NATURAL GAS

"MAGIC PUDDING" OR DEPLETING RESOURCE

A dissertation on the state of Australian natural gas

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August 2007

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CONTENTS

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Revision of a 2002 version, July 2007

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SUMMARY

The call for the Commonwealth government to prepare a National Energy Strategy made in 2002 by John Akehurst, then CEO of Woodside Energy, and Barry Jones, then Executive Officer of the Australian Petroleum Producers and Exploration Association, has now become even more urgent. Supporting action by State governments is needed.

World

❖ *Transporting natural gas costs 6-10 times the equivalent for oil*. Profiles of production and consumption tend to be regional and continental. These tend to be truncated compared to oil and decline begins late in the production cycle. Liquid natural gas (LNG) is the most expensive transport mode.

❖ Production decline once it starts tends to be steeper for gas than for oil.

❖ Major uses are for domestic and commercial heating, electric power generation, petrochemicals and industry. Seasonal gas consumption is more variable than for oil.

❖ *Natural gas production has begun its decline in Europe—starting with the United Kingdom, and in North America. Decline may begin in Russia next decade.*

North West Shelf Joint Venture

❖ Over 90 percent of Australia's natural gas reserves are offshore between Carnarvon and Darwin. Over half the undeveloped reserves are in deep water and will be expensive to develop. Sixty percent of Australia's reserves are in the Carnarvon Basin.

❖ *Their local development reflects the global pattern: three regional zones—eastern and central Australia, western and southwestern Australia and the Northern Territory.*

❖ Carnarvon Basin natural gas development began in 1980 with two 20-year contracts by the North West Shelf Joint Venture with ALCOA and the State Energy Commission. The latter constructed the Dampier Bunbury Natural Gas Pipeline. Development of LNG capacity *for export* followed in 1989 and the 5th LNG train will take capacity to 16.7 M.tonnes per year in 2010. The Harriet Joint Venture (HJV) supplies the domestic market from small gas fields as well. *The domestic* gas *price level was customer driven.*

❖ Thus began the vision of the "Magic Pudding"—industrial development based mainly on petrochemical plants. *The metaphor is* with *Norman Lindsay's 'Magic Pudding' story where there was always some left over no matter how much of it was eaten.*

❖ A boom in LNG development has begun for exports to Europe and North America, to supply China and India, and because it is a more "greenhouse" and environmentally friendly fuel than coal and oil. *A near doubling of capacity is possible*. The boom is facing acute resource and skilled labour shortages, and escalating costs.

❖ The global LNG boom has boosted the sale price of LNG such that the domestic gas sale price must rise from \$2.00-2.50/GJ to \$5.50-6.00/GJ to match the profit the NWSJV makes from its sale as LNG. Uncertainty on development costs and LNG markets is limiting domestic contracts to five years. *It is now a sellers market.*

❖ The NWSJV *domestic market capacity* is near its plants limits with no plans to expand, LNG has priority. 15 percent of the new Pluto field's gas *may be committed* to the

domestic market *after 2015* under the WA Governments policy of 15 percent for this market. Other existing fields are excluded under terms in State Agreement Acts.

❖ A company cannot meet its full contract obligations to supply gas via the HJV to a new ammonia/fertliser plant due to a gas field failing to perform as expected. The problem has not yet been resolved. The final solution will be at a higher price for gas.

❖ The domestic gas market is in crisis due to a supply ceiling—projects are being postponed, truncated or turning to coal. Some existing long-term domestic gas contracts will soon terminate. Renewal is uncertain and will be at higher prices. Major users have formed the Domestic Gas Alliance, Domgas.

❖ The NWSJV's *existing* gas fields will reach 80 percent depletion between 2020 and 2025. Without incorporating major new discoveries its LNG and domestic gas supply will decline rapidly. The 5th LNG train is being built anticipating new discoveries. The NWSJV is searching for new gas fields. It has gas fields in its sights held by the Gorgon JV.

Chamber of Commerce and Industry WA (CCI)

❖ The CCI has published a Discussion Paper, *Meeting the Future Gas Needs of Western Australia,* on responding to the gas supply crisis in WA. The Paper is a good comprehensive overview in defining the issues, their complex and evolving interactive nature, and the inherent conflicts of interest.

❖ The Paper fails to recognise the role and importance of natural gas production decline in North America and Europe, the emerging decline of world oil production, Climate Change as a fossil fuel issue. There is a need to question the short-term viability of Chinese economic development on pollution and resource limits criteria.

❖ The CCI supports the development of a government Energy Strategy that embraces ALL energy sources. Such a Strategy needs to embrace the wider global issues outlined above in a dynamic evolving framework. The process must include the participation of the wider community.

❖ The main role of remaining fossil fuels should be to facilitate the transition to a less fossil fuel dependent civilisation with reduced greenhouse gas emissions.

Energy Return on Energy Invested (EROEI)

❖ EROEI is a measure of economic performance from an energy perspective. *It is calculated by dividing the energy output by the sum of* <u>*direct*</u> *and* <u>*indirect*</u> *energy inputs embodied in the goods and services used.*

❖ A University of Sydney study found that the EROEI for Burrup LNG was about 10 in 1994-*95,* a year when there was *low input for gas field development and capital works*. During periods of major capital works EROEI would be a lot lower. *There is an inverse relation between energy input and labour. Energy is a substitute for labour.*

❖ The energy input per dollar (MJ/$) was also calculated in the UofS study for a range of minerals and other fuels in Australia for 1994-95.

The Gorgon project

❖ The Gorgon JV is planning its LNG development on Barrow Island based on the largest natural gas resource in Australia (1,500 Bcm), half in deep water offshore. The 1st stage is for 10 M.tonnes/year (~15 Bcm/year) on the Gorgon fields in shallow water where the gas has ~14 percent CO_2. They propose its removal and injection into geological formations for permanent disposal to mitigate these potential greenhouse gas emissions.

❖Since 2003 cost estimates have blown out from $11 billion to a reputed $23 billion. The CO_2 content in the other gas fields has not been published. The CO_2 sequestering will make the EROEI for LNG lower than for the NWSJV at Burrup due to the higher energy inputs involved, as yet unknown. *Is this partly responsible for the escalating costs?*

❖ Future development of the deepwater fields will also have a lower EROEI because of a higher energy input, doubly so if sequestering of CO_2 is necessary as well.

❖ *Does the Gorgon JV Agreement with Government cover gas for domestic sales?*

The Browse & Bonaparte Basins

❖ There are two separate proposals for 10 and 6 M.tonnes of LNG per year based on gas from the Browse Basin off the Kimberley coast, mostly in deep water and 330 km from the coast (total ~23 Bcm/year). There CO_2 content has not been published. Again the EROEI will most likely be lower than for the NWSJV's project.

❖ Opposition to two onshore LNG plants is leading to proposals for a combined site.

❖ A 6 M.tonnes/year LNG Plant was commissioned in Darwin in 2006 drawing gas from the Bayan Udan gas field in the Bonaparte Basin.

Eastern Australian Gas
Coal seam gas (CSM)

❖ *Production in the Cooper/Eromanga Basins that have supplied gas to Brisbane, Sydney and Adelaide since 1980 is in rapid decline.* Pipelines from the Gippsland/Otway basins to Adelaide and Sydney have been built to augment gas supply.

❖ *The Gippsland Basin should reach 80 per cent depletion of commercial reserves by 2015, if sub-commercial reserves are included, about 2020*. Scope for additional discovery in the Gippsland Basin appears to be limited. So far performance in the Otway Basin has been disappointing.

❖ *Rapid development of CSM is underway in Queensland. Less so in NSW and Victoria.* The potential resource base in Queensland and NSW is large, but not yet fully understood. The cost is higher than existing supply but rather less than gas piped from Papua New Guinea and major western natural gas fields.

❖ Methane can be extracted from coal seams by drilling wells and extracting water to release the gas. More wells are needed than for conventional gas. These are shallower and can have a higher production rate, but often have a shorter life.

❖ ***A major problem*** *is both the impact of this water extraction on aquifers and the subsequent environmental problems of its disposal. These are major issues in southern Australia's drying climate.*

❖ CSG in Central and Southern Queensland is being used to fuel gas turbines for electric power and for domestic gas consumption.

❖ The Sydney coal basin in NSW is regarded as a major potential source near its major market, but so far development is limited. **A major problem will be water management for gas extraction in a major urban environment**.

❖ The Owen Inquiry in NSW on future options for electric power has received submissions from Santos and Origin Energy for gas-fired power stations fueled by CSG. The submissions lack specific proposals.

❖ Santos has just announced a proposal to build an LNG Plant at Gladstone in Queensland with gas supplied from CSG in the Bowen Basin. **Santos says one of its**

motivations is to introduce international gas prices to the domestic gas market, as has happened in Western Australia.

❖ The *onshore* Otway Basin in Victoria is the focus of licensing applications for CSG. South Australia is less advanced than Victoria. Western Australia is evaluating the Sue coal formation at Vasse inland from Busselton.

ECONOMIC CONSEQUENCES

❖ Natural gas projects dominate investment in resource development in WA, followed by iron ore projects to supply the Chinese market. The direct labour force employed in construction is 3-10 times the permanent numbers required for operation foreshadowing a huge employment problem when the boom subsides.

❖ The deepwater and remote gas fields are becoming commercially viable as LNG projects *because* of production decline in North America and Europe with a likely reduced EROEI—a decline in net energy yield.

❖ The massive investment in both mineral and natural gas projects in WA is significantly increasing the energy investment and further reducing the contemporary EROEI for these LNG projects. What impact does this have on the Energy Multiplers (MJ/$) for the minerals industry? To what extent is this responsible for construction cost escalations? *Energy spent on these capital investments is energy not available for use elsewhere.*

❖ *Engineers and trades people are in the front line applying fossil fuels to this work. How much is this shortage due to the deteriorating energy quality of fossil fuels and how much to other factors?*

❖ *Are these factors partly responsible for our acute housing shortage and affordability crisis, as well as shortages of schools, teachers, hospitals, doctors and nurses?*

❖ *What are the consequences in the lifetime of our children for our urban and economic structures built around unsustainable exploitation of our finite high-grade mineral and petroleum resource bases?* Projects that develop and use these resources have life times of 20-30 years and more.

❖ *Do current methods of cost-benefit analysis need radical revision?* Discounted cash flows imply that new resource projects can fully replace exhausted ones.

Managing risk

❖ Business and other sectors routinely make assessments of risk as a central component of their culture, ranging from best to worst-case scenarios. These are often kept confidential. Government agencies are less inclined to do so.

❖ The WA Dept of Industry and Resources' publications quote probabilities for oil and gas reserve estimates, but express an eagerness for resource development with little regard for constraints, consequences and risks on how to adapt to the inevitable depletion of high quality mineral ores and petroleum.

❖ Natural gas resources as a vital primary energy source are an essential component where the evolution of the EROEI is a central issue that is neglected.

❖ Governments must engage with communities to develop long-term strategies that address the inevitable decline of high quality mineral and fossil fuel resources. There is no "Magic Pudding".

Uranium Mining

❖ The energy cost of mining and milling uranium varies inversely with ore grade and the *primary fuels used are usually petroleum products*. Currently over half the uranium feedstock is from Canadian ores of exceptionally high grade, dismantled nuclear weapons, and stocks accumulated from the 1980s—all due for depletion in the near future.

❖ A near doubling of uranium supply from mines with *much lower grade ores* will replace these stocks over the next 10 years. The reserves of good grade uranium are limited. The outcome will be a decline in the EROEI of nuclear power.

❖ If uranium mining begins in Western Australia it will be in remote locations and natural gas is likely to be a key fuel. Declines in the EROEI of petroleum fuels will be reflected in a decline in EROEI of nuclear power *over the whole nuclear power cycle*. The nuclear power lobby does not allow for this in its evaluation of the economics of nuclear power.

Related issues

❖ The population of Middle East countries has increased fivefold since 1950 and are heavily dependent on food imports. They have about one third of the world's oil and gas reserves. The youthful population is creating chronic employment and social problems tending to destabilise an already unstable region.

❖ Modern agriculture is *'a way of using land to convert petroleum into food'*. Most of the world's population depends on such food. The major petroleum input is often via energy-intensive nitrogen fertilisers where natural gas is the main fossil fuel input.

❖ The world is confronting the consequences of a warming climate arising from CO_2 emissions from burning of fossil fuels. *About half of the carbon content of these fuels burnt each year is contained in oil and natural gas.* Their production decline will be a major driver in reducing CO_2 emissions. The Intergovernmental Panel on Climate Change scenarios does not take these factors into account. Only the IPCC's lower emission projections for these fuels are relevant.

❖**These and other factors not discussed here need to be included in national and international strategies to address the decline of oil and natural gas production.**

BACKGROUND

In 2002 John Akehurst, CEO of Woodside Petroleum, and Barry Jones, Executive Director of the Australian Petroleum Producers and Exploration Association (APPEA) made statements on Australia's expected rapid decline in oil self-sufficiency. These were given in the context of the approaching decline of world oil production. Their emphasis was on the balance of payments and supply risks associated with dependence on Middle East imports and transport fuels as being most at risk.

Both advocated that Australia shift to natural gas-based transport fuels, and that transport demand management and public transport infrastructure provision should have a high priority. Australian petrol and diesel consumption is equivalent to our present natural gas production while the visions for natural gas development make little provision for a transport role. Industry and governments promote visions of vast quantities of cheap natural gas that should be rapidly developed and sold off.

A "Magic Pudding" mentality prevails, reminiscent of Norman Lindsay's famous story where no matter how much of the "pudding" was eaten there was always more left to eat.

These visions ignore the finite nature of the resource, its strategic importance in the transition to a world 'beyond petroleum', the significance of the energy cost of extracting the gas and the implications of over 90 per cent of our natural gas being located offshore from the north west coast, much of it in deep water.

But do we have vast reserves of natural gas as we are led to believe? What are the consequences of government and industries gas project "wish lists" coming to fruition? Conflicts between gas for export and local consumption are growing.

This paper updates one I wrote in 2002. Significant changes have occurred locally and globally since then. We are closer to the decline of global oil supply, also of natural gas as production declines in North America and Europe. China has become a major driver of world consumption growth in petroleum fuels and for key minerals—the latter particularly impacts on Australia and Western Australia. High exchange rates for the Australian dollar have made export-based petrochemical plants uneconomic, the vision of five years ago. But it has been replaced by visions of major liquid natural gas (LNG) exports.

The need for a long-term national strategy for natural gas has become urgent and more widely recognised.

This paper outlines the serious oil shortages Australia faces and the limits for natural gas based fuels to substitute for petrol and diesel in the context of an approaching world decline in oil production. Ageing giant oil fields supply half the world's crude oil from less than one per cent of all fields.

The petroleum industry is slowly accepting that *cheap oil production* outside the Persian Gulf region is about to decline with the supply focus shifting to the Gulf countries that have 60 percent of the world's oil reserves but supply nearly 30 percent. A supply shortfall is emerging, but the dynamics of an unstable situation are complex *(Laherrére 2006)*. The Gulf countries investment strategies in oil and gas are constrained by the huge problem of feeding rapidly increasing populations of alienated young people heavily dependent on food imports paid for by oil export revenue.

The world production peak will most likely be a ' bumpy plateau' to 2010. We may already be at 'the peak'. The International Energy Agency in its July medium term oil report says demand could begin to outstrip supply around 2010 as diminishing new supply struggles to both meet consumption growth and offset the increasing number of producing countries where production is in decline.

Transport consumes 60 per cent of world oil supply and road transport dominates. *Corporate globalisation* is creating integrated global manufacturing and agricultural networks *totally dependent* on cheap transport. The distance food travels from farm to kitchen is increasing significantly, and of other goods as well. Such trends are not sustainable in the medium term. *There is an assumption of permanent cheap transport.*

The limits of good quality agricultural land were reached in the 1950s. World population has doubled since then and has been fed by a more than doubling of grain production per hectare achieved by increased energy inputs, primarily petroleum products. Hybrid grain species and fertilisers made the Asian 'Green Revolution' possible. Nitrogen fertilisers made primarily from natural gas play a key role. A major ammonia/fertiliser plant for exports to India has been built at Burrup in Western Australia. *Agriculture has* *become a way of using land to convert petroleum products into food. Grain used for biofuels is competing with food supply.*

The net energy yield of cheap oil from the small number of giant oil fields has been extremely high. Net energy is the useable energy left after the energy used for the extraction and conversion processes is subtracted from the gross energy output. Energy must be used to extract energy from nature and to covert it into useful forms. None of the alternatives fuels to oil from giant oil fields can match its economic performance on net energy yield. The developing world cannot achieve the levels of labour productivity achieved by the developed world, nor can the latter sustain its present high levels of labour productivity. It is an issue that embraces both high quality energy availability and population.

Only the lowest estimates for hydrocarbon production and associated carbon dioxide emissions are relevant in the Intergovernmental Panel on Climate Change (IPCC) 40 climate scenarios to 2100. Petroleum resource depletion (oil and natural gas) will set the agenda for reduction of carbon dioxide emissions at the low end of these IPCC emission scenarios.

We face limits to oil consumption. Disrupt freight transport and food shortages develop within weeks. Alternative transport fuels will be expensive and less convenient than the petroleum products we know. They will take time to introduce. Rigorous criteria to assess the transport capabilities of alternative fuels are needed. *Essential freight traffic and agriculture must get priority for remaining petroleum—not all freight traffic can survive. Car dominated urban transport is the least justifiable use for oil.*

AUSTRALIA'S OIL AND CONDENSATE

Australia escaped the worst impacts of the 1970s oil crises as local oil and natural gas production commenced in offshore Gippsland oil fields and global demand for our mineral resources and coal increased. Three giant oil fields in Bass Strait were the main stay of our near self-sufficiency in oil until the mid-1980s when these fields began to decline. Many small offshore fields compensated for a while, principally in the Carnarvon Basin in Western Australia and the Bonaparte Basin in the Timor Sea. However, new discovery and development is not keeping pace with the decline of these small oil fields that are *here today and gone tomorrow*. Australia is better endowed with natural gas and considerable development has taken place since the late 1960s.

Giant oil fields supply nearly half the world's crude oil *(Simmons 2002).*

John Akehurst (2002), then CEO of Woodside Energy, said in a paper to the Australian Bureau of Agricultural and Resource Economics *Outlook 2002 Conference* in March 2002 that Australia had been *consuming oil at three times the rate of discovery since the early 1990s. He said our oil self-sufficiency could decline to 40 percent by 2010. The annual oil import bill could increase to $5.6 billion by 2005 and $7.6 billion by 2010 (at 2002 prices of US$20 a barrel, A$ = US55c).*

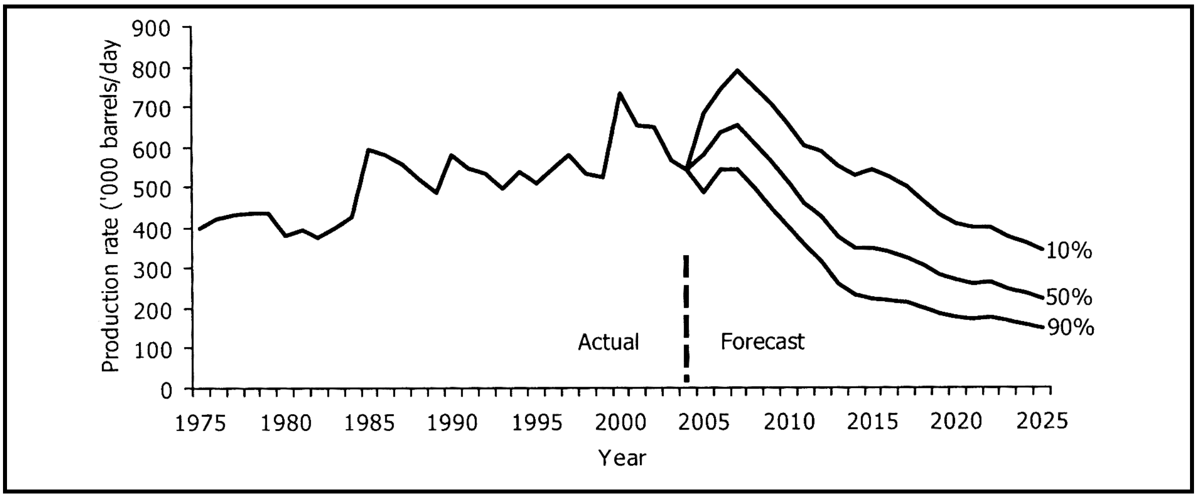
Barry Jones (2001 & 2002), then Executive Director of APPEA, made similar comments to an Australian Institute of Energy conference in Sydney in November 2001 and again in APPEA's Journal *Flowline* in January 2002.

Figure 1 shows actual production to 2004 and Geoscience Australia's forecasts for oil and condensate production to 2025 at 10, 50 and 90 percent probability levels[1].

Australia was almost self-sufficient in oil in 2000 when consumption was 837,000 barrels per day (305 million barrels for the year)[2].

Consumption in 2006 was 886 million barrels a day (323 million barrels) and production 544 million barrels a day (199 million barrels), net imports 125 million barrels. The import bill in 2006 was over A$10 billion (US$66 a barrel, A$=US76c) and is the major component of our trade deficit. The proportion of condensate (liquids stripped from natural gas) in liquid production is expected to increase substantially by 2010 *(GSA 2004. p.63).* Crude oil production decline will be steep.

FIGURE 1
Australian oil and condensate production
Actual 1975-2004, Forecast 2002-2025



Geoscience Australia: Oil and Gas Resources of Australia 2004, p.63

Akehurst and Jones' comments on Australia's oil supply position are outlined below:

- The three giant fields in Gippsland have been in decline since 1986. They have been partly replaced *so far* by many small fields that are here today and gone tomorrow.
- This has been happening in the context of an emerging global oil peak.
- Imports come from the unstable Persian Gulf countries. The risk of supply interruption is high.
- Transport and agriculture were the services at greatest risk from supply disruption.
- Government revenues from royalties and resources rent tax would be adversely affected by more than $1 billion (at 2002 oil prices). [~A$8 billion in 2006]
- Offshore investment has been increasing but the number of wells drilled is static.
- Offshore exploration is becoming more expensive with higher risk, discoveries are smaller, exploration for oil and gas is moving into deeper waters and frontier areas.
- Australia has declining prospectivity with fields still to be discovered of small size and technically demanding, e.g. heavy oil and in deep water offshore.
- Tax concessions for petroleum exploration and development are needed for Australia to be internationally competitive, e.g. accelerated depreciation and royalty concessions in the early years of projects, especially for deep water offshore.

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[1] The 50 percent probability is closest to the most likely outcome.

[2] One barrel of oil equals 159.9 litres.

- *Australia needs to shift to natural gas-based and other alternative fuels for transport.*
- *Demand management initiatives are needed to reduce oil consumption, particularly for transport.*
- *Priority should be given to public transport infrastructure.*
- *Jones said oil supply vulnerability was a far more important issue than the present focus of governments on electric power industry reform.*
- *The Commonwealth needs to prepare a National Energy Strategy on these issues.*

Sustaining the present level of oil self-sufficiency depends on bringing into production every year new oil fields in total much larger than the 200 million barrel Laminaria field in the Timor Sea. Laminaria was discovered in 1994 and commissioned in 1999. Over 70 percent of the oil has been extracted and decline commenced in 2001. It was the largest discovery in Australia for many years and has not met initial hopes.

Australia's geological history has favoured generation of natural gas rather than oil.

These issues have intensified since 2002. The price of oil has more than doubled and the trade deficit in oil is now A$7-8 billion a year, despite a brief recovery in production.

Australian oils are low in heavy hydrocarbons. An increasing portion of liquid production is condensate obtained from natural gas—expected to be over half by 2010. Australia exports liquids at premium prices and imports cheaper heavier Middle East oil to ensure a sufficient yield of lubricating oils and bitumen at refineries.

AUSTRALIAN NATURAL GAS

These issues raise important questions on future natural gas supply and the range of large gas consuming projects on the agenda.

Natural gas for transport has a low priority. To put that in perspective, the present Australian consumption of petrol, LPG and diesel on an equivalent energy basis is 50 percent higher than current natural gas consumption[3] (ABARE 2006). The electric power industry has visions for a shift away from coal to natural gas driven by Climate Change reasons and for peak load electric power generation.

The natural gas industry and governments in Western Australia, promote the view that Australia has an abundant supply of natural gas. An image is being portrayed of almost unlimited supply, like the magic pudding in Norman Lindsay's famous story of that name. No matter how much pudding was eaten there was always more left to eat.

Natural gas is not as abundant as people think. About 95 per cent of Australia's discovered natural gas is offshore between Carnarvon and Darwin and over half is in the Carnarvon Basin, much of it in water 800-1,500m deep. Australian natural gas reserves and production rates as at 2004 are shown in **Table 1**. The Browse Basin is off the Kimberley coast, the Bonaparte Basin is in the Timor Sea and the Cooper/Eromanga Basins are in Central Australia.

Nearly half of Australia's natural gas production in 1999 came from the Gippsland and Cooper/Eromanga Basins, down to 36 per cent in 2004. There was a slight rise in Gippsland more than offset by a 43 per cent decline in the Cooper/Eromanga Basins. Production in the Carnarvon Basin is increasing rapidly.

[3] A portion of LPG is used for heating and some diesel for regional electric power generation.

TABLE 1
Australian Natural Gas 2004
Reserves, Production and Discovered
Billion cubic metres (Bcm)

Basin	Reserves[4] Mean 2004	Production to 2004	Discovery to 2004	Production 2004	Production 1999	Reserves[5] 2005
Carnarvon	2,346	270	2,616	23.5	18.8	2,283
Browse	733	--	733	--	--	858
Bonaparte	666	3	669	2.8	--	649
Gippsland	178	180	358	9	7.6	89
Otway	49	3	52	0.3	0.24	68
Cooper/ Eromanga	45	151	196	5.5	9.64	54
Others	81	48	129	1.3	1.58	70
Coal Bed Gas[6]	94	5	99	1.2	0.3	N/A
Total	**4,192**	**660**	**4,852**	**43.6**	**38.2**	**4,071**

Geoscience Australia 2004, p.146 and Western Australian Oil & Gas Review 2006, pp.72-75

Production costs in the Cooper/Eromanga Basin are rising rapidly. This Basin supplies Adelaide, Sydney and Brisbane. Cumulative production to 2004 reached 75 percent of discovered-to-date gas. The production decline occurred despite an invigorated drilling program with a slight increase in reserves by 2006—a brief slowing of decline may follow as some of these come into production. It is unlikely significant gas is left to find.

A pipeline was constructed in 2004 from the Gippsland/Otway Basins to supply gas to Adelaide. A pipeline has linked the Victorian gas fields with NSW. Gas consumption in Victoria has a pronounced winter peak to meet space-heating demand. Storage of off-peak Gippsland/Otway production in abandoned fields has been proposed for withdrawal to meet the seasonal peaks.

The Gippsland Basin could reach a similar stage of depletion around 2015 and new discoveries are small. Discoveries in the adjacent Otway Basin have been disappointing. *The status of these basins is discussed further below.*

In the 1990s it was recognised that new gas supply for the eastern seaboard would be needed by 2010. The cost was anticipated to be about $5 billion from the Bonaparte Basin west of Darwin or $7 billion from Papua-New Guinea, requiring around 3,000 and 2,500 km of pipeline respectively. The companies failed to obtain long-term gas supply contracts to justify these two projects. Their estimated cost has increased substantially this decade. Protracted negotiations between Australia and East Timor to define their national boundaries in the Timor Sea also created uncertainty that inhibited investment. A Treaty was finally signed in 2006.

However, coal bed gas (CBG) is relieving the supply problem in the medium term at a slightly higher cost. Incremental expansion is possible near the point of use. Production from CBG seams began in Queensland and NSW in 1996 with half the production to

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4 The sum of reserves that are commercially viable plus those that are sub-commercial.

5 There appear to be some differences in definitions between GSA and WAO&GR.

6 This figure is based on exploration to 2004. It is too early to estimate CBG's future potential.

date occurring in 2003 and 2004. In Queensland a power station has been built at Townsville fuelled by CBG, and more are imminent west of Brisbane. Rapid development of gas from these sources has commenced in Queensland, but more slowly in NSW. Options from lower grade coalfields in Victoria (brown coal) and southwest Western Australia are being explored *(GSA 2004 p.53). This subject is discussed further below.*

Most current natural gas production comes from offshore fields in water depths up to 120m. However, 40 percent of Australian discovered but undeveloped gas reserves are even further offshore and in water 800-1,200 metres deep between Carnarvon and Darwin. These will be expensive to develop. Most of the undiscovered gas is expected to be in deepwater environments. Some has a significant carbon dioxide content with Greenhouse gas implications e.g. Gorgon/Chryasor in the Carnarvon Basin (12-15 per cent CO_2). The gas fields of the North West Shelf Joint Venture contain three percent CO_2, but this can vary. The energy cost of extracting the new gas into useable forms will increase, reducing the net energy yield.

WESTERN AUSTRALIAN DOMESTIC GAS SUPPLY CRISIS

The Bonaparte, Browse and Carnarvon Basins contain 95 percent of Australia's natural gas and condensate reserves. Half is in the Carnarvon Basin. Western Australia produces 60 percent of Australia's oil and condensate and over 65 percent of its natural gas, mostly from the Carnarvon Basin and will play a key role in any shift to natural gas-based transport fuels. The remaining life of the Cooper/Eromanga Basin (in decllne) and the Gippsland Basin are limited. These supply NSW, Queensland, Victoria and South Australia.

How are we to assess these basins undiscovered petroleum potential? What are the economic implications of the massive construction programs envisaged for natural gas projects in the Carnarvon Basin? How important is domestic consumption? Wesfarmers Energy plans a major expansion of its pilot project to supply LNG for freight transport in Western Australia, including expanding into other states. But domestic gas sales have come into acute conflict with LNG developments.

Domestic gas supply crisis in Western Australia

A major supply crisis has arisen for domestic gas consumers this year that challenges the "Magic Pudding" vision. It puts these local consumers on a collision course with production of liquid natural gas (LNG) for export. There is strong growth in gas consumption in Western Australia to fuel new and existing mines, mineral processing and electric power generation projects. An Indian company has built an ammonia/fertiliser plant at Burrup for export to India. The media says it is the world's largest. Commissioning began in 2006 and the company had a contract for gas with the Harriet Joint Venture (HJV) at Varanus Island, offshore from Onslow[7]. The plant was estimated to cost $600 million in 2002 and needs up to 0.85 Bcm of gas a year.

In December 2006 the HJV declared *force majeur* on the gas contract. Drilling in one of the new fields did not reveal the quantities of gas expected—the reserves were apparently less than expected (location not stated). They could not meet their contract

[7] Apache Energy Ltd, Kufpec Australia Ltd and Tap (Harriet) Pty Ltd. The contract was to supply gas for 15 years with an option to extend for 5 years. This would require about 17 bcm over 20 years.

obligations for 2007 or thereafter *(ERA 2007).*

The HJV has been selling gas to the local market since 1992. It directly controls five minor gas fields and produced 1.6 Bcm from these in 2005 (gas reserves were 4.4 Bcm in 2004)[8]. A major new field is John Brookes commissioned in September 2005 that the Western Australian Oil & Gas Review (2006 p. 41) says has reserves of 38 Bcm[9]. It would seem that the failure of this field to deliver the gas expected may be responsible for the force majeur, but this is not clear. Some nearby minor undeveloped gas fields may be a short-term option with higher gas prices.

The *ERA (2007)* report investigating the issue found that the boom in LNG projects (discussed further below) and recent much higher sale prices for LNG means that the competitive price for local gas consumers in competition with LNG exports has risen from $2.00-2.50/GJ to $5.50-6.00/GJ since early 2006[10]. Transport costs would be an additional cost to local buyers. Hitherto the gas suppliers have wanted 20-25 year contracts to guarantee revenue from sales to justify the high investment—most current contracts at the lower price are of this nature and many will soon expire[11]. *The gas suppliers are now only prepared to make five-year contracts and at much higher prices than hitherto*. This is partly due to the rapid rise and volatility in LNG sale prices and the escalating cost of constructing new plant[12] creating uncertainty in future production costs. BHP Billiton's Macedon gas field north of Exmouth may be an option for Varanus Island (reserves 18.5 Bcm), but would take several years to develop.

The NWSJV also supplies a substantial proportion of domestic gas sales. Its two-train processing plant at Burrup is at capacity and Woodside Energy is having difficulty upgrading it. Up to one Bcm of additional capacity might be possible in 2008, but not enough to meet expected short-term growth in demand by industry, public utilities and the Burrup ammonia plant. State Government Agreements with the NWSJV set the terms for current contracts, but not for the new Woodside Energy-owned Pluto field now being developed to supply a fifth LNG train due to start-up in 2010. This is why the Premier, Alan Carpenter, has insisted on an Agreement with Woodside Energy guaranteeing 15 percent of Pluto field reserves to domestic consumption (about 15 Bcm). Apparently the Agreement does not come into effect until five years after start-up of the fifth LNG train, when the NWSJV has agreed to *consider the issue* and whether to commit to a third processing train for domestic gas. If the NWSJV do commit to a third train it is unlikely to come into operation until about 2018 *(ERA 2007).*

As a consequence, tenders for 400 MW of generation capacity will exclude gas as a fuel. Coal is the only option for the Gindalbie iron ore project, Newmont's Boddington gold mine will have coal-fired electricity, tenders by Domgas Alliance members for new gas failed to get competitive offers, and in 2006 Dampier Bunbury Pipeline down sized its pipeline expansion from 300 to 100 TJ/day *(Domgas Alliance 2007).*

We will discuss these issues in more depth below from a national perspective after

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8 Bambra, Endymion, Linda, Rose, Sinbad and Wonnich, plus a small amount from East Spar.

9 John Brookes field is jointly owned by Apache Northwest Pty Ltd and Santos.

10 These include Alinta, Verve, ALCOA, Wesfarmers Energy, BHPBilliton and many other mining companies and mineral processors such as mineral sands and nickel.

11 The Dampier Bunbury Natural Gas Pipeline was constructed in 1981-84 by the State Energy Commission of WA. It had a substantial take-or-pay contract for gas with Woodside Energy and a separate confidential contract with ALCOA for 50 per cent of the pipelines capacity. ALCOA had its own contract for gas with Woodside Energy. By 1993 SECWA had paid $300 million for gas it had not used—gas its successor, Western Power, has since received.

12 These costs are volatile and have increased by around 50 percent since 2004 and the future is unclear.

outlining Wesfarmers Energy's plans for a national LNG supply network to fuel road freight transport in the first instance. It has the potential to significantly expand local consumption of natural gas as a transport fuel.

Chamber of Commerce and Industry Western Australia

The Chamber of Commerce and Industry of Western Australia (CCI) published a discussion paper, *Meeting the Future Gas Needs of Western Australia,* in May (CofC&I 2007)[13]. It was written in response to the Carpenter Government's proposal to reserve in future 15 percent of natural gas reserves for domestic consumption. The proposal arose from the supply crisis discussed above.

The report is comprehensive. It outlines the local industry's history and relevant technical features, the roles of governments and evolution of the gas market in national and international contexts. There is a good outline of the complex relationships and conflicting interests among all the players where every proposal for change has winners and losers in the short and long term that need reconciling. The industry is outgrowing the effectiveness of its historical legislative and administrative framework that does not fully recognise the dynamic complexity. Before commenting on its proposals it is worth mentioning major issues that were not recognised or addressed by the CCI:

- That the global boom in LNG and the consequent increased sale prices for LNG are driven primarily by the emerging decline in natural gas production in North America and Europe. Any reform in Western Australia must be recognise this international framework.
- That there is a concurrent approaching decline in world oil production where every country must develop a long-term strategy to adapt to this decline. Of particular concern is the dependence of transport, mining and agriculture on petroleum products.
- The CCI hardly refers at all to the phenomenon of anthropomorphic induced climate change and the need for energy policy to embrace this issue. *A major WA issue*.
- The current resources boom in WA, of which natural gas is a part, is driven by China's rapid economic development and insatiable demand for minerals. *No one is questioning its sustainability in the short and medium term.* The scale of pollution and loss of agricultural land in China and its consequences for food supply threaten the viability of its development path *in the near term*. There will be significant consequences for Western Australia. These issues will become sharply focused next year at the Beijing Olympics.

These issues must have a central focus in government strategies for the future management and development of the natural gas industry. To its credit the CCI does say a WA government energy strategy must embrace ALL energy sources.

The CCI recognises that the WA gas market does not fit very well into the classical economic framework of competitive markets. The large investments required, the high cost of gas transport and the domination of gas reserves in a few large fields leads to one or two suppliers dominating the market. On the demand side five major utility and industrial users dominate. Furthermore, the market is dynamic—the relationships and economics of supply and demand constantly change as gas fields are developed, mature and decline. Markets and the role of governments must adapt accordingly. The important issue is "to what end"? The complexity is increasing—in part a normal development.

It is wrong to describe this situation as "market failure", as the CCI does. It is more a

[13] The CCI represents 5,000 organisations in WA across all business sectors in all geographical regions. About 80 percent are small businesses. The Findings on pp.141-151 give a good summary of the issues.

failing of economic theory that does not match the real world of this market. Likewise to say that reform requires a ‘competitive’ market outcome is to ignore the over-riding need for all players to also co-operate to get the most ‘efficient’ outcome. It is a complex interactive system. Such outcomes must meet social and environmental needs and constraints as well—the latter is becoming even more essential, as underlined by the rise of Climate Change as a dominant issue.

New approaches to economics are emerging that give weight to these features, and that can cope with *dynamic complex systems with there inherent uncertainty*, giving due weight to the central role that energy and the physical laws of thermodynamics must play in economic theory. Social, environmental and resource depletion issues also integrate into this framework in a more realistic way (Beinhocker 2007).

A government Energy Strategy is urgently needed at national and state levels. The CCI Discussion Paper goes a part of the way by spelling out many of the issues. But the scope needs widening to embrace the issues discussed above. The process needs to embrace active community involvement as well.

Wesfarmers Energy: LNG for land freight transport

Wesfarmers Energy pioneered the use of LNG in Australia earlier this decade to replace diesel for heavy-duty trucks. It established a small LNG plant at Kwinana in Western Australia and a vehicle fueling station for a trucking company at Kewdale. The vehicles can do the round trips to Geraldton and Kalgoorlie on one fuel loading. Other truck companies have since changed to LNG in WA. The use of LNG in trucks is well established in the USA. Wesfarmers is building a new 175 tonne per day LNG plant to meet an expanding market, completion in early 2008. A major portion is committed to two gold mines for power generation and remote power generation. A fueling station will be built in the Pilbara supplied from Kwinana to establish a market, no doubt leading to a small LNG plant at Karratha. The potential market is huge.

Another company has established a small LNG plant at Port Hedland with contracts to supply LNG to regional electric power stations in the Kimberly, replacing diesel as a fuel.

Wesfarmers Energy has established an LNG base in Victoria with the Murray Goulburn Cooperative who use LNG to fuel their trucks that deliver dairy products to markets *(Bull 2007).*

LNG as a truck fuel is cheaper than diesel, in part due to the absence of fuel excise that is levied on diesel. But it has other important advantages over diesel:
- The engines are quieter and there is an absence of black smoke in exhaust fumes.
- More kilometres can be traveled between maintenance stops.
- It is likely that the engines will last longer.

Australia consumed 16,700 ML of diesel in 2005/06, mostly by road and rail transport, on farms, in mining and remote area electric power generation. This is equivalent to about 17 Bcm of natural gas, about 40 percent of current Australian production. *There is a good case for a substantial substitution of LNG for diesel in many applications for security of supply and balance of payment reasons (See Figure 1), given our growing dependence on oil imports from the Middle East. There are environmental advantages as well. Consumption of diesel by the mining industry is increasing rapidly.*

But this should be conditional on using LNG as a transport fuel to buy time to REDUCE our dependence on transport given the imminent global decline of crude oil and natural gas production.

These issues are discussed below focusing on Australian natural gas.

But first we must critique the reliability of these estimates for gas reserves and the prospects for likely future discoveries.

GEOSCIENCE AUSTRALIA ASSESSMENT METHODS

USGS World Petroleum Assessment 2000

GeoScience Australia (GSA), formerly the Australian Geological Survey Organisation (AGSO) and before that the Bureau of Resource Sciences (BRS), makes annual reviews of Australia's ultimate endowment of *oil, condensate and natural gas, including estimates for the undiscovered.* It uses information provided by companies and State government agencies, supplemented by its own work. The 2002 report concluded that its previous assessment method for the undiscovered was too conservative and GSA now prefers, with qualifications, that used in the *US Geological Survey World Petroleum Assessment 2000 (USGS WPA 2000)*. However, the validity of the USGS assessment has been widely criticised by many well-informed petroleum geologists as being too optimistic. These issues are discussed below.

The USGS assessment has 1995 as its base year and assesses the prospects for world petroleum discovery to 2025. The Bonaparte, Browse, Carnarvon and Gippsland Basins were assessed for Australia and the report gave mean estimates (statistically the most likely) for undiscovered oil, condensate and natural gas that were three to four times higher than the GSA's figures using its method.

Powell (2001) from AGSO (now GSA) commented on these differences and says the two approaches have fundamentally different aims that in turn lead to the different approaches and conclusions. The USGS method explicitly aims at achieving *an estimate largely unconstrained by economic, technological and social limits.* Its emphasis is on the *long-term geological potential* of a Total Petroleum System and as such is clearly orientated to an optimistic outlook. But Powell says much more work is required to determine how the resource potential identified might be achieved and in what time frame. *The USGS WPA 2000 report implies a statistical assessment with a low probability, say around five or ten percent (P05 & P10), not the most likely.*

By contrast the past AGSO assessment process was designed to underpin advice to governments on *immediate* decision-making and likely future production on a 5-10 year time frame, concentrating on extrapolation of current trends in existing fields and had not included fields in water depths of over 500m*. Furthermore, it did not consider the potential for reserves growth in the yet-to-be discovered fields, a central feature in the USGS method.* Powell says the *USGS WPA 2000* mean estimate for oil resembles the values at the five percent probability in the Australian approach. The USGS natural gas estimates are much higher again.

But Powell goes on to say the *USGS* assessment may be over optimistic. It does not appear to have factored in the preservation issues associated with hydrocarbon accumulations encountered on the North West Shelf and particularly in the Timor Sea, but he does not explain what these issues are. Furthermore, given the tendency for large oilfields to be found first, he says it is hard to reconcile the projected resource potential by the USGS with the discoveries made since 1995. *The world discovery pattern since*

Powell's paper is confirming its optimistic nature.

Colin Campbell (2002) also critiques the *USGS WPA 2000* for its excessive dependence on *reserves growth* in existing fields. He says in the early days of the United States, where individual landowners own the oil rights onshore, the ownership of oilfields was highly fragmented and reservoirs in the same field sometimes had different owners. There was no shortage of tricksters exaggerating the size of discoveries for promotional purposes and in the 1930s the newly established Securities & Exchange Commission (SEC) moved to prevent such fraud by imposing rigorous rules for reserve reporting. The owners could report *for financial purposes only* the reserves being drained by their *current producing wells*, and which were called *Proved.* The reports were to relate only to their particular holding and not to the field as a whole. No one minded if they under-reported the reserves. *The thrust of the rules was to stop fraud by over-reporting, which in fact fostered under-reporting.*

This practice was preserved by the US industry as it moved internationally and offshore, with most of the companies being listed on the US stock exchanges and subject to SEC rules. They found under-reporting the size of their reserves in this way conferred many benefits. It allowed them to smooth their assets, which would otherwise have fluctuated wildly from occasional discoveries separated by lean years, and it reduced tax in countries operating a depletion allowance based on *Proved Reserves.* For most purposes, it was perceived as a practical and equitable arrangement.

The practice of reporting *Reserve to Production Ratio* in terms of years was a derivative, whereby companies could say that their reserves could sustain *current production* for a given number of years. What they really meant was that the reserves had been *Proved So Far,* it was implied that more could be added by drilling up the fields. It was a reasonable assumption in a world perceived to have near limitless resources.

Laherrére (2001) says the reporting of *Proved* reserves under SEC rules led to systematically under-reporting, leaving room for future reserves growth. He said 88 percent of the annual additions to US oil reserves since 1980 came from re-evaluation of past discoveries because the previous estimates were too conservative. This has been the principle reason for high reserves growth for companies operating under US SEC rules. **It is unique to that country and cannot be applied elsewhere without heavy qualification. It is not clear whether Geoscience Australia was aware of this when it adopted the USGS assessment for Australia based in part on reserve growth.**

Colin Campbell (2002) says the past perception of inexhaustible resources is now being replaced by questions of how much is left. Most of the world's fields are now drilled up to an optimal well spacing, so little more can be added by new drilling. Advances in technology have also successfully raised the percentage of oil-in-place recovered*. It follows that Proved Reserves have evolved to the point that they cover the fields as a whole, not just the current wells.* It means that the companies have less and less left in their under-reported inventories. Some still claim positive reserve replacement, but close inspection shows that it comes more from acquisition of reserves than by new discovery. It is a perfectly valid financial measurement but does not reflect exploratory success. *The USGS WPA 2000 report erroneously anticipates continued high reserve growth for oil* *and gas fields in both the USA and the world.*

Government agencies and the petroleum industry in Australia still use the statistic *Reserve to Production Ratio.* They should stop the practice that has now become thoroughly misleading. More sophisticated approaches are needed and are possible.

The industry explores the world, drilling many dry holes in the process. The discovery of oil and natural gas is a transcendental event in terms of adding reserves. It follows that all the oil ever to be produced from the field in question, under whatever economic and technological conditions as may arise over its life, are logically attributable to the date of the original discovery.

Oil companies could improve their public accounts by *back dating* their claimed reserves to the discovery date on which they were found. The brokers might recover from the initial shock of discovering that the companies are far from replacing their reserves in any real sense and would conclude that what they have left would be an appreciating asset in increasingly short supply.

Campbell (2002) points out that the *USGS WPA 2000* report estimates that potential new discoveries of world conventional oil from 1995 to 2025 would be some 730 billion barrels, an average of 24 billion barrels per year. However, an average of 10 billion barrels per year has been discovered from 1995 to 2001 when you would expect this to be *higher* than the expected as giant fields are usually discovered first. *World oil discovery is not matching the USGS Report's expectations. The annual discovery rate has declined even further since 2001.*

Geoscience Australia's response

Earlier this decade Geoscience Australia (GSA) made preliminary assessments of some *offshore basins* for their prospective potential with an eye to the post-2010 exploration scene *(Powell 2001).* These are:

- North Queensland Basins offshore from the Great Barrier Reef. Water depths are about 1500m.
- The Lord Howe Rise 800 km offshore between Lord Howe Island and New Caledonia. Water depths are about 1500 - 2500m.
- The South Tasman Rise 550 km south of Hobart, Tasmania, water depth 1500m.
- Southern Margin Basins south and west of the Nullabour Plain, including the Naturaliste Plateau. Water depths are about 1500m or deeper.

The last three are basins on submerged plateaus that broke off the continent from the late Jurassic period 160 million years ago, as did the Naturaliste and Exmouth Plateaus in Western Australia. Comparisons have been drawn with similar environments on the Atlantic Ocean margins where significant oil has been found in deep water offshore from Brazil, Nigeria-Angola and in the Gulf of Mexico (Australian Financial Review 2001). However, there is a counter argument. *The great era of petroleum generation was in the Jurassic in areas that had shallow seas in tropical climates favouring prolific algae growth.* These regions included the Carribean and its hinterland, North Africa and Nigeria, and the Persian Gulf countries. The southern hemisphere continents were 2,500 to 3,000 km. further south. They were a part of the super continent Gwondanaland and well outside tropical climates, the principal reason these regions have limited petroleum resources.

These locations and water depths speak for themselves. The North Queensland basins will be contentious given their location adjacent to the Great Barrier Reef. Geoscience Australia has not reported any work on the three east coast locations, but has undertaken geophysical investigations on the Southern Margin Basins offshore from Eucla in South Australia and Bremer Bay in Western Australia. So far there has been negligible interest from exploration companies.

Petroleum exploration is searching in ever more marginal locations.

USGS estimates for undiscovered gas in Australia*.*

Table 2 shows the end 1995 BRS mean reserves estimates, cumulative production and discovery, the estimated undiscovered (June 1996) and the mean estimate of ultimate recovery of natural gas from these basins under its old assessment method. Data is from Oil and Gas Resources of Australia 1996 (BRS 1997). This is the closest we can get to the situation for 1995, the base year of the *USGS WPA 2000* report.

TABLE 2
Natural Gas at end 1995
Bureau of Resource Sciences
Discovery, Undiscovered and Ultimate Recovery
Billion cubic metres

Basin	**Reserves P50 1995**	**Production to 1995**	**Discovery end 1995**	**Undiscovered est. June'96**	**Ultimate recovery**
Bonaparte	205	3	210	70	280
Browse	625	--	625	150	775
Carnarvon	1,160	96	1,255	620	1,875
Gippsland	207	122	330	30	360
Total	2,200	220	2,420	870	3,290

Source: Data from BRS 1997, Oil & Gas Resources of Australia 1996, p.14 & 112.

Table 3 shows the discovered gas as at the end of 1995 from Table 2, the additional production and *net* reserves addition from end 1995 to end 2004 to give the cumulative discovery to the end of 2004. Note the downward revision of reserves for the Browse Basin. Large gas discoveries have been made in the Bonaparte and Carnarvon basins since 1995.

TABLE 3
Geoscience Australia
Natural gas end of 2004
Additional discovery and production from 1995

Basin	**Discovery by end 1995**	**Production 1996-2004**	**Reserves addition '96-04**	**Discovery By end 2004**
Bonaparte	210	3	456	669
Browse	625	0	108	733
Carnarvon	1,255	174	1,187	2,616
Gippsland	330	58	-30	358
Total	**2,420**	**235**	**1,721**	**4,375**

Table 2 and Geoscience Australia 2004, Oil & Gas Resources Australia, Appendix I

Table 4 shows cumulative discovery to end 2004 from Table 3 plus the *USGS WPA*

2000 report's P95, mean and P05 estimates for new discovery in these basins together with the corresponding derived estimates of ultimate gas recovery. Statistically, the mean is the most likely. Note the comparison for the USGS new gas discovery in Table 4 with the reserves additions in Table 3.

TABLE 4
Natural Gas Ultimate Recovery
USGS WPA 2000 Discovery Estimates

Billion cubic metres

Basin	Discovery by end 2004	USGS est. new discovery			USGS est. ultimate discovery		
		P95	Mean	P05	P95	Mean	P05
Bonaparte	669	159	674	1,406	779	1,294	2,026
Browse	733	137	569	1,,293	722	1,155	1,880
Carnarvon	2,616	612	1,832	3,145	2,497	3,717	5,030
Gippsland	358	35	160	343	401	526	709
Total	**4,375**	**943**	**3,235**	**6,187**	**4,400**	**6,690**	**9,645**

Data sources: Geoscience Australia 2001, Appendix I and Table 3

Discovery in the Bonaparte Basin since 1995 about equals the USGS mean estimate for new discovery (Tables 1 and 3). More discoveries in this relatively unexplored basin are possible due to protracted territorial negotiations between Australia and East Timor delaying exploration. Bonaparte Basin fields are well offshore mostly in deep water. Development costs will be high in this cyclone prone region.

New discoveries in the Browse Basin will almost certainly be in deep water and it is relatively unexplored—its isolation has discouraged company interest until recently. Discoveries between 1995 and 2004 were 233 Bcm (Tables 1 and 3). The USGS mean estimate for new discoveries should be reached, but is less certain for higher ones.

In the Carnarvon Basin at least 1,300 Bcm was discovered between 1995 and 2006, taking the total discovered to 2,670 Bcm, more than the USGS P95 estimate and the BRS 1995 mean estimate for the undiscovered, and 70 percent of the USGS mean estimate for ultimate discovery (Tables 1 and 3 plus 2005/06 consumption). Nearly all of these discoveries have been in the Greater Gorgon fields in water around 1,200m deep, when GSA says its undiscovered assessment method was confined to waters under 500m. The USGS mean ultimate estimate has a good chance of being achieved.

The earlier discoveries in deep water in the Browse and Carnarvon Basins (both mostly in about 1,000m water depth and 400 km. offshore) were made in the 1970s as a response to the oil supply crises at the time. The technology for operation in deep water was developed from the mid 1980s and mostly applied in Atlantic Ocean regimes—the Gulf of Mexico, Africa and Brazil. The limited exploration since the 1970s suggest more discoveries are likely, but their location will make development expensive. Exploration has increased since 2003 as international oil and gas prices have risen.

There is agreement in the industry and government agencies that most new Carnarvon Basin discoveries will be in deep water offshore, locations outside the GSA's historical assessment framework. *The critical question here is the extent to which the USGS mean estimates may be over-stated due to their 'reserve growth' philosophy.*

There have been very few new gas discoveries in the Gippsland Basin between 1995 and 2004 and some down grading of reserves that still leave these well below the USGS P95 estimate. This Basin may prove the USGS 'reserve growth' approach to be unrealistic. There do not appear to be opportunities in the Gippsland Basin for discoveries in deep water offshore. So far outcomes for the adjacent Otway Basin are not promising. The picture may become clearer when the GSA publishes OGRA 2005.

THE CARNARVON BASIN 2001

Industry and government convey an impression of abundant gas reserves and discovery potential in this Basin that should be developed and mainly exported as rapidly as possible. This is the dream of the "Magic Pudding".

Government agencies typically quote reserve production ratios of more than 90 years for Carnarvon Basin gas, unaware of the historical origins of this statistic and its misleading character, as discussed above. It implies that the *current* production rate will continue for 90 years and then *abruptly* cease, a concept bearing no relation to the actual performance of oil and gas fields. Production peaks much sooner followed by a long decline. The more gas consuming projects the sooner this stage is reached. Major expansion of gas consuming projects for export are planned and under construction, such as LNG and petrochemical plants. *But the publicity is very coy about discussing the downside of production, when this might occur and the consequences.*

About 95 per cent of discovered gas in the Carnarvon Basin is in a small number of large fields (>100 Bcm, mean estimate), mostly associated with the North West Shelf Joint Venture (NWSJV) and the Greater Gorgon group. The rest are small fields, some of which are in production and some not, depending on their ready access to gas transport facilities. A few small fields are linked in to the NWSJV facilities that currently dominate supply *(WAO&GI 2006, p.46).* The discussion below will be confined mostly to the NWSJV and Greater Gorgon projects. Current mean estimate reserves for the NWSJV are about 634 Bcm[14] and 980 Bcm for the Greater Gorgon fields. About 90 percent of all gas production in 2005 from the Carnarvon Basin has been from the NWSJV fields, 23.4 Bcm.

Appendix 1 lists the "wish list" of gas consuming petrochemical and LNG projects that were on the agenda in 2001 for the Carnarvon Basin. The construction cost (2001 prices), product output, timing and expected annual gas consumption for each project are shown in Table A1. By 2011 approximately 75 percent of the then discovered gas in the NWSJV fields would have been consumed under this "wish list", even with substantial new discoveries. Thereafter additional gas would have been needed from stage 1 of the Greater Gorgon scheme, as production decline would be imminent.

But we will not pursue this line any further as significant rises in the exchange rate of the Australian dollar against the $US since 2003 have eroded the international sale price of the petrochemicals rendering these projects unviable.

The focus on gas development in Western Australia has shifted from petrochemicals to LNG for export. *A worldwide boom in LNG development began this decade.*

[14] Includes 100 Bcm contingent estimate for Woodside's Pluto field discovered in 2005, it may increase.

THE LIQUID NATURAL GAS BOOM

The cost of transporting natural gas any distance is 6-10 times the equivalent for oil—because it is a gas. This limits international trade. The most expensive form is as LNG. For this reason production and consumption of gas tends to be on regional and continental bases. There will tend to be regional production peaks with flattened peaks. The same regional pattern applies to Australia.

Natural gas projects *offshore* have flattened production profiles constrained by the high cost of infrastructure compared to oil, even more so for LNG. Consequently the onset of decline occurs later in the depletion cycle than is the case for oil. Furthermore, natural gas tends to have steeper decline rates because of its free-flowing characteristics in geological formations. More of the gas-in-place can be extracted than is the case for oil.

Three factors are transforming the market for natural gas. *Firstly*, in 2000 production decline began in North America, the largest consumer of natural gas. *Secondly*, production decline began in the UK in 2004 and will extend to Europe about 2010. These regions consume 45 percent of world gas. Russia is a large consumer of gas and of exports to Europe—its production decline could begin before 2020. China and India plan to expand their use of natural gas and are in the market for LNG. *Finally*, the low carbon dioxide emissions associated with burning natural gas make it a preferred fuel for many applications, especially electric power. As a consequence there is a very rapid growth in the market for LNG. *This global background is described in* ***Appendix 2***.

North West Shelf Joint Venture

Table 5 shows the principal producing gas fields for the North West Shelf Joint Venture (NWSJV) and remaining producing fields in Western Australia[15]. Gas production began in the Perth Basin in 1971 and by the NWSJV in the Carnarvon Basin in 1984 when the Dampier Bunbury Natural Gas Pipeline (DBNGP) was built. North Rankin production began and other independent minor gas and oil field development followed. The first two NWSJV LNG trains were commissioned in 1989, the third in 1992, the fourth in 2004 and the fifth will be commissioned in 2010. Current capacity is 11.9m tonnes LNG a year increasing to 16.7m tonnes in 2010.

TABLE 5
West Australian Gas Production 2005
NWSJV and rest of WA
Billion cubic metres

Gas fields	Start-up	Gas production		Reserves	Ultimate
		2005	Cumulative		
North Rankin	1984	5.5	190	163	353
Goodwyn	1995	7.6	93	115	208
Perseus-Athena	2001	7.4	37	249	286
Ecoh-Yodel	2002	2.2	10	4	14
Angel	2009	0	0	52	52
Pluto	2010	0	0	102	102
Xena	2010	0	0	14	14
Total NWSJV	***1984***	***22.7***	***330***	***700***	***1,030***
Rest WA production	1972	3.8	60	45	105
Total W. Australia	**1972**	**26.5**	**390**	**745**	**1,135**

Sources: Issues of Western Australian Oil & Gas Review (WAO&GR)

15 In the Carnarvon and Perth Basins. Some of the minor fields supply to the NWSJV processing plant.

The WAO&GR obtains most of its production, sales and reserves data from companies.

Woodside Energy says in its 2002 Annual Report (p.14) that; *"Woodside reports reserves net of the gas required for processing and transportation to the customer, fuel and flare gas".* Such use would be for operation of offshore rigs and pumping the raw gas to shore, clean up of the gas, removal of carbon dioxide and recovery of condensate and LPG for sale[16]. *The Annual Report also includes a category "Remaining Discovery", meaning the volumes that have been demonstrated to be recoverable from the sub-surface. It is equal to the sum of reserves plus the gas required for its processing and transportation to the customer*—a category not included in WAO&GR reports. Raw gas from the NWSJV gas fields also contains three per cent carbon dioxide.

The 2002 Annual Report (p.14) also lists *'dry gas' reserves* (assumed to be after clean up and extraction of condensate and LPG) and 'future fuel and flare gas' (11.9 percent of dry gas) to yield a *net* product for reserves. These reserve figures are presumably those published in WAO&GR. The provision for 'dry gas' would include that consumed in LNG plants and for domestic sales production. This figure is probably conservative and will improve with bigger and modern LNG plants—however, the proportion will increase as LNG production expands faster than domestic gas sales. In the following discussion we will assume that the Woodside Energy *gas reserve* figures have already taken this process provision into account, with the reminder that actual raw gas production will be larger.

We will assume that other company's reserve data is similar to Woodside Energy's and discuss these issues again later.

NWSJV gas production in 2005 was 22.7 Bcm (17.1 M.tonnes). Domestic sales gas were 5.27 Bcm (3.95 M.tonnes), LNG production 11.2 M.tonnes (14.9 Bcm of gas), and LPG 0.30 M.tonnes, total 15.45 M.tonnes[17]. The difference of 1.65 tonnes mostly represents the raw gas input consumed in production of sales gas, LPG and LNG production, or 10 percent of raw gas—some may also be flared. We will assume 4 per cent of raw gas is consumed in cleaning up the gas for domestic sales and LNG plant *input* and another 8 per cent in LNG plant operation, a total of 12 percent for LNG[18].

Table 6 lists *actual* production for 2005 and *estimates* at five yearly intervals to 2025; the LNG plant is assumed to run at near maximum capacity, and sales gas to near the limit of processing capacity with a third processing train commissioned in 2017 based on allocation of 15 percent of Pluto field reserves. Raw gas figures required have been derived from sales gas data by multiplying by 1.04 to allow for gas used in clean up and rig operations as well as extraction of LPG, and by 1.12 for LNG raw gas input. It is assumed that the fifth LNG train will be commissioned in 2010, the Echo-Yodel field will close down by 2015 and a third process train for domestic gas sales will be commissioned in 2017.

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[16] Condensate *spontaneously settles out* of the raw gas on release of pressure and would not be included in raw gas production figures. LPG is light hydrocarbons extracted by separation processes. Both saleable products, leaving remaining gas for input to LNG plants and for domestic sale.

[17] One tonne of gas equals 1,333 cubic metres.

[18] A judgement on my part, I was unable to find reliable data.

TABLE 6
North West Shelf Joint Venture
Sales Gas and LNG Estimated production to 2025
Billion cubic metres

Sector and field	Gas production				
	2005	2010	2015	2020	2025
LNG production M.tonnes - As gas to LNG plant Bcm	*11.2* 14.9	*15.5* 20.8	*16* 21.3	*16* 21.3	*16* 21.3
NWSJV Sales gas Bcm	5.6	6.4	6.4	3.0	7.0
Raw gas for LNG + 12%	16.7	23.3	24.0	24.0	24.0
Gas for sales gas & LPG +4%	5.8	6.65	6.65	7.3	7.3
Raw gas input needed Bcm	22.5[19]	29.9	30.7	31.3	31.3
North Rankin	5.5	7.6	8.0	8.5	8.5
Goodwyn	7.6	8.2	5.0	6.0	6.0
Perseus-Athena	7.4	10.1	9.5	9.0	9.0
Echo-Yodel	2.2	0.3	0	0	0
Angel	0	3.7	3.0	3.0	3.0
Pluto	0	0	5.0	5.0	5.0
Xena	0	0	1.0	1.0	0.5

Production decline began in the United Kingdom North Sea gas fields in 2004 when 80 per cent of the originally discovered gas had been extracted. After adding 10 percent to the NWSJV reserves of 685 Bcm in Table 5 the equivalent raw gas reserve is 755 Bcm and the Ultimate would be about 1,080 Bcm. *Production decline due to depletion therefore could be expected when cumulative production reaches 860-870 Bcm.*

Table 7 uses data from Table 6 to estimate cumulative gas production to 2025. **On this agenda 80 per cent of the NWSJV current gas reserves would be extracted by 2025, in the absence of large new discoveries put into production.** North Rankin and Goodwyn could do so sooner and Perseus/Athena and Pluto later. Echo-Yodel is likely to cease production by 2015. *Would production cease around 2035?*

While domestic gas production prices are at levels less profitable to the NWSJV than LNG sales there will be a strong incentive for the partners to reduce domestic sales to a minimum when the opportunity arises.

TABLE 7
Cumulative NWSJV raw gas production
Projections to 2025
Billion cubic metres

Field	Cumulative production to 2025					80 percent of ultimate
	To 2005	To 2010	To 2015	To 2020	To 2025	
North Rankin	200	215	255	300	340	300
Goodwyn	97	119	135	165	190	175
Perseus-Athena	35	75	130	175	220	240
Echo-Yodel	10	13	14	14	14	11
Angel	--	5	17	32	45	45
Pluto	--	--	25	50	75	90
Xena	--	--	4	4	2	11
Total	**342**	**420**	**580**	**740**	**885**	**872**

19 This is 0.2 Bcm less than actual, allowing for miscellaneous and flaring.

The NWSJV may hope a large gas field will be discovered in the near future, and that the Pluto field reserves will prove to be larger than the provisional estimate.

On 27 July 2007 Woodside Energy CEO, Don Voelte, announced the NWSJV's commitment to the Pluto LNG project, now at an estimated cost of $12 billion (double the 2006 estimate) for a capacity of 4.8 M.tonnes LNG per year, an increase of 0.4 M.tonnes per year on previous announcements. This week it secured an exploration permit in partnership with US group Hess Corporation and plans to spend $196 million on exploration over three years. He said Woodside has also committed $300 million to prepare for future expansion that will allow it to process gas from other companies' fields as well as potentially supply WA industry *(West Australian 2007a). Woodside Energy is building Train 5 anticipating that many new discoveries will be made to justify its scale.*

Volte said it might be possible to process gas from Gorgon at its Pluto facility if the Chevron-managed project was unable to proceed on its own. Of interest are the Urania, Iago and Wheatstone fields (145 Bcm—Table 11) in shallow water and closer to the NWSJV Goodwyn platform than they are to Barrow Island, the site of the Gorgon project's proposed LNG plant. This could justify two more LNG trains. See the discussion on the Greater Gorgon project below.

Table 8 shows the Domgas Alliance expectations of domestic natural gas demand in Western Australia over the same period and compares it with NWSJV production to derive the production needed from other sources to 2025[20]. Actual production for 2005 is shown whereas the Domgas Alliance says demand was 7.2 Bcm, 0.3 Bcm more than the actual. The Domgas Alliance demand expectations may represent an optimistic outcome—how much longer will the Chinese driven commodity boom last? As NWSJV current contracts for sales gas expire they may be reluctant to renew them in whole or in part if the contract price is less profitable than that from LNG sales.

Alcoa's key supply contracts expire in 2014 and securing a competitive gas supply was pivotal to a planned $1.5 billion expansion of its Wagerup alumina refinery. Similarly Alinta last year baulked at the 80 percent increase demanded by the NWSJV when it sought to renew a key contract that expires in 2008 *(West Australian 2007). The later projections for NWSJV sales gas may be less than shown, placing further stress on alternative supplies.*

TABLE 8
Domgas Alliance projections
Domestic gas demand to 2025
Billion cubic metres

	2005 actual	**2010**	**2015**	**2020**	**2025**
Domgas projections	6.9	9.6	11.4	13.0	13.9
NWSJV Table 6	5.3	6.4	6.4	7.0	7.0
Other sources reqd	1.6	3.2	5.0	6.0	6.9
Perth Basin	0.2	Current production rate likely to decline			

The sale price of domestic gas is rising and may make small gas fields viable adjacent to the Harriet JV process plant on Varanus Island—perhaps 2-3 Bcm. The Gorgon LNG project is the next major gas development proposed for the Carnarvon Basin A decision on its development is close. It may be possible to divert some Gorgon gas to domestic sales, subject to negotiation.

[20] The Domgas Alliance's estimates are based on those by the Australian Bureau of Agricultural and Resource Economics, *Australian energy national and state projections to 2029-30,* December 2006, p.74.

Scarborough gas field

The Scarborough gas field was discovered in 1979 and is located 270 km north west of Onslow in water 900m deep. It is in joint ownership with Apache Energy and BHP Billiton, with the latter the operator. BHP Billiton wants to establish a six million tonnes a year LNG plant near Onslow. The gas lacks condensate and LPG components as income sources. These factors, its location and the water depth are all obstacles to its early development. The gas reserves are 147 Bcm. More proving wells are being drilled *(WAO&GR 2006, p. 75).*

Before discussing these issues further we will examine an important parameter in assessing the economic worth of projects. Energy return on energy invested, EROEI.

ENERGY RETURN ON ENERGY INVESTED

Economic assessment of projects is mostly carried out on a monetary basis, rarely on an energy basis. Both are needed to obtain an all-round picture.

The extraction of fossil fuels from nature and their conversion to useable energy forms, such as electricity and petroleum fuels, and applying these to economic work has been the basis for the high levels of productivity and economic growth of the last two centuries, particularly since the mid 20th century. But their extraction and conversion requires an input of the useable forms of these energy sources. Therefore an important economic indicator is the proportion of the fossil fuel output used for this purpose. The *net energy yield* is what matters, the difference between gross energy output and the energy input needed to extract and transform it into useable forms. This can be measured by the ratio of output to input, energy return on energy invested, EROEI.

$$\text{EROEI} = \frac{\text{Energy output}}{\text{Energy input}}$$

The *energy output* is the energy content of the final useable fuel (e.g. in Joules). The *energy input* includes both the *direct energy and indirect energy inputs* embodied in all the goods and services consumed in creating the final useable energy forms. Defining the system boundaries is an important aspect of these studies.

Manfred Lenzen published a paper, *A Generalised Input-Output Multipier Calculus for Australia,* in 2001 *(Lenzen 2001).* He used an approach pioneered by Leontieff in 1941, since widely used. Tables of monetary and physical data inputs and outputs across sectors in the economy are compiled. Non-square matrices can be introduced to enable the inclusion of finer detail in commodity matrices in the broader aggregated tables. Capital investment and imports are internalised into domestic inter-industrial intermediate demand. A range of energy and labour multipliers are calculated, referring to total output, final demand, final consumption, basic values, producers' prices, purchasers' prices, commodities and industries. Uncertainties in the multipliers are assessed in detail, using Monte Carlo simulations. For energy, the outputs are much broader than EROEI.

The study was *static* using the 1994-95 Australian input-output tables for 107 commodities and industries, initially compiled by the Australian Bureau of Statistics (ABS). *That is, the conclusions applied only to 1994-95.* Some aggregation of commodities is involved in this core approach. Capacity to address environmental issues was limited because ABS input-output tables focus more on inputs than outputs and many industries associated with significant resource use and pollution are highly aggregated in the tables. However, the ABS tables are compiled from a much finer detail of approximately 1,000 commodities and these industries can be incorporated from this finer detail, subject to limits imposed by confidentiality.

Some assumptions of homogeneous outputs are not always true, and can introduce errors. *There is an assumption of equivalence between domestic and imported commodity imports that is not always valid*. Capital investment is considered as final demand, an area where the statistics needed were limited.

The study assumed a constant and linear relationship between intermediate inputs and ignored economies of scale, structural, technological and price changes. However, this does not carry an uncertainty in to multipliers in the 1994-95 case. Multipliers refer to a single base year. Changes in prices, economic structure, technology or output scaling were not appraised. *The capital component in multipliers will vary with the years as there can be large changes from year to year*.

An inverse relationship between energy and labour is found in these studies. 'Energy' in the broadest sense is a substitute for labour.

The study used 1994-95 statistics for Australia as the latest available from ABS. Lenzen considers that some of these deficiencies could be solved by ABS compiling a much wider range of statistics over more commodities and industries, and should do so in a shorter time frame.

Table 9 shows the EROEI for fossil-fuel-related industries adapted from Table 4 in Lenzen's paper. The aggregated data for crude oil, condensate and natural gas is across all suppliers. LNG production was at the NWSJV project and LPG was across all producing fields. Well drilling activity was low in 1994-95 and there was no construction of LNG plants and capital input was low. Total electricity supply includes hydroelectric.

TABLE 9
Australian energy multipliers 1994-95
Fossil-fuel-related industries

Industry	Energy Multiplier MJ_{in}/MJ_{out}	EROEI	Process efficiency
Coal, oil & gas	0.038	26.3	96.3
Black coal	0.022	45	97.9
Crude oil & condensate	0.082	12.2	92.4
Natural gas	0.068	14.7	93.6
LNG & LPG	0.079	12.7	92.7
Brown coal & lignite	0.020	50	98.1
Petroleum & coal products	0.223	9.3	81.8
Thermal electricity supply	3.33	13.5	30.6
Thermal & hydro electricity	2.98	15	33.5

Black and brown coal dominated thermal electricity generation and the energy multiplier of 3.33 relates primarily to these fuels applied to the energy multipliers for coal. The energy multiplier for petroleum and coal products relates mainly to the energy inputs consumed in oil refineries and similar downstream inputs. Total electricity supply includes hydroelectric.

Crude oil production has declined since 1994-95 and smaller new fields developed suggesting the EROEI may have declined. Construction of LNG plants is being undertaken and the energy input would lower the EROEI for LNG, perhaps significantly. Also the energy input for LNG would be higher than for LPG, making the EROEI for LNG less than 12.7[21] and higher for LPG. Since 2002 the price of steel has doubled and the

[21] A good guess would be about 10 for LNG when compared to products from oil refineries.

cost of new construction and drilling has increased substantially, and there is an increasing emphasis on costly drilling in deep water offshore.

What are the consequences of these and other input factors for EROEI in this decade?

Table 10 shows energy multipliers for several fossil fuels, minerals and metals and the effect of introducing additional details into basic matrices on the energy multipliers for mining industries (Lenzen's Table 3). The column 'Deviation of aggregate (%)' shows the effect of introducing 29 additional rows into all basic tables to disaggregate the monetary input-output data of the coal, oil and gas, iron ores and non ferrous metals into ten sub-industry sectors.

TABLE 10
Energy-dollar multipliers
Australian fossil fuels and minerals

Industry sector	Energy Multipier MJ/A$	Deviation of Aggregates (%)
Coal, oil and gas	16.81	
Iron ores	10.74	
Old, copper, bauxite, silver, lead, uranium 7 other non-ferrous metal ores	16.53	
Black coal	10.04	53.6
Brown coal	11.64	44.4
Crude oil	21.83	23.0
Natural gas	35.93	53.2
Liquefied natural gas	23.48	28.4
Iron ores	11.14	3.6
Bauxite	18.17	9.0
Copper	18.17	9.0
Gold	16.23	1.9
Silver and zinc	17.03	2.9
Lead, uranium, other non-ferrous metals	18.17	9.0

Coal mining is considerably less energy intensive than oil and mining. Gold mining is slightly less energy intensive than the mining of other non-ferrous metals. Disaggregation also slightly increased the energy multiplier of the unchanged iron ores mining industry, which in monetary terms consumed four times as much natural gas as coal—the natural gas energy multiplier was twice as high as that for coal mining.

Since 2002 there has been a major boom in the minerals industry, especially in coal, iron ore, copper, nickel, zinc and lead in Australia with a massive expansion of investment in associated transport and other infrastructure. Capital costs have soared, and skilled labour shortages are extreme.

Similar studies to Lenzen's are urgently needed to obtain a deeper understanding of what is happening in these industries. In particular the trends in EROEI for fossil fuels in Australia and the energy intensity of the mining industry. A better data base for to assess the energy inputs embodied in inputs—these are quite large for capital goods.

Have we entered an era of declining EROEI for fossil fuels, especially oil and natural gas? If so to what extent and what are the implications for the future? This needs assessing in a global context.

These studies are particularly useful for allocating greenhouse gas emissions across industry sectors, now an important economic parameter.

THE GORGON GAS PROJECT

Gorgon Joint Venture

The Gorgon Joint Venture (GJV) comprises Chevron Texaco, Shell and Exxon Mobil. The Greater Gorgon Area is Australia's largest undeveloped natural gas resource. The first proposal is a two-stage 10 million tonne per year LNG plant based on the Gorgon field with the plant on Barrow Island. The development cost is $11 billion (2003 prices). The cost has since escalated and some reports suggest as much as $23 billion *(West Australian 2007)*. The GJV has yet to commit to the project. The gas from this field has a high carbon dioxide content (~14 per cent) with significant Climate Change implications and it is proposed to remove this and inject it into the subsurface.

The choice of Barrow Island was contentious as it is an A-Class nature reserve declared in 1910 where many animal species survive that are no longer present on the mainland. Legislation in 2003 gave formal in-principle support to the project. It limited the footprint on Barrow Island to a maximum of 300 ha, established a $40 million fund for implementing a net conservation benefit concept, and included provisions allowing the Minister to approve and regulate CO_2 disposal by injection into the subsurface.

Table 11 lists the fields under retention lease by the GJV partners in the Greater Gorgon Area and shows statistics relevant to the economics of the resource base. Barrow Island is 55km from the coast and 400 km west of Karratha *(WAO&GR 2005, p.19).*

TABLE 11
Greater Gorgon Area gas fields

Field	Discovery	Reserves Bcm	Water depth m.	Carbon Dioxide %	Km from Barrow Is.
Gorgon, Spar	1980	483	~500	14	65
West Tyral Rocks	1973	73	~500	?	65
Iago	2002	30	120	?	100
Wheatstone, Urania	2004	115	<500	?	100
Chrysaor, Dionysus	1994-96	96	800-1,000	?	85
Io-Eurytion	2001	193	1,300	?	135
Geryon, Orthrus, Meanad	1999	127	1,200-1,350	?	110
Jansz	2000	392	1,300+	?	145
Total		**1,500**			

Sources: Oil & Gas Resources of Western Australia 2006, pp.57&75.

The Gorgon, Spar and West Tyral Rocks fields are in shallow water 65 km west of Barrow Island, have one-third of the reserves and could be served by a single sub-sea pipeline and possibly one offshore rig. The Iago, Wheatstone and Urania fields are located 100 km north of Barrow Island, have 10 percent of the reserves and could be served by one offshore rig and sub-sea pipeline. They are also within reach of the NWSJV's North Rankin offshore platform. The remaining fields have 57 per cent of the gas reserves, are in deep water and mostly 100-145 km north west of Barrow Island. *The carbon dioxide content of the gas has only been reported for the Gorgon fields.*

Discussion

The most effective way of sequestering carbon dioxide is to remove it from the natural gas and then compressing it to a supercritical state[22]. In the supercritical state it is easier to inject into geological formations with good seals and be sure that it will stay there *(GSA 2002-04). Both steps will require significant capital investment that will have significant embodied energy and a considerable direct and indirect energy input to operate the process, most likely with natural gas as the primary fuel.* Its removal is a common practice for feedstock to LNG plants.

The current Gorgon reserves are about 20 percent more than the current NWSJV ultimate (Table 5), but most are in deep water and will be more expensive to develop, *in both energy and dollar terms.* Before the rise in international oil and gas prices began deepwater drilling rigs cost $US 200,000 per day to hire. Deepwater environments in the mid Atlantic hinterland are the major frontier for deepwater oil and gas exploration and development. Since 2004 demand for these rigs has increased and hire rates risen to over $US 300,000 per day. There is an acute shortage of these rigs and no immediate prospect of the number increasing due to stretched shipyard orders for container ships, oil and gas tankers and bulk carriers *(Appendix 2).* Floating deepwater platforms are more at risk to damage from cyclones, being anchored to the ocean floor by long cables. Operating costs are higher. *A surcharge would apply to deepwater rigs to cover the long trip to and from Western Australia.*

Carbon sequestration will reduce the EROEI for LNG from Gorgon Stage 1 at Barrow Island compared to the equivalent for the NWSJV's Burrup plant. The same will apply to deepwater field development, even more so if deepwater operations also yield gas that has a high carbon dioxide content requiring sequestration. The consequences are as yet unknown. *Is this partly responsible for the escalating capital costs for Gorgon Stage1?*

Where does gas supply for domestic consumption fit into this scenario? Mining companies need assured gas supply for at least 20-30 years to justify their heavy investment in mines and mineral processing, as do electric power utilities. These are the common time frames for the life and economic evaluation of such investments. Households and supporting industries dependent on natural gas as a fuel have even longer expectations. It is risky to expect enough new small gas discoveries to occur in the right place at the right time to meet this growing need. The concerns of the Domgas Alliance are justified.

Therefore diversion of some gas from the Gorgon JV Stage 1 project to domestic sales is prudent risk management. An initiative from governments is essential. But the circumstances of the Greater Gorgon project do mean a higher sale price for this gas and a lower EROEI.

THE BROWSE BASIN

Table 12 shows the statistics for the four discovered gas fields in the Browse Basin. The Scott Reef field was recently renamed as Torosa and the South Brecknock field to Calliance[23]. Scott Reef is an important reef environment and a contentious issue in the development of these gas reserves. Japanese companies have an interest in Icthys, a recent discovery. The other three fields are a joint venture between Woodside Energy, BP, Chevron Texaco, BHP Billiton Petroleum and Shell and were discovered in 1971 and 1979. Woodside Energy is the operator.

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[22] The gas is compressed until it reaches a state indistinguishable from the liquid state.

[23] Torosa was named Scott Reef. Has the name been changed to minimise references to environmentally sensitive Scott Reef in the media? Brecknock South's name has recently been changed to Calliance.

TABLE 12
The Browse Basin

Fields	Reserves Bcm	Distance offshore km	Water Depth metres
Torosa	322	330	<500
Calliance	111	330	~1,000
Brecknock	147	330	~1,000
Icthyus Brewster	198	300	<500
Icthyus Plover	71	300	<500
Total	**840**		

Source: Western Australian Oil & Gas Resources 2005, p.74.

Both groups are preparing proposals for *separate* LNG plants on the Kimberley coast and searching for suitable sites, 10 and 6 million tonnes per year LNG respectively. Both are planning for a 2012 start-up, but delays are likely.

Environmental groups are fearful of the mining and industrial development these gas developments could bring to the Kimberley's—mining companies have claims on large bauxite resources. There is strong opposition to separate sites for LNG plants on environmental grounds and pressure is mounting for a joint venture at one site. The coastal margin is pristine and subject to high tides and frequent intense cyclones. The locations are susceptible to tsunamis.

Woodside Energy may be pushing the Torosa-Brecknock project to have a major LNG source to replace its stake in the Burrup LNG joint venture, where production is likely to begin decline about 2025 in the absence of major new gas discoveries to extend its life. Woodside Energy CEO, announcing the commitment to LNG Chain 5 at Burrup, said one option open to Woodside Energy would be to pipe Browse Basin gas to an expanded Burrup LNG plant, a distance of 1,000 km *(West Australian 2007).*

An LNG plant based on Browse Basin gas would most likely stimulate exploration in this Basin and could lead to more petroleum discovery. Companies have given it low priority for exploration because of its isolation.

THE BONAPARTE BASIN

The Bonaparte Basin is offshore between Australia and East Timor. The Australian part straddles the boundary between the Northern Territory and Western Australia. Oil and Gas Resources Australia 2004 lists gas reserves in this basin at 666 Bcm, 308 Bcm of which are economically demonstrated Resources. A consortium has developed the Bayan Udan gas field in the Joint Production Development Area[24]. The gas field is located 500 km north west of Darwin and condensate is extracted at the site and dry gas piped to Darwin where a 3.2 million tonnes per day LNG plant was commissioned in 2006. A second train may be built in the future. The project has been designed as well to deliver up to 5.3 Bcm of sales gas per year *(GSA 2004).* More discoveries are possible.

There are six minor undeveloped gas fields in the West Australian part of the basin to the north of Wyndham with reserves of 40-50 Bcm *(WAO&GR 2005, p.74).* Their location makes early development unlikely.

[24] The Joint Production Development Area is shared under Treaty between Australia and East Timor.

COAL SEAM GAS (CSG)
EASTERN AUSTRALIAN GAS

Oil and Gas Resources of Australia has had chapters on CSG since 2000 *(GSA 2000-04).*

Coal seam gas is mainly methane formed as part of the burial of peat to form coal. The methane remains adsorbed to the coal and is held in the coal by burial pressure and water. Because of natural fractures coal has a large internal surface area and is capable of holding larger volumes of gas than conventional sandstone reservoirs. The amount of gas present depends on the depth of the seam, the thickness and the extent to which the fracture system is connected. Low-rank coal at shallow depths (100 to 600m) is more permeable than high-rank coal at intermediate depths. A large number of wells are required to develop coal bed methane fields.

When water is released from coal, the pressure is reduced, and gas flows through the fractures. When a well is first drilled into a coal seam, gas does not normally flow to the surface. Water is pumped from the well (dewatering) with gas flowing subsequently. As water production declines, gas production increases and subsequently declines. Sometimes the coal is mechanically fractured to assist the gas flow through the coal to the producing well. Production from a well must be continuous. If production is halted, water will re-enter the seam and dewatering must begin again. At the surface, the methane, other gases and water are separated and the cleaned gas product is marketed.

The significant volumes of water extracted must be handled in an environmentally sound way. The quality of the water can vary from drinkable to saline, depending on several factors. Evaporation, re-injection into deeper aquifers, flowage into natural drainage or local use have all been applied to water disposal overseas, depending on local circumstances.

Gas production is as much a water management exercise as it is coal bed methane exercise. Water management will be a major problem in Australia with our drying climate.

The capital cost of drilling CSG wells has decreased greatly in the last decade, with fit-for-purpose drilling technologies tried and developed on site in Australia. Gas compression costs to pipeline specifications adds significantly to operating costs. 277 CSG wells were drilled in 2004, 90 per cent of these in Queensland *(QNRM&W 2006).*

But first a brief look at the status of the Gippsland and Cooper/Eromanga fields and other gas fields in eastern Australia to put coal seam gas into a wider context.

Eastern Australian gas fields

Table 13 shows the cumulative production to 2006, commercial reserves, the likely ultimate, and production for 2006 for conventional natural gas.

Production peaked in the Cooper/Eromanga Basins at 8.7 Bcm in 2002 and is in rapid decline. In the near future production costs will rise as production declines in this remote gas field making its operation uneconomic.

Earlier this decade gas pipelines were constructed connecting Adelaide and Sydney to the Gippsland and Otway Basin gas fields, anticipating this decline, but not to Brisbane. The Cooper/Eromanga Basins were the sole supply source of gas to these three cities.

TABLE 13
Eastern Australian Natural Gas
Billion cubic metres

Basin	Cumulative to 2006	Commercial Reserves	Ultimate	Percent of ultimate	Production 2006
Gippsland	193	131	324	60	6.6
Bass	0.2	5	5	4	0.2
Otway	8	32	40	520	5.5
Cooper/Eromanga	151	34	185	82	5.4
Total	**352**	**202**	**555**	**62**	**17.7**

Sources: Geoscience Australia, Oil & Gas Resources of Australia 2004, Appendix 1 & p.32. Australian Petroleum Producers, Production & Exploration Asscn, www.appea.com.au for 2005 and 2006 production. GSA reserves corrected for 2005-06 production data.

At 2006 production rates the Gippsland Basin would reach 80 per cent of ultimate extraction from commercial reserves about 2015, in the absence of significant new discoveries. The Otway Basin should reach this 80 per cent stage earlier, but there may be scope for more commercial discoveries. There are additional sub-commercial reserves of 33 Bcm in the Gippsland Basin that could extend the threshold of decline to 2020. Their development would no doubt require higher sales prices. The Otway Basin has 12 Bcm of sub-commercial reserves that could extend its threshold of decline to about 2015. The Bass Basin supplies Tasmania.

This approaching decline of major Bass Strait and Central Australian gas fields is occurring at a time when the issue of Climate Change is placing a focus on natural gas as an alternative fuel to coal for electric power generation. Natural gas also supplies domestic and commercial needs through extensive urban pipeline networks. The following discussion on coal seam gas must be seen in this context.

Queensland coal seam gas

Development of coal seam gas is most advanced in Queensland. In May 2002 the *Queensland Energy Policy—a Cleaner Strategy* required 13 per cent of Queensland's gas demand to be generated from gas by 2005. In 2002, 25 percent of gas demand was met from CSG and production is currently restricted to the Bowen Basin inland from Gladstone. The first commercial production was from the Dawson Valley gas field south of Moura in 1996. Injune and Wandoan fields began production in 1998 and 2001-2 respectively. Total production has increased rapidly to about 0.7 Bcm in 2004, or 25 per cent of then current gas demand *(QNRM&W 2006).*

Exploration is focused mainly in the Bowen and adjacent Surat Basins, although all coal-bearing basins in Queensland are a potential source of CSG. The extensive coal deposits provide numerous exploration targets. Exploration is at a preliminary stage and few well-defined estimates are available. There are nine major explorers and producers in Queensland[25]. In 2004 the Moranbah project was commissioned in the Bowen Basin along with a 391 km pipeline to supply Townsville with coal bed gas. A gas-fired power station has since been commissioned at Townsville.

Statistics on developments after 2004 are hard to find, but much is happening.

Santos has just announced a proposal for an LNG plant at Gladstone based on CSG to

[25] Anglo Coal (Moura) Pty Ltd, Arrow Energy NL, CH4 Pty Ltd, Molopo Australia NL, Origin energy CSG Ltd, Queensland Gas Company Ltd, Santos QNT Pty Ltd, Tipperary Oil and Gas (Australia) Pty Ltd, Gaililee Energy Pty Ltd.

produce up to 4 million tonnes a year for export (AFR 2007). The project is still in the early planning stages and will take five years to build. A final decision will be made in 2009. Santos estimates the $7 billion cost will be split evenly between the LNG plant and drilling of 500 production wells and other infrastructure, mostly around Roma in central Queensland. Santos is a partner with ConcoPhillips in the Darwin LNG plant based on the Bayan Udan gas field.

Managing director Nick Davies said, "It takes a lot of gas out of the market. Our goal was to expose Queensland to export pricing. Whoever is doing the exports it has that effect". It has the support of the Queensland Premier, Peter Beattie.

This proposal, and a smaller one for LNG also at Gladstone by fast-growing coal seam gas producer Arrow Energy, are likely to increase gas prices in Eastern Australia, in the way prices in Western Australia are soaring to match what producers get for exports.

These fast-growing projects are progressing without a clear long-term national strategy at government levels. There is insufficient public focus on the significant environmental and social consequences, particularly where water impacts are concerned.

New South Wales coal seam gas

There is not much action in NSW as yet. The State and Regional Development Dept in NSW says Santos has a small commercial project in the Sydney Basin at Camden. Pilot production projects began in the Gunnedah and Gloucester Basins in 2004 (NE NSW), and in the northern Clarence-Moreton Basin in 2005 *(DPI 2007).*

A major prospect is the Sydney Basin that encompasses the Greater Sydney area from Wollongong in the south, to Lithgow in the west and south of Newcastle. **Drilling hundreds of gas wells in this basin with their attendant water disposal problems would pose immense environmental problems.** There is a lack of information on the NSW Dept of Primary Industries website.

The NSW Government has initiated the *Owen Inquiry into Electricity Supply in NSW* to explore the options for new generation capacity *(DPI 2007).* A gross excess of generation capacity was constructed in the mid 1980s to supply aluminum smelters that were cancelled. Ageing generators and consumption growth are finally using up the excess base load capacity. There are submissions from Santos Ltd and Origin Energy.

Santos' submission to the Owen Inquiry is a generalised argument for gas-fired generation plant, using both conventional natural gas and CSG, without any specific proposals (DPC 2007). Santos says the Australian Petroleum, Production and Exploration Association forecasts that new electricity plant in Australia will need 2,200 PJ (58 Bcm) of gas by 2020, no doubt an optimistic estimate by APPEA. It says current 2P reserves of *coal seam gas* in Eastern Australia are estimated at 3,900 PJ (103 Bcm) with conventional natural gas in the Otway, Gippsland and Cooper Basins adding a further 11,600 PJ (305 Bcm). *But they do not quote data sources nor refer to the advanced state of depletion of these basins, discussed above.*

Santos says it is the largest gas producer in Australia and has 1,451 PJ (38 Bcm) of 2P gas reserves in Eastern Queensland and 437 PJ (11.5 Bcm) in Southern Australia.

Origin Energy's submission also lacks specific generation proposals as well and is a general statement supporting gas-fired generation plant *(DPC 2007).* Origin Energy has extensive interests in Australia as an integrated company in oil and gas development, gas and electricity retailing, and power stations. It has committed this year to a 630 MW base load, gas-fired power station near Braemar in Queensland for $780 million, including about $500 million on associated gas field development. Origin energy says it has been granted development approvals for more than 2,500 MW of high efficiency gas-fired power stations in Queensland, western Victoria and South Australia.

These two submissions show that a volatile situation exists where much is happening on the CSG front in Queensland and less so in NSW, but not yet well recorded in official government documents and websites.

Other states

In Victoria the bulk of the *onshore* Otway Basin is now covered by Minerals Exploration Licenses or Exploration License Applications to explore for CBG. Drilling began in 2005.

In South Australia 13 Petroleum Exploration License Applications were under consideration in 2004, pending resolution of issues of conflicting rights with coal leases.

In Western Australia, several Special Prospecting authorities and a Drilling Reservation were granted in 2004 to explore for CBG in the Perth Basin. Target coal seams exist in the Sue Coal Measures of Permian age in the Vasse region near Busselton, where the drilling of five test wells began in 2005 *(GSA 2004).*

There is an urgent need for governments to develop a national strategy for coal seam gas in Australia in the context of wider natural gas issues. Such a strategy needs to be bedded in the context of declining natural gas production in Europe and North America.

DISCUSSION

Chris *Skrewbowski (2007)* published his annual review of the status of LNG mega projects in July, the earlier status of which was discussed in Appendix 2[26]. He said several factors in addition to cost escalations, material and skilled staff shortages and other factors, had contributed to the postponement of LNG projects in 2006 where construction had not commenced. Among these were concerns that not enough LNG tankers and re-gasifying terminals would be built to transport and receive all the LNG from new plants. He said these fears were now unfounded, there would be a surplus.

Another source of anxiety was the impact of high gas prices on gas consumption in late 2005 and early 2006 following on from the disruption caused by hurricanes in the Gulf of Mexico. Despite a cold winter in Europe high retail prices reduced demand in 2006, especially in the UK where gas production is falling. Steep rises in UK gas and electric power prices followed. This was partly in response to Russia's dispute with the Ukraine over gas transit charges for Russian exports to Europe and the low prices that the Ukraine pays Russia's Gazprom for gas. The dispute led to fears of supply disruptions from to Russian gas. If Russia is to develop new Siberian gas fields and build long pipelines to supply Europe, it must sell the gas at higher prices.

In the USA gas consumption also fell slightly, partly because of an exceptionally mild winter in 2006, but also due to a range of other factors limiting demand growth. These include more attention to end-use energy efficiency and fuel substitution, but also reduced industrial use—some petrochemicals from US plants are no longer competitive on international markets. The gas markets in 2006 proved to be more 'elastic' than expected, creating the perception of possible excess LNG capacity after 2010.

He says material and skilled staff shortages as well as rising construction costs are still

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[26] He is the editor of the UK Petroleum Review and a member of the Asscn for the Study of Peak Oil.

delaying LNG liquefaction projects worldwide. The weather is another unknown factor—it has a bigger impact on gas consumption than it does on oil because of its role in winter heating. Altogether Skrewbowski expects the delayed plant construction will lead to LNG shortages as we move into the next decade—it will override the factors limiting consumption. Companies also tend to under-estimate the rate at which gas production can decline once this starts. *See Appendix 2 and Laherrére (2006).*

Economic consequences

We discussed earlier that the high cost of transporting natural gas makes natural gas production/consumption a regional rather than global phenomenon compared to oil supply. This applies to Australia too. Over 90 percent of gas reserves are located off the northwest coast remote from population centres on the east coast and the southwest corner of Australia. The possibility of long distance transport of gas is now becoming viable as production decline in North America and Europe raises the sale price of LNG. There is an accompanying decline in the EROEI of natural gas, the extent of which is still to be determined. *The advocates of the "Magic Pudding" vision do not understand this basic fact. There is a role for natural gas in Australia, but it is quite different to this vision.*

There are other mining-based projects as well underway in Western Australia, driven mainly by the dramatic growth in exports to China. Iron ore exports have increased from 162 M.tonnes in 2000/01 to 250 M.tonnes in 2006. The sale price has doubled. New mines, railways and port extensions under construction will expand capacity to over 300 M.tonnes per year by mid 2008[27]. **Table 14** shows the principal minerals mined for export in Western Australia and their percentage of world production *(WADOIR 2007).* This State plays a major role in the Asian regional economy through its export of minerals and natural gas, especially to Japan and South Korea—and during this decade to China on a scale that is rapidly becoming the dominant market. Australia as a whole is the world's biggest exporter of coal, mainly to the Asian region, and an important supplier of copper, uranium and lead.

TABLE 14
Western Australian mineral production

Mineral	Percent of world
Alumina	17
Diamonds	18
Ilmenite	18
Iron ore	18
Nickel	15
Rutile	26
Tantalum	54
Zircon	32

Source: Dept of Industry and Resources WA
www.doir.wa.gov.au/mineralsandpetroleum

Table 15 gives an overview of Western Australian projects in mineral resource development that are in progress or in the planning stages *(WADOIR 2007).* Oil, gas and

[27] Rio Tinto, the major iron ore miner, anticipates a capacity of 500 M.tonnes/year is possible by 2015.

condensate represent over half the value[28]. Three LNG plants yet to commence have a nominal value of $24 billion[29]. Cost escalations for all these projects are likely to push the total to $100 billion or more. The six iron and steel projects under construction are in the Pilbara (~$6-7 billion), the other is Rio Tinto's Hismelt iron plant at Kwinana[30]. Most of the other iron ore projects are smaller ones inland from Geraldton. All these iron ore projects face substantial cost increases and require construction of new railways and ports. Petroleum products (diesel) and natural gas are primary fuels used in their construction, operation and service provision.

TABLE 15
Western Australian primary resource projects in progress and planning

Project Group	**Number**		**Value**	**Employment**	
	Started	**Total**	**Million $**	**Construction**	**Permanent**
Iron and steel	7	14	19,650	9,400	3,200
Nickel/cobalt	1	2	3,200	2,400	650
Petrochemicals	1	3	1,500	1,700	280
Oil, gas.condensate	7	10	37,000	11,600	1,500
Other	5	11	10,700	7,100	3,200
Total	**21**	**40**	**72,000**	**32,800**	**9,000**
In progress – approx	21		30,000	11,000	2,000

Source: Dept of Industry and resources WA
www.doir.wa.goc.au/documents/mineralsandpetroleum

The permanent employees over all projects are only 20 percent of those directly employed during construction. For oil, gas and condensate this figure is 14 percent (10 percent for LNG projects) and one third for iron and steel. Even greater numbers would be *indirectly employed* in support industries and services. Some items would be imported, about half the value of LNG projects.

Rio Tinto has just accelerated its iron ore projects in the belief that China's boom will continue for another 20 years. Current expansion by all players will raise capacity to 440 M.tonnes in 2009. Rio Tinto plans to increase its capacity from 220 M.tonnes/yr in 2009 to 320 M.tonnes/yr next decade[31], while BHP Billiton is preparing plans to double its capacity to 300 M.tonnes by the middle of next decade, taking Australian capacity to over 650 M.tonnes/yr, a threefold increase in 15 years (AFR 2007a). The investment and labour listed in Table 15 will increase significantly.

There is a large and unsustainable expansion of the construction industry, where natural gas related projects dominate. Their work force during the construction phase is large, but these capital-intensive industries have a small permanent work force of around one employee per $25 million investment in oil and gas projects (dominated by LNG plants) and $6 million for iron ore projects. The role of natural gas in mining is growing,

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28 Woodside Energy committed to develop the Pluto LNG project on 27 July 2007 for $11 billion, more than double the first estimate of $5 billion in early 2006. Additional work is included in the 2007 estimate.

29 The three are the Gorgon project, and two in the Browse Basin.

30 The HiSmelt process has been in development for 25 years and the first full scale plant is being commissioned now. It is more energy efficient than current iron production processes, producing an improved product with less pollution. The existing technology will become obsolete.

31 70 million tonnes/yr will be from a mine in Guinea in Africa.

especially where processing of ores is involved, often the case for nonferrous metals. There is a potential for LNG to replace diesel in transport and mine operations.

The boom in minerals is being driven by phenomenal economic growth in China—its steel production has quadrupled this decade to about 40 percent of world production. The booms cannot go on forever—the large high-grade petroleum and ore reserves are finite and China's economic expansion is rapidly running into major environmental, resource and social constraints that can no longer be ignored *(AFR 2007b).*

But there is an important difference between the mining and natural gas booms in Western Australia. The boom in LNG is being driven in the first instance by depletion of gas resources in North America and Europe who consume 45 percent of world gas production (Appendix 2). The depletion of many high-grade minerals is also looming, being hastened by China's growth, but not yet on the scale of natural gas and oil.

No one in business and government circles is questioning the realism of these Chinese growth visions.

The first large offshore gas fields in the Carnarvon and Browse Basins were discovered 30 years ago in remote locations, many in deep water. They are what the industry calls "stranded gas", too far from markets to be commercially viable because of the high cost of transporting natural gas. The initial development offshore by the NWSJV was only made possible by two 20-year contracts with the WA government, through the State Energy Commission, and ALCOA for its alumina refineries. *These made construction of the Dampier Bunbury Natural Gas Pipeline viable, but only for gas fields in shallow water. The dominant market was for local buyers only.*

The deepwater and more remote fields are becoming viable now *due to rising LNG prices arising from depletion of natural gas fields in North America and the North Sea. These prices are flowing through to the local market. No one is questioning whether these new markets can continue buying LNG when there own gas production continues to decline in parallel with a corresponding decline in their crude oil production.* Crude oil production *in the USA has been declining since 1971, and since 1999 in the UK.*

What changes have occurred since 1994-95 in the EROEI for fossil fuels *(Table 9) and the Energy Multipliers (Table 10), and what are the likely trends? The huge increases in capital investment in primary commodities must be absorbing a significant amount of current energy supply (declining EROEI's for natural gas and oil, increasing Energy Multipliers in other sectors). How much of the rising capital cost of these projects is due to declining EROEI arising from this investment.* ***Energy spent on these capital investments is energy not available for use elsewhere.***

There is an acute shortage of engineers and trades people in Western Australia. These are the skilled workers who are in the front line applying fossil fuel products to the extraction and transformation of fossil fuels, and for their subsequent use in the primary production and secondary sectors. *How much is this shortage due to a deterioration of the energy quality of fossil fuels and how much to other factors?* Is a greater proportion of labour now being used to produce these fuels than in applying them to productive and useful purposes?

There are many reasons for the acute housing shortage and affordability crisis in Australia, as well as for shortages of schools, teachers, hospitals, doctors and nurses. *To what extent is this also due to the declining energy quality of fossil fuel inputs as well as intense competition with new minerals and petroleum development projects for this fuel?*

When the intense construction boom does subside what will be the future of those employed in servicing the construction industry? It will surely shrink. At the same time we will have depleted a substantial proportion of our ultimate oil and natural gas production.

What are the consequences later this century for our urban and economic structures built around unsustainable exploitation of our finite high-grade mineral resource base?

Business evaluates the economic viability of large resource projects by cost-benefit studies based on discounted cash flows for up to 20-25 years. There is an implied assumption that new projects can always replace the current ones when these cease to be viable*. Is this approach of discounted cash flows now leading us to a future that will be fully discounted as EROEI's and ore grades decline?*

The scale of our exploitation of natural resources now needs comprehensive assessment over a longer time frame to take account of the diminishing resource base. Only governments can lead in this field.

The shift of price control for LNG from a domestic buyers market to a sellers global market in Western Australia challenges the "Magic Pudding" vision for natural gas. It is time we had a more broadly based long-term perspective from industry and governments.

Managing risk

Business and many other sectors make comprehensive assessments of risk as a central component of corporate culture. These range from worst to best-case scenarios, often with probabilities attached. The petroleum industry, out of commercial necessity, has some of the most sophisticated assessments when it comes to assessing oil and gas reserves and their related development risks. The detail is commercially confidential. They shy clear of publicly admitting petroleum is a finite depleting resource, except in muted ways. *Government agencies are less inclined to make such rigorous risk assessments.*

Publications on minerals and petroleum by the WA Dept of Industry and Resources reflect this approach. They contain valuable information and publish 90 and 50 percent probabilities for oil and gas reserve estimates provided by companies. But in a restrained way there is a culture to pursue growth of resources development to the limit, an eagerness for promotion of growth without serious discussion and assessment of the longer-term consequences and how to adapt to the *inevitable depletion* of high quality mineral ores and petroleum. The natural gas resources in Western Australia are central to this, being a vital primary energy source.

There is 'risk' assessment at the optimistic level, but not more sober ones for strategies to adapt to the inevitable declining quality of non-renewable fossil fuel and mineral resources.

Governments must publicly engage with communities in inclusive ways creating strategies to adapt to this inevitable depletion of high quality mineral ores and petroleum resources.

Petroleum products obtained from giant oil fields are far superior to any alternative fuels for transport *(Gever et al. 1991).* Crude production is declining. A critical factor is the role LNG can play as a freight transport fuel in managing the transition to an era 'Beyond Oil'. This is a most important role for our remaining natural gas: enabling a decades-long transition to a less transport intensive system and finding the balance between feasible alternative fuels to oil-based ones on one hand and transport demand management initiatives on the other. These must aim to reduce power-driven transport functions to essential needs.

This is the neglected side of risk management practice. We ignore it at our peril.

Uranium mining

The specter of Climate Change driven by CO_2 emissions from the burning of fossil fuels has raised interest in the role that nuclear power could play as an alternative to electricity generation using fossil fuels. The nuclear power lobby says it produces far fewer greenhouse gas emissions. Australia is a major supplier of uranium and there is scope for uranium mines in Western Australia.

There are 441 nuclear power stations in the world that consume about 70,000 tonnes of uranium a year. More are under construction. *Currently about two-thirds of the uranium comes from mines.* Some of the remainder comes from dismantled nuclear weapons. The rest comes from diminishing stocks of uranium accumulated under long-term supply contracts following the collapse of nuclear power station construction after the near-meltdown of the Three Mile Island nuclear power station in the USA. *These sources will be depleted about the middle of next decade, the immediate reason why there has been a sudden upsurge in uranium prices and interest in uranium mining.*

One-third of the mined uranium comes from Canadian mines with extraordinary high ore grades, averaging 8 percent uranium per tonne of ore[32]. These mines have a limited life and this source of uranium will also decline during the next decade. *Hence uranium produced from mines with much lower grade ores will have to double in the next ten years.*

The tonnes of ore that must be mined, milled, processed with acids to produce uranium 'yellowcake'[33] is inversely proportional to ore grade. Fossil fuels are used for this purpose, principally petroleum products, and the quantity needed is inversely proportional to ore grades. The acid wastes present a disposal problem that increases with decreasing ore grade *(DofP&C 2006).*

About 160 tonnes of uranium is needed each year to fuel one 1000 MW power station. At 8 per cent ore grade that is 2,000 tonnes of ore, at one percent, 16,000 tonnes, 0.1 percent 160,000 tonnes and 0.01 percent over two million tonnes. A 1000 MW coal-fired power station needs about three million tonnes of coal a year. The lower the ore grade the more energy inefficient is the uranium extraction process. There is a corresponding increase in the quantity of acid wastes to be disposed of as ore grades decline. The fossil fuel input at 0.1 percent grade is 80 times that at 8 percent grade *(DofP&C 2006). This is the Achilles heel of nuclear power.*

Over time the EROEI of natural gas and other petroleum fuels will decline due to resource depletion, further increasing the indirect fossil fuel input to uranium as a nuclear power fuel. The same trend will also impact adversely on the energy cost of building nuclear power stations. ***Current cost projections of nuclear power made by the nuclear power lobby do not take this important factor into account****.*

Natural gas is likely to be a key fuel for uranium mines developed in Western Australia.

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[32] One significant Canadian mine yields 20 percent grade uranium ore.

[33] Yellowcake is U_3O_8.

LIMITS TO CRUDE OIL PRODUCTION

The transition begins

The developed world's 25-year strategy to minimise the use of Persian Gulf oil has run its course. Only this region, with some 60 per cent of the world's remaining conventional oil, has the potential to provide limited additional supply at moderate cost beyond 2010, when world oil production may peak. We must now face the consequences of oil depletion and address the major issues on the downside.

The approaching peak of conventional oil production has been openly discussed in oil industry journals since 1998 (e.g. *Petroleum Review* and *Petroleum Economist* in the UK and *World Oil*, *Offshore* and *Oil & Gas Journal* in the USA). Production has been declining in the USA for 35 years and decline has commenced in the North Sea, Argentina, Egypt, Syria, India, Colombia, Mexico and Venezuela and Mexico *(IEA 2007).*

Production declined in the Former Soviet Union after its collapse in 1990. Production has recovered since 1999 when oil prices rose and the Russian economic and political climate stabilised under President Putin. But it could decline again in the near future. Production has been growing in deep water offshore since the late 1980s and could continue increasing to about 2010 (Gulf of Mexico, Brazil, Nigeria and Angola). *Laherrére (2006)* gives a comprehensive snapshot of the state of world oil and gas production. *But can Persian Gulf oil producers meet the coming shortfall later in the decade?*

A UN Security Council team inspected Iraq's oil facilities in January 2000 and concluded that without spare parts and several billion dollars for urgent oil field refurbishment, production would decline and permanent damage to oil fields was possible *(Townsend 2000).* The US inspired invasion of Iraq has severely compromised revival of Iraqi oil production, the only Middle East country with significant undeveloped giant oil fields.

The Middle East population has quadrupled since 1950 to over 130 million people and could double again in 30 years. Excluding Iran (population 65 million and one of the most food self-sufficient), the doubling time is around 30 years. *Over 60 million people depend on food imports paid for from oil export income.* The era in which ruling families could use seeming endless oil revenues to buy the loyalty and silence of the population is coming to an end *(Youngquist 1999).* Satellite television allows the population to observe how most people in oil-fuelled developed nations lead more prosperous lives.

Saudi Arabia produces 12 percent of the world's oil from about 2,000 wells. The USA produces eight per cent from 550,000 wells. Saudi Arabia is the centre of the fundamentalist Wahhabi Muslims, a sect associated with the Saudi's since the 18th century. Their ascetic values frown on luxurious and ostentatious living, as you would expect from a desert people. Unemployment is high and it is difficult for the Kingdom to expand employment opportunities, fund welfare and other subsidies in the face of a rising population. Fiscal constraints raise awkward questions: *Why should ordinary Saudis tighten their belts unless the 6,000 or so princes of the royal family do the same?*

The Saudis try to quell discontent by funding 'neo-Wahhabi' radicals and their education network, including in parts of Africa and in Pakistan. The latter gave rise to the Taliban and their role in Afghanistan. These radicals are xenophobic, anti-western and are critical of the Saudi ruling family.

The political risks to future Australian oil imports were high on the agenda of APPEA's Barry Jones and Woodside's John Akehurst. The USA consumes 25 per cent of world oil and imports 65 percent of this at a cost of US$1 billion a day at current prices.

A permanent oil supply shortfall is emerging under circumstances of high political risk. The risk of supply disruption is very high. But that is not all.

The limits of good agricultural land in the world were reached 50 years ago. Much new agricultural land developed since is marginal, not suited for agriculture and degrading rapidly. Since the 1950s crop yields per hectare have more than doubled to feed a doubling of world population (Brown 1999). Mechanisation, petrochemicals, fertilisers and use of high yielding hybrid grain varieties combined to produce the so-called Green revolution in Asia, with the first three fuelled by oil and natural gas. Modern agriculture has been described as the use of land to convert petroleum into food (Youngquist 1999).

About 90 per cent of the direct and indirect energy used in crop production is oil and natural gas. About one-third is used to achieve a hundred-fold reduction in the labour input per hectare in countries such as Australia through mechanisation. The countryside has been depopulated and urban populations have soared. The remaining energy is used for production, of which about two-thirds is for fertilisers *(Conforti & Giampietro 1997).* The principle grain exporters, the USA, Canada, Europe, Australia and Argentina, are highly dependent on petroleum-based industrial agriculture. *In Australia a drying climate threatens this export capability.*

Nitrogen fertilisers play a critical role. The starting point is the synthesis of ammonia from atmospheric nitrogen and hydrogen obtained from natural gas at a pressure of 200 atmospheres and 350^{o}C in the presence of catalysts. *Smil (2001)* says the world reached the limits of providing an adequate protein diet by using legumes and animal manures around 1960. Since then adequate protein diets for a doubling of world population have been achieved through enhanced crop yields in which nitrogen fertilisers have played a key role. World production of nitrogen fertiliser has increased from 10 to 85 million tonnes as nitrogen since 1960, with two-thirds used in Asia. The Indian-owned ammonia/fertiliser plant at Burrup Peninsula manufactures nitrogen fertilisers for export to India. Nitrogen fertilisers play a significant role in Australian agriculture.

How can the world manage a reduction and re-distribution of population to levels that can be fed without the need for a petroleum input to agriculture? This agenda must have first call on the world's remaining oil and natural gas. These issues lie behind the growing refugee problems in the world.

ENHANCED GREENHOUSE ISSUES

The Intergovernmental Panel on Climate Change (IPCC) uses 40 scenarios by climate change researchers in its assessments of the possible climate change impacts of carbon dioxide emissions from burning of fossil fuels. These scenarios have a wide range of production profiles for oil and natural gas to 2100, which leads in turn to a wide range of possible climate impacts. However, the IPCC has not assessed the probabilities that should be attached to each of the scenarios. The IPCC technical committee that discussed the issues could not reach agreement *(Pittock 2002).*

Laherrére (2001) has compared these 40 production profiles for oil and gas with his *most likely* production profiles for these fuels. In both cases his profiles are at the bottom range of the IPCC scenarios. His assessments date from the mid-1990s and are based on the collective lifetime experience of recently retired petroleum geologists. The time has arrived for IPCC to review the validity of those climate change scenarios based on the more extreme carbon dioxide emission cases for oil and natural gas. *The decline of oil and natural gas production will be major drivers reducing emissions responsible for global warming.*

Of course there is much more to energy policy issues than climate change from enhanced greenhouse effects arising from fossil fuel use.

Depletion of cheap hydrocarbon fuels is going to drive down their consumption long before nations agree to and implement their reduction for enhanced greenhouse reasons.

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APPENDIX 1

Petrochemical & LNG Plant Vision 2002
Gas Supply Estimate
Data Sources

The *Western Australian Oil and Gas Industry 2002,* published by the W.A. Department of Mineral and Petroleum Resources had a graph on p.10 showing potential gas growth in Western Australia to 2015 covering petrochemicals and mineral processing projects already announced by companies but not yet approved for construction—the “wish list” of projects. It included estimates for projects where the government had been approached by companies, but where announcements had not been made. This graph, with other information, was used to compile gas production profiles needed to 2020. It was assumed plants would take three years to reach full production.

Additional information was obtained from *Energy Western Australia 2001,* published by the Office of Energy in Western Australia. It provided data on some natural gas contracts with contract end dates. Austeel’s proposed iron and steel plant was assumed to start-up after 2010. There was inadequate information on likely future consumption of natural gas for electric power generation, possibly due to uncertainty created by proposals for a competitive wholesale market for electricity being evaluated at the time. The industry seems to be shifting to natural gas. Some additional projects in ABARE’s *Australian Gas Supply and Demand Balance to 2019-20* were included and not listed in the State government documents *(Fanstein 2002).*

It was assumed that the Dampier Bunbury Natural Gas Pipeline would be duplicated, but that not all of the capacity would be contracted to gas from the North West Shelf Joint Venture (NWSJV) and the proposed Gorgon project. The Goldfields Pipeline was assumed to reach capacity, but that most of the gas would come from minor producers. This paper has focused on the future of the NWSJV and Gorgon projects that dominate gas supply and will continue to do so.

Woodside Petroleum’s recent Annual Reports were another source of information, mainly to cross-reference their reported reserves against government sources. These provided guidance on the likely proportion of unaccounted for gas arising from discrepancies in gas metering, unmeasured gas and leakage, as well as on gas used ‘in-house’ by gas producers to run their offshore platforms and gas processing plants. Liquefying natural gas consumes 5-10 per cent of the gas input to LNG plants.

The NWSJV’s three LNG trains in 2001 could produce up to 7.5 million tonnes of LNG per year. The fourth train was commissioned in 2004 at 4.2 million tonnes per year. A fifth train of 4.4 million tonnes of LNG has commenced construction for start-up in 2009, based on a contract to supply China. Table A1 lists petrochemical and LNG projects that were on the Governments published “wish list” for the Karratha region in 2001.

At the time the exchange rate for the A$ was around US$0.60. Since January 2004 it has been over US$0.70 and is now over US$0.80. This change has made the petrochemical plants non-viable. Only the Burrup ammonia and fertiliser plant has been built and commissioned in 2006. The 2001 “wish list” has collapsed.

TABLE A1
Petrochemical and LNG plants as at 2001
Construction costs as at 2001

Projects	A$million	Tonnes/yr	Gas Bcm/yr	Start-up
Methanex Methanol No.1	2,000	4,000,000	2.80	2005
Burrup ammonia & fertiliser	600	760,000	0.85	2006-07
GTL Resources methanol	610	1,000,000	2.85	2005-06
Syntroleum GTL plant	1,000	470,000	3.70	2005-06
Plenty River ammonia urea	900	1,200,000	0.85	2006
Japan DME dimethyl ether	1,000	1,700,000	1.50	2010
NWSJV LNG 4th train	1,600	4,200,000	5.50	2004
NWSJV 5th train	1,600	4,400,000	5.50	2009
Total	**9,310**		**24**	

Western Australian Oil & Gas Resources 2002, p.10
WA Office of Energy, Energy Western Australia 2001

REFERENCE

Fanstein, M., Harman, J. & Dickson, A. 2002, *Australian Gas Supply & Demand to 2019-20,* Australian Bureau of Agricultural and Resource Economics, Canberra.

APPENDIX 2

OUTLINE OF WORLD NATURAL GAS SUPPLY

Table A2.1 shows the status of world natural gas reserves, production, consumption, exports and imports for major regions in 2006 *(BP 2007, pp. 22-31).* Discrepancies between production and consumption, and export and import figures would be due to variations in local storage, gas used in transport, leakage and errors in measurement. Some countries store gas in suitable geological structures in the summer for withdrawal in winter to meet demand for heating. Europe includes Eastern Europe, the former Yugoslavia and Turkey. Asia Pacific includes the Indian sub-continent eastwards and Australia-New Zealand.

TABLE A2.1
World Natural Gas 2006
Billion cubic metres

Region	Reserves	Production	Consumption	Exports	Imports
Nth America	7,980	75	770	2	8
Sth & C. America	6,880	145	131	15	0
Europe	6,300	294	533	0	209
Former Soviet U	57,830	779	813	152	0
Middle East	73,470	336	289	65	8
Africa	14,180	180	76	101	0
Asia Pacific	14,820	377	438	0	50
Total	**181,460**	**2,865**	**2,850**	**326**	**273**

Source: BP Statistical Review of World Energy 2007, pp.22-31.

The Former Soviet Union (FSU) and the Middle East have 72 percent of reserves. Russia has 80 percent of FSU reserves (47,650 Bcm). Qatar (25,360 Bcm) and Iran (28,130 Bcm) have 72 per cent of Middle East reserves (29 per cent of world reserves), mostly in one field complex spanning the Persian Gulf. *But these figures are unreliable and most likely over-stated—discussed further below.*

North American *imports* are all as liquid natural gas (LNG), as are *exports* from South & Central America and the Middle East. Venezuela and adjacent islands have 70 percent of South & Central American gas reserves, all exports are as LNG. FSU *exports* are all by pipeline and nearly all to Europe, and mainly from Russia. Africa's main *exports* are to Europe by sub-sea pipelines to Italy and Spain from Algeria, and as LNG, with lesser amounts to North America and the Asia/Pacific. Middle East *exports* are mainly to the Asia/Pacific as LNG. There are large exchanges *within* the FSU, Europe and the Asia/Pacific, the latter almost entirely as LNG, and it is currently the biggest LNG market.

The seasonal variation in gas consumption is often more variable than for oil due to the role that natural gas plays in winter heating and for electric power generation (gas turbines), especially where there is wide use of air conditioning in summer. *The weather will play an important role in determining when gas supply crises emerge.*

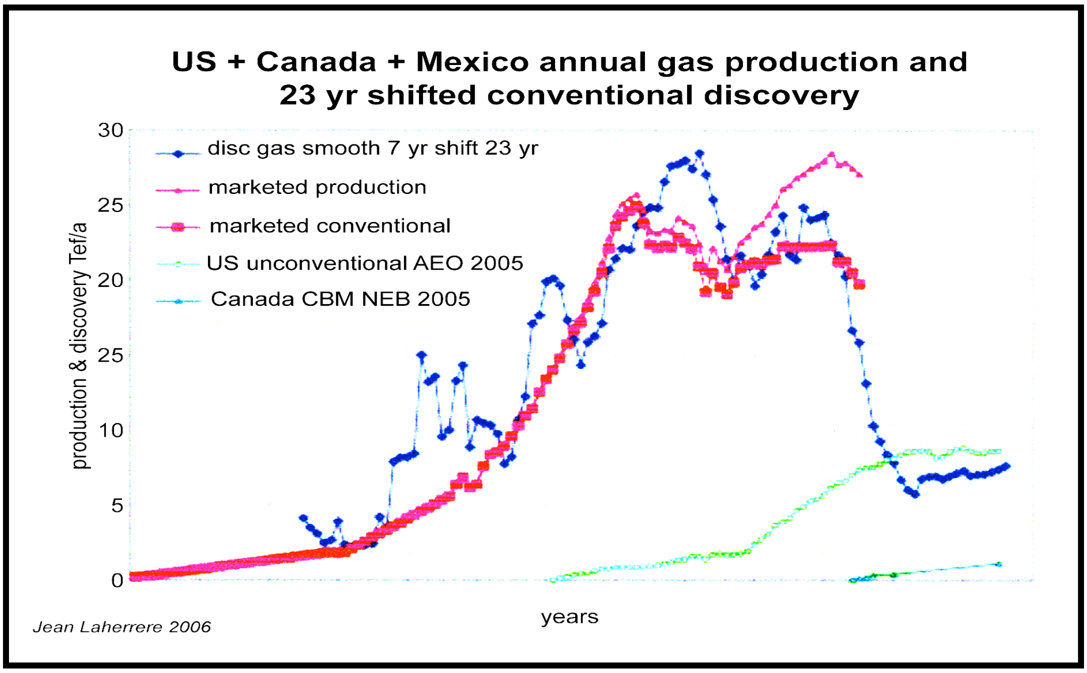
The cost of transporting natural gas any distance is six to ten times more expensive than the equivalent for oil, with LNG the most expensive. The liquefaction process consumes 5-10 percent of the natural gas input to the plant and LNG ships for international trade are two to three times the cost of equivalent oil tankers. At the terminal ports some of the LNG must be used to re-gasify the LNG. One percent of the gas entering a pipeline is consumed for every 500 km by compressors that pump the gas to consumers.

North America

The USA consumes 80 percent of North American natural gas and imports 16 percent from Canada. Production is declining. **Figure A2.1** plots the North American discovery profile since 1900 moved forward 23 years to show how the production profile mimics the discovery profile. The pink line shows the production from both gas fields (solid red line) and coal seam gas (green lines). About 80 percent of the discovered gas has been consumed *(Laherrére 2006, p.21).*

Since 1980 liquids from gas have been extracted and marketed separately and only the dry gas is sold. Coal seam gas has reached a plateau and *total* production will soon be a steep decline. 11,000 gas wells were drilled in the USA in 2000 and 27,000 wells in 2006, but production still declined *(Laherrére 2006, p.22).* The latter required over 1,400 drilling rigs, 45 percent of the world total. The USA is the most intensively explored and drilled petroleum region in the world.

FIGURE A2.1



Source: Laherrére 2006, p.21

There are proposals to tap gas from Alaska and NW Canada but these would cost about US$20 billion each and if built are unlikely to deliver gas until after 2015. The gas supplied would not compensate for the production decline in the interim.

From the late 1990s there was a steep increase in gas turbine electric power plant installed in the USA and the companies were unaware of the looming gas shortage. Wholesale gas prices have more than trebled and industrial use has declined and gas fired electric power plant use has been limited. Consumers are responding by adopting energy efficiency and substitution measures.

When the supply shortfall becomes real *the industry will have to give priority to domestic use to avoid the risk of air entering the gas reticulation network where it would pose a major fire hazard. Pipelines would be shut down for months to remove the air. Gas turbines play a key role in keeping electric power networks stable by responding rapidly to system failures. Diverting gas to domestic consumption in supply shortfalls increases the risks of system failures in electric power networks.*

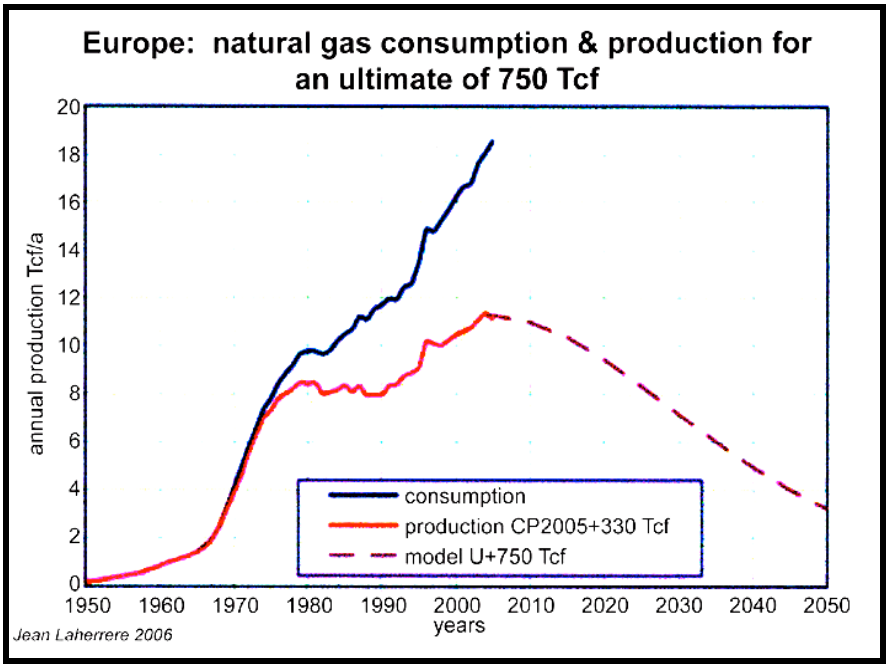
Europe and Russia

Nearly all of European gas production comes from gas fields in the North Sea. Production has commenced a steep decline in United Kingdom gas fields since 2002, by nearly 9 percent in 2006—80 percent of discovered gas has been consumed. The Netherlands and Norway will follow in turn—gas fields in the North Sea will be in steep production decline from about 2010 when 80 percent of North Sea discovered gas will have been consumed *(Laherrére 2006, p.22),* **Figure A2.2**.

A pipeline connecting Netherlands gas fields to the UK has been increased in capacity, but these will need to be supplemented by new gas pipelines from Russia from 2010 *(Nicholls 2004).* Russia's Gazprom is a partner in the project *(Gorst 2006).*

The UK is expanding its LNG import terminals but does not have the long-term supply contracts that other LNG importers have—importers pay spot prices. UK gas and electric power prices have risen steeply since 2005. Europe has also been installing significant numbers of gas turbines for electric power that compounds these problems.

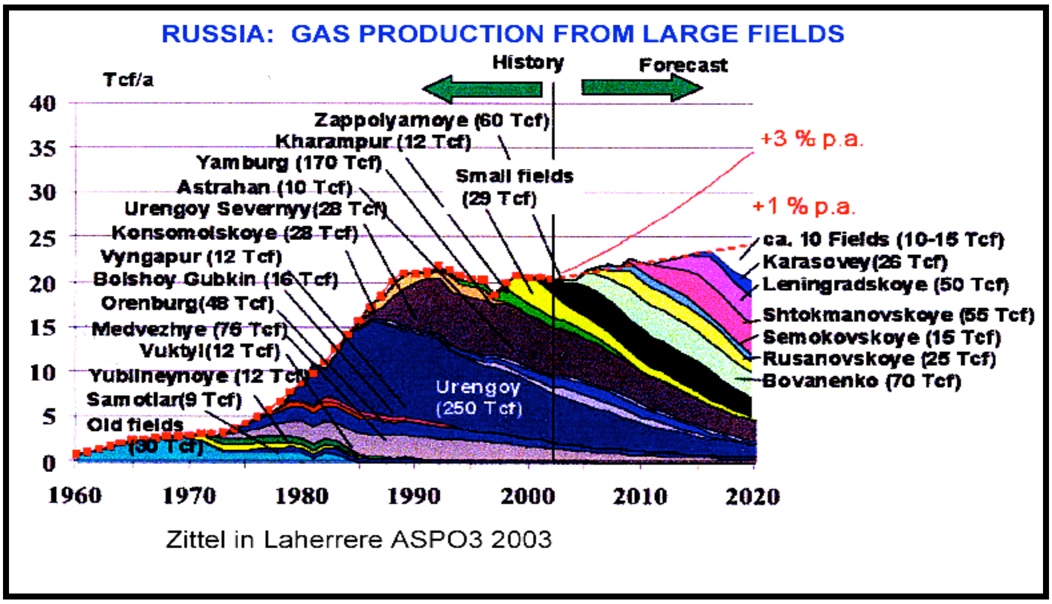
FIGURE A2.2



Source: Jean Laherrére 2006, p. 22

Laherrére (2006) maintains that Russian oil and gas reserves are over-stated by as much as 30 percent. He says their definition of reserves ignore social, environment and other constraints that limit options, a 10 percent probability estimate. The two largest Russian gas fields are already in production decline (Urengoy & Yamburg 11,900 Bcm). There are several smaller undeveloped fields (but still large compared to elsewhere), but they are in expensive-to-develop locations. *Will they be developed and pipelines constructed in time to compensate for the three large fields decline, and still expand production capacity?* It will be hard to justify new long pipelines if their capacity is only needed for a few years. **Figure A2.3** illustrates the position. It is possible that Russian gas production could begin decline around 2015-20 *(Laherrére 2004, p.43).*

FIGURE A2.3



LIQUID NATURAL GAS

Table A2.2 shows actual 2006 production and projected capacity to 2012 *(Skrebowski 2006).* New projects to 2010 are more or less all committed, though delays are likely due to resource shortages, discussed below. Sales of 210 bcm were made in 2006, a 22 bcm increase on 2004. About 10-12 percent additional raw gas is needed to fuel these LNG plants and the final marketable gas in the receiving countries will be reduced further as some of the LNG will be used for its re-gasification at the terminals.

TABLE A2.2
LNG EXPORT CAPACITY 2006-2012
Million tonnes per year

Country	2006	2008	2010	2012
Algeria	25	26	30	30
Nigeria	17	26	50	61
Egypt	15	23.5	24	24
Libya	1	1	1	1
Indonesia	29	40	44	53
Malaysia	28	28	29.5	37
Brunei	10	10	10	10
Australia	18	18	29	39
Qatar	31	51	75	83
Oman	12	14	14	14
United Arab Emirates	7	7	7	7
Iran	--	--	17	17
Yemen	--	6.5	9.5	9.5
Russia – Far East	--	9.5	9.5	9.5
Cent. & Sth America	16	18	27	27
Other	2	9	14	14
Total M.tonnes/yr	**210**	**290**	**390**	**436**
Total as gas, Bcm	**290**	**400**	**540**	**600**

Source: Skrebowski 2006 and BP Statistical Review of World Energy 2006

The unprecedented boom in LNG capacity is driven *first* by anticipated exports to North America and Europe to offset production decline, *secondly* for exports to China and India and *finally* by the attractions of natural gas as a low greenhouse gas emitter compared to coal and oil products.

Generally companies do not commit to LNG projects until sufficient long-term contracts for sales have been negotiated. Estimates in Table A2.2 from 2007 to 2010 are for plant already commissioned or under construction. Estimates from 2010 are more speculative as contracts are still under negotiation.

This is almost a doubling of LNG capacity to 2010. A corresponding increase in LNG receiving terminal capacity, LNG tankers and new gas field development is needed as well. All these projects are very capital intensive.

The principal markets for this *new* LNG capacity are in Europe and the USA where natural gas production is declining. The USA can import LNG from all these major suppliers, but with long trans-Pacific/Atlantic Ocean hauls. The US faces strong opposition to the building of new LNG terminals that will restrain its LNG import potential. Existing terminal capacity is being expanded, but new sites will be needed on the west coast. New markets are developing in China and India, the scale of which is as yet unclear, but potentially significant. China is getting alarmed at the rising costs.

Before discussing the realism of these aspirations we need to discuss other constraints.

Matthew Simmons[34] has doubt about the potential of the field shared by Iran and Qatar, which holds the world's largest gas reserves[35]. *"They've drilled only 25 holes in a tiny section in Qatar's North Field, and one has come up dry. That's why they announced a moratorium on further gas projects last April."* Reservoirs on the Iranian side are complicated, which is why development of South Pars has stalled *(Petroleum Economist 2006).* Qatar's moratorium was originally to 2008, now extended to 2010. There were two main reasons. Firstly, the acute pressure on construction resources and the flow-on to supporting projects arising from the rapid economic growth, a factor we in Australia are well aware of. Secondly, it was becoming clear that the North Field/South Pars reservoir is more complex and less homogenous than had been assumed. A review of the fields potential was needed to prove that the additional reserves existed to support plans to expand capacity to 25 percent of the global total by 2015.

There is doubt about Indonesia's capacity to expand LNG production. In 2006 Indonesia gas fields could not maintain production to meet its contractual commitments to Japan, and had to buy LNG on the spot market to meet these. It said it would not be renewing the contract that expires in 2010. Presumably new LNG plants would be supplied from discovered but undeveloped gas fields. An increase in capacity is unlikely until after 2010. Indonesia has become a net importer of oil and now plans to substitute natural gas for oil products wherever possible.

Construction of natural gas production capacity based on Iran's North Field is inhibited by US sanctions that penalise companies that do so.

US consultants Poten & Partners say the cost of constructing LNG units has been rising, partly as a consequence of higher prices for raw materials and partly because the world's LNG construction specialists are overwhelmed with orders *(Petroleum Economist 2006a).*

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[34] Matthew Simons is the founder and chairman of Simmons & Company, an energy investment company in Houston Texas servicing the energy industry, particularly for upstream oil and gas.

[35] Reputedly half of the Middle East's gas reserves, or 15-20 per cent of world reserves.

A driver of the boom in LNG projects from the late 1990s was falling construction costs. Larger train capacities (economies of scale) and other engineering developments had made LNG more competitive with pipelines, with some project costs at less than US$200 per tonne a year capacity. However, more recent contracts have been in the US$250-350t/yr range. Also the price of steel has doubled since early 2003 and nickel has nearly doubled. *These material prices are also impacting upon the cost of new pipelines and tankers.* There are only three big contractors for LNG units who typically completed only one or two trains until 2003. Ten trains are due for completion in 2009.

There is a massive increase in LNG shipping under way. The number of active LNG carriers increased from 154 in January 2004 to 175 in 2006. Last year the world order book increased from 56 to 107 (~US$200 million each) and the size of tankers is increasing. There is a similar rise in demand for offshore drilling rigs with steeply rising hire charges for some, such as deepwater rigs. A substantial increase in construction capacity is needed to meet demand. *This suggests the LNG capacity targets for later in the decade may not be achievable, or that rising costs will delay commitments.*

On gas fields, Matthew Simmons says: *"Every deep-water rig is at work, but it takes two or three years to test a block. If we had 300 rigs we could do it. But we only have 50 and the next ten will cost US$0.6-0.9 billion apiece—because shipyards are busy building container ships, LNG vessels and VLCC's …".* He does not envisage new deep water rigs being built before 2015, by which time rig hire charges will have soared from US$300,000 a day to close to US$1,000,000 a day *(Petroleum Economist 2006).*

The petroleum industry has an acute shortage of experienced professional exploration and production staff, and many are approaching retirement age. A new generation of young professionals is not emerging in the numbers required. The fall in oil and gas prices from the mid 1980s led to companies shedding staff and a slump in new graduates from universities *(Nicholls 2006).* Shortages of key staff may limit the expansion plans of the industry.

The sale price of new natural gas is going to rise—and already is in Europe and the USA. Add in rising oil prices and we have a climate for "demand destruction". For Europe this *may* shift the balance to new gas pipelines from FSU countries. But the geopolitical risks cannot be ignored. Diversity of sources of gas supply sources is important, a dilemma that European countries now face following the price conflicts between the FSU and Ukraine in the cold winter of 2006, when supply capacity was stretched. A mild winter in 2007 muted these conflicts.

This is the global background to the intensity of LNG development proposals in Australia and their economic impact on manpower and infrastructure. In Western Australia these economic stresses are compounded by the parallel boom in mineral development—iron ore, nickel and alumina—driven by the phenomenal economic growth in China.

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