NATURAL GAS
“MAGIC PUDDING”
OR DEPLETING RESOURCE

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SUMMARY

Earlier this year statements on Australia's expected rapid decline in oil self-sufficiency were published by John Akehurst, CEO of Woodside Petroleum, and by Barry Jones, Executive Director of the Australian Petroleum Producers and Exploration Association (APPEA). These were given in the context of the approaching decline of world oil production. They emphasised the balance of payments and supply security risks associated with dependence on Middle East imports and regarded transport fuels as 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 which 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', and the implications of 90 per cent of our natural gas being located offshore from the north west coast.

But do we have vast reserves of natural gas as we are led to believe? What are the consequences if the Government and industries gas project "wish list" for the Carnarvon Basin comes to fruition?

This paper elaborates on the serious oil shortages Australia faces and the limited scope 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 accepting that *cheap oil production* outside the Persian Gulf region is about to decline with the supply focus shifting to the Gulf countries who have 60 per cent of the world's oil reserves but supply only 30 per cent. A supply shortfall is emerging, but the dynamics of an unstable situation are complex. These countries investment strategies in oil 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'.*

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, and of other goods as well, is increasing significantly. Such trends are not sustainable in the medium term.

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. *Agriculture has become a way of using land to convert petroleum products into food.*

World per capita production of commercial energy, increased from 1850 to the 1940s, then rose steeply to 1973 as cheap oil production from newly discovered Middle East giant oil fields expanded rapidly. But since

1979 per capita energy production has not increased, and for oil has declined by more than 20 per cent. An historical turning point has been reached. Further increases in labour productivity by harnessing commercial energy to labour are no longer possible. 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 energy availability and population.

The net energy yield of cheap oil from the small number of giant oil fields has been extremely high. No alternatives fuels can match the economic performance of oil from these giant oil fields. Energy must be used to extract energy from nature and to covert into useful forms. Net energy is the useable energy left after the energy used for these extraction and conversion processes is subtracted from the gross energy output. None of the alternatives fuels to oil from giant oil fields can match its economic performance on this criteria.

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

We are faced with limiting oil consumption. Disrupt freight transport and food shortages develop within weeks. Alternative transport fuels will be more 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.

AUSTRALIAN PETROLEUM RESOURCES

Oil Supply

Australia escaped the worst impacts of the 1970s oil supply crises as local production commenced, principally in offshore Gippsland oil fields. Three giant fields in Bass Strait were the main stay of our near oil self-sufficiency until the mid-1980s when these fields began to decline. However, numerous small offshore fields have hitherto compensated, principally in the Carnarvon Basin in Western Australia and more recently the Bonaparte Basin in the Timor Sea. However, new discovery and development is not keeping pace with the decline of the older small 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 and continues.

However, John Akehurst (2002), CEO of Woodside Petroleum, said in a paper to the Australian Bureau of Agricultural and Resource Economics *Outlook 2002 Conference* in March this year 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 per cent by 2010,* ***Figure 1.*** *The oil import bill could increase to $5.6 billion by 2005 and $7.6 billion by 2010 (US$20 a barrel, A$ = US55c).*

Australia was just self-sufficient in 2000 when consumption was some 265 million barrels (720,000 barrels per day or 42 GL per year). The proportion of condensate (liquids stripped from natural gas) in liquid production is expected to increase from 21 per cent in 2001 to 44 per cent in 2010 (Geoscience Australia 2001). Crude oil production decline will be steep.

Barry Jones (2001 & 2002), 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.

Their comments on Australia's oil supply position are outlined below:

- The three giant offshore fields in Gippsland, discovered over 30 years ago, have been in decline since 1986 but have been replaced *so far* by a multitude of small fields that are here today and gone tomorrow.

AUSTRALIAN CRUDE OIL AND CONDENSATE PRODUCTION

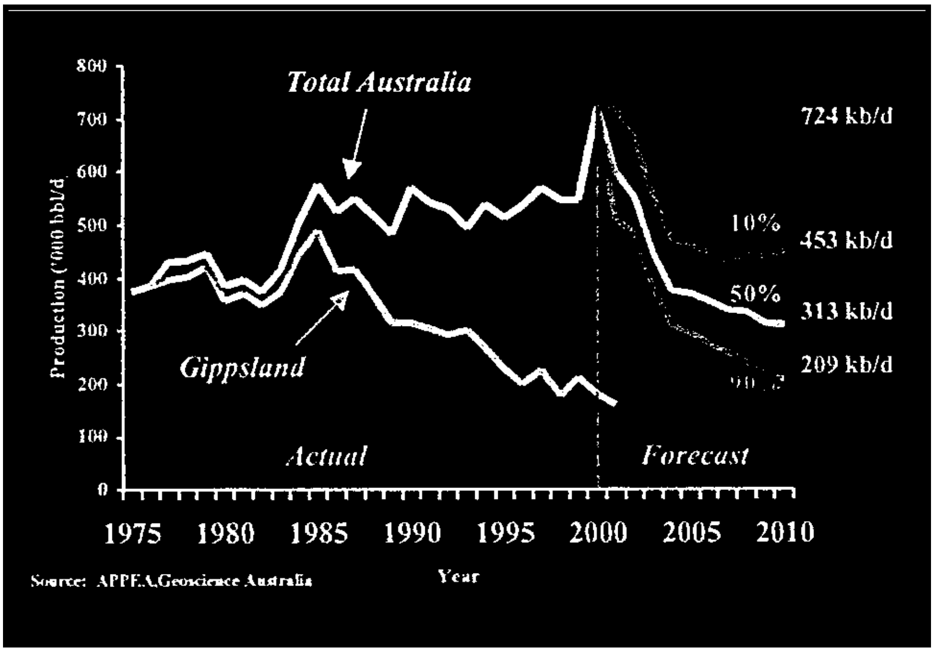

FIGURE 1

- This was happening in the context of an emerging global oil peak.
- Imports would have to come from the highly unstable Persian Gulf countries and the risk of supply interruption was high, including during delivery through the unstable region to our north. See further discussion below.
- 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.
- Offshore investment has been increasing but the number of wells drilled is static.
- Offshore exploration is becoming more expensive with higher risk as well depths increase, discovered fields are smaller and as exploration moves into deeper waters and into frontier areas.
- There is a general industry view that Australia has declining prospectivity with fields yet 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 - such as accelerated depreciation and royalty concessions in the early years of projects, especially for deep water offshore.
- The Commonwealth needs to urgently prepare a National Energy Strategy to address these issues.
- 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.
- *Oil supply vulnerability was a far more important issue than the present focus of governments on electric power industry reform.*

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 late 1994 and commissioned five years later. Half the oil has already been extracted and decline has commenced. It was one of the largest discoveries in Australia for many years.

Australia's geological history seems to have favoured generation of natural gas in its petroleum provinces, rather than oil.

Australian oils are low in heavy hydrocarbons. An increasing portion of liquid production will be 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.

Natural Gas

These proposals 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 and diesel on an equivalent energy basis is about equal to current natural gas production. The electric power industry has visions for a shift away from coal to natural gas, especially for peak power generation.

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

Natural gas is not as abundant as people think. Nearly 90 per cent of Australia's discovered natural gas is offshore between Carnarvon and Darwin and over half is in the Carnarvon Basin. Australian natural gas reserves and production rates as at 1999 are shown in **Table 1** (Data from Geoscience Australia 2001). The Browse Basin is off the Kimberley coast, the Bonaparte Basin in the Timor Sea and the Cooper/Eromanga Basins in Central Australia.

TABLE 1
Australian Natural Gas 1999
Reserves, Discovered and Production
Billion cubic metres (bcm)

BASIN	**Reserves Mean est**	**Prodn to '99**	**Discov. to 1999**	**Prodn 1999**
Carnarvon Basin	1720	170	1890	18.80
Browse Basin	530	-	530	-
Bonaparte Basin	620	neg	620	-
Gippsland Basin	216	150	366	7.60
Otway Basin	14	1	15	0.24
Cooper/Eromanga Basins	126	123	250	9.64
Other Basins	20	40	60	1.58
TOTAL	3245	480	3730	37.86

Data source: Geoscience Australia 2001.

Half of Australia's natural gas production in 1999 came from the Gippsland and Cooper/Eromanga Basins and these fields are ageing. Production costs in the Cooper/Eromanga Basin gas fields are rising rapidly, suggesting approaching decline (Australian Financial Review 2002). This Basin supplies Adelaide and Sydney. Cumulative production will reach 75 per cent of discovered-to-date gas about 2008 (reserves + produced-to-date) when production decline should be imminent. These onshore basins have been intensively drilled and it is unlikely significant gas is left to find.

A pipeline is under construction to supply gas to Adelaide from the Gippsland/Otway Basins by early 2004. A recently completed 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 to cater for the Cooper/Eromanga shortfall. But these solutions are short term unless large gas fields are quickly found and developed in the Otway Basin.

The Gippsland Basin could reach a similar stage of depletion around 2010. Current new discoveries are small. It remains to be seen if sufficient new discoveries in the adjacent Otway Basin can be found and developed to delay this decline. Discoveries in the Otway Basin since 1999 have lifted the discovered total to

44 billion cubic metres (bcm). So far large fields have not been discovered, when past experience suggest such fields are found first. *The status of these basins is discussed further below.*

New gas supply for the eastern seaboard could be needed by 2010 at current gas consumption rates. The investment cost will be around $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 to the east coast respectively. So far the companies have failed by a large margin to obtain long term gas supply contracts to justify these projects. The Bali bomb attack and its implications increases the risk associated with these projects.

But coal seam methane may partly relieve the supply problem. In Queensland a power station is to be built at Townsville fuelled by methane extracted from bitumenous and sub-bitumenous coal fields. Rapid development of gas from these sources is about to commence in Queensland and NSW. The resource may be considerable, especially in NSW. However, not all such gas-in-place is commercially extractable. The jury is still out on the prospects until further exploration is undertaken. This development makes it unlikely that a gas pipeline from Papua-New Guinea or the Timor Sea will be built this decade. *This subject is discussed further below.*

Most current natural gas production comes from offshore fields in water up to 120m. deep. However, some 40 per cent 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 also expected to be in such deep water 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 North West Shelf Project's gas fields contain three per cent CO_2 (W.A. Oil & Gas Industry 2002)

BONAPARTE, BROWSE, CARNARVON AND GIPPSLAND BASINS – NATURAL GAS

We will now review the petroleum position of the Bonaparte, Browse, Carnarvon and Gippsland Basins in the context of the preceding discussion. Half of Australia's natural gas and condensate reserves are located in the Carnarvon Basin and nearly 90 per cent are offshore between Carnarvon and Darwin. Western Australia supplies 55 per cent of Australia's oil and condensate, mostly from the Carnarvon Basin which will play a key role in any shift to natural gas-based transport fuels. How are we to assess these basins *undiscovered* petroleum potential? What are the economic implications of the massive construction program envisaged for natural gas projects in the Carnarvon Basin?

Geoscience Australia Assessment Methods
USGS World Petroleum Assessment 2000

The Australian Geological Survey Organisation (AGSO), now GeoScience Australia (GSA) and formerly the Bureau of Resource Sciences (BRS), makes annual reviews of Australia's ultimate endowment of *conventional 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 latest report concludes that its previous assessment method for the undiscovered is too conservative and now favours that used in the *US Geological Survey World Petroleum Assessment 2000 (USGS WPA 2000),* but with some qualifications. 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 for 30 years ahead to 2025. The Bonaparte, Browse, Carnarvon and Gippsland Basins were assessed by the USGS and the report gave mean estimates (statistically the most likely) for undiscovered oil, condensate and gas that were three to four times higher than the GSA's figures using its method.

Powell (2001) from AGSO has commented on these differences and says the two approaches have fundamentally different aims which in turn leads to the different approaches and conclusions. The USGS method explicitly aims at achieving *an estimate largely unconstrained by economic, technological and social limits.* It emphasises the *long term geological potential* of a Total Petroleum system and as such is clearly orientated to the optimistic outlook of explorers. But Powell says much more work is required to determine how the resource potential identified might be realised and in what time frame. *The implication is a statistical assessment with a low probability, say around five per cent probability (P05), not the most likely.*

By contrast the past AGSO assessment process is designed to underpin government advice on immediate decision making and production on a 5-10 year time frame, concentrating on extrapolation of current trends in existing fields and has not to date included water depths of over 500m. *Furthermore, it does 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 per cent probability in the Australian approach. The USGS natural gas estimates are much higher again.

But Powell also goes on to say the *USGS WPA 2000* 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 fields to be found first, he says at this stage of exploration it is hard to reconcile the projected resource potential by the USGS with the discoveries made since 1995.

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 eventually the newly established Securities & Exchange Commission (SEC) moved to prevent such fraud by imposing rigorous rules for reserve reporting. The owners were able to report for financial purposes only the reserves being drained by their current producing wells, which were termed *Proved.* The reports related 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 long established practice was preserved by the US industry as it moved internationally and offshore, with most of the companies being on the US stock exchanges and subject to SEC rules. They had no reason to complain because 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 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 being implicitly assumed that more could be added as needed by exploration and drilling up the fields. In those days it was not an unreasonable assumption in a world perceived to have near limitless resources which could be tapped at will and where under-reporting was sanctioned by the SEC.

Laherrére (2001) says the US practice of reporting *Proved* reserves under SEC edicts has led to systematically under-reporting of reserves, leaving room for future reserves growth. He says during the past 20 years, 88 per cent of the annual additions to US oil reserves came from re-evaluation of past discoveries because the previous estimates were systematically too conservative. This is 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 such 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 not just the current wells but the fields as a whole. 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 which 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 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 still 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 to 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 undiscovered world conventional oil from 1995 to 2025 to 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 to 2001 when you would expect this to be *higher* than the expected average as giant fields are usually discovered first! *World oil discovery is not matching the USGS Report's expectations.*

Geoscience Australia (GSA) is making 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 depths are about 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, Brazil, Nigeria-Angola and the Gulf of Mexico (Australian Financial Review 2001). However, there is a counter argument related to the locations of these regions during the Jurassic. The great era of petroleum generation was in the Jurassic in those 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. At the time the southern hemisphere continents were some 2,500 to 3,000 km. further south than now and well outside tropical climates, the principal reason these regions have limited petroleum resources. This environment may well have favoured gas rather than oil generation.

These locations and water depths speak for themselves. The North Queensland basins will be particularly contentious given their location adjacent to the Great Barrier Reef. Petroleum exploration is searching in ever more marginal locations.

We will now turn to the USGS estimates for undiscovered gas in Australia

Table 2 shows as at the end of 1995 the mean reserves estimates, cumulative production and discovery, the estimated undiscovered (June 1996) and the mean estimate of the likely 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 End of 1995
Discovery, Undiscovered and Ultimate Recovery
Billion cubic metres

Basin	Reserves Mean '95	Production to end 1995	Discovery end 1995	Undiscovered est. June '96	Ultimate recovery
Bonaparte	205	2	210	70	280
Browse	625	0	625	150	775
Carnarvon	1160	96	1255	620	1875
Gippsland	207	122	330	30	360
TOTALS	2200	220	2420	870	3290

Data source: Bureau of Resource Sciences 1997.

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Table 3 shows the discovered as at the end of 1995 from Table 2, the additional production and *net* reserves addition from end 1995 to end 1999 to give the cumulative discovery to the end of 1999. Note the downward revision of reserve estimates for the Browse Basin. There have been large gas discoveries in the Bonaparte and Carnarvon basins since 1995.

TABLE 3
Natural Gas End of 1999
Additional Net Discovery and Production from 1995
Billion cubic metres

Basin	Discovery End 1995	Production 1995-1999	Net Reserves Addn. 95-99	Discovery End 1999
Bonaparte	210	0	410	620
Browse	625	0	-40	585
Carnarvon	1255	75	555	1885
Gippsland	330	23	13	366
TOTALS	2420	98	938	3455

Data sources: Geoscience Australia 2001 and Table 2

Table 4 shows cumulative discovery to end 1999 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 undiscovered gas in Table 4 with the 1996 BRS (1997) mean estimates in Table 2.

TABLE 4

Natural Gas Ultimate Recovery For
USGS WPA 2000 Undiscovered Estimates
Billion cubic metres

Basin	Discovery	USGS New Discovery Estimates			Estimated Ultimate Recovery		
	End 1999	P95	Mean	P05	P95	Mean	P05
Bonaparte	620	159	674	1406	779	1294	2026
Browse	585	137	569	1293	722	1155	1880
Carnarvon	1885	612	1832	3145	2497	3717	5030
Gippsland	366	35	160	343	401	526	709
TOTALS	3455	943	3235	6187	4400	6690	9645

Data sources: Geoscience Australia 2001 and Table 3.

New discovery in the Bonaparte Basin since 1995 is 60 per cent of the USGS mean estimate and two and a half times the P95 estimate. More discovery can be expected as this is a relatively unexplored basin. Bonaparte Basin fields are generally well offshore in moderately deep to deep water, consequently development costs can be high. It would now be regarded as an area with high political risk following the Bali terrorist bombing.

New discoveries in the Browse Basin will almost certainly be in deep water. The USGS P95 estimate for the undiscovered should be reached, but whether the mean estimate is based too much on 'reserve growth' is another matter.

In the Carnarvon Basin some 630 bcm has been discovered since 1995, just over the USGS P95 estimate and the BRS 1995 mean estimate for the undiscovered, but only one-third of the USGS mean estimate. But nearly all of these new discoveries have been in the Greater Gorgon field in water around 1,200m. deep, when GSA says its undiscovered assessment method is confined to offshore waters under 500m. depth. Earlier deep water discoveries in the Browse Basin and on the Exmouth Plateau (both mostly about 1000m. water depth and some 400 km. offshore) were made in the 1970s as a response to the oil supply crises at the time. The limited exploration in these two areas suggests more discoveries are likely, but their location will make development expensive.

There is general agreement in the industry and government agencies that most new Carnarvon Basin discoveries will be in deep water offshore, locations outside GSA’s and its predecessors historical assessment framework. *The critical question here is the extent to which the USGS mean and P05 estimates may be over-stated due to an erroneous application of the 'reserve growth' philosophy.*

The 36 bcm of gas discovery in the Gippsland Basin since 1995 is about equal to the USGS P95 estimate. This Basin may be one where the USGS 'reserve growth' approach will prove to be unrealistic. The uncertainty associated with the unknown potential of the adjacent Otway Basin, along with coal seam methane extraction in Queensland and NSW will inhibit the development of multi-billion dollar alternative gas supply projects from the north west coast or Papua-New Guinea to the eastern seaboard. The cost of transporting gas up to 3,500 km. will be high. Long distance transport costs for gas are 5-10 times higher than for oil on an equivalent basis.

The Carnarvon Basin

Industry and government publicity conveys an impression of abundant gas reserves and discovery potential in this Basin that should be developed and exported as rapidly as possible. The “Magic Pudding” dream. Government agency reports typically quote reserves production ratios of more than 90 years, unaware of the historical origins of this statistic and its misleading character, as discussed above. It is misleading because it implies that the *current* production rate will continue for 90 years and then *abruptly* cease, a concept that bears no relation to the actual performance of oil and gas fields. Major expansion of gas using projects for export as LNG or in petrochemical plants are under construction and planned. But the publicity is very coy about discussing the downside of production, when this might occur and the consequences.

About 94 per cent of discovered gas in the Carnarvon Basin is in a small number of large fields (100-500 bcm, mean estimate), mostly associated with the North West Shelf Joint Venture (NWSJV) and the Greater Gorgon group. The remainder 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 which currently dominate supply (W.A. Oil and Gas Industry 2002). The discussion below will be confined to the NWSJV and Greater Gorgon projects. Current mean estimate reserves for the NWSJV are about 500 bcm and 980 bcm for the Greater Gorgon fields. Nearly all the production to 1999 from the Carnarvon Basin has been from the NWSJV fields, 170 bcm.

Appendix 1 lists the known gas consuming projects on the agenda for the Carnarvon Basin, as well as the year that industry and Government hopes commissioning will occur (the “wish list”), and the construction cost, product output and expected annual gas consumption for each project. This data, along with physical capacity limits of gas production infrastructure, data on NWSJV gas production to date and mean reserve estimates for discovered gas have been used to construct ***Figure 2*** showing the anticipated production profile. New discoveries of 600 bcm have been assumed, taking the 1995 undiscovered figure to 1200 bcm, or two-thirds of the *USGS WPA 2000* mean estimate for the Carnarvon Basin. *There is an assumption here that the USGS mean undiscovered estimate of 1832 bcm is partly due to unjustifiable 'reserve growth'.*

An assumption was also made that permanent production decline commences when 75 per cent of the estimated ultimate gas recovery has been reached, and assuming two subsequent decline rates of 7 and 10 per cent per annum, representing the range of possibilities. Natural gas projects offshore tend to have production profiles more constrained by the high cost of infrastructure capacity compared to oil. Consequently the onset of decline occurs later in the depletion cycle for such gas projects than for the corresponding cases for oil.

These figures are reasonable first order assumptions for natural gas which tends to have a steeper decline rate than for oil because of its more free-flowing characteristics (Laherrére 2002). Access to gas field and well physical performance data would be needed to refine these estimates. This information would currently be regarded as commercially confidential by petroleum companies.

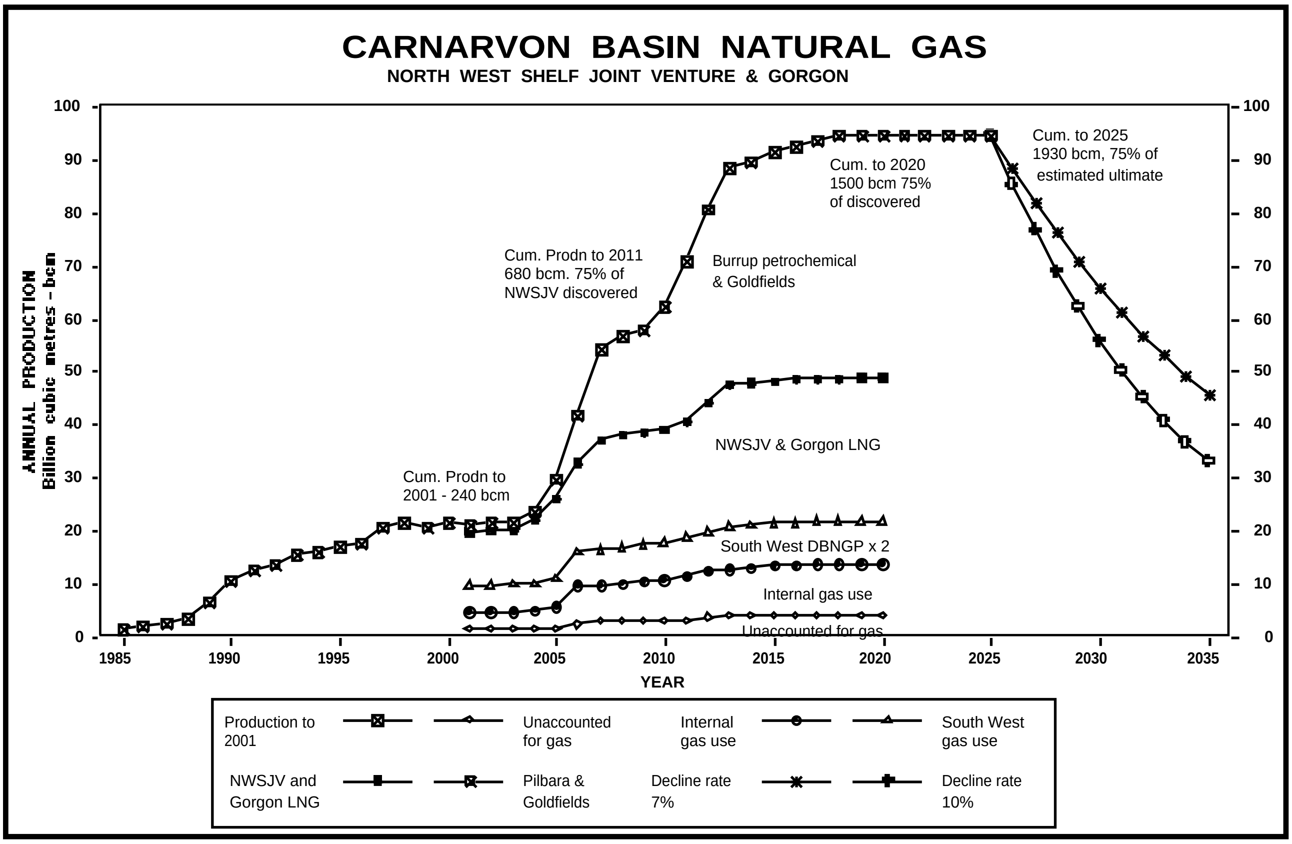


FIGURE 2

On this agenda 75 per cent of the NWSJV current gas reserves would be extracted by 2011, in the absence of large new discoveries put into production. Time is getting short for this to happen. Alternatively, stage 1 of the Gorgon project needs to come on stream by then to pick up the shortfall and to supply new gas consuming projects. The Gorgon gas field (520 bcm mean estimate) is the biggest in the Greater Gorgon group, the only one in shallow water and the formation has good gas flow characteristics. However, the Gorgon field has only two-thirds of the condensate content per unit of gas compared to the NWSJV project and contains 12-15 per cent carbon dioxide compared to three per cent for the NWSJV's fields (W.A. Oil and Gas Industry 2002). Condensate sales are a significant revenue source for the NWSJV. The remaining Greater Gorgon fields are scattered over a large area in water around 1200m. deep. These factors suggests Greater Gorgon gas will have to sell at a high price to be commercially viable.

Woodside Petroleum has the licences for the discovered gas in the Browse Basin (585 bcm) and says its current preferred option is to pipe this gas to Karratha – no firm proposal has been published (W.A. Oil and Gas Industry 2002). The Scott Reef field (325 bcm) is the only one in shallow water and all three fields are 300km. offshore. Some 800 km. of onshore pipeline would be needed to reach Karratha. However, initially the pipeline would only need to connect to Port Hedland, when additional supply southwards would be up to 5.5 bcm per year using the existing Burrup-Port Hedland pipeline. To offset NWSJV decline this pipeline's ultimate capacity would need to be considerably larger than the Dampier Bunbury Natural Gas Pipeline (5.2 bcm per year) and would require an investment of several billion dollars.

Figure 2 also shows that by 2020 75 per cent of currently discovered gas in the Carnarvon Basin will have been consumed on the "wish list" scenario, and decline would begin in the absence of new discoveries. Discovery and development of a further 600 bcm only extends this date to 2025.

The Scarborough field on the Exmouth Plateau has 170 bcm of discovered gas 270 km. offshore in water over 900m. deep. Furthermore, it is dry gas lacking in condensate and a significant portion of the undiscovered gas could be in this location. The gas will have to sell at a high price in this context and could well be the last of the gas resources developed in the Carnarvon Basin.

The development scenario of ***Figure 2*** involves an investment program of some $23 billion between 2001 and 2013 just for Burrup petrochemical plants, LNG expansion and Gorgon stage 1. On this scenario peak investment averages $3.7 billion per year between 2008 and 2011. Exploration expenditure and developing new discoveries in the same time frame would be additional. If some of the petrochemical plants lapse it is still possible for further LNG development.

Economic consequences

One consequence for W.A. would be a large and unsustainable expansion of the construction industry over the next decade building these gas-related projects. By the middle of next decade it would be in permanent decline. There is a large work force during the construction phase, but these capital intensive industries generally have a small permanent work force of around one employee per $5 million investment.

About 15 years after the intense construction boom subsides permanent gas production decline could begin and fall perhaps by a half to two-thirds over 10 years. Industries and LNG plants would be forced to close down and the construction industry would shrink further to a limited maintenance role. The mining industry could lose a vital fuel. Governments would be forced to allocate natural gas to priority uses.

Sustaining 90 bcm per year production levels indefinitely requires the discovery and development of around 110 bcm of extractable gas EVERY YEAR. Discovered gas in the Browse Basin only represents six years consumption and could only be transported to the Pilbara at high cost and in limited amounts.

These capital intensive gas supply and consuming industries require substantial long term contracts with stable prices to make their projects commercially viable. The NWSJV LNG contract with China covers supply from 2005 to 2030. Gas turbines for electric power can have 25-30 year lives. The more intensively gas resources are exploited, the shorter the time large scale expansion of these industries can be sustained.

The two proposed Syntroleum gas-to-liquids plants would only produce liquids equivalent to 19,000 barrels of oil or seven per cent of Australia's consumption when our oil self-sufficiency is expected to decline to 40 per cent by 2010. If fuel cell technology matures sufficiently in a decade or so then it might be possible to use methanol to generate electricity for transport and other purposes. The prospects for substantial and easy substitution of gas-based fuels for transport does not look promising.

A critical economic parameter for these fuel manufacturing processes is their net energy yield. What is the net energy yield after subtracting from the gross energy output the direct energy input and indirect energy embodied in the goods and services used in their production? The more often one form of energy is transformed into another, the less net energy in the final product. Only the net energy yield counts.

How do the net energy yields for these alternative transport fuels compare to the corresponding net energy yields for contemporary petrol and diesel? In this regard petroleum products obtained from giant oil fields are far superior to any alternative fuels, especially for transport (Gever et al. 1991). These are among the critical parameters for assessing transport fuel priorities, centred on finding the balance between feasible alternative fuels to oil-based ones on one hand and transport demand management initiatives on the other. These aim to reduce power-driven transport functions to essential needs.

There is an urgent need in Australia to obtain information on the net energy yields of energy sources over their production life cycle. It is difficult to develop priorities in a National Energy Strategy without this information.

The optimistic “Magic Pudding” approach to future petroleum supply development in this state has become an economically dangerous one – it only looks at the upside of production prospects, disregarding the downside. Here the concept of the ratio of reserves to current production is a thoroughly misleading one. This outlook is based on the optimism of the petroleum exploration industry, an outlook it needs to have to be successful in exploration. But the precautionary principle should apply when matching this outlook to strategic gas-fuelled economic development. The risk of a spectacular unsustainable economic rise and then a crash as gas production declines must be avoided.

A National Energy Strategy for natural gas should not be based on the optimistic low probability expectations of petroleum explorers, but on a lower more likely expectation and with a focus on the vital long term uses of natural gas to give time for adaptation to a world *Beyond Petroleum*. Even BP now proclaims that BP stands for 'Beyond Petroleum'.

ABARE: AUSTRALIAN GAS SUPPLY AND DEMAND BALANCE TO 2019-20

The Australian Bureau of Agricultural and Resource Economics (ABARE) published *Australian Gas Supply and Demand Balance to 2019-20* in August 2002 by Fanstein, Harman and Dickson (Fainstein et al., 2002). The report addresses concerns about the capacity of Australia’s natural gas supplies to keep pace with demand in *eastern Australia* and the potential for coal seam methane. Nearly 90 per cent of Australia’s gas reserves are on the opposite side of the continent. Australia’s gas markets are mainly single supplier regional ones due to the high transport cost of natural gas. There is limited scope for competition between suppliers.

Two cases were considered. *The reference case* was based on earlier ABARE work forecasting demand growth of 3.4 per cent per annum, almost doubling by 2020. *The high demand growth scenario* was based on the outlook for gas use in mining, electricity generation, LNG export and the gas-to-liquids industries. The latter use was partly in response to the expected decline in our oil self-sufficiency discussed above.

Fanstein et al. used Geoscience Australia’s *Oil and Gas Resources of Australia 2000* report for its information on gas reserves and the estimates for the undiscovered, supplemented by information from the Department of Industry, Tourism and Resources. The undiscovered was confined to the Bonaparte, Browse, Carnarvon and Gippsland Basins and based on the *USGS WPA 2000* report’s P95 estimates discussed above. The data, with some minor differences, corresponds to that used in this paper.

About 75 per cent of Australia’s discovered gas is classified as non-commercial - recoverable but not yet profitable to produce. The authors assumed for each basin that a fixed proportion of non-commercial reserves would be upgraded to commercial on an annual basis. They also adopted the simplifying assumption that Geoscience Australia’s reserve estimates would not change over time – not considering themselves able to independently forecast future exploration outcomes, nor revise Geoscience Australia’s current estimates. This assumes future gas discovery equivalent to that listed in Table 4 under USGS P95 undiscovered. The assumptions did not reflect the impact that higher gas prices might have. An exception was for the Otway Basin where there have been recent discoveries. The Gippsland and Cooper-Eromanga Basins constitute around 85 per cent of eastern Australian reserves. New discoveries in the former are unlikely to be large and the latter is approaching decline and has limited prospectivity.

Projected Australian gas production for each eastern states basin was estimated by the authors using standard historical trend analysis techniques, but the report does not explain what these are. Their plots show for all basins, except the Bowen-Surat, production either constant or rising substantially while reserves decline to almost to extinction. *This pattern contradicts the physical reality of gas field depletion discussed above and raises questions about the authors understanding of depletion, and therefore on the validity of their conclusions.*

In particular the plots for both the Gippsland and Cooper-Eromanga Basins show reserves declining by 90 per cent to 2019-20 while annual production doubles for Gippsland from 5.3 to 9-12 bcm and remains more or less constant at 6 bcm for the Cooper-Eromanga Basin. New discoveries are least likely in these two basins with the Otway Basin as yet an unknown factor. Similar criticisms are being made by the Australian Gas Association (AGA) and are discussed below. It is almost certain that there will be supply short falls from the Cooper-Eromanga before 2010 and from the Gippsland Basins shortly after.

Fainstein et al. also summarise the status of coal seam methane (CSM) in eastern Australia. There are substantial CSM resources in the Queensland and NSW coal basins, and the techniques for economic extraction have developed rapidly. Not all coal fields have the qualities needed for successful methane extraction and the extent of the ultimate recoverable resource is not yet clear. So far the gas is more expensive than present natural gas resources in eastern Australia by as much as 50 per cent. But the resource is close to markets, can be developed incrementally and will be cheaper than new supplies piped from the Timor Sea, Papua New Guinea or Western Australia. CSM has the potential to compensate significantly for gas production declines in existing eastern basins. Current CSM production is small, but likely to grow rapidly. It is too early to make reliable forecasts. They show CSM production increasing from 0.7 bcm in 1999/2000 to nearly 3 bcm in 2019/2020.

The authors also made an explicit assumption that gas consumption in a region will not be constrained by pipeline infrastructure; additional capacity is added where increases in demand warrant this new investment. AGA is also critical of this assumption.

On the demand side Fainstein et al's. high demand scenario has a 2020 gas consumption for Western Australia, including LNG, similar to that used in ***Figure 2***. The big increases are for manufacturing, followed by LNG. Exporting Carnarvon Basin gas to the eastern seaboard is the least attractive proposition.

The AGA summarises Fainstein et al's. report in its September Gas Journal and is critical of its conclusions for eastern and southern Australia (AGA 2002). AGA has a less optimistic view on the gas supply and demand balance, believing that commitments to deliver more remote gas to eastern Australia is required much earlier than these authors envisage to ensure that competitively priced gas is available when major long-term gas sales contracts come up for re-negotiation over the next three years. A critique of the report has been produced by ACIL Consulting for the Australian Pipeline Industry Association (Beasley 2002) and challenges ABARE's report on:

- its conclusion that there are more than sufficient gas supplies (given projected reserves and production levels from existing basins) to meet eastern Australia's growing gas demand well past 2019-20;
- its assumption that production capacity and gas delivery from existing fields can be effectively raised without limit to meet market demand as long as producible reserves remain available within the supply basin, denying the typical depletion characteristics of gas fields;
- implausible production profiles assumed for in the associated reserves backing with no explanation on how additional capital expenditure could be justified given the low remaining reserves level in 2019-20, for example in the Gippsland Basin;
- premature confidence in the future of CSM or of its cost structure, given its early development stage;
- the assumption that CSM production costs will fall from $3.60-$3.80/GJ to less than $2.00/GJ as intensive drilling is needed to extract quantities of methane from coal beds; and
- assuming that Timor Sea gas could be delivered to Moomba at $2.86 per GJ, an assumption that appears to be based on an expectation that for Timor Sea gas to proceed it needs to be competitive at Moomba with Cooper-Eromanga gas when it is one option to *replace* current Moomba gas as production declines.

The ABARE authors seem to focus on the need to achieve competitive markets for gas, as good economists do. They ignore the fact that in Australia the distance between major gas fields and domestic markets, the high capital investment required and the uncertain levels of gas demand dictate a monopoly orientation based on a minimum level of long-term contracts with gas retailers. The financial risk is high.

Andrew Dixon from ABARE has responded to these criticisms in the AGA December 2002 Gas Journal (Dickson 2002). He confirms that the report's authors do not understand depletion. They assumed production at Cooper-Eromanga could remain close to current levels because the bulk of reserves had been classified as commercial. He says ABARE is preparing a new set of projections for Australia's long-term energy consumption to 2019/2000, including gas. Preliminary assessments show higher gas demand to 2009/10 with growth tapering off by 2019/2020 compared with their August 2002 report. Northern gas supplies may be required to supplement existing eastern states production by 2013/15. ABARE expects to release a new *Australian Gas Supply and Demand Balance* report early in 2003.

These criticisms and Dickson's response raise questions about the way federal agencies report on energy policy issues. Agencies like Geoscience Australia and ABARE seem to carry out their charters with limited collaboration when a *thoroughly integrated approach* is called for. In the emerging era of sustainability 'triple bottom line' accounting requires an approach that *integrates* social, economic and environment performance assessments, as proposed in the Draft State Sustainability Strategy for Western Australia. In this context resource availability constraints would be part of environment. The depletion of cheap petroleum resources must be squarely faced. The approaching production downside and its consequences can no longer be denied.

INTERPRETING THE GLOBAL PETROLEUM DATA BASE

The above discussion has focussed on the Australian scene for oil and natural gas and has made passing reference to the imminent decline of world oil production. A brief outline of the status of world oil and natural gas supply is described below in support of this proposition.

Hydrocarbons range from natural gas and oil, to tars and bitumens. Free-flowing oils (*cheap, or conventional oil*) comprise 88 per cent of production. Natural gas liquids comprise another eight per cent. Of the 40,000 oil fields *some 360 ageing giant-sized ones that held > 500 million barrels (80 GL) of recoverable oil on initial discovery, supply 60 per cent of crude oil at low cost. 120 giants supply nearly 50 per cent, 14 supply 20 per cent, while FOUR super giants supply 11 per cent!* Crude oil supply is heavily skewed to a small number of large oil fields (Simmons 2002).

We have been picking the eyes out of a large hydrocarbon resource base.

The rest comes from high cost *non-conventional oil*, mainly obtained from offshore oil fields in deep water (say > 500m) as well as from heavy oils, fields in hostile locations, tars and bitumen. The resource base of the latter is much bigger than for conventional oil. Tars and bitumen are mined, heated and processed to produce liquids the equivalent of crude oil. The massive scale of these operations and the huge environmental problems preclude significant cost reduction. *The high energy consumption per unit of output and the consequent low net energy yield makes these fuels significantly inferior to current petroleum products. Net energy yield matters — the difference between total energy content of a fuel and the direct and indirect energy consumed in its production.* By contrast conventional oil from giant oil fields has a very high net energy yield – for most in their best producing years *much higher* than for any other fuel (Gever et al. 1991). Most non-conventional oil will be produced after conventional oil peaks, and in limited quantities.

The world became sufficiently explored by advanced techniques in the 1980s for confident estimates of ultimate recovery (EUR) of *conventional* oil to be made. Three retired petroleum geologists, Colin Campbell and Jean Laherrère from Europe and L.F. Ivanhoe from the USA, are leading the debate on this issue in oil industry circles and in the community. In 1998 the International Energy Agency (IEA 1998) acknowledged the approaching conventional oil peak.

Only statistical estimates of *oil-in-place* and of that economically extractable are possible for a resource well below ground in irregular geological formations. Petroleum geologists full understanding of the modes of oil and gas formation in source rocks and of the subsequent migration of a small percentage of it into geological traps (oil fields) only matured in the mid-1980s when the concept of the Petroleum System emerged. The recognition of the role of plate tectonics in the late 1960s was a significant development The first step in exploring a sedimentary basin for petroleum is to identify the existence of extensive organically rich source rocks as potential generators of oil and gas. If these are absent the basin has poor prospectivity.

Much of the key data is confidential and unreliable for political reasons. There are no rigorously enforced international standards on definitions, assessment, reporting and auditing of reserves. Reporters can choose criteria to suit their convenience. Honest auditing in some countries is a hazardous profession. Most published reserves data must be regarded as political statements and must be interpreted with great care.

The strength of Campbell and Laherrère's work arises from their background in oil exploration, their rigorous attention to definitions and the correct use of statistics, and of the failings of others in this regard. From 1994 to 1999 they had privileged access to Geneva-based Petroconsultants comprehensive data base on the performance of most oil and gas fields outside of Canada and the USA, the only such data base in existence. A consensus is converging on the 1800 to 2000 billion barrels range for ultimate *conventional* oil production – about half of which has already been produced. However, the US Geological Surveys *World Petroleum Assessment 2000* discussed above proposed a figure closer to 3000 billion barrels for oil. As discussed, above, discovery rates for oil since 1995 have not matched the USGS predictions.

Most of the debate on the size of ultimate recovery centres around the *'grey'* area between conventional and non-conventional oil, the potential of technology to enhance yields from new discoveries and from existing fields, and the accuracy of many countries reported petroleum reserves. The difference between 'political oil' and 'technical oil', as Laherrére puts it. *Many analysts do not understand how net energy yield limits the scope for production of non-conventional oil and of conventional oil from small fields in remote and hostile environments. Many are expecting more oil from such sources than will be possible.*

These and other issues are well covered in Campbell and Laherrère (1995), Campbell (1997) and Fleay (1999). See also Campbell and Laherrère (1998) and Laherrère (2001) The latter paper presented to an OPEC seminar in Vienna in September 2001 particularly addresses the statistical minefield and the political influences that shape the statistics for many countries. *It is conventional oil that matters.*

WORLD DISCOVERY

Annual oil discovery peaked in the early 1960s at 40 billion barrels and during the 1990s has been only one quarter of annual world consumption. Conventional natural gas production is beginning to exceed discovery, as happened for oil 20 years ago. See ***Figures 3 and 4.*** Periodic revisions to reserves have been backdated to the year of discovery (Data provided by J.H. Laherrére).

However, natural gas is likely to experience a series of regional peaks due to the much higher cost of its transport and storage compared to oil. These are 5-10 times higher than for oil over long distances (Campbell 1997). The data base for gas is poorer than for oil, partly due to gas in the past being flared and re-injected into fields to force out the oil, and with the quantities not always recorded. Gas is generated under more diverse circumstances than for oil and we are not so far advanced in its depletion.

The higher cost of gas infrastructure constrains the economic production capacity installed compared to similar oil installations, especially offshore. It is not economic to install large capacity that is only used for a short time at peak production. Therefore maximum gas production profiles tend to have extended plateaus well beyond the mid-point of ultimate production. Consequently decline begins later in the production cycle than for oil. Furthermore, as gas is more free-flowing than oil, ultimate extraction can often be up to 80 per cent of the gas-in-place. *Once natural gas production decline begins both these factors ensure it often proceeds more rapidly than for oil.*

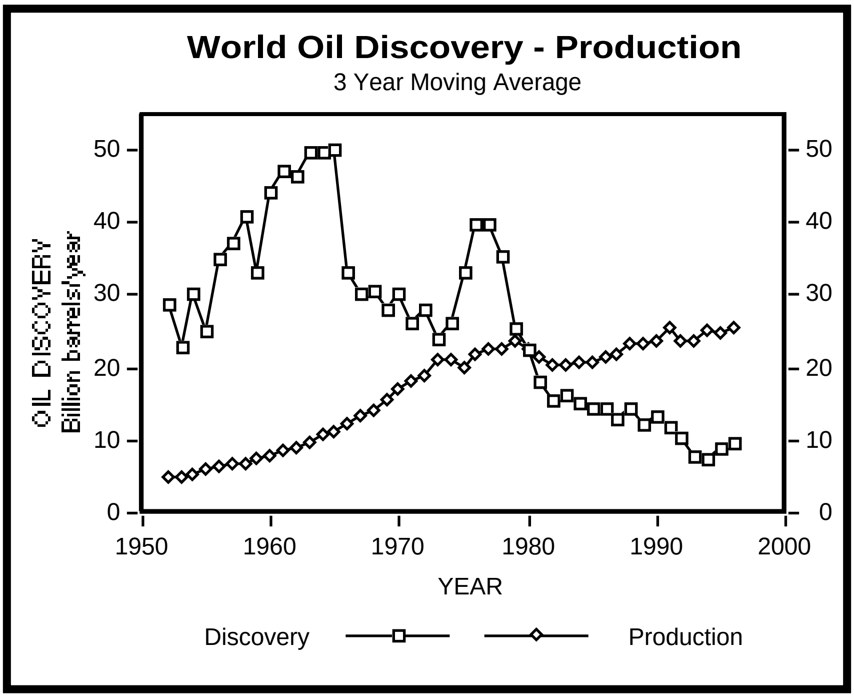


FIGURE 3

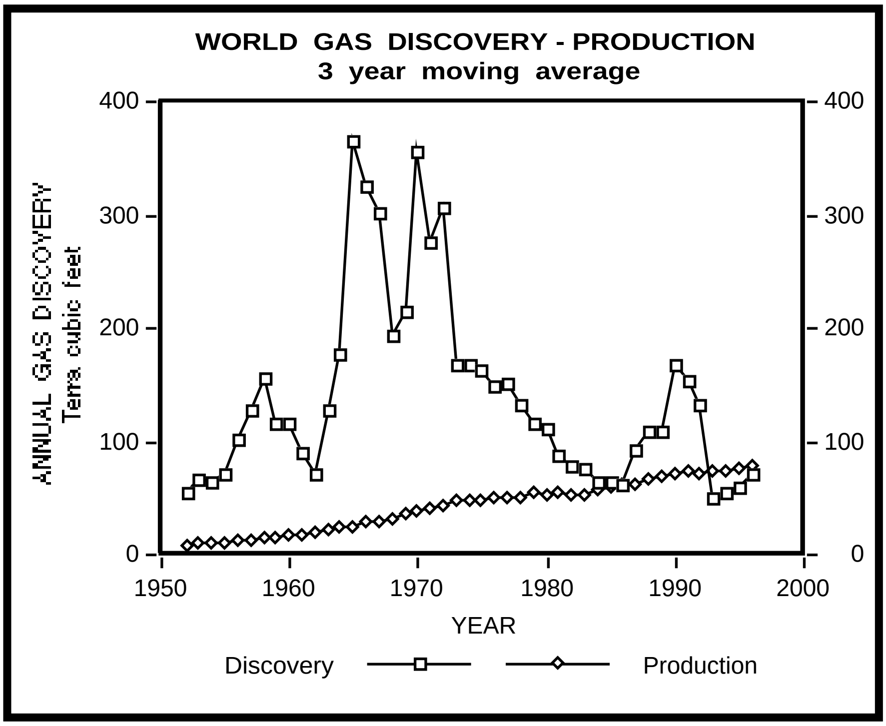


FIGURE 4

Most published data for annual changes in reserves incorporate both *revisions* for existing fields as well as new discoveries, after taking into account annual production. Revisions have accounted for three quarters of reserve additions since 1980, giving a misleading picture to the uninformed observer on the quantity of new oil actually being discovered. A revision is not a discovery; it is a clarification of what was discovered in a field at the time of its initial discovery. In this paper reserve revisions have been backdated to the year of discovery, unless otherwise stated. Access to data bases like those of Petroconsultants are needed to carry out this backdating. ***Figure 5*** from Laherrére (2001) illustrates the point for the world. The rising 'political' reserve line incorporating both revisions as well as discoveries disguises the real decline in *new* discovery that has been occurring since 1980.

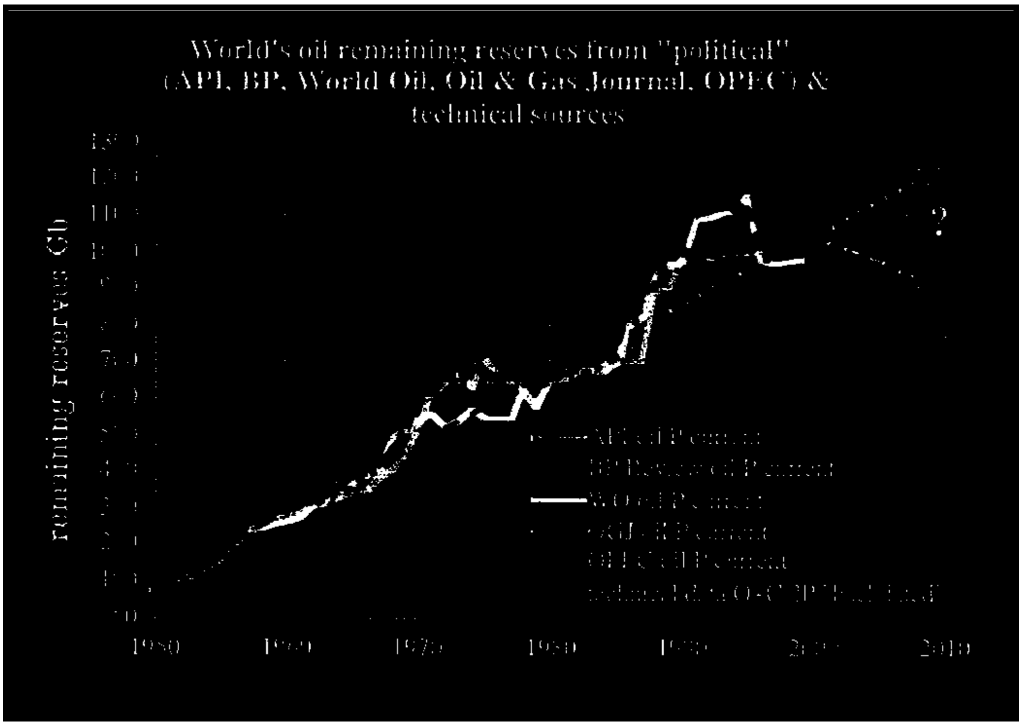


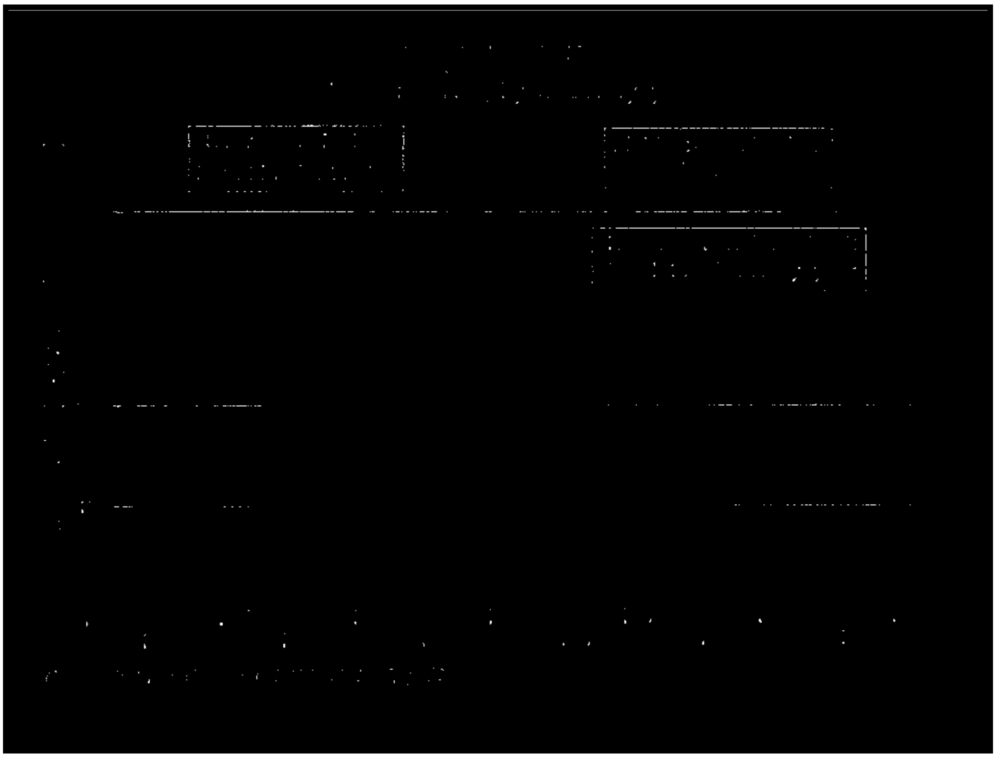
FIGURE 5

Giant fields are usually found first and their discovery has collapsed since 1980, ***Figure 6.*** There has been some limited discovery of giants since the late 1980s in deep water offshore – the Gulf of Mexico, Brazil and West Africa, with more expected this decade. A few have been discovered under the Caspian Sea since the late 1990s and were expected. However, most giant oilfields are old and past their prime, many are in decline. Increasingly costly work-overs are needed to sustain production. Perhaps 10 per cent of conventional oil is left to find. Most oil will continue to be produced from giant oil fields. Eighty per cent comes from oil fields over 25 years old (Campbell and Laherrère 1998, Simmons 2002).

Most fields yield 30-35 per cent of the oil-in-place and a few achieve up to 60 per cent. These outcomes include the use of gas injection and water flooding to push the oil into wells. Enhanced recovery techniques can further increase yields in some fields by changing the physical properties of both the oil-in-place and of the formation, all expensive and very energy intensive operations. Such enhanced recovery is in the non-conventional class based on high production cost and low net energy yields. Low yields are mostly from fields with heavy viscous oils and/or tight formations while high yields occur where the oil is free flowing, and the formation porous. These issues are discussed in Fleay (1999).

WORLD PRODUCTION PROFILES

M.K. Hubbert pioneered the use of the logistic equation to describe the discovery and production profiles for oil in major provinces. In 1956 he successfully predicted the time and magnitude of the 1970 peak of US oil production. These profiles for petroleum provinces are often bell-shaped and the peaks occur near the mid-points of ultimate economic production or discovery. ***Figure 7*** illustrates these points for world *conventional oil* and deep water oil (> 300m.) outside the Persian Gulf (Laherrére 2001). The discovery curve has been corrected to allow for the former Soviet Union reserves data where their definitions of reserves led to over-stating the position. The plot of discovery has been shifted forward 25 years to illustrate how the production profile is showing signs of mimicking the discovery profile *with a 25 year time lag*. The economic crisis after the collapse of the Soviet Union has delayed production from the region which is now making a partial recovery as conditions become more stable. The non-Persian Gulf peak for conventional oil is occurring now. Production constraints for *non-conventional oil* have a more uniform flat production profile and will not significantly impact upon the timing of the peak.



There are about 40,000 oil fields in the world
120 giant fields produce nearly half the world's crude oil
14 giant fields account for 20 per cent of crude oil supply
Their average age is 43.5 years
Four giant fields account for 11 per cent

FIGURE 6

Increasing the world ultimate from 1800 to 2000 billion barrels only shifts the mid-point of production forward about five years. See Campbell (1997), Fleay (1999) and Magoon (2001) for further discussion.

Laherrère (2001) gives more recent information *for both conventional and non-conventional oil*, and for natural gas in some key regions and the world.

Laherrére's figures 16-19 show the status of North American gas supply which is beginning a steep decline THIS YEAR. The US electric power industry is installing hundreds of gas turbines when the gas to run them is not available (Udall 2001). *North America gas production is peaking, the first major gas province to do so.* Simmons (2000 & 2002a) discusses how both government agencies and the petroleum and electric power industries came to find themselves in this unexpected predicament He says US gas production could decline by 10 per cent in the second half of 2002 and continue through 2003.

Figure 8 shows actual production of *conventional oil* to 1997 and future estimates for the world and for some major regions based on an ultimate of 1800 billion barrels (Campbell and Laherrère 1998). The USA (1970), the former Soviet Union (1989) and the North Sea (2001) have already peaked. See Campbell (1997), Fleay (1999) and Magoon (2001) for further discussion.

FIGURE 7

PAST AND FUTURE OIL PRODUCTION
WORLD AND REGIONS
Conventional Oil

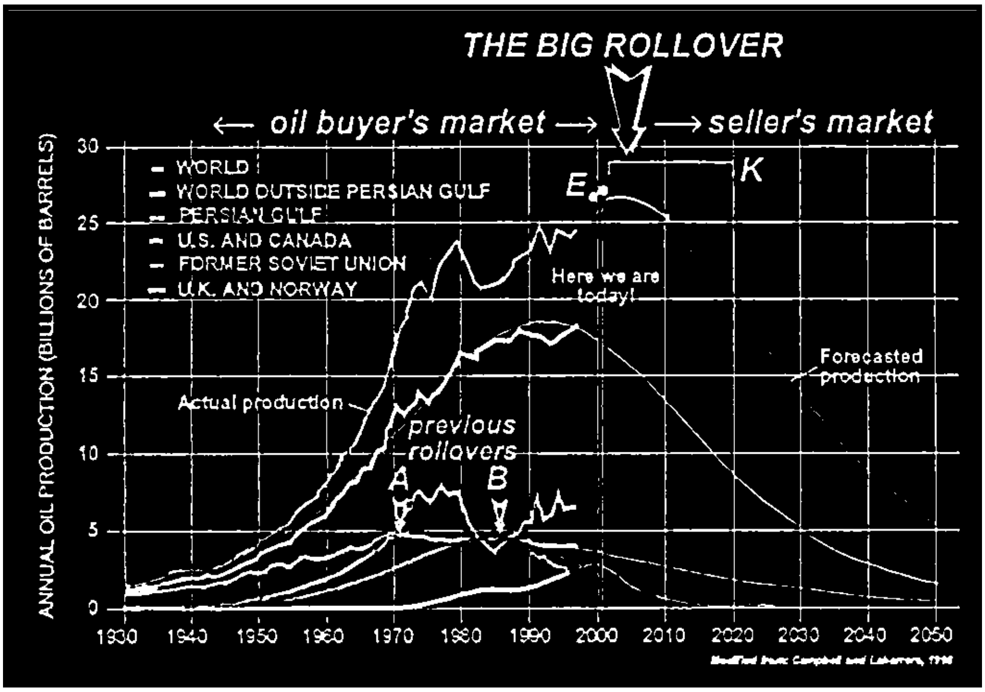


FIGURE 8

THE TRANSITION BEGINS

The developed world's 20 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. The world must now face the consequences of oil depletion and address the major issues on the downside agenda.

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 30 years and decline has commenced in the North Sea, China, Argentina. Egypt, Syria, India, Colombia and others, while Venezuela and Mexico are only holding their present level (IEA 2000).

Some production recovery began in the Former Soviet Union from 2000 when oil prices rose and the Russian economic and political climate stabilised under President Putin. But it is not expected to reach the 1989 peak level and could peak again by the end of the decade. Production has been growing in deep water offshore since the late 1980s (> 500m. depth) and could continue increasing to about 2010 (Gulf of Mexico, Brazil and off Nigeria and Angola) (Laherrére 2001). *But can Persian Gulf 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). Who knows what may happen if there is a US inspired invasion of Iraq to topple the regime of Saddam Hussein.

Campbell & Laherrère (1998) and others have long predicted that non-Persian Gulf conventional oil would peak around 2000 and Persian Gulf production about 2015. ***But they assumed that the investments required for this scenario would take place where and when needed.***

To meet modest consumption growth to 2010 requires Persian Gulf investment of around US$80 billion. Over half is required simply to sustain present production from ageing giant oil fields and to repair war-damaged facilities in Iran and Iraq (Ismail 1994). *This investment program has yet to commence on the scale required.* Bakhtiari from the National Iranian Oil Co. is pessimistic about the capacity of these countries to expand oil production given the long lead times required, when increasing investment is needed just to maintain existing production levels from ageing oil fields (Bakhtiari 2001). So it could be well after 2005 before Persian Gulf production capacity much beyond 2000 levels is possible. This scale of investment is beyond the financial and technical resources of these countries. *What are the obstacles to investment?*

The excess world supply capacity and low oil prices since the mid-1980s have strained these countries budgets. Rapidly growing populations plus low oil prices have substantially reduced their per capita export income needed to pay for food imports. *After food, welfare for the elite and the masses, plus high military outlays, little has been left for oil investment.*

The regions population has quadrupled since 1950 to over 100 million and could easily double again in 25 years. However, excluding Iran (population 62 million and one of the most food self-sufficient), the doubling time is around 17 years. Half the population of Saudi Arabia is under the age of 15, half in Iran are under 21 years. Since the mid-1970s Saudi Arabia from has become self-sufficient in food, and even exports wheat through heavily subsidised irrigation with ground water being mined at five billion cubic metres per year. The Saudis have the world's largest sea water desalination plants for drinking water (de Villiers 1999).

Perhaps 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). Fluctuating oil prices intensify these financial problems. Satellite television allows the population to observe how most people in oil-fuelled developed nations appear to lead more prosperous lives in comparison to themselves.

UN and US sanctions inhibit external investment in Iraq and Iran, where there is still damaged oil infrastructure from their 1980s war. Outside investment is a sensitive political issue for these countries. Their long-term interests are served by rationing oil at high prices, but not at levels damaging the world economy or provoking oil substitution. The narrow margin of supply over demand reduces their ability to pretend there is a large supply surplus. The circumstances surrounding the destruction of New York's World Trade Center in 2001 have revealed these inner tensions and intensified all these problems.

Saudi Arabia produces 12 per cent of the world’s oil from under 2,000 wells. By comparison 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. They have many faces and have ascetic values that frown on luxurious and ostentatious living, as you would expect from a desert people. Unemployment is over 15 per cent and it is becoming increasingly difficult for the Kingdom to expand employment opportunities, fund welfare and other subsidies in the face of rising populations and 17 years of falling oil revenues. Budget and fiscal deficits as well as welfare cuts raise awkward questions: *Why should ordinary Saudis tighten their belts unless the 6,000 or so princes of the royal family also tighten theirs?*

The Saudis have tried for years 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 mostly xenophobic, anti-western and critical of the Saudi ruling family and the presence of US troops in Saudi Arabia. King Ibn Saud is 80, had a stroke in 1995 and has handed day-to-day power to his half-brother, Crown Prince Abdullah. When Ibn Saud dies informed observers expect a power struggle will almost certainly arise among the princes that could shatter political stability and the aura surrounding the royal family. A fundamentalist Islamic revolution could sweep aside the House of Saud with unknown consequences for the future of oil supplies. Currently Saudi Arabia produces 11 per cent of the world’s oil.

The political risks to future Australian oil imports were high on the agenda of APPEA’s Barry Jones and Woodside’s John Akehurst, as was the USA’s high and growing dependence on oil imports. The USA consumes 26 per cent of world oil and imports 55 per cent of this at a cost of US$100 billion in 2000. President Bush's plans to topple Saddam Hussein in Iraq must be considered in this context.

A permanent oil supply shortfall is emerging over the next decade under circumstances of high political risk. The risk of supply disruption is very high, and will continue. But that is not all.

The limits of good agricultural land in the world were reached 50 years ago. Much new marginal agricultural land developed since is not suited for agriculture and is 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 yield hybrid grain varieties have 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).

Approximately 90 per cent of the direct and indirect energy used in crop production is oil and natural gas. About one-third of the energy is used to achieve a hundred fold reduction in the labour input per hectare in many developed countries 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 alone (Conforti & Giampietro 1997). The principle grain exporters, the USA, Canada, Europe, Australia and Argentina, are all highly dependent on such petroleum-based industrial agriculture.

A critical role is played by nitrogen fertilisers. The starting off point is the synthesis of ammonia from atmospheric nitrogen and hydrogen obtained from natural gas at a pressure of 200 atmospheres and 350°C in the presence of catalysts. According to Vaclav Smil the world reached the limits of providing people with an adequate protein diet by using legumes and animal manures for crop production around 1960. Since 1960 an adequate protein diet for a doubling of world population has been achieved through enhanced crop yields in which nitrogen fertilisers have played a key role. From 1960 to 1990 world nitrogen fertiliser production increased from 10 to 85 million tonnes as nitrogen, with two-thirds of the increase used in Asia (Smil 1993 & 1997). Such fertilisers made the so-called Asian Green revolution possible. Two of the petrochemical plants proposed for the Burrup Peninsula are for the manufacture of nitrogen fertilisers. One depends on contracts to export over 700,000 tonnes of urea per year to India. Nitrogen fertilisers play a significant role in Australian agriculture.

How can the world manage a reduction and re-distribution of population over the next century 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. A major issue is solving the population problems of the Persian Gulf countries who have over half the world's remaining conventional oil and close to one-third of its conventional natural gas. These issues lie behind the growing refugee problems in the world.

WORLD PER CAPITA ENERGY PRODUCTION 1850-1997

Richard Duncan (1999) discusses trends in world per capita energy production from 1850 to 1997 for the five principal commercial energy sources, oil, natural gas, coal, nuclear electricity and hydroelectric, compared on an energy equivalent basis.

He found that energy production per capita grew at 2.12 per cent per year from 1850 to 1930. Coal was king in this earlier period with oil and electric power emerging from the 1890s. The trend from 1930 to 1945 was erratic due to the 1930s economic crisis and World War II, but still an increase. From 1945 to 1973 energy per capita production grew rapidly at 3.54 per cent per year, as oil displaced coal and the use of electricity grew and diversified into many applications. Growth flattened from 1973 to 1979 when it peaked at 11.16 barrels of oil equivalent (boe) per capita. From 1979 to 1997 there has been a small decline to 11.0 boe per capita. ***See Figure 9***. In 2001 consumption was 11.15 boe per capita. There has been no growth in per capita energy production for 22 years. However, oil production per capita has declined from its peak of 5.50 barrels of oil per capita in 1979 to 4.51 in 1997. With the peak of conventional oil production imminent we can soon expect per capita energy production to decline.

WORLD TOTAL ENERGY PRODUCTION PER CAPITA 1850-1997

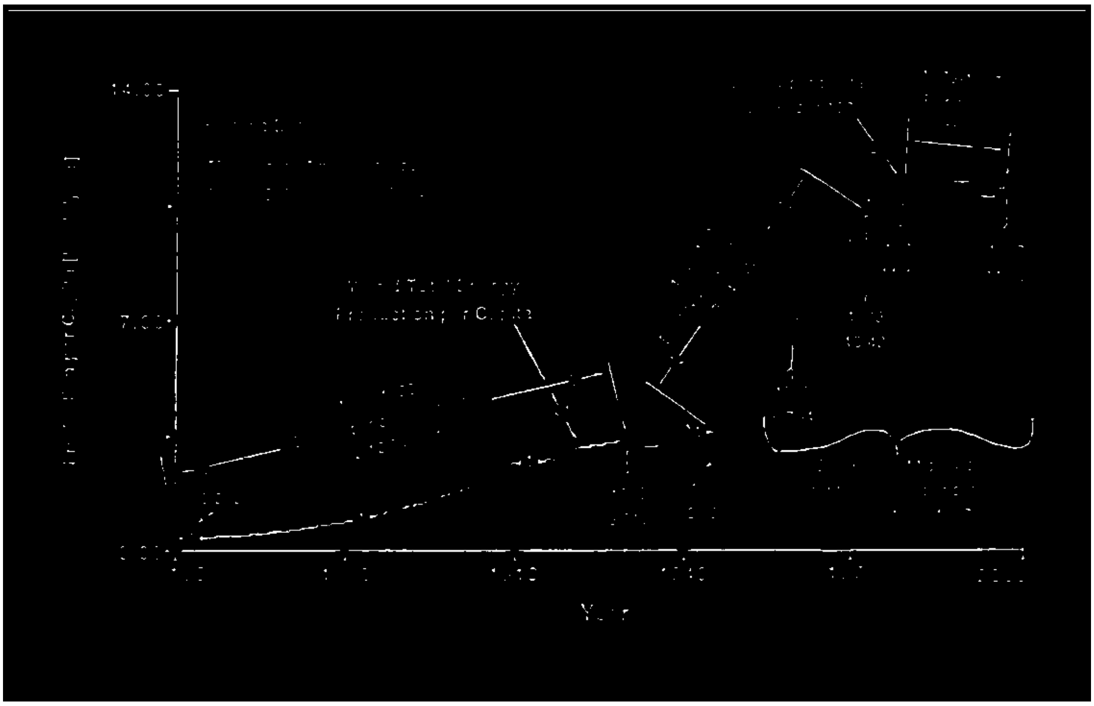


FIGURE 9

The huge increases in labour productivity over the last 150 years are a consequence of harnessing fossil fuels to labour. One driver on a diesel powered excavator can move earth that would take hundreds of labourers with shovels and wheelbarrows. Since the 1970s there has been a rapid increase in commercial energy consumption in newly developing countries with an expectation that this will continue, emulating the high labour productivity of the older developed industrialised countries. But the trends in global per capita energy production suggest this is not possible in the decades ahead, nor is it possible for the developed countries to continue with their high levels of labour productivity fuelled by commercial energy. We have reached an historical turning point. Economic development in the 21st century will soon become a reversal of the 20th century pattern.

Recognition of this trend challenges the wisdom of the current gas powered development agenda pursued in Western Australia. The remaining hydrocarbon fuels must be used to bring about a transition to less energy intensive development. Both energy and population issues are involved.

ENHANCED GREENHOUSE ISSUES

The Intergovernmental Panel on Climate Change (IPCC) uses 40 models by climate change researchers in its assessments of the climate change impacts of carbon dioxide emissions from burning of fossil fuels. These models have a very 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 models. The IPCC technical committee’s concerned have discussed the subject, but were unable to reach agreement on this issue (Pittock 2002). These IPCC models and their fossil fuel combustion profiles no doubt date back to the 1980s

Jean Laherrére has compared these 40 production profiles for oil and gas with his *most likely* production profiles for these fuels. See Laherrére (2001) pp. 25-26 and Laherrére (2001a) pp. 83-90. In both cases his profiles are at the bottom range of the IPCC models. These assessments date from the mid-1990s and are based on the collective life-time experience of recently retired petroleum geologists who have seen fit to alert the world to the realities of future petroleum supply and its future, as outlined above. The time has arrived for IPCC to review the validity of its climate models based on their more extreme carbon dioxide emission cases for oil and natural gas, where these are due to projected combustion of oil and natural gas.

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. I am not familiar with the details of the IPCC models.

ASSOCIATION FOR THE STUDY OF PEAK OIL - ASPO
OIL DPLETION ANALYSIS CENTRE - ODAC

Colin Campbell's and Jean Laherrére's work has been extensively quoted in this paper. Colin started his career as a petroleum geologist and finished it as executive director of Fina a Norwegian oil company, now merged with the French petroleum company, Total. Jean finished his career as deputy exploration manager for Total. During the mid-1990s they were associate consultants with Petroconsultants SA, a Geneva-based oil industry service company who have the world's most complete data base on the history and performance of oil exploration and development outside the USA and Canada. Colin and Jean had access to the data base and Petroconsultants published several reports by them on world oil and gas supply. They had a free hand to draw their own conclusions.

By 2001 Colin had gained the interest of academics in nine European tertiary education institutions who formed the Association for the Study of Peak Oil (ASPO) to co-ordinate work in this field. This attracted the interest of the UK Astor Foundation who expressed a wish to fund such work, leading to the formation last June of the London-based Oil Depletion Analysis Centre (ODAC). ODAC has a distinguished Board of International Advisers. ASPO has published a monthly Newsletter since early 2001 and copies can be found on the website www.energiekrise.de.

Every year ASPO/ODAC will publish their latest assessment on expected hydrocarbon production into this century. The 2002 assessment is in their June 2002 Newsletter. It covers both conventional and unconventional oil and gas to 2050. Their aim is to establish an association that can make regular authoritative assessments of oil depletion issues independent of companies and governments.

CONCLUSIONS

The Persian Gulf countries could soon be supplying half the world's oil. Add their problems in feeding and employing a growing population and we have scenarios where oil supply can face unexpected interruptions. There is no certainty that the high investments required in their oil industry will take place, nor that the petroleum infrastructure will be maintained in good working order. The expected rapid decline of Australia's oil self-sufficiency by 2010 must be viewed in this context. Transport is the most vulnerable sector – it consumes over 60 per cent of oil production and services every other economic sector and more.

Extremely cheap oil from a very small number of giant fields has played a major role fuelling economic growth since 1950, especially the expansion of cheap transport. But these fields most productive years are past. Natural gas is the next best substitute for oil in transport followed by electricity. However, both have inferior storage and transport characteristics. Coal is an inferior transport fuel because it is a solid. *There are alternative transport fuels but none that can match in economic performance oil from the giant oil fields as we have known it for the last 50 years.* The real cost of powered transport is going to increase and a decline in its scale and scope is inevitable. Conversion to alternative fuels requires massive investments and takes time. But time is running out for their early introduction. *Petroleum products are unique because of their high power-weight ratio, the fine control possible, their ease of storage and transport and hitherto high net energy yield – for oil from the giant oil fields, much higher than for any alternative fuels.*

Natural gas is the next most adaptable and is the critical transition fuel to see Australian transport and agriculture through to an era 'beyond petroleum'. *But natural gas is not a transport option for North America, natural gas production there is about to decline rapidly.* The sooner the transition to alternatives fuels begins the easier it will be. Delay, and a painful and traumatic adjustment is inevitable.

Fuel priorities will be needed and *essential* freight transport and agriculture must have first call on limited oil supplies. The 'carting of coal to Newcastle' must cease everywhere. *The global economic vision promoted by corporations and international bodies such as the WTO, the IMF and World Bank has no future in the medium term. It is a future totally dependent on expanding low cost transport networks.*

In Australia the main sacrifices will be in urban car travel, especially for short journeys within the scope of walking and cycling. But the urban population is blissfully unaware of the predicament they face.

We can no longer ignore the future availability of petroleum fuels, the alternatives and their viability. On the contrary, these issues needs to be at the top of the agenda. Rigorous criteria need developing and promoting for the evaluation of alternative fuels to petroleum, including their net energy yield. We cannot afford to be led down cul-de-sacs by the 'snake-oil' merchants who will emerge in the years ahead.

An alternative global vision is needed for the 21st century based on reducing and relocating population to levels that the world can support without the use of fossil fuels.

SOME RECOMMENDED ACTIONS

- The Commonwealth should give highest priority to developing a 30 year National Energy Strategy with a prime focus on Australia's expected rapid decline in oil self-sufficiency in the context of an approaching peak of world oil production. The Strategy should recognise the risks associated with dependence on oil imports from the Middle East, and that transport is the mode most at risk.

- The States should take complementary action to the Commonwealth as well. In Western Australia the Government should build on the initiatives for Oil Vulnerability already outlined in the draft State Sustainability Strategy.
- Governments should prepare co-ordinated transport contingency plans in case of major oil supply disruption from the Middle East arising from political instability.
- The implications of declining petroleum supply for the future of Australian agriculture need urgent attention in a global context.
- The medium to long term implications of declining oil supply on the future viability of long distance trade need exploring.
- Governments should promote the investigation and publishing of information on the life cycle net energy yield of energy sources and their trends, and promote development of consistent and sufficiently holistic methodologies for such studies.
- Develop in this context criteria for assessing the feasibility of alternative fuels to petroleum products for transport, incorporating net energy yield factors into the criteria.
- Investigate the options and limitations to using natural gas-based fuels for transport as alternatives to petrol and diesel. There should be a focus on the relative costs of developing alternative fuels and realistic time frames for their introduction on any scale.
- Broadly based demand management initiatives are needed in the transport sector as the main response to declining petroleum-based transport fuels, both for personal and freight transport. No substitute fuels can replace petrol and diesel derived from oil in the now passing era when giant oil fields were in their most productive years.
- There should be an end to building of urban freeways and strategies developed for urban restructure to cope with fuel supply constraints and the rising cost of transport.
- That government agencies stop using reserves to current production ratios for petroleum as an index of the expected life of these resources. The statistic is now an historical anachronism that gives a misleading picture of the status of petroleum reserves.
- Investigation is needed of the implications for employment and economic development of the end in 1979 of global per capita increases in commercial energy production.
- That regular studies be made and published of the likely *whole production life cycle* of oil and natural gas resources, given the known discovered extractable resource, the anticipated development of these and the depletion performance characteristics of oil and gas fields. One aim being to define the scale of new discoveries required to sustain the high production levels from anticipated gas consuming projects. The practice of focussing only on the 'upside' of the production cycle and avoiding detailed study of the 'downside' should cease.
- Petroleum companies should make publicly available information on the performance and depletion characteristics of their oil and gas fields to enable such studies to be carried out.
- Governments should use a conservative estimate of future natural gas resources when planing gas-related economic development, rather than the generally optimistic expectations of the petroleum explorers. The medium term risks from reaching too high are very great. The precautionary principle should apply.
- Governments should investigate the risk and cost implications, both in dollar and energy terms, of obtaining oil and natural gas from deep water environments offshore. Petroleum exploration and development is poised to move into ever more marginal prospects.
- The problems associated with replacing gas production from ageing eastern Australian fields highlights the need for *integrated* geological and economic assessment of options in government agencies as revealed by ABARE’s report, *Australian Gas Supply and Demand Balance to 2019-20*. Integrated “triple bottom line” approaches are now necessary.

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APPENDIX

DATA SOURCES FOR FIGURE 2

Recent editions of *Oil and Gas Resources of Australia (OGRA)* from 1996 to 2000, published in turn by the Bureau of Resource Sciences, the Australian Geological Survey Organisation and Geoscience Australia were used for information on past production up to 1999 and for discoveries of natural gas, supplemented by some more recent data from the *Western Australian Oil and Gas Industry 2002* report published by the W.A. Department of Mineral and Petroleum Resources. This latter publication had a graph on p. 10 showing potential gas growth in Western Australia to 2015 and covering petrochemicals and mineral processing projects already announced by companies but not yet approved for construction – the "wish list" of projects. The graph also includes the gas needs for some projects where government has been approached by companies, but where no public announcement has been made. This graph, with other information, was used to compile annual gas production projections to 2020. Generally it was assumed it would take a plant three years after commissioning to reach full production.

An additional source of information was *Energy Western Australia 2001* published by the Office of Energy, Western Australia. This provided data on some existing natural gas contracts by gas supplier and purchaser with contract end dates. Included were some potential future sales such as Austeel's proposed iron and steel plant – assumed to be commissioned after 2010. There was inadequate information on likely future consumption of natural gas for electric power generation, possibly due to uncertainty being generated by proposals for a competitive wholesale market for electricity. The industry seems to be shifting to natural gas. ABARE's *Australian Gas Supply and Demand Balance to 20119-20* included some additional company projects not listed in the State government documents.

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 transported would come from minor producers. This paper has focussed on the future of the NWSJV and Gorgon projects who dominate gas supply and are likely to continue to do so.

Woodside Petroleum Ltd's recent Annual Reports were used as another source of information, mainly to cross-reference their reported reserves against government sources. These annual reports also 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 to LNG consumes around 15 per cent of the gas content of the LNG.

The NWSJV's existing three LNG trains can produce up to 7.5 million tonnes of LNG per year. The fourth train will be commissioned in 2004 at 4.2 million tonnes per year. Now that the NWSJV has a contract to supply China the fifth train of similar size should follow well before 2010, especially as there is likely to be a rapid demand for LNG in North America as gas production there is expected to decline rapidly. On this scenario the NWSJV will have consumed 75 per cent of its *discovered* gas by 2011, when rapid decline could commence. New *large* gas fields would have to be found and developed before then to postpone such an event. These would need to be equivalent to about 75 bcm per year to postpone the likely NWSJV decline date by one year. For this reason it was assumed that the first stage of the Gorgon project would need to come on line no later than 2011 and would require an LNG project of 4.2 million tonnes per year to make stage one a commercially viable project.

The Table below lists some of the petrochemical and LNG projects in progress or on the Governments published "wish list" for the Karratha region.

TABLE A1

Projects	$million	Tonnes/yr.	Gas 10^9/yr.	Start Up
Methanex methanol plant No. 1	2,000	4.000,000	2.80	2005
Burrup fertilisers & ammonia	600	760,000	0.85	2006-7
GTL Resources methanol plant	610	1,000,000	2.85	2005-6
Syntroleum gas-to-liquids plant	1,000	470.000	3.70	2005-6
Plenty river ammonia urea plant No.1	900	1,200,000	0.85	2006
Japan DME dimethyl ether plant	1,000	1,700,000	~1.50	2010
NWSJV 4th LNG train (under constr.)	1,600	4,200,000	5.50	2004
NWSJV 5th train	1,600	4,200,000	5.50	2008?
TOTALS	9,310		23.55	

Methanex propose a second plant, no date set, but assumed to be commissioned in 2010. Austeel propose an iron and steel plant in two stages, no date set, but stage 1 assumed to start-up in 2009, stage 2 in 2013. Stage

1 on present plans would require 3.8 billion cubic metres (bcm) of gas per year. The Syntroleum plant has been delayed, but it has been assumed it will have a late 2006 start up, with a second plant starting in 2011.

Such an investment schedule to 2010 would severely stress the construction industry. The completion dates for some of these projects were delayed to a more realistic schedule when preparing ***Figure 2.***

The NWSJV's main LNG contracts with Japanese companies are due for renewal later this decade. Further LNG contracts with China are possible, if some of the petrochemical plants do not come to fruition.

Including the Gorgon stage 1 start-up and new LNG plants, the investment in the "wish list" comes to some $23 billion between 2001 and 2013. The peak years of investment on this agenda are from 2008 to 2011, averaging $3.7 billion per year. This agenda does not include expenditure on petroleum exploration, developing of new discoveries, and development of the Greater Gorgon and Scarborough gas fields.

Broadly speaking this schedule of investment is needed to meet the potential domestic gas growth in Western Australia as shown in the graph on p. 10 of *Western Australian Oil and Gas Industry 2002.*