation offer economically priced gas for domestic use.[120]

138. It is cautioned, however, that with LNG prospects being underwritten by long-term contracts (10 to 20 years), there is the risk that the majority of the gas supply from a particular project is contracted away prior to incremental domestic demand becoming effective.[121] The mitigation of this risk is the primary motivation behind the state's domestic gas reservation policy, which will be discussed in greater detail in Chapter 4.

(ii) Gas Processing Capacity

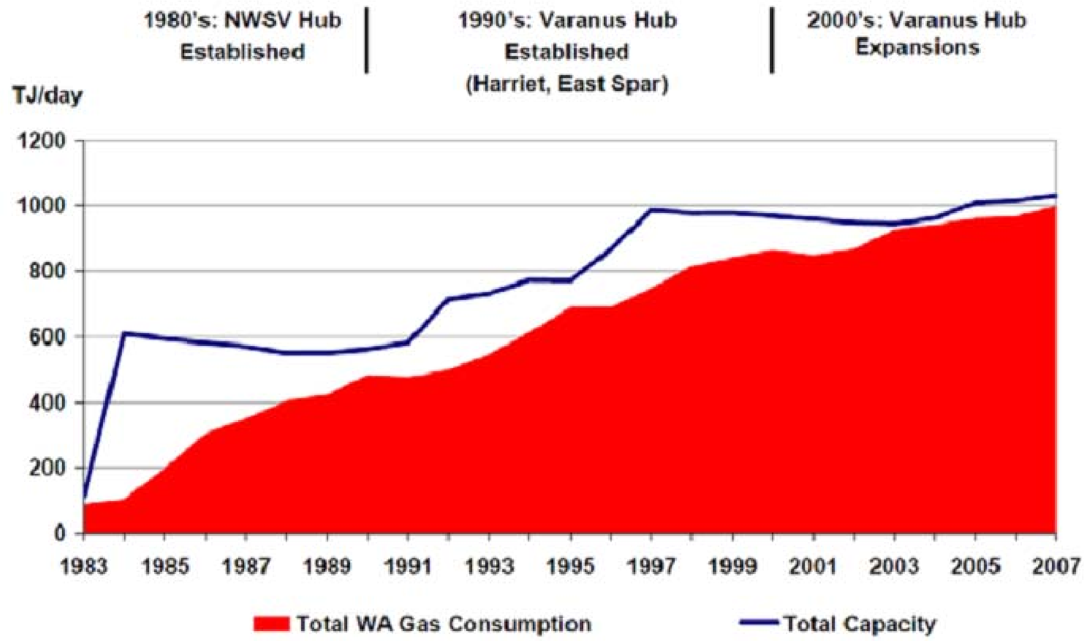
139. Western Australia was until around 2004 well provided for both in terms of available gas supplies and upstream gas processing capacity. This is illustrated in a diagram supplied by the North West Shelf Project Partners showing that until around 2003, upstream domgas processing capacity well exceeded demand (see Figure 12 below).

140. The demand for natural gas did, however, flatten from around 2001 to 2005 (Figure 7), which may have been the result of financial difficulties faced by the then owners of the Dampier to Bunbury Natural Gas Pipeline. During this time the capacity of the pipeline was not expanded and demand for natural gas in the state was suppressed. This situation changed in 2006 and 2007 with capacity of the pipeline being expanded and sales of natural gas returned to levels consistent with the historic trend.

[120] Submission No. 19 from Department of State Development, 30 June 2010, p. 8. See also Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, pp. 7-8.

[121] Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, p. 8.

Figure 12 Gas Consumption and Capacity Profile[122]



141. Looking forward, Figure 13 below projects the near straight line trend illustrated in Figure 7 above to 2030 together with 99 per cent upper and lower confidence limits determined by the statistical parameters obtained from the analysis discussed in paragraph 99 above. Also shown are known planned domgas processing capacity expansions over and above existing effective capacity.

142. It should be noted that the upper and lower limits shown in Figure 13 are not in the nature of scenarios. They simply indicate the limits within which demand is projected to occur at a 99 per cent level of confidence. However, the projected trend and associated confidence limits are only a statistical reflection of past events. Any fundamental shifts in supply or demand would not therefore be reflected in these projections.

143. As both demand and supply can shift, it is the net effect of these shifts that impact on future outcomes. Increased demand for natural gas resulting from the high levels of activity in mining and resources can be the source of an ongoing shift in demand. On the other hand, the higher cost of new gas supplies can be the cause of an ongoing shift in supply. On balance, and consistent with the Committee's Finding 5 above, future demand for natural gas is therefore expected to continue to expand along its historic trend.

144. Whilst gas resources in Western Australia are not seen as a constraint on supply, the state has experienced a tightening of domestic gas processing capacity since around 2004. This tightening

122 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 9.

of capacity appears to be associated with claims that the Western Australian gas market lacks competition and is suffering from some form of market failure.[123]

145. As illustrated in (Figure 13) effective gas processing capacity is currently very tight in Western Australia. Information on the state's processing capacity was provided in submissions which included a reference to a table by Wood Mackenzie reproduced as Table 3 below.[124]

Table 3 Gas Processing Infrastructure Western Australia

Facililty	Operator	Capacity (TJ/d)	Comments
Varanus Island - (East Spar JV)	Apache Energy	240	also processes John Brookes
Varanus Island - (Harriet JV)	Apache Energy	120	
NWSV Domestic Gas	Woodside	700	
AWE Energy	Dongara	100	2009 approx 5 - 10TJ/d thruput
Thevenard Island	Chevron	21	Ceased operation
Woodada	Hardman	10	2009 approx 2 TJ/d thruput
Beharra Springs	Orign Energy	30	2009 approx 11 TJ/d thruput
Onslow	Orign Energy	24	Ceased operation
Zyris	AWE / Origin	15	2009 approx 6 TJ/d thruput
Prospective Facilities			
Devil Creek	Apache Energy	220	under construction
Macedon	BHPBilliton	up to 200	Possible project ~ 2012
Gorgon DomGas	Chevron	300	Target end 2015
Pluto DomGas	Woodside		by 5 years after 1st LNG

Source: Wood Mackenzie
Office of Energy, Energy Western Australia, 2003, p24f.

146. The diagrammatic representation of anticipated capacity in Figure 13 below is based on assessed effective capacity as set out in Table 4. Effective gas processing capacity is assessed as that available in the short to medium term taking into account the gas resources currently available to utilise that capacity. For example, as indicated in the Wood Mackenzie table reproduced as Table 3 above, while total processing capacity in the Perth Basin is around 155 TJ/d, the APPEA data base shows that production from that basin has not exceeded 35 TJ/d since 1999.

[123] North West Shelf Project Participants confirmed that there were claims made in the media from buyers that recent price rises were a sign of market failure. Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 8.

[124] Wood Mackenzie, *Western Australia Gas Market Study*, 26 March 2010, p. 29. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/application. Accessed on 23 March 2011.

Table 4 Effective Gas Processing Infrastructure[125]

Current Effective Infrastructure	Proposed Commencement	TJ/d	Source
NWS Domgas		600*	APPEA Sub 10, p. 11
Varanus Island		390	Apache Sub 6, p. 1
Perth Basin		35	
Total Current		**1025**	
Proposed Infrastructure			
Devil Creek	2011	220	Apache Sub 6, p. 1; APPEA Sub 10, p. 13
Macedon**	2013	200	BHP Press Release, 24/9/10;[126] NWS Project Participants Sub 16, p. 9
Gorgon 1	2016	150	NWS Project Participants Sub 16, p. 9
Gorgon 2	2021	150	NWS Project Participants Sub 16, p. 9
Grand Total		**1745.0**	
Planned Infrastructure			
Wheatstone	n/a	n/a	
Pluto	n/a	n/a	

n/a: Details not available.
* It is noted that in the middle of 2008, production was able to be temporarily increased to above 700 TJ/day to compensate for loss of supply due to the Varanus Island explosion (APPEA Submission 10, footnote 14). Also see: http://www.nwsg.com.au/venture/karratha.aspx
** It is also noted that the Macedon field has estimated reserves of 1.2 Tcf (1298 PJ) sufficient for production at 200 TJ/d for up to around 15 years. See DMP Western Australian Mineral and Petroleum Statistic Digest 2008-09, p27, BHP Billiton, Transcript, 25 Oct 2010, p2, and ACIL Tasman, Energy Prices in Western Australia, Final Report, p11

147. Gas producers and upstream industry representatives have commented that the price increases experienced in recent years are not an indication of market failure but of the market working.[127] Although the proposed capacity expansions, illustrated in Figure 13 below, are evidence of suppliers responding to market signals, the lack of new capacity since around 2007 has put the adequacy of gas processing capacity of the state at risk.

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125 Also refer Department of Mines and Petroleum, *Petroleum in Western Australia*, September 2010, p. 21. Available at: www.dmp.wa.gov.au/documents/Petroleum_in_WA_magazine_09_10.pdf. Accessed on 17 March 2010.

126 *BHP Billiton Approves Macedon Gas Development in Western Australia*, Media Statement, BHP Billiton, 24 September 2010. Available at: www.bhpbilliton.com/bb/investorsMedia/news/2010/bhpBillitonApprovesMacedonGasDevelopmentInWesternAustralia.jsp. Accessed 15 December 2010.

127 Submission No. 10 from APPEA, 25 June 2010, p. 4; Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 8.

148. The North West Shelf Project Partners noted that the global commodities boom from 2005 (and more particularly 2007) onwards saw a spike in demand for gas in Western Australia. The spike was much greater than had been generally anticipated, was beyond the capacity of existing projects to supply and well ahead of the capacity of potential projects to bring gas quickly to market.[128]

149. Given that the demand for natural gas in Western Australia has expanded fairly consistently at an average annual rate of around 30 TJ/d, it should have been fairly obvious to market participants that the state would be likely to have insufficient capacity to meet requirements much beyond 2007, even without a global commodities boom. (Noteworthy is the fact that the North West Shelf project participants had sought an additional joint marketing authorisation in 1997 as part of a proposed doubling of its then domestic processing capacity to 1,100 TJ/d.[129] The authorisation was granted in 1998 but lapsed after 7 years[130] when expansion plans were shelved.) This lack of response by the market is inconsistent with a well functioning market.

150. APPEA noted that gas projects typically take 3 to 5 years to develop once a final investment decision has been taken. APPEA also commented that gas customers and suppliers need to anticipate their needs early and progressively firm-up contract terms as their respective projects obtain finance, markets, government approvals and other pre-requisites to an investment decision.[131]

151. In part, and as alluded to in paragraph 136 above, market failure may have arisen because the Western Australian gas market is in the process of transitioning from low priced legacy contracts that were negotiated more than two decades ago to market circumstances that are significantly different including in relation to costs of supply. In the circumstances, the failure by the market to maintain adequate levels of effective gas processing capacity may have been exacerbated by an unexpected spike in demand for gas on the back of the commodities boom, higher cost of new supplies, and buyers and sellers being unable to agree on price and terms and conditions in this new commercial environment.

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128 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 2.

129 ACCC Final Determination - NWS Project, 8 September 2010, s. 3.108.

130 ibid., s. 3.117.

131 APPEA provided the following additional information: ‘For example, time frames may involve 2 to 3 years before drilling explorations wells, then discoveries have to be appraised over 2 or more years, then an economic development has to be worked up over 2 or more years, then the projects has to be built over 2½ years or more.’ Submission No. 10 from APPEA, 25 June 2010, footnote 5, p. 5.

Finding 7

Although proposed future expansions of effective gas processing capacity are evidence of suppliers responding to market signals, the lack of new capacity since around 2007 has put the adequacy of gas processing capacity of the state at risk. This lack of new capacity is inconsistent with a well functioning market and is a significant contributing factor to recent price rises

152. In view of the above, there is a need to further explore the reasons why effective gas processing capacity has become as tight as it has. Associated with the tightness of the market, there is also a need to examine why gas prices for new contracts are high even by international standards. With the commodity cost of natural gas in Western Australia estimated in the range $5.55 to $9.25 per GJ (paragraph 183 below) plus transmissions costs (Table 8 below), delivered prices for new supplies at an 85 per cent load factor are therefore in the range $7.30 to $11.00 per GJ in Perth and $8.76 to $12.46 per GJ in Kalgoorlie.

153. Part of the answer to the first question on why gas processing capacity has become so tight as it has, is that this may well be the consequence of a lack of transparency and the absence of effective wholesale and secondary gas markets.[132] Hence, the realisation that upstream costs had increased significantly was not evident at an earlier time as it should have been. This raises questions of market design and competition, which are matters that receive further attention in sections 3.2(d) and 5.3(b) below.

154. In relation to the second question concerning why the price of natural gas under new contracts is high by international standards, raised in paragraph 152 above, a more detailed discussion of pricing and consideration of costs including opportunity costs is dealt with in section 3.5 below.

155. Looking forward, there is little doubt that higher gas prices have stimulated a supply response that should alleviate the current shortage of adequate domestic gas processing capacity. However, the planned new domgas capacity for the Gorgon development, illustrated in Figure 13 below, is in response to reservation obligations negotiated with the state. Moreover, it is recognised that additional domgas processing facilities (not shown in Figure 13) could be negotiated under the state's reservation policy for the Pluto, Wheatstone and possibly Scarborough LNG projects. Neither the extent nor the timing of these developments have been announced. Consequently, the Committee has not incorporated these projections into its calculations in Figure 13 below. It is important to note that the recently revised gas supply and demand forecast published by DMP [Figure 11] appears to make the assumption that these projects will add an extra 490 TJ/d of domgas plant capacity.[133]

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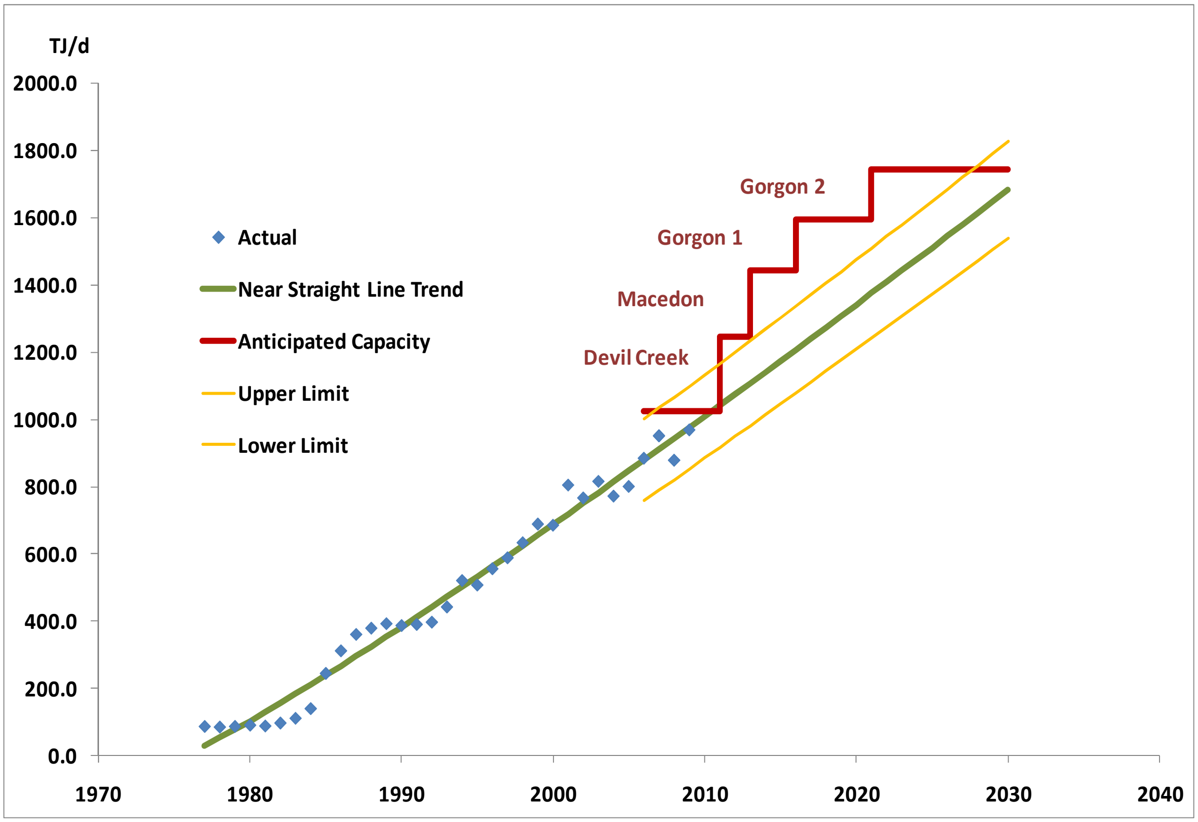
132 The North West Shelf Project Partners noted that: 'The [domgas] market is immature, lacking storage facilities, brokers and related financial instruments. These features contribute to the lack of transparency of the price of domgas.' Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 2.

133 Office of Energy, *Energy 2031 - Strategic Energy Initiative: Directions Paper*, Perth, March 2011, p. 20.

Figure 13 Existing Effective and Planned Gas Processing Capacity (Calendar Years)



The upper and lower lines give the 99 per cent confidence limits for the near straight line regression trend referred to in paragraph 99 above.

Finding 8

The commitments to establish domestic gas processing facilities at the Gorgon, Macedon and Devil Creek projects will increase the supply of domestic gas. If historic rates of demand growth are maintained, this should ease the current capacity constraints that have contributed to recent price prises.

(iii) Gas Transmission Capacity

156. The Committee is aware that there is currently little or no spare capacity on regulated pipelines in Western Australia.[134] Mr Brett Langley, General Manager, Gas Marketing, BHP Billiton commented that:

> *At the moment, there seems to be quite a rigid regulatory framework around pipeline investment, which is encouraging any new expansions to be fully contracted. I think as part of any energy reform agenda, we should look more at an incentive-based pipeline regulatory mechanism that encourages pipeline owners and developers to build in some excess capacity in the services they provide. What that means is that that will provide additional flexibility in what we sometimes see as the lag between supply meeting demand.*[135]

157. While the matters broached in paragraph 156 raise concerns about the effectiveness of the existing national regulatory regime, the Department of State Development has noted that pipeline capacity is unlikely to be a constraint on domestic gas supply and that if domestic gas supplies were to increase, pipeline capacity could be expanded in a timely manner.[136] This view, however, would only be applicable to large increments in required capacity and does not give recognition to the need for greater liquidity in the Western Australian gas market as discussed in Chapters 5 and 6 below.

(d) Conclusion

158. On the basis of information provided by industry participants, the Committee is of the view that Western Australia is adequately endowed with a gas resource sufficient to satisfy domestic demand. The apparent shortage of gas to the domestic market is therefore not attributed to an insufficient gas resource but a lack of effective gas processing capacity since around 2007. Such an environment gives suppliers a decided advantage in commercial negotiations with buyers. The Committee considers that this extended lack of capacity is inconsistent with a well functioning market and is a significant contributing factor to recent increases in the price of gas. It is acknowledged that the inherently "boom-bust" nature of the Western Australian economy makes it difficult to definitively forecast upstream processing requirements. However, the current capacity constraints should have been foreseeable given the historic trend in demand growth.

159. While there is evidence of the market responding to market signals, the Committee considers that Western Australia's domestic gas supply has become overly concentrated and lacks effective competition. Future domestic gas processing capacity will rely significantly on planned new capacity from the Gorgon development, which is occurring in response to reservation obligations negotiated with the state. The gas market in the state continues to be illiquid, lacking transparency and effective wholesale and secondary markets.

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[134] See Section 6.1(b) below.

[135] Mr Brett Langley, General Manager, Gas Marketing BHP Billiton, *Transcript of Evidence*, 25 October 2010, p. 5.

[136] Submission No. 19 from Department of State Development, 30 June 2010, p. 5.

160. The Committee is therefore of the view that the state needs to consider measures that will improve liquidity, transparency and competition in the Western Australian domestic gas market. There is also a need to consider other measures including the ongoing role of the state's gas reservation policy so as to ensure that adequate supplies of gas are available to the domestic market. These matters are taken up in more detail in the following chapters.

Finding 9

The government needs to consider measures that will improve liquidity, transparency and competition in the Western Australian domestic gas market. There is also a need to consider other measures including the ongoing role of the state's gas reservation policy so as to ensure that adequate supplies of gas are available to the domestic market.

CHAPTER 3 CURRENT GAS PRICES

161. The primary focus of this Inquiry is the price of domestic gas in Western Australia and how this compares nationally and with the state's LNG export market. The Committee has received information on this issue through submissions and by way of hearings. Before any analysis is undertaken it is important to consider two issues.

162. Firstly, much of the data the Committee has received or has obtained independently refers to average prices. Producers regularly cited average prices to argue that Western Australian domgas remained comparatively inexpensive.[137] This quote from the North West Shelf Project Participants is illustrative:

> *…it remains that the vast majority of domgas in Western Australia continues to be supplied at ex-plant prices which are low by national and international benchmarks*[138]

163. The dominant use of average price data is attributable to a lack of market transparency. Whilst these averages provide little indication as to the cost of developing new supplies or the prices being achieved for them,[139] econometric techniques (see 189 to 194 below) do provide some insight.

164. Throughout the remainder of this report, average price data will be regularly quoted, as these are the most freely available and quotable. Yet whenever possible, the Committee will look to demonstrate where prices for new supplies of gas—or for contracts that have been renegotiated—sit relative to these averages.

165. The second issue pertains to the inherent difficulty in comparing prices across gas markets. Gas suppliers, in the main, have validly cautioned that gas sales in different markets are not directly comparable because of important differences between markets. It is represented that comparing domgas, LNG and gas markets on the east coast does not offer an 'apples with apples' comparison.[140]

166. This point was strongly supported by Mr John Boardman, a respected independent consultant who appeared before the Committee. Mr Boardman agreed that, due to stark differences in market structures, comparisons should not be made between the local market and those in other states or overseas.[141]

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137 Submission No. 6 from Apache Energy Limited, 25 June 2010, p. 2.

138 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 2.

139 A point acknowledged in whole or part, by a number of producers. See, Mr Niegel Grazia, Vice President, Corporate Affairs, Woodside Energy Limited, *Transcript of Evidence*, 25 October 2010, p. 12; Submission No. 14 from BP Australia, 2 July 2010, p. 3; Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 23 July 2010, p. 4.

140 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 3.

141 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 11 October 2010, p. 2.

167. Throughout its research the Committee has come to understand that there are contrasts in the cost and price-chain components of domgas and LNG markets. Importantly, whilst domgas prices in Australian jurisdictions share similar cost and price-chain components, they too vary significantly in terms of their respective market characteristics.

168. It is also acknowledged that there are difficulties in comparing prices reported or estimated and made public at different points in time, particularly for new supplies of gas. Since new contracts may include linkages to oil prices or other indexes (to account for cost increases) and may be related to US dollars, direct comparisons of prices quoted at different points in time would be invalid without adjustment. Many of these contrasts will be identified in this chapter where an examination of prices across jurisdictions and at different points in time is undertaken.

3.1 Domestic Gas Price

169. The most commonly cited benchmark for domestic gas prices is the "wholesale price." The wholesale price is a reflection of the upstream cost (or commodity cost).

170. The upstream/commodity cost is what energy retailers, power generators and mining and industrial customers face when purchasing gas from upstream suppliers (producers). For producers the upstream cost entails, at a minimum, the recovery of exploration, development and domgas processing costs plus a required rate of return. Development costs can vary from project to project depending on the complexity involved in recovering the gas. Moreover, costs on Greenfield sites may comprise the additional capital expense of building a new processing facility.

171. The wholesale gas price usually refers to the "*ex-plant*" price: the price that producers charge for supplying gas to their juncture of the transmission pipeline. Wholesale gas prices are determined via confidential bilateral contracts that are negotiated between the buyer and seller in Western Australia.

172. The wholesale gas price can be significantly impacted by the terms of an individual contract. These terms and conditions can vary widely and address issues such as contract length; seasonal flexibility around daily volume; take-or-pay weightings; interruptibility provisions and price review and escalation mechanisms. As John Boardman confirmed, '…there is an enormous difference that a buyer will pay for gas under a plain, vanilla type of contract and under an all-singing, all-dancing, bells-and-whistles type of contract.'[142] Mr Boardman cited a contract that he had worked on as an expert witness several years ago where the service elements required saw the price double from its standard vanilla parameters.

173. Estimates differ as to the proportion that the upstream or wholesale cost of gas represents in the final retail gas price paid by residential customers. While producers argued that the figure is somewhere between 15 and 30 per cent, retailer representatives say 40 per cent is more accurate.[143] The Office of Energy has estimated that gas commodity costs represent '…in the order

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142 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 11 October 2010, p. 10.

143 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 2.

of 30 per cent of the cost stack'[144] that Western Australian regulators use to determine retail tariffs.

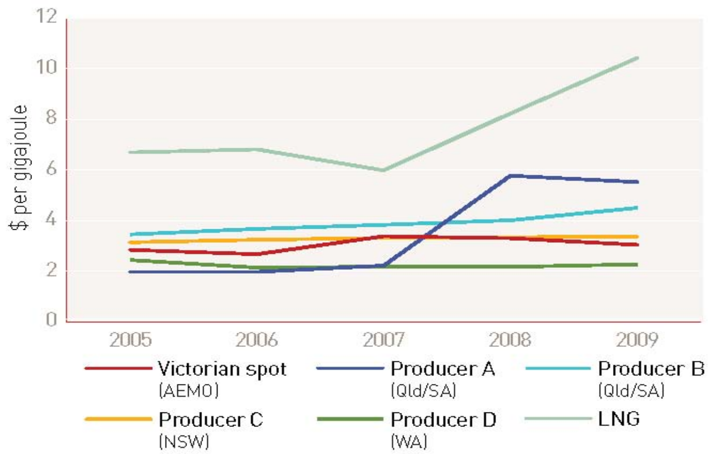
3.2 Current Domestic Gas Prices

174. The wholesale price of gas is the primary focus of this Inquiry. In Western Australia, less than 5 per cent of gas is sold to residential and commercial customers at the retail level. The vast majority of gas in Western Australia is used in industry, for power generation and in mining. Consistent with its terms of reference, the Committee has undertaken an examination of recent prices being achieved in Western Australia and in other states.

175. Notwithstanding the limitations around average prices alluded to in paragraph 163, producer groups maintain that '…average price outcomes for WA and other wholesale gas markets in Australia, including Victoria, are not significantly different, with prices in WA lower during recent years.'[145]

176. Such claims are independently supported by Energy Quest, whose September quarter 2010 average price range for West Coast domgas of \$1.52-\$3.80 is lower than the "East Australia" range of \$2.48-\$4.23.[146] Energy Quest average data was also used in this chart compiled by the Australian Energy Regulator (AER) to demonstrate Western Australia's relative competitiveness.

Figure 14 Indicative Wholesale Natural Gas Prices[147]



144 Submission No. 12(A) from Office of Energy - Response to Question on Notice, 3 November 2010, p. 6.

145 Submission No. 10 from APPEA, 25 June 2010, p. 21.

146 Energy Quest, *Energy Quarterly*, November 2010, p. 20.

147 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 280. Note: Data for producers A, B, C and D are average company realisations for specific Australian gas producers.

177. The AER makes the qualification that the average prices in Figure 14 may understate prices made under new contracts. This is an especially important point in the context of the Western Australian domgas market.

(a) Western Australian Prices

178. Some submissions have estimated the average wholesale price for the local market to be at $3.25 and $3.50 per GJ respectively.[148] More recent data published by the Department of Mines and Petroleum indicates the average price to be $3.70 per GJ for the financial year ending 30 June 2010.[149] Yet in terms of total contracted volumes, these averages are weighted down by the North West Shelf's large legacy contracts which have been described as '…long-term take-or-pay contracts with considerable flexibility….[at prices] up to around $3 per GJ.'[150] The other major supplier, Apache Energy, has a portfolio of contracts—including the low priced long-term contract with Burrup Fertilisers from 2001 (see paragraph 45)—that in Q1 2010 produced an average price of US$2.05 per GJ.[151] These average figures comprise many contracts that were established before 2007. In the period that has followed, there is clear evidence that the pricing landscape has changed.

179. This change in landscape is clearly indicated in the quantity and value data published by the Department of Mines and Petroleum (Figure 15).

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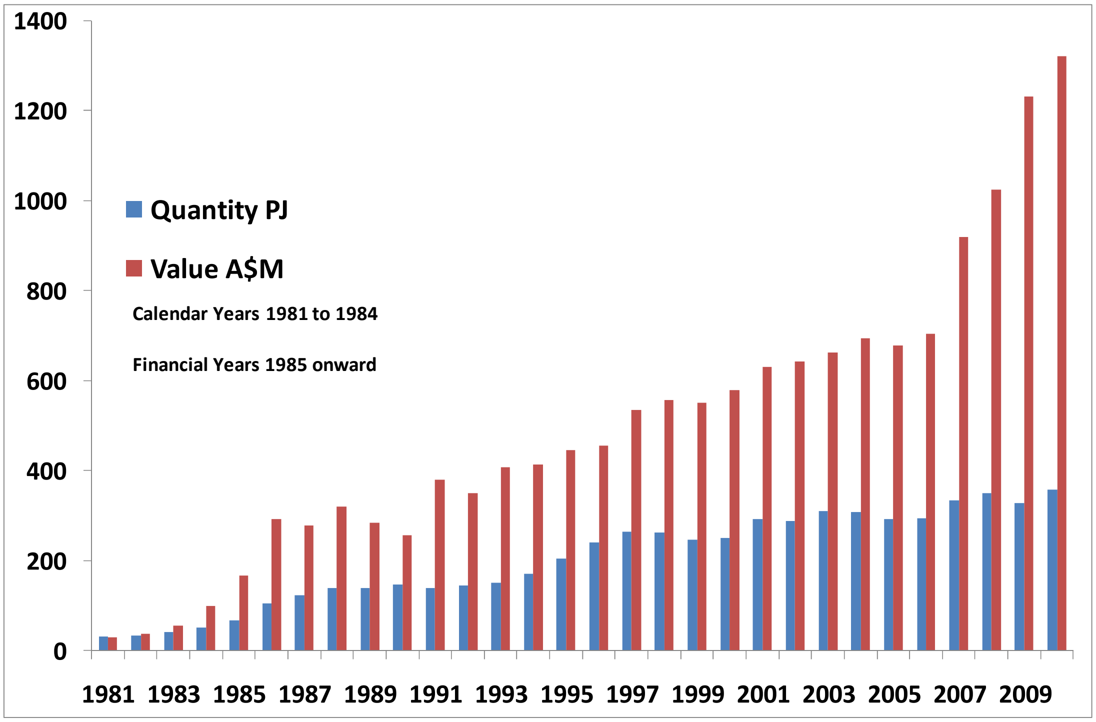
148 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 13; Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, pp. 3-4.

149 Using data from Department of Mines and Petroleum, 'Resources Data Files - Quantity and Value 2009-10'. Available at: www.dmp.wa.gov.au/documents/qtyandvalue0910(1).xls, Accessed on 15 January 2011.

150 Office of Energy, *WA Retail Gas Tariffs Review*, report prepared by ACIL Tasman, Perth, November 2010, p. 70.

151 Submission No. 6 from Apache Energy Limited, 25 June 2010, p. 2. Prices in the submission were expressed in USD per Thousand Cubic Feet (MCF) and have been converted over to US$ per GJ for this report.

Figure 15 Quantity and Value (Natural Gas) [152]



180. Figure 15 shows that the value of natural gas (unadjusted for the effects of inflation) has significantly outstripped the growth in quantity with this growth in value being especially prominent from 2006-07 onward.

181. Even so, average value (generally referred to as average price) in 2009-10 is significantly below what it was for much of the period before 1993-94 after adjustment for the effects of inflation (Figure 16).

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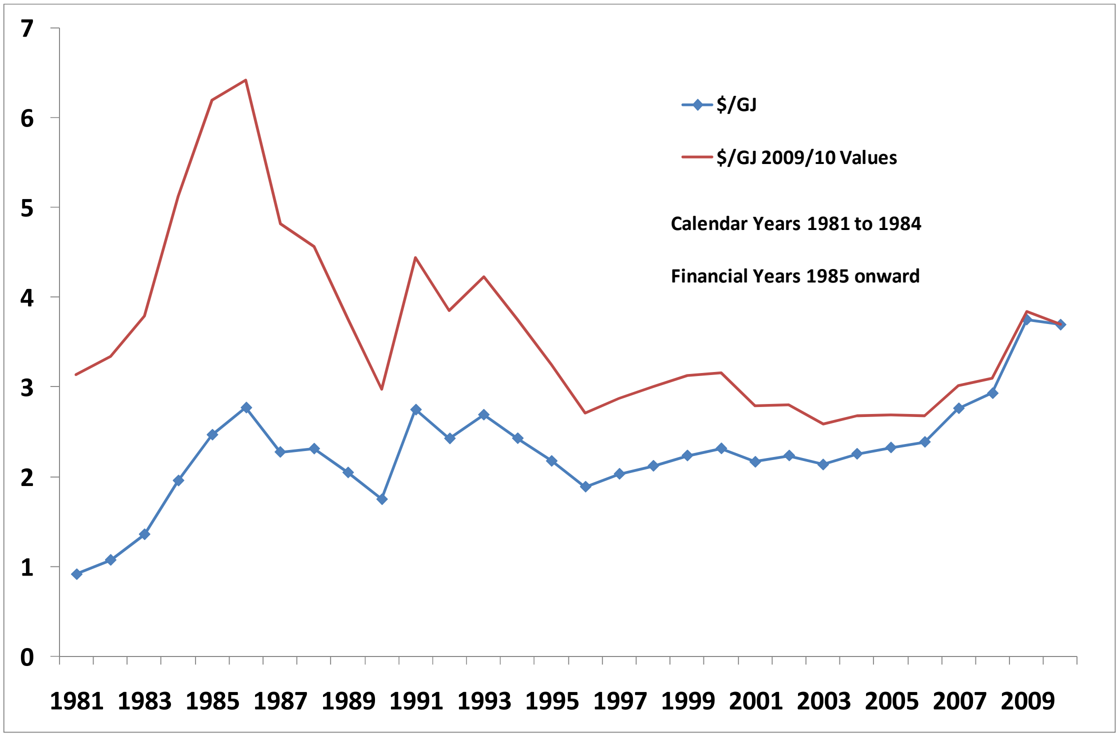
[152] Using data from Department of Mines and Petroleum, 'Resources Data Files - Quantity and Value 2009-10'. Available at: www.dmp.wa.gov.au/documents/qtyandvalue0910(1).xls. Accessed on 15 January 2011.

Figure 16 Average Value per GJ (Nominal and After Adjustment for Inflation)[153]



182. Nonetheless, reports of $14-$16 per GJ gas prices (see Figure 10) for short-term wholesale contracts sent shock waves through the local market in mid-2008. However, these prices seem to be somewhat of an anomaly attributable to both the Varanus Island explosion cutting a third of local supplies and the rise in commodity prices sharply driving up the price of oil and alternative fuels like distillate. Whilst inflation adjusted average prices may be below historical highs, the average price of natural gas in Western Australia is increasing rapidly and is anticipated to continue to increase as legacy contracts expire and are replaced by new contracts. This point will be demonstrated in paragraphs 183 to 194 below.

183. In December 2010, Wood Mackenzie reported that new contracts have been established in the range of US$6.00-$10.00 per thousand cubic feet (MCF).[154] With the AUD/USD exchange rate

[153] Using data from Department of Mines and Petroleum, 'Resources Data Files - Quantity and Value 2009-10'. Available at: www.dmp.wa.gov.au/documents/qtyandvalue0910(1).xls. Accessed on 15 January 2011; Australian Bureau of Statistics, *1350.0 - Australian Economic Indicators, January 2011*, p. 71. Available at: www.abs.gov.au. Accessed on 21 March 2011. Data is from section 5.1 - Consumer Price Index by Group, All Groups.

now trading around parity, this equates to a range of A$5.55 to A$9.25 per gigajoule and presents a more likely picture of price activity for the last few years.[155]

184. A shift away from long-term nominal averages is notable. A report commissioned by the commonwealth government in 2007 found that local prices had at least doubled in the space of one year. This report cited four contracts, albeit of relatively short duration and low volume, that Apache's joint venture partner Santos had signed for the supply of gas from the John Brookes field for prices ranging between $4.70 and $7.50 per GJ.[156]

185. In December 2008, a Concept Economics report said that whilst figures varied substantially, '…new contracts that have been struck recently have been priced significantly higher than has historically been the case.'[157] This analysis cited another small volume Santos contract, this one signed with Moly Metals for 33PJ over six years. Whilst Concept Economics put the original implied price in the range of $20 per GJ, a recent assessment by ACIL Tasman puts the estimated commodity price at $6.70 per GJ.[158]

186. Santos was active again in January 2009 signing a deal—of medium-size by local market standards—for the supply of 75 PJ of gas to CITIC Pacific from 2011. This contract was for gas from the Reindeer field that Santos is developing with Apache. Under the terms of this contract, the price is fixed for the first three years with periodic adjustments indexed to the consumer price index (CPI). From the fourth year, the price is indexed to international oil prices.[159] Independent analysts have since tried to calculate the price of this contract, a task complicated by the subsequent volatility in the oil price and the AUD/USD exchange rate. Whilst initial estimates,

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[154] Wood Mackenzie, 'The cost of supplying Western Australia's domestic gas market', *Upstream Insight - Asia Pacific*, December 2010, p. 1.

[155] Using a conversion factor of 1 MCF = 1.0817 GJ. Conversion factor derived using an energy value for WA gas of 38.2MJ/m^3 and a volumetric equivalent of 35.3147 cubic feet per m^3. Both values obtained from Department of Mines and Petroleum, *Western Australian Mineral and Petroleum Statistics Digest 2009*, 2010. Available at: www.dmp.wa.gov.au/1088.aspx. Accessed on 14 March 2011, p. 41. One cubic foot = 1.0817MJ (38.2 / 35.3147), hence 1MCF = 1.0817 GJ.

[156] Terms were for between 3 and 5 years. Actual volumes not stated, but described as low volume. See McLennan Magasanik Associates, *Natural Gas in Australia: Report to the Joint Working Group on Natural Gas Supply,* Melbourne, 16 July 2007, pp. 19, 25.

[157] Fisher, B. and Schnittger, S., 'Concept Economics Report on Marketing of Natural Gas in the Western Australian Domestic Gas Market', 1 December 2008, p. 11. Available at: www.accc.gov.au/content/index.phtml/itemId/873291/fromItemId/401858/display/application. Accessed on 21 March 2011.

[158] ibid. It could not be determined whether Concept Economics were referring to an *ex plant* wholesale price. For ACIL Tasman estimate, see Submission No. 12 (Att 3) from Office of Energy, 29 June 2010, p. 14.

[159] *Santos signs US$585 million Sino Iron gas supply contract*, ASX/Media Statement, Santos Limited, 7 January 2009.

working off a then US$50 per barrel oil price, placed the base price at US$7.80 per GJ[160], ACIL Tasman's most recent estimate suggests an implied *ex plant* price at A$10.40 GJ in 2010-11.[161]

187. The upper end of the price band recently confirmed by Wood Mackenzie (paragraph 183 above) may take into account the Santos-CITIC Pacific deal, although it might reflect prices obtained on other shorter term, lower volume deals.

188. Larger, longer term contracts are harder to quantify. The Committee notes that Verve Energy declined an offer for long-term gas supplies at $9.25 per GJ in 2008.[162] The Committee is unable to ascertain whether this price was a reflection of market conditions following the Varanus Island shutdown. Noteworthy, however, is the latest observation from ACIL Tasman (citing mostly anecdotal evidence), '…that the current pricing for new medium term to longer term contracts—for significant quantities of gas on flat 100 per cent take-or-pay terms—has been around the $7.80 per GJ mark in 2009-10.'[163]

189. A more detailed analysis of average price per gigajoule of gas sold in the Western Australian market is presented in Figure 17 below. While the following analysis is likely to be indicative of gas pricing in Western Australia, attention is drawn to the caveats around data quality that were offered in paragraphs 89 to 93 above.

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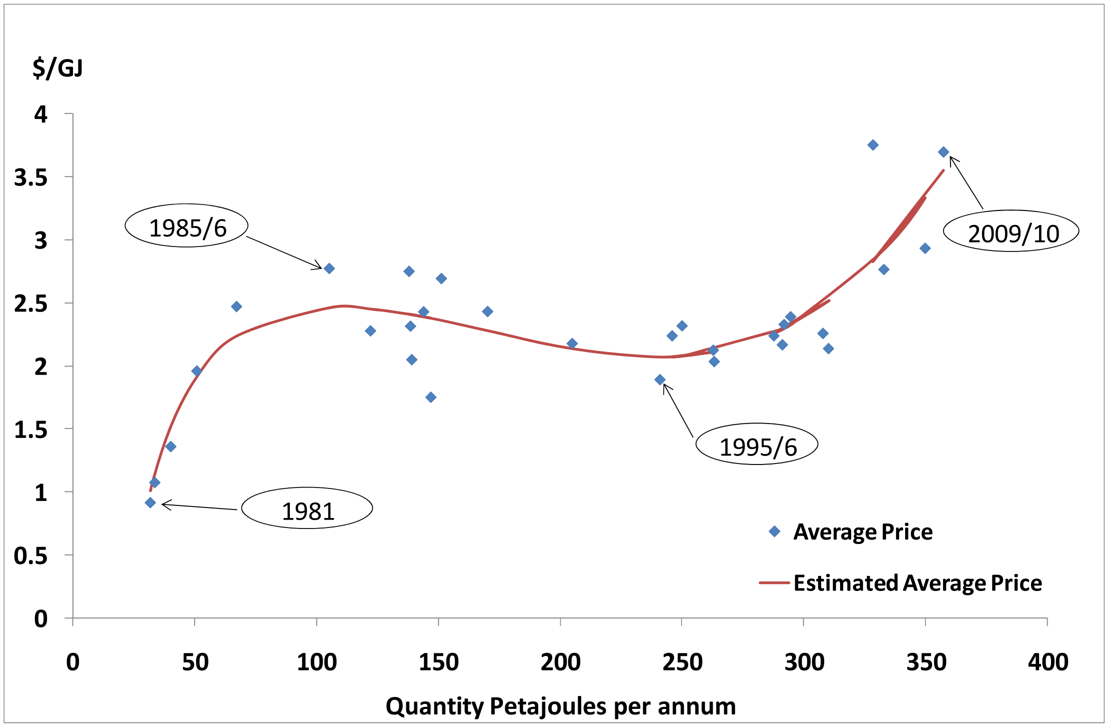
[160] Submission No. 12 (Att 3) from Office of Energy, 29 June 2010, p. 14.

[161] Office of Energy, *WA Retail Gas Tariffs Review*, report prepared by ACIL Tasman, Perth, November 2010, p. 72.

[162] Submission No. 8 from Verve Energy, 25 June 2010, p. 2.

[163] Office of Energy, *WA Retail Gas Tariffs Review*, report prepared by ACIL Tasman, Perth, November 2010, pp. 73-74. Note: AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 16 has recently cited 'anecdotal evidence' suggesting that 'some long term contracts' had been written at $8-$9 per GJ in the 18 months to June 2010.

Figure 17 Average Price per Gigajoule (1981 - 2009)



190. Figure 17 shows average price per gigajoule ($/GJ) calculated from Department of Mines and Petroleum data.[164] Also shown is an estimated average price calculated from total value information as presented in Figure 15 above.[165] The figure shows how average price has varied as total Western Australian consumption of gas has increased. This increase in consumption approximately (but not precisely) corresponds to years from 1981 onward.

191. Figure 17 indicates how average price increased from around $1 in 1981 to around $2.80 per gigajoule in 1985-86 and then declined to about $1.90 per GJ in 1995-96 as consumption increased to just over 240 petajoules per annum. As consumption increased further, the average price once again increased reaching around $3.70 per GJ in 2009-10.

192. The increase to $2.80 per GJ in 1985-86 will have been influenced by the take-or-pay obligations of the legacy contracts but as the inventory was subsequently drawn down and with the availability of competitively priced gas from the Varanus Island producers, average price declined until around 1995-96. Since then average price has increased quite markedly.

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164 Using data from Department of Mines and Petroleum, 'Resources Data Files - Quantity and Value 2009-10'. Available at: www.dmp.wa.gov.au/documents/qtyandvalue0910(1).xls. Accessed on 15 January 2011.

165 Total value was estimated using least squares and by adapting an essentially cubic functional form: Total Value = f(quantity). The regression analysis obtained an R^2 of 0.946 and a standard error of y estimate of $79.46 million against total value of $1,320.8 million for 2009-10.

193. Given the information illustrated in Figure 17 above, it is possible to make an estimate of what buyers of gas pay on average per gigajoule for the estimated annual increase in demand.[166] In 2009-10, this value (referred to as incremental value) was estimated at $13.80 per GJ. [167]

194. Incremental value at $13.80 per GJ is above, and different to, the price of new supplies coming into the market. The price of new supplies was estimated at $5.55 to $9.25 per GJ (paragraph 183 above). The reason why incremental value at $13.80 per GJ is above the price of new supplies is because this measure also reflects:

- Any additional income derived from increases in the price of existing contracts. These increases can come as a result of indexation clauses in a contract or from a negotiated or arbitrated price review.
- Any additional income derived from the tightening of terms and conditions in a contract (e.g. more stringent take-or-pay obligations). [168]

195. Even a modest increase in the price of a sizable existing contract can have a significant impact on incremental value.

196. The analysis of the average gas price for Western Australia not only confirms the higher cost of new supplies but also lends support to claims of tightening of terms and conditions (refer paragraph 226 below) and increases in the price of existing contracts. In effect, the analysis indicates that total value was increasing at a rate in the order of A$13.80 per GJ during 2009-10 for increased sales of gas. As the price of gas for recent new contracts is estimated at $5.55 to $9.25 per GJ (paragraph 183 above), the higher incremental value estimate is therefore attributable to increases in the price of existing contracts and the tightening of terms and conditions.

Finding 10

Based on data published by the Department of Mines and Petroleum, the average price of all domestic gas contracts in Western Australia in 2009/2010 is calculated to be $3.70 per GJ. However, prices for gas under new contracts have recently been reported to be in a range of approximately $5.55 to $9.25 per GJ.

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166 Incremental value is calculated by dividing the estimated increase in total value by the estimated increase in demand for each year.

167 The estimated total value function also allows an estimate to be made of marginal value (akin to marginal revenue). Estimated marginal value for 2009-10 was 6.9 per cent higher than incremental value indicating that the growth in average price at the end of 2009-10 was increasing.

168 The tightening of contractual terms and conditions was noted by ACIL Tasman, refer paragraph 226 below.

Finding 11

Based on data published by the Department of Mines and Petroleum, the growth in total value of gas sold in the domestic market has exceeded the growth in quantity sold. This means that the average price of gas is increasing. This Committee has estimated that the *incremental value* of gas (value of the additional gas sold) in 2009/10 was in the order of $13.80 per gigajoule.

This figure is greater than the prices seen for new gas contracts because total value also reflects income earned from increases in the prices and a tightening in terms and conditions of existing contracts.

(b) Interstate Prices

197. In 2010, the ACCC confirmed '…that prices for new domgas contracts have risen sharply from the long term average in WA in recent years.'[169] The ACCC added '…that there currently is a significant differential in the price of new domgas contracts in Western Australia compared to those in eastern states.'[170] The Committee has reached similar conclusions based on the comparative data it was able to obtain.

198. Wholesale prices in Queensland are reported to have risen from $2.90 per GJ to around $4 per GJ between 2006 and 2008.[171] In the December 2009 quarter, prices ranged between $2.49 and $5.74.[172] Modelling undertaken by McLennan Magasanik Associates has since calculated an estimated aggregate price of just under $5 per GJ for new medium to long-term contracts established in 2010.[173]

199. Similar modelling has promoted a figure of just over $5 per GJ for new contracts in southern states of the eastern seaboard[174], although other information received by the Committee puts Victorian prices a little lower than this estimate.

200. Alcoa cited data from Energy Advice to suggest that wholesale prices out of Longford in Victoria were in the range of $3.85 to $4.20 per GJ.[175] The Australian Energy Market Operator (AEMO)

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169 ACCC Final Determination - NWS Project, 8 September 2010, p. iv.

170 ibid., s. 5.238.

171 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 245.

172 Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, p. 4.

173 McLennan Magasanik Associates, *Annual Gas Market Review: Report to DEEDI*, Brisbane, 23 June 2010, p. 62. For the methodology behind the modelling see pp. 49-50.

174 McLennan Magasanik Associates, *Annual Gas Market Review: Report to DEEDI*, Brisbane, 23 June 2010, p. 62.

suggested that $3.00 to $3.50 per GJ was the commodity cost of a typical Victorian contract[176], while DMP reported that a realised price of $3.41 per GJ was published last year on one contract.[177]

201. Victoria has also operated a formal spot market since 1999. This market allows counterparties to trade gas flows that may be superfluous (or required in addition) to daily volume limits established under private contracts. Gas traded at the spot price now accounts for between 10 and 20 per cent of all volumes in Victoria. Since 2009, Victoria's quarterly average spot prices have ranged between $1 and $3 per gigajoule.[178]

202. It is important to qualify that the Committee was not able to ascertain the terms and conditions that underpinned the published prices on wholesale contracts in the eastern states, although it was noted that medium to long-term supplies were proving difficult to source in Queensland.[179] Notwithstanding this caveat, the Committee did not receive any evidence to suggest domgas prices in the eastern states were at or near levels being witnessed in Western Australia.

203. The ACCC quantified the extent of this disparity in 2010 when it concluded that '…new domgas contracts are priced in at approximately $2-$3.50GJ in eastern states while in Western Australia the range is $5-$8 GJ.'[180] The Committee considers that the ACCC has made an accurate assessment of the price differential across the respective markets, albeit with slightly conservative (lower) estimates of the relative price ranges.

Finding 12

The prices of new domestic gas contracts in Western Australia are at least double those of the eastern states.

175 Submission No. 24 from Alcoa of Australia, July 2010, p. 3.

176 Briefing with the Australian Energy Market Operator, 2 September 2010.

177 Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, p. 4.

178 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 79.

179 Briefing with Mr Kelvin Askew, Chief Executive Officer, ERM Gas Pty Ltd, 30 August 2010.

180 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.238.

(c) Where Interstate Markets Differ

204. The Committee acknowledges the point made by local producers that markets differ in structure and in the factors that impact the supply and demand balance, and therefore the prices paid.[181] Given the significant contrast in current prices, it is important to examine these differences.

205. For example, the North West Shelf stated that despite comparable wholesale costs, gas prices on the east coast generally appear to be considerably lower than in Western Australia.[182] They attribute this to a greater diversity in supply, the existence of many smaller customers and a relatively dense distribution network.

206. In contrast to the highly concentrated wholesale market of Western Australia, there is a much healthier level of competition in the eastern states. Whereas five major consumers dominate trade in this state, there are at least 70 major buyers competing for gas across the eastern seaboard and South Australia.[183] There is also strong "gas on gas" competition evident among suppliers in these jurisdictions. Multiple sources of supply are available from offshore basins that are often located far closer to major centres of demand than in Western Australia.

207. Competition is underpinned by a transmission sector that now fully integrates all jurisdictions bar the Northern Territory and Western Australia. AEMO confirmed that there are now at least 40 different gas plants and/or major transmission pipelines across eastern Australia.[184] Figure 18 below illustrates the multiple sources of supply and transport now available and how this compares with Western Australia.

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181 Mr David McDonald, General Manager, BP Developments Australia, *Transcript of Evidence*, 18 October 2010, p. 2; Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 23 July 2010, pp. 3-4.

182 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 2.

183 Kerr, P. & Barrett, J., 'WA businesses hit by gas attack', *Australian Financial Review*, 20 July 2010, p. 3.

184 Briefing with Mr John Savage, Senior Manager, Gas Wholesale Market Development, AEMO, September 2010.

Figure 18 Gas Basins and Pipeline Infrastructure, Australia[185]

185 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 70.

208. Brad Page, CEO of the Energy Supply Association of Australia (esaa), told the Committee that the integration of the eastern states pipeline network—completed during the last decade—has 'changed the [market] dynamics utterly.'[186] As a result of this integration, no pipeline has a monopoly position. All major cities in eastern and southern Australia (excluding Tasmania) now have multiple pipelines feeding their markets from multiple basins.

209. The hydrocarbon composition of several basins in the eastern states and the development of coal seam gas reserves have also had a significant effect on domgas prices.

210. When hydrocarbon reserves are rich in liquids (oil and condensate) developers are less sensitive to the prices they receive for the gas that is often seen as a by-product of the liquids recovery process. Victoria's reserves have proven to be rich in oil. When these fields were first developed this enabled very cheap legacy contracts to be offered for gas. While many of these contracts have now rolled off, gas as a by-product still has an impact on prices. Associated gas from new oil discoveries in the Otway and Bass Basins flooded the Victorian spot market for much of 2009 keeping average prices down around $2 per GJ.[187]

211. Another factor that has altered the supply situation markedly in the eastern states is the development of coal seam methane, also known as coal seam gas (CSG) in Queensland and New South Wales. As its name implies, CSG is gas that is attached to the natural fractures of coal seams and surrounding rock and is released when pressure on the seam is lowered. This is normally done by removing the water trapped within the seam. Unlike conventional gas reservoirs, gas within coal seams cannot be capped once the water removal process is complete.

212. Queensland's CSG reserves are of such magnitude that they have attracted the interests of a number of international oil companies who have established four separate joint ventures to develop a major LNG export hub with up to eight "trains" (processing facilities) near Gladstone.[188] It appears as though these LNG producers are now in a reserves-build stage which could involve trying to ring-fence up to 5,000 PJ of reserves for each 4 million tonne per annum train.[189] There has been a substantial "ramp up" of coal seam methane as these companies have sought to prove their reserves. This has created a short-term oversupply situation in the eastern states and led to very cheap short-term gas prices particularly in Queensland. [190] The Committee was advised that prior to this reserves build-up process it had been quite easy to contract cheap gas for terms of longer duration.[191]

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186 Briefing with Mr Brad Page, Chief Executive Officer, Energy Supply Association of Australia (esaa), 2 September 2010.

187 Briefing with Mr Paul Balfe, Executive Director, ACIL Tasman, 31 August 2010.

188 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 35.

189 Briefing with Mr Paul Balfe, Executive Director, ACIL Tasman, 31 August 2010.

190 Briefing with Mr Dan Hunt, Associate Director General Mines and Energy, Queensland Department of Employment, Economic Development and Innovation (DEEDI), 31 August 2010.

191 ibid.

213. The current absence of an alternative LNG market on the eastern seaboard is another contributor to the lower price outcomes being observed there. Exposure to international markets allows Western Australian producers to seek an LNG netback equivalent price for their domestic gas. Currently without an alternative market, eastern states producers can only price their natural gas to achieve the cost of production with a rate of return commensurate with prevailing market and economic conditions.[192] The sentiment expressed to the Committee was that when LNG exports commence out of Queensland, it is likely that domgas prices in the eastern states will trend upwards towards netback equivalents.[193]

214. On the demand side, the appetite for gas for power generation is significantly lower in the eastern states. In Victoria, gas fuels as little as three per cent of total electricity production.[194] Coal remains the primary energy fuel in the eastern states. As a cheaper competing commodity this keeps the price of gas capped. Conversely, many gas buyers in Western Australia—particularly mining companies without access to the electricity grid—rely on comparatively expensive diesel as their alternative energy producing fuel. This allows local producers to exploit opportunity cost pricing (see 267 below).

215. Generally speaking, gas markets in the eastern states enjoy greater transparency of pricing. Whilst still dominated by confidential bilateral contracts, Short Term Trading Markets (STTM) based on the existing Victorian spot market model (see paragraph 201) have now been established in Sydney and Adelaide. A Queensland STTM is due to commence in 2011. The eastern states have also developed a Gas Market Bulletin Board, an internet-based application that publishes current information on production, demand and capacity across the integrated gas transmission system.[195]

216. Complementing the Bulletin Board is an annual Gas Statement of Opportunities (GSOO), which provides an updated forecast for each state on the supply and demand balance, current production capacity and future commitments of major buyers and sellers.

217. Finally, Victoria in particular has benefited from the development of plant-based gas storage facilities. Whilst still limited in capacity, these facilities significantly exceed those currently available in Western Australia. Gas storage has a number of advantages. It allows supplies to be maintained in the event of an upstream disruption, thereby keeping pressure off short-term prices. Moreover, storage enables buyers to stockpile short-term surpluses, which can be traded later in an attempt to reduce their effective wholesale price.

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192 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 11.

193 Briefing with Mr Tom Leuner, General Manager Markets Branch, Australian Energy Regulator, 2 September 2010; Briefing with Mr Cameron O'Reilly, Executive Director, Energy Retailers' Association of Australia (ERAA), 1 September 2010.

194 Briefing with Mr Peter Clements, Director of Energy Programs, Department of Primary IndustriesVictoria, 2 September 2010.

195 Briefing with Australian Energy Market Operator (AEMO), 2 September 2010.

Finding 13

Structural differences exist between the eastern states' and Western Australian domestic gas markets, which need to be considered when comparing price differences across jurisdictions.

Finding 14

Some of the structural differences that contribute to lower gas prices in the eastern states would be difficult or impossible to replicate in the Western Australian market. These include:

- multiple sources of supply much closer to major centres of demand and pipeline infrastructure;
- an integrated transmission pipeline sector that enables competition between four gas producing states;
- oil fields (particularly in Victoria) that are still rich in associated gas;
- a significantly greater reliance upon coal-fired power generation;
- the absence of an alternative (LNG export) market for gas.

Finding 15

There are a number of structural advantages currently enjoyed by eastern states' gas markets that the Western Australian government should pursue. These include:

- mechanisms that promote greater liquidity and transparency, such as official secondary trading markets; and
- the facilitation of greater competition among producers through the development of new supply sources including unconventional gas deposits.

(d) Factors Driving Prices in Western Australia

218. The factors driving prices in Western Australia that are listed below were cited regularly throughout the Inquiry's submissions and hearings. As noted already in paragraphs 215 through 217 above, Western Australia currently lacks many of the features that underpin the liquidity and transparency observed in the eastern states markets.

219. Western Australia also suffers for a lack of competition in the transmission sector with more than around 90 per cent of domgas shipped via the Dampier to Bunbury Natural Gas Pipeline into the south-west of the state.

220. In addition, the local market has witnessed an extended period of oversupply, courtesy of the existence of large low-priced legacy contracts, which removed the incentive for further exploration and development of alternative gas resources. Some of these resources are located in deposits much closer to Perth that could be dedicated to the production of domgas.[196]

221. The predicament in Western Australia has been exacerbated by the fact that production costs have risen sharply for existing domgas developers and new entrants to the LNG market. This is attributable to a combination of factors including the commercial reality that the cheapest fields—and those with higher liquids content—have already been developed. Moreover, the cost of supplying materials and labour has doubled during the global commodities boom (see Figure 9): a problem made more acute in Western Australia due to the remote locations where local gas reserves are being extracted.

222. Many of the contracts most recently signed have been for gas from the Reindeer field owned by Apache and Santos. This field is comparatively small and is subject to the development of the Devil Creek processing facility on a Greenfields site. As such, unit costs of production are expected to be relatively high. Some argue these costs were exploited by the North West Shelf who reportedly sought an $8 per GJ revised price when it and Alinta went to arbitration in 2008 after their contract price review process reached an impasse.[197] When the arbiter handed down his decision, which included an assessment of current market costs, Woodside's Don Voelte said he was 'pleased' and that the decision would provide '…a new price foundation to work from.'[198]

223. While the Committee can not comment on the final outcome of that particular arbitration, it does support the view that $2 to $3 per GJ gas is no longer a realistic price outcome for domgas in Western Australia. This view was widely accepted among contributors to the Inquiry, including

[196] Upton, D., 'Can the Perth basin ride to the rescue?', *Petroluem News.net*, 31 July 2008. Available at: www.latentpet.com/_content/documents/540.pdf. Accessed on 16 February 2011.

[197] Submission No. 8 from Verve Energy, 25 June 2010, p. 2. For reference to the $8 per GJ reported price that North West Shelf was seeking see, Burrell, A., 'Alinta teeters in the balance', *Australian Financial Review*, 13 November 2009, p. 5.

[198] Phaceas, J., 'Woodside hails new domgas price mark', *WA Business News* (online), 24 February 2010.

buyers and buyer representative groups.[199] More accurate is the prediction offered by the Department of State Development that, '…a more likely outcome is that long-term gas prices will be in excess of $5 to $6 per gigajoule.'[200]

224. The Committee accepts that production cost increases are an inevitable reality in the Western Australian market. However, it is concerned that insufficient competitive pressure amongst upstream producers is facilitating opportunistically excessive price outcomes.

Finding 16

An increase in domestic gas prices from historical levels is inevitable given the recent surge in production costs. Even so, insufficient competition amongst upstream producers is currently generating excessive prices.

225. The Committee also accepts the argument that a gas price reflects the balance of its contractual terms and that buyers would normally be prepared to pay higher prices for contracts offering them greater flexibility and relatively lower obligations vis-à-vis the producer.[201] Yet it appears that this maxim around flexibility is not as evident in the recent period of sharply higher prices.

226. ACIL Tasman has just reported that:

> *Where gas supply contracts are available, terms are becoming increasing[ly] stringent. Upstream gas suppliers now require close to 100 per cent take or pay terms, impose penalties for swing, and no longer offer banking of gas. Contract prices now tend to be linked to oil prices in US dollars*[202]

227. The link to oil prices is another notable development and marks a departure from historical domgas pricing, which the North West Shelf verifies has '…traditionally been indexed to local inflation'.[203] Woodside confirmed this change in pricing bias for some contracts, but argued that it:

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199 See, for instance, Mr Michael Parker, Director, Business Development and Marketing, Alcoa of Australia, *Transcript of Evidence*, 17 November 2010, p. 6; Mr Gavin Goh, Executive Director, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 13.

200 Submission No. 19 from Department of State Development, 30 June 2010, p. 9.

201 Briefing with Mr Paul Balfe, Executive Director, ACIL Tasman, 31 August 2010.

202 Office of Energy, *WA Retail Gas Tariffs Review*, report prepared by ACIL Tasman, Perth, November 2010, p. 70. Swing is the term that addresses variability around the daily contracted quantity. "Banking" allows some flexibility in take-or-pay provisions that enable buyers to receive volumes already paid for at a later date without further penalty.

203 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 12.

> *…is a reflection of the nature and location of the consuming party. The customer has typically been a mining project located in the north of WA whose alternative energy source would have been diesel*[204]

228. Alcoa, the state's largest consumer of domgas, disputes this claim and supports the observations of ACIL Tasman that the practice of linking gas prices to that of oil is more widespread. Based on its own discussions with suppliers since 2006, Alcoa argues that there is, generally, '…an increased trend towards wanting to link gas price to oil price.'[205]

229. The volatility that comes with oil indexation can be absorbed by customers who base their fuel costs on the price of diesel, which in some parts of the state equates to an energy equivalent price of $20 per GJ.[206] The recent commodities boom has led to a proliferation of such customers with resource companies soaking up much of the available gas at the current higher levels, as this still offers them a cheaper alternative fuel. Indeed, it has been reported that customers willing to pay closer to diesel equivalent prices have not had any difficulty sourcing gas.[207] The reality for power generators and other industrial customers, whose business models do not price their fuel off diesel, is that they will be compelled to abandon gas and, where possible, revert to coal (notwithstanding the current uncertainties that surround a potential carbon price). For those reliant on feedstock gas, such as ammonia producers, it is unlikely that Western Australia will remain competitive with the cheap supplies of feedstock that are available in the Middle East (see 46 above).[208]

230. With the abundance of reserves in this state, the level of upstream competition should not be so tight that it enables incumbent producers to continue to exploit the market in this manner for an extended period.

231. Much of the tightness in the current market is attributable to the failure of the market to respond to looming capacity constraints that should have been identified, and acted upon, from as early as 2007 (see Finding 7). The Committee acknowledges that a supply response is now underway through domgas projects such Reindeer and Macedon and via increased exploration for unconventional gas resources. However, this response will take time to flow through. In the interim, the balance of market power—and the majority of the benefits from the state's gas reserves—will be enjoyed by producers having earlier been shared more evenly amongst buyers and sellers alike. Therefore, it is important to facilitate further improvements in gas on gas competition, and market transparency, in order to alleviate the extreme swings in the supply and demand balance, and the associated dynamics of the marketplace. The following chapters will be dedicated to identifying measures designed to this end.

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204 Submission No. 15 from Woodside Energy Limited, 2 July 2010, p. 16.

205 Submission No. 24 from Alcoa of Australia, July 2010, p. 14.

206 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 34.

207 Ms Anne Hill, A/Coordinator, Office of Energy, *Transcript of Evidence*, 11 Oct 2010, p. 7.

208 Mr Basil Lenzo, Solicitor/General Counsel, Burrup Fertilisers Pty Ltd, *Transcript of Evidence*, 17 November 2010, pp. 5, 8.

3.3 Domestic Prices Relative to LNG Prices

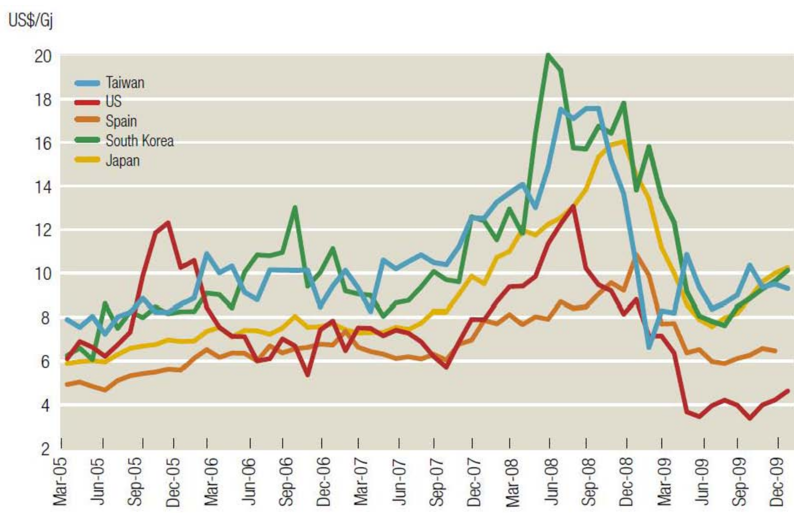
232. The Committee has been asked to compare domgas prices in this state with international LNG prices following public concern that local prices were trading at a significant premium (see paragraph 59 above). This task has been arguably the most difficult for the Committee to undertake for a number of reasons:

- The lack of a universally applicable international LNG price;
- Disparities between average and current export prices; and
- The limitations of netback pricing for deriving domgas equivalent prices.

(a) International LNG Prices

233. It is difficult to find a universally applicable international benchmark price against which local domgas prices can be compared. As the North West Shelf project participants stated, European and U.S. LNG markets compete against overland pipeline gas and are often influenced by domestic factors.[209] In the U.S. for example, the Henry Hub price that is used as the benchmark for LNG imports has recently fallen from above US$13 to below US$4 per GJ as the local market has been flooded with domestically developed shale gas reserves. Figure 19 below demonstrates the divergence across various international markets.

Figure 19 Average LNG Import Prices 2005-2009[210]



[209] Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 12.

[210] As cited in Submission No. 10 from APPEA, 25 June 2010, p. 22.

234. The most appropriate international standard for comparing Western Australian domgas prices is the Asian LNG market, as this is the exclusive destination of all current Western Australian exports (Japan, South Korea and China). More so than U.S. and European markets, Asian LNG prices remain highly correlated with the price of imported crude oil, which is the main competing fuel for industry and power generation in this region. Consequently, prices have generally traded higher in Asia relative to other international jurisdictions (see Figure 19).

235. Commonly, the LNG contract price in this region is derived by multiplying an oil price benchmark by an energy equivalent "slope factor" before adding on a negotiated "factor" or "constant."[211] North West Shelf confirmed that the most commonly used oil price benchmark in North Asia is the Japanese Customs-cleared Crude index (JCC).[212]

236. The slope factor represents an energy equivalent pricing component. Energy Quest has defined the energy equivalent price for gas as '…17.2 per cent of the oil price, based on the energy composition of LNG compared with a barrel of oil.'[213] The agreed slope factor can vary depending on the prevailing supply/demand balance with a slope factor of 0.172 equating to 100 per cent "oil parity". If gas trades above this level (17.2 per cent of the barrel of oil price), it is cheaper for the buyer to revert to oil, if available, to produce the same amount of energy.

237. The negotiated factor or constant is a figure negotiated between the buyer and seller that represents an agreed value placed on non-petroleum related terms and conditions of an individual contract.[214] This figure can act as a floor price to ensure that the LNG project underpinning the contract covers its costs.[215]

238. To illustrate, an oil benchmark price of USD$80 per barrel multiplied by a slope factor that reflects full oil parity (0.172) with a $1.25 constant[216] added will produce an LNG price before shipping costs of USD$15.01. The final price is based on US dollars per million British Thermal Units (MMBtu). A per gigajoule equivalent price (USD$14.23) can be derived by dividing the MMBtu price by a conversion factor of 1.05506.

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211 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 11 October 2010, p. 3.

212 Submission No. 16(A) from North West Shelf Project Participants, 15 October 2010, p. 4.

213 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 28.

214 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 15 October 2010, p. 3.

215 Kazuya Fujime, 'LNG Market and Price Formation in East Asia', April 2002. Available at: www.lngpedia.com. Accessed on 11 January 2011.

216 While the value of the constant can change with each contract, the figure of 1.25 has been described as an accurate reflection of Japanese LNG contracts since 2004. See Rushforth, J., 'Japanese LNG contracts yet to reflect oil plunge', 7 Feb 2009. Available at: www.lngpedia.com/japanese-lng-contract-prices-yet-to-reflect-oil-plunge/. Accessed on 11 January 2011.

(b) Disparity between Average and Current Prices

239. Having determined that the Asian LNG market is the most appropriate barometer for judging the relative price of local domgas, the problem of average pricing again arises. Like domgas markets, average LNG prices are widely quoted but do not provide an accurate indication of the new contract market. Once more these average figures contain contracts with highly varied terms and conditions, which obviously lead to a wide range in prices.

240. Almost 85 per cent of Australia's current LNG exports are produced by the North West Shelf JV, with the balance (14.7 per cent) coming from ConocoPhillips' LNG plant in Darwin.[217] North West Shelf confirmed that it has 12 contracted customers: 10 in Japan and one each in South Korea and China. Some of these customers have numerous contracts in place with the full joint venture or with various collaborations of joint venture participants.[218]

241. Most North West Shelf contracts range in term from 10 to 25 years. Usually they have take-or-pay provisions with individual pricing formulas impacted by prevailing oil prices, infrastructure costs[219], delivery costs and the level of supply available from competing projects mainly in Qatar and Indonesia. Critically, the price may be agreed to many years before the first supply date.[220]

242. A chart showing average prices for Australia's LNG exports to Japan and China is provided in Figure 20 below.

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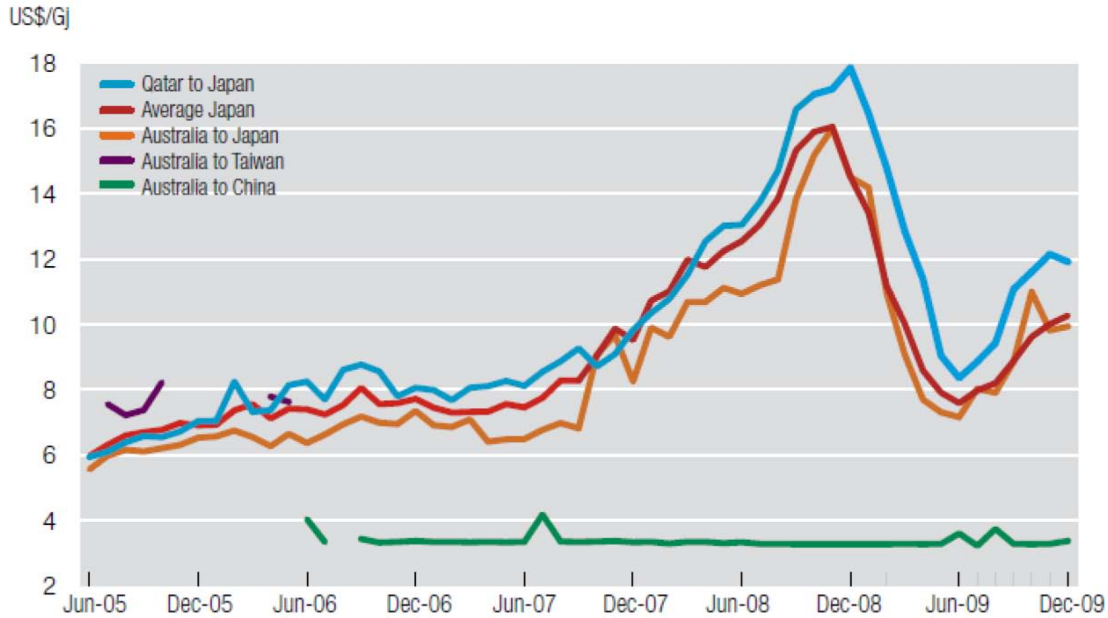
217 Energy Quest, *Energy Quarterly*, November 2010, p. 80.

218 Submission No. 16(A) from North West Shelf Project Participants, 15 October 2010, pp. 3-4. For a full list of medium and long-term contracts in place as at 2009, see The International Group of Liquefied Natural Gas Importers, 'The LNG Industry', Spring 2009, pp. 16-18. Available at: www.giignl.org/fr/home-page/lng-industry/. Accessed on 10 January 2011.

219 LNG infrastructure costs are markedly different from domgas. They include, among other things, the costs of liquefying the natural gas in preparation for export.

220 Submission No. 16(A) from North West Shelf Project Participants, 15 October 2010, pp. 6-7.

Figure 20 LNG Import Prices - Various Locations[221]



243. The sharp disparity with Australia's price to China demonstrates the nuanced nature of individual contracts and has a substantial impact on published consolidated average figures.

244. North West Shelf advised that it has one contract with China.[222] According to published data, this contract is the second largest under which deliveries are being made by the joint venture and represents over 22 per cent of volumes exported from Australia to Asia.[223]

245. North West Shelf confirmed that this contract was established in 2002, a period when oil was trading under US$30 per barrel and the international LNG environment was oversupplied. Competitive pressures at the time enabled the buyers to negotiate an oil indexation component fixed within a set price range.[224] Implicit in the information displayed in Figure 20 is that the North West Shelf's contracts with its major export market, Japan, have much greater flexibility around oil indexation.

221 As provided in Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 12. Original chart attributed to Argus Monthly LNG.

222 Submission No. 16(A) from North West Shelf Project Participants, 15 October 2010, p. 4.

223 See, The International Group of Liquefied Natural Gas Importers, 'The LNG Industry', Spring 2009, pp. 16-18. Available at: www.giignl.org/fr/home-page/lng-industry/. Accessed on 10 January 2011; Energy Quest, *Energy Quarterly*, November 2010, pp. 17-19.

224 Submission No. 16(A) from North West Shelf Project Participants, 15 October 2010, p. 4.

246. The contract with China has a noticeable effect on the most recently reported average prices. Australia's September quarter 2010 LNG exports to Asia had an average Free on Board (FOB)[225] value of A$9.69 per GJ.[226] If the effect of the contract with China is removed from these figures, the average price increases to $A11.39 per GJ.[227]

247. Based on the information provided in paragraphs 183 through 188, it can easily be argued that domgas prices in Western Australia are trading significantly higher than the price of LNG exports to China and, in some instances, at a level approaching the average price of LNG exports to Asia. However, this comparison is not valid, as these LNG averages reflect old contracts some of which diverge considerably from the current commercial environment.

248. Equally as important is the fact that LNG has a different production process that increases its cost base relative to domgas. "Netback" pricing tries to account for these differences in the LNG cost base, but it too has complexities that make definitive comparisons difficult to achieve.

(c) Netback Pricing and its Limitations

249. This Inquiry has called for a comparison of domgas prices in Western Australia against international LNG prices. The Committee acknowledges that such a comparison is fraught with complexity. Allowances need to be made for the differences in contract formulae, supply/demand balances and production processes across the respective markets. "Netback" pricing attempts to address these issues in order to provide a comparative price.

250. Netback pricing essentially takes all the revenues generated by the production of a unit of a commodity and removes the costs of getting that commodity to market.[228] Netback pricing for LNG can be attempted using a "bottom-up" or "top-down" methodology.

251. Bottom-up calculations may involve taking an estimate of the consolidated, pre-liquefaction unit cost of establishing an LNG facility plus a required rate of return. This figure determines the required netback that can be used for calculating a domgas equivalent price. The equivalent price is derived by adding the domgas processing cost to the required netback.

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225 FOB prices remove the costs of shipping and regasification at the buyer's destination from the full price. The full price is often referred to as the 'Delivered Ex-Ship' (DES) price.

226 This is the average figure for all exports to Asia from Australia, including those out of Darwin which could not be separately identified. Energy Quest, *Energy Quarterly*, November 2010, p. 17.

227 Energy Quest, *Energy Quarterly*, November 2010, pp. 17, 19. Methodology involved removing China's quarterly figures (1,165,000 tonnes delivered with an average value of US$3.78) from the consolidated quarterly figures for Asia (5,211,000 tonnes delivered with an average value of US$9.69). AUD/USD exchange rate of parity was used for conversion.

228 Investopedia, 'Netback', 2010. Available at: www.investopedia.com/terms/n/netback.asp. Accessed on 10 Jan 2010.

252. Alternatively, the top-down approach entails making an assumption around the final LNG price (using any quoted price components) before subtracting the costs of re-gasification at the import terminal, transport and liquefaction.[229] Once again, the domgas equivalent price is derived by adding the processing cost for domestic natural gas.

253. Producers had mixed views on netback pricing methodology. Dr Aidan Joy, Commercial and Business Development Manager with Apache Energy Ltd said, 'It is pretty easy to work out what the netback price is.'[230] Referring to the top-down approach Dr Joy added '…you take off shipping and you take off liquefaction and you take off marketing, and there you are.'[231]

254. The North West Shelf was more guarded, cautioning that '…netback pricing is complex, involves many assumptions and has no settled methodology.'[232] Meanwhile Mr Steven Gerhardy, a consultant with APPEA, expressed the view that LNG netback was simply not an accurate benchmark for price in the domestic market.[233]

255. The Committee admits that netback pricing is a complex process. Cost-base assumptions on bottom-up pricing need to take into account the various factors that influence production costs across different projects (level of impurities in gas; depth and pressure within reservoir; environmental compliance costs etc). Conversely, a lack of price transparency makes it difficult to arrive at a final price from which deductions can be applied using a top-down approach.

256. Notwithstanding these limitations, the Committee argues that netback pricing still has relevance because it represents an opportunity price for producers of LNG and domgas who hold uncontracted surplus reserves that they are looking to take to market. Therefore, it is important to try to make an estimate, however basic, of current LNG netback prices to see if they are impacting local domgas market activity.

3.4 Current Netback Price Estimates

257. When highlighting the range of factors that have been driving up domgas prices in Western Australia, the ACCC confirmed that the '…price of LNG impacts on the domestic price.'[234] This impact can be measured by attempting to determine where current domgas prices sit relative to an LNG netback equivalent.

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229 Office of Energy, *WA Retail Gas Tariffs Review*, report prepared by ACIL Tasman, Perth, November 2010, p. 73.

230 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy Ltd, *Transcript of Evidence*, 20 September 2010, p. 7.

231 ibid.

232 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 12.

233 Mr Steven Gerhardy, Consultant, APPEA, *Transcript of Evidence*, 20 September 2010, p. 8.

234 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.241.

258. ACIL Tasman has attempted to calculate a Western Australian netback equivalent price. In May 2010 they determined that:

> *LNG netback prices, with allowance for Domgas processing costs, could approach $8 per GJ, depending on oil price and the LNG pricing formula for the particular supply contract*[235]

259. Using a top-down methodology and the formula cited in 235 above, ACIL Tasman's actual figure was A$7.85 per GJ. Assumptions included a US$80 per barrel oil price and a slope factor of 0.14375 (around 80 per cent of oil parity), which produced an LNG price of 'around US$11.50 per MMBtu.' From this figure, US$2 per MMBtu was removed for regasification and shipping and a further US$3 was taken off for liquefaction costs. This produced a netback price into the plant of US$6.50. Using an exchange rate of AUD/USD 0.9 and converting MMBtu to GJ at a rate of 1.05506 produced an AUD equivalent of $6.85. The final adjustment required was for the addition of domgas processing costs ($1 per GJ), which took the domgas netback commodity cost to $7.85 per GJ.[236]

260. The Committee is wary that LNG netback pricing is extremely fluid, as any or all of the parameters can change quickly. For a more accurate assessment, some allowance also needs to be made for the value of the constant.

261. The Committee has sought to undertake its own estimate using updated parameters including a constant of 1.25, which has been cited as a 'fairly good fit' for average long-term LNG contracts with Japan undertaken since 2004.[237] The US$80 per barrel oil price has been maintained, as it offers a benchmark around which prices traded for much of 2010. The combined US$5 per MMBtu price for liquefaction, regasification and transport is unchanged in the absence of a more reliable estimate being received. The same applies to the A$1 domgas processing cost. The slope factor has been revised from ACIL Tasman's estimate of 0.14375 to 0.15. This is based on John Boardman's view of the current level[238] and the argument from the North West Shelf that oil-linked LNG prices are '…nearing oil parity…for some long-term contracts [into Asia]'.[239] Finally, the exchange rate has been revised to parity to reflect more recent currency movements during the latter part of 2010 and to maintain consistency with the conversions applied in paragraph 183 above. The comparative calculations are displayed in Table 5 below.

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235 ACIL Tasman, *Gas Prices in Western Australia: Review of inputs to the WA Wholesale Energy Market*, May 2010, p. 13. Available at: www.imowa.com.au/f2138,484255/ACIL_Tasman_Final_Report_-_Updated.pdf. Accessed on 27 December 2010.

236 ibid., p. 11. ACIL Tasman, quoted a slope factor of 0.14. The US$11.50 per MMBtu result implies an actual slope factor of 0.14375 (81.4 per cent of oil parity).

237 Rushforth, J., 'Japanese LNG contracts yet to reflect oil plunge', 7 Feb 2009. Available at: www.lngpedia.com/japanese-lng-contract-prices-yet-to-reflect-oil-plunge/. Accessed on 11 January 2011.

238 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 11 Oct 2010, p. 4.

239 Submission No. 16(A) from North West Shelf Project Participants, 15 October 2010, p. 7.

262. Applying the ACIL Tasman methodology to the Committee's nominated parameters produces a domgas netback commodity cost of A$8.82 per GJ. This higher figure reflects the intention of the Committee to provide a conservative estimate given its inability to obtain definitive levels for various components of the formula.

263. Still noteworthy is the fact that the estimated range ($7.85 to $8.82) generated by ACIL Tasman and the Committee is well within the $9.25 figure derived from Wood Mackenzie's estimate of the cap of recent domgas price activity in Western Australia (see 183 above).

264. Even allowing for the acknowledged complexities of using netback calculations for cross-market comparison, the Committee is confident that the recent rise in local prices has created an environment where—for certain contracts—domgas prices can trade at or above LNG netback equivalent levels.

Table 5 LNG Netback Domestic Wholesale Gas Price Equivalent Estimates

Parameters	**Committee Estimate**	**ACIL Tasman Estimate**
Oil Price Benchmark (US per barrel)	$80	$80
Slope Factor	0.15	0.14375
Constant	$1.25	$0.00
LNG Price (delivered ex-ship) (US$/MMBtu)	**$13.25**	**$11.50**
less liquefaction, transport and regasification	$5.00	$5.00
Netback LNG Price (US$/MMBtu)	**$8.25**	**$6.50**
Exchange Rate	1.0000	0.9000
Netback LNG Price (AUD$/GJ)*	$7.82	$6.85
plus Domgas Processing Cost (AUD$/GJ)per GJ	$1.00	$1.00
Netback Domestic Wholesale Gas Price	**$8.82**	**$7.85**
Latest Domgas Price Range Estimate (AUD$/GJ)	**$5.55 - $9.25**	

* Using energy conversion factor for MMBtu to GJ of 1.05506

Finding 17

Despite the inherent differences in the respective markets, LNG prices do impact domestic gas prices in Western Australia. It is now highly likely that the recent rise in local gas prices has created an environment where—for certain contracts—domestic prices will trade at or above LNG netback equivalent levels.

265. In its submission the North West Shelf acknowledged that, '…the price for a domgas customer may be greater than or less than any LNG price as a result of many and varied factors specific to the Western Australian gas market and the global LNG market.'[240]

266. The ERA also agreed that domgas prices were currently capable of exceeding netback due to a lack of 'gas on gas competition' in the upstream sector.[241]

240 Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 3.

267. The Committee has already recognised that markets differ in their characteristics and that this impacts relative pricing. However, the concentration of suppliers and an alternative market offshore with a seemingly voracious appetite for LNG has provided the ideal setting for opportunity cost pricing to occur in Western Australia. [242]

268. In light of current price outcomes, the argument around how opportunity cost pricing should be addressed needs to be explored.

3.5 The Committee's Position on the 'Market Price' for Domestic Gas

269. Gas producers, such as Apache, have suggested that the best way to facilitate lower prices is '…to allow the market to operate freely'.[243] Buyers of gas, on the other hand, have expressed the view that domestic gas should be supplied at a price that maintains Western Australia's competitive advantage in energy, and that adds value to other manufacturing and resource production in the state.[244]

270. A major part of the Committee's remit is to consider the respective merit of these positions. This requires a clearer understanding of how the current market price is set in Western Australia and whether this provides the optimal outcome for the broader economy.

271. This chapter has demonstrated that there is a physical connection between the Western Australian domgas market and the Asian LNG market as some producers are, or soon will be, active in both. Apache conceded that such companies could theoretically make real time choices to supply gas to one market over another, thereby influencing prices. Apache qualified this point by arguing such behaviour would be rare, as both domgas and LNG sales are usually tied to long-term contracts that often underpin a project's development.

272. However, to the extent that producers in Western Australia sell LNG into spot markets, choices between the domestic market and overseas markets may be more prevalent than suggested by Apache. Shell Development Australia, (a partner within the North West Shelf Joint Venture) confirmed that it can sell excess production into the LNG spot market that is developing in Asia.[245] Therefore, it is reasonable to conclude that LNG prices influence values in the local market: a point implicitly acknowledged by the ACCC (see 257 above).

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241 Mr Lyndon Rowe, Chairman, Economic Regulation Authority, *Transcript of Evidence*, 13 September 2010, pp. 3-4, 6.

242 Opportunity cost pricing is where prices are struck at or just below a buyer's next best alternative. It is a form of monopoly pricing and is likely to occur where there is no gas on gas competition.

243 Submission No. 6 from Apache Energy Limited, 25 June 2010, p. 5.

244 Submission No. 3(A) from Domgas Alliance, 26 October 2010, p. 1.

245 Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia Pty Ltd, *Transcript of Evidence*, 24 November 2010, p. 6.

273. Having established that LNG prices influence values in the local market, it can be deduced that local prices are subject to the oil-linked volatility that drives international gas prices in Asia, Western Australia's exclusive export market (see Figure 20 above).

274. As noted in 245 above, most Asian LNG prices (particularly those in Japan) remain highly correlated with the price of imported crude oil, which is a competing fuel for industry and power generation.[246] Given movements in the oil price, particularly since 2008, these LNG prices have become some of the highest in the world (see Figure 19).

275. The movement of Asian LNG prices is therefore likely to have a significant effect on local economic activity if domgas prices in Western Australia continue to trade at levels that can meet or exceed LNG netback equivalents.

276. In the Western Australian domestic gas market, buyers whose energy costs are budgeted on diesel as an alternative fuel, have a greater capacity to withstand this higher price environment. Indeed, much of the recent increase in demand has come from resource companies who have demonstrated an ability to absorb recent higher gas prices that remain below diesel equivalent costs (see paragraphs 185 through 187 above). Where capacity constraints lead to a continued under-supply in the domestic market—a likely scenario in the absence of effective gas on gas competition—it may be that the demands of resource companies will likely determine the price.

277. Other buyers who have made strong commitments to the use of gas do not have the price tolerance of resource companies. In the case of utilities, the only way to compete with resource companies for domgas is by paying similar prices and passing the higher costs on to end users. As Synergy's Managing Director, Mr Jim Mitchell, told the Committee 'I would strongly prefer not to be competing against the miners for gas.'[247]

278. The Committee is of the view that the economic benefits to be derived from the state's natural endowment of gas resources need to be more accessible to all major users. This outcome is unlikely to be achieved if domgas prices persistently reach or exceed LNG netback equivalent levels. Such prices reflect an absence of adequate competition and are inconsistent with a well functioning market. The Committee therefore believes that there is a need for domgas prices to settle at levels substantially below LNG netback values, whilst offering producers returns that encourage exploration and development. This outcome should be possible, but is unlikely to be achieved by an exclusive reliance on the forces of the market as it is currently structured.

279. Hence, government needs to consider what sort of policy mix can facilitate the development of a commercial environment that provides a better balance between the interests of buyers and producers.

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[246] For confirmation that oil and gas are competing fuels for power generation and industry in Japan, see Dr Tsutomu Toichi, Senior Managing Director and Chief Executive Economist, Institute of Energy Economics Japan, 'Japan's Energy Challenges and the Role of Gas', Presentation to Institute of Energy Economics, April 2008. Available at: http://eneken.ieej.or.jp/data/en/data/pdf/433.pdf. Accessed on 16 February 2011.

[247] Mr Jim Mitchell, Managing Director, Synergy, *Transcript of Evidence*, 20 Oct 2010, p. 6.

280. The policy response should not necessarily be price focused. Rather, the priority should be to ensure lower prices are achieved in a well functioning market that generates an appropriate level of domgas supply. A key driver in this quest is to promote greater gas on gas competition—that is multiple suppliers engaging in a competitive and transparent domestic market. This has been the key to gas market improvements in the eastern states and overseas.

281. The Committee believes that the Domestic Gas Reservation Policy is an essential instrument for achieving this goal. However, a gas reservation policy, whilst necessary, is not sufficient and will need to be implemented flexibly and carefully for reasons that will be discussed in section 4.2 below. This tool should also be seen as part of a suite of policy responses that aim to improve the overall level of liquidity, competition and transparency in the Western Australian domgas market.

282. The remainder of this report will examine each component of the gas supply chain to identify where such policy responses could be introduced or enhanced.

Finding 18

Prices that persistently reach or exceed LNG netback values reflect an absence of adequate competition and are inconsistent with a well functioning domgas market. Under such circumstances, some form of policy intervention in the market is appropriate

Finding 19

The Domestic Gas Reservation Policy is an essential policy instrument for ensuring that an appropriate level of gas is supplied into the local market to achieve reasonable price outcomes.

This instrument should be part of a suite of policy responses, the primary aim of which should be to improve the overall level of liquidity, competition and transparency in the Western Australian domestic gas market.

CHAPTER 4 LNG PRODUCTION AND THE DOMESTIC MARKET

4.1 Background

283. Ever since the State Agreement was signed between the government of Sir Charles Court and the North West Shelf joint venture, there has been a connection between Western Australia's LNG and domestic gas market.

284. LNG projects have been termed "enablers" of domestic gas by producers who claim that these projects improve diversity of supply and competition for the local market (see 40 above). In theory, this is a valid argument. LNG projects are prohibitively expensive undertakings that require voluminous long-term contracts with offshore entities to underwrite their profitable development. The comparatively smaller demand requirements of the domestic market, while not insignificant,[248] do not meet this criterion. Through the development of these larger fields, predominantly for export, there is potential for the domestic market to access incremental supplies that would otherwise remain untapped.

285. Local buyers argue these potential benefits are not being realised, leading to a domestic market that is undersupplied and excessively priced. Alcoa claimed that there is an '…excessive focus on LNG exports'[249] and that under current conditions, LNG producers are not adequately driven to supply the local market. Horizon Power argued that the '…direction of gas away from the domestic market into export LNG'[250] was the main factor impacting domgas prices. According to the DomGas Alliance, the problem has now been exacerbated by LNG producers aggregating smaller fields for export that could otherwise be developed exclusively as domgas projects.[251]

286. This report has already confirmed that local domgas prices now trade at a significant premium to interstate markets and in a range where netback LNG equivalents can be reached or exceeded. It has also been demonstrated that insufficient upstream competition and production capacity have been major contributing factors to this outcome. In order to facilitate the greater volumes of supply necessary to reduce pressure on price, the Committee has been repeatedly urged to examine two policy tools targeting LNG exporters: domestic gas reservation obligations and retention lease arrangements.

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248 Domestic gas represented around 28 per cent of the combined LNG and domestic gas market in 2009-10. Submission No. 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 6 October 2010, p. 8.

249 Mr Michael Parker, Director, Business Development and Marketing, Alcoa of Australia, *Transcript of Evidence*, 17 November 2010, pp. 2, 10.

250 Submission No. 11 from Horizon Power, 25 June 2010, p. 9.

251 Mr Tony Petersen, Chairman, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, pp. 7-8.

287. Prior to undertaking this examination, it is beneficial to identify the current and future list of LNG projects off the Western Australian coast to which such policy options are, or could be, targeted (see Table 6 below):

Table 6 Current and Proposed LNG Projects Located in Western Australia[252]

Project	Partners	Basin	Reserves	Capacity (mtpa)	FID	Prod
North West Shelf	Woodside, BHP, BP, Chevron, CNOOC, MIMI, Shell	Carnarvon	40 TCF	16.3	Operating	Operating
Gorgon	Chevron. ExxonMobil, Shell	Carnarvon	40 TCF	15.3 (initial) 20 (possible)	2009	2015-16
Pluto	Woodside	Carnarvon	5 TCF	4.3	2007	2010-11
Browse	Woodside, BHP, BP, Chevron, Shell	Browse	14 TCF	12 - 15	Unknown	2016-17
Ichthys	Inpex, Total	Browse	12.8 TCF	8.4	2011	2016
Pluto (upgrade)	Woodside	Carnarvon	not available	4 x 4.8	2010-11	2013-14
Prelude/Concerto (FLNG)	Shell	Browse	3.6 TCF	3.5	2011	2016
Scarborough	BHP, ExxonMobil	Carnarvon	8 TCF	6	Unknown	2016-17
Sunrise (FLNG)	Woodside, ConocoPhillips, Osaka Gas, Shell	Bonaparte	5.1TCF	4 -5.8	2012	2016
Wheatstone	Chevron, Apache, Kufpec	Carnarvon	4.5 TCF	8.6 (initial) 25 (possible)	2011	2016

4.2 Domestic Reservation Obligations

(a) How Domestic Reservation Obligations are Established

288. Domestic reservation obligations are agreed to between LNG producers and the government as a precondition for allowing on-shore processing facilities on state land.

[252] Information collated from Submission No. 19(A) from Department of State Development - Response to Question on Notice, 29 September 2010, p. 2; Wood Mackenzie, *Western Australia Gas Market Study*, 26 March 2010, p.50. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/application. Accessed on 23 March 2011; APPEA, *State of the Industry 2010*, Canberra, 2010, p; 16. Mr Bill Townsend, General Manager External Affairs, Inpex, *Transcript of Evidence* (Supplementary Material), 22 November 2010; Various producers' websites. NOTE: There are a range of other speculative projects that have not been included. For the full list, refer to the Wood Mackenzie report. Table 6 did not include the Darwin LNG project, operated by ConocoPhillips, which sources gas from the Bonaparte Basin.

289. The original mechanisms used by government for this purpose were State Agreements, defined as contracts '…ratified by an Act of the State Parliament.'[253]

290. The first state agreement applied to an LNG project was with the North West Shelf in 1979 (see 16 above). Under a 1995 revision to this agreement, the North West Shelf was obligated to supply 5,064 PJ of gas to the domestic market.[254] Whilst this commitment is expected to be met by 2014[255], there is also a provision requiring the joint venture to consult and reach agreement with the Minister '…on the requirements in the State and the manner in which they will be met' before entering into new export contracts between 2010 and 2025.[256]

291. The Gorgon LNG project was also subject to a state agreement. Under the *Barrow Island Act 2003*, the Gorgon joint venture partners are required to build a 300 TJ per day capacity domgas plant on Barrow Island and supply 2000 PJ over the life of the entire project.[257] The joint venture has committed to build its plant up front to its full 300 TJ per day capacity, [258] but is only required to supply half of that amount by the end of 2015: subject to commercial viability provisions. It is not required to supply its remaining 150 TJ per day commitment until 2021.[259]

292. In 2006, a formal "WA Government Policy on Securing Domestic Gas Supplies" (hereafter Reservation Policy) was adopted. Under this policy, project proponents are required to reserve up to 15 per cent of LNG production for supply to the domestic market. The Reservation Policy allows for 'case-by-case flexibility', allowing potential producers to negotiate with government as to the amount to be reserved and the manner in which it is to be supplied.[260]

293. Woodside's Pluto LNG project is the first to be subject to the Reservation Policy. Woodside has agreed to supply the equivalent of 15 per cent of LNG production as domgas within five years of the first Pluto LNG shipment, or after the 30 millionth tonne of the LNG has been exported. Negotiations as to how this domestic obligation will be met are continuing. Woodside advised the Committee that because Pluto gas is considered relatively expensive to refine for domestic market specifications, the company is promoting the use of third party gas or gas obtained from further

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[253] Department of State Development, 'State Agreements', 17 December 2008. Available at: www.dsd.wa.gov.au/6641.aspx#7022. Accessed on 14 January 2011.

[254] Submission No. 19 from Department of State Development, 30 June 2010, p. 6.

[255] Mr Kevin Gallagher, Chief Executive Officer, North West Shelf, *Transcript of Evidence*, 18 October 2010, p. 5.

[256] North West Gas Development (Woodside) Agreement Act *1979* (Western Australia), Schedule 2 s46 (1a).

[257] Barrow Island Act *2003* (Western Australia), Schedule 1 Clauses 17 (1) and (2).

[258] Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, *Transcript of Evidence*, 10 November 2010, pp. 4, 7.

[259] Submission No. 19(A) from Department of State Development - Response to Question on Notice, 29 September 2010, p. 2.

[260] Submission No. 19 from Department of State Development, 30 June 2010, p. 6.

alternative exploration programs rather than constructing a stand-alone domgas processing plant.[261]

294. The Reservation Policy has enjoyed bi-partisan support since its inception with the current Premier recently describing the policy as '…part of the "jigsaw" in ensuring gas is available for Western Australia at a competitive price.'[262] Table 7 below shows how state agreements or Reservation Policy requirements are being applied to current and proposed LNG projects.

Table 7 Domestic Obligations Applicable to LNG Projects in Western Australia[263]

Project	Domestic Gas Obligation
North West Shelf	**State Agreement:** 5,064 PJ to be supplied over the life of the project. Commitment due to be met by 2014. Provisions exist within the agreement for further supplies to be negotiated.
Gorgon	**State Agreement:** 2,000 PJ supplied over the life of the project. Domgas plant with 300 TJ/day capacity to be constructed. Delivery of 150TJ/day to commence at 31 Dec 2015 with balance to be supplied by 2021. Supply subject to commercial viability provisions.
Pluto	**Reservation Policy:** 15 per cent of LNG production to be supplied within 5 years of LNG exports commencing or after 30 million tonnes of LNG has been shipped. Supply subject to commercial viability provisions. Manner of supply subject to further negotiation.
Wheatstone	**Reservation Policy:** Under negotiation
Browse	**Reservation Policy:** To be negotiated
Scarborough	**Reservation Policy:** To be negotiated

(b) Arguments Around Domestic Reservation Obligations

295. The principle of reservation obligations remains contentious among participants in the Western Australian gas market. The Office of Energy has held stakeholder workshops to discuss problems

[261] Mr Stewart Gallagher, Pluto Commercial (Foundation) Manager, Woodside Energy Ltd, *Transcript of Evidence*, 25 October 2010, pp. 6-7.

[262] Hon. C. Barnett, MLA, (Premier), 'Energy Resources Down Under - Right Place, Right Time', Speech to James A. Baker III Institute, Houston, Texas, 13 April 2010, 28. See also, Hon. C Barnett, MLA, (Premier), *Transcript of Interview - 6PR*, Media Monitoring Unit, Department of Premier and Cabinet, 16 April 2010, p. 4.

[263] Submission No. 19(A) from Department of State Development - Response to Question on Notice, 29 September 2010, p. 2.

with the local market and whilst consensus has been reached on many issues, the Reservation Policy is an area where '…we could not get agreement on any way forward.'[264]

296. The sentiment amongst major buyers is that the Reservation Policy is required in order to address what they see as an ongoing supply deficit against current and future levels of demand.[265] Other advocates, whilst generally supportive of the market process to address supply/demand imbalances, insist that the policy is currently needed '…to get the market functioning.'[266] Brad Page from the Energy Supply Association of Australia (esaa) also espoused market principles, but accepts that domestic obligations may be necessary in the current circumstances.[267]

297. Arguments against the policy were numerous and came from a variety of sources. Consultants, producers and regulators argued that reservation policies represent a subsidised price for gas, which produces an economically inefficient outcome.[268] For the ERA, such inefficiencies manifested in unsustainable developments in downstream industry that would be overly reliant on artificially priced gas.[269]

298. APPEA's opposition to the policy was palpable. Amongst its criticisms, APPEA argued that compulsory reservation prevents the market from adjusting to equilibrium.[270] Woodside added that domestic obligations on projects like Gorgon and Wheatstone will '…tip the market into long-term oversupply again, likely causing prices to fall'.[271]

299. Apache claim that having to compete with supplies that are '…unrelated directly to demand….is kind of like a sword of Damocles over us because it is going to drop the price.'[272] Both Apache and North West Shelf argue that this policy-induced surplus of gas will deter specialist domgas

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264 Mr Peter Kiossev, A/Director, Strategic Energy Initiative, Office of Energy, *Transcript of Evidence*, 11 October 2010, p. 3.

265 Mr Tony Petersen, Chairman, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 12; Submission No. 24 from Alcoa of Australia, July 2010, p. 22.

266 Mr Jason Waters, General Manager, Trading and Fuel, Verve Energy, *Transcript of Evidence*, 20 October 2010, p. 7.

267 Briefing with Mr Brad Page, Chief Executive Officer, Energy Supply Association of Australia (esaa), 2 September 2010.

268 For example, Briefing with Mr Paul Balfe, Executive Director, ACIL Tasman, 31 August 2010; Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 35; Submission No. 16 from North West Shelf Project Participants, 2 July 2010, p. 13.

269 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 32.

270 Mr Tom Baddeley, Director (WA), APPEA, *Transcript of Evidence*, 20 September 2010, pp. 2, 11.

271 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 6.

272 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy Limited, *Transcript of* Evidence, 20 September 2010, p. 6.

producers from entering the market, undermining diversity of supply and—according to Apache—inadvertently risking future price increases as domgas-specific projects are shelved.[273]

300. Others argued that the onerous compliance conditions attached to reservation requirements might also drive potential investors in the Western Australian LNG industry to alternative jurisdictions.[274]

301. Finally, the Committee received objections to reservation policies from entities vying with gas producers to supply energy fuels. Wesfarmers Premier Coal argued that surplus gas tied to domestic obligations would '…impact on price and the competitive position of coal.'[275]

(c) Committee's Position on Domestic Reservation Obligations

302. As Finding 7 concluded, the market does not appear to have responded in a timely manner to the looming domgas capacity constraints that were evident in 2007. This failing has contributed significantly to the often excessive price outcomes that are now being realised, as demonstrated in Chapter 3.

303. Whilst there has been evidence that these prices have generated a substantial supply response from the market (Devil Creek and Macedon), over 40 per cent of the new domgas capacity now being built (Table 4) is directly attributable to commitments made under a state agreement. Appearing before the Committee on behalf of the Gorgon Domgas sellers, Mr Chris Sorensen confirmed that the Gorgon Project's domgas plant was not built in response to market signals: 'It was not our decision; it was a state obligation.'[276] The Gorgon Domgas plant will play a critical role in alleviating current capacity constraints (if demand observes historic trends) and offers evidence that government intervention can occur without generating adverse market outcomes.

304. It is not evident that LNG producers would, of their own accord, commit to a domestic gas project in the absence of some form of reservation obligation. BP, in another example, has averted a reservation obligation by having gas from its Io field processed into LNG by the Gorgon Joint Venture (see 358 below). Given the current level of concentration in the upstream sector, reservation requirements are needed to expedite the diversity of supply now required to reduce the inordinate advantages enjoyed by incumbent producers in the marketplace (see 231 above).

305. The Committee had considered the merit of the state assuming the role of an aggregator to correct the imbalance in the current market dynamic. However, the earlier experience of the SECWA

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273 Submission No. 6 from Apache Energy Ltd, 25 June 2010, p. 5; Mr Ben Coetzer, General Manager, North West Shelf Gas Pty Ltd, *Transcript of Evidence*, 18 October 2010, p. 9.

274 Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 23 July 2010, p. 12; Submission No. 5 from Gorgon Domgas Project, 25 June 2010, p. 5.

275 Mr William Moody, General Manager, Marketing and Development, Wesfarmers Premier Coal, *Transcript of Evidence*, 11 October 2010, p. 4.

276 Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, *Transcript of Evidence*, 10 November 2010, p. 5.

contract (see 18 above)—which led to an extended period of oversupply and discouraged the development of other gas resources—suggests this would be a retrograde step. Instead, the Committee wants to encourage diversity of supply, multiplicity of participants and greater liquidity in the domgas market. A flexible and actively managed domestic reservation process is not inconsistent with these objectives.

306. The Committee is not persuaded by producer arguments that reservation policies will deter ongoing investment in the LNG industry. In support of this point, the Committee notes the Fraser Institute's 2010 survey of international petroleum industry executives. In this latest survey, which measures the extent of barriers to investment, Western Australia has moved into the 'most attractive' quintile of international jurisdictions. Notwithstanding the current regulatory climate, Western Australia has improved 35 places from 2009 to be 21st out 133 destinations.[277]

307. Western Australia's ranking places it above other current or aspiring LNG export nations that also implement some form of domestic reservation obligation: Qatar (30th); Malaysia (63rd); Algeria (109th); Indonesia (111th); Timor-Leste (118th); Russia (131st) and Venezuela (132nd).[278]

308. The U.S. Energy Information Administration has confirmed that '…many countries that are LNG exporters' have some form of domestic reservation regime in place to encourage local consumption.[279]

309. Importantly, Inpex confirmed that its decision to locate its Ichthys LNG processing plant in Darwin was not due to the Reservation Policy, but to a failure to gain approval to use the Maret Islands as the company's production site.[280] Inpex advised the Committee that it had been prepared to negotiate an outcome surrounding the Reservation Policy and that, '…it was not a deal breaker at all in our consideration.'[281]

310. In a similar vein, whilst Shell has not yet factored in a reservation commitment for its Prelude floating LNG project, it did indicate to the Committee that it would be prepared to enter discussions on the topic if circumstances warrant it.[282]

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277 Angevine, G. & Cervantes, M., *Fraser Institute Global Petroleum Survey 2010*, 24 June 2010, pp. 12, 18. Available at: www.fraseramerica.org. Accessed on 10 July 2010.

278 ibid., pp. 12-15. For information on other countries with reservation policies, see Submission No. 24 from Alcoa of Australia, 30 July 2010, pp. 21-22. For a list of 15 current or aspiring LNG exporting countries, see Chandra, V., 'International Gas Trade', (n.d). Available at: www.natgas.info/html/gastrade.html. Accessed on 23 February 2011.

279 U.S. Energy Information Administration, 'Liquefied Natural Gas: Global Challenges', 2008. Available at: www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2008analysispapers/lngge.html. Accessed on 23 February 2011.

280 Mr William Townsend, General Manager External Affairs, Inpex, *Transcript of Evidence*, 22 November 2010, p. 5.

281 ibid., p. 11.

282 Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia, *Transcript of Evidence*, 24 November 2010, pp. 8-9.

311. Despite the positive attitude towards Western Australia noted in the Fraser Institute survey and expressed by several producers, policy makers should still avoid an overly prescriptive approach to domestic reservation obligations. Flexibility in the application of this policy is crucial, particularly pertaining to the volumes to be supplied. As stated in 278 above, the aim should be to foster the supply and competition needed to allow domgas prices to settle at levels substantially below LNG netback values, whilst offering producers returns that encourage exploration and development. The Committee remains wary that, whilst domestic reservation policies remain a necessity, any heavy-handedness with the application of this tool could conspire against this outcome.

312. The following section examines the current approach to domestic reservations as it applies to the volumetric, price and marketing obligations placed on producers. The recommendations that follow are designed to ensure that the domgas market achieves outcomes that are consistent with a well functioning competitive market.

Finding 20

In the absence of a gas reservation policy it is unlikely that LNG producers would develop adequate domestic gas processing facilities.

Finding 21

There is no evidence to suggest that the state's current approach to domestic gas reservation obligations has deterred LNG producers from pursuing development opportunities in Western Australia.

Finding 22

Domestic gas reservation obligations remain a valuable tool for policy makers to ensure that a proportion of the state's gas reserves are supplied to local consumers in volumes and at prices that are consistent with a well functioning market.

However, this policy requires delicate handling to ensure that market outcomes reflect those of a well functioning competitive market.

(i) The Appropriate Volume for Domestic Reservation

Finding the Right Balance

313. The Committee strongly supports the current Reservation Policy, but recognises that great care needs to be exercised when determining the appropriate volumes to be held for the domgas market.

314. In its submission, Alcoa recommended that producers be obligated to reserve 15 to 20 per cent '…of all offshore gas reserves' for domestic use.[283] It added that this portion should remain fixed and applicable to any projected growth in reserve estimates.[284] The Committee is of the view that such rigidity in the Reservation Policy is neither plausible nor appropriate.

315. To demonstrate, if a 15 per cent allocation was mandated on the current estimated reserves for the six fields listed in Table 7, there would be over 18,000 petajoules of gas set aside for the domgas market.[285] This equates to approximately 50 years of domestic consumption based on current levels.[286] If, alternatively, the full 15 per cent obligation was applied to the proposed LNG production capacity of these same projects—as is the case with Pluto—this would equate to between 500 and 835 PJ being made available to the local market each year. This range is well in excess of current domgas consumption of around 355 PJ a year.[287]

316. The Committee acknowledges that this annual domgas consumption figure may underestimate the true level of underlying demand in the current market. However, it remains concerned that a rigid application of a 15 per cent reservation obligation risks flooding the local market with more gas than it genuinely needs, thus driving prices down to a level where development again becomes uneconomic for current and prospective producers. Verve Energy acknowledged this point when it conceded that the Reservation Policy needs to be '…very delicately implemented….We do not want the upstream losing their shirts over the supply of this gas.'[288]

317. Of added importance is the need to consider the impact on competing fuel industries. For some buyers, coal offers a cheaper and viable fuel alternative to higher gas prices. Wesfarmers Premier

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283 Submission No. 24 from Alcoa of Australia, 30 July 2010, p. 22.

284 ibid., p. 24.

285 Formula: 111.5TCF of combined reserves equals 120.6 exajoules of gas (120,600 petajoules) using conversion factor of 1.082. Fifteen percent of this figure equals 18,090 petajoules. The 111.5TCF estimated reserve capacity of NWS, Gorgon, Pluto, Browse, Scarborough and Wheatstone was taken from Submission No. 19(A) from Department of State Development - Response to Question on Notice, 29 September 2010, p. 2.

286 Based on DMP's estimated domgas consumption for 2009/2010 of 355PJ. Submission No. 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 6 October 2010, p. 6.

287 Minimum (62.2mtpa) and maximum (102.3mtpa) production capacity figures for the six projects taken from Department of State Development as per footnote 285 above. Mtpa multiplied by conversion factor of 54.4 to arrive at total PJ figure from which 15 per cent is worked back.

288 Mr Jason Waters, General Manager, Trading and Fuel, Verve Energy, *Transcript of Evidence*, 20 October 2010, p. 7.

Coal expressed concern regarding its ongoing competitiveness should too much gas enter the market via reservation obligations.[289]

318. The Committee is also concerned that the reservation of excessive volumes for future use in the domestic sphere prevents the gas from being monetised in a timely manner in the lucrative LNG market. Producers who are unable to realise profits as readily as anticipated, might be prompted to limit the extent of their developments thereby impacting local labour opportunities. There could also be considerable ramifications for the national economic interest if LNG reserves are under-utilised because of excessive reservation commitments. The commonwealth would forego significant royalty revenues that serve to benefit the broader economy. Moreover, with Australia's oil export volumes in decline since 2000,[290] the LNG export industry has emerged as a new and lucrative source of future foreign exchange income. Policy makers need to ensure that this revenue stream is also appropriately developed.

319. The benefit of the Reservation Policy in its current format is that it offers sufficient flexibility in its application to promote a rational approach to establishing an appropriate balance between domestic supply and demand. Any move to tighten gas reservation obligations would need to be based on demonstrable proof that this would provide a more valuable and efficient use of the resource. The Committee was advised that the best way to make this determination would be through a detailed cost-benefit analysis.[291] The Office of Energy confirmed that such a study had not yet been undertaken '…but we certainly have looked at it as a concept.'[292]

320. Queensland is one of the few jurisdictions that has commissioned such a study when its coal seam gas industry geared up towards developing its LNG export potential. Modelling was undertaken to compare a "standard" LNG scenario with another under which a 15 per cent reservation policy was applied to Queensland's coal seam gas reserves. The results showed marginally poorer outcomes in terms of GDP, GSP, royalty revenues, employment rates and standard of living indicators under the 15 per cent reservation regime.[293] Interestingly, the Queensland Government later chose to reject the adoption of the policy in that particular form.[294]

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289 Submission No. 9 from Wesfarmers Premier Coal, 25 June 2010, p. 3.

290 Geoscience Australia and ABARE, *Australian Energy Resource Assessment*, 2010, Canberra, pp. 47, 64.

291 Submission No. 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 29 November, 2010, p. 5.

292 Ms Anne Hill, A/Coordinator of Energy, Office of Energy, *Transcript of Evidence*, 11 October 2010, p. 8.

293 McLennan Magasanik Associates, *Queensland LNG Industry Viability and Economic Impact Study - Final Report to Queensland Department of Infrastructure and Planning*, 1 May 2009, pp. xx, 151-152. Available at: www.dip.qld.gov.au/resources/project/liquefied-natural-gas/final-mma-1-may-09.pdf. Accessed on 15 January 2011.

294 Briefing with Mr Dan Hunt, Associate Director General Mines and Energy, Queensland Department of Employment, Economic Development and Innovation (DEEDI), 31 August 2010.

321. Instead, it opted to implement several initiatives[295], including the appointment of an independent Gas Commissioner to monitor the supply/demand balance in the market to determine if reservations were required. If it is deemed that extra supplies are warranted, unallocated lands containing coal seam reserves will be released for development on the condition that production is exclusively directed to the domestic market under the Prospective Gas Production Land Reserve policy (PGPLR).[296]

322. On the evidence it has received it is simply not possible for the Committee to conclude that it is more beneficial to abandon the current flexibility within the Reservation Policy in an attempt to better balance the needs of local gas users with the ongoing development of the state's LNG industry. Such a course of action should not be pursued unless supported by a detailed, independent cost-benefit analysis.

Recommendation 3

The flexibility within the state's domestic gas reservation policy should be maintained unless an independent cost-benefit analysis demonstrates that a strict reservation of 15 per cent of the gas from each LNG project for the domestic market represents a more valuable and efficient use of the resource.

Gas Market Monitor

323. The Committee was impressed with a Queensland initiative that could be used locally to enhance the application of the reservation policy in its current form.

324. As noted in 321 above, the Queensland government decided against a reservation policy based on the Western Australian model. However, it did agree that the supply/demand balance in the Queensland domgas market now needed constant monitoring. For this purpose an independent "Gas Commissioner," Ms Kay Gardiner, was appointed in September 2010.[297]

325. The Queensland Gas Commissioner's responsibilities include overseeing an independent Annual Gas Market Review.[298] This review:

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295 Other initiatives included the implementation of a Short Term Trading Market and the establishment of an annual Gas Market Review.

296 Briefing with Mr Dan Hunt, Associate Director General Mines and Energy, Queensland Department of Employment, Economic Development and Innovation (DEEDI), 31 August 2010.

297 ibid.

298 ibid. A copy of the first Gas Market Review can be accessed at: www.dme.qld.gov.au/zone_files/Gas/ann_gas_mkt_rev_mma_report_to_deedi_23-06-2010.pdf

> *…includes modelling and analysis of a range of factors, including future pricing, supply-demand balance and demand peak issues, as well as constraints and barriers to market growth and increased competition in the Queensland gas market*[299]

326. The results of the review are used to inform the Queensland Government on how and when it subsequently applies its land reservation policy (PGPLR).[300]

327. In addition to this market monitoring role, the Gas Commissioner is responsible for '…facilitating frequent and open dialogue between government and industry'[301] over issues in the gas market.

328. The Committee was impressed with the potential of the Gas Commissioner to act as a monitoring mechanism to identify deficiencies in the local market and to discuss with market participants how to expedite corrective measures. Significant was the point raised by Mr David Maxwell, Senior Vice President, QGC, that the Gas Commissioner '…takes actions with the market participants to help ensure the market is working.'[302]

329. The introduction of a similar "Gas Market Monitor" in Western Australia could yield several important benefits. Firstly, as paragraphs 100 through 109 demonstrated, there is a dearth of reliable forecasting currently available that accounts for price sensitivity when estimating future supply and demand requirements. Similar to the Gas Commissioner in Queensland, a local Gas Market Monitor could be tasked with conducting an annual review of the gas market to ensure forecasts are as accurate and current as possible.

330. The annual review mechanism could also be used to provide an early indication of possible market failures, particularly those pertaining to shortages in transmission and/or domgas processing capacity. It is arguable that such a regular review mechanism, involving liaison with market participants and government, could have identified the failure of the market to appropriately respond to the looming domgas processing capacity constraints that were evident in the local market in 2007 (Finding 7). In future, the Gas Market Monitor's annual review could identify these problems earlier and facilitate discussions on remedial measures between government and industry to ensure that the subsequent price impact is minimised.

331. An annual market review has the further benefit of providing a sound basis for ministerial and departmental negotiations with producers over reservation commitments applicable to future LNG projects. Up to date advice from the Gas Market Monitor could be used to determine the

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299 Queensland Department of Employement, Economic Development and Innovation (DEEDI), 'Gas policy - new initiatives', 25 October 2010. Available at: www.dme.qld.gov.au/Energy/gas_policy___new_initiatives.cfm. Accessed on 14 January 2011.

300 Queensland's equivalent of the Reservation Policy, the PGPLR takes large tracts of unallocated land, rich in CSM reserves, and mandates that these tracts can only be developed for domgas supply. Briefing with Mr Dan Hunt, Associate Director General Mines and Energy, Queensland Department of Employment, Economic Development and Innovation (DEEDI), 31 August 2010.

301 DEEDI, 'Gas policy - new initiatives', 25 October 2010. Available at: www.dme.qld.gov.au/Energy/gas_policy___new_initiatives.cfm. Accessed on 14 January 2011.

302 Briefing with Mr David Maxwell, Senior Vice President, QGC, 30 August 2010.

appropriate volumes required to keep prices below LNG netback and the manner in which this reserved gas should be supplied to the local market. While the Gorgon State Agreement required an obligation to build a 300 TJ/day domgas processing facility, it may be appropriate for future obligations from other projects to be delivered via third party processing arrangements. Representatives from Shell made the valid point that governments should avoid inadvertently over investing in processing capacity through rigid application of the Reservation Policy.[303] The Gas Market Monitor would be well placed to advise on the adequacy of existing effective domgas processing capacity before future reservation policies are finalised.

332. The Gas Market Monitor could also advise the Minister on pipeline capacity requirements that will be needed to facilitate the delivery of new supplies agreed to under future reservation policies. Pipeline capacity is an important complementary aspect of any domestic gas obligation, but this issue was not directly addressed when the initial Reservation Policy was announced in 2006.[304] The Committee is surprised that the Dampier to Bunbury Natural Gas Pipeline, whilst fully contracted to 2019, has no expansion plans out to 2015 (see 493 below).

333. A final advantage of this role is the improvement in market transparency that the activities of the monitor would offer. Participants in the gas market could be better prepared for pending fluctuations in the supply/demand balance and the advice of the monitor would leave policy makers better informed when considering whether some form of intervention is warranted.

334. Whilst the Committee has not formed a view on who would be the most appropriate candidate for the role of a Gas Market Monitor, it is strongly persuaded by the merit of such a position. The review powers should improve the accuracy and transparency of key market data. It would also ensure that any government intervention is well-informed and likely to improve, rather than impede, the efficient operation of the market.

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303 Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia Pty Ltd, *Transcript of Evidence*, 24 November 2010, p. 4.

304 Department of the Premier and Cabinet, *WA Policy on Securing Domestic Gas Supplies*, October 2006. Available at: www.dmp.wa.gov.au/documents/DomGas_Policy(1).pdf. Accessed on 21 March 2011.

Recommendation 4

The government establishes an independent Gas Market Monitor to oversee the operation of the local wholesale gas market. Modelled on the Queensland Gas Commissioner and reporting to the Minister for Energy, the Gas Market Monitor's primary duties would be to:

- publish an annual gas market review that includes price-sensitive supply/demand forecasts and identifies deficiencies in the operation of the market;
- facilitate discussion between government and market participants on how to address identified market inefficiencies; and
- provide the basis for ministerial and departmental discussions with LNG producers before future domestic reservation obligations are finalised.

<u>Status of Current Domestic Reservation Obligations</u>

335. In the absence of a robust annual review of the Western Australian gas market, there remains a lack of transparency that has led to ongoing speculation over domestic gas supplies. This speculation is fuelled by concerns over the North West Shelf's commitment to maintain its current rate of supply after its 5,064 PJ obligation under the State Agreement is satisfied in 2014 (see paragraphs 132 and 133 above). The conjecture created by this uncertainty has led the Committee to examine what scope exists within current domestic reservation agreements to bring greater clarity to the market's outlook on future supplies.

336. The North West Shelf's Karratha Gas Plant currently supplies over two-thirds of the gas consumed in the domestic market. The continuation of production from this facility is vital to ensuring that domgas processing capacity can begin to realign with demand from 2013 as anticipated in Figure 13 above.

337. Representatives from the North West Shelf were keen to allay fears that the joint venture would not continue to supply the domestic market once its volumetric obligation under the State Agreement was met. Mr Ben Coetzer, General Manager North West Shelf Gas Pty Ltd, assured the Committee:

> *The 5,064 petajoules is under the state agreement and we very much see that as a lower limit, not an upper limit. There is no intent and there is no capacity to cut off supply once we hit that level. We are contractually obliged [with customers] to continue supplying gas beyond that point and we will continue to do so*[305]

[305] Mr Ben Coetzer, General Manager, North West Shelf Gas Pty Ltd, *Transcript of Evidence*, 18 October 2010, p. 5.

338. Mr Coetzer later implied that it is an imperative of producers to ensure that their LNG and domgas facilities are being constantly commercialised to their full potential.[306]

339. Mr Niegel Grazia, Vice President Corporate Affairs, Woodside Energy Ltd said from Woodside's perspective, '…we see no reason why we would not continue to supply the market,'[307] if reserves remain accessible and counterparties can reach agreement on contract terms. Mr Grazia added that should North West Shelf production capacity become underutilised as new competition enters the market, Woodside saw commercial opportunities in using the Karratha facility as a hub for processing third party gas.[308]

340. Ian McKenzie from Shell advised that the North West Shelf is currently undertaking a $5 billion redevelopment of its North Rankin and Perseus fields that is expected to allow existing LNG and domgas capacity to be maintained for at least the next ten years.[309]

341. These public reassurances are significant and have led the Committee to conclude that the local market should remain confident that the North West Shelf intends maintaining its domgas processing plant at the full 600 TJ per day capacity well after current long-term contracts roll off. Even so, the market would benefit from a formal assurance to this effect and the State Agreement seems to provide the vehicle through which this could be acquired.

342. Whilst the Department of Mines and Petroleum (DMP) was of the view that the North West Shelf did not have an obligation after the 5,064 PJ commitment was completed,[310] the DomGas Alliance made the valid argument that the government retains leverage under the State Agreement to '…ensure that local needs are met.'[311]

343. Clause 46(1a) of the State Agreement compels the joint venturers to meet and reach agreement with the Minister on '…the requirements in the State and the manner in which they will be met'[312] before entering into further commercial arrangements for the supply of natural gas between 2010 and 2025. This clause enables due consideration to be given to the supply status of the domestic market before the North West Shelf contemplates entering into new LNG contracts.

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306 Mr Ben Coetzer, General Manager, North West Shelf Gas Pty Ltd, *Transcript of Evidence*, 18 October 2010, p. 8.

307 Mr Niegel Grazia, Vice President, Corporate Affairs, Woodside Energy Ltd, *Transcript of Evidence*, 25 October 2010, p. 5.

308 ibid.

309 Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia Pty Ltd, *Transcript of Evidence*, 24 November 2010, p. 6.

310 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 4.

311 Mr Gavin Goh, Executive Director, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 10.

312 North West Gas Development (Woodside) Agreement Act *1979* (Western Australia), Schedule 2, Clause 46 (1)(a).

344. The Committee sees merit in the government utilising this clause—and the declared intent of the joint venture to maintain its market presence—to receive an undertaking from the North West Shelf that full production capacity will be sustained through until 2025. This report has argued that incumbent producers have enjoyed significant increases in revenue from domgas sales after the market failed to respond appropriately to a looming shortage in production capacity from 2007 (see 189 to 194 above). It is critical that buyers are now assured that these same producers will maintain full capacity as new sources of supply (such as Macedon, Devil Creek and Gorgon) enter the market.

345. Of concern to the Committee was the seeming lack of urgency shown by the Department of State Development (DSD) towards expediting negotiations given the level of public concern over future supply projections and the impact this may have on prices.

346. DSD confirmed that there was a specific requirement under the State Agreement to hold discussions with the North West Shelf joint venture regarding the latter's obligations after its current volumetric commitment is met in 2014. However, the Director General, Ms Anne Nolan, stated that there was '…no formal timetable for those discussions'[313] and that they had not yet commenced.[314]

347. DSD's attitude towards future negotiations was possibly influenced by the view that, 'We are not expecting that supply will dry up from there,'[315] and the assumption that the operators will look to continue maximising the commercial potential of their plant. Neither assumption is unreasonable in principle. However, as the North West Shelf project represents such a disproportionate component of Western Australia's domgas processing capacity, it is beneficial to the market to remove any uncertainty around the joint venture's future supply commitments. Therefore discussions under the auspices of the State Agreement that would remove this speculation should be brought forward.

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313 Ms Anne Nolan, Director General, Department of State Development, *Transcript of Evidence*, 13 September 2010, p. 3.

314 ibid., p. 10.

315 Ms Nicky Cusworth, Deputy Director General, Department of State Development, *Transcript of Evidence*, 13 September 2010, p. 3.

Recommendation 5

The Department of State Development commence discussions with the North West Shelf Joint Venture to obtain a commitment from the joint venturers that production capacity at the Karratha Domestic Gas Plant will continue at current levels, as per the terms of the existing State Agreement, until at least 2025.

Scope should remain open within the agreement to allow third party gas processing at the Karratha Gas Plant should North West Shelf reserves prevent full production capacity from being maintained after 2020.

348. The Gorgon Joint Venture is the other LNG project currently operating under a State Agreement. The key features of the Gorgon State Agreement are summarised in Table 7 above. They include the commitment to construct a 300 terajoule (TJ) per day domgas plant and to supply half of the plant's capacity to the market by 2016. Other notable elements of this agreement include:

- Until the 300 TJ per day capacity is fully contracted, the joint venture must report to the Minister at least annually on the status of its marketing activities and the construction of the domgas plant.
- The Minister reserves the right to appoint an independent party to monitor the level of compliance.
- With the permission of the Minister, the joint venturers may process and use gas produced from other areas.[316]

349. The Gorgon domgas plant based on Barrow Island is a critical addition to what is currently an insufficient level of domestic processing capacity (see Figure 13 above). Still, there is suspicion amongst buyers that the Gorgon joint venturers do not envisage marketing their full quota of 300 TJ per day earlier because of an expected oversupply in the market.[317] However, the Committee has reason to believe that the full capacity of the Gorgon domgas plant could be available to the market well before the current 2021 deadline.

350. While Clause 17(2) of the State Agreement sanctions the '…progressive expansion of the connection(s) to deliver at least 300 terajoules…per day of natural gas', a representative of the Gorgon domgas sellers confirmed to the Committee that the intention was to build the plant to full capacity before being obliged to be fully contracted.

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316 Barrow Island Act *2003* (Western Australia), Schedule 1 Clauses 17(3), (4) and (18).

317 Submission No. 11 from Horizon Power, 25 June 2010, p. 8.

351. According to Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, the sellers have been actively marketing their first 150 TJ per day tranche and expect to have '…a contract or two'[318] signed by early 2011. The reason for the five-year extension to supply the remaining 150 TJ per day capacity was to ensure that the production rates of Gorgon's as yet untested reservoirs were capable of supporting these extra requirements:

> *If they are performing as expected, we will be back to the market as quickly as we can to market the remaining gas that is for domgas*[319]

352. On the evidence it has received, the Committee is of the view that the Gorgon Joint Venture intends honouring its domestic market obligations under the State Agreement in a prompt manner. The decision to build the domgas plant to full capacity `before it has to be fully contracted to supply indicates a preparedness to comply with the conditions placed on LNG exporters who establish facilities in this state.

353. Gorgon has confirmed it is 'highly motivated' to maximise its domgas processing capacity '…as soon as possible to get the return on their investment.'[320] Importantly, if Gorgon's reservoir production rates are below par, there is provision in the State Agreement that conceivably allows the processing of third party gas from the Barrow Island facility.[321] Assuming gas specifications suited, this third party processing potential could be exploited until as late as 2021 including by other LNG producers who may also be subject to future reservation obligations.

354. The 300 TJ per day Gorgon domgas plant will undoubtedly enhance the production capacity of, and the level of competition in, the domgas market. Under the terms of the State Agreement, the Minister for State Development should maintain discussions with the Gorgon joint venturers regarding options for utilising this capacity as soon as possible. These discussions should include investigating the potential for interim third party processing should the Gorgon reservoirs initially fail to produce at the rates required to meet its maximum supply obligations.

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318 Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, *Transcript of Evidence*, 10 November 2010, p. 6.

319 ibid., p. 3.

320 ibid., p. 4.

321 Barrow Island Act *2003* (Western Australia), Schedule 1, Clause 18.

Recommendation 6

Under the terms of the State Agreement, the Minister for State Development confirm with the Gorgon joint venturers and advise Parliament on:

- the current date by which the Barrow Island domestic gas processing plant is expected to be built to its full 300 terajoules per day capacity; and
- the potential of this facility to process third party gas as an interim measure.

Floating LNG and Domestic Reservation Obligations

355. Floating LNG is a recent industry development that could pose serious ramifications for the application of future domestic gas reservation obligations.

356. Floating LNG (FLNG) technology allows producers to extract and process gas into LNG for shipment all from a transportable floating facility thereby negating the need for traditional onshore liquefaction plants. As these projects can remain entirely in commonwealth waters, the state has no formal leverage over negotiating a domestic reservation component.

357. Shell is planning to develop gas from its exclusively-owned Prelude field in the Browse Basin using FLNG technology. The project is due for FID in 2011 with production possibly starting in 2016.

358. Representatives of Shell Development Australia advised the Committee that FLNG is a welcome innovation, as it allows gas which would have previously remained stranded in smaller fields to be developed.[322] The Committee struggled to accept this argument in the case of Prelude, as the field is located in the midst of License Areas held by Inpex for the Ichthys project that is sending gas 680 kilometres via sub-sea pipeline to Darwin for processing. It seems feasible that Prelude gas could be processed by Inpex via some form of sale and purchase agreement (or tolling arrangement). BP has negotiated such a deal to have gas from its Io field developed through the Gorgon LNG project.[323]

359. Notwithstanding this point, the Committee's greater concern is the fact that FLNG allows all processing to be kept offshore, removing the power of the state to implement its Domestic Gas Reservation Policy. It also significantly reduces the local content contribution on the project potentially towards zero. Shell Development Australia indicated to the Committee that there could

[322] Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia Pty Ltd, *Transcript of Evidence*, 24 November 2010, p. 8.

[323] *Significant Milestone for Io and Jansz Gas Fields*, Media Statement, BP Australia, 29 May 2009. Available at: www.bp.com/genericarticle.do?categoryId=9008681&contentId=7053385. Accessed on 5 February 2011.

be other opportunities for FLNG in the outer Carnarvon Basin.[324] Were FLNG technology to proliferate, this could have a significant and ongoing impact on future domestic supplies.

360. Despite the diminution of the state's formal bargaining powers, the Committee asked whether Shell would nonetheless be willing to negotiate a domestic obligation against the Prelude project with gas possibly provided from another source. Mr Ian McKenzie, Vice President of the Sunrise development (Timor Sea), replied:

> *Yes….It is not something that we have incorporated into our base planning. I think it is something we would be prepared to discuss*[325]

361. Mr McKenzie did qualify this statement by suggesting that Shell would be particularly willing to negotiate in an environment where a clear shortfall existed. However, he felt that the recent supply response, both in terms of volumes and capacity, had made this prospect increasingly unlikely.[326]

362. Independent Consultant, Mr John Boardman, hinted that moral suasion may still be effectively applied in the case of Shell as it looks to develop its FLNG technology in the waters off the Western Australian coast. Asked about the impact of the Prelude FLNG project on the principle of domestic reservation, Mr Boardman replied:

> *I do not personally see it as a show stopper….I believe that a company like Shell will be extremely conscious of its public image, extremely conscious of sort of the spirit of the obligations under the WA domestic gas reservation policy, and will seek to provide that gas from its other resources*[327]

363. In the case of Prelude, it is not the volumetric obligation that is of primary importance. FLNG technology offers production rates in the order of approximately 3.5 million tonnes per annum (mtpa). A full 15 per cent reservation applied to the production capacity of the plant (similar to the Pluto Reservation Policy) equates to around 29 PJ per year or 78 TJ per day, which significantly exceeds the annual rate of growth in the domestic market (see paragraph 99 above).[328]

364. Of greater significance here is the establishment of a precedent whereby FLNG proponents are aware that the government will pursue a domestic reservation commitment even from projects based exclusively in areas of commonwealth jurisdiction off the state's coast. Western Australia has already lost an important source of domestic supply from the Browse Basin after Inpex made

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324 Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia Pty Ltd, *Transcript of Evidence*, 24 November 2010, p. 7.

325 ibid., p. 8.

326 ibid.

327 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 11 October 2010, pp. 11-12.

328 Using the same conversion methodology as cited in Footnote 287 above.

the decision to locate its Ichthys plant in Darwin.[329] The state must now do all it can to encourage investment in the domgas market including from developments using FLNG technology.

Finding 23

Floating LNG (FLNG) technology enables project proponents to conduct all aspects of production at sea in commonwealth waters. This greatly reduces the formal powers of the state government to negotiate a domestic gas supply commitment under the state's reservation policy.

Recommendation 7

Even with reduced formal powers, the state government should do all it can to obtain a commitment to the domestic gas market, including from developments using Floating Liquefied Natural Gas (FLNG) technology.

The government should encourage the promotion of third party gas processing to meet such commitments.

(ii) Appropriate Price for Reserved Gas - "Commercial Viability"

365. At the recent Office of Energy gas market stakeholder workshop, '…there was a general feeling that the gas reservation policy needs clarification, there is insufficient detail there.'[330] It has become apparent to the Committee that considerable ambiguity still surrounds the price conditions for which reserved gas has to be sold to the domestic market.

366. Producers on the Gorgon and Pluto LNG projects have provision to delay the sale of reserved gas to the domestic market until such time as it is deemed "commercially viable" to do so.

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329 Reserves for Inpex's Ichthys Project are currently estimated at 12TCF or slightly less than 13,000 petajoules. Mr William Townsend, General Manager, External Affairs, Inpex, *Transcript of Evidence*, 22 November 2010, p. 4. A domestic reservation applied to these reserves could have generated up to 1,950 petajoules (if a full 15 per cent was applied). If a 15 per cent reservation was applied to the project's stated production capacity (8.4mtpa), this would equate to approximately 69PJ per year (using the same methodology cited in Footnote 287 above. In 2009, total domestic gas consumption in Western Australia was around 357 PJ.

330 Ms Anne Hill, A/Coordinator, Office of Energy, *Transcript of Evidence*, 11 October 2010, p. 3.

367. While Woodside confirmed that under its letter of arrangement with the government, the commercial viability parameters for Pluto are still to be agreed,[331] the Gorgon State Agreement does define commercial viability in relation to its plant construction and gas sales:

> [Commercially viable]… *in relation to a Domgas Project means that a Domgas Project could be established in conjunction with an LNG or other gas processing facility within the Gas Processing Area on Barrow Island such that the commercial rates of return (including recovery of all capital and operating costs, taxes, royalties and other charges associated with the delivery of domestic gas) meet or exceed the minimum return considered acceptable for this type of project by a reasonable petroleum developer or by investors or lenders to this type of project* [332]

368. Aspects of this definition remain open to interpretation, although the Minister is empowered to appoint an independent expert—at the cost of the project proponents—to determine the veracity of any request for delay based on commercial viability claims.[333]

369. The principle of commercial viability is causing consternation amongst buyers who feel that the term is not adequately defined and allows producers too much scope to hold supplies from the local market, thereby contributing to higher prices (see 285 above).

370. Alcoa typified the frustrations of buyers regarding the commercial viability provision:

> *It should be commercial, but it should actually be rigorous and actually test the market, rather than being so subjective, or having holes in it, that the objective can be avoided* [334]

371. Buyers have expressed a range of views regarding what represents a commercially viable price for reserved gas. The DomGas Alliance endorsed the view expressed by the Premier in April 2010 that, '…the price at which it is made available to the domestic market should not be above the effective price [cost] at which the gas is fed into the LNG plant.'[335] When challenged by the Committee to quantify what this figure should equate to, the DomGas Alliance equivocated before taking the question on notice. It later responded without offering any greater clarity: 'The alliance supports the Premier's contention that the price of domestic gas should be the cost of the gas as it enters the LNG processing plant - plus a fair profit margin.'[336]

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[331] Mr Stewart Gallagher, Pluto Commercial (Foundation) Manager, Woodside Energy Ltd, *Transcript of Evidence*, 25 October 2010, p. 6.

[332] Barrow Island Act *2003* (Western Australia), Schedule 1 Clauses 17(13)(a) and (b).

[333] ibid., Schedule 1 Clause 17(8).

[334] Mr Tim McAuliffe, General Manager, Climate Strategy, Alcoa of Australia, *Transcript of Evidence*, 17 November 2010, p. 14.

[335] Hon C Barnett, MLA, (Premier), 'Energy Down Under – Right Place, Right Time', Speech to the James A. Baker III Institute for Public Policy, Rice University, Houston, Texas, 13 April 2010, p. 28.

[336] Submission No. 3(A) from DomGas Alliance, 25 October 2010, p. 1.

372. Verve Energy made a similarly ambiguous suggestion. It stressed that producers should not be forced to sell this gas below cost, calling instead for '…a fair return based on the capital employed specific to that portion of the project'.[337]

373. In its submission, Alcoa initially suggested '…the incremental cost of gas production at a rate of return that reflects the lower risk associated with domestic production.'[338]

374. So what is a commercially viable price of domestic gas? The Committee does not support the view that producers should supply reserved gas at levels reflecting the cost of delivery to the LNG processing plant. At a minimum, domgas processing costs need to be accounted for, as does the inclusion of an industry-recognised reasonable rate of return. Enforcing sales below these levels will deter future developments. As argued earlier, this could serve to reduce the volume and diversity of future supplies, thus leading to further periods of excessively priced gas.

375. Conversely, opportunity cost price outcomes, such as LNG netback equivalent or greater are considered excessive by the Committee.

376. In the current environment, the Committee argues that a domgas price that covers the cost of production and provides an industry-recognised reasonable rate of return can satisfy the principle of commercial viability. This benchmark should offer a commercially acceptable outcome to producers and facilitate a market environment where the appetite for further exploration and development is maintained. This will lead to improved liquidity and competition in the local wholesale market over the longer term, which should facilitate an environment of lower prices for domestic gas.

Finding 24

The parameters for commercial viability, as it pertains to the supply of gas reserved from LNG projects for the domestic market, need to be clarified. Acceptable parameters for commercial viability might include, but not be restricted to:

- a price that covers the cost of production and provides an industry-recognised reasonable rate of return.

337 Mr Jason Waters, General Manager, Trading and Fuel, Verve Energy, *Transcript of Evidence*, 20 October 2010, p. 6.

338 Submission No. 24 from Alcoa of Australia, 30 July 2010, p. 24.

Recommendation 8

Department of State Development refine, and publish a list of, any general parameters that are deemed to satisfy "commercial viability" as it pertains to domestic gas reservation obligations.

377. Whilst parameters around commercial viability should be clarified, it is equally important to ensure any producer's claim that it is not commercially viable to supply gas under a domestic reservation obligation can be appropriately evaluated. In this respect, the review clauses within the Gorgon State Agreement (referred to in paragraph 348 above) appear to offer an encouraging development.

378. Under the Barrow *Island Act 2003*, the Gorgon Joint Venture is obliged to '…actively and diligently undertake….ongoing marketing of natural gas in Western Australia' until it is delivering the full 300 TJ per day of capacity from its domgas production plant.[339] These marketing activities can be randomly evaluated at the behest of the Minister who retains the power to appoint an independent party for this purpose (at the expense of the joint venturers). The joint venturers are further obliged to provide, on a confidential basis to the assessor, evidence of Gorgon's marketing activities including prices received and other details pertaining to its Expression of Interest process.[340]

379. Should the joint venturer wish to request an extension to the timing of its domgas commitments under the State Agreement, the Minister may again appoint an 'Independent Expert' to assess the veracity of the claim. Any claims are to be considered against 'prevailing market conditions', which includes contract prices and duration.[341] Regarding commercially sensitive materials, the state and the joint venturers '…shall use all reasonable endeavours to make available…all information relevant to the matter and which the Independent Expert reasonably requires in order to make a recommendation'.[342]

380. The information to which independent assessors are privy under the Gorgon State Agreement review process should enable any commercial viability claims from the joint venturers to be assessed in a robust manner. The Gorgon Joint Venturers made no suggestion that the review conditions around its domgas activities are overly onerous. The Committee concluded in 352 above that the Gorgon Joint Venture appears to be acting in a manner consistent with the terms of its state agreement regarding its marketing obligations. Even so, the independent review mechanism within this agreement should be regularly utilised until Gorgon satisfies its domestic

[339] Barrow Island Act *2003* (Western Australia), Schedule 1 Clause 17(3).

[340] ibid., Schedule 1 Clause 17(4).

[341] ibid., Schedule 1 Clause 17(13)(b).

[342] ibid., Schedule 1 Clause 17(8)(d).

market requirements. Furthermore, this process should be included as a standard term of all future reservation policies.

Recommendation 9

The review mechanism articulated in Clause 17 (Schedule 1) of the *Barrow Island Act 2003* should be regularly enforced until the Gorgon Joint Venturer's full domestic gas production capacity is contracted.

381. To further promote the accountability of the producers to use commerciality provisions in their true spirit, a register of any independent assessment of commercial viability claims should be maintained and published by the Department of State Development. Whilst commercially sensitive materials relating to any decision should remain confidential, a detailed explanation of the reasons behind the judgement on all claims should be provided.

Recommendation 10

To ensure that commerciality provisions applicable to domestic gas reservations are used appropriately, a register of all independent assessments of commercial viability claims should be maintained by the Department of State Development.

Whilst commercially sensitive material should remain confidential, a detailed explanation of the reasoning behind each assessment should be published.

(iii) Testing the Market

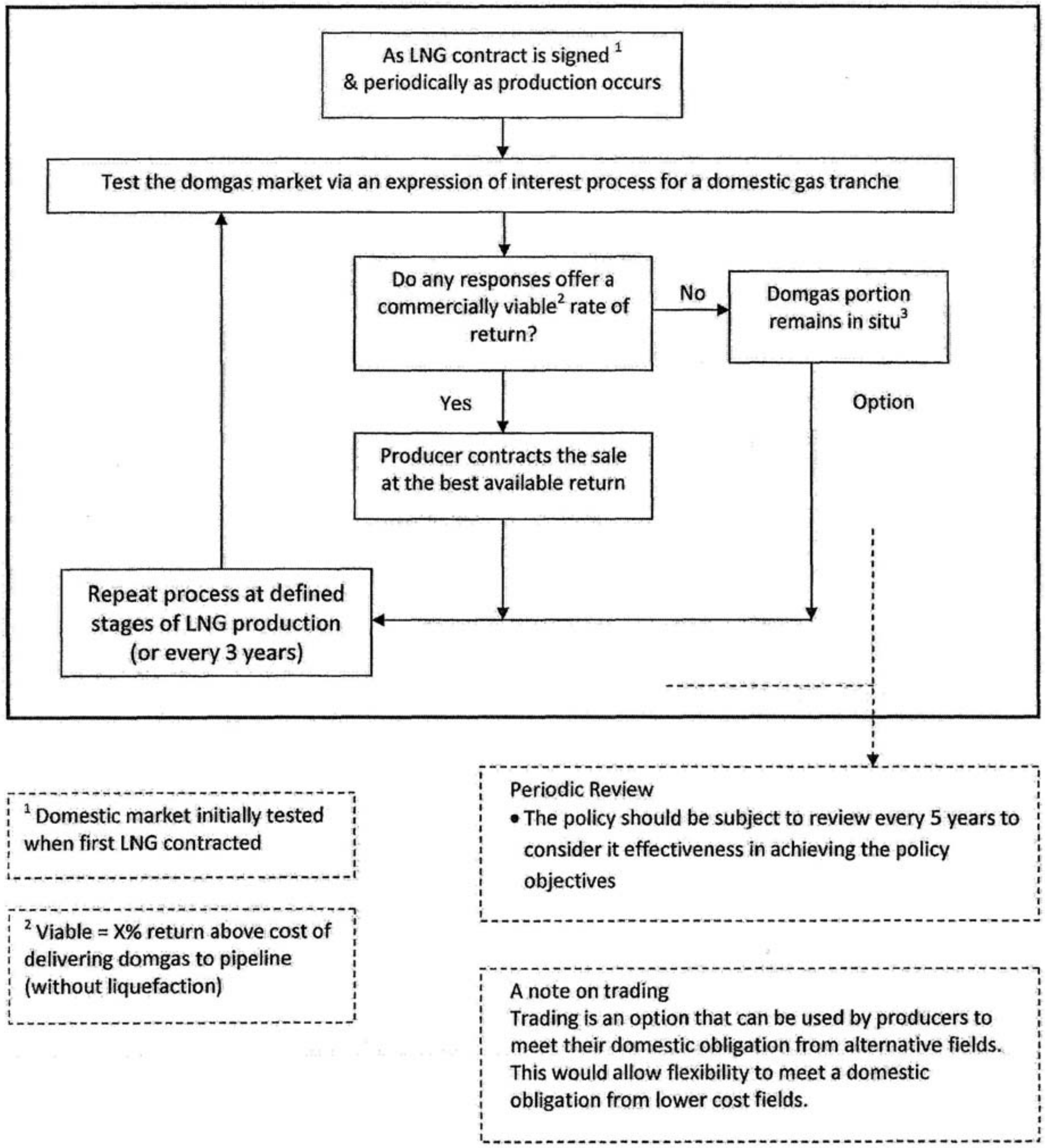
382. With an appropriate independent review mechanism in place (as per Recommendation 9 above), the onus should be on all LNG producers holding gas under reservation to regularly "test the market." The Committee saw merit in a proposal put forward by Alcoa that aimed, in the spirit of the Reservation Policy, to achieve an appropriate balance between the interests of producers and consumers of gas in Western Australia.

383. The key features of the proposal from Alcoa are illustrated in Figure 21 and included:

- An obligation on producers to test the domestic market when an LNG contract is first signed. An Expression of Interest process could be used.

- If commercially viable rates of return were available, producers would proceed to contract at the best rate available.
- If commercially viable returns were not available, the domgas could remain in situ at the discretion of the producer with the process repeated at pre-defined intervals.
- The entire process should be reviewed after five years to assess its effectiveness.

Figure 21 Suggested Implementation of Domestic Gas Reservation Policy (Alcoa) [343]



384. The benefits of such a process are three-fold. Firstly, producers are obligated to genuinely test the domestic market as LNG projects are developed. This removes the perception that reserved gas

343 Submission No. 24(D) from Alcoa of Australia - Response to Question on Notice, 22 December 2010, p. 4.

might be getting warehoused for export. Secondly, producers are still able to supply only when a viable commercial return can be achieved. Finally, an appropriate supply/demand balance is maintained. If demand is not there, producers are not compelled to "flood" the local market.[344]

385. The Committee is of the view that it is not an unreasonable undertaking for producers to be subject to a similar process under future reservation agreements. Under the *Barrow Island Act 2003*, the Gorgon Joint Venturers are already obliged to actively market their domgas commitments (378 above) with the Minister reserving the right to call for an independent evaluation of the process. With a similar independent review mechanism to monitor marketing activity and adjudicate on the viability of returns available in the market, producers could be assured that they would not be compelled to operate unprofitably.

Recommendation 11

All future domestic gas reservation agreements should include a review mechanism, similar to that contained in Clause 17 of the *Barrow Island Act* 2003, which obliges producers to actively and diligently test the market and be subject to independent assessment.

If prices are deemed by such an independent assessor to be commercially viable, producers should be further obliged to enter into contractual arrangements at the most attractive terms available to the producer.

386. There may be other options for the sale of gas reserved under domestic reservation that warrant further consideration. It could be worth considering the feasibility of staging periodic auctions managed and administered by an independent assessor who is agreed to by government and LNG producers. Contracts offering standardised terms for duration, volume, take-or-pay, daily swing and indexation could be publicly listed before calls for bids and offers were made.

387. The independent assessor could determine the commercial viability of the bids and offers received before matching producers and buyers off at the cheapest price. Counterparties who transact via the auction could later negotiate any changes or additions to the terms and conditions [e.g. interruptibility provisions and price review mechanisms].

388. Once again, producers are only compelled to sell gas when a commercial rate of return can be achieved. The auction process will also allow standard contract terms to be made public, bringing to the market a level of transparency that is currently lacking and much needed. As section 5.3(a) below demonstrates, transparency is seen as key to improving the efficiency of markets.

344 Submission No. 24(D) from Alcoa of Australia - Response to Question on Notice, 22 December 2010, pp. 1-4.

389. The Committee did not investigate in detail how an auction of domestically reserved gas could operate, but urges the government to explore the potential merit of such a process for bringing gas to the market at rates that are viable and reasonable to local buyers and producers.

Finding 25

If the gas reservation policy does not lead to a reduction in domestic gas price beyond LNG netback, the government should consider additional options to create a functioning market for gas-on-gas competition in Western Australia, including a regulated auction or limiting specific fields to domestic use (as per Queensland's Prospective Gas Production Land Reserve policy)

4.3 Retention Lease Arrangements

390. Similar to domestic reservation obligations, the Committee was repeatedly urged to examine the management of retention lease arrangements currently available to upstream producers.

391. Retention leases are available to exploration licence holders who make a petroleum discovery which, in its own right, may not yet be commercially viable to develop. Explorers can maintain the title on that licensed area by applying for a retention lease. Under current criteria, the holder of a retention lease must be able to prove that the lease will be commercially viable within 15 years. Applicants must reapply every five years to maintain the lease, proving each time to the satisfaction of the relevant Minister that the holdings remain uneconomic to develop at that time. On occasions, the applicants may be entitled to a renewal subject to the satisfaction of certain development conditions. However, if the discovery is deemed to be commercial, the holder must apply for a production licence or forfeit the holding. Retention leases for areas in Western Australian waters or on-shore are administered by the state government, whilst those further offshore are managed by the commonwealth and the state under "Joint Authority". [345]

392. Retention leases are an important feature of the Western Australian gas market. A recent DMP estimate put the volume of P90[346] reserves held under retention lease across the Bonaparte, Browse and Northern Carnarvon basins alone at around 36,000 petajoules (PJ).[347] DMP argued that retention leases can spur companies on towards development.[348] An example of this occurred

345 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 11; Submission No. 24 from Alcoa of Australia, 30 July 2010, p. 24.

346 Reserves with a 90 per cent probability of being produced. Also referred to as 1P or 'proven reserves'. See, 'Hydrocarbon Exploration', Wikipedia (n.d). Available at: http://en.wikipedia.org/wiki/Hydrocarbon_exploration#Reserves_and_resources. Accessed on 24 January 2011.

347 Department of Mines and Petroluem, *Petroleum in Western Australia September 2010*, September 2010, p. 39. Available at: www.dmp.wa.gov.au/documents/Petroleum_in_WA_magazine_09_10.pdf.

348 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 11.

in 2009 when the commonwealth and state governments made Woodside's Browse Basin retention lease renewal contingent upon commencement of a $1.25 billion work program that would enable FID by mid-2012.[349]Yet a common sentiment expressed to the Committee was that the management of these retention leases—particularly those under commonwealth jurisdiction where the majority of gas is located—needs to be addressed.

393. A common criticism of the current retention lease regime was that it was sufficiently lax as to enable producers to "warehouse" or "hoard" reserves, many of which could be commercially developed already for domestic markets.[350] Other critics argued that the commercial viability parameters lacked transparency, were overly reliant on the input of the producer and should be subject to greater independent scrutiny.[351] Another concern was that the current approvals process '…creates significant barriers to entry for new players and protects larger incumbent producers.'[352]

394. The most notable critic of the retention lease management process was the incumbent domestic producer, Apache Energy Limited. The arguments presented by Apache, a company that currently holds retention leases in the Carnarvon Basin, covered the full gamut of criticism aimed at the retention lease process:

> *This policy is a market distortion unique to Australia. Acreage prospective for gas fields suited to supply the domestic market in WA, in many cases containing gas discoveries, is being "warehoused" by companies to supply the LNG market many years in the future….*
>
> *Abolition of the retention lease policy and stringent application of the commerciality requirements on existing retention leases would result in acreage prospective for gas fields suited to supply the WA domestic market being released for exploitation by companies qualified and motivated to supply that market.*[353]

395. Appearing before the Committee, Apache's Commercial and Business Development Manager, Dr Aidan Joy added that:

> *I think that one could clearly demonstrate that it is perfectly commercial to develop some of those fields into the WA domestic market at the present time. I do not think there is any doubt about it*[354]

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349 Woodside Energy Ltd, 'Annual Report 2009' (n.d), p. 6. Available at: www.woodside.com.au/Investors+and+Media/Annual+Reports/. Accessed on 20 January 2011.

350 Mr Tony Petersen, Chairman, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, pp. 2, 7-8; Submission No. 8 from Verve Energy, 25 June 2010, p. 3.

351 Submission No. 2 from Alinta Pty Ltd, 22 June 2010, p. 3; Submission No. 11 from Horizon Power, 25 June 2010, p. 12.

352 Submission No. 7 from Synergy, 25 June 2010, p. 7.

353 Submission No. 6 from Apache Energy Ltd, 25 June 2010, pp. 4-5.

354 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy Ltd, *Transcript of Evidence*, 20 September 2010, p. 6.

396. The Australian Petroleum Production and Exploration Association (APPEA) countered that powers were available in the legislation and regulations to deal with any improper accumulating of reserves, but stressed that there was no evidence to suggest such activities were taking place.[355]

397. Mr Chris Sorensen from Gorgon Domgas Marketing defended retention leases as a vital component in the commercial considerations of LNG proponents negotiating long-term contracts:

> *Retention leases are all about providing gas at the end of the contract. If retention leases are not available, that risks our ability to meet long-term contracts, which is what our customers are looking for*[356]

398. The Committee accepts that retention leases may play a role for prospective LNG producers who need to aggregate sufficient reserves to make a new project bankable. This point was even acknowledged by some critics of the current retention lease management process who met with the Committee.[357]

399. Moreover, the Committee was not able to verify claims that this policy was being exploited by LNG producers to warehouse reserves. Interestingly, Apache's Dr Joy was also not able to provide evidence in support of his implied claim that fields are being retained by LNG producers who have over-committed on long-term contracts.[358]

400. The Committee is nonetheless persuaded by the argument that if the evaluation process underpinning the application for and renewal of retention leases lacks rigour, the potential exists for the excessive stockpiling of reserves for the LNG market. Managed efficiently, retention lease arrangements should be able to balance any competing objectives of the LNG and domestic markets. As the ERA argued in its submission, retention lease arrangements need to be:

> *…appropriately balanced to provide sufficient time for the upstream gas industry to commercialise discoveries but not to allow these arrangements to be used to warehouse acreage and thereby sterilise resources that might otherwise be available to the domestic market* [359]

401. Currently, it appears that this balance is lacking and the process is working to the detriment of the domestic market. Observing the Western Australian market, the ERA said there was a 'continuing perception' that the current retention lease process is 'overly generous' towards leaseholders.[360]

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355 Mr Damian Dwyer, Director, Energy Markets and Climate Change, APPEA Ltd, *Transcript of Evidence*, 20 September 2010, p. 11.

356 Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, *Transcript of Evidence*, 10 November 2010, p. 7.

357 Briefing with Mr Brad Page, Chief Eexecutive Officer, Energy Supply Association of Australia (esaa), 2 September 2010.

358 Dr Aidan Joy, Commercial and Business Development Manager, Apache Energy Ltd, *Transcript of Evidence*, 20 September 2010, p. 6.

359 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 32.

360 ibid.

This sentiment is not a recent development. In 2007, a report commissioned by the commonwealth Joint Working Group on Natural Gas Supply (JWG) commented that '…the urgency of the Western Australian supply situation'[361] was such that the Joint Authority might request re-evaluating the commercial viability claims[362] of leaseholders who were not indicating any intention of developing their reserves in the near future.

402. The Committee was interested in ascertaining how the government has responded to this apparent flaw in the current retention lease management process, particularly after several departmental officials expressed to the ACCC their personal opinion that changes to retention lease processes would promote '…competition in and supply of domgas in WA'.[363]

403. The Department of State Development stressed that the government did not have a position on retention lease management: '…because most of the gas is in commonwealth waters; unfortunately we do not have a massive amount of leverage over that process.'[364]

404. The Department of Mines and Petroleum, by contrast, advised that it has contributed to an Options Paper on the Granting and Renewal of Retention Leases released for comment in 2009 by the Commonwealth Department of Resources, Energy and Tourism (DRET). The Options Paper had supported the continuation of the retention lease process but conceded that, 'Consideration should…be given to definition [sic] and application of the commerciality test.'[365] Among its draft conclusions, the DRET paper found that commerciality tests '…should include an explicit treatment of the potential of the project to supply to the domestic market.[366]

405. Acknowledging some of the other criticisms that were also conveyed to the Committee, the DRET paper stated there were opportunities to provide improvements to the retention lease guidelines by way of independent technical and economic reviews and greater transparency and accountability.[367]

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361 McLennan Magasanik Associates, *Natural Gas in Australia: Report to the Joint Working Group on Natural Gas Supply*, Melbourne, 16 July 2007, p. 63.

362 ibid.

363 ACCC, 'Record of Meeting Between ACCC and WA Government Departments', 1 June 2010. Available at: www.accc.gov.au/content/index.phtml/itemId/922104/display/submission. Accessed on 24 January 2011.

364 Ms Nicky Cusworth, Deputy Director General, Department of State Development, *Transcript of Evidence*, 13 September 2010, p. 7.

365 Department of Resources, Energy and Tourism, *Review of Policy Relating to the Grant and Renewal of Retention Leases - Options Paper*, 12 June 2009, p. 9. Available at: www.ret.gov.au/resources/Documents/Grant_and_%20renewal_of_retention_leases-optionspaper.pdf. Accessed on 21 March 2011.

366 Department of Resources, Energy and Tourism, *Review of Policy Relating to the Grant and Renewal of Retention Leases - Options Paper*, 12 June 2009, p. 23. Available at: www.ret.gov.au/resources/Documents/Grant_and_%20renewal_of_retention_leases-optionspaper.pdf. Accessed on 21 March 2011.

367 ibid., p. 14.

406. In its 'detailed' response to the Options Paper, DMP urged that the technical and economic objectives under which retention leases were assessed needed to be made more explicit and should include a clear statement that '…management of the retention leases system should support domestic gas security'[368]. DMP advised the Committee that it had still not received a response to its submission and that it had only recently become aware that DRET had prepared a policy position paper on retention lease management for discussion with the Federal Minister.

407. The lack of engagement by the federal government over this issue demonstrates the limited influence that state departments have over the issue of retention lease management in commonwealth waters. Still, the Committee acknowledges the efforts of DMP and urges the department to request an urgent update from DRET on the status of the 2009 Options Paper, as the feedback to this Inquiry suggests that little progress has been made to address ongoing flaws in retention lease management.

408. The Committee sees further merit in the department urging the commonwealth to consider the JWG Report proposal (see 401 above) for the Joint Authority to re-evaluate the commercial viability of all retention leases that have no development plans in place within the next five years. Given the current lack of competition in the upstream sector in Western Australia, it is critical that fields best suited to domestic supply are not reserved unconditionally for extended periods by incumbents if other parties are willing and able to commence development. For this to eventuate, incumbent leaseholders need to be rigorously held to account under the retention lease regime.

Finding 26

The current process underpinning the application for and renewal of retention leases lacks sufficient rigour and enables the stockpiling of gas reserves by incumbent producers. These reserves may include fields that are suitable for the development of domestic supplies.

[368] Submission No. 18(A) from Department of Mines and Petroleum - Response to Question on Notice, 6 October 2010, pp. 3-4.

Recommendation 12

The Department of Mines and Petroleum should request that the Commonwealth Department of Resources, Energy and Tourism (DRET) respond urgently regarding:

- A detailed update on the status of the 2009 “Review of Policy relating to the Grant and Renewal of Retention Leases”.
- DRET’s current position on retention lease management processes.
- The merit of subjecting all retention leases with no development plans in place within the next five years to a re-evaluation of commercial viability by the Joint Authority.
- Ensuring that the supply of gas to the domestic market is included as a priority in the process of renewing or issuing a retention lease.

CHAPTER 5 DOMESTIC WHOLESALE MARKET

5.1 Background

409. Despite the impending entry of several new upstream projects, the wholesale gas market in Western Australian remains highly concentrated. Currently, two major producers supply almost all of the state's domgas with over 90 per cent of demand coming from five major buyers. As alluded to in paragraph 24 above, the local market has often been described as "project-driven" or "lumpy."

410. In 2009, there were only 26 active gas sales contracts in the Western Australian wholesale market.[369] The majority of domestic sales contracts vary in size from 10 terajoules (TJ) per day to over 100 TJ per day, are linked to take-or-pay provisions and have a wide range of maturities (some extending out for 25-years).[370] The terms of these contracts are negotiated bilaterally and are highly confidential.

411. Western Australia also has an "unofficial secondary market." Mr Allan McDougall, Manager of Gas Procurement with Synergy explained:

> *There are some major players in the downstream market. Everyone knows who everybody is and we call each other up to complete a transaction*[371]

412. Contracts on this unofficial market vary in length from one day to a month.[372]

413. The Committee has concluded (see Finding 15) that the Western Australian wholesale market lacks the level of liquidity, transparency and competitive pressure that is evident in other states. Whilst not the dominant factor, these market deficiencies have arguably contributed to the price differential now being witnessed between the local market and the eastern states.

414. Throughout this Inquiry, the Committee's attention has been drawn to a range of measures that might improve the transparency and level of competition within the local market. These include:

- addressing the right of joint venturers to collectively market domestic gas;
- establishing an official Short-Term Trading Market; and
- introducing a Gas Market Bulletin Board and a Gas Statement of Opportunities.

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369 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 8.

370 Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, p. 3.

371 Mr Allan McDougall, Manager, Gas Procurement, Synergy, *Transcript of Evidence*, 20 October 2010, p. 8.

372 ibid.

415. Whilst some of these initiatives have proven quite divisive (joint-marketing), others (Bulletin Board and Statement of Opportunities) have received broad-based support from nearly all market participants.

416. This chapter will examine the respective merit of these proposals.

5.2 Joint Marketing of Domestic Gas

417. Provision exists within the national legislative framework for joint venture partners in gas projects to market their gas collectively.

418. Even though joint venture partners are increasingly pursuing sales independently, there may be occasions where it is deemed more commercially beneficial to seek authorisation from the ACCC to conduct joint marketing. The ACCC approval process is designed to ensure that joint marketing does not breach the anti-competitive conduct provisions within the *Trade Practices Act 1974*. To obtain authorisation, applicants must demonstrate that '…the public benefits of joint marketing exceed any anti-competitive costs.'[373]

419. In Western Australia, the Gorgon Joint Venture partners were granted authorisation in November 2009 to jointly market until the end of 2015. In September 2010, the ACCC approved a similar application from the North West Shelf Joint Venture to re-establish its joint marketing authority. This authorisation was also granted until 31 December 2015. Both authorisations are subject to ring-fencing provisions, which are designed to ensure that rival domgas projects compete openly and do not share commercial information (i.e. Shell and Chevron are partners in each joint venture).[374]

420. In 2008, a Senate Standing Committee could not conclude whether joint marketing had an impact on upstream competition and prices paid by customers in the wholesale market.[375] However, most wholesale customers in Western Australia remain highly critical of the effect that joint marketing is having in both these areas.

421. Alcoa argued that the lack of competition attributable to joint marketing was contributing to increased prices and higher costs for users, but did not quantify what these costs were.[376] DomGas Alliance argued that joint selling was '…the biggest barrier to affordable gas prices in the State'[377]

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373 AER, *State of the Energy Market 2008*, ACCC, Canberra, 2008, p. 30.

374 ACCC Final Determination - NWS Project, 8 September 2010, p. ii. See also, Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, *Transcript of Evidence*, 10 November 2010, p. 2.

375 ACCC Final Determination - NWS Project, 8 September 2010, s. 3.77.

376 Submission No. 24 from Alcoa of Australia, 30 July 2010, p. 28.

377 Submission No. 3 from DomGas Alliance, 24 June 2010, p. 5.

and claimed that it would cost Western Australian consumers $2 billion a year.[378] This claim was later undermined when the Alliance confirmed that this figure was a 'back of the envelope calculation' that had attributed an estimated average price increase of $2.50 to $8 per GJ entirely to the effects of joint marketing.[379]

422. A number of other critics argued that joint marketing enabled non-competitive behaviour.[380] Alinta claimed that joint marketing results in further concentration among upstream gas suppliers and thereby '…reduces competitive tension in the market.'[381] It went on to add that these arrangements:

> *…are likely to result in gas sales taking place under agreements that provide limited scope for gas consumers to negotiate important non-price terms and conditions of sale*[382]

423. In another criticism, Synergy argued that each joint venture partner in Western Australia was sufficiently skilled and profitable to undertake commercial negotiations individually and that '…a transition to separate marketing should be considered.'[383]

424. Significant commentary was also noted from outside the coterie of buyers, with the Economic Regulation Authority (ERA) submission suggesting that:

> *Considering the high degree of concentration in the market and the prospect that it will take a long time for alternative sources of supply to be developed, the Committee could usefully consider the joint marketing issue*[384]

425. Naturally, gas producers and their affiliates defended the recent ACCC decisions sanctioning joint marketing. APPEA stressed the independence of the authorisation process and pointed to one of the ACCC's conclusions that separate marketing might actually lead to smaller volumes of gas coming on shore.[385]

426. North West Shelf referred to a related ACCC conclusion that joint marketing would not harm competition, nor lead to any reduction in the supply of gas or any noticeable increase in price.[386]

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378 Submission No. 3 (Att 1) from DomGas Alliance, 24 June 2010, p. 1.

379 Mr Gavin Goh, Executive Director, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 14.

380 Mr Tony Petersen, Chairman, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 2; Briefing with Mr Brad Page, Chief Executive Officer, Energy Supply Association of Australia (esaa), 2 September 2010.

381 Submission No. 2 from Alinta Pty Ltd, 22 June 2010, p. 4.

382 ibid.

383 Submission No. 7 from Synergy, 25 June 2010, p 6.

384 Submission No. 13 from Economic Regulation Authority, 1 July 2010, pp. 34-35.

385 Mr Tom Baddeley, Director (WA), APPEA and Mr Damian Dwyer, Director Energy Markets and Climate Change, APPEA, Transcript *of Evidence*, 20 September 2010, p. 11.

386 Mr Ben Coetzer, General Manager, North West Shelf Gas Pty Ltd, *Transcript of Evidence*, 18 October 2010, pp. 8-9.

427. BP argued that joint marketing was a valuable tool in maximising supply and therefore competition in the Western Australian market.[387] Gorgon, alternatively, said it would have preferred to market separately. However, its decision to pursue a joint marketing authorisation '…was a reflection of the different nature of the WA wholesale gas market.'[388] Gorgon implied that the local market was neither liquid nor transparent enough to support a greater number of individual sellers.[389]

428. Advocacy for joint marketing was noted from other sources. The Chamber of Minerals and Energy WA (CME) represents both gas producers and some of the larger gas consumers from the mining sector. CME contradicted BP's argument about enhancing competition, but was of the view that joint marketing would lead to increased upstream investment.[390]

(a) ACCC's Authorisation of Joint Marketing for the North West Shelf JV

429. In September 2010, ACCC released its "Final Determination" granting the application from the North West Shelf Joint Venture to have its joint marketing authority re-instated. The joint venture had obtained an authorisation originally in 1977 but had asked the ACCC to revoke this status in 2007.[391] Within two years the North West Shelf sought a new joint marketing authorisation after cartel provisions were introduced into the *Trade Practices Act 1974*.[392] The 2010 Final Determination of the ACCC provides an interesting insight into the arguments around joint marketing and the Commission's views of the current Western Australian wholesale gas market.

430. The ACCC made an important concession that in liquid markets, separate marketing '…is likely to result in competitive benefits to domgas customers in the form of lower prices and more flexible terms and conditions.'[393] However, the Commission held the view that the Western Australian market had not developed sufficiently over the last decade to make separate marketing of incremental volumes from the North West Shelf partners a viable prospect. The ACCC did acknowledge that suitable market conditions may evolve in the medium term and that this factor had influenced the decision to grant authorisation to North West Shelf (and Gorgon) only out to 2015.[394]

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387 Submission No. 14 from BP Australia, 2 July 2010, p. 4.

388 Submission No. 5 from Gorgon Domgas Project, 25 June 2010, p. 5.

389 ibid.

390 Submission No. 17(Att 1) from Chamber of Minerals and Energy (WA), 29 June 2010, p. 16.

391 Despite this revocation, the North West Shelf did advise the ACCC that it intended to continue jointly marketing incremental volumes of gas. ACCC Final Determination - NWS Project, 8 September 2010, s. 3.106

392 Submission No. 16(C) from NWS Project Participants - Response to Question on Notice, 11 November 2010, p. 3.

393 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.167.

394 ibid., p. v, s. 3.101.

431. Interestingly, the Commission found against the argument of the Applicants (North West Shelf) that joint marketing would be likely to lead to public benefits in the form of lower prices because of lower producer costs. The ACCC countered that:

> *…it is not clear that the potential for lower costs under joint marketing will necessarily result in lower prices for consumers than would be the case under separate marketing* [395]

432. Still, the ACCC thought joint selling was currently appropriate given the illiquid and immature state of the Western Australian market. A key risk in enforcing separate marketing at this time was that '…supply volumes would be jeopardised…as JV partners sought to negotiate gas balancing arrangements.'[396] Gas balancing arrangements (GBAs) enable joint venture partners who are marketing separately to sell or supply gas beyond their nominal entitlements. GBAs include "make up provisions" that allow those partners using less than their entitlement to be reimbursed with cash or other physical gas.[397] The Applicants were concerned that in the absence of an effective spot or secondary market (and inadequate storage facilities) imbalances may have to be carried for longer than is commercially desirable.[398]

433. The risk to supply volumes was a major consideration behind the ACCC's decision to grant joint marketing authorisation to the North West Shelf. For the ACCC, the supply of appropriate volumes of gas had a greater influence on price than the practice of joint or separate marketing.[399] The Commission ultimately determined that joint marketing from the North West Shelf would 'enable the supply of domgas volumes' at higher levels and that this constituted a 'significant public benefit' given the current supply/demand imbalance in Western Australia.[400]

434. Later in the determination there was the notable admission that the development of new projects such as Gorgon, Reindeer, Macedon and Pluto '…may encourage the development of market characteristics that could enable separate marketing - such as shorter term contracts, increased storage and secondary trading.'[401] In an earlier authorisation application, the ACCC had argued that short-term and spot markets; the entry of brokers and aggregators; a much greater number of customers and more competitive suppliers were among the pre-conditions that would make separate marketing viable.[402]

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395 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.184.

396 ibid., s. 5.219.

397 ibid., s. 5.64.

398 ibid., ss. 5.66-5.67.

399 ibid., p. v.

400 ibid., s. 5.160.

401 ibid., s. 5.332.

402 ibid., s. 3.114.

(b) The Committee's Position on Joint Marketing

435. When it travelled to Melbourne the Committee was not able to meet and discuss the joint-marketing issue with the ACCC, as the Commission had published its draft decision around the North West Shelf authorisation and could not provide further comment. Whilst such a meeting would have been beneficial for the Committee's deliberations, the Committee feels that the following observations are still worth consideration.

436. The Committee agrees with the conclusion of the ACCC that the level of supply is a greater influence on price movement in the Western Australian domgas market than the existence of joint marketing. Indeed, prices remained low under a joint marketing regime whilst the market was in a period of oversupply during the legacy contract period. The Committee has further argued that increases in production costs witnessed since 2005 have been another contributor to recent price movements (see 115 above).

437. The Committee cannot disprove the ACCC argument that the current difficulties with facilitating gas balancing arrangements might lead to smaller volumes reaching the market under separate marketing. However, this issue should not remain a permanent obstacle to separate marketing in Western Australia and underlines the importance of establishing a Short-Term Trading Market (see 5.3 below).

438. Whilst acknowledging the priority afforded security of supply in the ACCC decision-making process, the Committee argues that there is currently a delicate balance between managing this proposed benefit against the potential cost of reduced competitive tension in the upstream sector.

439. Alinta expressed what appears to be valid concern that joint marketing limits the ability of buyers to negotiate terms and conditions. It was reliably reported (see 226 and 228 above) that domgas contract conditions have become increasingly stringent and are moving increasingly towards US dollar oil-based pricing. Such demands from producers are consistent with a market lacking competitive pressure and it is difficult to see how the continuation of joint marketing will alleviate this issue.

440. The ACCC was of the view that the high level of concentration amongst Western Australian domgas producers would remain under either joint or separate marketing. The Commission added that the best prospect for competition was between joint ventures.[403] It claimed there was 'a degree of competitive tension'[404] with Santos entering the market with new supplies from the John Brookes field. However, this competitive tension does not appear to be reflected in the increasingly stringent terms and conditions being reported.

441. Joint marketing will remain contentious in Western Australia, but the Committee respects that the issue has now been resolved until 2015 as a result of the ACCC decisions around the North West Shelf and Gorgon. Even so, and particularly in light of concerns over insufficient competition

403 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.171.

404 ibid., s. 5.174.

amongst producers, it is important that the government pursue a transition to separate marketing. The ACCC lauded the competitive benefits of separate marketing and has not dismissed the potential of the Western Australian market to develop the characteristics required to enable this transition. To this end, heed must be taken of the need to develop the pre-conditions listed by the Commission (see 434 above).

Finding 27

While arguments can be made in support of the continuation of joint marketing in the current Western Australian domestic gas market, it is plausible to claim that the practice has facilitated a reduction in competitive tension between gas producers.

This may have contributed to the increasingly stringent contractual terms and conditions that some gas buyers have been reportedly facing and the higher prices being realised in this state.

Recommendation 13

The government should vigorously pursue the elimination of the joint marketing authority currently granted to the North West Shelf and Gorgon joint venturers when the applications come up for renewal in 2015.

5.3 Short-Term Trading Market (STTM)

442. Short-Term Trading Markets (STTM) have been introduced in several eastern states to promote the trading of gas at a wholesale level at defined gas hubs.[405]

443. In 2005, the commonwealth Ministerial Council on Energy (MCE) appointed an industry-led Gas Market Leaders Group (GMLG) to produce a plan to satisfy the MCE's objectives for '…a competitive, reliable and secure natural gas market delivering increased transparency'.[406] A key recommendation of the GMLG was the establishment of a Short-Term Trading Market in all states. The exception to this recommendation was Victoria, where a wholesale gas market has

[405] AEMO, *Overview of the Short Term Trading Market*, 1 March 2010, p. 3. Available at: www.aemogas.com.au. Accessed on 28 January 2011.

[406] ibid., p. 1.

been operating since 1999 and already accounts for between 10 and 20 per cent of market volumes.[407]

444. STTMs commenced operation on 1 September 2010 in Adelaide and Sydney. An additional STTM hub is planned for Brisbane in September 2011 with others in Roma (Qld) and the Australian Capital Territory being considered for 2012-2013.[408]

(a) How the Short-Term Trading Market operates

445. The MCE established the Australian Energy Market Operator (AEMO) in 2009 to manage the operation of the Short-Term Trading Markets. The AEMO has funded the establishment of the Adelaide and Sydney STTMs and will recover these costs through fees charged to market participants.[409] Whilst the Gas Market Leaders Group retained ultimate responsibility for creating the STTM, all gas industry stakeholders were welcome to provide input to the design process.[410]

446. The STTM operates in conjunction with the bilateral contract market, but allows participants to trade any short-term imbalances they might incur through their daily operations. Market participants nominate the volumes and prices at which they are willing to transact one day in advance. The AEMO collates this data and determines a market clearing price based on the cheapest level at which nominated supplies can meet demand. Trades are then prioritised in the order of the supply bids with the cheapest bids settled first.

447. Commercial incentives in the way of "deviation" payments exist to ensure participant forecasts are as accurate as possible. Users who take less than their nominated quantity will pay a higher price for their gas dependent on the extent of the deviation. Conversely, shippers who deviate from their supply schedule will be paid less than the clearing price. AEMO has a market operator service (MOS) that organises the balancing of discrepancies between the scheduled and delivered volumes of gas. Where an under or over supply situation exceeds the balancing capabilities of the MOS, AEMO coordinates "contingency gas"[411] operations among market participants.

448. Importantly, commercial arrangements between pipeline operators and shippers for haulage priority and contracted capacity are recognised under the STTM system. Pipeline operators

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407 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, pp. 245-246.

408 Briefing with Australian Energy Market Operator (AEMO), 2 September 2010.

409 AEMO, *Overview of the Short Term Trading Market*, 1 March 2010, p. 2. Available at: www.aemogas.com.au. Accessed on 28 January 2011..

410 ibid., p. 3.

411 Contingency Gas operations are considered an extraordinary measure and are rarely required. The process involves obtaining a separate round of bids and offers from users and shippers who are able to manage withdrawals or injections into the hub in order to alleviate the imbalance. Offers that are called are settled above the daily ex-ante clearing price while bids that are called are settled below the daily ex-ante clearing price with deviation fees used to help cover the settlement. See AEMO, *Overview of the Short Term Trading Market*, 1 March 2010, pp. 17-18. Available at: www.aemogas.com.au. Accessed on 28 January 2011.

provide AEMO with a daily forecast of projected available capacity to ensure that nominated flows are scheduled to fit within operating limits.[412] If capacity on a pipeline is constrained, a shipper with a firm-capacity (highest priority) contract can be displaced in the STTM queue by other shippers who have offered their gas at a lower level and met the clearing price (see 446 above). In this instance, the firm-capacity shipper receives a "capacity payment" that is charged to the successful shipper for any gas that the former had offered at the market price but was not able to deliver.

449. Participants in the STTM settle their accounts monthly with the AEMO. The settlement figure takes into account the net quantity supplied to or withdrawn from the pipeline plus any charges/payments for MOS services, deviations or contingency gas operations.[413]

450. On its travels interstate, the Committee received positive feedback on the value of STTMs. The Energy Retailers Association (ERAA), suggested that STTMs could benefit other states by allowing some reduction in the level of direct contracting as buyers, in particular power generators, could use the market to manage their seasonal fluctuations. The ERAA also felt that the pricing transparency of the STTM would help attract more investment and new entrants into the supplier and retailer markets.[414] The Energy Supply Association of Australia (esaa) echoed this sentiment suggesting that '…you only get new entrants when they can see what the price is and they understand the market.'[415]

451. The transparency provided by STTM's was also a major factor influencing the Queensland government's decision to pursue this option from 2011:

> *It was a policy tool that, amongst other things, gave us a transparent price that we could use to gauge the Queensland gas market performance against other places. It is a very important information gathering exercise for government in discharging its market monitoring role in the future*[416]

(b) Potential for Western Australian Short-Term Trading Market

452. Whilst there are concerns about the potential for a STTM to operate in Western Australia, the proposed benefits such a mechanism can bring to the operation of the local market present a compelling argument in its favour.

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412 AEMO, *Overview of the Short Term Trading Market*, 1 March 2010, pp. 4, 12. Available at: www.aemogas.com.au. Accessed on 28 January 2011.

413 ibid., pp. 18-19.

414 Briefing with Mr Cameron O'Reilly, Executive Director, Energy Retailers Association of Australia, 1 September 2010.

415 Briefing with Mr Brad Page, Chief Executive Officer, Energy Supply Association of Australia (esaa), 2 September 2010.

416 Briefing with Mr Paul Connolly, Director of Gas Policy, Department of Employment, Economic Development and Innovation (DEEDI), 31 August 2010.

453. The Committee was especially interested to read BHP Billiton's view on a STTM in Western Australia, given the company's unique position as a major supplier and consumer of gas in the local market. BHP endorsed the STTM as one of several measures that would help to 'improve market efficiency' and 'reduce barriers to entry'.[417] The opportunity to attract new entrants is critical to building the liquidity currently absent in the Western Australian domgas market.

454. The development of a STTM will also satisfy one of the major pre-conditions cited by the ACCC for making separate marketing viable in Western Australia (see 434 above). The North West Shelf Project successfully argued to the ACCC that the absence of an 'effective spot or secondary market' was a factor preventing the development of commercially viable gas balancing arrangements that were needed for separate marketing to succeed.[418]

455. A STTM could promote the development of brokers and aggregators: another key component of liquid markets. Brokers and aggregators can parcel the daily imbalances of larger customers for later sales to smaller clients who are not looking for longer-term contracts with the major producers. Gorgon advised the Committee that, 'Having aggregators in the market would definitely help develop the maturity of the market.'[419] Interestingly, Woodside confirmed that the absence of a spot gas market (and a lack of pipeline capacity) '…has impeded the emergence of gas brokers and aggregators in WA.'[420]

456. A further benefit of a formal secondary trading market is that it offers hedging facilities for market participants. The Economic Regulation Authority validly argued that this is important for smaller gas market participants.[421] The discussion around aggregators in the preceding paragraph supports this point. However, hedging opportunities are also likely to be exploited by larger players thereby adding substantial liquidity to the market.

457. Shell Development Australia confirmed that LNG producers can offset any LNG volumes extracted in excess of contracted commitments on to international spot markets. Shell confirmed that with their domestic gas, '…we do not have the opportunity to do that because we do not have that liquid market in place at the moment.'[422]

458. The ability to hedge has become arguably more pressing for the major buyers of gas. This report has noted that buyers are now being subject to increasingly stringent contract conditions including take-or-pay provisions of close to 100 per cent (see 226 above). In such a market environment, a

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417 Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 23 July 2010, p. 14.

418 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.65. The other factors were the lumpy nature of the Western Australian market and a lack of adequate gas storage facilities.

419 Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing, *Transcript of Evidence*, 10 November 2010, pp. 8-9.

420 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 9.

421 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 33.

422 Mr Ian McKenzie, Vice President, Sunrise, Shell Development Australia, *Transcript of Evidence*, 24 November 2010, p. 6.

STTM would enable buyers to sell surpluses incurred from full take-or-pay conditions in an attempt to lower the effective price they pay for gas.

459. Several parties have questioned the potential of a STTM for Western Australia. The Committee observed varying opinions on the issue among the North West Shelf joint venturers. Even though BHP Billiton 'strongly encouraged' the adoption of a STTM[423], other members of the North West Shelf Joint Venture doubted whether the levels of liquidity required to support the market could be generated.[424]

460. This caution was shared by the ACCC who found that the lumpy nature of the Western Australian market has been a 'significant' factor in the slow development of a local spot market.[425]

461. Independent consultant John Boardman now holds similar doubts about the prospects for any form of spot market. He had thought such a market would develop throughout the mid-1990s when several aggregators first appeared. The fact that the market did not emerge at that time has left Mr Boardman of the view that, 'I just cannot see it happening in my lifetime.'[426]

462. It is important to acknowledge that the Western Australian Gas Supply Emergency Management Committee (GSEMC) 2009 report argued that the STTM model being implemented in the eastern states was '…not appropriate for the Western Australian market.'[427] The GSEMC cited concerns over the limited interconnection of the transmission sector and the fact that the major pipeline operators often retain control over the balancing of gas flows (unlike the Sydney and Adelaide STTMs where AEMO now has this responsibility - see 447 above).[428] As an alternative, the GSEMC recommended the creation of a 'non-compulsory facilitated trading market' where gas and transport arrangements would still be transacted separately. The concession was made that 'future consideration be given'[429] to a STTM after the experiences of other states was assessed and after a Gas Market Bulletin Board was implemented and reviewed in Western Australia.

463. The Committee acknowledges the doubts expressed regarding the viability of a STTM in Western Australia, but concludes that the market can not be allowed to continue operating in its current state. The Committee concurs with the view expressed by the ERA:

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423 Mr Brett Langley, General Manager Gas Marketing, BHP Billiton, *Transcript of Evidence*, 25 October 2010, p. 3.

424 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 9; Mr Ben Coetzer, General Manager, North West Shelf Gas Pty Ltd, *Transcript of Evidence*, 18 October 2010, p. 8; Mr David McDonald, General Manager, BP Developments Australia, 18 October 2010, p. 7.

425 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.55.

426 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 11 October 2010, p. 3.

427 Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009, p. 36.

428 ibid., p. 36.

429 ibid., p. 37.

The lack of transparency and the absence of a market facility supported by legislation and rules for the trading of gas have adversely impacted on energy efficiency in the state.[430]

464. Given the state's heavy reliance on gas as an energy fuel (see 7 above), it is vital that steps are taken to improve the efficiency and competitiveness of the wholesale market. The Committee feels that a Short-Term Trading Market is an important mechanism for promoting such competitiveness and efficiency.

465. Whilst the challenges facing the development of a local STTM are genuine, they should not be seen as insurmountable. The Committee agrees with much of the GSEMC's analysis of the current issues within the transmission sector that impede the development of a STTM, but is not convinced by the argument that a STTM should be delayed. This issue is explored in Chapter 6 below.

466. In terms of concerns over liquidity, the Committee agrees that the Western Australian market will remain lumpy. However, the introduction of a STTM is likely to reveal latent sources of supply and demand that will improve liquidity.

467. As Figure 12 illustrates, the market has come to the end of an extended period of oversupply that has conspired against the creation of a liquid market. However, the recent prices rises have generated a significant supply response with three major projects expected to enter the market by 2015 (see Table 3). On the buyers' side, evidence received by the Committee suggests that there may be between 25 and 30 customers now buying gas from upstream producers.[431]

468. The STTM will also provide a fillip to local attempts to establish an active broker/aggregator market. APPEA acknowledged that there has been 'some modest evolution'[432] in recent years in broking and aggregating services. These limited services are provided by Alinta, Perth Energy, Synergy, Verve Energy and an "Inlet Trade" system operated by Dampier Bunbury Pipeline. According to APPEA, these services would currently represent no more than 10 per cent of the daily throughput on the Dampier to Bunbury Natural Gas Pipeline.[433]

469. The ACCC noted that a separate marketing regime in Western Australia '…would create additional market opportunities for aggregators and brokers'.[434] It is important to remember that should the STTM develop successfully, the argument for transitioning to separate marketing becomes increasingly persuasive. If the Western Australian market can evolve to the stage where joint venturers are marketing separately and transacting under gas balancing arrangements, the underlying liquidity of the market will be enhanced even further.

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430 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 33.

431 DomGas Alliance reported there were 'over 30' customers now buying gas whilst Woodside suggested there were 26 active domgas contracts in 2009. See Submission No. 3 (Att 1) from DomGas Alliance, 24 June 2010, p. 13; Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 8.

432 Submission No. 10 from APPEA, 25 June 2010, p. 14.

433 ibid., pp. 14-15.

434 ACCC Final Determination - NWS Project, 8 September 2010, s. 5.251.

470. The benefits that could flow from a Short Term Trading Market are, to some extent, self-perpetuating. The transparency and competition promoted by the STTM is likely to generate the greater depth and liquidity that is required to sustain such a market.[435]

Finding 28

The introduction of a Short Term Trading Market (STTM) will improve the efficiency of the Western Australian wholesale gas market by promoting a level of transparency, competition and liquidity currently lacking.

Whilst there are challenges facing the establishment of a STTM in Western Australia, these should not be seen as insurmountable

Recommendation 14

The Minister for Energy proceed with the introduction of a Short Term Trading Market in Western Australia as a matter of priority.

5.4 Gas Market Bulletin Board and Statement of Opportunities

471. The commonwealth Gas Market Leaders Group (see 443 above) concluded that a Gas Market Bulletin Board (Bulletin Board) and Gas Statement of Opportunities (GSOO) would—along with the STTM—improve the transparency and efficiency of Australia's wholesale gas markets.

(a) Gas Market Bulletin Board

472. In July 2008, a National Gas Market Bulletin Board was established. Operated by AEMO, this web-based application[436] publishes current data on production, demand and capacity across the interconnected pipelines of the eastern states. The bulletin board also provides peak demand forecasts and 3-day capacity outlooks for pipelines (see Figure 22 below).[437] Data is obtained via mandatory reporting requirements with civil penalties imposed if any information is provided in

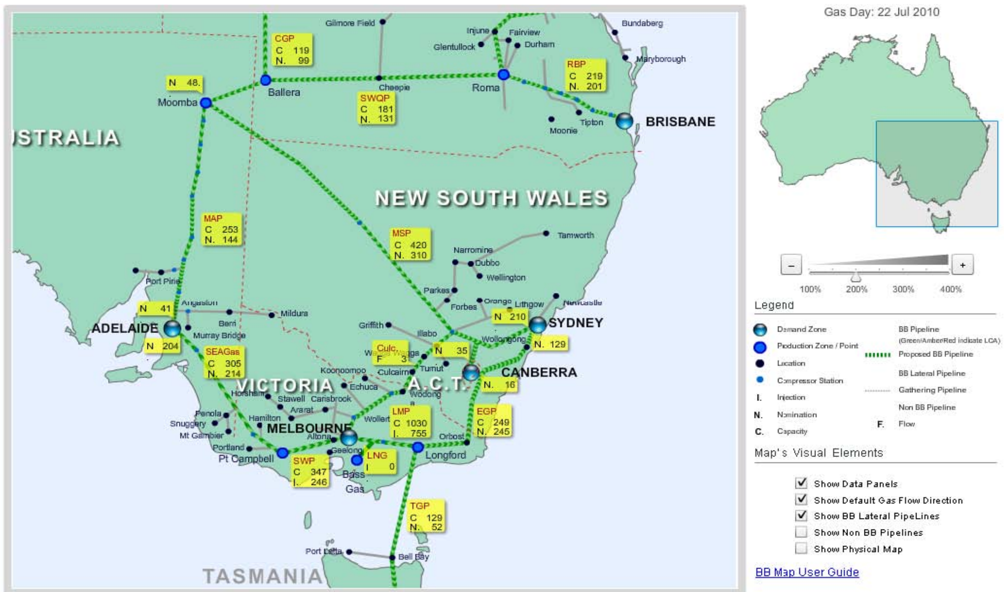
435 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 47.

436 To view the latest display of the Bulletin Board, go to: www.gasbb.com.au/mapoverview.aspx.

437 Briefing with the Australian Energy Market Operator (AEMO), 2 September 2010.

"bad faith."[438] The operating cost of the AEMO Bulletin Board is approximately $170,000 per year.[439]

Figure 22 National Gas Market Bulletin Board[440]



473. The Committee received a live demonstration when it met the AEMO in Melbourne and was impressed by the clarity and simplicity of the bulletin board.

474. The main advantages noted since the bulletin board's implementation in the eastern states pertain to transparency. It has been seen to provide information once restricted to major market players. Transparent pipeline flow data has been particularly beneficial to parties seeking to establish a shipping contract, as they can now form a view around the levels of spare transmission capacity.[441]

475. There are numerous advantages for Western Australia from a bulletin board. These were articulated well by Mr Chris Sorensen, Marketing Manager, Gorgon Domgas Marketing:

> *The first thing we envision with the bulletin board is operational transparency. It would be helpful to understand daily demand, how much seasonal swing there is, how much production there is every day and how much is consumed every day. That will start to give*

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[438] Briefing with the Australian Energy Regulator (AER), 2 September 2010.

[439] Briefing with the Australian Energy Market Operator (AEMO), 2 September 2010.

[440] This copy of a download from the web page was provided in Submission No. 24 from Alcoa of Australia, July 2010, p. 14.

[441] Briefings with the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER), 2 September 2010.

> *the market signals about how much storage is available and how much pipeline capacity is available. These are tools that market participants need to understand*[442]

476. Another key advantage of a local bulletin board is the prompt manner in which it could alert government and market participants to a sudden major disruption, such as that experienced during the Varanus Island explosion in 2008.

477. Importantly, the ACCC has also concluded that a bulletin board would be another contributing factor to '…the potential development of the Western Australian domgas market.'[443]

(b) Gas Statement of Opportunities (GSOO)

478. The second Gas Statement of Opportunities (GSOO) for Eastern and South Australian gas markets was published in 2010 by AEMO. The GSOO has been developed in collaboration with industry participants and '…aims to assist existing participants and new investors in making commercial decisions about investment in infrastructure or entering into contracts' in their respective gas markets.[444] Provision was made under the National Gas Law for the AEMO to prepare, review and revise the GSOO in addition to its publishing responsibilities.[445]

479. Where the Bulletin Board provides transparency for the shorter-term, the GSOO is longer-term in focus and contains '…comparisons of peak day and annual gas demand growth forecasts against infrastructure capabilities for the next 10 years, and gas reserve projections for the next 20 years.'[446]. Forecasting accounts for three economic scenarios (low, medium and high) with the demand projections incorporating a 'relative value of gas' into the modelling process.[447]

480. The current GSOO does not provide any information on either Western Australia or the Northern Territory, as neither comes under the jurisdiction of AEMO. Even so, there appears to be a place for a similar document in this state. The GSEMC has endorsed the implementation of a local GSOO, suggesting that the document would '…facilitate a competitive market and efficient investment, and inform Government policy development'.[448]

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442 Mr, Chris Sorensen, Marketing Manager, Domgas Marketing, *Transcript of Evidence*, 10 November 2010, p. 8.

443 ACCC Draft Determination - NWS Project, 8 July 2010, s. 4.58.

444 AEMO, '2010 Gas Statement of Opportunities', 2010. Available at: www.aemo.com.au/planning/gsoo2010.html. Accessed on 30 January 2011.

445 AEMO, *2009 Gas Statement of Opportunities for Eastern and Southern Australia*, 2009, p. 1. Available at: www.aemo.com.au/planning/0415-0005.pdf. Accessed on 21 March 2011.

446 AEMO, *2010 Gas Statement of Opportunities*, 2010, p. 1. Available at: www.aemo.com.au/planning/1410-0003.pdf. Accessed on 30 January 2011.

447 AEMO, *2009 Gas Statement of Opportunities for Eastern and Southern Australia*, 2009, pp. 1-8. Available at: www.aemo.com.au/planning/0415-0005.pdf. Accessed on 21 March 2011.

448 Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009, p. 36.

(c) Development of a Bulletin Board and GSOO in Western Australia

481. Strong momentum has developed in Western Australia for the establishment of a bulletin board and GSOO. Both initiatives have been recommended by the Gas Supply Emergency Management Committee and there is broad-based support from market participants. Supporters include BHP Billiton; Gorgon Domgas Joint Venture; BP; DomGas Alliance and the ERA.[449]

482. Both the Western Australian Bulletin Board and GSOO appear to offer few logistical challenges. Responsibility of each could be assumed quite readily by AEMO. The Committee was advised that Western Australia had already contributed to the establishment of the national bulletin board through its Ministerial Council on Energy jurisdictional payments. The process of incorporating a Western Australian component on the National Bulletin Board map was considered relatively simple.[450]

483. However, there is enthusiasm for utilising a local operator for both initiatives.[451] This too looks highly feasible. AEMO have advised that they are prepared to supply the GSOO software at cost to a possible Western Australian operator.[452] Preparation of the GSOO might also be able to make use of data collected and obtained by the Gas Market Monitor that has been proposed by the Committee (see Recommendation 4). AEMO added that it had been in regular contact with the Office of Energy to provide information regarding the potential for a bulletin board.[453] Moreover, the state already has some experience with bulletin boards, having established one temporarily to assist the market after the explosion at Varanus Island.

484. As it stands, the Office of Energy has been in contact with the Independent Market Operator (IMO) and Retail Energy Market Company Limited (REMCo) asking both entities to put forward their bona fides for managing the local bulletin board and GSOO.[454] The Office of Energy confirmed that it intends to implement both measures. It had originally planned to announce the Market Operator in July 2010 and to have legislation introduced to the Parliament by the end of 2010.[455] As at the tabling of the Committee's report, neither action has been completed.

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449 Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 23 July 2010, p. 2; Submission No. 5 from Gorgon Domgas Project, 25 June 2010, p. 6; Submission No. 14 from BP Australia, 2 July 2010, p. 4; Mr Tony Petersen, Chairman, DomGas Alliance, *Transcript of Evidence*, 15 September 2010, p. 9; Mr Lyndon Rowe, Chairman, Economic Regulation Authority, *Transcript of Evidence*, 13 September 2010, p. 8.

450 Briefing with Australian Energy Market Operator, 2 September 2010.

451 Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009, pp. 35-36.

452 Mr Allan Dawson, Chief Executive Officer, Independent Market Operator, *Transcript of Evidence*, 25 October 2010, p. 6.

453 Briefing with Australian Energy Market Operator, 2 September 2010.

454 Mr Allan Dawson, Chief Executive Officer, Independent Market Operator, *Transcript of Evidence*, 25 October 2010, p. 6.

455 Submission No. 12 from Office of Energy, 29 June 2010, p. 9.

485. There is strong support for a Western Australian bulletin board and GSOO from producers, buyers and regulators alike. Along with the STTM, these measures are likely to enhance the transparency and efficient operation of the market without the need for heavy-handed government intervention. It is arguable that such transparency mechanisms might have helped avert the tight supply/capacity situation that has afflicted the local market in recent years. The Committee supports the introduction of these measures—operated locally or as part of the existing national framework—and urges the Minister for Energy to expedite the implementation process for each.

Finding 29

The establishment of a Gas Market Bulletin Board and Gas Statement of Opportunities (GSOO) is likely to enhance the efficient operation of the Western Australian wholesale gas market.

The Committee supports the introduction of these measures and urges the Minister for Energy to expedite the implementation process for each.

Recommendation 15

The Minister for Energy expedite the introduction of a Gas Market Bulletin Board and Gas Statement of Opportunities in Western Australia.

CHAPTER 6 TRANSMISSION (PIPELINE) SECTOR

6.1 Background

486. Although hosting some of the longer gas transmission pipelines in Australia, Western Australia's gas transmission system is less integrated and currently connects fewer gas producing basins with fewer and more concentrated markets than that on the eastern seaboard (Figure 18).[456] Nonetheless, with the highest level of domestic demand in the nation (Table 1), the quantity of gas shipped on transmission pipelines in Western Australia is large by comparison with other Australian jurisdictions.

487. A list of Western Australia's major gas transmission pipelines is presented in Figure 23 below.

Figure 23 Major Gas Transmission Pipelines, Western Australia[457]

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
Dampier to Bunbury Pipeline	WA	1854	892	1984	Yes
Goldfields Gas Pipeline	WA	1427	150	1996	Yes
Parmelia Pipeline	WA	445	70	1971	No
Pilbara Energy Pipeline	WA	219	188	1995	No
Midwest Pipeline	WA	353	20	1999	No
Telfer Pipeline (Port Hedland to Telfer)	WA	443	25	2004	No
Kambalda to Esperance Pipeline	WA	350	6	2004	No
Kalgoorlie to Kambalda Pipeline	WA	44	20		Yes (light)

Note: The far column of this chart refers to whether pipelines are "covered" or not. Covered pipelines are subject to regulation under the National Gas Law.

488. Transmission pipelines in Western Australia are not interconnected with other jurisdictions and are regulated by the WA Economic Regulation Authority (ERA), whereas the Australian Economic Regulator (AER) performs this function elsewhere in Australia.

456 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p.79. It should be noted, however, that the Dampier to Bunbury Natural Gas Pipeline is inter-connected with the Goldfields Gas Pipeline, the Parmelia Pipeline and pipelines into the Pilbara.

457 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 80. Note: the term "covered" refers to a pipeline that is regulated under the National Gas Access (WA) Act 2009.

(a) Regulation of Gas Transmission Pipelines

489. Gas pipelines in Australia are regulated under a nationally consistent regime: The National Gas Law (gas law) and Gas Rules. As the owners of the Goldfields Gas Pipeline (GGP) lodged an application to revise the access arrangement[458] for that pipeline on 23 March 2009[459], prior to the new gas law coming into effect in Western Australia, the GGP continues to be regulated under the previous National Gas Pipelines Access Code until the next revision to the access arrangement is approved by the regulator. The submission date for the next revision to the GGP access arrangement is 1 January 2014.[460]

490. An application to revise the access arrangement for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) under the new gas law is currently before the Economic Regulation Authority. A draft decision by the regulator is expected early 2011.[461]

491. The Kalgoorlie to Kambalda pipeline, which links the GGP to the Kambalda to Esperance pipeline, is also a covered pipeline but is subject to light regulation. Unlike fully regulated pipelines, those subject to light regulation do not require up front regulatory approval of terms, conditions and transmission reference tariffs. Service providers of pipelines subject to light regulation are only obliged to publish certain information including prices and terms and conditions for access to the pipeline on their websites.[462]

(b) Investment in Gas Transmission Pipelines

492. Although there has been substantial investment in Western Australian pipelines over the past decade, including major expansions of the DBNGP, expansions of the GGP and new pipelines to supply gas to the mining and resources sector, there is very little spare capacity on regulated pipelines.

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458 An access arrangement, which must be approved by the relevant regulator, sets out the terms and conditions including tariffs applicable to third party users of that pipeline.

459 Rowe, L., (Chairman), *Goldfields Gas Pipeline - Proposed Revised Access Arrangement*, Media Statement, Economic Regulation Authority, 25 March 2009. Available at: www.erawa.com.au/cproot/7435/2/20090325%20Notice%20%20Goldfields%20Gas%20Transmission%20Pty%20Ltd%20%20Goldfields%20Gas%20Pipeline%20Proposed%20Revised%20Access%20Arrangement.pdf. Accessed on 18 March 2011.

460 Economic Regulation Authority, 'Goldfields Gas Pipeline - Revised Access Arrangement - 2010', (n.d). Available at: www.erawa.com.au/3/1094/48/goldfields_gas_pipeline__access_arrangement__.pm. Accessed on 18 January 2011.

461 Rowe, L., (Chairman), '*Proposed Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, Media Statement, Economic Regulation Authority, 5 January 2011. Available at: www.erawa.com.au/cproot_download/9214/56382/20110106%20D58077%20Notice%20-%20Proposed%20RAA%20for%20the%20DBNGP%20-%20COT%20for%20Publication%20of%20a%20FD.pdf. Accessed on 18 January 2011.

462 AER, *State of the Energy Market 2010*, ACCC, 2010, pp. 82-83.

493. Actual and anticipated capital expenditure for the DBNGP over the 5 years to the end of 2010 was around $1.8 billion with the pipeline now almost 85 per cent looped.[463] The full haul capacity of the DBNGP is stated to be 869 TJ/d for 2011 increasing to 888 TJ/d in 2012 and is projected to remain at that level until the end of 2015.[464] Capital expenditure projected for the pipeline until the end of 2015 is $137.4 million on the assumption that there will not be a further expansion of the pipeline over this period.[465] The revised access arrangement information shows that the firm full haul capacity on the pipeline is fully contracted for the period to the end of 2015. However, Mr Stuart Johnston, CEO, Dampier Bunbury Pipeline confirmed that the pipeline was actually fully contracted to 2019.[466]

494. Capital expenditure for the GGP over the 5 years to the end of 2009 was reported in the revised access arrangement information for the pipeline to be $10.4 million.[467] Capital expenditure for the 5 y+ears to the end of 2014 is projected at $26.4 million.[468] Total contracted and available capacity on the pipeline was given as 110.46 TJ/d for 2010 of which 3.81 TJ/d was stated as available.[469] The access arrangement information does not project any expansion in capacity over the period to the end of 2015.

(c) Reference Tariffs

495. The estimated costs of transmitting gas on the DBNGP from the North West Shelf to Perth or from the North West Shelf to Kalgoorlie on the GGP are presented in Table 8 below.

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463 DBNGP (WA) Transmission Pty Ltd (DBP), *Revised Access Arrangement Information*, 1 April 2010, pp. 6-7. Available at: http://www.erawa.com.au/cproot/8466/2/20100415%20DBNGP%20-%20REVISED%20AAI%20-%20PUBLIC%20VERSION%20-%20Date%20Submitted%201%20April%202010.pdf. Accessed on 18 January 2011. DBP confirmed that capital expenditure of $1.7 billion has been spent expanding the pipeline so that it is now 83 per cent looped. Mr Stuart Johnston, Chief Executive Officer, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2010, p. 2.

464 DBNGP (WA) Transmission Pty Ltd (DBP), *Revised Access Arrangement Information*, 1 April 2010, p. 17. Available at: http://www.erawa.com.au/cproot/8466/2/20100415%20DBNGP%20-%20REVISED%20AAI%20-%20PUBLIC%20VERSION%20-%20Date%20Submitted%201%20April%202010.pdf. Accessed on 18 January 2011. Note that capacity was stated by Mr S Johnston, CEO, DBP to be 845 TJ/d, Transcript, Dampier to Bunbury Pipeline, 15 November 2011, p. 4. It is also noted that the Australian Energy Regulator estimated the capacity of the pipeline as 892 TJ/d as per Figure 23 above.

465 DBNGP (WA) Transmission Pty Ltd (DBP), *Revised Access Arrangement Information*, 1 April 2010, p. 13. Available at: http://www.erawa.com.au/cproot/8466/2/20100415%20DBNGP%20-%20REVISED%20AAI%20-%20PUBLIC%20VERSION%20-%20Date%20Submitted%201%20April%202010.pdf. Accessed on 18 January 2011.

466 ibid., p. 18; Mr Stuart Johnston, Chief Executive Officer, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2011, p. 3.

467 Goldfields Gas Transmission Pty Ltd (GGT), *Proposed Revisions to Access Arrangement Information*, 5 August 2010, p. 4. Available at: www.erawa.com.au/cproot/8796/2/20100909%20D49960%20Goldfields%20Gas%20Transmission%20Pty%20Ltd%20-%20GGP%20-%20Revised%20AAI.PDF. Accessed on 18 January 2011.

468 ibid., p. 8.

469 ibid., p. 13.

Table 8 Gas Transmission Tariffs for Regulated Pipelines in Western Australia[470]

	DBNGP	**DBNGP**	**GGP**
	Regulated Tariff	**Standard Shipper Contract**	**Regulated Tariff**
	NWS to Perth	NWS to Perth	NWS to Kalgoorlie
Adjusted	Annually		Quarterly
Rates current to:	Under review*		31-Mar-11
Tariff components			
Toll ($/GJ MDQ#)	0		0.245517
Capacity ($/GJ MDQ or $/GJ km MDQ for GGP)	1.069105		0.001461
Commodity ($/GJ or $/GJ km for GGP)	0.122512		0.000402
Distance km (NWS to Perth or Kalgoorlie for GGP)	1400	1400	1378.3
Cost for 1GJ (100% Load factor)	**1.19**	**1.49**[471]	**2.81**
Cost for 1GJ (85% Load factor)	**1.38**	**1.75**	**3.21**

* As the access arrangement for the DBNGP is currently under review, there is no annual adjustment (Refer Rule 92(3) under the new gas law).

\# MDQ stands for maximum daily quantity

496. The cost of transmitting gas on the GGP is more than double that of the DBNGP over basically the same distance. The higher transmission cost of the GGP is mainly attributed to economies of scale achievable by the DBNGP. As discussed in paragraphs 493 and 494 above, the available capacity of the DBNGP is about seven and a half times that of the GGP.

497. The second column of Table 8 shows the standard shipper tariff that actually applies for the transmission of gas on the DBNGP. The standard shipper contract and tariff were negotiated at the time that the pipeline was acquired by the current owners: Dampier Bunbury Pipeline (DBP).[472] The standard shipper contract sits outside of the regulatory regime with a tariff above the regulated tariff but having '...a tariff path that in 2016 reverts to a regulated tariff.'[473] Parties to the standard

470 Economic Regulation Authority, *Goldfields Gas Pipeline - Annual Tariff Variation*, 31 December 2010. Available at: www.erawa.com.au/3/1097/48/goldfields_gas_pipeline__quarterly_tariff_variatio.pm. Accessed on 21 March 2011; Economic Regulation Authority, *Dampier to Bunbury Natural Gas Pipeline - Annual Reference Tariff Variation 2010*, 22 January 2010. Available at: www.erawa.com.au/3/1090/48/dampier_to_bunbury_natural_gas_pipeline__annual_ta.pm. Accessed on 21 March 2011.

471 Mr Stuart Johnston, Chief Executive Officer, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2010, p. 5.

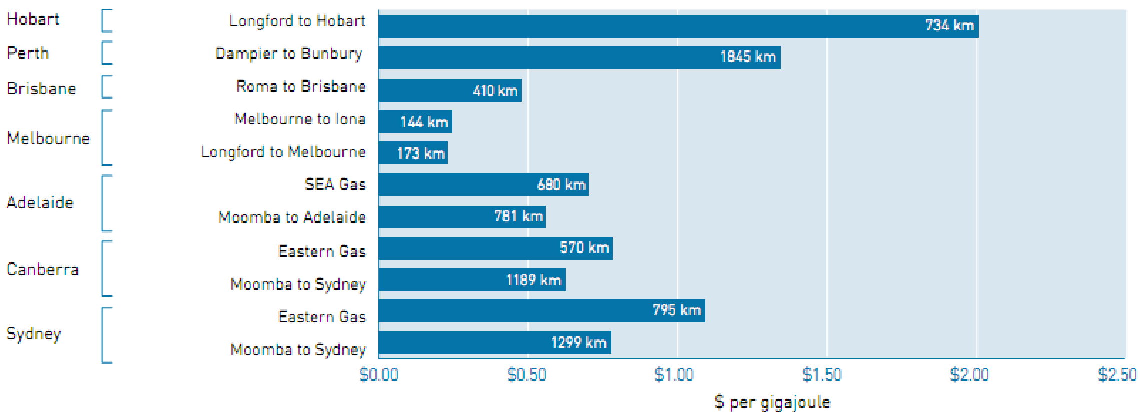
472 The pipeline was acquired by DBP in 2004. Dampier to Bunbury Natural Gas Pipeline, 'Pipeline History', (n.d). Available at: www.dbp.net.au/the-pipeline/history.aspx, Accessed on 27 January 2011.

473 Mr Anthony Cribb, Company Secretary, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2010, p. 5.

shipper contract agreed on the terms, conditions and tariff in order to ensure that there was sufficient revenue to justify the price paid to the banks to bring the pipeline out of receiver management.[474]

498. Indicative transmission tariffs to major centres are shown in Figure 24 below.

Figure 24 Indicative Pipeline Tariffs to Major Centres[475]



Note: Distances are indicative.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

499. Although dated, the information shown in Figure 24 should still be relevant in comparative terms.

500. A number of issues were raised in the course of the Committee's inquiry relating to gas transmission. These issues, which are discussed in the following paragraphs, are relevant to the terms of reference for this inquiry in that they impact on the cost of delivering gas in Western Australia.

501. In summary, the issues relate to security, spare capacity on regulated gas transmission pipelines, gas storage and the integration of gas transmission into an effective market arrangement that facilitates pipeline users to efficiently contract for gas and transmission capacity.

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474 Mr Lyndon Rowe, Chairman, Economic Regulation Authority, *Transcript of Evidence*, 13 September 2010, p. 5. For confirmation that the Dampier to Bunbury Natural Gas Pipeline was sold by a receiver manager in 2004, see Epic Energy, 'History', 2009. Available at: www.epicenergy.com.au/index.php?id=18. Accessed on 24 February 2011.

475 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 272.

6.2 Security

502. Much of Western Australia's domestic gas market relies on the DBNGP.[476] To the Committee's knowledge, gas supplies currently enter the Western Australian domestic market via one of three transmission pipelines including the DBNGP. The other pipelines are the GGP and the Parmelia Pipeline that takes gas from the Perth Basin. In 2009, around 970 TJ/d of sales gas was produced in Western Australia of which 17 TJ/d was produced in the Perth Basin and 86.4 TJ/d was transmitted on the GGP.[477] As a result, and taking into consideration that the GGP is likely to have sourced some gas via an interconnect to the DBNGP, more than 90 per cent of Western Australia's domestic gas supplies will have been shipped on the DBNGP at least for part of the way.

503. Security of supply into the Western Australian domestic gas market is therefore significantly dependent on the reliability of the DBNGP and the ability to respond to any disruption in supply owing to some unplanned event. On this issue Mr Stuart Johnston commented:

> *…we believe the pipeline is safe; that is, it is reliable and it is flexible. There has been no curtailment due to pipeline failure since June 2004—since the current ownership came in. In fact, there have been only two interruptions to supply in the past 26 years, and both of those were for only a few minutes' duration and were isolated to a single delivery point.*[478]

504. In regard to disruptions, it is worth clarifying that the 3 June 2008 Varanus Island pipeline rupture and explosion that cut domestic gas supplies by around 30 per cent for an extended period of time was not related to the state's gas transmission system but rather was associated with the domestic gas processing plant operated by Apache Energy.[479] Partial supplies of 120 TJ/d were restored on 6 August 2008 and 230 TJ/d (about 73 per cent of Varanus Island production in 2007) by October 2008.[480]

505. Nonetheless, the fact that the state has experienced supply disruptions, some more serious than others, raises the storage issue together with the need to integrate gas transmission into an effective market arrangement that facilitates pipeline users to efficiently contract for gas and transmission capacity.

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476 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 30.

477 APPEA, *2009 Production Statistics*, (n.d). Available at: www.appea.com.au/images/stories/Statistics/Annual_Production_Statistics.xls. Accessed on 21 March 2011; Goldfields Gas Transmission, 'Goldfields Gas Pipeline Revised Access Information,' 5 August 2010, p. 12. Available at: www.erawa.com.au/3/1094/48/goldfields_gas_pipeline__revised_access_arrangemen.pm. Accessed on 18 March 2011.

478 Mr Stuart Johnston, Chief Executive Officer, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2010, p. 2.

479 Further information on the Varanus Island incident is available on the Department of Mines and Petroleum website. Department of Mines and Petroleum, 'Varanus Island Incident' (n.d.). Available at: www.dmp.wa.gov.au/7202.aspx. Accessed on 24 January 2011.

Department of Industry and Resources , *Background on Varanus Island and the Incident* (Fact Sheet), n.d. Available at: www.dmp.wa.gov.au/documents/081786_Background2.pdf. Accessed on 24 January 2011.

506. The government's Gas Supply Emergency Management Committee (GSEMC) highlighted the following cost effective contingency options for mitigating the impact of gas supply disruptions on electricity and gas markets in the state:[481]

- increasing the number of duel gas/liquids generators in electricity markets;
- maintaining a strategic stock of liquid fuel;
- developing a gas storage facility near Perth with an additional pipeline interconnect to ensure that gas distribution networks do not collapse in the event of a major supply disruption;
- achieving consumer demand reductions; and
- increasing the level of gas market information and transparency to facilitate a more competitive and efficient market.

507. Of the options listed in paragraph 506 above, the Committee received substantial comment through submissions and hearings on the matter of gas storage and in relation to augmenting gas market information and transparency to facilitate a more competitive and efficient market.

6.3 Gas Storage

508. An important attribute of natural gas is that it can be stored either in its natural state or as LNG. Gas in transmission and distribution systems (linepack) also provides a storage capability. Gas storage can greatly assist in smoothing out seasonal and short-term fluctuations in demand, particularly where gas is used for power generation, and as security against upstream disruptions in supply. Storage also assists in contract management where terms such as take-or-pay requirements add to costs.[482]

509. Experience in the United States shows that gas storage played an important part in the development of that country's highly liquid and mature gas market. For example, Woodside submitted that:

> *Storage and interconnection (hubs) allow producers and consumers to manage exposure to seasonal and outage related fluctuations in supply and demand*….

and:

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[481] Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009. p. 4.

[482] Mr James Mitchell, Managing Director, Synergy, *Transcript of Evidence*, 20 October 2010, p. 2.

> *Surplus physical storage furthermore promoted the development of futures markets and related financial markets/instruments*[483]

510. Gas storage is still in the early stages of development in Australia. Conventional gas storage facilities exist in Victoria, the Cooper Basin and in Western Australia. Victoria also has a relatively small (0.7 petajoules) LNG storage facility at Dandenong. It provides the Victorian transmission system with peak shaving and security of supply services together with truck loading services for LNG tankers.[484] The Dandenong facility, which is operated by the APA Group, liquefies surplus gas during quiet periods and sells it back to the market as natural gas at peak times.[485] Additional gas storage facilities are proposed in both New South Wales and Queensland.[486]

511. In Western Australia, the Mondarra storage facility near Dongara currently provides a modest amount of gas storage. The facility, which is owned and operated by the APA Group, is ideally located between the DBNGP and the Parmelia Pipeline providing substantial flexibility especially for shippers that have transmission contracts on both pipelines.[487] The Parmelia Pipeline basically runs parallel to the DBNGP from Dongara to Pinjarra (see Figure 18 (No 14)) with a current capacity of 65 TJ/d which is expandable up to 120 TJ/d.[488]

512. Mondarra has a capacity of 5 TJ/d injection and 10 TJ/d withdrawal but is currently fully contracted.[489] Its working capacity equates to about three petajoules. APA plans to expand the Mondarra facility to 150 TJ/d withdrawal and 75TJ/d injection taking capacity to 12 PJ, hopefully by 2013.[490] Mr Steven Lewis, General Manager, Western Australia, APA Group is confident that this could meet 15-20 per cent of the state's southern demand on any given day and, most importantly, meet all of the requirements for electricity generation and gas supply to the Perth market.[491] Mr Lewis stated that the Mondarra facility '…is ideally placed to basically keep the lights on in Perth for months and keep gas supply up in winter'.[492]

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483 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 9.

484 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 87.

485 Mr Steven Lewis, General Manager, Western Australia, APA Group, *Transcript of Evidence*, 25 October 2010, pp. 1-2.

486 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010, p. 87.

487 Mr Jason Waters, General Manager, Trading and Fuel, Verve Energy, *Transcript of Evidence*, 20 October 2010, p 10.

488 Mr Steven Lewis, General Manager, Western Australia and Ms Suzy Tasnady, Regulatory Manager, APA Group, *Transcript of Evidence*, 25 October 2010, p. 2.

489 Mr Steven Lewis, Head of Commercial and General Manager (WA), APA Group, Electronic Mail, 4 February 2010, p. 1.

490 Mr Steven Lewis, General Manager, Western Australia, APA Group, *Transcript of Evidence*, 25 October 2010, p. 2.

491 ibid.

492 ibid.

513. The DBNGP has for a couple of years provided relatively small volumes of in-line storage '...helping people match their purchase obligations with producers'.[493] In response to recent requests, DBP is also working actively with parties on a transport service to assist the development of the Mondarra storage facility. Mr Mark Cooper, General Manager, Commercial, DBP commented that: 'If you apply our standard contract terms and conditions, I do not think the economics stack up...'[494] DBP is therefore looking at developing '...a more creative transport solution...' that would facilitate the use of the Mondarra facility.[495]

514. In its report to government, the GSEMC recommended, among other things, that government:

> *…require gas retailers to have adequate back-up supply arrangements to ensure continuity of supply for small use customers on standard contracts, with standard tariffs, (such as residential and small business customers) and offer such back-up supply arrangements as an opt-in service for other gas distribution system customers*[496]

515. The report also recommended that the government should note that the GSEMC has identified at least two potential cost effective gas contingency options, one of which being:

> *…additional gas storage capacity capable of withdrawal rates of between 35 terajoules per day and 100 terajoules per day from a gas reservoir, such as the Mondarra storage reservoir, and additional interconnection of the Parmelia pipeline with the Dampier to Bunbury Natural Gas Pipeline (DBNGP) to allow stored gas to flow into these pipelines and WA Gas Network's distribution system*[497]

516. Additionally, the report recommended that the government:

> *…note that the effective implementation of contingency service regulatory frameworks should provide for efficient pass-through of implementation and usage costs to those consumers (tariff or contract) that benefit from the improved reliability of supply…*[498]

517. In relation to the efficient pass-through of implementation and usage costs raised in paragraph 516 above, APA Group's Steven Lewis commented:

> *The biggest commercial challenge that we see at the moment is that our customers are unable to recover the value of security of supply in their tariffs; so we want customers to take storage contracts. Clearly, there is a storage benefit for security of supply, but how do*

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493 Mr Mark Cooper, General Manager, Commercial, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2010, p. 10.

494 ibid.

495 ibid.

496 Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009. p. 5.

497 ibid.

498 ibid.

they recover that cost from their customers—particularly if they are supplying gas into regulated markets in which the tariffs are set?[499]

Finding 30

The Committee finds that gas storage is important to the development of a more liquid and mature gas market in Western Australia and strongly supports the Gas Supply Emergency Management Committee's recommendations relating to gas storage.

6.4 Gas Market Information and Transparency

518. Currently, gas users in Western Australia contract for gas and transmission capacity separately. In line with other Australian jurisdictions, except Victoria, gas transmission contracts in this state are managed under a "contract carriage" arrangement that involves each shipper entering into a contract with a transmission service provider. A prospective shipper therefore needs to enter into separate back to back arrangements for the supply of gas and transport. This is difficult, especially for smaller prospective shippers, particularly in circumstances where there is a lack of market information on both gas and transport availability. This situation is exacerbated where pipelines are built without spare capacity and indeed where the regulatory regime acts as a disincentive to build speculative capacity.

519. For example, Woodside submitted that:

In WA, increments to gas supply and demand occur infrequently and in large tranches. Being a bilateral contract-based market, these large increments on both sides give the WA gas market its "lumpy" nature. Furthermore, the successful matching of supply with demand must be coordinated with the required level of transportation capacity. As investment in additional transmission capacity is also based exclusively on long-term contracts for capacity, there is currently no mechanism to provide capacity to support the development of short and medium term trade, which impedes gas suppliers [sic] efforts to provide incremental volumes during periods of market tightness[500]

520. APPEA expressed similar concerns adding that the state's main transmission pipeline is capacity constrained and that it is only expanded when they have firm commitments to do so.[501] As noted in paragraph 493 above, Stuart Johnston confirmed that the DBNGP is fully contracted to 2019.

499 Mr Steven Lewis, General Manager, Western Australia, APA Group, *Transcript of Evidence*, 25 October 2010, p. 4.

500 Submission No. 15 from Woodside Energy Ltd, 2 July 2010, p. 7.

501 Mr Steven Gerhardy, Consultant, APPEA, *Transcript of Evidence*, 20 September 2010, p. 12.

521. Mr Peter Kiossev, Acting Director, Office of Energy (Strategic Energy Initiative), confirmed that getting shorter term contractual arrangements in place for the DBNGP '...has been one of the issues that has long been identified as a constraint.'[502] Ms Anne Hill, Acting Coordinator of Energy added that '...large infrastructure access regulation is a dilemma across the country and, quite possibly, internationally'.[503] Ms Hill was concerned that speculative investment would have to be funded by the people who are currently using the pipeline; whereas the beneficiaries are really future users who are not there yet.

522. Mr Lyndon Rowe, Chairman, ERA, explained that regulated pipelines can build spare capacity. The regulatory authority is able to take this into account and, if appropriate, the cost of such an expansion can be added to the capital base. The circumstances of the DBNGP are however somewhat different. If spare capacity were available on the DBNGP that could undermine the higher price that was negotiated outside of the regulatory regime to get the pipeline out of administration in 2004. Spare capacity for the DBNGP offers the opportunity for someone to seek access to that capacity at a lower regulated price that would, under the terms of the negotiated standard shipper contract, flow on to all other shippers.[504]

523. DBP, however, considers that the regulatory framework is not flexible enough to allow expansions to occur without the current negotiated framework. DBP's Stuart Johnston commented that 'We should be clear that that is not just an issue here. If you look at all the pipeline investments in Australia, they are all happening outside the regulatory regime to enable them to happen.[505]

524. Expansions are also a problem for the GGP. APA Group's Steven Lewis explained that: '...whenever we expand the pipeline beyond a certain point, some of the tariffs paid by existing customers automatically reduce. On the one hand, we are trying to expand our pipeline to capture additional revenues, but every time we do that, revenues from existing customers go down; that is actually a disincentive to expand'[506] However, this raises the question of whether foundation shippers on a pipeline that committed to paying high upfront infrastructure costs should share in the economies of scale benefits that are available as additional shippers come on to the pipeline. As advised by Mr Lewis, the ERA's last regulatory decision for the GGP which raises this issue is currently subject to merits review by Western Australia's Electricity Review Board.[507]

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502 Mr Peter Kiossev, Acting Director, Strategic Energy Initiative, Office of Energy, *Transcript of Evidence*, 11 October 2010, p. 9.

503 Ms Anne Hill, Acting Coordinator of Energy, Office of Energy, *Transcript of Evidence*, 11 October 2010, p. 9.

504 Mr Lyndon Rowe, Chairman, Economic Regulation Authority, *Transcript of Evidence*, 13 September 2010, pp. 4-5.

505 Mr Stuart Johnston, Chief Executive Officer, Dampier to Bunbury Natural Gas Pipeline, *Transcript of Evidence*, 15 November 2010, p. 11.

506 Mr Steven Lewis, General Manager, Western Australia, APA Group, *Transcript of Evidence*, 25 October 2010, p. 5.

507 ibid. Also refer: Economic Regulation Authority, 'Electricity Review Board Application No 1 of 2010 and No 2 of 2010', 2011. Available at: www.erawa.com.au/2/971/43/electricity_review_board_application_no__of__and_n.pm. Accessed on 28 January 2011.

525. As already noted at 156 above, Mr Brett Langley, General Manager, Gas Marketing, BHP Billiton commented that:

> *… there seems to be quite a rigid regulatory framework around pipeline investment, which is encouraging any new expansions to be fully contracted. I think as part of any energy reform agenda, we should look more at an incentive-based pipeline regulatory mechanism that encourages pipeline owners and developers to build in some excess capacity in the services they provide.*[508]

526. In contrast to the rest of Australia, Victoria operates a "market carriage" system as distinct from a contract carriage system. Under a market carriage system transmission capacity is expanded to meet market requirements and shippers are not required to enter into contracts for capacity with the owners of the pipeline system.

527. The Victorian Transmission System (VTS) is operated by AEMO under the Victorian market carriage system. While APA owns and maintains the VTS, the AEMO is responsible for the shipment of gas through the VTS. To ship gas through the VTS, shippers must register with AEMO as a participant in the Victorian wholesale gas market, which is also operated by the AEMO.[509] In so doing shippers are bound by the market and system operations rules which govern all participants in the market. Under these rules shippers must enter into a transmission payment deed with APA Group.[510]

528. NERA Economic Consulting in a report to the Australian Energy Market Commission cite the following benefits of the market carriage model:[511]

- smaller retailers and other smaller market participants have been able to enter the market more readily because they have been able to avoid the difficulties faced in other jurisdictions in obtaining 'reasonable' commercial contracts;
- the ability to trade imbalances coupled with the pricing signals provided by the spot market enable market participants to manage their short term imbalances and to optimise their portfolios; and
- the separation of asset ownership from market operation enables operational decisions to be undertaken in an impartial manner and thus more acceptable to market participants. [512]

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508 Mr Brett Langley, General Manager, Gas Marketing, BHP Billiton, *Transcript of Evidence*, 25 October 2010, p. 5.

509 AER, *State of the Energy Market 2010*, ACCC, Canberra, 2010,,p. 76.

510 APA Group 'Victorian Transmission System' (n.d). Available at: www.apa.com.au/our-business/economic-regulation/vic-gas-assets/victorian-transmission-system.aspx. Accessed on 28 January 2011.

511 NERA Economic Consulting, *The Gas Supply Chain in Eastern Australia. A Report to the Australian Energy Market Commission*, March 2008, p. 31. Available at: www.aemc.gov.au/Media/docs/NERA%20Report-9a77d84d-b7c4-496d-8ed2-a651a0eacd86-0.pdf. Accessed on 21 March 2011.

512 ibid.

529. A more recent development is the short term gas trading market (STTM) launched in September 2010 in the metropolitan hubs of Sydney and Adelaide. This initiative is designed to work in conjunction with the contract carriage system operating in those jurisdictions but achieve some of the benefits listed in paragraph 528 above. The reform creates a day-ahead wholesale spot market operated by the AEMO. Users can buy or sell gas on a spot basis without entering delivery contracts in advance and manage their short-term supply and demand variations relative to their contracted quantities. As noted in section 5.3(b) above, the STTM aims to enhance market transparency and competition to address concerns that traditional gas balancing arrangements hinder retail market entry and gas supply efficiency.

530. The Committee acknowledges the work done by the Gas Market Development Working Group (GMDWG) as part of the review undertaken by the Gas Supply and Emergency Management Committee (GSEMC).[513] It notes the recommendation by the GSEMC in its report to government that '…future consideration be given to a compulsory Short Term Trading Market (STTM) following a review of the operation of the WA Bulletin Board and the gas market experiences in other Australian jurisdictions.'[514]

531. On the basis of the evidence presented to the Committee and considering the significance of the gas market to the Western Australian economy, the Committee is not convinced by the analysis presented by the GMDWG that consideration of a Western Australian STTM or more fundamental market reform should be delayed for reasons that:

- the cost benefit analysis cited by the GMDWG does not support the conclusion that a STTM should be delayed[515];

- the GMDWG cost benefit analysis does not give recognition to the costs of the poorly performing access regime for regulated pipelines in this state;

- the inadequate recognition given to the need for gas suppliers to place short-term supplies onto the market without the need for customers to arrange prior transmission contracts; and

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513 Gas Market Development Working Group, *Western Australian Gas Market Developments: Final Report*, report prepared by Marchment Hill Consulting, Melbourne, 10 September 2009.

514 Gas Supply Emergency Management Committee, *Report to Government*, Office of Energy, Perth, September 2009, p. 5.

515 The Gas Market Development Working Group's Final Report (p. 21) quotes a 2006 cost-benefit analysis to confirm that the indicative cost of establishing a STTM hub in Western Australia is estimated at $4 million. The 2006 analysis also estimates that a STTM hub in Western Australia could generate a net benefit of $44 million and benefit-cost ratio of 15.0. This additional point does not appear to be acknowledged in the GMDWG Final Report, which only quantifies the benefits of a 'National STTM'. See Gas Market Development Working Group, *Western Australian Gas Market Developments: Final Report*,, report prepared by Marchment Hill Consulting, Melbourne, 10 September 2009, p. 21; McLennan Magasanik Associates, *Gas Market Options Cost Benefit Analysis - Report to Gas Market Leaders Group and MCE Standing Committee of Officials*, 13 June 2006, pp. xiii, xvi-xviii, 72. Available at: www.ret.gov.au/Documents/mce/_documents/GasMarketOptionsCBAFinalReport20060626121510.pdf. Accessed on 10 March 2011.

- the inadequate consideration given by the GMDWG to the lack of capacity available on Western Australian regulated pipelines and the need for arrangements to be put in place to address this matter.

Recommendation 16

That the Minister for Energy arrange for a review to be undertaken of identified shortcomings in Western Australia’s regulated gas transmission sector with a view to urgently progressing reforms that will overcome the need for gas market participants to trade in gas without first or separately having to enter into long-term transmission contracts.

CHAPTER 7 DISTRIBUTION AND RETAIL SECTORS

7.1 Background

532. Retail gas prices encompass wholesale gas costs, transmission pipeline costs, distribution network costs and retailer operating costs (including net margin).

533. The AER's State of the Energy Market 2009 report states that there is 'little systematic publication of actual retail prices in Australia'.[516] Much of the information available to the Committee has been extrapolated or may be out of date. It is therefore difficult to make comparisons of the retail gas price and the composition of residential gas bills between the states.

534. The State of the Energy Market 2009 report provides a graph (Figure 25) showing actual and extrapolated retail gas prices across Australia from 1996/97 to 2008/09.

Figure 25 Real Retail Gas Prices, By State and Territory, July 1996—March 2009[517]

Note: The dashed lines are estimates based on inflating 1998–99 AGA data by the CPI series for gas and other household fuels for the capital city in that state.

Sources: AGA, *Gas statistics Australia*, Canberra, August 2000, p.73; ABS, *Consumer price index, Australia, March quarter 2009*, cat. no. 6401.0, Canberra.

535. The graph indicates that retail prices in Western Australia have traditionally sat above New South Wales and Victoria, but below South Australia and Queensland. The sharp increase in Western Australia's retail prices from 2007-2008 is consistent with the Committee's findings on wholesale

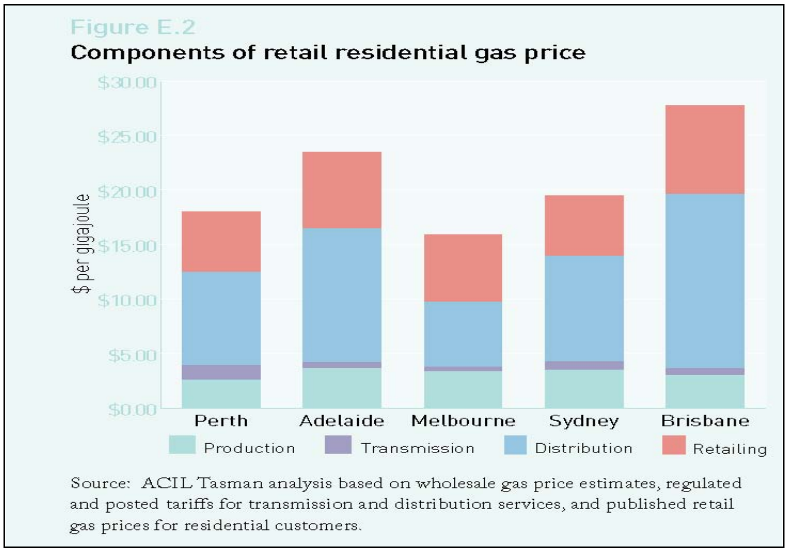
516 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 306.

517 ibid., p. 308.

gas price movements (Finding 11) and also coincides with the commencement of a series of retail gas tariff resets from July 2008.

536. Again, information on the composition of residential gas bills across the states is difficult to obtain, however the data complied by ACIL Tasman in Figure 26 offers one of the more reliable and most recent assessments available.

Figure 26 Components of Residential Retail Gas Price 2007-2008 (ACIL Tasman)[518]



537. Based on information collated by the Committee, the most recent breakdown for Western Australia's retail residential prices is something in the order of: distribution charges 40 per cent; wholesale gas costs 30 per cent; retail operating costs 23 per cent; retail net margin 5 per cent and transmission charges 2 per cent.[519]

538. The Committee asked the Office of Energy which component of the gas supply has the greatest impact on final retail gas prices. The answer supplied confirmed the proportion of the current retail cap attributable to distribution (40 per cent) and wholesale gas costs (30 per cent).[520] However, it did not clarify whether increases in these areas, or in transmission or retail operating costs, were exercising the greatest influence on current retail prices.

539. The Western Australian small business and residential sector consumes only 4 per cent of the state's domestic gas supplies (see paragraph 13 above). By contrast, residential consumption in

518 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 33.

519 Note these figures represent indicative averages. The individual components (particularly retail operating costs and transmission charges) may vary significantly depending on where the retail residential customer is based. Submission No. 12(A) from Office of Energy - Response to Question on Notice, 3 November 2010, pp. 6-7; Mr Richard Begley, Senior Associate, ACIL Tasman, Electronic Mail, 2 February 2011, p. 1.

520 Submission No. 12(A) from Office of Energy - Response to Question on Notice, 3 November 2010, pp. 6-7.

Victoria is approximately forty per cent.[521] As at October 2009, 83 per cent of Perth dwellings and 32 per cent of those outside Perth were connected to mains gas and 50 per cent of dwellings outside of Perth used LPG or bottled gas. This represents a total of 746,100 dwellings.[522] Victoria, by comparison, has a total of 1,863,000 dwellings (more than 82%) connected to mains gas or using LPG or bottled gas.[523]

540. During and after Perth's record winter cold snap in 2010, there was some discussion in the media concerning the sharp increase in electricity and gas costs and reports that pensioners and low-income earners could not afford to heat their homes (see paragraph 53 above).

541. The Committee is mindful of the increase in energy costs facing householders and small businesses and has used this report to investigate where improvements can be made in each sector of the retail gas price chain. The focus of this chapter will be on the sectors whose operations pertain exclusively to retail consumers and whose costs comprise the majority of a retail bill—distribution networks and gas retailers.

7.2 Distribution Market

542. Unlike wholesale buyers, who receive their gas directly, retail customers (small business and residential) are also subject to distribution costs. Distribution networks reticulate gas from the juncture of the transmission pipeline into homes, offices and small businesses. This cost is normally negotiated between the network operator and energy retailers who aggregate wholesale gas volumes for on-sale to their retail client base.

543. ACIL Tasman has reported that distribution charges form the largest part of retail prices across the country ranging anywhere from 38 to 58 per cent of the final figure.[524] The Office of Energy puts the figure at 40 per cent of the cost stack for determining retail tariffs in Western Australia.[525]

544. Distribution networks are expensive to set up and incur declining marginal costs as output is increased. As such, they are prone to becoming monopolistic enterprises.[526] Competitive pressure in the distribution sector is difficult to achieve, as it is impractical from both an infrastructure and cost perspective to run multiple pipelines down a street. In markets large enough to support

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521 Derived from figures cited in Submission No. 10 from APPEA, June 2010, p. 19.

522 Australian Bureau of Statistics, *4656.5 - Household Choices Related to Water and Energy, WA*, October 2009, p. 30. Available at www.abs.gov.au. Accessed on 29 January 2011.

523 Australian Bureau of Statistics, '4602.2 - Household Water, Energy Use and Conservation, Victoria', October 2009. Available at: www.abs.gov.au. Accessed on 29 January 2011.

524 AER, *State of the Energy Market 2008,* ACCC, Canberra, 2008, p. 33.

525 Submission No. 12(A) from Office of Energy - Response to Question on Notice, 3 November 2010, p. 6.

526 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 280.

multiple distributors, such as in Victoria, each distributor still has a monopoly over the geographical area in which they operate.

545. Therefore, maintaining a reasonable price for distribution is achieved mostly through regulation. Currently, all major distribution networks in New South Wales, Victoria, Queensland, South Australia, the ACT and Western Australia are regulated. WA Gas Networks (WAGN) owns and operates the majority of Western Australia's gas distribution infrastructure. WAGN's distribution network is regulated by the Economic Regulation Authority under the National Gas Access (Western Australia) Act 2009 (NGA).

546. Under the NGA, WAGN must periodically submit a proposed access arrangement to the ERA for approval. When assessing the proposed access arrangement, the ERA must take into account the national gas objective and the revenue and pricing principles set out in the NGA. If the ERA withholds its approval to any element of the proposal, the entire proposal is declined. After releasing the Draft Decision on the proposed access arrangement, the ERA calls for public comment via submission, and takes this information into consideration before making a Final Decision.

Finding 31

The distribution sector is a natural monopoly and usually requires ongoing regulatory oversight.

The Committee is satisfied with the current regulatory regime for distribution networks in Western Australia.

547. The Committee had suspected that residential gas connection rates were declining because of rising prices and households switching to electrical heating and hot water systems. In particular, the Committee was concerned that new housing developments were not being reticulated with gas because of the cost to the developer and declining connection rates. Obviously, if the rate of connection or the volume of consumption decreases, prices will rise.

548. The Committee questioned several stakeholders in the distribution area about residential gas usage and connections. The Committee found that while the rate of connection was not decreasing, residential consumption had decreased from an average of approximately 20 gigajoules per annum to approximately 17 to 18 gigajoules per annum.[527] WAGN believes that the reduction in consumption has resulted from customers switching to reverse cycle air-conditioning for heating and from gas hot water storage to solar hot water.[528]

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527 Mr Justin Scotchbrook, Senior Manager, Commercial and Business Development, WA Gas Networks, *Transcript of Evidence*, 10 November 2010, p. 4.

528 ibid.

549. Regarding connections in new subdivisions, WAGN stated that it has almost 100% connection in new subdivisions but that it does have difficulty with subdivisions leaping the development front. When a subdivision expands incrementally, it is much less costly to connect those new houses, but when a new subdivision is established some distance from WAGN's arterial pipes, connection becomes cost prohibitive.[529] WAGN stated that, given Perth's growth rate, they have proposed building in excess capacity in the access arrangement that is currently under review by the ERA, but that there is a restriction on WAGN undertaking what is viewed as speculative investment.[530]

550. Following its discussions with the ERA, the Committee noted that the regulatory regime does not place restrictions on speculative investment. [531] However, the Committee understands that the regulator reserves the right to determine whether such expenditure is recovered through reference tariffs. Alternatively, WAGN could seek a capital contribution from entities such as the property developer. The Committee notes that in its draft decision for WAGN's gas distribution systems dated 17 August 2010, the ERA has, subject to some particular requirements, approved the service provider's actual capital expenditure for the period 2005 to 2009 and forecast capital expenditure for the period 2010 to 2014.[532]

7.3 Retail Operations

551. Retail operating costs are those borne and passed on by gas retailers for the administration of their businesses. The Office of Energy confirmed that retail operating costs can be influenced by '…customer location, regulatory obligations, other market administration costs…and labour costs.'[533]

552. In Western Australia, retail operating costs account for around 23 per cent of the final retail price, whilst a regulatory determination has provided for a 5 per cent retail net margin to be incorporated. [534]

553. Alinta is the only retailer for the small customer market (residential and small business) in Western Australia. Table 9 below shows the number of active retailers and the market size for all

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529 Mr Justin Scotchbrook, Senior Manager, Commercial and Business Development, WA Gas Networks, *Transcript of Evidence*, 10 November 2010, p. 5.

530 ibid.

531 Mr Lyndon Rowe, Chairman, Economic Regulation Authority, *Transcript of Evidence*, 13 September 2010, p. 5.

532 Economic Regulation Authority, *Draft decision on WA Gas Networks Revisions Proposal for the access arrangement for the Mid-West and South-West Gas Distribution Systems*, 17 August 2010, paragraphs 316, 461. Available at: www.erawa.com.au/3/1076/48/wa_gas_networks_formerly_alintagas_distribution_sy.pm. Accessed on 7 February 2011.

533 Submission No. 12 from Office of Energy, 29 June 2010, p. 5.

534 This was a weighted average calculation for the whole of the South West Tariff Area. Mr Richard Begley, Senior Associate, ACIL Tasman (Perth), Electronic Mail, 31 January 2011.

Australian states and territories except the Northern Territory. It should be noted that the Queensland, South Australia, Tasmania and Australian Capital Territory markets are smaller than that of Western Australia but have multiple retailers. Full retail contestability has been introduced in each of these states, and in all except Tasmania, each retailer provides duel fuel (electricity and gas) packages. The importance of providing duel fuel to the promotion of competition is discussed in paragraph 572 below.

Table 9 Active Gas Retailers—Small Customer Market, June 2009[535]

RETAILER[1]	OWNERSHIP	QLD	NSW	VIC	SA	WA	TAS[2]	ACT
ActewAGL Retail	ACT Government and AGL Energy		Host					Host
AGL Energy	AGL Energy	Host	Host	Host	New entrant			
Alinta	Babcock & Brown Power					Host		
Aurora Energy	Tasmanian Government						New entrant	
Australian Power & Gas	Australian Power & Gas			New entrant				
Country Energy	NSW Government		Host					
EnergyAustralia	NSW Government		New entrant					
Origin Energy	Origin Energy	Host	Host	Host	Host			
Red Energy	Snowy Hydro[3]			New entrant				
Simply Energy	International Power			New entrant	New entrant			
Tas Gas Retail (formerly Option One)	Babcock & Brown Infrastructure						New entrant	
TRUenergy	CLP Group		New entrant	Host	New entrant			New entrant
Victoria Electricity	Infratil			New entrant				
Active retailers		2	6	7	4	1	2	2
Approx. market size ('000 000 customers)[4]		0.15	1.19	1.68	0.37	0.58	0.005	0.09

Host (incumbent) retailer New entrant retailer

1. Not all licensed retailers are listed. Some of the retailers listed offer gas services only as part of a gas and electricity contract. The list excludes three small retailers (BRW Power Generation (Esperance), Dalby Town Council and Roma Town Council).
2. There is no host retailer in Tasmania because gas distribution and retail services have been available only for a short time and FRC existed from market start.
3. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).
4. Customer numbers in Queensland, New South Wales and the ACT are estimates based on the number of distribution connection points.

Sources: Jurisdictional regulator websites; ESAA, *Electricity gas Australia 2008*, Melbourne, 2008; updated by information on retailer websites and other public sources.

554. Full retail contestability (FRC) is achieved when all customers are permitted to enter a supply contract with a retailer of their choice.[536] FRC has been introduced in gas markets in all states and territories in Australia under various arrangements with mixed results. Retail gas prices are unregulated in Queensland, Victoria, Tasmania, the Australian Capital Territory and the Northern Territory.[537] A 'light regulation' regime exists in South Australia and New South Wales while the West Australian market is fully regulated.

555. Under the Australian Energy Market Agreement 2004, all jurisdictions agreed to review the continued use of retail price caps and remove them where effective competition can be demonstrated. The Australian Energy Market Commission is responsible for assessing the effectiveness of retail competition in each jurisdiction (excluding Western Australia, where the Economic Regulation Authority is responsible) and advising on the appropriate time and way to

535 AER, *State of the Energy Market 2009*, ACCC, Canberra, 2009, p. 280.

536 ibid, p. 193.

537 ibid., p. 304.

remove retail price caps. The final decision however is made by the relevant state or territory government.

556. In Queensland, gas prices were fully deregulated at the time of the introduction of FRC on 1 July 2007.[538] For a time after introduction, customers had the option to move to a negotiated market contract with a retailer or remain on the standard contract, the tariff for which was regulated by the government. This has been phased out and there are '…no longer any regulated or Government-controlled prices for small gas customers in Queensland who do choose not to enter into market contracts'.[539] In 2008 the Queensland Competition Authority conducted the Review of Small Customer Gas Pricing and Competition in Queensland which revealed that there were no new entrants currently active in the market (a third retailer had operated for a short period) and that prices had increased significantly.[540]

557. The report identified that the '…lack of activity by new retailers suggests that the current level of profitability is not sufficient to attract new entrants' [541] and that below cost-reflective pricing was a barrier to new entrants.[542] In its submission to the Review, the retailer Origin expressed the view that historically low retail gas prices had created an expectation of relatively low, subsidised gas prices in Queensland and explained that as a result, it was raising its tariffs to cost reflective levels incrementally, in order to minimise the impact on consumers.[543]

558. FRC in the gas market was introduced in Victoria in January 2002. In 2007 the Australian Energy Market Commission conducted a Review of the Effectiveness of Competition in the Electricity and Gas Retail Markets in Victoria. The Commission found that competition in both electricity and gas retailing in Victoria was effective, citing active participation in the market by customers and strong rivalry between retailers facilitated by the current market structures and entry conditions. The AEMC provided advice on phasing out retail price regulation and energy retail prices were subsequently deregulated in January 2009 and a program of price monitoring put in place. As mentioned in paragraph 539 above, Victoria has a large customer base that is able to support multiple distributors and multiple retailers. The way in which the Victorian market has historically operated has also influenced the expeditious implementation of FRC in that state.

559. In the early 1990s the Victorian government began restructuring, corporatising and privatising the government-owned energy assets and businesses. As part of this process, the government established a number of corporatised retail businesses, which in the gas sector were established as separate corporate entities but linked to the corresponding distribution business with two retailers

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538 Queensland Competition Authority, *Final Report - Review of Small Customer Gas Pricing and Competition in Queensland*, November 2008, p. 6. Available at: www.qca.org.au/files/GR-RSCSPComp-QCA-FinalRep-1208.PDF. Accessed on 29 January 2011.

539 ibid., p. 31.

540 ibid., p. iv.

541 ibid.

542 ibid, p. 73.

543 ibid., p. 74.

servicing a distribution area.[544] In 1999, the linked gas retail and distribution businesses were sold off by the Victorian government and privatised. At this time there were three distribution/retail businesses operating in Victoria.[545]

560. The existence of multiple retailers from the introduction of FRC promoted a natural rivalry as the retailers attempted to win market share from each other from an already established customer base. This competition, along with full retail contestability in the electricity market encouraged retailers from other states and new retailers to enter the Victorian market. This is vastly different from the situation in Western Australia, where (due to the gas market moratorium on Synergy[546] and the lack of full retail contestability in the electricity market) any new entrants to the retail gas market must build a local customer base without the ability to defray capital and operating costs by offering duel fuel packages.

561. In Tasmania, natural gas has only been available since 2002, with the connection of a sub-sea transmission pipeline from Victoria. Gas has been fully contestable and unregulated since distribution began in October 2002. The Office of the Tasmanian Energy Regulator considers that as the '…supply of natural gas is new, it is not an essential service and its pricing must be competitive with electricity in order to gain new customers. This need to be competitive imposes pricing restraint which might otherwise need to be imposed by regulation'.[547] The market in Tasmania is small (approximately 7,500 customers) but is growing steadily. Residential customers consume approximately 40GJ per annum, more than twice the amount consumed by residential customers in Western Australia, and the retail gas price per megajoule (MJ) remains below that of every state except Victoria.[548]

562. New South Wales and South Australia have both introduced full retail contestability in their gas markets (on 1 January 2002 and 28 July 2004 respectively), however both have standing contract prices established in legislation as a measure of protection for small use customers who choose not to enter into a market agreement with a retailer. In New South Wales the pricing for standard contracts are set by the Independent Pricing and Regulatory Tribunal of NSW (IPART). The New South Wales Government has agreed to phase out this regulation when effective competition can be demonstrated but has determined to retain the regulated tariff until at least 2013.[549] Each

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544 Australian Energy Market Commission, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria, First Final Report*, 19 December 2007, p. 27. Available at: www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Effectiveness-of-Competition-in-the-Electricity-and-Gas-Retail-Markets-Victoria.html. Accessed on 29 January 2011.

545 ibid., p. 28.

546 The Gas Market Moratorium will be discussed in paragraph 569 below.

547 Office of the Tasmanian Economic Regulator, 'Gas Regulation in Tasmania', 2 June 2010. Available at: www.gpoc.tas.gov.au/domino/otter.nsf/gas-v/001. Accessed on 29 January 2011.

548 Office of the Tasmanian Economic Regulator, *Tasmanian Energy Supply Industry Performance Report 2009-10*, January 2011, pp. 192-193. Available at: www.energyregulator.tas.gov.au. Accessed on 29 January 2011;

Independent Pricing and Regulatory Tribunal of New South Wales (IPART), *Review of regulated tariffs and charges for gas 2010-2013*, June 2010, p. 1. Available at: www.ipart.nsw.gov.au/investigation_content.asp?industry=1&sector=1&inquiry=205. Accessed on 29 January 2011.

nominated standard retailer (one per region) makes a proposal to IPART for a designated period of supply (currently 2010-2013) and IPART conducts a public Inquiry before making a determination.

563. In South Australia, the standard contract prices are set by the Essential Services Commission of South Australia (ESCOSA). As with NSW, the retailer (Origin Energy only) must submit a proposal to the regulator, which then conducts a public Inquiry before making a determination. In 2008, the AEMC conducted a Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia. As with Victoria the year prior, the AEMC found that the South Australian gas and electricity markets were effective and provided advice on ways to phase out retail price regulation.[550] However, the South Australian Minister for Energy did not accept the recommendations of the AEMC and the South Australian gas market remains regulated.

564. While FRC was introduced in the retail gas market in Western Australia in May 2004, there have been no new entrants to the market in that time. Competition in Western Australia is impeded by non-cost-reflective tariffs, the lack of full retail contestability in the electricity market and the gas market moratorium on Synergy.

565. The Queensland experience (see 556 and 557 above) shows that even with unregulated pricing and FRC in retail energy markets, the transition to a competitive marketplace is impeded by the low profit margins initially available to retailers as consumers adjust to cost reflective tariffs. The Office of Energy recognises that this is a significant issue that is likely to affect the Western Australian retail gas market and has sought to address it before removing other barriers to competition. As with Queensland, Western Australian customers have historically had low retail gas prices provided by ongoing government subsidies to the retailer and/or regulation of tariffs.

566. In 2007 the Office of Energy conducted the Gas Tariff Regulations Review which noted that, despite the introduction of gas FRC in May 2004, little competition had emerged. The Gas Tariff Regulations Review found that tariff regulations were still required and that there was upward pressure on the costs to retail gas to small use customers in the areas covered by the tariff regulations.[551] Essentially, the review determined that tariffs were not cost-reflective and this may be a barrier to entry into the retail gas market.

567. The Gas Tariff Regulations Review recommended that a more detailed study of the level and structure of gas tariffs should be undertaken. Consequently the Gas Tariffs Review was commenced in 2008, but has been delayed by the wholesale gas price dispute between Alinta and the North-West Shelf Joint Venture (see 222 above). In the meantime, there have been three interim tariff resets (2008, 2009 and 2010). In each, the Office of Energy recommended increases

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550 AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, Second Final Report*, 18 December 2008. Available at: www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Effectiveness-of-Competition-in-Electricity-and-Gas-Retail-Markets-in-South-Australia.html. Accessed on 29 January 2011.

551 Office of Energy, *Gas Tariff Regulations Review Report*, report prepared by the Minister for Energy the Hon Francis Logan MLA, Perth, October 2007, p. 1.

in the tariff above CPI in order to assist the move towards cost-reflective tariffs.[552] In each case the Minister for Energy endorsed the recommendations and the tariffs were implemented with minor adjustments made in 2010. The Draft Recommendations Report for the Gas Tariffs Review was released in December 2010 and continues to promote a move towards cost-reflective tariffs in order to ensure continuity of supply and promote competition.[553]

568. Despite a move towards cost-reflective tariffs, competition may still be hindered by the gas market moratorium on Synergy and the lack of full retail contestability in the electricity market.

569. The gas market moratorium was originally imposed on Western Power in October 2000 as part of the disaggregation of the State Energy Commission of Western Australia (SECWA) into Western Power and AlintaGas and the subsequent privatisation of AlintaGas.[554] In 2002, towards the end of the moratorium period, the state government entered into a Gas Market Agreement with AlintaGas which included a direction to Western Power that imposed a moratorium on it supplying gas to customers taking less than one terajoule per annum.[555] This moratorium was subsequently extended to Western Power's successor entities Synergy and Verve Energy.

570. The revised moratorium in the Gas Market Agreement was '…based around the proposition that Western Power should not be allowed full access to the gas market while AlintaGas was denied full access to the electricity market'.[556] The Gas Market Agreement does not have a provision for the moratorium to lapse, however it provides that the moratorium will be automatically lifted following the introduction of full retail contestability in electricity or that the state government may change the moratorium from July 2007.[557]

571. In 2006 the Office of Energy produced an issues paper on the review of the moratorium and invited comment. As a result, from July 2007 the threshold at which Synergy can supply gas to customers was reduced from 1 terajoule (TJ) to 0.18 TJs per annum and the supply threshold for Verve Energy was removed altogether. However, Verve is precluded from retailing electricity until 2013 and the inability to offer duel fuel to customers may therefore deter it from entering the retail gas market.[558]

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552 Office of Energy, *Gas Tariffs Review Interim Report*, Perth, June 2008, p. 1; Office of Energy, *Gas Tariffs Review Interim Report*, Perth, June 2009, p. 1; Office of Energy, *Gas Tariffs Review Interim Report*, Perth, March 2010, p. 1.

553 Office of Energy, *Gas Tariffs Review, A Review of Retail Gas Tariff Arrangements under the Energy Coordination (Gas Tariffs) Regulations 2000, Draft Recommendations Report*, Perth, December 2010, pp. 25, 30.

554 Office of Energy, *Gas Markets Moratorium: Issues Paper*, Perth, April 2006, p. 3.

555 ibid.

556 ibid., p. 5.

557 Office of Energy, *Gas Markets Moratorium: Issues Paper*, Perth, April 2006, p. 4.

558 Office of Energy, 'Gas Market Moratorium', (n.d.) Available at: www.energy.wa.gov.au/3/3177/64/gas_market_moratorium.pm. Accessed on 29 January 2011.

572. This is also true for many other retailers who provide energy services in Australia. In each state or territory of Australia (except Tasmania), each of the retailers can offer duel fuel packages to their customers.[559] In its draft recommendations report for the Gas Tariffs Review, the Office of Energy notes that:

> *[i]n commentaries and assessment of competition in other jurisdictions, the ability to offer duel fuel products is noted as an important retailer strategy - especially where there are lower levels of residential consumption (as is found in South Australia, Queensland and Western Australia)*[560]

573. Removing the gas market moratorium and thus encouraging duel fuel retailers cannot happen without the introduction of full retail contestability in the electricity market. This in turn cannot happen without a move towards cost-reflective tariffs in the electricity market. In 2008/2009 the Office of Energy conducted the Electricity Retail Market Review, which reviewed electricity retail tariff arrangements and the introduction of full retail contestability, among other issues. This review determined that that current retail electricity tariffs were not cost-reflective and would need to increase in the future in order to ensure continuity of supply and financial viability of industry participants.[561]

574. The Committee recognises that Western Australian retail gas customers have historically been supplied gas at relatively low rates. However, this report has already concluded that wholesale domestic gas prices paid by retailers have now increased significantly (see Finding 12). The move towards cost-reflective tariffs in both the gas and electricity markets could provide a way of reflecting this increase, while attempting to lessen its impact by improving competition for the retail gas sector. Still, the Committee acknowledges that any move towards cost-reflective tariffs will put pressure on customers, especially in light of current community concerns about rising energy bills, and believes the government should consider policies to resolve this issue.

Finding 32

The government needs to consider policies that will mitigate the impact on retail residential gas bills that will emanate from the recent increases in the wholesale price of gas and from any move towards cost-reflective tariffs in gas and electricity.

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559 Except in some regional areas of Australia, including regional Queensland.

560 Office of Energy, *Gas Tariffs Review, A Review of Retail Gas Tariff Arrangements under the Energy Coordination (Gas Tariffs) Regulations 2000, Draft Recommendations Report*, Perth, December 2010, p. 22.

561 Office of Energy, *Electricity Retail Market Review, Final Recommendations Report, Review of Electricity Tariff Arrangements*, Perth, January 2009, p. 1.

575. Significant public concern has been raised about the impact of rising energy bills in Western Australia, particularly since the first interim tariff reset in 2008. As mentioned, the Minister for Energy is making policy decisions and arrangements in order to bring energy tariffs up to cost-reflective levels. The three interim tariff resets from since 2008 have resulted in increases of between 27 and 32 per cent on top of CPI for the "median customer".[562]

576. In line with the increase in tariffs, the state government introduced the Hardship Utilities Grant Scheme (HUGS) in August 2008 to assist individuals and families experiencing financial or social disadvantage in relation to essential services debt. HUGS is administered by the Department for Child Protection and covers electricity, water and gas service provision. Synergy, Horizon Power and Alinta all participate in the HUGS. HUGS grants are available for up to 85 per cent of the outstanding amount, up to a limit of $450 for those living south of 26°S (south of Carnarvon) and $750 for those living north of 26°S.[563]

577. Alinta joined HUGS in August 2009 and in the 11 months to June 2010, there were 1,641 HUGS grants approved for Alinta customers, equating to approximately 0.28% of its customer base. The Western Australia Council of Social Service Inc (WACOSS) believes this is a concerning level of uptake by gas customers, considering it is the first year customers have been granted access to HUGS.[564] While the Committee supports the scheme, it is concerned with the unnecessarily complicated application process. To apply for HUGS, an applicant must be referred by the utility to a HUGS-registered financial counselling service for an assessment to be conducted. The onus is on the utility provider to identify eligible applicants under their hardship criteria. Ms Irina Cattalini, Director of Social Policy with WACOSS, informed the Committee that financial counselling services are very stretched in Western Australia and the wait time is often four weeks or more.[565]

578. Another assistance program available to gas customers is AlintaCARE which is funded by Alinta and provides a $100 grant towards an Alinta bill for customers experiencing financial hardship. Demand far exceeds the program's limited funding, and Alinta is forced to routinely reject eligible applications due to insufficient funds. Customers can apply for the grant through a community service agency and Alinta conducts an allocation round each month. Limited funding means that the scheme is restricted to two customers per agency per month. In October 2010, 106 AlintaCARE applications were approved from 53 individual agencies.[566]

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562 Submission No. 12(A) from Office of Energy - Response to Question on Notice, 3 November 2010, p. 6.

563 Department of Child Protection, *Hardship Utility Grant Scheme Information Sheet*, July 2010, p. 1. Available at: www.dcp.wa.gov.au/SupportingIndividualsAndFamilies/Documents/HUGS%20information%20sheet.pdf. Accessed on 29 January 2011.

564 Ms Irina Cattalini, Director, Social Policy, Western Australian Council of Social Service, *Transcript of Evidence* (Supplementary Material), 24 November 2010, p. 6.

565 Ms Irina Cattalini, Director, Social Policy, Western Australian Council of Social Service, *Transcript of Evidence*, 24 November 2010, p. 3.

566 Ms Irina Cattalini, Director, Social Policy, Western Australian Council of Social Service, *Transcript of Evidence*, 24 November 2010, p. 5; (Supplementary Material, p. 8).

579. Customers accessing grants schemes such as HUGS and AlintaCARE are primarily on fixed incomes. In the twelve months to June 2010, people depending on government payments as their primary source of income accounted for approximately 85 per cent of all HUGS recipients and 97 per cent of all approved AlintaCARE applications.[567]

580. In addition to HUGS and AlintaCARE a number of state concessions exist to assist concession card holders experiencing difficulty in paying their energy bills. However, WACOSS advised the Committee that at present there is no cohesive policy framework to formulate or administer state concessions and rebates. The concessions are administered by several different government departments with the responsibility for accessing concessions and proving entitlement being the sole responsibility of the consumer. WACOSS argues that the monetary value of rebates is insufficient to ensure an affordable supply of gas and that the '…current inadequate and dispersed administration of state concessions means that many people who are eligible to receive rebates and concessions do not currently receive them'.[568]

581. The Committee notes that the Office of Energy, in partnership with WACOSS, intends to conduct a Tariff and Concession Framework Review in 2011. Among other issues, the review will look at the way retailers charge for electricity and assess whether there are other more equitable alternatives and will also consider the most fair and efficient way to assist those who genuinely cannot afford to pay for the power they need. One of the options for a change in tariff structure that the review will assess is an Inclining Block Tariff (IBT).

582. IBT pricing means that the price increases as consumption increases. In Western Australia currently, water usage is charged under an IBT structure,[569] electricity usage is charged using a two-part flat rate tariff and gas usage is subject to a declining block tariff structure. Under the two-part flat rate and declining block tariff structures the average cost per unit to the customer declines as consumption increases. There are many ways to structure an IBT system, including charging a below cost-reflective price to those who consume below the average household consumption rate. IBTs are used all over the world, including in Australia where the regulated tariff for electricity in South Australia is an IBT and many other states offer it as an option to customers.[570] WACOSS supports the implementation of an IBT structure for retail gas tariffs in Western Australia, stating that it would provide an essential level of gas to all households at an affordable price.[571]

583. Further investigation of the use of IBTs in Western Australia is warranted. However, the Committee notes that an IBT structure could be unfair to certain sectors of the community, particularly households with large numbers of people where basic consumption of energy is

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[567] Ms Irina Cattalini, Director, Social Policy, Western Australian Council of Social Service, *Transcript of Evidence* (Supplementary Material), 24 November 2010, p. 9.

[568] ibid., p. 10.

[569] Office of Energy, 'Tariff and Concession Framework Review - Frequently Asked Questions' (n.d.). Available at: www.energy.wa.gov.au/3/3625/64/frequently_asked_questions.pm#Question 7. Accessed on 29 January 2011.

[570] ibid.

[571] Ms Irina Cattalini, Director, Social Policy, Western Australian Council of Social Service, *Transcript of Evidence* (Supplementary Material), 24 November 2010, p. 13.

inherently higher. Therefore any proposed implementation of IBTs in the retail energy market in Western Australia should also include facilities and mechanisms to account for these groups.

584. IBTs encourage customers to be more conscious of their consumption. It is possible that consumer appliance and lifestyle choices that were made when energy prices were low may now be resulting in some households experiencing financial difficulty as these prices rise. In October 2009 the Australian Bureau of Statistics conducted a survey of Household Choices Related to Water and Energy in Western Australia. Interestingly, when householders were asked about the factors that influenced their choice when purchasing household appliances, the most commonly considered factor was energy ratings, at 61 per cent of those surveyed.[572] However, the report notes that:

> *In the last few years, a lot of work has been done to improve the energy efficiency of new white goods. While improvements continue to be made, the increased efficiencies are offset by increased ownership of a variety of high energy using electrical appliances. It is anticipated that energy consumption by household appliances is likely to grow rapidly due to increased availability of plasma and LCD televisions, standby-ready for use electronics, DVD players, entertainment systems, computers and associated products, dishwashers and clothes dryers (DEWHA 2008)*[573]

585. Additionally, the Office of Energy states that:

> *Tariff structures are weighted towards variable changes that result in the average consumer facing marginal costs that do not accurately reflect actual levels of gas consumption. Consumers therefore do not face adequate price signals related to their actual consumption.*[574]

586. Essentially, this means that while energy prices were low consumers were relatively unaffected by their choices to purchase more high energy use electrical appliances. Unfortunately this is no longer the case. Even without an IBT pricing structure, the Committee believes that individuals and households need to focus on reducing their consumption. The move towards cost-reflective tariffs in both gas and electricity now means that prices will remain significantly higher than historical prices. Additionally, future state and federal climate change policies will require both residential and non-residential customers to reduce their consumption and will also likely see a carbon tax passed through from producers and retailers, leading to further tariff increases.

587. The Committee commends the Office of Energy and WACOSS for undertaking the Tariff and Concession Framework Review, but notes that the review intends to focus only on electricity. As both electricity and gas tariffs are being raised incrementally to cost-reflectivity, and evidence suggests that there are an increasing number of households struggling with energy costs, the Committee would like to see the review extended to gas tariffs and concessions.

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572 Australian Bureau of Statistics, *4656.5 - Household Choices Related to Water and Energy, WA*, October 2009, p. 19. Available at www.abs.gov.au. Accessed on 29 January 2011.

573 ibid., p. 15.

574 Office of Energy, *Gas Tariffs Review, A Review of Retail Gas Tariff Arrangements under the Energy Coordination (Gas Tariffs) Regulations 2000, Draft Recommendations Report*, Perth, December 2010, p. 25.

Recommendation 17

That the Office of Energy extends the planned Tariff and Concession Framework Review to cover the retail gas market.

(a) Other Considerations for Government

588. As noted in 539 above, the small business and household sector represents just 4 per cent of the state's domestic demand for gas. Based on current annual consumption, this equates to around 14 PJ per year or 40 terajoules per day.

589. This figure is small in percentage terms, but nonetheless represents a large portion of Western Australian's reliant on affordable gas. The residential sector alone has over 600,000 householders connected to mains gas.

590. It is important to mitigate the financial burden being faced by householders as a result of the recent sharp increases in wholesale gas prices. In addition to the initiatives discussed above in Section 7.3, the Committee is of the view that other options need to be considered to assist retail consumers of gas.

591. The following idea was not explored in detail throughout the Inquiry, nor was it promoted during the evidence gathering process. The Committee can not confidently assess what the flow-on effect of this idea would be, but thinks that it should nonetheless be subject to further investigation:

(i) Government act as aggregator for household and small business sector

592. The Committee has discounted the merit of the government acting as an aggregator in the wholesale gas market (see 305 above), particularly in the event that a Short Term Trading Market can be developed. However, given the small proportions consumed by householders and small business, there could be merit in government entering into the wholesale market to procure gas for this cohort. Having purchased the gas, the government would on-sell to the retailer who would maintain responsibility for deliveries and account management, with any benefits from the transaction passed onto the consumer.

CHAPTER 8 UNCONVENTIONAL GAS

…the opportunity that we have in Western Australia is onshore gas, particularly unconventional gas….It has changed the world supply picture[575]

8.1 Background

593. Unconventional gas deposits are trapped in highly impermeable formations and can not be recovered using the standard drilling methods applicable to conventional gas reservoirs. The three main classes of unconventional gas are commonly referred to as coal seam gas (CSG), tight gas and shale gas.

594. As noted in paragraph 211 above, CSG is attached to the natural fractures of coal seams and surrounding rock. By contrast, tight gas is usually found in impermeable and non-porous sandstone and limestone, while shale gas commonly occurs in the rock that caps conventional hydrocarbon reservoirs.[576] Producers have traditionally considered these unconventional gas sources too complex and costly to extract. However, with advances in drilling and rock fracturing technologies over the last decade, unconventional gas development has had a considerable effect on the supply/demand balance in several jurisdictions.

595. While the advent of CSG has turned Queensland from a gas-poor to a gas-rich state,[577] the impact of shale gas has been even more profound in the United States. Prior to the development of shale gas, the U.S. was expected to be importing more than 10 billion cubic feet (BCF) of LNG per day from 2015.[578] However, this prospect is no longer likely with shale gas production increasing ten-fold in the last decade and now accounting for 20 per cent of all gas produced in the U.S.[579] The proliferation of shale gas has been a significant contributor to a 75 per cent drop in the U.S. spot gas price from above US$13 per MMBtu in July 2008 to below US$4 per MMBtu in November 2010.

596. Whilst rich in conventional gas resources, the Western Australian domgas market, and indeed the broader economy, could still reap several substantial benefits from the development of unconventional gas:

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575 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 6.

576 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, pp. 1-2.

577 Briefing with Mr Paul Connolly, Director Gas Policy, Department of Employment, Economic Development and Innovation (DEEDI), 31 August 2010.

578 Mr Aubrey McLendon, Chief Executive Officer, Chesapeake Energy, 'The Shale Gas Revolution: What Does it Really Mean for the Global Industry?', World Shale Gas Conference, Grapevine, Texas, 3 November 2010. This figure equates to approximately 10.8 PJ per day or 3,950 PJ per year

579 Dr Abdul Rahim Hashim, President, International Gas Union, 'Shale Gas - A True Energy "Game Changer"?', World Shale Gas Conference, Grapevine, Texas, 3 November 2010.

- **Diversity of supply:** Much of the state's unconventional gas reserves are located in the Perth and Canning basins (see Figure 27 below). Developments from these areas could break down the level of concentration in the upstream market and enhance gas on gas competition among producers. Improving upstream competition is a key means of achieving a more efficient market and lower domgas price outcomes.

- **Security of supply:** At present, local buyers are almost exclusively reliant on gas coming from the Carnarvon Basin. In the event of any disruption in this area, Canning Basin gas could conceivably maintain mining operations in the Pilbara and Goldfields, whilst the Perth Basin would offer a vital alternative to consumers in the state's South West.

- **Lower transmission costs:** Unconventional gas deposits in the Perth Basin may provide an opportunity to obtain lower transmission costs. The Committee understands that the Parmelia Pipeline, which starts at the northern end of the Perth Basin, offers cheaper shipment charges than the much longer Dampier to Bunbury Natural Gas Pipeline.

- **Increased royalty revenue:** All royalties collected from onshore petroleum projects are retained by the state. Onshore unconventional gas production could present a new and sizeable revenue stream that would flow through to the broader local economy.

597. Mr Richard Sellers, Director General of DMP, made the valid observation that '…the more discoveries there are the better operation of a natural market there will be.'[580] In light of this benefit and those listed above, it is important to consider the potential for unconventional gas in Western Australia.

8.2 Unconventional Gas Techniques

598. The process for extracting CSG, tight gas and shale gas differs from conventional gas production in several ways. The most notable difference is the use of horizontal drilling techniques.

599. CSG is released by lowering the pressure in the coal seams and surrounding rock. The process involves drilling a well through the coal to remove the water trapped within the seams, which then enables the gas to flow. Drilling can be conducted vertically or horizontally and fracturing of the seam is rarely required.[581] A notable feature about coal seam gas is that is usually found at much shallower depths than other forms of gas (see Figure 28).

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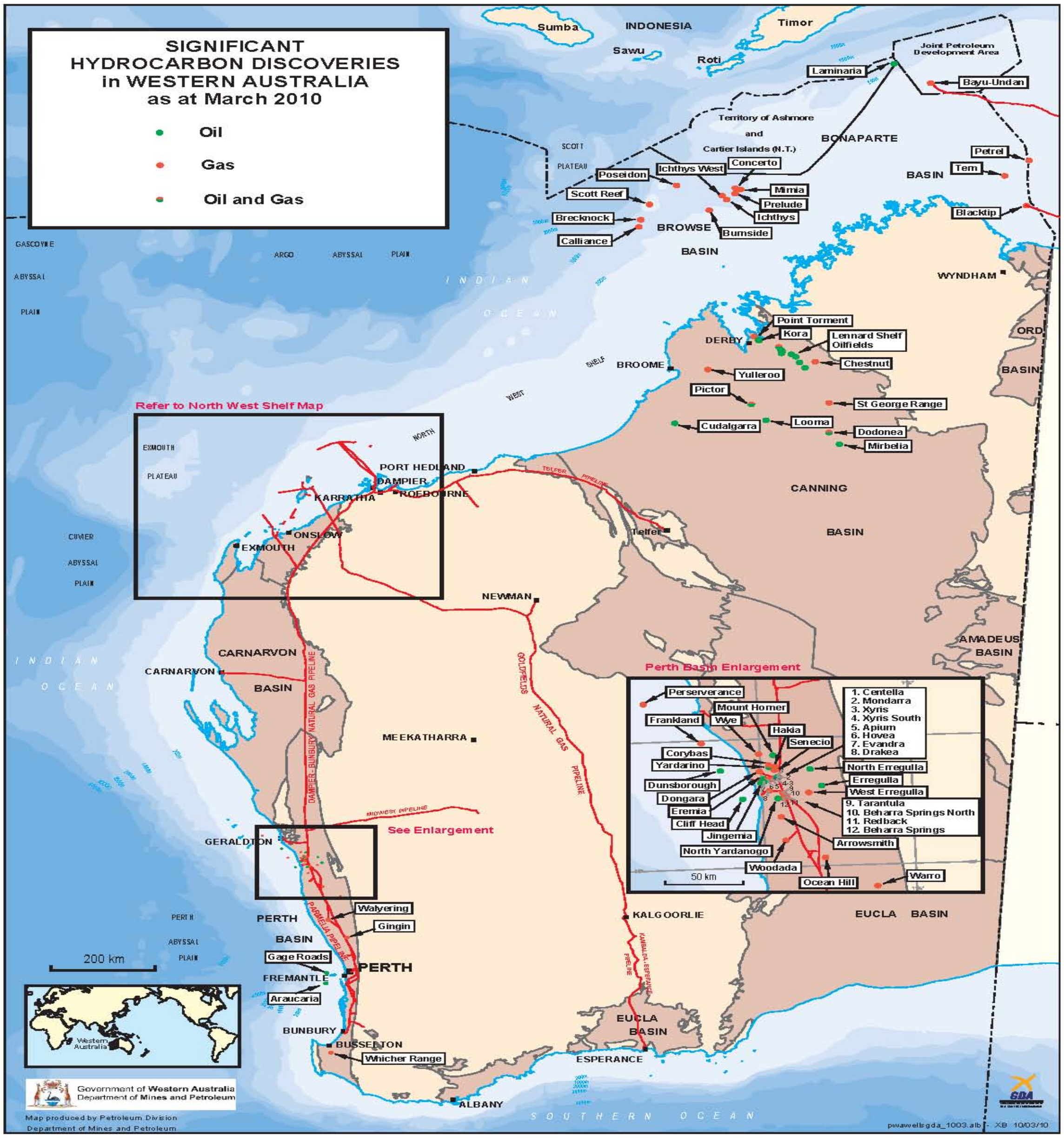
[580] Mr Richard Sellers, Director General, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September, 2010, p. 2.

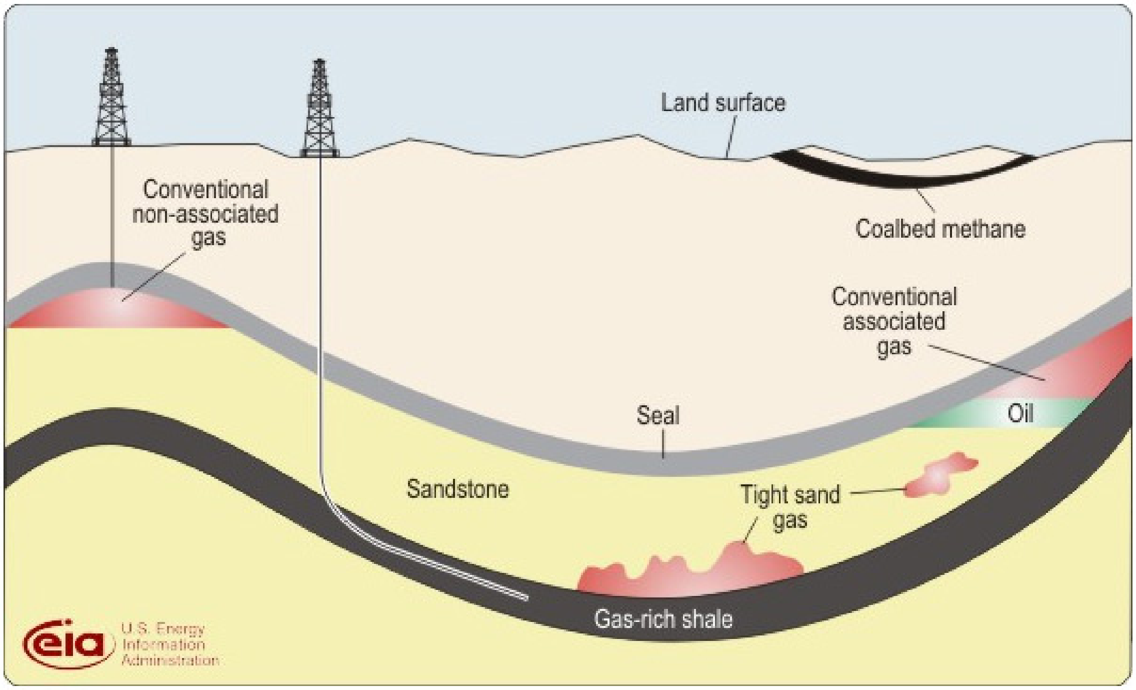
[581] Origin, 'Coal Seam Gas (CSG) - Production', n.d. Available at: www.originenergy.com.au/1144/Production. Accessed on 10 February 2011; Briefing with QGC, 30 August 2010.

Figure 27 Hydrocarbon Basins (Onshore and Offshore), Western Australia[582]



[582] Department of Mines and Petroleum, 'Maps and Downloads', (n.d.). Available at: www.dmp.wa.gov.au/5590.aspx. Accessed on 9 February 2011.

Figure 28 Schematic Geology of Natural Gas Resources[583]



600. In comparison, tight and shale gas deposits are usually found at significantly greater depths and are less permeable. A process called hydraulic fracturing (or "fraccing") has been developed to stimulate the release of these reserves. After drilling down vertically to locate the tight or shale deposit, the drill is turned horizontal and run along for distances up to 3,000 metres. Fraccing then involves pumping fluids down the wells to crack the rocks open and access the gas. Over 99 per cent of fraccing fluid is a mixture of water and sand (or man-made ceramics), the granules of which are used to maintain cracks in the rock formations.[584] It is the development of commercially viable horizontal drilling techniques and enormously powerful portable fraccing units that has made tight and shale gas production possible.[585]

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583 U.S. Energy Information Administration, 'What is shale gas and why is it important', 16 December 2010. Available at: www.eia.doe.gov/energy_in_brief/about_shale_gas.cfm. Accessed on 10 February 2011.

584 See, Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, pp. 1-2; BP, *Unlocking Tight Gas*, August 2007. Available at: www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/frontiers/STAGING/local_assets/pdf/bpf19_08-13_tightgas.pdf. Accessed on 11 February 2011.

585 Briefing with Mr Paul Balfe, Executive Director, ACIL Tasman, 31 August 2010.

8.3 How Prospective is Unconventional Gas in Western Australia?

601. On the strength of the evidence received, arguably the least prospective of the unconventional resources for Western Australia is coal seam gas. According to Professor Brian Evans, Head of the Department of Petroleum Engineering at Curtin University, the coal seams in Western Australia present a much deeper drilling target than those found in Queensland.[586]

602. Conversely, Professor Evans was quite effusive in his assessment of the potential for tight gas. His views were supported by DMP's William Tinapple. Mr Tinapple argued that the current reserve estimates for tight gas in the Perth Basin, which range between 9,700 and 12,900 PJ,[587] are the most reliable figures available for unconventional gas in Western Australia. These reserves are adjacent to the Dampier to Bunbury and Parmelia pipelines and hold enough gas '…to supply our domestic market at the current rate for 20 or 30 years.'[588] Wood Mackenzie has also lauded the potential of tight gas in the Perth Basin, noting that it is '…close to market and could be less capital intensive than offshore projects'.[589]

603. Two of the tight gas plays currently being considered are the Whicher Range field south of Busselton and the Warro field, just over 100 kilometres north of Perth. Whicher Range has almost 4,900 PJ reserves and its location would allow its gas to be fed into the bottom of the Dampier to Bunbury Pipeline. However, these reserves remain unproven and are located at depths (over 4,000 metres) that exceed any drilling currently being undertaken in the state.[590]

604. Developments in the Warro Field appear to be more advanced. Alcoa has formed a joint venture with Latent Petroleum in an attempt to establish its own domgas supply source. The Warro Field is estimated to hold up to 5,400 PJ of gas and the joint venture has secured a licence to build a 150 terajoule per day pipeline linking Warro with the Parmelia Pipeline. Latent Petroleum's Managing Director, Mr Stephen Keenihan, has been quoted as saying that, '…if we pushed the button next year [2011], we would anticipate getting first gas out in late 2012 or early 2013.'[591]

605. Of increasing significance are the prospects for shale gas. Professor Evans' research has led him to conclude that there are five stacked layers of shale in the Perth Basin that could collectively be four times larger than the Barnett Shale that spreads throughout vast areas of Forth Worth, Dallas,

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586 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, p. 1.

587 Cited as 9 to 12 trillion cubic feet (TCF).

588 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 6.

589 Wood Mackenzie, 'The cost of supplying Western Australia's domestic gas market', *Upstream Insight - Asia Pacific*, December 2010, p. 6.

590 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, pp. 2, 5, 9-10.

591 Phaceas, J., 'New gas stream a possible game changer', *WA Business News*, 15 April 2010, p. 7.

Texas.[592] The Barnett Shale has been the epicentre of shale gas production in the U.S. and is estimated to contain 168 TCF or more than 180,000 PJ of gas, around 25 per cent of which is currently considered recoverable.[593]

606. Professor Evans advised that while a typical shale play might be around 2 kilometres deep, one has been located north of Perth that is only 400 metres below the surface.[594] DMP confirmed that, '…there could be huge amounts of shale gas available.'[595] The department added that some early estimates done by private consultants suggest that one company alone may have 400 TCF (430,000 PJ) of shale reserves with a potential recovery rate of up to 20 per cent.

607. Shale gas is appealing for producers as it has a very low CO_2 content and is processed relatively easily.[596] AWE Ltd is one of the prominent shale gas explorers currently operating in Western Australia. The company's recent drilling program at its Woodada Deep-1 well in the north Perth Basin confirmed 4 TCF (4,300 PJ) of potentially recoverable reserves.[597] Due to the earlier production of conventional oil and gas, there is existing infrastructure on site and the company has access to the Parmelia Pipeline.[598] AWE Ltd's Managing Director, Mr Bruce Wood, told the Committee that while there is '…enough incentive to go forward', it could be 2 to 3 years before AWE would be '…confident of being able to produce quantities of gas commercially.'[599] Like Professor Evans,[600] Bruce Wood confirmed that one of the major challenges facing shale gas development is geological risk. Acknowledging the idiosyncratic nature of shale plays around the world, Mr Wood cautioned, '…whether or not we can get that gas out is the big question.'[601]

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592 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, p. 2.

593 Mr Jeff Wright, Director - Office of Energy Projects, Federal Energy Regulatory Commission, 'Natural Gas Infrastructure Siting and Shale Gas: A Federal Perspective', World Shale Gas Conference, Grapevine, Texas, 3 November 2010; Richard G. Smead, Director, Navigant Consulting, 'Shale Gas - Global Potential and Lessons from the United States', World Shale Gas Conference, Grapevine, Texas, 3 November 2010.

594 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, p. 5.

595 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 7.

596 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, p. 2; Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 8

597 AWE Limited, *AWE announces 13-20 TcF Gas in Place in its Perth Basin Shale Gas acreage*, ASX Announcement, 9 November 2010, p. 2.

598 Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 2, (Supplementary Material, p. 10).

599 Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, pp. 1, 6.

600 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, p. 2.

601 Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 2.

608. After years of remaining relatively under-explored, the Canning Basin in the state's north (see Figure 27 above) has now attracted speculative interest. Buru Energy has conducted drilling at its Yulleroo field, which suggests tight and shale gas is evident in the company's permit areas. The prospectivity of these deposits is such that Mitsubishi has committed $150 million of funding through to the project via a farm-in agreement. Alcoa has also contributed $40 million as part of an option arrangement to secure a portion of any gas that might be developed.[602] In addition to Buru Energy's activities, companies such as New Standard Energy also hold permits and are currently considering shale exploration in this area.[603]

8.4 How Viable is Unconventional Gas in Western Australia?

609. Whilst the reserves potential of unconventional gas is cause for optimism, the Committee sought to determine what the prevailing domgas price would need to be to make production of these resources commercially viable.

610. What is clear is that the techniques used to extract tight and shale gas in particular are high cost relative to traditional onshore developments. ERM Power has recently acquired exploration acreage in the Perth Basin with unconventional gas potential. ERM's Chief Executive Officer, Mr Kelvin Askew, told the Committee that tight gas in Western Australia could be a resource of the future, '…but it takes very deep pockets to get the technology right.'[604]

611. Professor Brian Evans attempted to quantify this point. He advised that if a rig that can drill and fracture could be found, it could cost up to $30 million to drill a typical 2 kilometre deep shale play. Even then, multiple wells would need to be drilled to confirm the viability of the site.[605] Significantly, AWE Ltd's Bruce Wood confirmed that it may take between $75 and $150 million before AWE could produce commercial quantities of gas from its Woodada well.[606]

612. The cost of acquiring the appropriate technology has caused some industry experts to question the current viability of unconventional gas in Western Australia. Mr John Boardman acknowledged the resource potential of shale gas, but argued that production costs would not be any lower than what is expected for the Pluto, Gorgon or Wheatstone projects. Mr Boardman concluded that '…shale gas is sort of good for getting share prices up for the juniors at the moment, but it has got a long way to go.'[607]

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602 Mr Eric Streitberg, Director, Buru Energy, *Transcript of Evidence*, 15 November 2010, pp. 2-3.

603 Phaceas, J., 'New gas stream a possible game changer', *WA Business News*, 15 April 2010, p. 7.

604 Briefing with Mr Kelvin Askew, Chief Executive Officer, ERM Power, 30 August 2010.

605 Professor Brian Evans, Head of Department of Petroleum Engineering, Curtin University, *Transcript of Evidence*, 25 October 2010, pp. 5, 7.

606 Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 6.

607 Mr John Boardman, Independent Consultant, *Transcript of Evidence*, 15 October 2010, p. 12.

613. The Committee asked several explorers what sort of underlying domgas price would be required to maintain their development interests. Even allowing for the construction of the required pipeline from the Canning Basin to Port Hedland that could cost as much as $500 million, Buru Energy argued that '…things will certainly work at $7 to $8 [per GJ].'[608] The permit areas held by Buru Energy have a high liquids content. This would enable the company to '…cross-subsidise the gas with oil production.'[609]

614. In the Perth Basin, AWE Ltd's reserves are 'certainly very dry'[610] by comparison. Even so, Bruce Wood posited that, '…the shale industry should be profitable in that $6 to $9 range….supplied into the market.'[611]

615. The Department of Mines and Petroleum has not conducted its own feasibility study into unconventional gas. However, based on the work of consultants, DMP suggested that $6 to $7 per GJ, '…is the price it would take to encourage unconventional gas.'[612] ACIL Tasman's Paul Balfe offered a slightly higher estimate. He suggested that while developments were currently marginal, if the technology costs came down and domgas prices stayed around $7 to $8 per GJ, shale gas could contribute significantly to the local market.[613]

616. The Committee acknowledges that it is difficult to determine a definitive price range at which unconventional gas becomes a viable option in the Western Australian market. However, based on the evidence it has received, the Committee supports the view expressed in the DMP submission:

> *In Western Australia, the development of unconventional gas is initially expected to be more expensive than historical conventional gas prices but about the same as new contract conventional gas*[614]

617. As the Queensland and U.S. experiences show, the initial high costs associated with new technology can be overcome. This can lead to the rapid development of alternative supply sources, which have a substantial impact on the supply/demand balance and the level of local gas prices.

618. Whilst start-up costs are prohibitive for smaller companies, these projects, once proven, quickly attract the interest of major petroleum companies with the necessary technology and capital to

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608 Mr Eric Streitberg, Director, Buru Energy, *Transcript of Evidence*, 15 November 2010, p. 6.

609 ibid.

610 Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 5.

611 ibid.

612 Mr William Tinapple, Executive Director, Department of Mines and Petroleum, *Transcript of Evidence*, 8 September 2010, p. 8.

613 Briefing with Mr Paul Balfe, Executive Director, ACIL Tasman, 31 August 2010.

614 Submission No. 18 from Department of Mines and Petroleum, 2 July 2010, p. 9.

bring the gas to market.[615] For Western Australia, unconventional gas could present an important opportunity to ensure that domestic market competition is enhanced while encouraging further development of the state as an international gas hub.

619. The appropriate role for government is to make sure it is aware of the challenges and potential pitfalls facing the development of unconventional gas and to act, where appropriate, to encourage the responsible development of the industry.

8.5 Challenges Facing Local Unconventional Gas Development

620. In addition to the geological risks already noted in paragraph 607 above, the biggest challenges confronting aspiring unconventional gas producers in this state appear to be technological and environmental.

(a) Technological Deficiencies

621. Currently, there is a dearth of appropriate equipment for the exploration and development of unconventional gas in Western Australia. DMP confirmed that the state has one rig capable of drilling below 2,500 metres and no fraccing units. Most of the fraccing units in Australia are presently being used on CSG projects in the eastern states. Buru Energy has been advised that it faces a minimum 12-month wait before it can access one of these units.[616]

622. Interestingly, Alcoa estimated that there are currently more than 1,600 rigs suitable for drilling and fraccing in the U.S. with over 650 lying idle.[617] DMP confirmed that it is currently working with local companies to source some drilling and fraccing equipment either from overseas or interstate. The Committee acknowledges the efforts of DMP in this respect. It is important to prove these reserves as soon as possible in order to encourage the expansion of the industry. As AWE Ltd noted, if an established resource can be proved, '…the rigs and the frac spreads will come, the people will come, and it is quite organisable.'[618]

623. Arguably, a more important focus for government is the regulatory regime that oversees the importation of this type of equipment into the state. Alcoa argued that, '…there are significant regulatory hurdles with respect to standards, making it even more costly and difficult for these rigs to enter Australia.'[619] The regulatory process in Western Australia is reported to be especially

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615 BHP Billiton has just spent $4.75 billion acquiring Chesapeake Energy Corporation's interests in the Fayetteville Shale, in Arkansas, USA. BHP Billiton advised that, 'Longer term, the expertise we gain here will be usable elsewhere as we continue to grow our business.' AAP (with Reuters), 'BHP buys US shale field for $US4.75b', Sydney Morning Herald (Online), 22 February 2011.

616 Mr Eric Streitberg, Director, Buru Energy, *Transcript of Evidence*, 15 November 2010, p. 7.

617 Submission No. 24 from Alcoa of Australia, July 2010, p. 27.

618 Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 3.

619 Submission No. 24 from Alcoa of Australia, July 2010, p. 27.

onerous. A submission to the Productivity Commission highlights that for one particular piece of drilling equipment it will cost more than $1 million to meet local and national compliance standards.[620] Buru Energy agreed that the process for having larger drilling rigs delivered in this state was '…extremely difficult and costly'.[621]

624. Given the potential benefits that may accrue from unconventional gas development, it would be a pro-active move by government to review its regulatory regime to see where the compliance process for drill rigs and fraccing units can be improved without compromising safety standards.

(b) Environmental Compliance

625. After its introduction on to the U.S. market, shale gas has been described as a potential 'game changer' for international energy supplies.[622] As Western Australia is seemingly well-endowed with this resource, two members of the Committee travelled to Texas to meet with industry stakeholders and to examine the operation of rigs across the Barnett Shale play.

626. The clear message that was conveyed to the Committee was that while tight and shale gas had fundamentally altered the supply and demand balance in the U.S., the hydraulic fracturing process has generated environmental issues that the industry is still coming to grips with.

627. The primary concerns around fraccing pertained to its impact on groundwater supplies and the management of wastewater.[623] Professor Peter Hartley from Rice University in Houston has explained that shales require 11 to 23 million litres of water per well. While the majority of this fraccing fluid returns through the well bore, '…preventable problems can arise during disposal [and]….casing failures can also lead to contamination of near surface layers.'[624] While more than 99 per cent of fraccing fluid is made up of sand and water, it is the chemical composition of the residual mixture that is causing consternation, particularly where shale gas production occurs in highly urbanised areas—as is the case throughout much of Dallas and Fort Worth.

628. At the World Shale Gas Conference in Fort Worth in November 2010, the composition of fraccing fluid was the source of lively debate. Several producers conceded that the industry needed to

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620 AWE Western Region, *Submission to Productivity Commission Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, n.d, p. 3. Available at: www.pc.gov.au/__data/assets/pdf_file/0005/83444/sub017part2.pdf. Accessed on 18 March 2011.

621 Mr Eric Streitberg, Director, Buru Energy, *Transcript of Evidence*, 15 November 2010, p. 7

622 Cross, A., 'Natural gas from shale rock promises energy revolution', *BBC Online*, 8 September 2010. Available at: www.bbc.co.uk/news/science-environment-11175386. Accessed on 10 February 2011.

623 Richard G. Smead, Director, Navigant Consulting, 'Shale Gas - Global Potential and Lessons from the United States', World Shale Gas Conference, Grapevine, Texas, 3 November 2010; Dr Abdul Rahim Hashim, President, International Gas Union, 'Shale Gas - A True Energy "Game Changer"?', World Shale Gas Conference, Grapevine, Texas, 3 November 2010.

624 Conversion based on US gallons to litres. Professor Peter Hartley, 'Potential world-wide effects of shale gas', Presentation at University of Western Australia, Perth, WA, 2010, pp. 6-7.

improve its level of transparency in this area to calm public concerns, now emerging in the U.S. and internationally, over the environmental impact of hydraulic fracturing.[625] During the conference the Committee obtained a list of the components of fraccing fluid (see Table 10 below).

625 Mr Jack Williams, President, XTO Energy, ‘Shale Gas - The Industry’s Road Ahead’, World Shale Gas Conference, Grapevine, Texas, 3 November 2010; Mr Melvyn Giles, Global Theme Leader for Unconventional Gas, Shell Exploration and Production, ‘Global Challenges of Unconventional Plays’, World Shale Gas Conference, Grapevine, Texas, 3 November 2010.

Table 10 - Components of Hydraulic Fracturing Fluid[626]

Component	% of Total	Purpose	Common Use
Water and Sand	99.5%		
Acids	0.123%	Help dissolve minerals	Swimming pool cleaner
Glutaraldehyde	0.001%	Eliminates bacteria in water	Disinfectant
Sodium chloride	0.01%	Allows a delayed breakdown of the gel polymer chains	Table salt
Formamide	0.002%	Prevents corrosion	Pharmaceuticals
Borate salts	0.007%	Maintain fluid viscosity	Laundry Detergent
Petroleum distillates	0.088%	Minimise friction	Laxatives, Candy
Cuar gum	0.056%	Thicken the water	Toothpaste
Citric acid	0.004%	Prevents precipitation	Food additive
Potassium chloride	0.06%	Creates a brine carrier fluid	Table salt substitute
Potassium carbonate	0.011%	Maintain effectiveness of other components	Detergents, soap
Ethylene glycol	0.043%	Prevents scale deposits in the pipe	Automotive anti-freeze, household cleaners
Isopropanol	0.085%	Increases the viscosity of the fracture fluid	Glass cleaner, anti-perspirant

629. Concerns over water treatment have led to a moratorium on shale gas development in New York State along the Marcellus Shale while an environmental impact assessment is conducted.[627]

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626 Dr Abdul Rahim Hashim, President, International Gas Union, 'Shale Gas - A True Energy "Game Changer"?', World Shale Gas Conference, Grapevine, Texas, 3 November 2010.

627 Mr Robert E. Curry, Commissioner, New York State Public Service Commission, 'Working with Industry to Unleash the Power of Shale Gas', World Shale Gas Conference, Grapevine, Texas, 4 November 2010.

630. In Fort Worth, there have been a variety of other complaints that appear understandable given the proximity of the drill sites to residential areas (see Figure 29). Topics for complaint include air emissions; noise; lights; truck traffic; set backs from homes; landscaping and fire code issues.[628]

Figure 29 Shale Gas Drill Site - Fort Worth, Texas[629]

631. Many of the issues affecting the local residents of Fort Worth are not likely to be as problematic in Western Australia. The majority of local tight and shale gas reserves are found in sparsely populated areas with extensive landholdings throughout the Perth and Canning Basins. AWE Ltd has been working in its section of the Perth Basin for over 20 years and claimed it had 'good relationships' with the landholders.[630]

632. That said, AWE's Bruce Wood did acknowledge the issues surrounding water, both in terms of the volumes used and the impact on local aquifers. Mr Wood was nonetheless of the view that the Perth Basin had a number of "saving graces":

> *I think our depths help us….Our depths—we are now looking at going to 2,500 and 3,000 metres. That is well below anywhere that people are using those aquifers commercially….Perth Basin is one of the few shale gas opportunities in the world where access to seawater is possible. Seawater has never been used as a fraccing fluid but it*

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628 Council Member Joel Burns, District 9, City of Fort Worth, Texas 'City of Fort Worth Perspective', World Shale Gas Conference, Grapevine, Texas, 4 November 2010.

629 ibid.

630 Mr Bruce Wood, Managing Director, AWE Limited, *Transcript of Evidence*, 22 November 2010, p. 4.

> *might be technically possible to even source our seawater for use and hence reduce our water usage on local aquifers. I think it is an issue that requires close management*[631]

633. The Committee is of the view that aquifer impacts and water disposal practices are among the biggest hurdles facing unconventional gas development in Western Australia. Whilst this issue has not yet stymied development of coal seam gas in Queensland, it is something that the government there has had to 'manage really carefully.'[632] In this respect, the Queensland Department of Environment, Economic Development and Innovation (DEEDI) has implemented a monitoring regime to continually assess the environmental impact of coal seam gas production. Through this process, DEEDI retains the capacity to scale back any developments that are having an adverse effect on the water table and surrounding environment.[633]

634. A similar provision appears to exist in Western Australia, where DMP's Environment Division has the ability to conduct periodic Environment Management Plan compliance audits and reviews prior to and after a production licence is granted.[634] To ensure responsible development, and to allay public concerns regarding environmental consequences, this review mechanism will need to be applied rigorously as local unconventional gas projects move towards the production stage.

8.6 Other Considerations for Government

635. The Committee feels it is worth noting several other factors that are likely to encourage the development of unconventional gas in Western Australia.

636. The current growth in unconventional gas exploration underpins the importance of maintaining a flexible approach to the domestic gas Reservation Policy. As argued in 316 above, a rigid and literal application of this policy risks discouraging prospective producers from developing alternative sources of supply on economic grounds.

637. While the current reservation regime has not deterred unconventional gas explorers, they remain critical of the policy and wary of its impact should it result in gas flooding the market.[635] Given these concerns, and in light of the significant costs involved in exploration and development, the Committee supports the government's 2010 decision to reduce the royalty rate from 10 per cent to

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631 Mr Bruce Wood, Managing Director, AWE Limited, *Transcript of Evidence*, 22 November 2010, p. 6.

632 Briefing with Mr Dan Hunt, Associate Director General, Mines and Energy, Department of Environment, Economic Development and Innovation (DEEDI), 31 August 2010.

633 ibid.

634 Department of Mines and Petroleum, *Petroleum Production Licence Approval Process Overview* (State), 26 August 2010. Available at: www.dmp.wa.gov.au/documents/PR-PLT-OV-013_(WEB)STATE.pdf. Accessed on 12 February 2011.

635 Mr Eric Streitberg, Director, Buru Energy, *Transcript of Evidence*, 15 November 2010, pp. 4-5; Mr Bruce Wood, Managing Director, AWE Ltd, *Transcript of Evidence*, 22 November 2010, p. 5; Mr David Archibald, *Transcript of Evidence*, 15 September 2010, p. 7.

5 per cent on 'tight gas' projects. The definition applied to tight gas in this amendment to the *Petroleum and Geothermal Energy Resources Act 1967*[636] should satisfy the criteria for most shale gas plays as well.[637]

638. With royalty relief measures in place, and a flexible approach to reservation obligations on LNG projects (such as that articulated in Section 4.2(c) above), the Committee is confident that unconventional gas projects can develop in Western Australia. Indeed, should unconventional gas proliferate here as it has in the U.S., there may be the option in future of reducing the volumes of gas acquired under reservation.

639. Finally, it is vital that improvements be made to the approvals process facing prospective producers in Western Australia. The approvals process has been the subject of ongoing criticism from explorers and producers. In 2009, an Industry Working Group report to the Minister for Mines and Petroleum noted that a series of reports had made recommendations over the last decade about making substantial improvements to the approvals process. The 2009 report found that, '…the acceptance and implementation of the recommendations from all reports has been dismal.'[638]

640. DMP conceded that approvals processes '…have become complex and unclear', but argue that the department is undertaking a wide range of initiatives to counter this problem.[639] The Committee was not able to thoroughly investigate this issue within the timeframe of this Inquiry. However, it did receive feedback from unconventional and conventional gas explorers and developers still critical of the regulatory, environmental and native title approvals processes.[640]

641. Any refinements to the approvals process must also ensure that issues pertaining to the compliance of emerging technologies are addressed promptly. This will increase competitive pressure in the domgas market via new sources of supply and maintain the state's reputation as an internationally attractive destination for petroleum investment (see 306 above).

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636 Defined as 'petroleum in a gaseous state occurring in subsurface rock with a permeability of 0.1 millidarcy or less.' Petroleum and Geothermal Energy Resources Act (1967), Western Australia, s52(3).

637 Alberta Geological Survey, 'Shale Gas', 26 October 2010. Available at: www.ags.gov.ab.ca/energy/shale-gas/shale-gas.html. Accessed on 9 February 2011.

638 Industry Working Group, *Review of Approvals Process in Western Australia*, April 2009, Department of Mines and Petroleum, Perth, WA, p. i.

639 Dr Tim Griffin, Deputy Director General, Approvals, Department of Mines and Petroleum, 'Improving Western Australia's Petroleum Approvals Process', Presentation to Petroleum and Geothermal Open Day, September 2010, Fremantle, WA.

640 See, for instance, Mr Eric Streitberg, Director, Buru Energy, *Transcript of Evidence*, 15 November 2010, p. 7; Mr David Archibald, *Transcript of Evidence*, 15 September 2010, p. 7; Submission No. 23 from BHP Billiton Petroleum Pty Ltd, 25 July 2010, pp. 6-8; Submission No. 14 from BP Australia, 2 July 2010, p. 4.

Finding 33

Unconventional gas developments have the potential to significantly improve the level of upstream competition in the domestic gas market.

Finding 34

While tight and shale gas have fundamentally altered the supply and demand balance in the U.S., the production process has generated environmental concerns regarding water use and treatment methods.

Recommendation 18

To encourage the development of unconventional gas, and to ensure it is undertaken in a responsible and environmentally sustainable manner, the Department of Mines and Petroleum should:

- work with all stakeholders to promptly resolve issues in the regulatory, environmental and native title approvals process; and
- ensure that Environment Management Plan compliance audits and reviews are undertaken regularly in order to identify and act upon any practices that demonstrate improper or unsafe water management processes.

APPENDIX ONE

SUBMISSIONS RECEIVED

List of Submissions received for the inquiry.

Date	Name	Position	Organisation
16 May 2010	Mr Otto Mueler		
22 June 2010	Mr Geoff Hobley	Executive General Manager	Alinta Pty Ltd
24 June 2010	Mr Tony Petersen	Chairman	DomGas Alliance
24 June 2010	Dr David Worth	Past-Convenor	Sustainable Transport Coalition of WA Inc
25 June 2010	MrChris Sorensen	Sales Representative	Gorgon Domgas Project
25 June 2010	Dr Aidan Joy	Commercial and Business Development Manager	Apache Energy Limited
25 June 2010	Mr Simon Adams	Senior Legal Counsel	Synergy
25 June 2010	Mr Jason Waters	General Manager, Trading and Fuel	Verve Energy
25 June 2010	Mr Rob Swan	Marketing Manager	Wesfarmers Premier Coal Limited
25 June 2010	Mr Tom Baddeley	Director, Western Australia	Australian Petroleum Production and Exploration Association Limited (APPEA)
25 June 2010	Mr Rod Hayes	Managing Director	Horizon Power
29 June 2010	Ms Anne Hill	A/Coordinator of Energy	Office of Energy
29 June 2010	Mr Reg Howard-Smith	Chief Executive	Chamber of Minerals and Energy of Western Australia (CME)
30 June 2010	Ms Anne Nolan	Director General	Department of State Development

1 July 2010	Mr Lyndon Rowe	Chairman	Economic Regulation Authority (ERA)
2 July 2010	Mr Peter Metcalfe	External Affairs Manager, WA, SA and NT	BP Australia
2 July 2010	Mr Niegel Grazia	Vice President, Corporate Affairs	Woodside
2 July 2010	Ms Renay Sheehan	Senior Government Affairs Adviser, Corporate Affairs, North West Shelf	North West Shelf (NWS) Project Participants
2 July 2010	Mr Richard Sellers	Director General	Department of Mines and Petroleum
12 July 2010	Mr David Archibald		
21 July 2010	Professor Brian Evans and Professor Ronald D. Ripple	Department of Petroleum Engineering / Centre for Research in Energy and Minerals Economics	Curtin University
21 July 2010	Mr Stephen Eliot	Chief Executive Officer	REMCo
23 July 2010	Mr James Ralph	BHP Billiton Group Legal	BHP Billiton Petroleum Pty Ltd
30 July 2010	Dr Mike Shaw	Energy Services Manager	Alcoa of Australia
21 October 2010	Mr Wilson Tuckey		
9 November 2010			WA Gas Networks Pty Ltd
21 December 2010	Professor Peter R. Hartley and Professor Kenneth B. Medlock III	Rice Scholar in Energy Studies / Deputy Director, Energy Forum	James A. Baker III Institute for Public Policy, Rice University, Houston, Texas, US

APPENDIX TWO

HEARINGS

Date	Name	Position	Organisation
8 September 2010	Mr Richard Sellers	Director-General	Department of Mines and Petroleum
	Mr William Tinapple	Executive Director	Department of Mines and Petroleum
	Mr Derek Perez	Principal Policy Officer	Department of Mines and Petroleum
	Mr Richard Borozdin	General Manager, Policyand Coordination	Department of Mines and Petroleum
13 September 2010	Ms Anne Nolan	Director General	Department of State Development
	Ms Nicola Cusworth	Deputy Director General	Department of State Development
	Ms Jenness Gardner	Manager, Strategic Policy	Department of State Development
	Mr Lyndon Rowe	Chairman	Economic Regulation Authority
	Mr Gregory Watkinson	Chief Executive Officer	Economic Regulatory Authority
	Mr Stephen Eliot	Chief Executive Officer	Retail Energy Market Company (REMCo)
15 September 2010	Mr David Archibald		
	Mr Tony Petersen	Chairman	DomGas Alliance
	Mr Gvain Goh	Executive Director	DomGas Alliance
20 September 2010	Mr Tomas Baddeley	Director (WA)	APPEA Ltd
	Mr Damian Dwyer	Director, Energy Markets and Climate Change	APPEA Ltd
	Mr Steven Gerhardy	Consultant	APPEA Ltd

	Dr Aidan Joy	Commercial and Business Development Manager	Apache Energy Ltd
	Mr Graham Weaver	Gas Marketing Manager	Apache Energy Ltd
	Mr David Parker	Government and Public Affairs Manager	Apache Energy Ltd
11 October 2010	Mr John Boardman	Independent Consultant	
	Mr William Moody	General Manager, Marketing and Development	Wesfarmers Premier Coal
	Mr Robert Swan	Marketing Manager	Wesfarmers Premier Coal
	Ms Anne Hill	Acting Coordinator of Energy	Office of Energy
	Mr Peter Kiossev	Acting Director, Strategic Energy Initiative	Office of Energy
	Mr Matthew Martin	Senior Manager, Energy Supply and Security	Office of Energy
13 October 2010	IN-CAMERA HEARING		
	Mr Frank Tudor	General Manager, Strategy and Business Development	Horizon Power
18 October 2010	Mr Kevin Gallagher	Chief Executive Officer, North West Shelf	Woodside Energy Ltd
	Mr William (Ben) Coetzer	General Manager	North West Shelf Gas Pty Ltd
	Mr David McDonald	General Manager	BP Developments Australia
	Mr Peter Metcalfe	External Affairs Manager	BP Australia
	Mr Damian Callachor	Director	Chamber of Minerals and Energy

	Ms Michelle Chiasson	Project Officer, Infrastructure	Chamber of Minerals and Energy
20 October 2010	Mr Jason Waters	General Manager, Trading and Fuel	Verve Energy
	Mr Frank Tanner	Manager, Fuel	Verve Energy
	Mr James Mitchell	Managing Director	Synergy
	Mr Allan McDougall	Manager	Synergy
	Mr Simon Adams	Acting Head of Wholesale	Synergy
25 October 2010	Professor Brian Evans	Head of Department of Petroleum Engineering	Curtin University of Technology
	Mr Allan Dawson	Chief Executive Officer	Independent Market Operator WA
	Mr Niegel Grazia	Vice President, Corporate Affairs	Woodside Energy Ltd
	Mr Stewart Gallagher	Pluto Commercial (Foundation) Manager	Woodside Energy Ltd
	Mr Steven Lewis	General Manager (WA)	APA Group
	Ms Suzy Tasnady	Regulatory Manager	APA Group
	Mr Brett Langley	General Manager, Gas Marketing	BHP Billiton
	Mr James Ralph	Solicitor	BHP Billiton
10 November 2010	Mr Justin Scotchbrook	Senior Manager, Commercial and Business Development	WA Gas Networks Pty Ltd
	Mrs Deborah Evans	Manager, Regulatory Affairs and Risk	WA Gas Networks Pty Ltd
	Mr Chris Sorensen	Marking Manager	Gorgon Domgas Marketing
15 November 2010	Mr Stuart Johnston	Chief Executive Officer	Dampier to Bunbury Natural Gas Pipeline

	Mr Mark Cooper	General Manager, Commercial	Dampier to Bunbury Natural Gas Pipeline
	Mr Anthony Cribb	Company Secretary	Dampier to Bunbury Natural Gas Pipeline
	Mr Eric Streitberg	Executive Director	Buru Energy
17 November 2010	Mr Basil Lenzo	Solicitor/General Council	Burrup Fertilisers Pty Ltd
	Mr Tim McAuliffe	General Manager, Climate Strategy	Alcoa of Australia
	Mr Michael Parker	Director, Business Development and Marketing	Alcoa of Australia
	Dr Michael Shaw	Energy Services Manager	Alcoa of Australia
22 November 2010	Mr Gary Watson	Manager, Infrastructure and Government Relations	Perdaman Chemicals and Fertilisers
	Mr Bruce Wood	Managing Director	AWE Ltd
	Mr William Townsend	General Manager, External Affairs	Inpex
	Mr Richard Wilson	Government Affairs Adviser	Inpex
	Mr Michael Chin	Senior Legal Counsel	Inpex
24 November 2010	Ms Irina Cattalini	Director, Social Policy	Western Australian Council of Social Service (WACOSS)
	Mr Ian McKenzie	Vice President, Sunrise	Shell Development (Australia) Pty Ltd
	Mr Douglas Buckley	Vice President, Commercial	Shell Development (Australia) Pty Ltd
29 November 2010	IN-CAMERA HEARING		
	Mr John Nicolaou	Chief Officer	Chamber of Commerce and Industry Western Australia

	Mr Noel Richards	Policy Adviser	Chamber of Commerce and Industry Western Australia

APPENDIX THREE

BRIEFINGS HELD

Date	Name	Position	Organisation
17 May 2010	Mr Anthony Petersen	Chairman	DomGas Alliance
	Mr Gavin Goh	Executive Officer	DomGas Alliance
	Ms Anne Hill	Acting Coordinator of Energy	Office of Energy
	Mr Gary Jeffery		On behalf of Australian Petroleum Production & Exploration Association Ltd (APPEA)
	Mr Lyndon Rowe	Chairman	Economic Regulation Authority
	Mr Russell Dumas		Economic Regulation Authority
	Mr Greg Watkinson		Economic Regulation Authority
	Mr Peter Kolf		Economic Regulation Authority
19 May 2010	Ms Nicky Cusworth	Deputy Director General, Strategic Policy	Department of State Development
	Mr Gavin Agacy	Senior Policy Officer	Department of State Development
	Paul Farnhill	Principal Policy Officer	Department of State Development
21 June 2010	IN CAMERA BRIEFING		
	IN CAMERA BRIEFING		
30 August 2010	Mr David Maxwell	Senior Vice President	Queensland Gas Company (QGC)
	Mr Matthew Squire	General Manager, Economics and Planning	Queensland Gas Company (QGC)

	Mr Tom Clarke	Commercial Manager	Queensland Gas Company (QGC)
	Mr Allan Ford	Risk and Analytics Manager	Arrow Energy
	Ms Leisa Elder	Vice President, Community and Corporate Affairs	Arrow Energy
	Mr Clint Adams	Chief Commercial Officer Upstream	Arrow Energy
	Mr Kelvin Askew	Chief Executive Officer	ERM Gas Pty Ltd
	Mr Trevor St. Baker	Chairman	ERM Power
	Mr Peter Constantini	Chief Executive Officer, SAS	Representing ERM Power
31 August 2010	Mr Ian Fletcher	Director General	Department of Employment, Economic Development and Innovation (DEEDI)
	Mr Dan Hunt	Associated Director General, Mines and Energy	Department of Employment, Economic Development and Innovation (DEEDI)
	Mr Paul Connolly	Director, Gas Policy	Department of Employment, Economic Development and Innovation (DEEDI)
	Mr Paul Balfe	Executive Director	ACIL Tasman
1 September 2010	Mr Rob Wheals	General Manager, Commercial	APA Group
	Mr Peter Bolding	General Manager, Regulatory and Strategy	APA Group
	Mr Brad Evans	Commercial Manager, NSW	APA Group
	Mr Steve Lewis	General Manager WA and Head of Commercial Energy and Resources	APA Group

	Mr John Short	General Manager Government Relations, Australia and New Zealand	Origin Energy
	Mr Tim O'Grady	Head of Policy Unit	Origin Energy
	Mr Cameron O'Reilly	Executive Director	Energy Retailers Association of Australia (ERAA)
	Mr John Pierce	Chairman	Australian Energy Market Commission (AEMC)
	Ms Ann Pearson	Senior Director	Australian Energy Market Commission (AEMC)
	Ms Catriona Webster	Senior Lawyer	Australian Energy Market Commission (AEMC)
2 September 2010	Mr Tom Leuner	General Manager, Markets Branch	Australian Energy Regulator (AER)
	Mr Chris Pattas	General Manager, Network Regulation South	Australian Energy Regulator (AER)
	Mr Jeremy Llewellyn		Australian Energy Regulator (AER)
	Mr Terry Grimwade	Executive General Manager, Market Performance	Australian Energy Market Operator (AEMO)
	Mr John Savage	Senior Manager, Gas Wholesale Market Development	Australian Energy Market Operator (AEMO)
	Mr Peter Clements	Director of Energy Programs, Energy and Earth Resources Policy Division	Department of Primary Industries (Vic)
	Mr Jeff Cefai	Acting Director, Energy Division	Essential Services Commission
	Mr Brad Page	Chief Executive Officer	Energy Supply Association of Australia (esaa)
	Mr Kieran Donoghue	Policy Development Manager	Energy Supply Association of Australia (esaa)
	Mr Duncan Loydell	Policy Adviser	Energy Supply Association of Australia (esaa)

3 September 2010	Mr Don Vigilante	Market Development Manager (Gas)	TRUenergy
	Mr David Markham	Head of Government Affairs	TRUenergy
23 November 2010	IN CAMERA BRIEFING		
29 November 2010	IN CAMERA BRIEFING		
1 November 2010	Mr John A. Crum	Co-Chief Operating Officer - President, North America	Apache Corporation
	Ms Janine J. McArdle	Vice President, Global Oil, Gas and LNG Marketing	Apache Corporation
	Mr Urban F. O'Brien, III	Vice President, Government & Regulatory Affairs / Corporate Outreach	Apache Corporation
	Mr Robert J. Dye	Vice President, Corporate Services	Apache Corporation
	Professor Kenneth B. Med	James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics	James A. Baker III Institute for Public Policy, Rice University
	Professor Peter R. Hartley	George and Cynthia Mitchell Professor of Economics and Deputy Director, Energy Forum	James A. Baker III Institute for Public Policy, Rice University

APPENDIX FOUR

LEGISLATION

Legislation	**State (or Country)**
Barrow Island Act 2003	Western Australia
Gas Supply (Gas Quality Specifications) Act 2009	Western Australia
National Gas Access (WA) Act 2009	Western Australia
North West Gas Development (Woodside) Agreement Act 1979	Western Australia
Petroleum and Geothermal Energy Resources Act 1967	Western Australia

APPENDIX FIVE

CONVERSION FACTORS[641]

Energy

1 kJ (Kilojoule)	= 10^3 Joules (1,000 Joules)
1 MJ (Megajoule)	= 10^6 Joules (1,000,000 Joules)
1 GJ (Gigajoule)	= 10^9 Joules (1,000,000,000 Joules)
1 TJ (Terajoule)	= 10^{12} Joules
1 PJ (Petajoule)	= 10^{15} Joules
1 EJ (Exajoule)	= 10^{18} Joules
1 Therm	= 100,000 Btu (British Thermal Units)
1 Btu	= 1,055.06 Joules (or 1.05506 kJ)
1 kWh (Kilowatt hour)	= 3.6 MJ
100 MW Gas Turbine 35% efficiency	= 24.7 TJ/d or 9.0 PJ/a
1 Tcf (Trillion ft^3) of WA natural gas	= 28.317 Bcm (Billion m^3) of WA natural gas
1 Tcf (Trillion ft^3) of WA natural gas	= 1.082 EJ
1 Tcf (Trillion ft^3) of WA natural gas	= 176.8 billion barrels of oil equivalent

Energy Content of Fuels

Coal	19.7 GJ/tonne (t)
Condensate	32.0 GJ/Litre (L)
Crude Oil	37.0 MJ/L
LNG	25.0 MJ/L
Natural Gas	38.2 MJ/m^3
LPG (Butane)	28.7 MJ/L
LPG (Propane)	25.4 MJ/L
Petrol	33.7 MJ/L
Distillate	38.4 MJ/L

Volume Equivalents

1 m^3 (Cubic metre)	= 35.315 ft^3 (Cubic feet)
1 kL (Kilolitre)	= 6.28980 Barrels

641 Submission No. 13 from Economic Regulation Authority, 1 July 2010, p. 36.