House of Representatives Standing Committee on Industry and Resources

Inquiry into Resources Exploration Impediments

July 2002

APPEA

Australian Petroleum Production & Exploration Association Ltd

GPO Box 2201 , Canberra ACT 2601
Telephone 02 62470960 Facsimile 02 62470548
Email : appea@appea.com.au Website : www.appea.com.au

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Terms of Reference

Inquiry into resources exploration impediments

On 24 May 2002 the Minister for Industry, Tourism and Resources, the Hon Ian Macfarlane MP, referred the following inquiry to the committee.

That the committee inquire into and report on any impediments to increasing investment in mineral and petroleum exploration in Australia, including:

- An assessment of Australia's resource endowment and the rates at which it is being drawn down;
- The structure of the industry and role of small companies in resource exploration in Australia;
- Impediments to accessing capital, particularly by small companies;
- Access to land including Native Title and Cultural Heritage issues;
- Environmental and other approval processes, including across jurisdictions;
- Public provision of geoscientific data;
- Relationships with indigenous communities; and
- Contributions to regional development.

Key Recommendations

Resource Access – Impediments to Exploration and Development Activities

Pre-Competitive Research

Governments should increase funding for pre-competitive research by public geographical survey agencies directed at identifying new petroleum provinces and upgrading information on existing provinces as a necessary pre-cursor to identifying exploration acreage for release. The Commonwealth Government should review the tax treatment of expenditure on such pre-competitive research undertaken by companies.

Access to Resources

Management of the acreage release process needs to be efficient and timely so that companies can allocate the necessary capital and not be hindered in the bidding process.

To reduce the risks, delays and costs of approvals and facilitate access to acreage for exploration, governments should provide information packages accompanying acreage releases that are comprehensive and include all relevant information on native title, environment and cultural heritage relevant to the acreage being released.

Standard industry operational activities should be excluded from having to seek specific approvals where they are carried out in accordance with appropriate guidelines. This information, and the requirements of any guidelines should also be included in the pre-release package.

On native title, governments should review the Native Title Act to ensure that it creates more certainty for parties negotiating native title agreements, for example to clarify that conjunctive agreements have the same status as other agreements. Governments should also develop mechanisms for consultation on native title prior to issuing of exploration permits so that native title negotiations post issuing of licences can be completed in the shortest possible time.

On environmental approvals, Commonwealth and State governments and all relevant agencies should coordinate environmental assessment and decision making so that there is a single assessment and a single decision without duplication.

On marine conservation regimes, governments should clearly identify how proposed regimes are necessary to protect conservation values and coordinate any new regulation with that already governing petroleum industry activities. In addition, before any discussion about the physical boundaries of a regime can constructively take place, industry believes that the goals, objectives and procedures for the regime must first be discussed and developed. The use of blanket bans is a simplistic and inappropriate conservation management method.

To better coordinate approvals, processes should be established within governments for initial and regular consultation between all involved agencies and project proponents, timelines should be identified and a single agency should take on the coordinated management of the approvals processes.

Fiscal Issues Impacting on Exploration and Access to Capital

Resource Taxes

For new projects, the carry forward rate for undeducted general project related expenditures be increased from the long term bond rate plus five percentage points to a minimum of the long term bond rate plus ten percentage points.

The PRRT Act should be amended to respond to the greater risks associated with deepwater exploration and production activity.

The five year GDP factor for undeducted exploration expenditure should be modified to recognise the long lead times between exploration and production.

Company Tax

That the Committee recommend consideration be given to assessing options (in consultation with the industry) to encourage exploration in high risk and/or under-explored areas via the use of incentives through the company tax system.

That the Committee notes the importance that depreciation provisions play in influencing project economics and the need for Australia to maintain a competitive regime to further stimulate exploration and development activity.

All costs associated with petroleum exploration and production activities, including native title related costs, should be deductible for company tax purposes.

Junior Exploration Companies – A Tax Induced Impediment to Capital Raising

The Committee recommend a detailed analysis of the changing pattern and influences on exploration activity by junior exploration companies with a view to developing a set of proposals to minimise the tax induced distortions that constrain the ability of such companies to attract investment capital.

Taxes on Business Inputs – Diesel Fuel Excise

That all activities associated with mining operations be covered by the scope of the Diesel Fuel Rebate Scheme (or from 1 July 2003, the Energy Credits Scheme) to ensure that the pool of funds for future exploration is maximised.

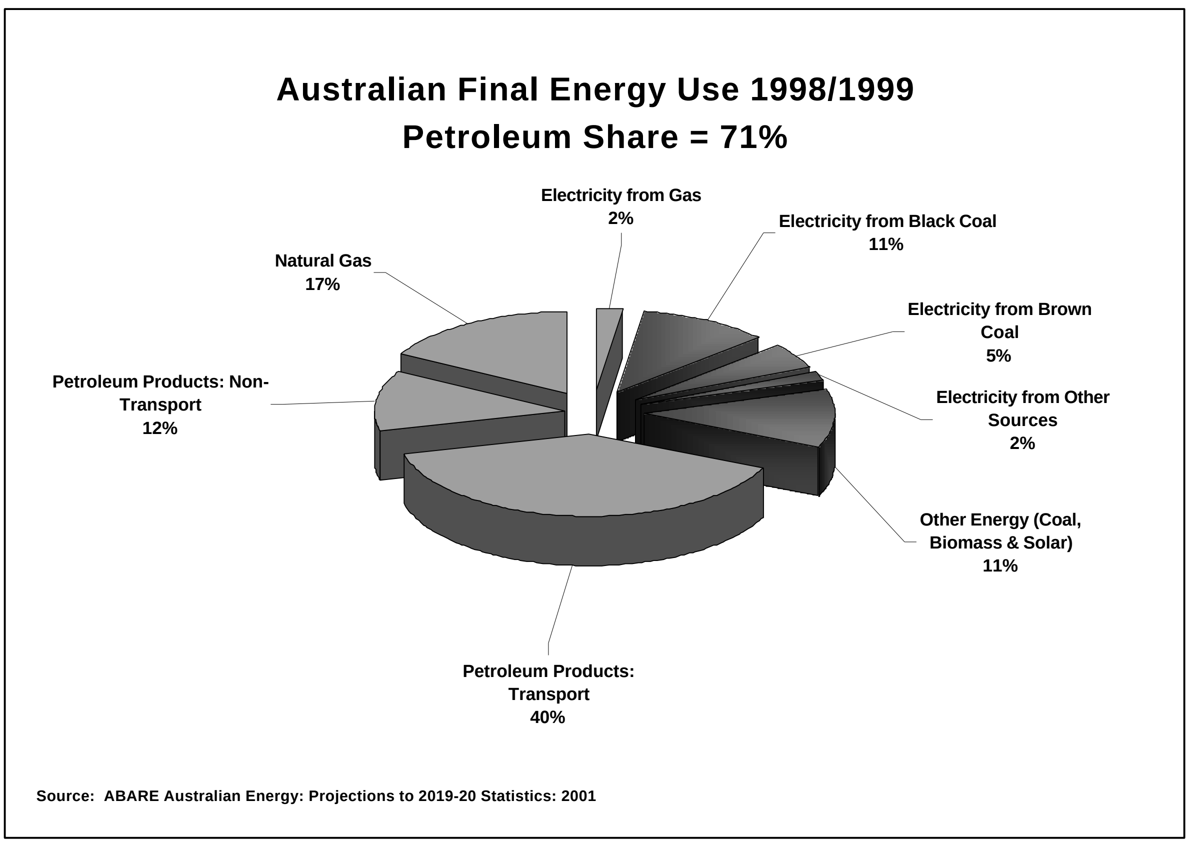
1: Petroleum : Usage, Economic Contribution and Future Trends

1.1 Introduction

The Australian Petroleum Production and Exploration Association (APPEA) is the national body that represents companies involved in oil and gas exploration and production in Australia. APPEA welcomes the opportunity to submit to the Standing Committee its views on impediments to oil and gas exploration and policies and actions which governments need to take urgently to ensure that more oil and gas is discovered and produced.

APPEA believes that the need to act is urgent in view of the imminent rapid decline in Australia's crude oil production combined with relatively low levels of exploration activity. Also, while Australia has abundant gas resources in the ground, reserves presently declared commercial fall short of projected demand over the next twenty years. Policies to facilitate healthy exploration levels are necessary to expand the resource base and ensure future production requirements – today's exploration is tomorrow's oil and gas production. The post-exploration investment regime is also critical since a petroleum exploration licence, unlike a mining licence, carries with it the right to obtain a production licence and produce petroleum which may be discovered. Companies will only explore for petroleum if the investment climate for the petroleum industry in Australia allows them to attract internationally mobile capital investment to develop petroleum finds and earn an adequate return on those investments.

Chart 1.1



A reliable and competitively priced supply of petroleum is essential to the Australian economy and to meeting community needs and maintaining our lifestyle. Petroleum (oil and gas) supplies 71 per cent of Australia's final energy consumption; liquid petroleum supplies 51 per cent, including nearly all our transport energy needs (Chart 1.1). The Australian Bureau of Agricultural and Resource Economics (ABARE) projects a continuing reliance on petroleum for the foreseeable future.

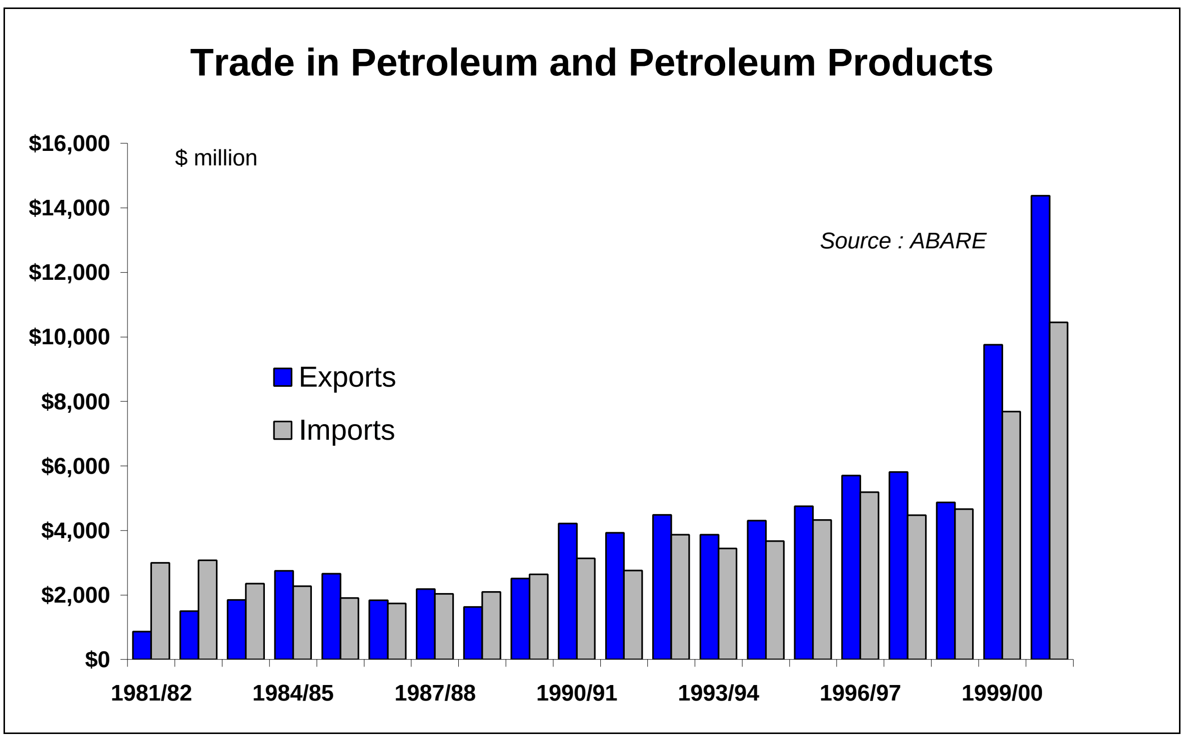
1.2 Economic Contribution and Significance

The petroleum exploration and production industry makes a significant contribution to Australia's economic growth and well-being. A range of studies have been conducted over the last decade that have evaluated the economic worth of the industry, at the national, state and regional levels. A range of the key results are outlined below.

1.2.1 Trade

In 2000/01, Australia exported more than $14 billion dollars worth of crude oil and petroleum related products compared with petroleum imports that totalled around $10 billion. Over the last two decades, Australia has gradually moved from being an energy importer to an energy exporter. In the 20 year period covering 1981/82 to 2000/01, the total value of exports was $84 billion, while imports totalled $75 billion. Chart 1.2 outlines the trends over the 20 year period

Chart 1.2



In addition to the export/import impact, domestic production of crude oil, condensate, LPG and gas has also allowed Australia to replace significant levels of potential imports. APPEA estimates that indigenous production replaced potential imports of petroleum of more than $10 billion in 2000/01.

1.2.2 Taxation

The petroleum exploration and production industry has historically been a major contributor to the Federal and State Governments via direct taxation payments. In 2000/01 alone, APPEA estimates that the industry paid to governments in excess of $3.3 billion in secondary taxation (in return for the right to produce the community's resource), with the majority being sourced from the petroleum resource rent tax and petroleum royalties (Chart 1.3).

In addition, the industry significantly assists the overall federal budgetary position through company tax payments. Since the mid 1990's, payment have consistently exceeded $1 billion per year, peaking at $2.5 billion for the year 2000/01, a year which coincided with a spike in international oil prices.

Chart 1.3 : Estimated Taxation Payments - 1987/88 to 2000/01

	Resource Taxes $m	Company Tax $m		Resource Taxes $m	Company Tax $m
1987/88	2756	873	1994/95	1156	1163
1988/89	1793	390	1995/96	1184	1218
1989/90	1370	641	1996/97	1290	1509
1990/91	1540	970	1997/98	1469	1398
1991/92	1499	817	1998/99	1021	1078
1992/93	1792	894	1999/00	1777	1381
1993/94	1442	882	2000/01	3387	2523

Source : APPEA

1.2.3 Economy Wide Benefits

In June 1996, ABARE released a comprehensive report into the net economic benefits arising from the development of Australia's oil and gas resources (ABARE: Net Economic Benefits from Australia's Oil and Gas Resources). The report quantified the overall significance of the industry for the national and state/territory economies, as well as identifying those industries that are particular beneficiaries from a robust and expanding oil and gas sector.

As highlighted in Chart 1.4, for the nation as a whole, a 20 per cent rise in the Australia's oil and gas output would lead to increased economy wide output of between 0.3 and 0.5 per cent. On a state level, output was expected to increase by up to 1.0 percentage point in Western Australia and by significant amounts in South Australia, the Northern Territory, Victoria and Queensland.

In addition, the short term results indicated a rise in aggregate employment of up to 0.4 per cent (see Chart 1.5). In effect, while the industry makes a significant contribution through the payment of secondary and income taxes, the additional growth generated through the remainder of the economy provides potentially even greater benefits.

Chart 1.4

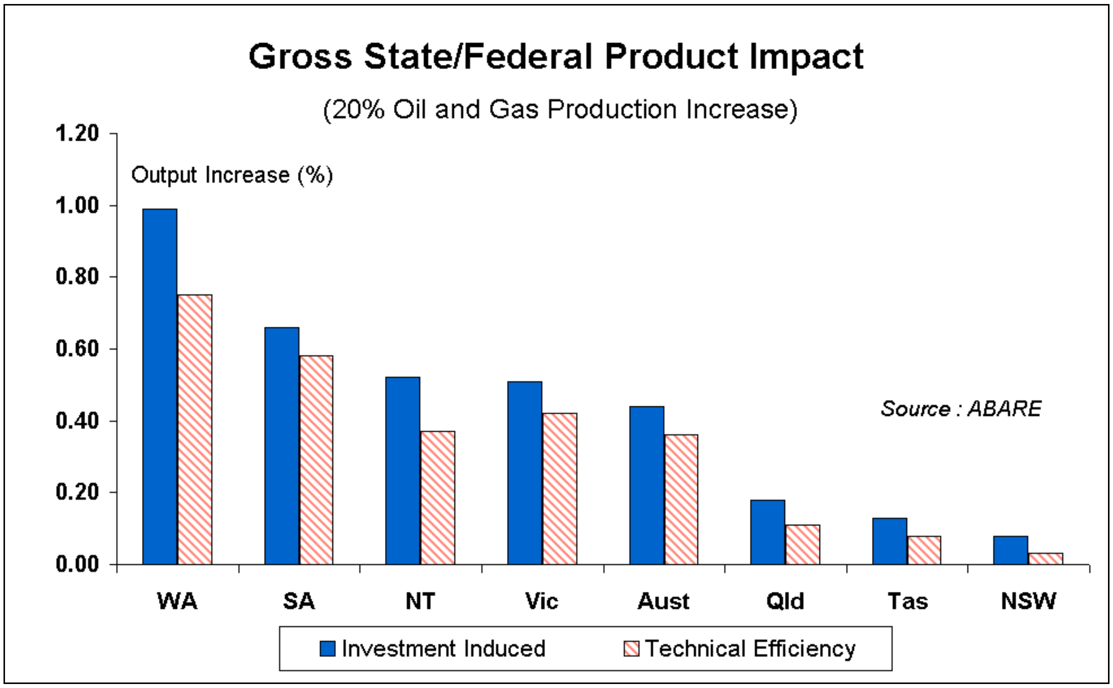


Chart 1.5 : Industry Economic Benefits (1995 $)

Gross Industry Net Present Value	
• 1980 to 1995	$178 billion
• 1996 to 2010	$37 to 77 billion
Oil & Gas (Economy Wide) Output Multiplier	1.8 to 2.4
A 20% rise in production leads to the following increases:	
• Gross Domestic Product	0.4 to 0.5 per cent
• Aggregate Investment Expenditure	0.3 to 0.8 per cent
• Aggregate Employment	0.2 to 0.4 per cent
• Real Wages	0.4 per cent
• Balance of Trade	0.3 to 0.5 per cent
Gross Taxation Payments 1996 to 2010	$26 billion

Source : ABARE 1996

The industry's output multiplier is estimated at between 1.8 and 2.4. This means that a $1 million increase in oil and gas production generates additional economic output valued at between $800,000 and $1.4 million. As part of the study, ABARE identified the following industries as particularly benefiting from a robust oil and gas industry:

- Cement & Concrete
- Basic Iron & Steel
- Various Metal Products
- Electrical Goods
- Construction Machinery
- Electricity (Gas) Generation

1.2.4 Employment

As a capital intensive industry, the petroleum exploration and production industry generates relatively less direct employment than other sectors of the economy. However, APPEA's annual survey of member companies suggests that the total level of direct employment in the industry exceeds 6,000, while the use of contractors in the industry is likely to double this number. Indeed, it has been noted in some studies that the industry tends to have a small petroleum company employment base with a reliance on a larger service sector.

A report conducted in 1999 by Economics Consulting Services Pty Ltd for APPEA undertook a detailed survey to ascertain the level of involvement across the services sector in Western Australia with the petroleum exploration and production industry. Of the 954 companies that were approached, 889 companies indicated that they have some involvement with the industry, 52 did not respond and 13 indicated that they had no involvement. The focus of the companies involved cover activities such as geoscience services, materials/good supplies, engineering/construction, administration, technical services and transport. The survey concluded that over 17,000 employees depend on the petroleum sector for their work.

1.2.5 Regional Energy Benefits: Western Australia

The development of reliable energy supplies has provided significant regional development benefits to Western Australia. Natural gas fuels power stations at Port Hedland, Newman, Kalgoorlie, Geraldton, Carnarvon, Mount Keith, Leinster, Karratha and Kambalda. In these areas, natural gas provides a reliable and relatively cheap fuel when compared with traditional energy supplies that must be transported by road over long distances. At the same time, significant quantities of natural gas are being reticulated to Mandurah, Kalgoorlie, Leonora and Busselton.

In addition, natural gas is providing significant opportunities for minerals processing ventures in the Pilbara and south west of the State. Alumina, nickel and iron ore projects are likely to be customers for large quantities of natural gas. ABARE's most recent forecast of gas demand projects significant additional growth in gas use in Western Australia for direct reduced iron production and for expanded alumina refining. This will see the highest growth in primary energy consumption of any State (2.9% a year to 2020), including a more than doubling of gas consumption over the period. This growth in energy demand will fuel significant regional economic development in the State (see also next sub-section).

1.2.6 Project Benefits: Expansion of the North West Shelf Project

The results of an Access Economics study of the economic and fiscal impacts of the North West Shelf LNG Expansion Project are summarised in Chart 1.6. It is estimated for example that the LNG Expansion Project and the economic activity which it stimulates would increase government revenue by some $20 billion (in 1997 dollars) over the 20 years to 2019. Around $6.7 billion of this would be direct royalty and tax payments by the project and the remainder would be paid by suppliers, their suppliers, employees, etc.

Access Economics also estimated that the LNG Expansion Project would provide an overall economic benefit to Australia of $9.5 billion in net present value terms comprising a $7.6 billion boost to private consumption and a $1.9 billion increase in the public sector surplus (after providing $3.7 billion in tax cuts).

Chart 1.6 : NWS Expansion Project : Economic and Fiscal Benefits during the Construction and Operation (% change over a base year with no expansion project) - 1997 $

	During Construction	Mature Operational
GDP	+0.15% (+$700 million)	+0.83% (+$4billion)
Employment	+10,000 (2,000 direct; 8,000 indirect)	+25,000
Government revenue	+$280 million pa	+$1.6 billion pa
	+$20 billion over the 20 years to 2019 ($6.7 by the project, remainder by suppliers, PAYE, etc.)	
Overall Economic Welfare	Overall economic benefit to Australia of $9.5 billion (@7%NPV) comprising: Private Consumption: +$7.6billion Public sector surplus: +$1.9b (after $3.7billion in tax cuts)	
Gross National Expenditure	+0.33% (+$1.6 billion)	+0.66% (+$1.7 billion)
Exports	-0.19% (-$151 million)	+2.1% ($1.7b pa) (+$26b to 2019 from the NWS project)
Imports	+0.85% ($718 million)	+1.09% ($922 m)

Source: Access Economics; North West Shelf Expansion Project, Australian Economic and Fiscal Impacts; October 1997.

1.3 Australia's Petroleum Resources and Depletion

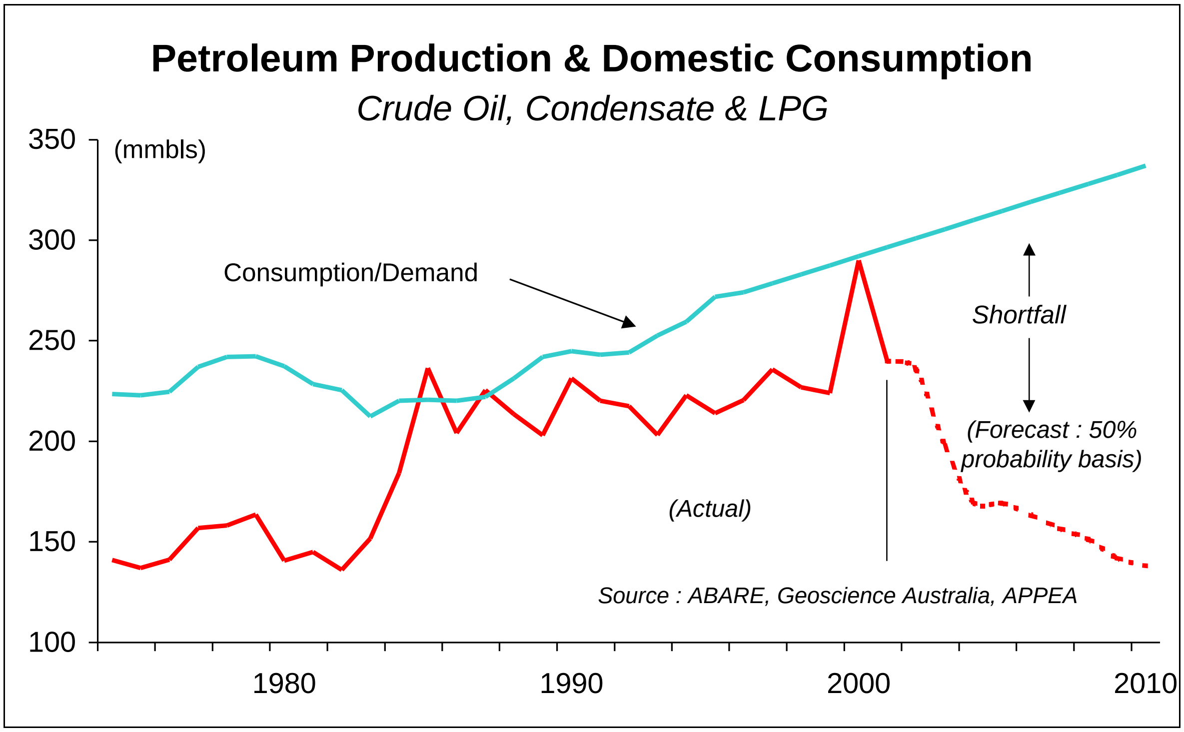
1.3.1 Liquid Fuels

Geoscience Australia estimates Australia's remaining commercial reserves of crude oil to be 1213 million barrels (mmbbl) and of condensate to be 758 mmbbl (as at 1 January 2000), which is equivalent to about 6 years current consumption. Estimates of reserves that have not yet been declared commercially viable are 452 mmbbl and 1407 mmbbl respectively. While reserves of condensate are significant, their potential rate of production depends in part on the commercialisation of the associated gas resource. Geoscience Australia has estimated the production from these oil and condensate resources and from possible new discoveries at different probability levels. The forecast production (at a 50% probability for new discoveries) is compared with ABARE's projections of liquid fuels consumption in the period to 2010 (Chart 1.7).

As can be seen, production of crude oil and condensate is about to decline rapidly. Unless there are significant new discoveries, Australia will be importing 60% of its requirements by the year 2010. The lower production and resulting import bill will have a considerable impact on the balance of payments, on secondary tax collections and on the costs of holding stocks of petroleum to meet Australia's international obligations under the International Energy Program treaty to which Australia is signatory.

More importantly, over the next twenty years, there will be increasing global reliance on the Middle East where the majority of remaining supplies of crude oil and condensate are located. APPEA believes that in these circumstances it would be detrimental to Australia's security of supply to increase unnecessarily our reliance on imports.

Chart 1.7



1.3.2 Natural Gas

Natural gas production has increased substantially over the last four decades and ABARE forecasts a considerable expansion of gas demand in Australia in the years to 2020. **ABARE has not projected gas supply but assumes that supply will be available to meet the projected demand.**

APPEA does not believe that ABARE's assumption that gas supply will simply follow demand is supportable, especially when ABARE also projects a fall in real prices of 20 per cent over the period. Total gas resources certainly exceed the amount of gas required in the next 20 years. Chart 1.8 compares the Geoscience Australia total remaining reserves as at 1 January 2000 with ABARE's prospective demand over the period.

The Geoscience Australia estimates include all gas reserves in the Timor Gap Joint Petroleum Development Area which, although subject to revenue sharing with East Timor, are assumed to be available to the Australian market on commercial terms. Since the Geoscience Australia estimates, additional resources have been announced by companies, notably about 1,000 Petajoules in the Otway Basin. PNG gas reserves of about 13,000 PJ which may be available to the Australian market over the period have not been included. Geoscience Australia quotes inferred coal bed methane resources at 62 tcf or 66,700 PJ. The amount which may be producible in the period is much less. Other data sources have been used to estimate potential coal seam methane supply availability of about 400 PJ.

Chart 1.8: Natural Gas Resources and Demand 2000-2020
Total Reserves (Petajoules)

	Eastern Australia	WA + NT (incl LNG exports)	Total
Total natural gas reserves	14,100	109,200	123,300
Coal seam methane supply	400		400
Natural gas demand	16,200	30,300	46,500

Source: Geoscience Australia and ABARE Conversion: 1 tcf = 1076 PJ

However, as Geoscience Australia data points out, these reserves are not all commercial and may not be producible. If only reserves classified by Geoscience Australia as commercial are taken into account, it is clear that additional reserves must be commercialised if projected demand is to be met. Chart 1.9 compares Category 1 reserves with demand over the period. (Category 1 comprises current reserves of those fields which have been declared commercial; it includes both proved and probable reserves.)

Chart 1.9: Natural Gas Resources and Demand 2000-2020
Category 1 (Commercial) Reserves (Petajoules)

	Eastern Australia	WA + NT (incl LNG exports)	Total
Category 1 reserves (commercial)	8,600	24,100	32,700
Coal seam methane supply	400		400
Natural gas demand	16,200	30,300	46,500
Additional reserves needing to be commercialised	7,200	6,200	13,400

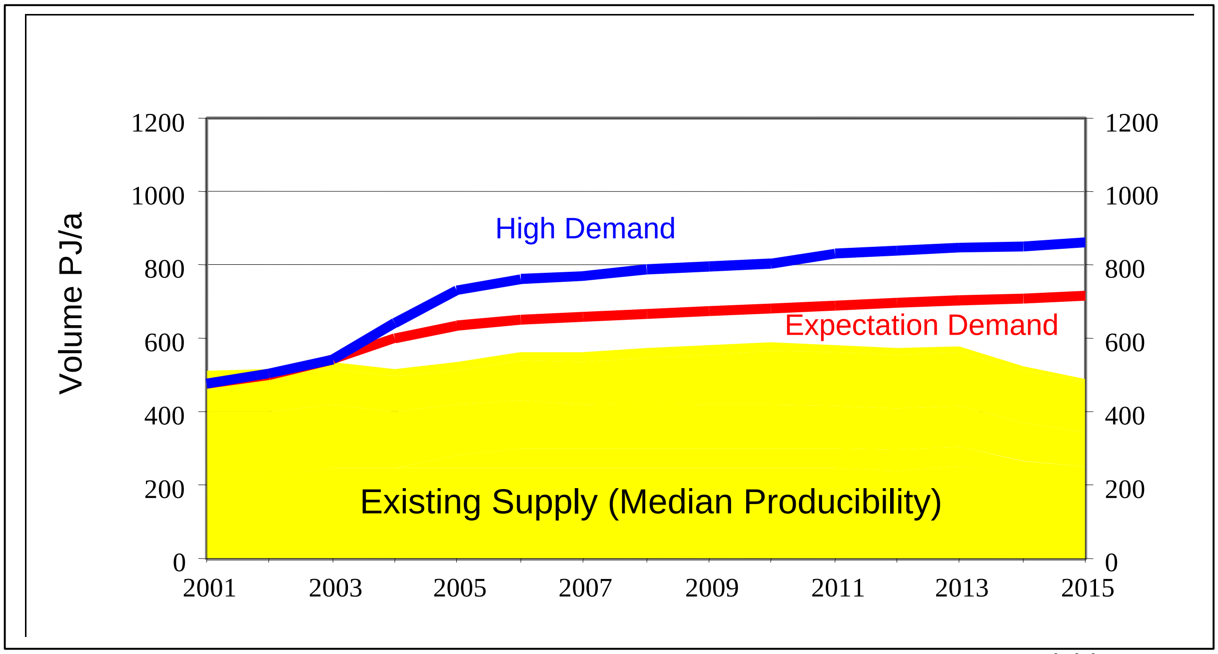
Source: Geoscience Australia and ABARE

An indication of the shortfall to be made up in the eastern States gas market is shown in Chart 1.10.

Chart 1.11 shows the distribution of Australia's gas resources. Much of Australia's vast gas resources are remote from centres of population and gas markets. The long distances involved in transporting some of this gas to markets have a significant impact on the economics of gas development. In addition, significant reserves remain undeveloped in the Gippsland and Otway Basins and there also remains substantial exploration potential in those basins close to the southeastern Australian market demand centres.

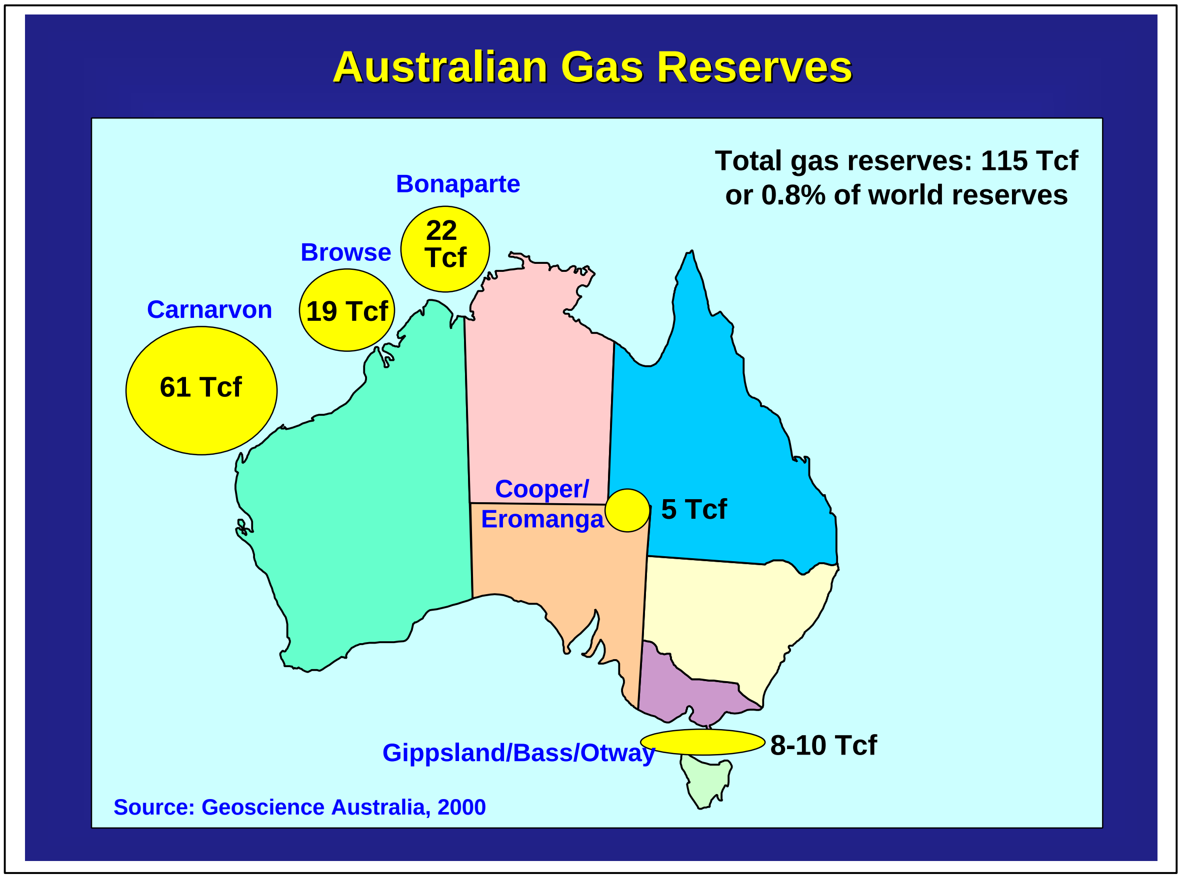
To ensure that there are adequate gas supplies over the period to 2020, either more commercial gas will have to be found, or more reserves will need to be proved commercial and gas resources developed and transported to markets in time to meet growing demand.

Chart 1.10: Eastern States Domestic Gas Market (Qld, NWS, SA, Vic)
Existing Gas Supply Vs Forecast Demand



Source: Woodside Energy

Chart 1.11

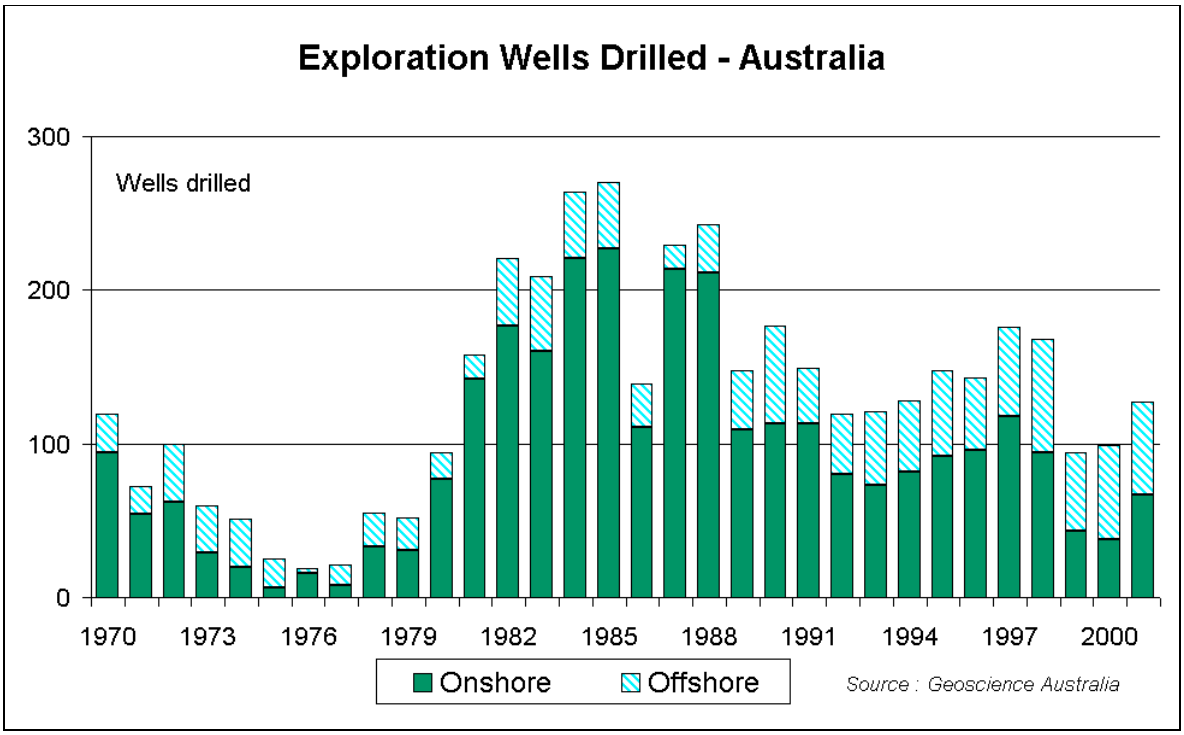


1.4 Exploration Trends

As measured by the number of exploration wells drilled, petroleum exploration and development in onshore Australia has declined in recent years (Chart 1.12) although there has been a pick up since the low of 2000. Offshore exploration wells have continued at a more consistent level but with some decline after the peak of 1998. While the recent improvement in exploration levels overall is encouraging, APPEA believes it is far from adequate in the face of the massive imminent decline in liquid fuels self sufficiency. In addition, the drilling success rate associated with activities in Australia (particularly offshore) is generally regarded as being poor in relative terms compared with other countries.

To reverse this decline, policy needs to address the perceptions that prospectivity of Australia for both oil and gas is not as attractive as that in many other parts of the world and that Australia is a high cost and relatively high technical risk investment destination.

Chart 1.12



Petroleum exploration in Australia is undertaken by companies ranging from large multinationals and two (now) large Australian petroleum companies through to small explorers. Larger companies that have the financial resources have tended to dominate offshore exploration with small and medium sized companies exploring onshore. But this pattern is changing. Large multinational companies are exploring less offshore as they seek exploration targets with higher probabilities of success, usually in other countries, and the two large Australian companies are doing the same. They are also tending to focus more on known areas because there is a higher probability of success, but the likely size of field is small. Middle sized companies are moving to explore more offshore and overseas rather than exclusively onshore.

Small explorers have played a significant role in onshore exploration - and it is also worth noting that the North West Shelf resources were discovered by a fledgling Woodside. They have been prepared to accept higher risks, move into new areas and try new techniques.

However, some smaller Australian explorers are now exploring overseas rather than exclusively in Australia.

Examples of Small and Medium Australian Explorers Operating Overseas

Icon Energy Ltd	USA
Amity Oil Ltd	Turkey, USA
Hardman Resources Ltd	Africa (Mauritania and others), Falkland Islands
Victoria Petroleum NL	USA
First Australian Resources Ltd	China, USA
Matrix Oil NL	Indonesia
Global Petroleum Ltd	Falkland Islands, Kenya, Jordan

To understand these shifts, it is necessary to understand the exploration decision making process. Companies will assess prospectivity, the fiscal regime and political risk.

Clearly political risk in Australia is much less than in many other countries (Chart 1.13).

Chart 1.13

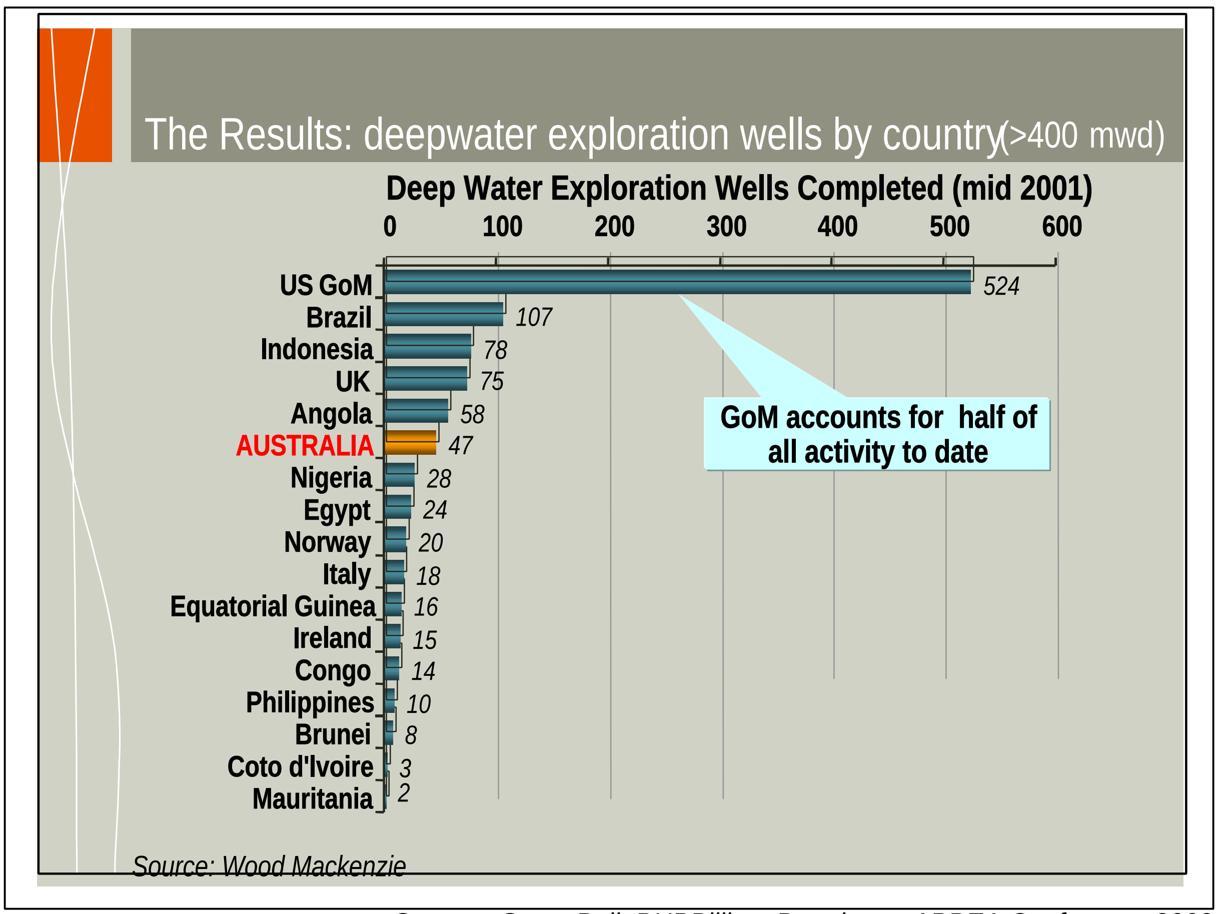
Source: Steve Bell, BHPBilliton Petroleum, APPEA Conference 2002

Fiscal terms are not as favourable as might be imagined. While the tax regime for shallow waters is often considered to be competitive, in world rankings it only ranks in the middle. For deepwater exploration, however, Australia does not rank favourably at all, particularly in relation to the smaller field sizes that are more typical in Australia (survey conducted by Wood Mackenzie, consultants, and reported by Steve Bell, BHPBilliton Petroleum, APPEA Conference 2002).

In terms of prospectivity, the perception is that in onshore Australia and in mature shallow water basins which have been the focus of exploration to date the likelihood of finding a large oil field is small. Access to deepwater fields has become technologically feasible with the development of floating facilities and tension leg platforms. Nevertheless, deepwater exploration and developments involve significantly higher costs and increased technical and economic risks compared with alternative field developments. The development of new technologies that convert gas to liquids may create new opportunities for the development of remote gas fields. There could well be opportunities for large finds in deep water but the area is under-explored and will remain so unless fiscal disincentives are addressed so that companies are encouraged to explore there.

It is presently more attractive for companies to explore in the Gulf of Mexico, Brazil or many other places (Chart 1.14 shows deepwater exploration wells (over 400m water depth) drilled to date).

Chart 1.14



Source: Steve Bell, BHPBilliton Petroleum, APPEA Conference 2002

Australia has complex geology relative to some other countries and the cost of bringing seismic vessels and drilling rigs the long distances to Australia is high. Indeed, the cost of getting a drilling rig with deepwater capability from the US or Africa to Australia is prohibitive for a single company. Any uncertainties or delays can significantly add to these costs as equipment has to be rescheduled. It is therefore imperative that there is policy certainty and regulatory risks are eliminated so as not to increase the cost burden.

2: Resource Access - Impediments to Exploration and Development Activities

While there are a number of commercial drivers influencing exploration levels, the policy framework which underpins exploration is also critical. If Australia is to find more oil and gas – exploration is usually not specific to one or the other – a range of policy responses are needed to facilitate petroleum exploration and development. These relate to:

- pre-competitive research aimed at resource identification;
- approvals processes, which not only impact on exploration but also on development and production; and
- the taxation regime, especially as it affects frontier areas such as deepwater and affects small explorers onshore.

2.1 Pre-Competitive Research

Australia needs to increase funding of pre-competitive research directed at identifying new petroleum provinces and upgrading the information available on existing under-explored provinces. It is in the national interest to have this type of information in the public domain to promote releases of exploration acreage and attract exploration investment to new areas in Australia. Without it, Governments will not be able to make available adequate information on releases of exploration acreage so as to overcome perceptions of low prospectivity and attract overseas companies to explore in Australia.

There is some evidence to suggest that there is already declining interest in the uptake of petroleum exploration acreage in offshore Australia. Between 1997 and 2000, the total number of bids for the areas on offer fell from 76 to 26 despite the number of areas offered increasing from 34 to 86. The take up of the areas offered fell from 79 per cent to only 22 per cent.

If governments do not accept this role by providing adequate resources to Geoscience Australia, state geoscience agencies, the CSIRO and universities, pre-competitive work would need to be done by petroleum companies themselves. The small explorer sector will not be able to afford the risk of such speculative work. If it is performed by larger companies, they will seek an appropriate reward for the risk and will only be able to justify the investment by retaining proprietary rights to the information for as long as possible. This would be in their commercial interests but may not be in the national interest. The real risk is that, if this work is not adequately funded by governments, it will not be undertaken at all since companies will find it more attractive to invest in more prospective areas in other countries or in established petroleum provinces in Australia.

If companies are to be encouraged to take on more pre-competitive surveys, their taxation treatment needs to be reviewed. These pre-competitive activities are conceptually akin to R&D rather than commercial exploration and would be encouraged if they were treated accordingly for tax purposes.

An added and essential benefit of continued government sponsorship of pre-competitive research is to assist in training and maintaining a core of geophysical and petroleum engineering expertise within the country.

Recommendations: Governments should increase funding for pre-competitive research by public geographical survey agencies directed at identifying new petroleum provinces and upgrading information on existing provinces as a necessary pre-cursor to identifying exploration acreage for release.

The Commonwealth Government should review the tax treatment of expenditure on such pre-competitive research undertaken by companies.

2.2 Access to Resources

It needs to be recognised that Australia's geology is relatively more complex than some other petroleum provinces in the world and is a more risky area to explore than elsewhere. Also, Australia is remote from other petroleum provinces. Therefore, bringing expensive exploration equipment such as seismic vessels and drilling rigs to Australia means that any delays or disruption to schedules can be very costly. Approvals processes need to be as efficient as possible to minimise the impact of risk and costs.

APPEA is concerned that a major disincentive to investment in petroleum exploration and development is occurring because of:

- the costs associated with the complexity and duplication of approvals processes; and
- the uncertainty resulting from policy risk in approvals processes.

Investment is moving from Australia to overseas destinations as a result of these disincentives.

To overcome these disincentives what is needed is a more integrated system which provides:

- approvals processes that are coordinated and timely
  - rather than having multiple processes running sequentially, processes need to run in parallel, with similar time frames and with outcomes required within specified timeframes
  - processes need to be consistent between jurisdictions
  - consideration needs to be given to extracting some more standard activities from approvals processes if they meet pre determined criteria (eg drilling using water based fluids, onshore seismic, pipelines and offshore seismic if Commonwealth whale guidelines are met); and
- approvals processes which are more certain – that is they
  - minimise the risk of unforeseen or new factors coming into play in decision making
  - minimise the risk of capricious decision making by relying on verifiable scientific data and risk assessment techniques
  - are transparent (based on adequate consultation and accompanied by clear statements of reasons).

2.2.1 Why APPEA is Concerned

The basis of concerns is highlighted in APPEA's annual surveys of members on issues affecting exploration and production, as well as a recent survey of the impact on smaller exploration companies.

The year 2000 survey showed a strong level of concern amongst exploration and development companies about approvals processes:

- all respondents saw uncertainties created by native title and environmental approvals processes as a cause of concern in relation to their exploration and development activities; and
- 100% of small company respondents and 92% of large company respondents saw the Commonwealth Environment Protection and Biodiversity Conservation Act 1999 as a cause of operational uncertainty, although this situation has improved as more of the administrative and regulatory arrangements for the Act have been disseminated.

In the 2001 survey:

- over 70% of respondents saw improved acreage release approvals processes as a key issue;
- over 80% of respondents saw improved environmental approvals processes as a key issue;
- over 70% of respondents saw approvals processes relating to native title as a key concern;
- over 80% of respondents saw the provision of better information (as part of acreage release processes) in relation to native title and the environment as a priority;
- over 90% of respondents saw it as a priority to ensure that
  - there is minimum duplication in approvals processes in relation to native title and the environment
  - environmental, acreage release and native title approvals processes operate in parallel, not sequentially; and
- over one third of respondents said they had experienced delays in receiving licences or carrying out activities due to native title. Over one quarter said they experienced delays in relation to environmental approvals. Given that a significant number of companies are not actively engaged in undertaking new activities and, as a consequence, are not currently seeking approvals, these figures are significant.

APPEA also recently conducted a survey of its smaller member companies in relation to the impact of native title and environmental approvals processes on their operations. The principal finding was that native title processes and delays were the dominant factor in a significant number of these companies deciding to shift future investment to countries other than Australia.

Of the 24 companies surveyed, 11 of whom responded:

- four had already moved their future investment to other countries, notably the US (of which one company had relinquished an Australian exploration permit and invested the funds in the US). In one of these cases, environmental approvals were an equally important reason;
- two more had decided to invest more outside Australia or to shift the focus of their investment to offshore Australia and overseas; and
- one was considering moving investment overseas.

Other observations were that:

- the main delays have been in obtaining native title approvals. Delays in environmental approvals were generally much shorter, but still a concern. However, several companies had not yet tried to obtain environmental approvals while native title issues remain unresolved;
- companies had experienced long delays in obtaining native title approvals prior to exploration permits being granted, typically two years (but as long as five years and still waiting in several cases); and
- one company experienced delays in drilling approvals of one and a half years at one site and over two years at another due to delays in environmental approvals.

The principal cause cited for the delays was the complexity of the native title processes and the apparent inability of government resources and energy departments to manage those processes. Some respondents saw the problem more as one of the processes themselves and others saw it more as one of inadequate management of the processes.
Agreement reached in late 2001 between exploration companies and native title holders in relation to a number of South Australian exploration permits took over two years and involved significant costs in legal fees, meetings and payments to be made under the agreement. In Queensland, some permits have been pending for up to five years and negotiations with native titleholders are only just about to commence.

The key conclusion from this is not simply that delays in approvals are adding to costs even before exploration can begin, but that investors are deciding to take their funds elsewhere with a loss of investment to Australia.

2.2.2 The Acreage Release Process

How the release of acreage for bidding by companies interested in exploration for oil and natural gas is managed can go a long way towards avoiding unexpected delays for all parties in subsequent approval processes.

The acreage release process involves up to four steps:

- governments (after consideration of data collated and generated by pre-competitive research, usually by government agencies like Geoscience Australia and state geological survey organisations) choose acreage that is going to be released for bidding by industry;
- data packs are assembled to accompany the acreage release - these serve as a basis on which companies decide whether to bid for a particular block of acreage and what component activities (desk top studies, seismic, drilling) to include in their bids and the prospective timing of these component activities;
- companies have between six and eighteen months to assess the acreage and make bids; and
- government assesses the bids and decides successful bidders (usually a process of four to six months but sometimes longer).

Management of the bidding process (the fourth step above) must be efficient and timely. If delays in assessing bids and notifying successful bidders are too long, companies may not have access to the capital required for the exploration work program. This is because capital is internationally mobile and companies will in any financial year allocate a certain amount of funding for new ventures in a particular country or region. If they are not notified of a successful bid in a reasonable time, that funding may then be allocated to exploration in another country and be unavailable for Australian exploration. This may inhibit companies from bidding and may even cause them to withdraw from the bidding process.

The second of the four steps identified above is an area where APPEA is seeking change. As the previous survey data suggests, if companies bidding for acreage are as fully informed as possible about potential factors that may impact on future approvals processes, they can take appropriate action to avoid/minimise costs and delays. Governments cannot offer a product “for sale” and not disclose all relevant information in the possession of its agencies. It has an obligation of full disclosure to all potential bidders for acreage. It is unreasonable to expect the bidders to seek what information on potential constraints is available.

This does not however mean that approvals processes (and associated layers of bureaucracy and regulation) should intrude into the acreage release process.

At the point of acreage release there is no precise knowledge of potential impacts on other stakeholders – target areas have to be identified and exploration activities decided and sequenced. There is no “party/development proponent” until the relevant government has approved the successful bidder. Even when this occurs, it may well be that the successful bidder will need to do substantial desk top studies (drawing on all the available data) before exploration activities can be finalised.

In relation to the release of new acreage for bidding by the petroleum industry, a key issue is to ensure that the information packages accompanying acreage release are substantially expanded from their current form, which contains precise geographic coordinates, all relevant geological and geophysical data, and all available information on safety and geological/technical activity related approvals processes, so that it also includes:

- all available data on environmental values (eg whale migration routes and breeding areas, other endangered species habitats on and offshore, historical sites, marine and terrestrial conservation areas, regional marine plans);
- information on environmental approval and management processes that apply to all or part of the relevant acreage;
- all available data on proven and claimed native title including the relevant areas and parties, the nature of the claims and contact points for consultation;
- native title approval processes (onshore, either under the right to negotiate or approved Indigenous Land Use Agreements – by statute the government is a party to both of these options); and
- all available information on proven or claimed cultural heritage sites.

If it is possible to reach inter-agency agreement to exclude certain standard industry operational activities (eg drilling using water based fluids, onshore seismic, pipelines and offshore seismic if Commonwealth whale guidelines are met) from approvals processes if they are carried out subject to appropriate guidelines, this information, and the requirements of the relevant guidelines, should also be included in the pre-release package.

APPEA recognises that government would need to include appropriate disclaimers in such a package to protect itself against new and unforseen data becoming relevant.

Recommendations: Management of the acreage release process needs to be efficient and timely so that companies can allocate the necessary capital and not be hindered in the bidding process.

To reduce the risks, delays and costs of approvals and facilitate access to acreage for exploration, governments should provide information packages accompanying acreage releases that are comprehensive and include all relevant information on native title, environment and cultural heritage relevant to the acreage being released.

Standard industry operational activities should be excluded from having to seek specific approvals where they are carried out in accordance with appropriate guidelines. This information, and the requirements of any guidelines should also be included in the pre-release package.

2.2.3 The Post Acreage Release Process

APPEA’s preferred position is that all approvals processes relating to upstream petroleum activities be handled by the one agency with a single Minister acting as the decision maker. Given the Commonwealth/State issues involved and the extreme difficulty that would be faced in achieving legislative change, APPEA considers that a "second best" approach is more practicable.

The issue can be stated as follows.

> *Once governments have awarded a licence to a company (via the acreage release process), how do governments ensure that approvals processes across a number of agencies and jurisdictions are coordinated, run in parallel rather than sequentially and meet commercial imperatives while at the same time allowing for appropriate third party input and the efficient exercise of Ministerial responsibility?*

In relation to petroleum industry activity onshore, following the award of a licence at the completion of the acreage release process, four broad categories of approval processes may arise, namely:

- native title;
- cultural heritage;
- environmental; and
- local government/statutory authority (water/roads).

These approvals involve both Commonwealth and state law. For example:

- native title is determined by the National Native Title Tribunal operating under the Commonwealth Native Title Act 1993; and
- the Commonwealth Environment Protection and Biodiversity Conservation (EPBC) Act may also be involved via one of a number of triggers (eg endangered species or Ramsar wetlands). It should be noted that the Commonwealth has flagged the possibility of adding a greenhouse gas emission trigger to the EPBC Act that may impact on petroleum related activities (eg via the venting of CO_2 at the extraction phase or the flaring of gas at extraction or the generation of CO_2 in energy production or in processing gas).

The coordination of approvals is not just a matter of co-ordination within state agencies (although this would be an excellent first step). Coordination between Commonwealth and State jurisdictions is also essential.

<u>Native Title</u>

Once the government has decided on a successful bidder, if the block of land is on vacant crown land or a pastoral lease, it is possible that native title will exist. In that event, the process of the government offering a license to a successful bidder may activate native title processes. It would appear that while it may not be possible to formally commence native title processes at the moment of release of acreage for bidding, a number of informal steps could be contemplated by governments.

As government knows well in advance of release which blocks will be included in bidding rounds, with sufficient advanced planning of acreage releases the actual or potential native title parties could be identified before blocks are released. In addition Indigenous Land Use Agreement (ILUA) processes could be used to develop protocols to cover exploration and development activity on relevant lands either pre the release process or while the release is being evaluated. If ILUA processes are not suitable other informal consultative mechanisms should be established.

APPEA and its members believe that consultation prior to the awarding of an exploration licence will have significant benefits to all parties concerned as it should:

- identify whether there could be potential native title claims over the licence area;

- ensure that all relevant parties are informed about what activities may take place and what impacts they may have on land;
- initiate right to negotiate processes prior to issuing a licence to ensure that right to negotiate processes run in the shortest possible timeframe with all parties being fully informed; and
- allow for cultural heritage surveys to commence (or at least relevant custodians that need to be consulted for particular areas could be identified).

It is important that processes under these sections run in parallel with approvals with cultural heritage matters and environmental approvals. In addition, governments need to ensure that there are adequate trained staff in State agencies to deal with native title negotiation processes.

The requirement for government action is twofold:

- to ensure that all parties are fully informed and aware of the processes and risks in bidding for a licence, and
- to ensure that, once the decision to grant a licence is made, the Native Title Act works with more certainty.

While this outcome could be partly achieved through better organisation of governmental processes, a review of the Native Title Act with the objective of creating more certainty in negotiation processes is clearly preferable. For example, the present Act probably better meets the needs of the mining industry rather than the petroleum industry. The differences arise in the larger size of petroleum licence areas and the larger number of joint venturers often involved, such that there can be a number of industry parties to a single native title claim. The petroleum industry also has a clear need for conjunctive processes (covering both the exploration phase and the production phase) which is apparently not of such concern to the mining industry. Matters such as this should be clarified by a review of the Act and legislative change. It is also urgent that the ownership of resources is clarified, ie whether native title extends to resources below the surface, either in legislation or via court decision. Related issues include that all native title related costs should be deductible for company tax purposes.

<u>Environment – Stating a case for access</u>

One of the most important factors facing Australia's petroleum exploration sector is continuing access to resources. APPEA and its member companies are strongly committed to sound resource conservation and environment protection practices as an integral part of industry operations. The oil and gas industry has been exploring and operating internationally in some of the world's most sensitive environments for over a century, ranging from deserts, coral reefs, tropical rainforests and urban environments. Within Australia, the industry has been active since the 1950s, with no significant environmental impacts because there has been an effective (but arms length) working relationship between regulators, the community and the industry. Since that time the Australian industry has sought to continually improve its performance to further minimise potential impacts to the range of sensitive environments in which it is capable of operating.

APPEA and its members recognise that in meeting the needs of the Australian community, the industry must also operate safely and responsibly to protect and maintain the natural environment. Australia's oil and gas exploration and production companies are committed to protecting the environment and maintaining public health and safety during all phases of operation. They do so on behalf of their shareholders and employees, and on behalf of present and future generations of Australians.

Australia's petroleum industry supports the use of conservation systems that define the significant conservation values of a particular ecosystem or biological community. The industry believes that with its long track record of environmental management in sensitive environments, it should be given the opportunity to make a case on a project-by-project basis to continue to access sensitive environments, including protected areas. Companies are continuing to adopt new environmental management practices, to continually improve them, and refine them to ensure conservation values are not compromised.

The industry's commitment to responsible environmental management is laid out in APPEA's Code of Environmental Practice, which provides a set of recommended minimum standards for industry activities. Member companies must determine the specific needs of their own operations, including relevant regulatory requirements, and develop suitable environmental management systems and practices necessary to prevent and control the potential for environmental impacts. This self-determination allows for rapid adoption of new technologies and continuous improvement in management practices.

<u>The Industry's Environmental Performance</u>

The results of an independent scientific review of *Environmental Implications of Offshore Oil and Gas Development in Australia* found that the offshore exploration and production industry in Australia not only met statutory requirements, but had "set an excellent example in taking all possible steps to safeguard the marine environment".

The key findings of the review were:

- there is minimal oil spill threat caused by Australian explorers and producers;
- there is no evidence of significant impacts on marine ecosystems by seismic activity;
- Australian oil producers are world leaders in water treatment standards and technology;
- coastal facilities associated with offshore activities cause minimal marine impacts;
- offshore drilling has little toxic effect on the marine environment; and
- overall, the industry has had no significant impact on the marine environment in its 25 years of operation.

One of the greatest perceived impacts of the oil and gas exploration and production industry is oil spills into the environment. However, the perception and what has occurred in reality are quite different. World wide, the exploration and production industry contributes only about 2% of the annual petroleum inputs to the worlds oceans compared with 33% from marine transportation operations and 12% from tanker spills. In Australia, around 16,000 tonnes of oil pollution per year enter the marine environment through terrestrial runoff via sewage systems and urban catchments. The contribution of the oil and gas exploration and production industry is less than 1% of this contribution.

<u>Conservation management tools</u>

Industry supports the use of conservation management tools where the significance of a particular ecosystem or biological community or species (eg, seagrass, wetland, forest) is assessed in respect of potential impacts of industry activities (eg seismic, drilling, production). Where activity is proposed within an area where a significant environmental value could be affected, the industry operator has the responsibility to institute management controls to protect conservation values. The review and approval of such an approach should be conducted on the basis of the available evidence and in a scientific manner, free of preconceived notions as to the impacts and outcomes.

Such an approach allows industry the capacity and flexibility to adopt innovative concepts or new technology to explore and develop potential resources without presenting a threat to conservation objectives. It permits industry the opportunity to assess whether it wishes to meet the environmental costs of gaining access to areas where significant conservation values demand appropriate technical or management measures.

APPEA and its members recognise that there may be instances where, with the current levels of technology and costs of mitigating measures, an activity could not be undertaken without compromising the conservation values of an area. However, APPEA and its members strongly believe that blanket bans and prohibitions are inappropriate and simplistic management mechanisms that fail to recognise the ability for the Australian oil and gas industry to operate with little or no impact in a wide range of sensitive environments. Blanket bans also fail to recognise the technological advances regularly made by the industry that will only improve its ability to operate in these sensitive environments.

Increasing cooperation

APPEA strongly believes that, throughout all jurisdictions within Australia, there is far greater scope for inter-agency cooperation, particularly in regards to approvals processes.

APPEA and its members have identified and experienced first hand a wide range of examples demonstrating the number of complexities which exist in gaining approvals. APPEA strongly recommends that governments consider appropriate mechanisms to address the following examples in order to provide more certainty to industry:

- multiple agencies and statutory authorities are potentially involved, so it is important for industry to understand the roles and relationships of each agency;
- the key agency can change during the process. While changes of this type do not necessarily change the values being protected, it can change the decision-makers, the processes and the attitudes. Inter agency coordination requires these potential changes to be advised well in advance to all parties, perceptions to be managed in public consultation processes and existing rights of title holders to be protected;
- conservation and cultural values can change as petroleum activities are progressed;
- elements of “policy risk” may arise. For example, management of conservation values not directly related to petroleum activities can constrain activities (eg forestry management practices may change, altering petroleum access arrangements; State policies on management of conservation values can change);
- with the introduction of the Commonwealth EPBC Act, there is far greater potential for the Commonwealth to be involved in approvals for exploration projects. It is therefore essential, in APPEA’s view, for processes to be set in place to coordinate Commonwealth decision making under the EPBC Act and State environmental assessment processes. Having to go through environmental assessment processes in two separate jurisdictions that may operate on different time frames and result in different management conditions is very inefficient; and
- in addition the range of Commonwealth and State/Territory regional marine planning and conservation zone arrangements has the potential to further complicate inter-jurisdictional arrangements and approvals processes. Often, the process covers both biodiversity management and the interface between commercial activities and biodiversity. This process is creating uncertainty for petroleum exploration and production companies, and it will be important to ensure that long term assurances are created from the planning and development phases.

Further to the above mentioned complexities in the environmental approvals regime that applies to Australia’s petroleum industry, the range of Commonwealth and State/Territory regional marine planning and conservation zone arrangements also has the potential to complicate inter-jurisdictional arrangements and approvals processes. Often, the process covers both biodiversity management and the interface between commercial activities and biodiversity. This process is creating uncertainty for petroleum exploration and production companies, and it will be important to ensure that long term assurances are created from the planning and development phases.

APPEA believes that a prime objective of any conservation regime should be to add value to what is already in place. It needs to avoid duplication by seeking to fill the identified gaps (in scientific data and management processes) and thus give comprehensive and coordinated conservation coverage. For example, if impact assessment processes have already regulated upstream petroleum industry operations in an area, the focus of the conservation regime should be on:

- the impact of other commercial activities (eg transport, tourism and fishing) on the environmental values;
- how the proposed conservation regime will provide this protection; and
- how this new regulation will be coordinated with that already in place for petroleum industry activities.

Recommendations: On native title, governments should review the Native Title Act to ensure that it creates more certainty for parties negotiating native title agreements, for example to clarify that conjunctive agreements have the same status as other agreements. Governments should also develop mechanisms for consultation on native title prior to issuing of exploration permits so that native title negotiations post issuing of licences can be completed in the shortest possible time.

On environmental approvals, Commonwealth and State governments and all relevant agencies should coordinate environmental assessment and decision making so that there is a single assessment and a single decision without duplication.

On marine conservation regimes, governments should clearly identify how proposed regimes are necessary to protect conservation values and coordinate any new regulation with that already governing petroleum industry activities. In addition, before any discussion about the physical boundaries of a regime can constructively take place, industry believes that the goals, objectives and procedures for the regime must first be discussed and developed. The use of blanket bans is a simplistic and inappropriate conservation management method.

Industry Expectations of Regulators

While APPEA welcomes the review into the existing systems of regulation and assessment processes as part of the ongoing process of continuous improvement, the petroleum industry expects that consideration of any new arrangements would:

- involve a transparent and open consideration by all stakeholders of possible changes to the current process;
- recognise the need for consistency and streamlining in approvals processes between State & Commonwealth jurisdictions;
- ensure a clear understanding of requirements, including the depth and methodology required of environmental studies, for all stakeholders;
- be cost effective and appropriately resourced by independent personnel, knowledgeable about hazard, risks and practical controls. For example:
  - there should be adequate numbers of staff, adequate levels of skilling and availability of all appropriate types of skills able to provide timely and competent/practicable/informed/consistent feedback to proponents in the environmental assessment process;

- promote continuous improvement in risk management by operators consistent with sustainable development principles;
- ensure that under-utilisation of resources is avoided (and, for example, consideration needs to be given to appropriate ways of sharing scarce and occasionally used skilled resources);
- provide timely, certain, coordinated and efficient processes and, in particular, in the interests of cost effectiveness, processes must be fully coordinated and integrated with the other applicable statutory processes for approvals, for example environmental assessment processes required by the Environmental Protection and Biodiversity Act 1999 (EPBC Act); and
- timeframes for processes must be clearly defined, including those for public consultation and decision making.

2.3 A Suggested Approach

It therefore seems clear to APPEA that improved interagency (and intergovernmental) consultation/coordination is essential at two stages:

- in the exploration/evaluation phase covering from the decision to issue a licence to a particular company (or group of companies) to the decision by these parties to commercialise a discovery; and
- in the development phase (post the application for a production licence).

The concept of inter agency consultation/coordination applies to both these phases and is the cornerstone to the preferred APPEA approach. It not only requires process changes within government but also attitudinal changes. APPEA's perception is that the potential for dysfunctional processes between agencies increases the further down the management system one progresses. It is therefore important that the message of interagency cooperation is targeted at all levels of the management structure and that processes are established to build cooperation at all levels.

The key management step is for processes to be established within government so that once a decision has been made to issue an exploration licence, or an application is made for a production licence:

- all relevant agencies in government meet urgently with project proponents to:
  - identify all relevant approvals
  - identify time lines
  - coordinate time lines
  - identify critical commercial and process decision points;
- an agency takes over the coordinated management of approvals processes (it is important that this central coordinating agency have authority from all relevant Ministers to require agencies to report on time and that the agency has ready access to relevant Ministers to ensure timely decisions are made); and
- there is a process for regular consultation between the proponent and all relevant agencies (this is necessary to remove the temptation for proponents to start dealing directly with agencies when a delay or problem appears to arise – it is critical that all parties understand what is going on in all agencies and the project at any point of time).

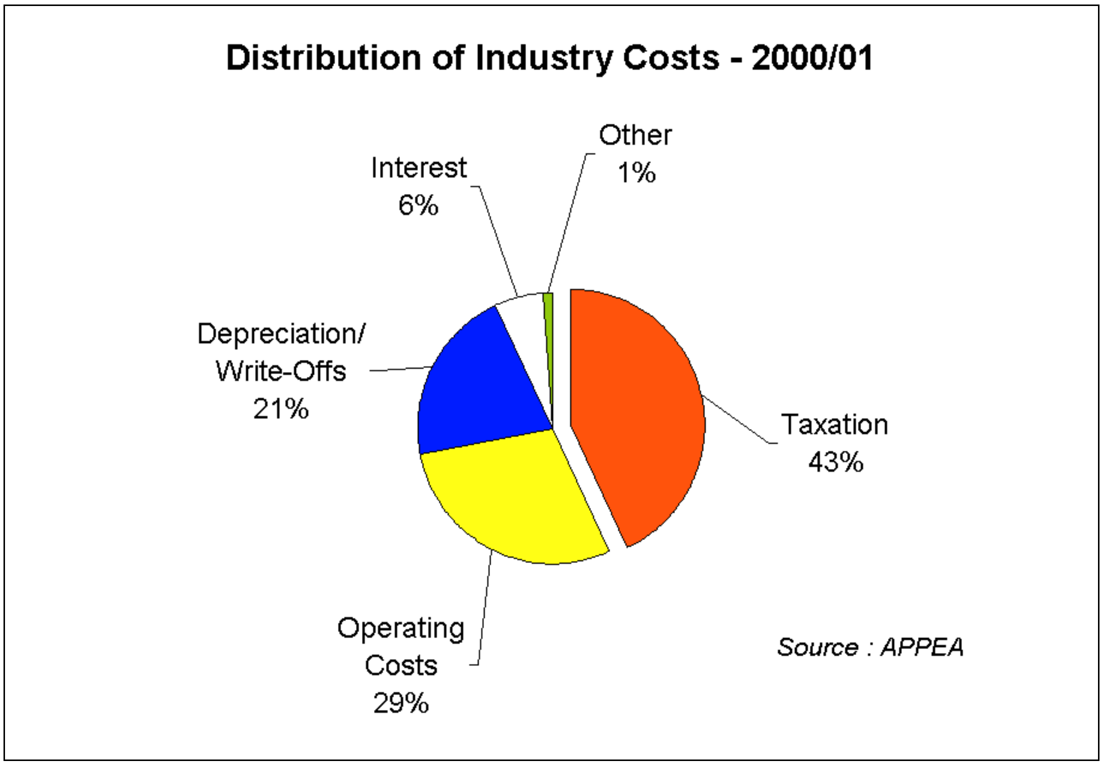
Recommendation: To better coordinate approvals, processes should be established within governments for initial and regular consultation between all involved agencies and project proponents, timelines should be identified and a single agency should take on the coordinated management of the approvals processes.

3: Fiscal Issues Impacting on Exploration and Access to Capital

3.1 Level of Tax Payments

The Australian petroleum exploration and production industry is part of a wider globalised industry and the flow of capital responds to differences in the overall risk/reward balances between individual countries. Overall, APPEA estimates that taxation, in one form or another, accounts for 43 per cent of the total operational costs faced by the industry (see Chart 3.1). This equated to $A13.10 per barrel of oil equivalent (boe) production in 2000/01, compared with an average price of petroleum during the same period of around $A41.00 per boe. It is essential from the petroleum industry's perspective that the Australian taxation framework be internationally competitive and that these costs, where possible, are minimised.

Chart 3.1



The timing and magnitude of cash flows resulting from tax is critical to exploration and development decisions. Specifically, after tax cash flows are important in the context of:

- the competition for investment funds against projects in different jurisdictions can only be accurately compared on an after tax basis, given the different tax regimes involved; and
- projects are generally undertaken following a program of exploration within an exploration permit. A commitment to a project is generally only made after drilling several exploration and appraisal wells. The cost of the exploration and appraisal program are directly attributable to the development project. The tax deductions attributable to the exploration and appraisal project, if not already claimed, will be included in the project cash flows.

Indirect taxes also can play an important role in decision making. For example, imposts associated with exploration and development activities can influence project economics, particularly as these costs are invariably incurred at the early stage of the investment cycle.

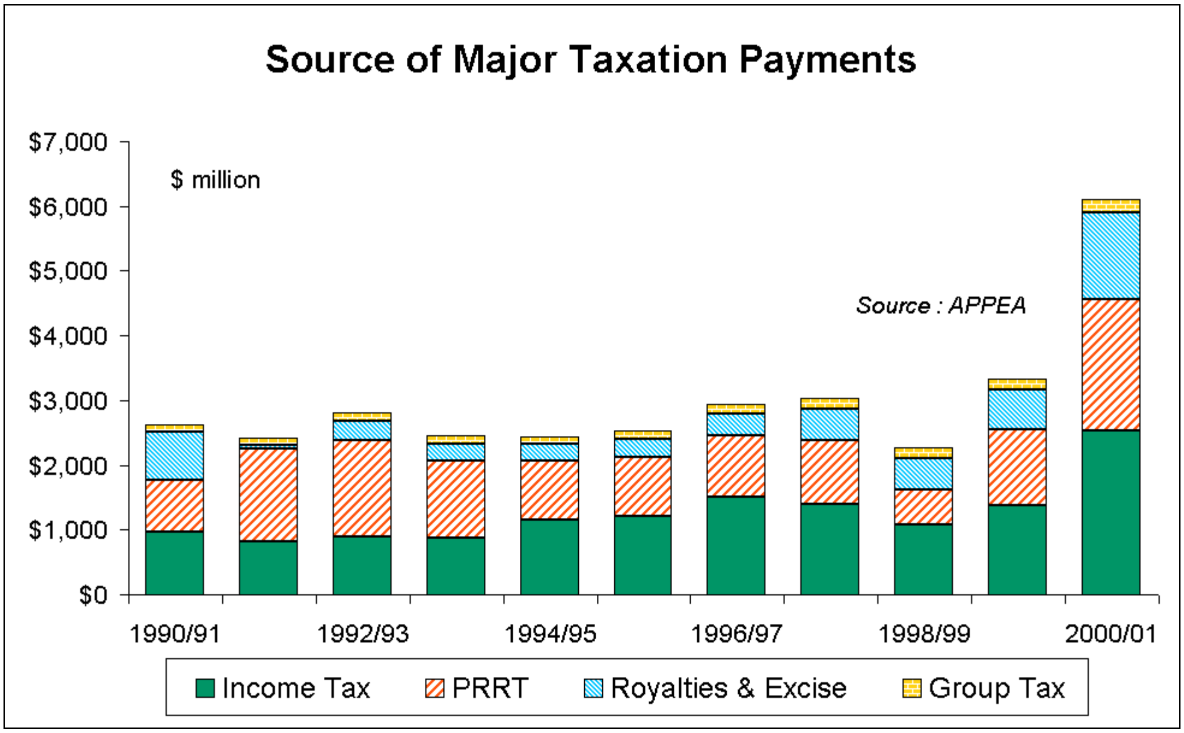
As many prospective petroleum projects can be marginally economic, the impact of taxation imposts can have a important bearing on project decisions and the subsequent allocation of funds.

Composition of 'Direct' Tax Payments

The Australian taxation system has developed over the last century in a way that reflects the division of powers between the various levels of government. As a result, the overall taxation framework has become multi-layered with the consequential imposition of structural and efficiency constraints. The impact of the totality of the taxation mechanisms (income, resource and indirect) must be considered as a whole to assess their impact on exploration and development decisions.

Petroleum companies are confronted with a range of taxes which are applied at both the federal and state levels, some of which are largely unique to the industry. Chart 3.2 estimates the distribution of taxation payments based on APPEA survey data.

Chart 3.2



The primary taxes in terms of the quantum of payments are clearly income tax and petroleum resource rent tax, although the level of excise and royalty (particularly the latter) are also significant. Each of these taxes are discussed in further detail below.

3.2 Resource Taxes

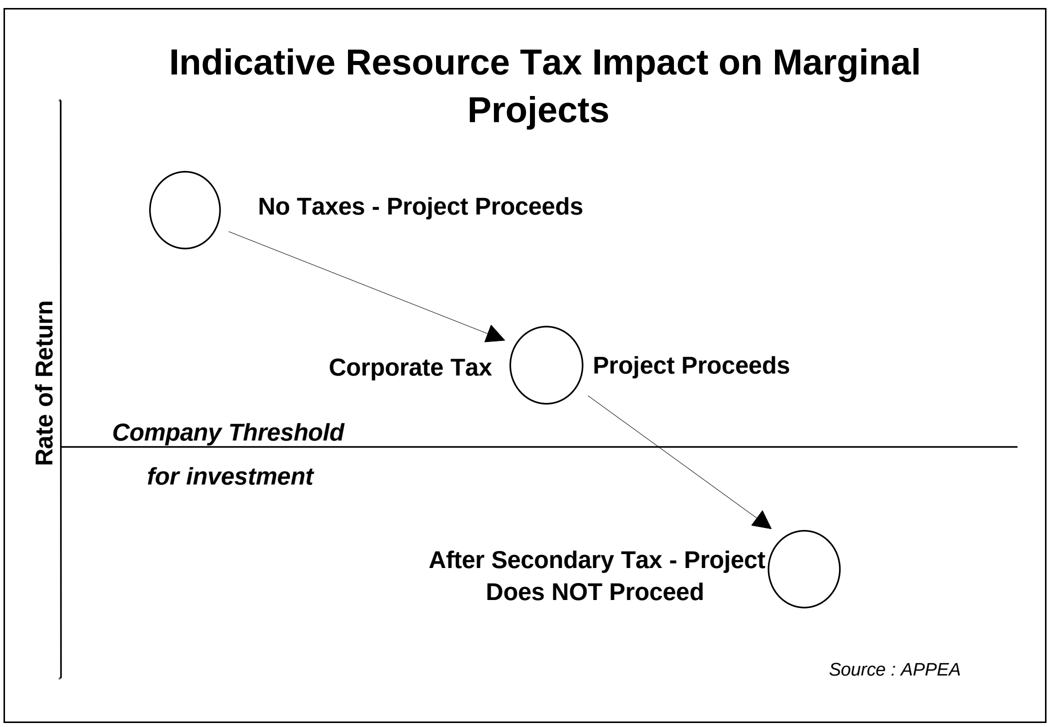
3.2.1 Introduction

Under the terms of the 1979 Offshore Constitutional Settlement and the division of powers under the Australian Constitution, the power to impose taxation and other charges on oil and gas production has been divided between the Commonwealth and States/Territories. The Commonwealth holds title for all areas seawards of the outer boundary of the territorial sea while the States/Territories control areas landwards of this boundary.

With respect to the application of taxation for areas outside the territorial sea, the Commonwealth has sole control, with the main instrument being the petroleum resource rent tax (PRRT). PRRT applies to all projects seawards of the outer limit of the territorial sea, with the exception of those production licences drawn from the North West Shelf permit area (Exploration Permits WA-1-P & WA-28-P) and the Australia/East Timor Joint Petroleum Development Area. Production from licences drawn from the North West Shelf permit area is subject to Commonwealth royalty and crude oil production excise, while production from areas under state/territory jurisdiction is subject to the respective state/territory petroleum royalty regime and Commonwealth crude oil production excise .

It is important that policies be developed that provide a balance between the objectives of governments and investors. Governments cannot deny investors adequate returns on high risk investments, while investors must recognise that the community should be adequately rewarded for the development of the nation’s resources. In many respects, the risks must be shared between the key stakeholders.

Chart 3.3



Resource taxes must balance the objectives of creating an investment climate that stimulates investment while ensuring that the community receives an appropriate return for the use of its resources. The current provisions, if not correctly structured, can have a negative impact, as indicated in Chart 3.3.

In September 1990, the Federal Government released a paper titled "*Background Report on Petroleum Production Taxation*". That report made the following observations about resource taxation:

> *"Ideally, when economic efficiency is a prime policy goal, all resource projects that would have been undertaken without resource charges would still proceed under the chosen resource taxation regime. ... If rents are collected in a manner such that government charges exceed the economic rent, they will reduce normal profits - an outcome leading to effects not in the national interest, such as premature closures, under-exploitation of reserves and a sub-optimal level of exploration.*
>
> *In practice, the application of economically efficient resource taxation depends on the level of economic rent to be extracted. While revenue and direct costs are relatively straightforward elements of the cash flow to calculate, more difficult to evaluate are costs associated with risk, which depend on the firm and the project. These represent a hidden cost pertaining to perceptions a company has about investment, geological, market and political risks. Risk aversion varies between companies, geographical regions, between resource operations and over time.*
>
> *If governments attempt to extract all the rents and overestimate these rents, this will inevitably deter some risk averse investors and reduce efficiency." (p.22)*

****

> *"Resource charges should be set at a level which allows firms to earn an after tax return which recognises the risks associated with resource exploration and development. Failure to do so would distort companies investment decisions and lead to reduced exploration and development activity." (p.28)*

3.2.2 Petroleum Resource Rent Tax

PRRT was introduced in the mid-1980's and replaced the Commonwealth's crude oil excise, LPG excise and royalty provisions for offshore 'greenfields' projects. It is levied under the provisions of the *Petroleum Resource Rent Tax Assessment Act 1987*. The basic features of the PRRT are:

- it is assessed on a project basis;
- liability to pay PRRT is on a producer/company basis;
- it is levied before company tax and PRRT payments are deductible for company tax;
- it is assessed at a rate of 40 per cent;
- is payable quarterly on an instalment basis;
- a liability is incurred when all allowable expenditures (including compounding) have been deducted from assessable receipts;
- assessable receipts include the amounts received from the sale of all petroleum (or a marketable petroleum commodity);
- deductions include capital or operating costs that directly relate to the petroleum project, and are deductible in the year they are incurred. Deductible expenditures include exploration, development, operating and closing activities;
- expenditures which are currently non-deductible include financing costs, some indirect administration costs, income tax, FBT and cash bidding payments; and

- undeducted expenditures are compounded forward at a variety of set rates depending on the nature of those expenditures and the time that they are incurred prior to the granting of a production licence.

The regime was substantially altered in 1990 to allow undeducted exploration expenditure incurred after 30 June 1990 to be transferred to other projects. Simultaneously, the carry forward rate for undeducted augmented general project expenditures was significantly reduced from the long term bond rate plus 15 percentage points to the LTBR plus 5 percentage points. A number of other technical amendments have also been made since this time.

PRRT is a significant source of Federal Government budgetary revenue and the collections are wholly retained by that Government. Collections for the period 1989/90 to 2002/03 are outlined in Chart 3.4.

Chart 3.4: Petroleum Resource Rent Tax Collections

	$m		$m
1989/90	42	1996/97	1308
1990/91	293	1997/98	907
1991/92	876	1998/99	419
1992/93	1389	1999/00	1184
1993/94	1072	2000/01	2379
1994/95	865	2001/02*	1360
1995/96	791	2002/03*	1520

(estimate) Source : Federal Budget Papers*

Impact of PRRT on Exploration and Development Decisions

The overall PRRT framework ultimately influences the nature of exploration and development decisions undertaken by the industry in offshore waters. While the wider deductibility provisions that were introduced in 1991 allow for exploration costs incurred in PRRT areas to be offset against other PRRT income, the detailed provisions of the regime ultimately influence where exploration funds will be directed and what types of projects are likely to be the focus of development attention.

A number of specific concerns with PRRT are outlined below which can adversely impact on development decisions, and as a consequence, determine where companies may to wish to focus future exploration efforts. Ensuring that investors generate adequate returns prior to the payment of PRRT across all types of projects will aid in providing a framework that does not distort the suite of exploration and development decisions. It is also important to understand that the level of tax payments (including PRRT) ultimately reduces the size of the pool of funds available for future exploration (and development) activity.

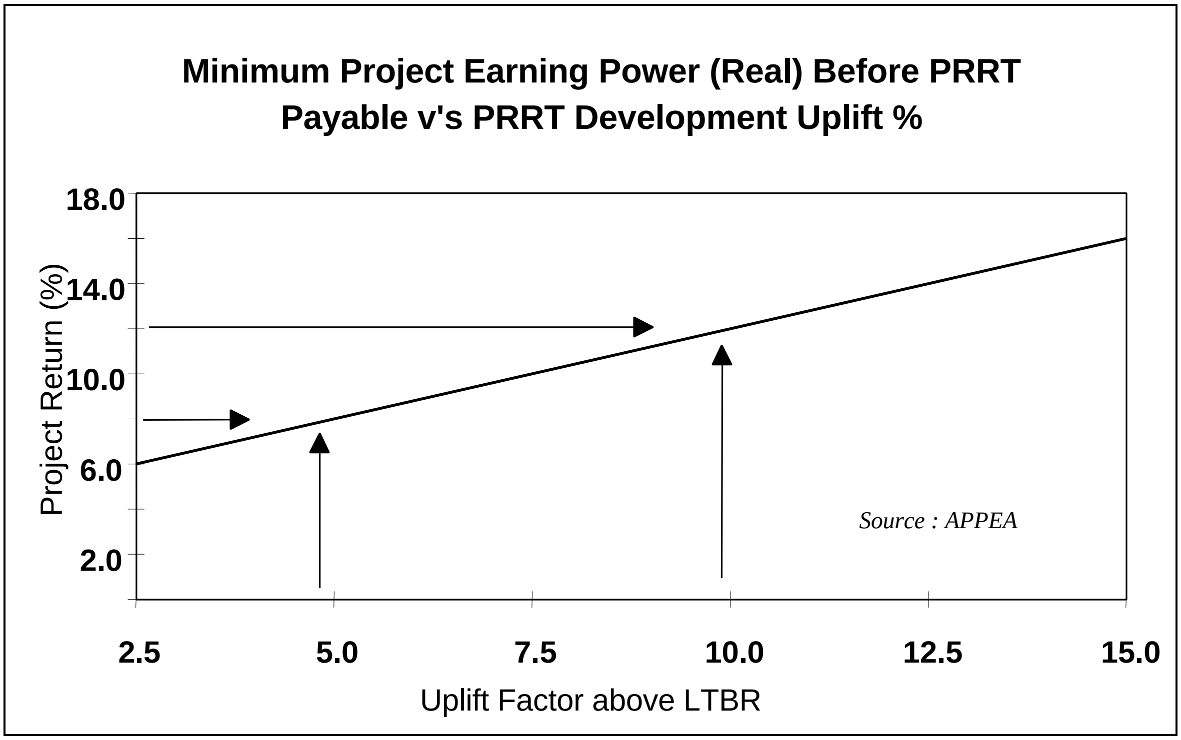
General Project Cost Uplift Provisions – Impact on Project Development Decisions

The carry forward rate that applies to undeducted general project costs is a crucial parameter within the operation of PRRT. It has an important impact on when an initial PRRT liability is incurred for a project. At the time that PRRT was modified in 1991 to allow undeducted exploration costs incurred after 30 June 1990 to be transferred to other projects, the carry forward rate for undeducted general project costs was significantly reduced from the LTBR plus 15 percentage points to the LTBR plus 5 percentage points.

Concern is held across the industry about this reduced carry forward rate. Specifically, there is a broad consensus that the rate should be increased to more adequately reflect the risks associated with developments encountered in the petroleum exploration and development industry. In effect, the industry is concerned that the current provision has the potential for a tax liability to be incurred before a true economic rent associated with a project has been generated. This runs counter to general principles of PRRT.

Chart 3.5 highlights the impact of the current carry forward provisions on the timing when a PRRT liability can be incurred. Under this scenario, the limitation in the carry forward rate for general project costs to the long term bond rate plus five percentage points imposes a PRRT liability when a project rate of return is approximately 8 per cent.

Chart 3.5



It is important that PRRT be structured in a way that reflects a petroleum industry investor's perception of risk if PRRT collections are to be maximised. The fundamental point is that a tax liability should not be incurred until a risk adjusted return has been generated by an investor. It is acknowledged that the above analysis ignores the impact of the wider deductibility of exploration costs, due to the diverse range of positions that confront investors. Importantly however, as more companies incur PRRT liabilities, the greater the number that will be confronted with this situation.

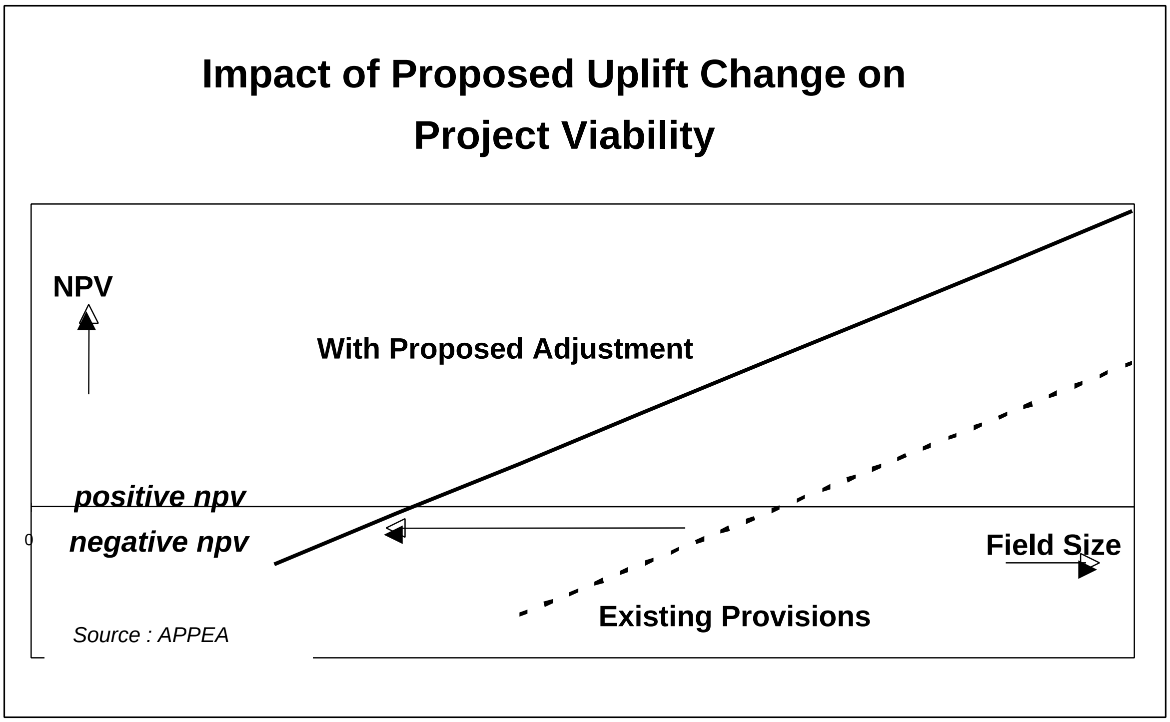
APPEA would argue that there are many risks that when combined, provide a strong case to support the claim that the current carry forward provision (ie LTBR plus five percentage points) is inadequate, including:

- construction risk
- operation risk
- reserves risk
- market risk
- contract risk

- regulatory risk
- exchange rate risk
- fiscal risk

As a means of addressing these factors, APPEA considers that the carry forward rate for undeducted general project costs should be increased to a minimum of the long term bond rate plus 10 percentage points to more effectively account for these risks. The hypothetical impact of such a change is outlined in Chart 3.6.

Chart 3.6



Such a change will help to ensure that projects are not discouraged by the early payment of PRRT. Importantly, it will also present a more attractive outlook for exploration because investors will be aware that the application of PRRT to marginal projects (ie deepwater and/or large scale gas developments) will less likely deter positive development decisions.

The change would not be expected to significantly impact on government revenues emanating from profitable new projects due to the typical very early recovery of general project related expenditures, while marginally economic projects would receive a positive signal within the PRRT system for their early development, thereby increasing taxation revenues (plus generating a range of economy wide benefits).

<u>Exploration and Development Activity in Deepwater Areas</u>

> *"...when economic efficiency is a prime policy goal, all resource projects that would have been undertaken without resource charges would still proceed under the chosen resource taxation regime." (*p.22 Federal Government's "Background Report on Petroleum Production Taxation - 1990")

The parameters of the PRRT regime were largely set for operations on the continental shelf that were more typical in the mid 1980's. At the time PRRT was introduced and subsequently revised, prospectivity assessments were limited to, *"...conventional oil and gas accumulations that may occur in recognised geological plays and could be brought into production within the next 20 to 25 years."* (p.38) To date, the only operations to have paid PRRT generally fit this description.

Exploration, development and production in deepwater and frontier areas represent a quantum increase in cost, time and uncertainty over equivalent operations in more conventional and established areas on the continental shelf. It has been argued that PRRT is intended, in effect, to apply across a portfolio of exploration and production assets such that the varying risks are balanced to produce an average level against which PRRT is applied. However, the cost, time and risk characteristics of some activities are so much greater that it invalidates this argument (it also ignores the fact that some companies may only have activities in deepwater, high risk areas). As such, an adjustment to the PRRT parameters applying to deepwater activities is necessary.

Why Petroleum Activities In Deepwater Are More Risky

- Poorly understood geological frontiers
- Leading edge technology required
- Low commercial success rates
- Exploration costs are higher (rig-rates, mooring, work boats, technology etc)
- Extensive appraisal work is required to mitigate against development risks
- Extensive reservoir modelling and design work is required to optimise development concepts – mistakes are very costly!
- New technology is required (heated flow lines, high pressure subsea equipment etc)
- Specialist construction techniques required – limited number of skilled contractors
- Huge capital expenditures and long lead times drastically reduce a projects net present value (gaps between exploration and production significantly greater)

While exploration activity is influenced by issues such as prospectivity, the minimal level of exploration in Australian deepwater areas as opposed to the significantly higher levels in deepwater basins in other countries (as well as the Australian continental shelf) suggests that Australia's deepwater fiscal terms are relatively unattractive in terms of prospectivity and risk. An important first step to address this concern would be to adjust key aspects of the PRRT regime.

Taking no action will see a continued distortion of exploration and development with activity skewed towards the continental shelf and against deepwater/frontier areas. The Government should recognise that this is not simply a matter of timing or that industry will somehow be forced to move to deepwater areas once continental shelf prospectivity and reserves are depleted. Funds will most likely be diverted to other countries.

There are a number of key PRRT parameters that offer options to improve its application to deepwater activities, including:
- a per project barrel of oil equivalent production exemption from the assessment PRRT;
- a risk premium in the carry forward rate for undeducted costs; or
- a lower PRRT tax rate for production from such projects.

Of the options, an exemption from PRRT for a fixed amount of production offers a potentially practical solution for a number of reasons, including:
- a production exemption can be quarantined to specific projects (possibly those in a water depth of 400 metres or greater);

- a production exemption would not affect the operation of any other aspects of PRRT and would be relatively simple to administer. There would be no impact on current expected Government revenues from projects subject to PRRT. If no deepwater projects are developed, then this measure will have no cost to the Government as the measure will only come into effect if production occurs;
- a fixed production exemption strictly limits the total cost to Government to a broadly quantifiable amount; and
- a production exemption would be equitable as all eligible projects would benefit by the same amount. The significance for small, marginally economic projects would be greater than for larger, more profitable projects.

Five-Year GDP Factor Rule

Under the present provisions, to have prior exploration expenditure compounded forward at the long term bond rate plus fifteen percentage points, it must have been incurred within five years of the date in which all of the relevant information for the granting of a production licence has been provided to the applicable Designated Authority. If this period is exceeded, the totality of any exploration expenditure incurred more than five years earlier than this date is compounded forward at the significantly lower GDP factor rate. This represents a dramatic drop in the value of the eligible exploration deductions for companies without a production licence.

This rule in its current form fails to recognise the long lead times that are often involved in many investments. For example, the time lags between the discovery of gas and/or deepwater resources and subsequent decisions to develop those resources (including after markets, contracts and project approvals have been obtained) will significantly discount the value of exploration expenditures. This can act to discourage investments in such deepwater areas, particularly for explorers without an existing production licence. Indeed, it could actually discourage exploration in these areas entirely.

Chart 3.7

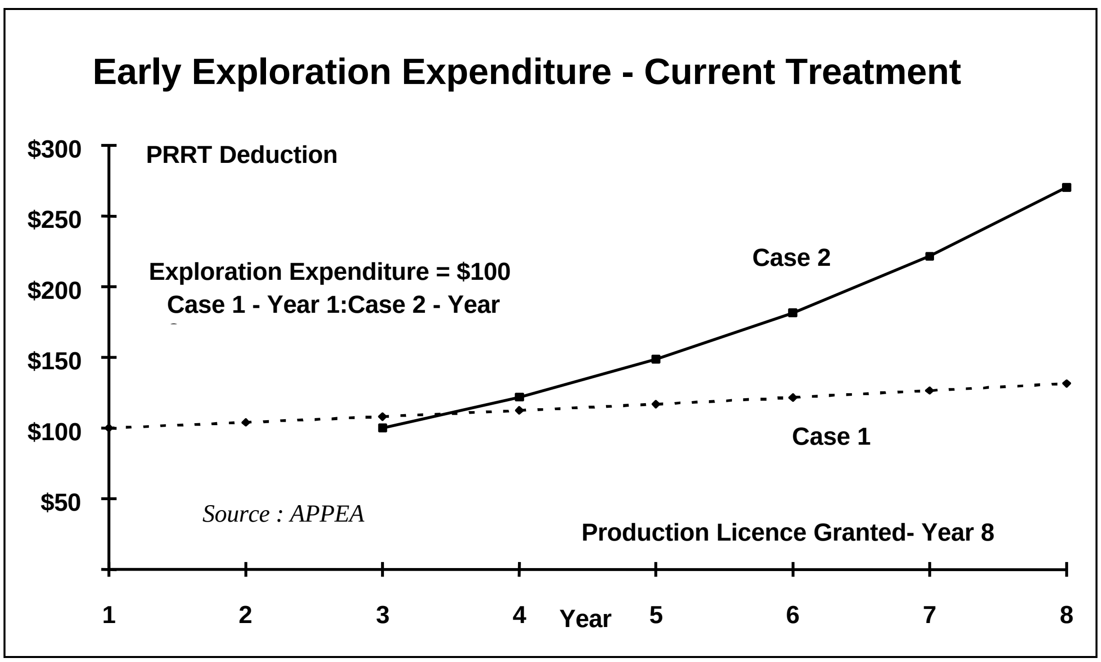


Chart 3.7 simulates the theoretical impact of the current provisions. For Case 1, the expenditure is incurred 7 years prior to the provision of the data for the granting of production licence, while in Case 2, it is assumed to have occurred 5 years prior to the submittal of the information. It is clear that there is a dramatic impact associated with falling outside the five year period in terms of potential exploration deductions available for PRRT purposes. While in both cases the value of the expenditure is $100, at year 8, following the granting of a production licence, the compounded value under Case 1 (where the expenditure was incurred 7 years beforehand) is significantly less than under Case 2.

APPEA is of the view that for exploration expenditure incurred more than five years prior to the provision of the data for the granting of a production licence (providing such a licence is ultimately issued), such expenditure should be compounded forward at the augmented bond rate (LTBR plus 15 percentage points) for the most recent five years, and for any excess periods before this, it be compounded forward at the long term bond rate. For example, expenditure incurred six years earlier will receive fives years of full factor growth (the most recent five years) and one year at the LTBR. This modification will have the effect of ensuring that any exploration expenditure incurred more than five years prior to the granting of a production licence will always receive five years worth of full factor growth.

Recommendations: For new projects, the carry forward rate for undeducted general project related expenditures be increased from the long term bond rate plus five percentage points to a minimum of the long term bond rate plus ten percentage points.

The PRRT Act should be amended to respond to the greater risks associated with deepwater exploration and production activity.

The five year GDP factor for undeducted exploration expenditure should be modified to recognise the long lead times between exploration and production.

3.2.3 Other Resource Taxes

Petroleum Royalties

Federal Government royalties apply to those licence areas in offshore waters which are not subject to PRRT (production sourced from exploration permits WA-1-P and WA-28-P), while the various states and territories apply royalties on the production of petroleum under their jurisdiction.

Royalties are generally assessed as a percentage of the wellhead value of oil and gas production. The wellhead value is calculated by subtracting from the sales value of all petroleum products sourced from the wellhead, the cost of transportation and processing involved in bringing the raw products from the wellhead to a point at which marketable products are sold. Deductions include:

- crude oil production excise (for Commonwealth royalties only);
- a proportion of the platform costs;
- certain processing and transportation costs;
- interest on the depreciated value of capital items (the cost of debt and equity capital); and
- specified depreciation and operating expenses.

Exploration costs are not deductible.

Royalties are levied at a rate between 10 and 12.5 per cent of the wellhead value, depending on the jurisdiction.

Crude Oil Production Excise

Prior to 1 July 1990, crude oil excise applied to all production sourced from the Bass Strait and North West Shelf project areas, as well as all fields located under state/territory jurisdiction (ie those not covered by the provisions of the Commonwealth Petroleum (Submerged Lands) Act 1967). The scope of the crude oil excise system was considerably narrowed from this date following the Federal Government's decision to extend the scope of PRRT to include production from the Bass Strait project.

Crude oil excise is payable on production from individual fields in a manner such that higher percentage rates apply to higher levels of production from each field. The excise scale that applies to production from each field is dependent on the date of discovery and/or the commencement of production. The crude oil excise provisions allow for the following:

- the exemption from excise of the first 30 million barrels of cumulative crude oil production from each field where excise applies;
- condensate marketed or produced separately from crude oil is excise free;
- the exemption from excise of all gas production, including liquefied petroleum gas, liquefied natural gas and commercial gas/ethane.

While the existing royalty and excise provisions are not seen as a major impediment to exploration and development activity, all jurisdictions will need to remain aware of the impact that such imposts can have on the economics of marginal projects. Specifically, the royalty regimes should provide for the deductibility of all post-wellhead costs (including platform removal and rehabilitation expenditures), while the excise system should encourage investors to apply new exploration and recovery techniques to old and new discoveries.

3.3 Company Tax

3.3.1 Why Company Tax Is Important

The company tax system plays a fundamental role in shaping the framework within which petroleum exploration and production decisions are made. In simple terms, it influences Australia's ability to compete for limited international investment funds.

Investments in petroleum related activities are often very different to those in other types of business enterprises. Petroleum projects are often characterised by substantial time lags between the discovery and commercialisation of a resource. In Australia, reserves are also often located in geographically remote locations, with extremely long distances to markets. In addition, projects often involve the expenditure of vast sums of capital over long periods, with significant outlays prior to the commencement of initial production not being uncommon. Another factor that differentiates this type of project from many others is that the pay-back period for an investor to achieve a positive economic return is often quite lengthy, sometimes in the order of 10 to 20 years.

As a result of the characteristics of such projects (high capital expenditures, competitive prices and long pay-back periods), project viability is very sensitive to a number of key parameters, including the timing and nature of taxation.

For example, the impact of Australia's company tax system on the economics of gas production projects was demonstrated in a study that was prepared for the Department of Primary Industries and Energy (now DITR) by Aberdeen University Petroleum and Economic Consultants (AUPEC). Specifically, the study concluded that the Australian company taxation system introduced a significant element of regressiveness which leads to gas production projects becoming less profitable, particularly as a result of the depreciation provisions.

Indeed, under a range of representative scenarios, the net present value of company tax collections exceeded the entire pre-tax net present value of the project. In effect, the company tax system (even through the application of relatively low discount rates) can extract the entire economic rent from a gas project. The study highlighted that even under a relatively modest set of development cost assumptions, the Australian company tax regime is uncompetitive with a range of other gas producing countries.

It is important to recognise that a bias is already inherent in the current system in that the net present value of costs which can be immediately expensed (eg operating costs), is greater than the net present value of plant and equipment costs which are generally depreciated at historical value. The result is that a dollar spent on operating related activities can be more tax effective than a dollar spent on capital. This treatment by definition favours industries which are non-capital intensive in nature.

In addition, the inability to claim deductions until equipment is 'installed, ready for use' is a further disincentive. The lead times between investment expenditure and when equipment is commissioned for some large resource projects (which can be more than five years) can disadvantage such projects when compared with other investments due to the timing of tax payments.

3.3.2 The Treatment of Exploration Costs

Exploration is an essential element of conducting business in the upstream oil and gas industry. It can cover a range of activities including regional surveys, geophysical evaluation, seismic operations, exploration drilling and field appraisal. In a practical sense, exploration represents the key element of the research and development activities undertaken by the industry.

The immediate and full write-off of expenditures associated with exploration correctly acknowledges the nature and importance of such expenditures. These outlays reflect a real cost of conducting the business of producing oil and gas, and the immediate deductibility of such costs is the appropriate method of treating such expenditures. In the absence of this treatment, a highly distortionary disincentive to risk-taking would be established which would ultimately reduce the overall petroleum exploration effort in Australia.

A direct consequence of any other treatment would be to discourage exploration, particularly in those areas where risks are perceived to be higher. This would impact on exploration in deepwater and frontier areas where the likelihood of success is more uncertain and would clearly be at odds with general energy policy objectives of resource security and diversifying sources of supply.

The focus of the majority of the exploration effort in Australia to date has been confined to relatively few areas. The higher risk areas (including deepwater regions and remote areas within Australia's onshore basins) have been relatively lightly explored. In part, this has been a result of the acreage released as well as reflecting general prospectivity perceptions. In terms of stimulating a greater flow of funds to these lightly or unexplored areas, a range of tax related options exist that merit close examination, including:

- an allowance or bonus that would increase the deduction allowable for exploration in designated high risk areas (similar to an R&D allowance);
- a grant or assistance to offset the cost of high risk exploration; or
- a rebate associated with nominated acreage.

3.3.3 Depreciation Provisions

The ability of the company tax system to respond to the economics of long life and high risk projects influences both exploration and development decisions. Specifically, the regime must be competitive with those applying in countries with which Australia competes for exploration and development funds. Prior to the changes announced as part of the Business Tax Reform program, capital expenditures incurred in the industry often be written off against income over periods of between 7 and 10 years.

As part of the package of changes, accelerated depreciation was abolished for new investments, with the determinant of an assets depreciation life being either that contained in the Effective Life Schedule released by the Commissioner of Taxation or a taxpayers self assessment of the life of the relevant asset. Under the effective life provisions contained in the Schedule, the write-off periods for most oil and gas production and processing equipment ranges from 10 to 30 years. Importantly, legislation was recently passed that ‘capped’ the effective lives for these assets at rates of 15 years for oil and gas production and processing assets, and 20 years for platforms. This decision was supported by the industry, but it nevertheless remains important that we do not become complacent and assume that this mitigates against the need to continually monitor this crucial area of the taxation system in terms of international competitiveness.

For example, an analysis was prepared for APPEA as part of the industry’s response to the tax reform process to examine the potential impact of a trade-off between the company tax rate and the period over which assets could be depreciated for taxation purposes. A conclusion of that study was that a loss of accelerated depreciation, even with a lower company tax rate, would tend to discourage investment in some long-life marginal projects.

Chart 3.8: After Tax Return on a Large Scale Gas Field (LNG)

Assumption	Project Status	After Tax Return(%) (Nominal)
36% Tax, 20%pa Dep	Profitable	14.4
30% Tax, 6%pa Dep	Profitable	14.1
36% Tax, 20%pa Dep	Marginal	9.0
30% Tax, 6%pa Dep	Marginal	8.8

Source : ACIL Consulting

The estimated after tax nominal return for both profitable and marginally profitable projects also falls with the adoption of a lower tax rate/extended depreciation set of parameters, as outlined in the above chart.

3.3.4 Native Title Related Costs – Company Tax Treatment

Through various processes, companies can incur a range of expenditures on native title related activities. All costs associated with such activities should be fully deductible either as an immediate deduction in the year incurred or amortised over the period to which the payments relate. Most overseas tax jurisdictions allow either immediate or periodic deductions for native title expenditures.

Recommendations : That the Committee recommend consideration be given to assessing options (in consultation with the industry) to encourage exploration in high risk and/or under-explored areas via the use of incentives through the company tax system.

That the Committee notes the importance that depreciation provisions play in influencing project economics and the need for Australia to maintain a competitive regime to further stimulate exploration and development activity.

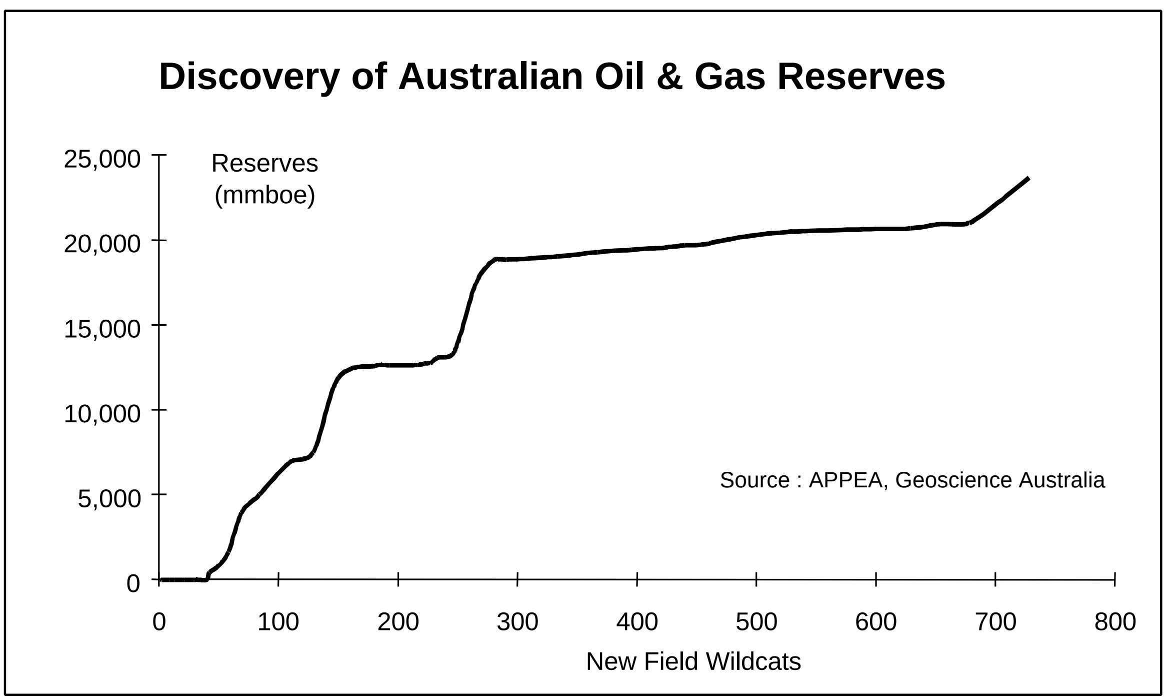
All costs associated with petroleum exploration and production activities, including native title related costs, should be deductible for company tax purposes.

3.4 Junior Exploration Companies – A Tax Induced Impediment to Capital Raising

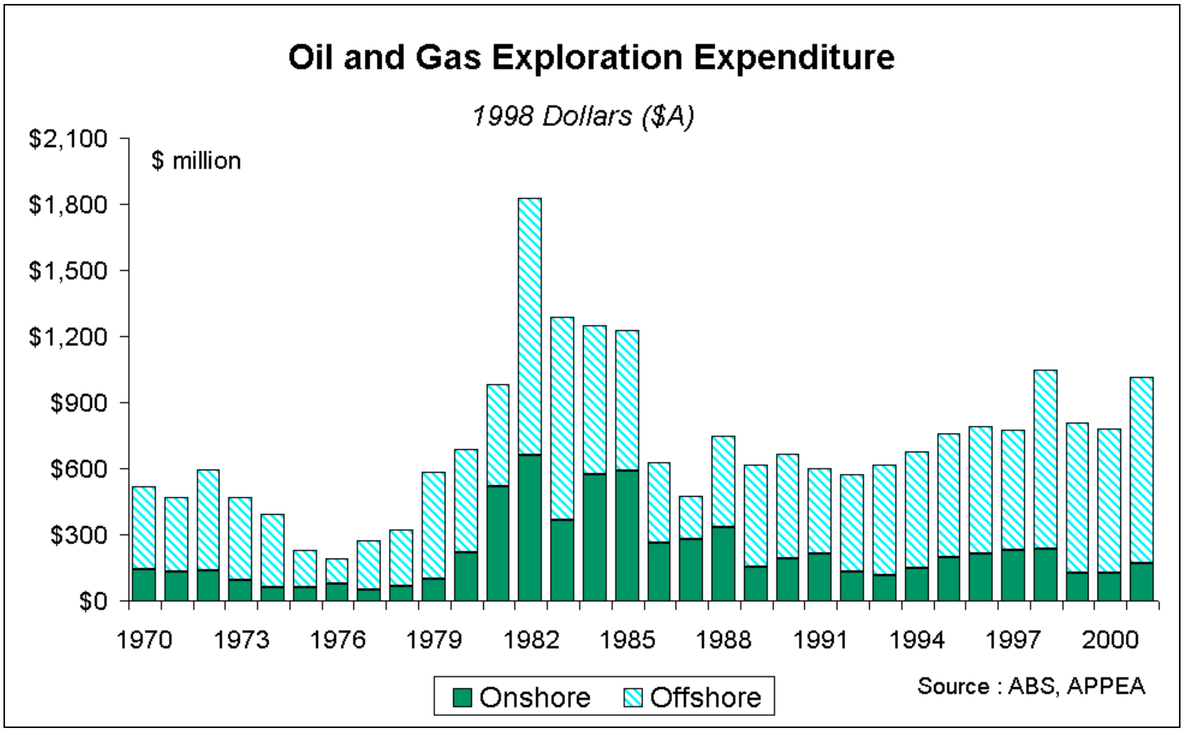
Petroleum exploration activity in Australia has fluctuated considerably over the last three decades. Overall, exploration and production is affected by a range of factors, including access to acreage, prospectivity, prices, rig and seismic mobilisation costs, geographic location, perceptions of risk/rewards (eg potential field sizes), international competition for funds and the fiscal regime.

In Australia, Chart 3.9 illustrates that the first 300 New Field Wildcat (NFW) wells discovered approximately 80% of Australia's total offshore reserves; over 400 more NFW wells drilled from 1982 have only managed to add the remaining 20% of known reserves of gas and liquids. The vast majority of reserves discovered since the 1960s have been gas which now accounts for the majority of the total amount. Discoveries of the scale of those in the 1960s (whose original liquids reserves account for nearly half of total liquids discovered) and 1970s are no longer guaranteed.

Chart 3.9



A key measure of exploration activity is the level of expenditure incurred on exploration related activities. Chart 3.10 outlines the level of expenditure incurred on exploration in real 1998 dollars. Such a measure provides a good guide as to trends in actual expenditure over time.



While the level of expenditure incurred in offshore areas has remained relatively static, there has been a noticeable and consistent reduction in the level incurred onshore. There are a number of potential factors that have contributed to such a trend – a reason that is consistently identified by junior exploration companies as a concern is their inability to attract capital as a result of the operation of the company tax system.

Exploration undertaken onshore has been the more traditional (although by no means exclusive) domain of junior (Australian domiciled) companies. In addition, a number of the significant offshore discoveries have been as a result of the initiative and risks undertaken by such companies. In many respects, the health of the entire industry is reflected in the strength and vitality of the junior exploration sector of the industry.

Why do the Company Tax Provisions Cause Difficulties?

The company income tax laws presently allow for the immediately deducibility of costs associated with exploration activity for the entity that incurs the expenditure. For entities that have an income tax liability, the ability to immediately expense such costs provides an important form of cost relief that is clearly anticipated (and encouraged) under the company tax laws.

Conversely, those entities that do not have such income are unable to obtain tax relief and are therefore required to carry forward any such costs until such time as an opportunity arises to claim a deduction. As a direct consequence, this inability to obtain a tax deduction significantly reduces the after tax value of exploration activity undertaken by these companies. While the costs may ultimately be deducted when a tax liability is incurred, the value is kept constant in nominal dollars and is therefore significantly eroded in real terms. Indeed, the deduction may never be utilised.

Coupled with the reduced level of exploration onshore, the industry has become increasingly alarmed over the inability of many junior Australian based companies to continue to remain active in the sector. Specifically, the tax related outcome raised above in the context of the activities of junior explorers is a demonstrable example of where the taxation system is behaving in a manner that makes elements of a high risk venture less attractive to investors. In effect, Australian companies which are exploration focused and capital market dependent are disadvantaged when compared with competing lower risk industries because investors are aware of the high risk nature of the activity and that funds spent may be on an unsuccessful venture (ie exploration).

A Possible Solution

Historically, public companies had access to a number of schemes that allowed for the deductibility for petroleum exploration expenditure to be passed to their shareholders. These schemes were generally regarded as having increased the exploration efforts of eligible companies. In the 1960s and early 1970s, a petroleum company raising new capital could pass a tax deduction directly to each subscriber through the applicable income tax law.

In the late 1970s, a rebate scheme was developed for certain offshore areas that was later expanded to cover onshore exploration. Unlike the previous arrangement, a number of restrictions were placed on the operation of this system, including allowing a rebate that was considerably lower than the prevailing company tax rate and limiting the timing and scope for which the funds could be used. This scheme was subsequently terminated.

While not specifically recommending the adoption of a particular system (either a company direct rebate or shareholder deduction system are clearly two options), anecdotal evidence strongly suggests that the implementation of a scheme (with adequate control mechanisms) would lead to a significant expansion in the funds available for exploration activity (particularly in onshore areas). While it is not possible to quantify the absolute level of funding that could potentially be generated, it is inevitable that increased funds would be raised which would translate into an increased oil and gas exploration effort.

While the overall level of expenditures made by small to medium sized companies is somewhat unclear, APPEA estimates that the total level of petroleum exploration expenditure made by this general category of Australian public companies is less than $100 million per annum. Of this amount, not all would be expended on exploration in Australia, and in the case of some companies, a taxable income stream exists to allow for the deductibility of such costs. As such, the undeducted amounts attributable to Australian exploration activity would be somewhat less than this full amount. In this context, the cost to revenue of any prospective change would be modest, however it could realistically be expected to produce a significant boost to the overall exploration effort.

Recommendation : The Committee recommend a detailed analysis of the changing pattern and influences on exploration activity by junior exploration companies with a view to developing a set of proposals to minimise the tax induced distortions that constrain the ability of such companies to attract investment capital.

3.5 Taxes on Business Inputs – Diesel Fuel Excise

While the oil and gas industry accounts for a significant percentage of the total value of resource production in Australia (the Australian Bureau of Statistics estimated that for 1999/2000, oil and gas accounted for 38 per cent of the resource sector's value adding activities), APPEA estimates that it accounts for a fraction (possibly less than two per cent) of total payments attributable to the resources sector under the diesel fuel rebate scheme (DFRS). Notwithstanding the petroleum industry's relatively minor usage of the scheme, it still provides an important mechanism whereby the industry can remain domestically and internationally competitive, and help ensure that the pool of funds for Australian petroleum exploration is maximised.

Diesel Fuel Usage in the Petroleum Exploration and Production Industry

Exploration Activities

Diesel fuel is integral to oil and gas exploration operations in a variety of ways. In terms of onshore operations, the size of petroleum exploration permits requires the movement of high technology, capital intensive equipment to fulfil exploration program commitments. Seismic, drilling, mapping and sampling activities can be carried out within a permit area and all require diesel fuel to varying degrees. A significant proportion of the cost of conducting onshore drilling activities can be attributed to the cost of diesel. Increases in the cost of diesel increases the cost of (and therefore potentially reduce the size of) exploration programs.

For offshore exploration operations, a large portion of diesel is consumed as part of geophysical and drilling activities undertaken by specialised service, support and seismic vessels. These vessels are wholly dependent on diesel fuel for their operations.

Development and Production Activities

For development and production activities, the use of diesel fuel is also diverse. Due to the wide geographic spread of onshore activities within a single integrated production site, vehicular transport represents an important mechanism for ensuring that such operations are run and maintained in an efficient manner. APPEA estimates that the use of diesel in light vehicles represents by far the most significant diesel dependent activity for onshore production operations. This is easily understood in terms of the nature of petroleum operations, which do not rely on large scale mechanical processes to extract an ore body as often is the case for traditional mining operations at a single pit.

For offshore operations, the movement of equipment and supplies to offshore installations is a fundamental part of the production process. Unlike onshore operations, where there is an ability to locate infrastructure at a point that is often adjacent to ongoing operations, the use of an onshore supply base for offshore activities is unavoidable. The most significant usage of diesel for offshore operations is associated with service and support vessel usage. APPEA estimates that this category of usage potentially accounts for the majority of the total diesel used in offshore production operations. Other offshore activities that consume diesel include platform operations, plant requirements and the maintenance/stand-by use of safety/support vessels.

Scope of Eligibility & Administrative Uncertainties

An on-going concern that confronts some company claimants with respect to the DFRS is the inability to gain duty relief for some activities. This situation has arisen due to the arbitrary exclusion of some operations that fall within the scope of an industry's normal activities. This has particularly been the case since the mid to late 1990's when a number of revenue based decisions were made to find savings from the Scheme.

A specific example that impacts on a range of companies with onshore gas operations relates to the use of light vehicles for field operations. As outlined above, light vehicles are an essential part of onshore oil and gas operations, both from the perspective of exploration and production activities. The movement of equipment and personnel within an exploration permit area is a part of normal exploration operations. Similarly, onshore production operations are carried out through a complex network of wells that form a single integrated production unit.

The Federal Government announced a number of modifications to the scheme in 1996/97. One of the most significant changes was the exclusion from eligibility of the use of light vehicles. Specifically, the use of a vehicle not exceeding 3.5 tonnes gross vehicle weight (other than those that are extensively modified) was deemed ineligible under the definition of mining operations. A direct consequence of the change was to deny eligibility for diesel consumed in a key part of petroleum exploration and production operations, thereby harming the economics of such operations. At no time has it been suggested that such activities were not part of genuine mining (oil and gas) operations. APPEA considers that it is now timely for these activities to reincorporated under the provisions of the Scheme.

Recommendation : That all activities associated with mining operations be covered by the scope of the Diesel Fuel Rebate Scheme (or from 1 July 2003, the Energy Credits Scheme) to ensure that the pool of funds for future exploration is maximised.

Attachment

List of Acronyms

ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ATO	Australian Taxation Office
AUPEC	Aberdeen University Petroleum and Economic Consultants
BOE	Barrel of Oil Equivalent
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DFRS	Diesel Fuel Rebate Scheme
DITR	Department of Industry, Tourism and Resources
EPA	Environment Protection Agency
EPBC	Environmental Protection and Biodiversity Conservation Act
FBT	Fringe Benefits Tax
GA	Geoscience Australia
GDP	Gross Domestic Product
GRIG	Gas Reform Implementation Group
ILUA	Indigenous Land Use Agreement
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTBR	Long Term Bond Rate
NFW	New Field Wildcat
NPV	Net Present Value
NWS	North West Shelf
PJ	Petajoules
PRRT	Petroleum Resource Rent Tax
P(SL)A	Petroleum (Submerged Lands) Act 1967
R&D	Research and Development
tcf	Trillion Cubic Feet