NATURAL GAS: "MAGIC PUDDING" OR DEPLETING RESOURCE
VARANUS ISLAND FAILURE 3 JUNE 2008
CAN WE LEARN FROM IT?

Brian Fleay Version 4, 9 September 2008[1]

INTRODUCTION

Natural gas is half of Western Australia's primary domestic energy consumption, the major consumers being mining and mineral processing, chemicals, electric power and gas utilities that consume 95 percent of domestic consumption. Western Australia's economy, mining industry, electric power and residences are heavily dependent on natural gas.

On 3 June 2008 a gas pipe burst and caught fire at Apache Energy's Varanus Island processing plants. One plant was severely damaged another less so, cutting off 30 percent of Western Australia's domestic gas supply.

The major users and some service industries had to reduce consumption and the electric power industry took drastic action to reduce demand. Gas was hastily replaced with diesel at ten times the price costing $4.5 million a day. Costs from the failure could reach $7 billion. Partial supply was restored during July-August but it may be December before full supply is restored.

There will be a sobering reassessment of the future of natural gas in Western Australia*. Since the 1970's governments and bodies such as the Chamber of Commerce and Industry have regarded it as "The Magic Pudding", a nirvana opening the way to a golden future.* The reference here is to the famous book of this title by Norman Lindsay where there was always some pudding left over no matter how much of it was eaten.

Central to the reassessment must be the central role that energy plays in economic activity and the need for energy as well as dollar assessments in economic analysis. A key economic parameter is energy-return-on-energy-invested (EROEI). See the Appendix for more detail.

The Varanus Island failure underlined revelations in 2006 that reservations of gas for domestic consumption from LNG projects were seriously deficient just as long-term supply contracts made in 1979 became due for renewal. A global boom in LNG prices has led to the domestic market becoming a sellers market with short-term contracts, not a buyers one as it had been. Domestic gas prices under new contracts are rising steeply with the details hidden in commercially confidential contracts.

Mandated supply of domestic gas under the North West Shelf Joint Venture State Agreement Act 1979 will be used up by 2020 at current consumption rates. Decline of gas production is likely about 2020 at both the NWSJV and Varanus Island fields unless major discoveries are made and developed in the near future.

Mandated domestic gas supply from Woodside Energy's Pluto project and Chevron's Gorgon LNG project are limited and the latter is dependent on the project proceeding as development costs rise steeply to sequester the high levels of carbon dioxide in the Gorgon gas.

---

[1] This paper has evolved from version 1 in late June as my understanding of the Varanus Island failure and its ramifications grew. This version gives greater weight to the consequences for domestic natural gas consumption in Western Australia in the immediate future and its consequences for economic development and the resources boom.

Future supplies of natural gas in Western Australia face significant declines in EROEI with increasing energy investment per unit output. A similar situation is developing in petroleum products as the world's cheap and convenient oil sources are depleted.

Trades people and engineers are the workers whose prime task is organising the efficient use of energy to construct and operate the energy intensive LNG and iron ore projects and supporting service industries at the centre of the resources boom. The acute shortages of this labour class are a direct consequence of the resources boom and are being diverted to it at the expense of other infrastructure projects such as housing, hospitals, schools and their supporting infrastructure.

These shortages will limit the rate of development of new LNG projects to one at a time. They are by far the largest in the resources sector and dominate investment and the need for skilled labour.

This paper also explores the more serious consequences of a similar failure to Varanus Island at the NWSJV's domestic gas processing plant at Burrup. It supplies 70 percent of Western Australian's domestic gas and shows our vulnerability to disruption of gas supply.

There would be major economic consequences from such a failure and some are summarised below. The Australia wide and international impacts need investigation.

- Shut down of big gold mines, alumina and nickel refineries – force majeure declared on product contracts with global consequences for aluminium and nickel markets. Other mining operations could face similar consequences.
- Numerous minor industries and commercial businesses shut down or restricted.
- Electricity would be rationed in power grids in the Pilbara and South West Interconnected System (SWIS), putting at risk high power users, water supply and air conditioning.
- Sewage pump stations and public water supply at risk with severe water restrictions.
- Significant unemployment and financial consequences for everyone.
- Reticulated gas supply rationed – heating, cooking and hot water constraints.
- The internet may be compromised – impacts on the financial system are possible.
- The real cost of rising natural gas is hidden in commercially confidential contracts, a practice that needs prohibiting for key contracts.

There is an urgent need for a *Western Australian Natural Gas Strategy 2060* to address long-term solutions to the impending shortage of natural gas supply and rising prices for domestic consumption. The consequences of high and low consumption rates need evaluating. Risk management strategies are needed to improve supply resilience and limit the impact of failures such as happened at Varanus Island.

The vision of continuous economic and population growth must be questioned.

The need is discussed for greatly improved risk management approaches and its relevance in the Western Australian context for the future of competitive markets on both electric power and domestic gas supply.

But first some background to the natural gas industry.

HISTORY OF NATURAL GAS IN WESTERN AUSTRALIA

North West Shelf Joint Venture

Western Australia has over 90 per cent of Australia's gas reserves (excluding coal-seam-gas in Queensland and New South Wales) almost all offshore in the Carnarvon and Browse Basins off the northwest coast. 83 per cent are undeveloped and half of these are in deep water, expensive to develop and located in a few large gas fields.

Western Australia has 3,500 billion cubic metres (Bcm) of proved and probable gas reserves with more discoveries likely (DofIR 2008, p.79-82). About 75 percent is in the Carnarvon Basin that has been more thoroughly explored than the Browse Basin (DofIR 2008. p.6).

The first major development was made possible by the government building the Dampier Bunbury Natural Gas Pipeline (DBNGP) via the State Energy Commission of WA together with 20-year contracts for gas by SECWA and Alcoa with the North West Shelf Joint Venture (NWSJV)[2]. The contracts were on a take-or-pay basis[3]. The 1800 km pipeline, gas fields and initial processing plant were commissioned in 1984. This plant, now duplicated, is near its capacity and supplies nearly 70 percent of domestic consumption. Part of the pipeline has been duplicated and its capacity (785 TJ/day, 7.6 Bcm/year) is fully contracted (OofE 2003, p.25-26). There are branch lines to Carnarvon, Geraldton and some mine sites.

The 20-year contracts guaranteed domestic gas supply with the expectation at the time that renewals would also be for 20 years. These initial domestic gas contracts were the driver of the development of gas projects in the Carnarvon Basin and to LNG developments by the NWSJV. The NWSJV Agreement Act in 1979 allocated 133 billion cubic metres (Bcm) of gas for domestic consumption of which 76 Bcm has been supplied and the 57 Bcm remaining has been fully allocated (SLP 1979, DofP&C 2006).

The NWSJV's gas fields are located in waters under Commonwealth jurisdiction whose consent was necessary for these allocations as well as its agreement to forgo royalties on condensate to help make the projects commercially viable. In the early years some gas was extracted, the condensate removed for sale and the gas returned to the fields for extraction in the future.

The NWSJV was allocated gas in the Agreement Act for 6.5 million tonnes/year of LNG (9 Bcm/year)[4] for 20 years from the fields discovered at the time. *The first two LNG trains were commissioned at Burrup Peninsula in 1989 for exports to Asia.* A third LNG train was commissioned in the early 1990s and a fourth train in 2005. A fifth train will be commissioned this year taking capacity from 11.9 to 16.4 million tonnes/year LNG (22.6 Bcm/year).

Amendments were made to the NWSJV Agreement Act in 1985 that separated the LNG arrangements from Domgas and allowed SECWA to market additional gas to industrial customers in the Pilbara to 2025. From 2010 to 2025 the NWSJV was required to inform government of future LNG export proposals. Large gas discoveries were made by the NWSJV at Perseus-Athena in 2001 (257 Bcm). The field came on-line in 2007. The Angel field (52 Bcm) is expected to be on-line in 2008 (DofIR 2008, p.53).

---

[2] The NWSJV comprises Woodside Energy as operator, Shell, BP, BHPB, Japan Australia LNG & Chevron.

[3] These contracts required the buyers to pay for the annual contracted quantity even if they did not use it. Delivery would be made in subsequent years. By the mid 1990s Western Power had paid well over $300m. for gas it had not yet received. Delivery was made from the late 1990s as gas turbine capacity expanded and gas became more widely used by industry and commerce. Alcoa had similar contracts for its gas.

[4] Additional gas (about 7 percent) is needed to fuel the LNG plant.

Further amendments were made in 1994 to formalise the break up of SECWA into Western Power and Alinta Gas as government owned utilities, and the Agreement for domestic gas was extended to end in 2008. The domestic gas allocations were divided between Alcoa (170TJ/day), Western Power (120TJ/day + 12TJ/day for the Pilbara), Alinta Gas (95TJ/day), Hamersley Iron (14TJ/day) and Robe River Iron (4TJ/day), a total of 415TJ/day (4 Bcm/year)[5]. Government agencies had 227 TJ/day and others 188 TJ/day. The latest amendment in 1996 formalised the take over of Alinta Gas by Epic Energy and the latter sold out to Alinta in 2004[6].

Table 1 shows the 2007 production from the five NWSJV fields, cumulative production, reserves at end 2007 and the likely ultimate production, assuming constant supply from 2008. Additional gas consuming plant is coming on line to 2010, discussed further below.

Table 1

NWSJV Production Statistics 2007 by Field
Billion cubic metres

Field	Production	Cumulative	Reserves		Ultimate
			2007	2020 est.	
North Rankin 1984	2.9	186.5	161.3	100	348
Goodwyn 1995	7.1	107.7	85.1	10	193
Perseus 2001	12.8	70.9	232.5	100	303
Echo-Yodel 2004	1.3	12.4	0.6	0	13
Angel 2008	0	0	52.4	15	52
Total	**24**	**378**	**532**	**~225**	**910**
Domgas share	*~6*	*76*	*57*	*0*	*133*

Source: Western Australian Oil and Gas Review 2008, Dept of Industry and Resources WA, p.80-81.

Echo-Yodel will shut down before 2010 based on these figures and Goodwyn will begin decline about 2015. See discussion below.

***At 2007 consumption rates* this Domgas allocation from the NWSJV will be consumed by 2018*.* About one-third of domestic gas comes from small fields based on Varanus Island. But these too will only supply gas for about 10 years (discussed further below). And production from the five NWSJV fields should begin decline by 2020 when 75 percent of the original reserves will be depleted.**

As at 2007 remaining proved and probable reserves in the NWSJV gas fields were 532 Bcm in five fields for annual production of 24 Bcm. By 2020 these reserves will decline to about 220 Bcm at current production rates with production decline imminent (DofIR 2008, p.80-81).

But new gas consuming projects will deplete reserves to this level before 2020. Woodside Energy announced in March this year a $5 billion proposal for a second platform adjacent to the original North Rankin one to drill additional wells into this field and Perseus, start up in 2013. The CEO, Don Voelte, said "This project will extend the life of the North Rankin and Perseus fields and will support the venture's onshore gas commitments to supply customers post 2013" (Woodside Energy 2008). After 23 years this field must have reached a mature stage

5 One TJ (terrajoule) equals 26.46 thousand cubic metres of natural gas.

6 In 2007 Alinta was taken over by Singapore Power International, Babcock & Brown Power and Babcock & Brown International. These companies have extensive ownership of electric power and gas infrastructure in Australia and New Zealand. The B&B parent company is based in the USA. Babcock and Brown are currently facing a severe financial crisis arising from poor financing of growth strategies.

Varanus Island Natural Gas Hub

From 1996 Apache and Santos commissioned small gas fields off Varanus Island, east of Barrow Island. There are now two processing plants on the island connected to the DBNGP by two pipelines and operated by Apache. Other small offshore gas fields owned by minor companies have been linked to the processing plants. The Varanus Island plant is near its capacity and supplies about one-third of domestic gas, about 350 TJ/day (3.3 Bcm/year). Nearby undeveloped fields exist that are now economic after recent big increases in domestic gas prices (see discussion below). Reindeer will come on-line in 2009. *Table 2* shows the 2007 production, cumulative production, reserves and ultimate for these small fields serviced by Varanus Island.

Table 2

Fields Serviced by Varanus Island Gas Plant 2007
Billion cubic metres

Field	Production	Cumulative	Reserves	Ultimate
Bambra	0.05	0.25	0.16	**0.4**
Endyman	0	0.59	0.06	**0.65**
Harriet	0.01	1.48	0	**1.5**
Linda	Neg.	1.1	0.3	**1.4**
Rose	0.15	0.82	0.16	**1.0**
Wonnich	0.33	3.28	0	**3.3**
11 others	0.1	0.16	0	**0.15**
John Brookes (2005)	2.23	4.82	35.1	**40**
East Spar	0	6.86	0.2	**7**
Reindeer (2009)	0	0	12.7	**12.7**
Total	**2.9**	**19.4**	**36**	**55**

Source: Western Australian Oil and Gas Review 2008, Dept of Industry and Resources WA, p.80-81

All these fields except John Brookes should shut down by 2010 and John Brookes should begin decline before 2020 at current Varanus Island production rates. Apache has a vigorous exploration agenda with some potential small field discoveries.

Apache has announced construction of a new gas processing plant for the domestic market to be located onshore at Devil's Creek west of Dampier. The gas will come from its Reindeer/Caribou fields, 100km offshore (14 Bcm reserves). Start up is expected in 2010 (West Australian 2008). Apache has a vigorous exploration program.

BHPB's Macedon is a possible addition (200 km from Varanus Island, reserves of 18.4 Bcm), but it lacks condensate as an additional revenue source. Macedon is more in line with BHPB's Scarborough field (147 Bcm) north of Exmouth (DofIR 2008, p.80-81). Higher gas prices will encourage more exploration. Chevron operates minor gas fields on Thevenard Island south of Varanus Island.

The Goldfields Gas Pipeline (GGP) was commissioned in the late 1990s to supply inland mining districts down to Norseman. A branch line was recently extended to Esperance. A branch goes to Port Hedland and the Telfer goldmine in the Pilbara. These pipelines have spare capacity. Most of the Varanus Island gas is contracted to consumers on the GGP.

A small part of domestic gas comes from the Perth Basin at Dongara south of Geraldton and is delivered into the Parmelia Pipeline (about 30 TJ/day, 0.03 Bcm/year).

It was a long-term buyers market during this era and the gas price was until recently around $2-2.5/GJ (West Australian 2008a).

WHY DOMESTIC GAS PRICES HAVE RISEN STEEPLY SINCE 2006

The cost of transporting natural gas any distance is six to 10 times that for oil, because it is a gas. Transport as LNG is the most expensive. These cost factors mean production and consumption of natural gas tends to be more regional than for oil and the production cycle has flattened profiles compared to oil. The decline of production can begin when 75-80 percent of the extractable gas has been produced and can be rapid[7]. North America reached this stage 10 years ago and began in the UK in 2005, and will for Europe about 2010. These two regions consume 45 percent of world gas production, and their dependence on imports is increasing, especially Europe. Currently Asia is the main consumer of LNG (BP 2008, p.22-31).

This has sparked a global boom in building LNG plants and made LNG projects in Western Australia potentially economic that five years ago were uneconomic. The sale price of LNG has become volatile and has risen up to $7-9/GJ (DofIR 2008, p.10). Rising construction costs associated with the resources boom are also contributing to higher gas prices.

In 2006 the NWSJV told its domestic gas customers that future contract prices would be negotiated in the $5.5-6/GJ range to match the new profits from LNG. They would be limited to 5 years duration due to LNG price volatility, a more than doubling of the price. Some new domestic gas contracts have reached $7/GJ (DofIR 2008, p.10).

The original 20-year contracts expire this year. The price increases hit mineral and chemical processing plants hardest, particularly Alcoa and gas-fired electric power. It poses a dilemma for new mineral processing proposals whose sale prices depend on depreciating construction costs over 15-20 years when they can only be sure of gas prices for the next five years in a volatile market.

It is difficult to understand the short-term impact of the new gas contract market due to commercial confidentially provisions, especially on rise and fall clauses. Some contracts have expiry dates as late as 2010-15. These new high prices began feeding in during 2006 as new contracts are negotiated and will continue to do so as old contracts expire (OofE 2005, p.26).

But without the price rises it would be difficult to develop significant natural gas supply beyond the current NWSJV project.

However, higher domestic gas prices do increase the opportunities to explore for more small gas fields adjacent to Varanus Island.

Some commentators have advocated that contract prices for LNG should be linked to the Tapis oil price in Singapore that has doubled since early 2007. Further price increases for gas can be expected from carbon trading to combat climate change. What are the rise and fall clauses being negotiated for new domestic gas contracts?

The market for domestic gas supply is now a short-term sellers market.

---

[7] The stage of depletion when decline begins and the rate of decline will depend on the porosity and permeability of the formation, being later and steeper for porous formations.

IMPLICATIONS OF THE VARANUS ISLAND FAILURE

Evidence so far suggests a comparatively small steel gas pipe burst due to corrosion followed by fire that damaged and shut down both processing plants with major consequences. Other factors yet to be revealed may be involved.

The raw gas is mainly methane, CH_4. These plants clean up the raw gas by removing, carbon dioxide, sulphurous compounds, nitrogen and water (increases as the gas fields age). The first two with water are acidic and corrosive to pipelines, and some also hazardous. A high standard of removal is necessary. Some lighter hydrocarbons are extracted as condensate for sale as fuels and input to the chemical industry. Such plants require high quality design, construction, maintenance and operation, much of it automated. There is always a high fire risk. Similar comments apply to the offshore platforms and their associated sub sea wells and head works that extract and deliver raw gas to the processing plants.

Then there is nearly 1800 km of steel pipeline to the southwest with ten gas-fired compressors to pump the gas (225 MW)[8]. It is 2000 km to the Goldfields and Esperance. Three per cent of the gas entering the pipelines is used to fuel these compressors. Again high quality workmanship is needed at all stages.

The risks of failures from corrosion increase as the various systems age, a problem that plagues the petroleum industry generally.

Some small failures in the Western Australian domestic gas supply system can lead to dramatic consequences because of the long gas supply chains and limited number of offshore sources supplying raw gas to just two processing plant sites.

The current failure suggests the resilience of the system is seriously deficient.

Improving resilience requires building in where possible redundancy and standby capacity to promptly respond to failures and have sufficient resources and critical spare parts for swift repair of damage and failure. Parallel plants should be separated by firewalls. These measures increase for the owners the level of capital investment and maintenance costs required primarily for the benefit of the system as a whole and its customers.

There is a conflict of interest here that is exemplified in neoclassical economic theory and its weaknesses with its focus on competitive markets where pursuit of the "bottom line" is stressed at the expense of the greater common good. This particularly applies to gas pipelines systems in Western Australia markets where there are and probably always will be only one pipeline to a market and a limited number of processing plants and offshore head works.

FUTURE DOMESTIC GAS SUPPLY IN WESTERN AUSTRALIA

Woodside's Pluto Project

Woodside Energy discovered the Pluto and Xena fields off Karratha in 2005 (144 Bcm reserves) and promptly announced a new LNG project for this field, cost $12 billion (West Australian 2007). Woodside is the sole owner of the lease. *The funding included provision for further exploration as the size of the Pluto Project needed additional gas to justify expansion beyond one train to achieve economies of scale.*

Approval procedures were initiated for a site on the Burrup Peninsula that prompted objections from environmentalists and others because of its proximity to the Burrup

[8] The compressors are not electrically driven to the best of my knowledge.

Peninsula's indigenous rock carvings of world heritage significance. Two LNG trains were proposed in two stages of 4.3 million tonnes/year (5.9 Bcm/year each), with the possibility of a third. Environmental approval was granted in 2007 (Woodside Energy 2008a). Construction has started on the first train with commissioning expected in late 2010.

Government and business expect significant expansion of gas-fueled electric generators and industries for mineral processing to continue, increasing the dependence on gas as a primary energy source. The Domgas Alliance[9] expects up to 50 percent growth in domestic gas consumption by 2030 (Synergies 2007). Existing domestic gas supply has reached the limits of process plant capacity and mandated allocations may be consumed by 2020, as discussed above.

Early in 2006 the Premier, Alan Carpenter, proposed mandating a 15 percent domestic reserve allocation from future LNG projects to overcome the emerging domestic gas shortage. After consultation, the government issued a *Policy on Securing Domestic Gas Supplies* in October 2006. It says: *"The WA government will negotiate with proponents of export gas to allocate gas for domestic consumption as a condition for access to Western Australian land for the location of processing facilities".* Gas fields for future LNG projects are all in waters under Commonwealth jurisdiction. The WA government can only negotiate allocations indirectly in the absence of action by the Commonwealth *(DP&C 2006)*.

The WA government's Landcorp has negotiated with Woodside for it to lease land at Burrup for its LNG plant on condition that it supply the domestic market with a specified quantity of gas. The lease details have not been published. The allocation is 21 Bcm applying the 15 percent criteria, about three years at current domestic gas consumption and leaving 123 Bcm for the LNG plant. *By 2025 one train at 6 Bcm/year for LNG would consume 90 Bcm and production would begin to decline, merging with the NWSJV decline.*

So far Woodside has not discovered the extra gas needed. However, in 2004 Chevron discovered its Wheatstone gas field southwest of the NWSJV fields in water 200m deep (127 Bcm reserves). Woodside made overtures to Chevron to participate in its Pluto proposal using Wheatstone gas -- the combined reserves are less than 30 percent of those remaining in the NWSJV fields (West Australian 2008). Chevron refused and In March 2008 proposed its own onshore 5 million-tonne/year LNG plant with design to begin in 2009. But this would have a very short life and is hardly credible. Wheatstone would fit conveniently in the Gorgon project.

Woodside is now investigating the option of transporting gas to its LNG plants at Burrup from its large undeveloped gas fields in the Browse Basin offshore from the Kimberley coast. Using its existing LNG plants at Burrup, refurbished where necessary, would limit the investment mostly to developing the new fields and transporting gas the gas to Burrup. The distance is around 1200 km.

Woodside seems to be gambling on finding more large gas fields to improve the viability of the Pluto project.

The Greater Gorgon Project

The ten Greater Gorgon gas fields have reserves of 1,500 Bcm with three (including Gorgon 475 Bcm) containing two-thirds. All except the Gorgon field are in deep water further offshore (DofIR 2008, p.80-81). However, Gorgon has a CO_2 content of 12-14 percent where sequestering of CO_2 was an environmental condition attached to its

[9] The Domgas Alliance comprises Alcoa of Australia, Alinta, Synergy, Dampier Bunbury Pipeline, ERM Power/NewGen Power, Newmont Australia Ltd, Fortescue Metals Group, and Perth Energy.

approval[10]. The LNG plant will be constructed on Barrow Island close to sites suitable for sequestering CO_2. The approval was given after strong protests from environmentalists. Barrow Island is an A class nature reserve.

In 2005 Chevron estimated the construction cost was $11 billion for a two-train 10 mill. tonnes/year LNG plant (14 Bcm/year). Labour shortages and rising costs driven by the resources boom a reputed to have doubled the cost to around $23 billion (West Australian 2007. p.1). In 2008 Chevron announced it would incorporate a domestic gas plant in its initial construction, now to be expanded to three trains to make the project viable. Additional approvals for the expansion are required and Chevron is willing to negotiate a domestic gas price lower than recent prices to facilitate the process (DofIR 2008 p.9).

A large project with an LNG plant for export will be needed by 2020 to justify a new mandated domestic gas source to replace the NWSJV as a commercially viable source and cater for expected consumption growth. The Barrow Island Act 2003 mandated Gorgon gas for domestic consumption, but only 53 Bcm – 11 percent of Gorgon reserves. At least 2.9 Bcm (300 TJ/day) of annual domestic capacity was to be available by end 2012, less than the current capacity from Varanus Island and about one quarter of domestic gas consumption (SLP 2003).

A 15 percent allocation would be about 10 years current domestic gas consumption from the NWSJV (see Table 1).

The costs are now said to be around $30 billion due to the third train and the resources boom exceeding skilled staff availability, and the high cost of sequestering 60 million tonnes of CO_2 over the life of the field.

Developing other Greater Gorgon gas fields would also be expensive to build and operate as they are all in deep water that will require floating platforms anchored to the sea floor capable of surviving category 5 cyclones and tsunamis. Data on there CO_2 content has not been published.

An acute shortage of petroleum geologists and engineers is emerging worldwide. Large numbers will retire in the next decade. A new generation is not coming forward over the next decade on the scale needed (AFR 2008). Likewise the number of floating rigs for drilling in deep water is limited and most are engaged in the Gulf of Mexico and off the coast of Angola (daily hire charge is around $300,000 a day).

The Dept of Industry and Resources Prospect magazine says gas construction projects in WA employ over five times the workers in the construction phase than in operation and maintenance. For iron ore projects the ratio is nearly three to one. Table 3 summarises by industry category (Prospect 2008 p.33). The category other includes power stations as well as mineral projects. Some projects are near completion and it is likely some understate the project value.

The iron ore industry in Western Australia exported 116 million tonnes of ore in 1993, 172 million tonnes in 2002 (DofIR 2003, p.52). The estimate for 2008 is 330 million tonnes. The industry has a vision of 700 million tonnes capacity a year by 2020, driven by expectations of continuing growth in China (AFR 2007, p.66).

Additional skilled staff is needed in the service industries directly supporting construction and project operation activities. There is a further flow-on to the rest of the economy that affects service provision such as housing, schools and hospitals. These are the main reasons for the acute shortage of skilled staff in Western Australia.

---

[10] Gorgon is owned by Chevron (operator),Shell, Exxon Mobil, BHPB and Woodside Energy.

Table 3

Resource Projects Underway or Planned in WA

Industry Group	Project value (estimated A$m)	Employment	
		Construction	Permanent
Alumina	4,000	2,500	410
Iron and steel	21,704	10,200	4,030
Nickel/cobalt	4,200	3,000	950
Petrochemicals	260	500	--
Oil, gas & condensate	45,825	12,200	1,465
Other	30,484	7,850	2,200
Total	**106,473**	**36,250**	**9,055**

The CEO of Woodside, Don Voelte, earlier this year said these resource constraints meant only one LNG project can be constructed in Western Australia at any time. This scenario is unlikely to change much in the future. On this criteria Woodside's Pluto project and the NWSJV's second platform for its North Rankin field will delay the start of the Gorgon project until 2014 to avoid overlap. A long construction phase is likely as the sequestering of CO_2 is a pioneering project and skilled labour shortages will limit the rate of construction. It would probably take until 2020 to complete and delay commencement of new LNG projects in the Browse Basin until after 2020.

But the mandated domestic production from the first stage of Gorgon is well below that required to replace domestic gas from the NWSJV project, let alone cater for further consumption growth. Should the 2003 Barrow Island Act be amended to substantially increase the mandated gas allocation for domestic consumption, say to 30 percent of the Gorgon reserves as a condition for building its LNG plant there? Agreement with the Commonwealth government would be required as the Gorgon gas field is in Commonwealth waters. Barrow Island is under Western Australian jurisdiction.

It is likely that Western Australia will only have one or two operating processing plants for domestic gas in the decades ahead. Apache plans a new domestic gas processing plant at Devil's Creek nearer Karratha for it's hoped for new gas fields, probably retiring the Varanus Island plant next decade. Growing dependence on natural gas will make the risks from plant failures even greater.

These factors and the plant failure at Varanus Island demonstrate that a long-term strategy for domestic gas supply is urgently needed.

Tight Gas and Other Options

'Tight gas' is that stored in geological formations with low permeability and porosity that prevent its free release into wells. The formation adjacent to the well must be fractured to release the gas. Many wells are required and often have short lives due to the difficulty of making the formation yield gas. It is high cost gas with a low EROEI. Fields with tight gas exist in the Perth Basin, Warro near Moora and the Witcher Range near Busselton (DofIR 2008, p. 14). Several attempts have been made by junior companies to obtain producing wells at Witcher Range, so far without success. Some companies are interested in trying at Warro. If it is successful at all significant production will be difficult and expensive.

Alcoa has engaged with a local company to explore for gas in the onshore Canning Basin between Port Hedland and Broome. Hitherto it has not attracted much attention for exploration. Alcoa is also interested in the tight gas option at Warro.

These options are discussed in the Dept of Industries and Resources journal, *Western Australian Oil and Gas Review 2008.* The journal seems to view this option playing an important part in the state's future gas supply.

The Scarborough Fields

The Scarborough field (147 Bcm reserves) is located 300 km north west of Onslow in water 900m deep under license to Exxon Mobil with BHP Billiton as a partner. BHPB has discovered a new field at Thebe in deeper water 330 km offshore. Further drilling is being undertaken to assess the extractable reserves and a site at Onslow for an LNG plant investigated. However, Scarborough has 'dry' gas lacking condensate and other saleable liquids (DofIR 2008 pp.80-81 & 69). The dry gas, the remoteness and water depth makes Scarborough a poor commercial project without substantial new gas discoveries to achieve economies of scale. Early development is unlikely.

THE VARANUS ISLAND FAILURE AND RECOVERY

The plant failure on 3 June at Varanus Island reduced domestic gas supply by 350 TJ/day (30 percent)[11]. The immediate response was demand reduction of 160 TJ/day by industry, commerce, electricity generators, and by appeals to the public. Alcoa had to declare force majeure for some of its alumina supply contracts. Distillate replaced 95 TJ/day of gas for those able to do so at a cost of $4.5 million/day (3 ML/day). Urgent steps were taken to divert tankers with distillate to ports. Winter is the low consumption period for natural gas and the NWSJV and Perth Basin producers had some spare capacity to bridge the remaining gap of 95 TJ/day. But there was negligible reserve capacity[12]. *The consequences would have been more severe if this failure had occurred in summer when there is maximum demand for gas-fired electricity to run air conditioning and pump water.*

The South West Interconnected System (SWIS) for electricity had 900 MW of generation capacity off-line, most of it for annual maintenance (Albany to Kalgoorlie and Geraldton). Winter is the low demand period for electricity. Of this 560 MW was on annual maintenance, (Muja, 200 MW and Kwinana, 120 MW -- both coal-fired; and 240 MW of combined cycle gas plant at Cockburn)[13]. The new 340 MW Collie-A coal-fired plant failed on 30 May, some turbine blades ruptured taking it off-line for 6-8 weeks. Appeals were made for everyone to reduce electric power and gas consumption, leading to many companies reducing production and some unemployment. Fine-tuning of daily demand for commercial users were being made in response to weather related variations in gas consumption. There was good stakeholder cooperation.

Four old coal-fired generators at Muja were retired in June 2006 (4x60 MW) and replaced by the 240 MW Cockburn combined cycle gas plant referred to above. Verve Energy is restoring three of the old Muja generators using the fourth for spare parts. The first was put on-line in mid August, the second will be on-line early in September and the third about a month later.

The 560 MW of Cockburn, Kwinana and Muja plant on maintenance started up at the end of June and were carefully run up to capacity. The 340 MW Collie-A generator started up

---

11 350 TJ/day is equivalent to 9.3 million m^3 per day.

12 This information was obtained in June 2008 from the Office of Energy website but seems to have been removed subsequently.

13 In combined cycle plant hot exhaust gases from a gas turbine are used to raise steam to run another generator. This way about 60 percent more electricity can be generated than with a single cycle plant. A switch can turn on a single cycle generator. In combined cycle it takes time raising steam in the boiler.

in mid July, completing restoration of 900 MW of generation capacity by August. Early in August the first retired Muja plant came on line and a second Kwinana plant was taken off-line for maintenance. These actions progressively restored about 60 TJ/day of gas to other users over six weeks and increased supply reliability.

The first Varanus Island process plant started up shortly after and the second retired Muja Plant (60 MW) followed. By mid September another 200 MW Muja generator will start planned maintenance. By early October the third retired Muja plant should start up. This will make another 150 TJ/day of gas available through September, restoring gas supply to almost all users and reducing use of distillate by about 80 percent. By December the second Varianus Island plant is expected to come on line (140 TJ/day) restoring full gas supply[14]. The Office of Energy has regular updates of progress on its website.

But the electric power and gas systems will still be vulnerable to plant failures, given the scale of the disturbances and the delayed maintenance of major plant, the lean reserve capacity and the approach of summer.

In November the new coal-fired Bluewater power station at Collie (208 MW) is scheduled to start-up. However, the new Boddington goldmine has a contract for 100 MW of its capacity. A new 320 MW combined cycle gas-fueled plant is scheduled to start up at Kwinana for the 2008-09 summer. The additional gas required for this station should fully test the supply limits for domestic gas consumption in Western Australia in the coming summer. Again new plant can have teething troubles in the first few months of operation.

Table 4 shows the installed generating capacity in Western Australia as at July 2008 (OofE 2008). New capacity comes on line in SWIS in late 2008; 208 MW coal-fired and 320 MW gas-fired. The list does not include the retired plant at Muja being temporally restored for the current emergency. Retired gas plant (steam) at Kwinana (240 MW) is not included. A further 240 MW at Kwinana (coal-fired?) is due for retirement in 2009. The list includes combined cycle gas plants at alumina refineries. It is possible some of these planned retirements may be reviewed as a consequence of the Varanus Island failure.

About 60 percent of installed capacity in Western Australia is gas-fired. In the Pilbara gas power stations are owned by mining companies and/or operated by companies contracted to these miners.

There is 1,430 MW of gas-fired plant in the Pilbara and Goldfields-Esperance regions and much of it serves the mine and natural gas industries. Kalgoorlie is also connected to SWIS. State-owned Horizon Power purchases power from the mining companies for its Pilbara regional grid. The grid supplies coastal towns from Dampier to Port Hedland and Panawonica, Tom Price and Paraburdoo. Mt Newman depends on gas–fired electricity drawing its supply from the Goldfields Gas Pipeline.

There rapid expansion of iron ore exports and other mineral projects as well as ones for natural gas and petroleum will require significant expansion of electric power supply in the Mid West and Pilbara. Substantial growth of Pilbara generation capacity is imminent, at this stage planned to be gas-fired.

A significant failure of gas supply can have a severe impact on Western Australia's economy and people's lifestyle.

---

[14] This information was obtained from the Dept of Industry and Resources website updating progress on the recovery from the Varanus Island failure.

Table 4

Generation Plant in Western Australia

Region	Fuel	MW installed	Total MW
Kimberley	Distillate	45	**150**
	Gas	69	
	Renewable	36	
Pilbara	Distillate	3	**875**
	Gas	872	
Goldfields Esperance	Distillate	89	**647**
	Gas	558	
Gascoyne	Distillate	19	**42**
	Gas	23	
South West Interconnected System	Gas single cycle	1,288	**4,373**
	Gas comb. cycle	804	
	Coal	2,056	
	Wind	192	
	Other renewable	33	
Totals	**Distillate**	**156**	**6,087**
	Gas	**3,614**	
	Coal	**2,056**	
	Renewable	**261**	

Source: Office of Energy: www.energy.wa.gov.au Publications

WHAT IF THE NWSJV'S PROCESSING PLANT FAILED?

This plant's capacity (about 800 TJ/day) is almost fully committed and is nearly 70 percent of Western Australia's domestic natural gas supply that supplies 49 percent of primary energy consumption and 60 percent of primary energy for electricity (SWIS, most regional power and industry). **Its failure would reduce the state's primary energy supply by about one-third and seriously compromise electric power grids.**

Reticulated gas in Perth is about 5 percent of gas consumption and a minimum supply would be necessary to avoid air entering the pipes, with dangerous consequences. Use of gas for heating would need to be prohibited and its use for cooking minimised. Businesses and services dependent on gas would be severely impacted. Restaurants and food processing are high gas users for cooking and food processing.

Gas turbines in the Pilbara and Goldfields have 40 percent of the gas-fired generator capacity in the state. Water and wastewater services in these regions depend on electric pumps. Karratha depends in part on a seawater desalination plant for its water supply. Water use would need to be rationed and priority given to maintaining wastewater disposal.

Half of SWIS generation capacity is gas-fired, 40 percent of which is combined cycle gas for base and intermediate loads. One-third is coal fired. In winter coal fired plant must be taken off-line for annual maintenance with gas-fired generation substituting, increasing dependence on gas plant. However, summer is the high gas consumption period for electric power. Use of air conditioning in summer would need to be banned except in special circumstances. Refrigeration would be compromised.

Perth has 750 sewage pump stations, nearly 1,000 after adding regional towns in the SWIS network. Very few have standby power plants. The water supply systems are also heavily dependent on pumping – especially north of the Swan River in Perth. In Perth nearly 90 per cent of water is pumped, some several times. Perth water supply also serves the Goldfields and Agricultural Water Supply[15]. Priority would have to be given to maintain electricity services to these pump stations at a minimum sustainable level – no garden watering, shower with a friend and not every day, limit water hungry businesses.

Horticulture and public parks are irrigated with pumped groundwater and could be among those restricted as well as residences that have backyard bores.

Alumina refineries, nickel mines and processing, as well as gold mines and chemical industry's using gas as a feedstock would be forced to shut down – all are very energy intensive and dependent on gas for processing heat and electricity. There would be repercussions on international markets for aluminium and nickel, and possibly most other metals as well. Brick and tile works use gas to make their products, threatening brick supplies to the building trade. Gas has a major role in food supply.

The possibility needs to be considered that unstable electricity supplies could compromise operations on the internet and interfere with financial transactions.

The economic consequences would be huge with a national flow-on and significant loss of revenue to governments, depending on how long it would take to repair the damage. Many workers would be temporally unemployed, including a flow-on to retail as sales declined.

Substitution of distillate for gas may be possible at high cost but would be limited by the enormous logistic problems involved.

Before commenting we will briefly discuss how the technical features of electric power networks conflict with the thrust to develop competitive markets in electric power systems. Risk management to preserve system resilience is highly developed in the electric power industry.

Operating characteristics of electric power networks

Unlike other energy sources, electric power cannot be economically stored on a large scale, as in batteries. Therefore generators in power grids must supply electricity the instant it is used. Large grids operate on alternating current (AC), not direct current (DC), because with AC it is easy to use transformers to step up to high voltage to transmit electricity over long distances. Likewise it can be stepped down to low voltage for safer use in homes and elsewhere. These features have technical consequences that pose significant problems in attempts to introduce competitive markets for electricity. The relevant features are:

- All generators must rotate at 3,000 rpm within close limits to ensure cycle frequency of 50 Hz.

- Three-phase electricity is produced and the load on each phase must be kept balanced. Three-phase power used in transmission systems enables three power circuits requiring only four wires to be used instead of six at considerable cost savings.

---

[15] The new Kwinana seawater desalination plant and its associated pump stations have doubled the electric power use for pumping in the Perth and Goldfields & Agricultural Water Supply systems. The second desalination plant will increase this by a similar amount.

- As load on the system varies (diurnal, seasonal and often weather related) all generators have to respond promptly and keep rotating at 3,000 rpm, including when generators are turned on and off, or failure occurs while on load.
- The distance between generators and load centres should be limited to limit power losses in transmission (averages about 7 percent of electricity generated).
- At least two transmission lines are necessary to load centres to safeguard against failure in one and to allow shut downs for maintenance.
- Spare generation capacity is needed to come instantly on line if a generator fails, or a power line fails in a critical location.
- Peak demand usually occurs on hot days in summer in SWIS (air conditioning load). Over 300MW of generation capacity is required that is only used for about 24 hours a year at high cost – and it requires reserve generation capacity as well.
- Opportunities for routine maintenance have to be built into the supply schedule.
- Generators and transmission lines have protective equipment to automatically shut down the plant when failure occurs to prevent disastrous damage from occurring. If this happens and available reserve capacity is limited there is a high risk that another part will be over-loaded and trigger a cascading failure in the system.
- The transmission control centre at East Perth keeps in constant contact with all generators and key transmission staff to continuously supervise and control operations and respond to system disturbances. Key transmission centres are monitored on line by remote control.
- All assets must be designed, built, maintained and operated to high standards by skilled staff at all times.

By these means electric power systems have resilience built into them achieved by a high level of technical sophistication and redundancy in their generation and transmission infrastructure. Failures are mostly brief and localised by this approach (Booth 2000).

One thing is clear. All the major participants in electric power systems must first of all cooperate for the common good and behave in open and honest ways. Any beneficial role from competitive markets must be subordinate to this.

For competitive markets to 'work' in electric power grids economists say al least five competing 'generators' and five 'retailers' are required who compete to buy from the generators and in turn compete to on-sell electricity to end users. There are two broad market categories, base-load (mostly coal-fired), intermediate (coal, gas and renewable) and peak load (mostly gas). In SWIS large users (e.g. in WA, miners, mineral processors, water utilities) can independently negotiate contracts with generators for base-load power.

Generators are expected to compete 24 hours ahead for the next day's supply of electricity in separate bids for supply at one to half hour intervals – mostly residual power for intermediate and peak demand. The result is a distraction to companies in the market that has the potential to down grade their ability to participate 'for the common good'. Elaborate rules are needed to deal with the contradictions.

The small size of SWIS limits the scope for competitive markets and its extended power grid limits the scope for competition – the losses on long distance transmission lines are against it. Then there are the multiple overhead and marketing costs of generators and retail companies, and the added costs to buyers participating in the market place.

DISCUSSION

From the Appendix the EROEI for NWSJV liquid natural gas at Burrup would be about 11 after taking into account energy inputs in plant construction[16]. Additional energy costs would be incurred in building and operating LNG ships, re-gasifying it at the receiving port and distributing the gas to final customers.

Applying these EROEI's to the Gorgon project as a first estimate and including a guesstimate for the sequestering of CO_2 would bring the EROEI for LNG at Barrow Island perhaps down to 6 or 7. Include the energy cost of the final delivery of this LNG, its re-gasification and distribution to customers, then the EROEI from gas field to the final customers would be even less. This suggests that the energy input to extract and deliver the gas to these customers could be about one-third of the energy content of the original gas. The CO_2 emissions could be very high. *Is the Gorgon project economically viable when considered from energy and CO_2 perspectives? Energy input-output analyses of these projects incorporating EROEI and CO_2 assessments are urgently needed.*

The Varanus Island gas failure highlights the inadequacy of the present risk management approach to gas supply in Western Australia. Just two gas sources supply half the primary energy consumption in the state, both near their maximum capacity and with drastic consequences for everyone if there is a comparatively minor failure. Resilience is lacking.

This degree of dependence on natural gas has risen rapidly in the last decade with the partial duplication of the DBNGP, construction of the Goldfields Gas Pipeline and associated mineral processing[17]. Natural gas is widely used in many industry and commercial enterprises, large and small. There has been rapid expansion of natural gas generation in SWIS this decade along with reduction of coal-fired plant, including a significant component by combined cycle gas turbines, as part of a shift towards a competitive market in electricity. A small beginning has been made in renewable electricity plant. There is a vision of further development down this gas pathway.

This optimistic vision for a gas fueled future was driven by the expectations of a future with more cheap gas available on 20 year contracts and that this pattern would continue, a "Magic Pudding" vision. There were unspoken expectations in business, government and across major political parties that more mandated cheap gas for growing domestic consumption would be forthcoming when required.

Insufficient attention was given to evolving global gas markets and the emergence of the boom in LNG markets that have undermined this vision. The need to remove CO_2 from Gorgon gas at high dollar and energy cost were ignored. And the remaining large gas fields in the Carnarvon Basin after Gorgon gas are in deep water where development cost will be much higher and supply risk much higher.

A general lack of understanding of the energy concepts underlying EROEI assessments and the implications are the background to this flawed vision.

The rapid change in 2006 in Western Australia to a sellers gas market with short term contracts has shattered this vision and focused attention on the inadequate attention given to long-term guarantees for domestic gas supply. Even at current gas consumption rates and supply commitments there is a real risk that domestic gas supply could decline by 2020, much sooner with consumption growth as it is envisaged at present.

---

[16] In 1994/95 the EROEI of natural gas was about 14.7 for Australian gas and may not have changed much since then. LNG and LPG together had an EROEI of 12.5. See the Appendix for more detailed discussion.

[17] The development of the Varanus Island domestic gas processing plant and associated gas fields provided the basis for supply contracts to miners that led to the building of the Goldfields Gas Pipeline.

The major consumers of natural gas use it as a fuel for capital-intensive industries with long lives that require long-term guarantees of supply and price. They no longer have such guarantees.

Alternative sources for domestic gas to those from the NWSJV and Varanus Island plants must now be on the agenda due to the approaching decline of production from their current gas fields. This is in an environment of rising prices for domestic gas, even before price rises arising from carbon trading to combat climate change.

The mandated commitment to the domestic market by Chevron's Gorgon LNG project is very limited. Finding and negotiating a significant alternative will be challenging. Real domestic gas prices are likely to be on a relentless rising trend.

WESTERN AUSTRALIAN GAS STRATEGY TO 2060

There is an urgent need for the government to initiate a **Western Australian Gas Strategy to 2060** to address the future role of natural gas in this state. A systems approach to risk management should occupy a central place in the strategy, linked with those in electric power. It should include the role of renewable energy for electric power and address the impact of carbon trading to combat Climate Change.

Mandating gas for the domestic market by binding agreements from future projects for gas export must be a high priority.

The Water Corporation released in April this year its draft report for public comment, *Water Forever, options for our water future (Water Corp. 2008)*. It is based on a Western Australian Planning Commission forecast for a Perth population of 2.8 million in 2060. It outlines comprehensive options for new supply and demand management in the context of shrinking supply from surface and groundwater arising from a drying climate. The leading options are seawater desalination and recycling of treated wastewater at much higher dollar and energy costs. *The Water Forever report did not address the future of electric power supply to 2060. Real costs for water supply will increase with steep increases in consumption of electricity supply based on natural gas.*

The *Water Forever* report reinforces the need for a corresponding report on natural gas to 2060, given its assumptions on future electric power consumption for public water services. **The important issues that need addressing in a Western Australian Gas Strategy to 2060 are outlined below.**

- Make *high and low* estimates to 2060 for gas production for domestic consumption and export as LNG based on known gas fields in the Carnarvon Basin, including additions to infrastructure required for domestic gas. Both optimistic and conservative assessments are needed to give a range of possibilities.
- Give assessments of EROEI for energy sources a central place in this context.
- Develop a long-term strategy for mandating a percentage of gas supply for domestic consumption. Review the Barrow Island Act 2003 in this context.
- Assess when gas production will begin decline at the NWSJV and Varanus Island gas fields and short-term options for offsetting this.
- Assess the likely range of the real cost of new domestic gas from the Gorgon project and its further development based on undeveloped Greater Gorgon gas fields in deep water, taking into account emissions trading to adapt to Climate Change and the imminent decline of world oil production.

- Investigate and report on the consequences if domestic gas processing plants fail, noting that the NWSJV plant supplies 70 percent of domestic gas consumption.
- Investigate the skilled labour and other constraints that are likely to limit construction of new LNG plants to one at a time and explore the consequences for meeting future domestic gas consumption.
- Establishment of a government agency to oversee and audit risk management practices in the gas supply industry in Western Australia.
- Audit risk status and its management in the industry's gas supply chains, identifying critical risk locations and options for building in resilience.
- Report on the corrosion status of gas plant and pipelines and the consequences for future supply reliability and its management.
- Recommend improvements to increase resilience in the gas supply chain and for management of plant failures, including on the design and layout of processing plants, duplicate plant and increasing the number of processing plants.
- Investigate the remaining life of existing bauxite, nickel and gold mining and processing in southern Western Australia and the implications for future domestic gas consumption.
- Explore the options for storing reserve gas supply from the northwest in depleted oil and gas field in the Perth Basin at Dongara, for use in emergencies.
- Review risk management practices in the SWIS electric power grid taking account of the need to reassess these as a consequence of the Varanus Island failure.
- Expand the use of renewable energy sources such as wind farms and solar to make generation units smaller and more dispersed in networks to decrease the risks from plant failures.
- Investigate options and innovations needed to maintain and supervise electric power system quality, reliability and management as the number of such small power sources increases.
- Review and reform the market-based reforms in electric power and domestic gas supply, moving to ones based more on cooperation for the common good and a lesser focus on competitive markets,
- In this context prohibit commercially confidential contracts in electricity and gas supply for existing and new contracts.

SOURCES

Fleay, B.J. 2007. *Natural Gas: "Magic Pudding" or Depleting Resource*, www.aspo-australia.org.au. Scroll Bibliography.

OofE 2003. *Energy Western Australia,* Dept of Energy, Government of Western Australia.

Woodside Energy 2008. *North West Shelf Venture approves North Rankin 2 project*, ASX Announcement, 31 March, www.woodside.com.au.

Woodside Energy 2008a. *1st Quarterly Report 2008*, April, www.woodside.com.au.

West Australian 2008, *Delayed Devil Creek back on track for 2010,* 16 August, p.64.

West Australian 2008a, *Voelte lights gas price row fuse,* 21 April, p.71.

BP 2008. *Statistical Review of World Energy 2008,* British Petroleum, pp.22-31.

Synergies 2007. *WA Gas Supply and Demand for the Domgas Alliance*, Synergies Economic Consulting, June. Report for the Chamber of Commerce and Industry

ERA 2007, *Discussion Paper: Gas Issues in Western Australia,* Economic Regulation Authority, Western Australia, June 2007, www.era.wa.gov.au.

DofIR 2008. Western Australian Oil and Gas Review 2008, Dept of Industry and Resources: publications, www.doir.wa.gov.au,

DofPC 2006. *WA Government Policy on Securing Domestic Gas Supplies,* Department of Premier and Cabinet October 2006. www.dpc.wa.gov.au.

DofIR 2003. *Iron Ore Industry,* Dept of Industry and Resources Western Australia.

AFR 2007. *Pilbara expansion blasts off, Australian Financial Review, 3 August, p.66.*

AFR 2008. *Labour risk for energy giants,* 10 July, Australian Financial Review, p.22.

Prospect 2008. *Significant Resource Projects Planned or Underway in Western Australia,* Dept of Industry and Resources, p.33.

Water Corporation April 2008, *Water Forever: options for our water future,* www.watercorporation.com.au.

Chamber of Commerce and Industry Western Australia May 2007, *Meeting the Future Gas Needs of Western Australia; A Discussion paper, www.cciwa.com.*

Securities Pty Ltd, September 2007, *The Western Australian Gas Market,* www.argonautlimited.com.

Booth, Robert R. 2000, *Warring Tribes: The Story of Power Development in Australia,* Bardak Group, www.bardak.com.au.

SLP 1979. North West Shelf Joint Venture Agreement Act 1979, and amendments in 1985, 1994 and 1996, *State Law Papers,* www.slp.wa.gov.au,

SLP 2003. Barrow Island Act 2003, *State Law Papers,* www.slp.wa.gov.au.

APPENDIX

ENERGY RETURN ON ENERGY INVESTED

Relationships Between Energy and Money Investment

Economic assessment of projects is mostly carried out on a monetary basis, rarely on an energy input-output basis. Both are needed to obtain an all-round picture. Currently energy assessments are neglected and too much weight given to dollar assessments

*Long-term economic performance is best assessed on a metabolic basis with energy flows as central inputs and outputs. Energy inputs have a threefold purpose. **Firstly**, energy drives the day-by-day operations in an economic system. **Secondly**, energy is used to maintain, refurbish and replace capital infrastructure as it wears out and becomes obsolete. **Thirdly**, only if there is a surplus of available energy after the first two purposes are met is some energy available to power economic growth[18].*

The extraction of fossil fuels from nature and their conversion to useable energy forms,

[18] The analogy here is with our daily diet. As adults we measure our food intake in calories to ensure that the first two criteria are met, but not enough for us to grow and become overweight.

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 to useable energy forms requires an input 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 energy 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[19]. Defining the system boundaries is an important aspect of these studies.

The 20th century was the era of oil and natural gas development from cheap and readily accessible sources with high EROEI's making possible the rapid economic development and growth we experienced. The high labour productivity achieved was a consequence of applying these high quality fuels. But these high grade and accessible primary energy resources are depleting and their EROEI is declining. Limits to further expansion of labour productivity are being reached. Population increase further limits the scope to maintain labour productivity growth. The scope for economic growth with high broadly-based labour productivity is declining, limited by resource constraints in a finite world.

In 2001 Manfred Lenzen published a paper, *A Generalised Input-Output Multipier Calculus for Australia (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* that used 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*

---

[19] This is a simplification of the real situation. Different types of fuel and different end uses have a significant influence on the economic outcome of specific fuels. We are unlikely to ever see coal fired aeroplanes. See my paper *Energy Quality and Economic Effectiveness*, www.aspo-australia.org.au, *scroll Bibiography.*

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 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 A1 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. Energy used in capital investment in this industry was low with minor contribution to economic growth. Total electricity supply includes hydroelectric.

TABLE A1
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.

The energy input for LNG would be higher than for LPG, making the EROEI for LNG, say less than 12.7[20] and higher for LPG in 1994-95.

Crude oil production has declined since 1994-95 and smaller new fields developed suggesting the EROEI may have declined. Since 2002 the price of steel has more than doubled and the cost of new construction and drilling has increased substantially, and there is an increasing emphasis on costly drilling in deep water offshore. Construction of

[20] A good guess would be about 10 for LNG when compared to products from oil refineries. The EROEI at the point of use would be even lower after the ocean transport of LNG to users and the use of some product to re-gasify the LNG, and its storage and distribution as gas to customers. Gas to final consumers by the LNG route is likely to be more energy intensive than corresponding oil refinery products.

LNG plants is being undertaken and the energy input would lower the EROEI for LNG, perhaps significantly. Australian Bureau of Statistics data is used in these studies and it takes ABS several years to compile them.

What are the consequences of these and other input factors for EROEI in this decade with its high rate of resource development?

Table A2 shows energy multipliers (MJ/A$ input) 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 A2
Energy-dollar multipliers
Australian fossil fuels and minerals 1994-95

Industry sector	Energy Multipier MJ/A$	Deviation of Aggregates (%)
Coal, oil and gas	16.81	
Iron ores	10.74	
Gold, copper, bauxite, silver, lead, uranium and 7 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 and other non-ferrous metals	18.17	9.0

The resources boom since 2000 will have changed these multipliers and would now include additional energy inputs for the high levels of investment in new mines, processing plants and transport infrastructure. The MJ/A$ for resource output would certainly be higher at constant dollars. Prices for many minerals now reflect an inflation component due to supply shortages and some speculation.

Coal mining in Australia is considerably less energy intensive than oil production and most 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 in Australia, especially in coal, iron ore, copper, nickel, zinc and lead with massive expansion of investment in associated transport and other infrastructure. Capital investment has 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 studies on the trends in EROEI for fossil fuels in Australia and the energy intensity of the mining industry are needed. A better database to assess the energy inputs embodied in inputs is needed. ABS needs more resources to assemble more comprehensive data in shorter time frames.

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? Does the same situation exist for mineral resources (rising MJ/A$) where concern is being expressed at declining ore grades in more difficult locations? We cannot have our cake and eat it too.

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

REFERENCES

Lenzen, Manfred 2001, *A Generalized Input-Output Multiplier Calculus for Australia,* Economic Systems Research, Vol. 13. No.1 2001.

DofP&C 2006, *Life-Cycle Energy Balance and Greenhouse Gas Emissions of Nuclear Industry in Australia,* A study undertaken by the University of Sydney Integrated Sustainability Analysis Centre for the Dept of Prime Minister and Cabinet of the Australian Government, www.pmc.gov.au/. ISA's website is www.isa.org.usyd.edu.au.

Fleay, BJ 2007, *Energy Quality and Economic Effectiveness, www.aspo-australia.org.au,* scroll Bibiography.