APPEA

AUSTRALIAN PETROLEUM PRODUCTION & EXPLORATION ASSOCIATION LIMITED

27 August 2008

The Secretary
Select Committee on Fuel and Energy
The Senate
PO Box 6100
Parliament House
Canberra ACT 2600

Email: fuelenergy.sen@aph.gov.au

Dear Committee Secretary

The Australian Petroleum Production & Exploration Association (APPEA) is the peak national body representing the collective interests of companies engaged in petroleum exploration, development and production in Australia.

APPEA is pleased to provide you with the attached submission in relation to the Inquiry. Also attached are copies of documents referred to in the submission.

Yours faithfully

Belinda Robinson
CHIEF EXECUTIVE

Encl.

- *APPEA Submission*
- *Upstream Industry Strategic Leaders' Report (2007)*
- *Discovering Australia's Future Petroleum Resources Report (2008)*

ABN 44 000 292 713

HEAD OFFICE
GPO BOX 2201
CANBERRA ACT 2601

LEVEL 10
60 MARCUS CLARKE STREET
CANBERRA ACT 2600
PHONE 61 2 6247 0960
FAX 61 2 62
0548

BRISBANE OFFICE
PO BOX 1151
BRISBANE QLD 4001

LEVEL 9
10 Market St
BRISBANE QLD 4001
PHONE 61 423 592 722
FAX 61 7 32
2811

PERTH OFFICE
PO BOX 7039
CLOISTERS SQUARE
PERTH WA 6850

LEVEL 1
190 ST GEORGES TERRACE
PERTH WA 6000
PHONE 61 8 9321 9775
FAX 61 8 93
9778

INTERNET
www.appea.com.au

EMAIL
appea@appea.com.au

AUSTRALIAN PETROLEUM PRODUCTION & EXPLORATION ASSOCIATION LIMITED

ABN 44 000 292 713

HEAD OFFICE

GPO BOX 2201
CANBERRA ACT 2601

LEVEL 10
60 MARCUS CLARKE STREET
CANBERRA ACT 2600
PHONE 61 2 6247 0960
FAX 61 2 6247 0548

PERTH OFFICE

PO BOX 7039
CLOISTERS SQUARE
PERTH WA 6850

LEVEL 1
190 ST GEORGES TERRACE
PERTH WA 6000
PHONE 61 8 9321 9775
FAX 61 8 9321 9778

INTERNET
http://www.appea.com.au

EMAIL
appea@appea.com.au

SUBMISSION TO THE SENATE SELECT COMMITTEE ON FUEL AND ENERGY

AUSTRALIAN PETROLEUM PRODUCTION & EXPLORATION ASSOCIATION (APPEA) LTD

AUGUST 2008

TABLE OF CONTENTS

SECTION 1: BACKGROUND AND INDUSTRY ECONOMIC SIGNIFICANCE

SECTION 2: SPECIFIC COMMENTS

SECTION 1: BACKGROUND AND INDUSTRY ECONOMIC SIGNIFICANCE

1.1 Introduction

The Australian Petroleum Production & Exploration Association (APPEA) is the peak national body representing the collective interests of companies engaged in petroleum exploration, development and production in Australia. The Association's membership comprises companies that account for an estimated 98 per cent of Australia's petroleum production and the vast majority of exploration.

1.2 Energy Use in Australia

Reliable and competitively priced petroleum is essential for the well being of the Australian economy. Petroleum (oil and gas) is currently the source for over 50 per cent of Australia's primary energy consumption, while liquid petroleum supplies nearly all of our transport energy requirements.

Table 1: Share of Primary Energy Consumption in Australia (per cent)

	Oil	Natural Gas
2005-06	35.5	18.7
2011-12	35.1	20.7
2019-20	34.5	23.1
2029-30	35.5	23.9

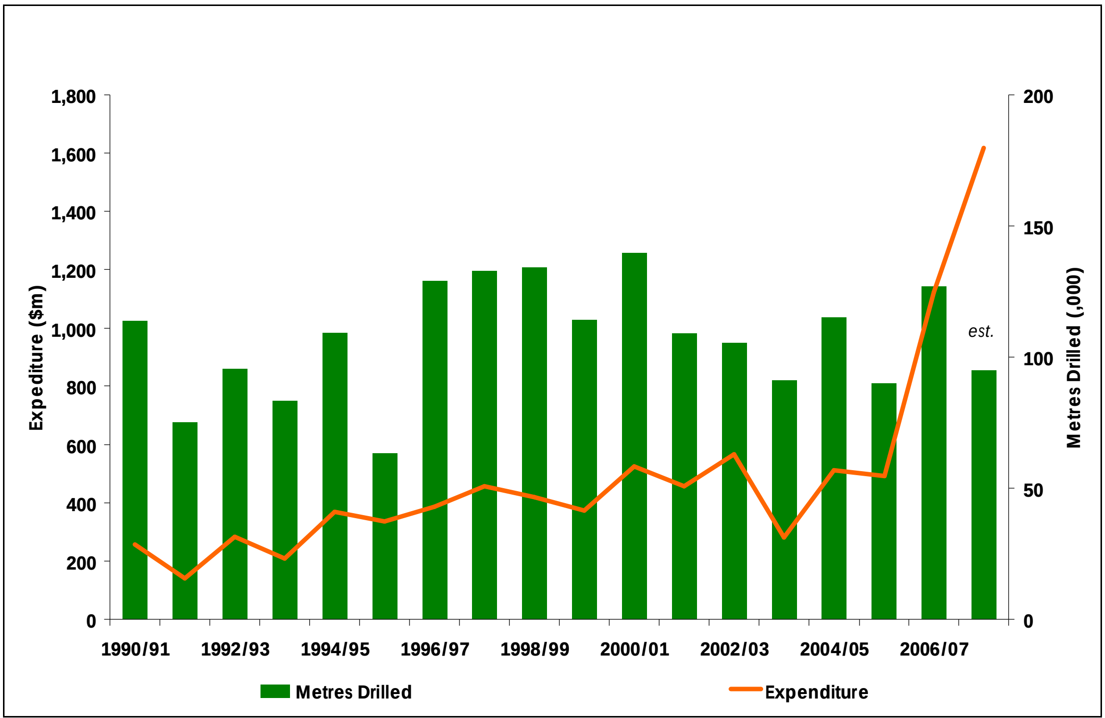
Source: ABARE Research Report 07.24 (December 2007)

The Australian Bureau of Agricultural and Resource Economics (ABARE) forecasts that the percentage level of oil used in primary energy consumption will remain relatively constant over the next two decades, while the percentage attributable to natural gas is expected to rise from 18.7 per cent in 2005-06 to 23.9 per cent in 2029-30.

1.3 Petroleum Exploration in Australia

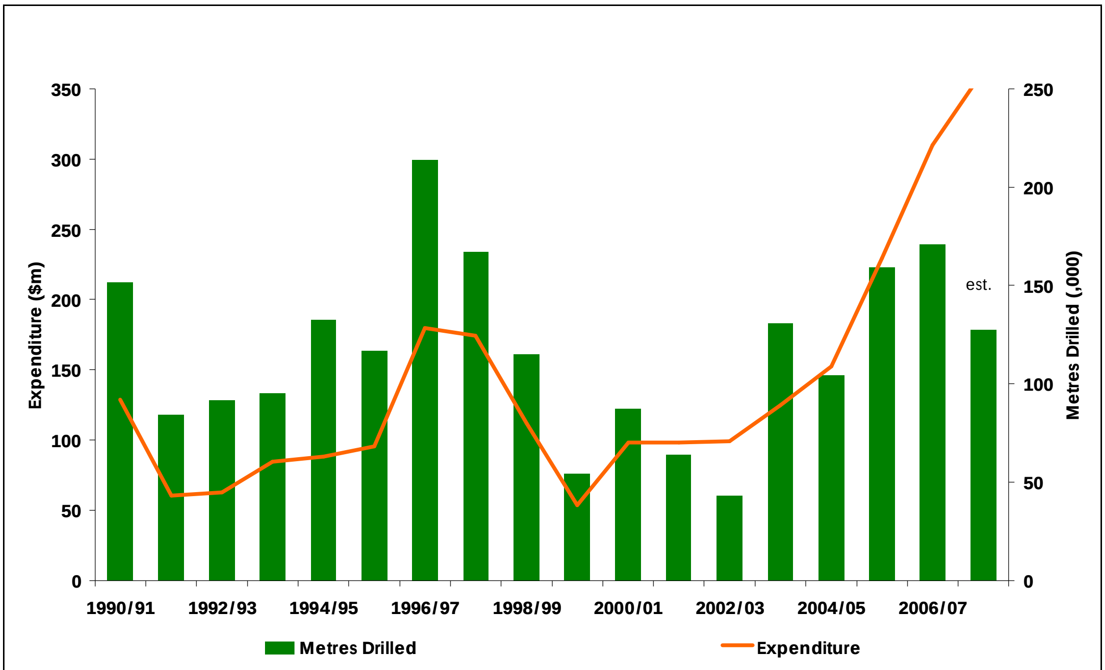
Exploration is a key determinant of future domestic oil and gas production. There are a number of indicators that can be used to measure exploration activity. Charts 1A and 1B highlight the trends in exploration expenditure in onshore and offshore areas in the period covering the years 1990-01 to 2007-08, together with the number of exploration metres drilled.

Chart 1A: Offshore Exploration Drilling & Drilling Expenditure (1990/91 to 2007/08)



Source: ABS, Geoscience Australia, APPEA

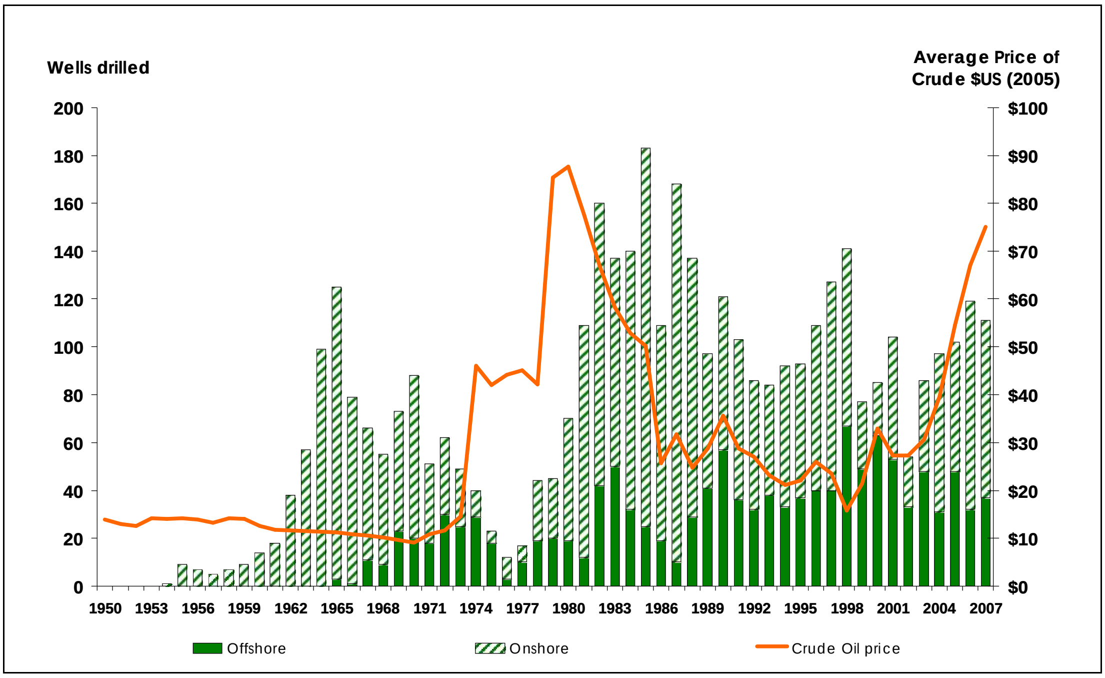
Chart 1B: Onshore Exploration Drilling & Drilling Expenditure (1990/91 to 2007/08)



Source: ABS, Geoscience Australia

While the quantum of expenditure is the most often cited measure of exploration activity, it is arguably the most unrepresentative in terms of the actual level undertaken, a fact that can be clearly seen in the above charts. The rise in expenditure that has been recorded in the last five years has outpaced a rise in the actual number of metres drilled. This is clear when it is understood that the cost of drilling has risen over the same period. Advice from APPEA members suggests that drill rig rates have more than doubled over the last two years.

Chart 2: Exploration Wells Drilled



Source: Geoscience Australia, BP, APPEA

Chart 2 provides an alternative measure of exploration activity, namely the number of wells drilled. Again, while there has been some growth in the number of wells drilled over the last five years (particularly onshore), the rise has been far less than would be expected based on the quantum of exploration expenditure. This Chart also plots the average price of crude oil in real $US over the corresponding period. Suggestions that rises in oil prices lead to an increase in exploration activity is not supported by the data presented in the Chart.

1.4 Gas and Liquids Production

Gas

Australia has vast reserves of natural gas that remain largely undeveloped. Opportunities exist to develop new gas based projects, including through the export sale of gas (both conventional and coal seam gas). Export gas sales have the potential to exceed an additional 30 million tonnes per year over the next decade.

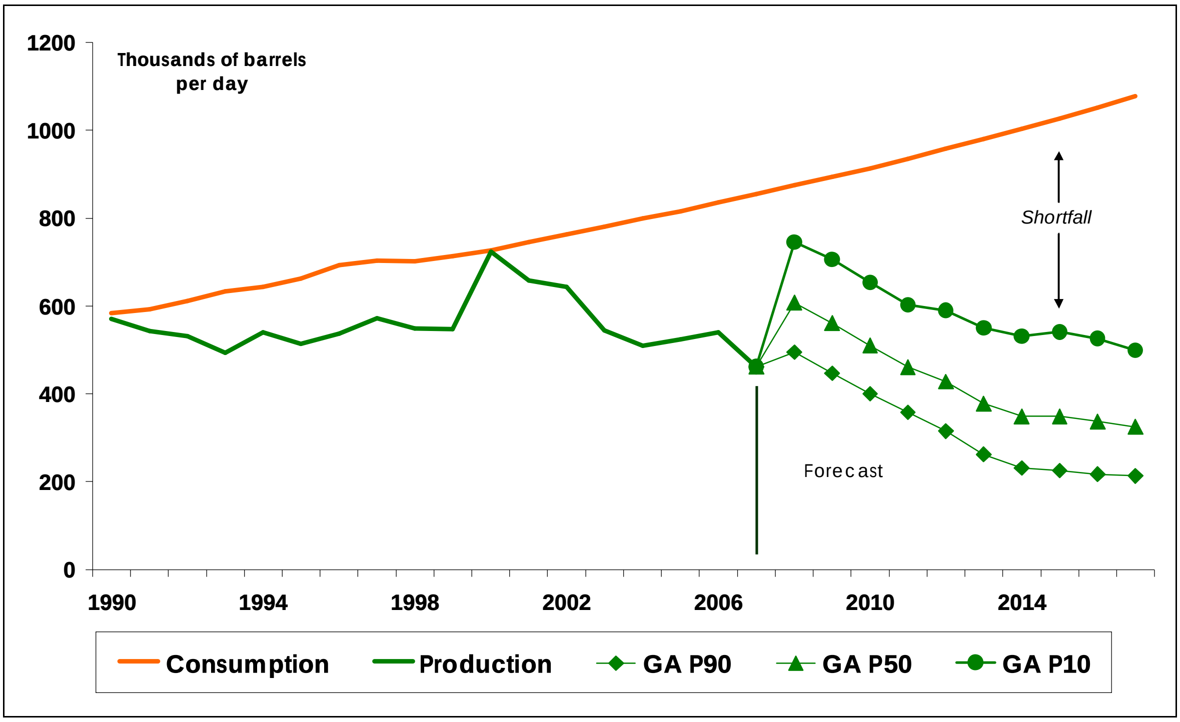
ABARE forecasts relatively strong growth in domestic gas production (approximately 2.6 per cent per year), however challenges such as high development costs, relatively low prices, limitations on interconnecting pipelines, fiscal imposts and competition from competing fuels (including those benefiting from the mandatory renewable energy target) in one way or another will impact on the growth of this sector.

Not all reserves are currently commercial and therefore may not be able to be developed. The long distances involved in transporting some of this gas to market has a significant impact on the economics of gas developments. The emerging growth of coal seam gas (CSG) as a resource that is capable of meeting Australia's electricity and heating requirements also presents new opportunities. Under appropriate fiscal and policy settings, Australia's gas reserves may also be capable of supplying sustainable and cleaner alternative fuels to the Australian market.

Petroleum Liquids

Chart 3 highlights historical crude oil and condensate production, Geoscience Australia's production forecasts for crude oil and condensate, together with ABARE's forecast level of consumption (demand). The Geoscience Australia forecasts are based on high (P90 - 90 per cent level of success), medium (P50 – 50 per cent level of success) and low probability cases (P10 – 10 per cent level of success).

Chart 3: Crude Oil and Condensate Production and Demand



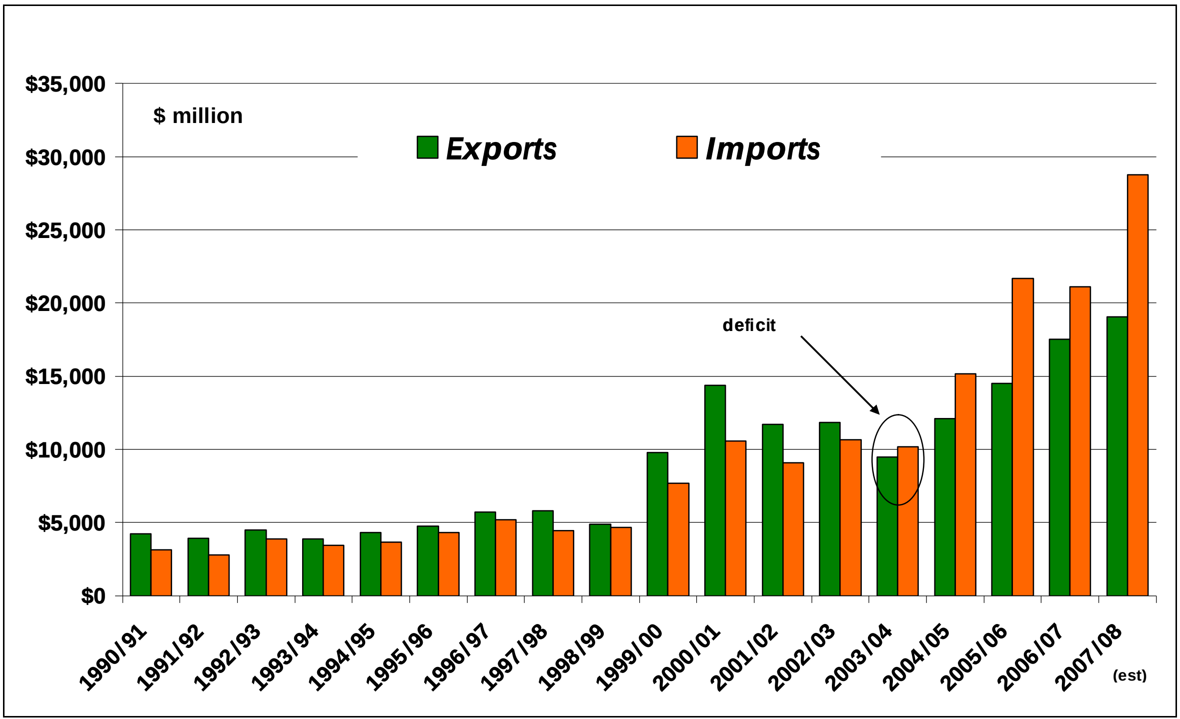
Source: ABARE, Geoscience Australia (GA), APPEA

Assuming the most optimistic scenario (P10), petroleum liquids production is expected to fall well short of domestic demand – as noted below, this will have implications for the nation's trade position.

1.5 Trade in Petroleum & Products

Until recent times, Australia had been a net exporter of oil, gas and derived petroleum products. This has allowed Australia to generate valuable export earnings and therefore positively contribute to our overall trade position. The ability of domestic production to replace costly imports of petroleum has also been significant.

Chart 4: Trade in Petroleum and Petroleum Products



Source: ABARE, APPEA

There has been a significant turnaround in this surplus position in last five years as a consequence of both a rise in international oil prices and a fall in the level of domestic crude oil production. This has led to the emergence of a growing trade deficit (Chart 4).

Chart 4 includes petroleum liquids (crude oil and condensate), gas (LPG and liquefied natural gas) and petroleum products. While Australia was in surplus prior to 2003/04, the net deficit position has grown to now exceed more than $10 billion per annum. It is expected that this deficit will continue to increase, notwithstanding a possible rise in the level of export gas (LNG) over the coming years.

The annual trade deficit in crude oil and condensate could grow to exceed $25 billion per year by 2020.

1.6 The Australian Resource Taxation Framework

1.6.1 Resource Taxes

At present, the resource (secondary) taxation framework that applies to petroleum production in Australia is broadly as follows:

- all 'offshore' projects, with the exception of those production licences derived from Exploration Permits WA-1-P and WA-28-P, are subject to the provisions of the *Petroleum Resource Rent Tax Assessment Act 1987*;
- production sourced from licences derived from Exploration Permits WA-1-P and WA-28-P are subject to Commonwealth crude oil excise and Commonwealth petroleum royalty; and

- onshore production and that sourced from projects located in submerged lands under state jurisdiction is subject to Commonwealth crude oil excise and royalty under the relevant state/territory jurisdiction.

Petroleum Resource Rent Tax (PRRT)

PRRT is an economic based tax with the following basic features:
- it is assessed on a project basis;
- liability to pay PRRT is on a producer/company;
- 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 (a 'marketable petroleum commodity');
- deductions include capital and operating costs that relate to the petroleum project, and are deductible in the year they are incurred. Deductible expenditures include those related to exploration, development, operating and closing down activities;
- expenditures which are non-deductible include financing costs, some indirect administration costs, income tax 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 application for a production licence.

Petroleum Royalties

While the specific details of the various royalty regimes vary across jurisdictions in Australia, the basis features are as follows:
- royalty is levied on a licence area basis;
- liability to pay royalty is on the net wellhead value of production;
- it is levied at rates of between 10 and 12 ½ per cent of the wellhead value;
- limits often apply to deductions such that a minimum royalty liability must be paid in any single period (usually from the commencement of production); and
- costs incurred between the wellhead and the point of sale (ie post wellhead costs) are deducted from gross receipts to ascertain the wellhead value. Deductible costs can include the post wellhead depreciated value of capital equipment, an allowance for the cost of capital, operating expenses and crude oil excise (in some cases).

Crude Oil Excise

Crude oil excise is calculated as a percentage of the volume weighted average of realised f.o.b price (VOLWARE) made from a designated region. Crude oil is subject to excise in a manner such that higher percentage rates apply to higher levels of production or liftings from each prescribed production area.

The excise scales that apply to production from each prescribed production area are dependent on the date of discovery and/or the commencement of production.

In addition, the current crude oil excise provisions allow for the following:
- the exemption from excise of the first 4,767.3 megalitres or 30 million barrels of cumulative crude oil production from each petroleum field where excise applies; and

- the exemption from excise of all gas production, including liquefied petroleum gas, liquefied natural gas and commercial gas/ethane.

1.6.2 Other Imposts: Company Taxes and Indirect Charges

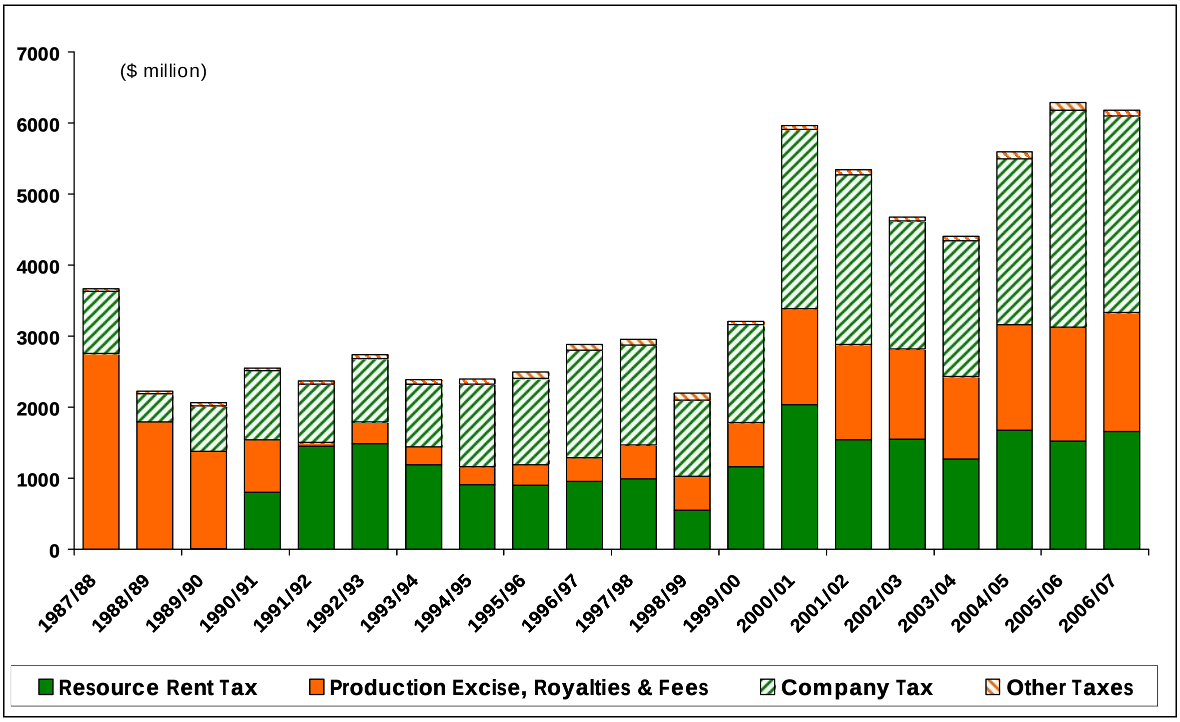
In addition to resource taxes, the industry faces a range of other taxes, fees and charges.

Income (or company) tax is generally levied uniformly across corporate activities at a rate of 30 per cent, with most income being assessable and the majority of costs being deductible. Costs are generally broken into two categories– those that are immediately deductible (such as operating or administrative costs) and those that are depreciated over a defined period or the life of a project (capital costs).

The treatment of capital costs largely accounts for the variable impact of income tax between different business activities in the economy. Costs generally incurred within the non-capital sectors (for example, those associated with the finance, retail or services-related sectors) are generally capable of being deducted relatively quickly, while those that are more capital intensive in nature (for example, within the infrastructure and resource development sectors) are generally deductible over extended periods. Costs that can be immediately deducted will generally have a higher after tax net present value for an investor.

The results of the project modelling undertaken by APPEA indicates that company tax can account for more than 90 per cent of the total taxes paid on an LNG project when measured on a net present value basis (see Table 2).

Chart 5: Estimated Petroleum Industry Taxation Payments



Source: APPEA

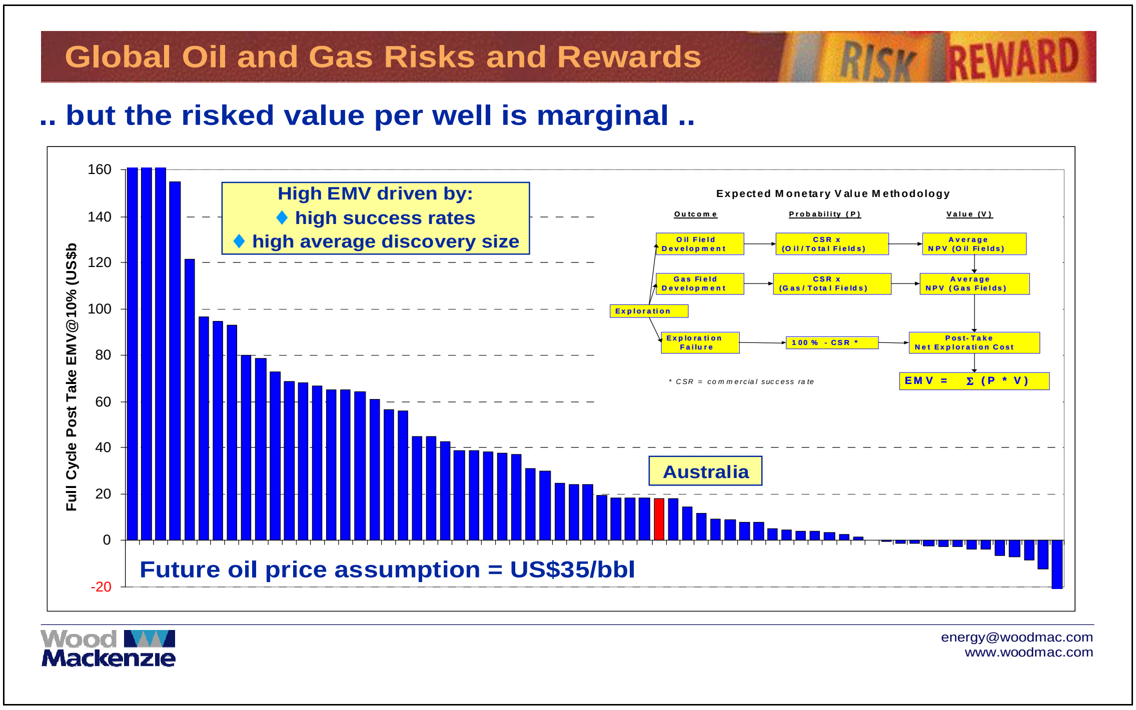
Taxes, charges and fees also apply to a range of transactions and activities in the petroleum industry. Imposts include tariffs on imported equipment, licence fees, stamp duties, fuel excise, regulatory charges and local government rates. Some costs apply at the commencement or construction phase of a project, while others apply during the exploration, development and production phases. Various government initiatives have seen the financial impact of some of these imposts reduced (such as the introduction of the Enhanced Project By-law Scheme and the Fuel Tax Credit system) while others still continue to apply.

1.7 Australia as a Petroleum Exploration Province

There are many factors that influence a company's decision to explore and develop resources, and therefore a country's ability to attract investment funds. A tool used for comparing the relative attractiveness of competing international investment alternatives is the 'Expected Monetary Value' (EMV) analysis. EMV estimates the full risked value of an exploration decision, taking into account not only tax terms, but also the technical and commercial environment, geological prospectivity, and the risks that are applicable to each region.

Exploration companies generally apply this technique in allocating exploration funds. Chart 6, which was prepared by Wood Mackenzie, highlights that Australia ranks relatively poorly compared to competitor nations in terms of overall attractiveness for exploration. This Chart measures (and compares) the approximate value associated with drilling an exploration well in different countries.

Chart 6: Risk Ranking – Expected Monetary Value' of Exploration Decisions



Source: Wood Mackenzie

On a commercial success rate basis, the offshore Australia region ranked 41st globally when compared to other countries. Wood Mackenzie also estimates that offshore Australia's success rate for commercial oil discoveries was around 6 per cent (that is on average one in fifteen exploration wells drilled in the study period resulted in a commercial petroleum discovery in offshore Australia), compared to a global average success rate of

17 per cent. In addition to the generally low success rate, the average commercial discovery size in offshore Australia is also estimated to be small compared to other regions.

To-date, much of the exploration activity undertaken in Australia's offshore region has been in shallow water mature basins, with field recovery sizes generally becoming smaller. The discovery of significant new accumulations will to a large extent be dependent on exploration in new basins (both onshore and offshore), where the risk/reward balance is fundamentally different. The pre-competitive work being undertaken by Geoscience Australia is a good first step, but more needs to be done.

SECTION 2: SPECIFIC COMMENTS

2.1 Upstream Oil and Gas Industry Strategy

Together with government and non-government stakeholders, the industry has undertaken a coordinated initiative that commenced in 2006 with a view to maximising the potential contribution that the upstream oil and gas sector can make to the well-being of Australians and the economy. *"Platform for Prosperity: Australian Upstream Oil and Gas Industry Strategy – Strategic Leaders' Report"* (the Strategic Leaders' Report) was released in April 2007 and followed a period of consultations with many interested parties (see separate attachment for a copy of the report).

A range of targets and options were identified as part of the Strategy, a number of which form the basis of the issues raised in this submission. The key targets jointly agreed are as follows:

In the decade to 2017:

- *Oil and condensate production as a proportion of liquid fuels consumption is, on average, maintained at the 2006 level of 57 per cent or better.*
- *LNG production capacity increases from 20 million tonnes a year in 2008 to at least 50 million tonnes a year.*
- *Natural gas use for industrial purposes and as a competitive feedstock for resources processing doubles.*
- *In a competitive electricity market, 70 per cent of all new electricity generation capacity installed in Australia is gas fired.*

While there are many factors that will dictate the future of the industry in Australia, exploration activity underpins the framework for future production. Long term government support for Geoscience Australia's pre-competitive data program remains vital to creating a healthy exploration framework. Providing long term certainty for the future of the agency assists in building organisational capability and the development of long term plans is essential.

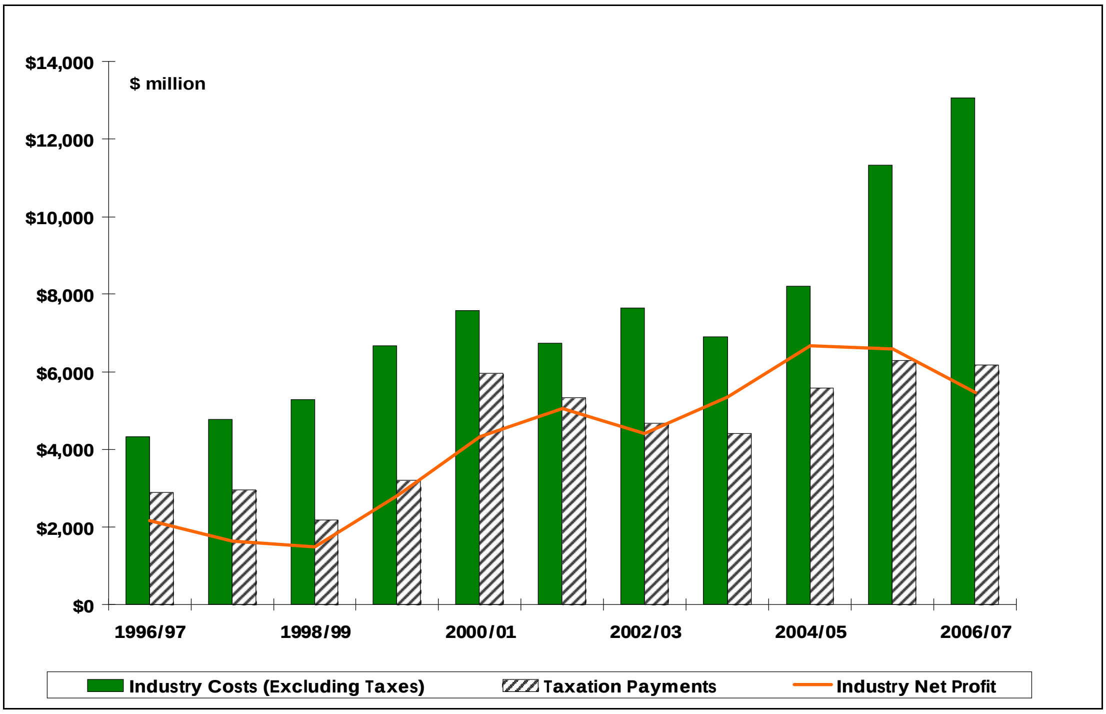
The development of Australia's oil and gas resources generates significant economic benefits. Enhancements to both our regulatory and fiscal parameters are important elements in aiding the development of the nation's petroleum resources. In addition, ensuring that our workforce is capable of meeting both the ever increasing technical and project challenges is also critical. The final details of Australia's response to greenhouse issues will also be important in shaping future investment decisions in the sector.

The oil and gas industry is arguably one of Australia most capital intensive sectors, with tens of billions of dollars of capital needing to spent in the next two decades if frontier exploration is to expand and new oil and gas projects are to be developed. Expansion of Australia's LNG capacity to the industry target of 50 million tonnes per annum will require new capital investment of in excess of $40 billion. Establishing and maintaining an economic framework that is conducive to investments of this magnitude is essential for the industry to deliver the potential economic gains to Australia.

2.2 Industry Performance and Profitability

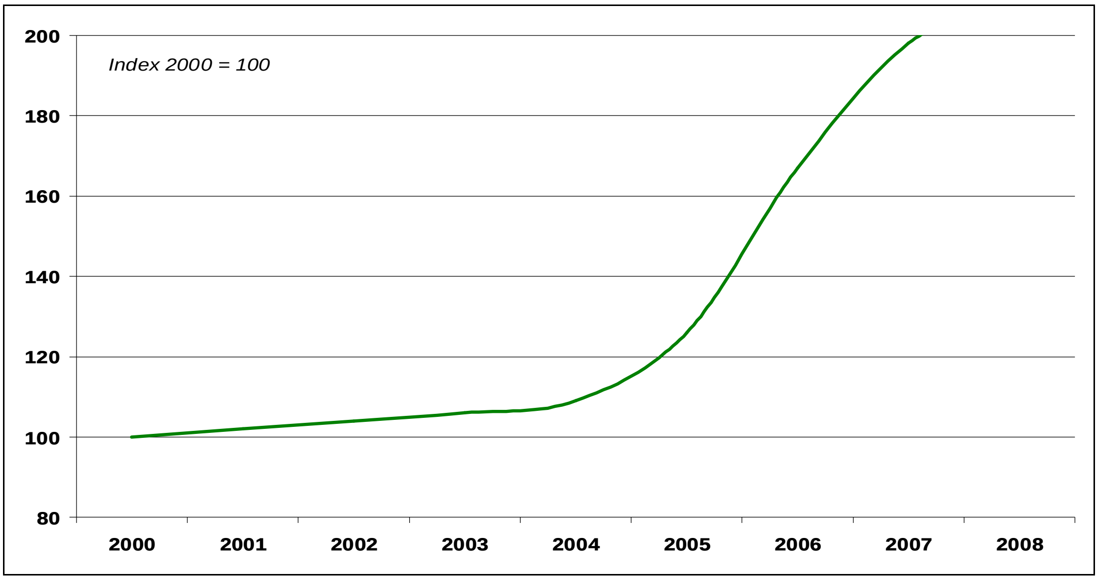
The recent strength in commodity prices has coincided with a period of rapid cost growth in the industry. Annual financial data compiled by APPEA highlights the unprecedented increase in industry costs over the last four years, while industry profits have remained relatively flat (see Chart 7).

Chart 7: Industry Financial Performance



Source: APPEA Financial Survey

Chart 8: Upstream Capital Cost Index



Source: Cambridge Energy Research Associates

The Cambridge Energy Research Associates (CERA) compiles an index of upstream industry capital costs. Dramatic growth has been recorded in the period 2004 to 2007 (see Chart 9). This confirms the trends recorded in the growth in industry costs highlighted in the APPEA data.

There has also been a significant rise in the level of exploration expenditure recorded over the last three years (see Charts 1A and 1B). The growth has been necessary to maintain drilling activity at previous levels. This again confirms the cost challenges confronting the sector.

2.3 An Improved Framework for Exploration

A strong and globally competitive domestic exploration sector is crucial to the long term future of the industry as well as ensuring that the nation remains capable of producing reliable, clean energy and substantial wealth for all Australians. To achieve this objective, it is important that Australia seeks to achieve high level, but realistic exploration targets. The following targets have been agreed by industry and government stakeholders in the Strategic Leaders' Report:

- Increase Australia's share of global exploration expenditure, with increased exploration in both known provinces and onshore and offshore frontier areas.
- Drill at least 40 wells in Australia's offshore frontier basins and 100 wells in onshore frontier basins during the next decade—compared with 12 offshore and 26 onshore frontier wells drilled from 1997 to 2006—in addition to coal-seam methane drilling.
- Double Australia's known 2P (proved plus probable) oil reserves as at 2006 and discover at least one new oil and gas province.
- Expand gas reserves - including coal-seam methane - to reassure the domestic energy market of long-term supply security.
- Become one of the top five most attractive locations globally for oil and gas exploration and development investment.

2.3.1 Fiscal Settings

It has been suggested that higher oil and gas prices and a buoyant LNG market are stimulating increased interest in exploration acreage as well as leading to higher exploration spending commitments in acreage bids (particularly in offshore areas around known petroleum provinces). As highlighted in Section 1, in recent years, the increase in exploration expenditure has not necessarily translated into equivalent rises in actual activity. In reality, much of the recent increase in exploration expenditure is due to increases in costs.

The real challenge is to greatly increase exploration in onshore and offshore frontier areas. At present, it is estimated that only 17 per cent of Australia's offshore sedimentary basins and 26 per cent of potentially prospective onshore basins are covered by petroleum permits, so we simply do not know what resources remain to be discovered.

Offsetting the enormous unexplored potential are Australia's disadvantages in the form of a reputation for relatively low commercial oil prospectivity, extremely high rig mobilisation costs and concerns about approvals processes. These factors need to be recognised and offset by fiscal settings that respond to the additional risks associated with exploring in frontier areas. While the industry is subject to a wide variety of taxes, any measures that are directed towards responding to the challenges of exploring in high risk areas must have the widest application possible.

The designated frontier area PRRT incentive that will cease following the release of offshore acreage in 2008 has generally been of limited impact as it potentially provides a benefit to only a small pool of investors and has a very limited application. Industry believes that a mechanism associated with the company tax system will provide a far greater stimulus – this can be achieved through both an investment allowance for eligible expenditures and a flow through share type mechanism for junior explorers.

2.3.2 Pre-competitive Geoscience

The availability of high quality pre-competitive geoscience research and data is one of the country's competitive strengths. Australia is regarded as a world leader in the collection and provision of this information. This data is invaluable in making a preliminary assessment of the exploration potential of these areas.

However, this effort needs to be maintained and arguably strengthened. APPEA and Geoscience Australia have commissioned a report on the value and importance of pre-competitive geoscience to stimulate exploration in frontier areas. Historically, both the Big New Oil Program (since 2003) and the Energy Initiatives Program (since 2006) have both funded some crucial acquisition and assessment of data from frontier and under-explored basins. This work is still in its infancy and it would be vital to continue this funding until the foreseeable future to ensure that our unexplored hydrocarbon bearing basins are adequately assessed and explored.

There is also a need for a coordinated effort between the states/NT and the Commonwealth in realising the full potential of Australia's undiscovered resources in the onshore geological provinces. The report commissioned by APPEA and GA includes case studies from various offshore and onshore programs and strongly supports the case for increased geoscience funding for geological surveys in all federal, state and territory jurisdictions.

2.3.3 Improved Land Access

There is now over 15 years of experience in undertaking land access negotiations within the *Native Title Act 1993*. Over these years the industry has worked closely with native title parties in negotiating appropriate land access for exploration and development of Australia's oil and gas resources. The industry believes that there are sufficient examples around the nation that could underpin the creation of a template agreement, which would not preclude existing methods of negotiation, but in the interests of efficiency will provide an alternative and efficient approach. This model agreement is not suggested in any way to detract from procedural fairness that the legislation provides through the existing negotiation mechanisms. Instead, it recognises that in many places, the form of documentation in use has become settled, with negotiations between experienced parties resolving commercial terms only.

Such a model agreement will provide an ease of use, reduce expense (legal, administrative and travel), flexibility in managing cultural priorities and a streamlined approach. It is also likely to accelerate exploration and provide an earlier income stream. Additionally, APPEA has previously made representations that native title representative bodes be adequately resourced. This is critical to ensure that these bodies are able to assist in land access negotiations.

2.4 Consistent and Efficient Approvals and Regulation

Australia's oil and gas exploration and production industry is fully supportive of a strong regulatory system that is well enforced. This ensures that the industry has a clear understanding of the requirements it must meet, while giving the public confidence that petroleum producers are adhering to sound, responsible operating practices.

However, the length and complexity of the multi-jurisdictional approvals regime is contributing to an international perception that Australia is a difficult place to invest in oil and gas exploration and development. This is reducing Australia's competitiveness for petroleum investment. This is emphasised in the latest Fraser Institute Survey of Mining Companies 2007-08 in which Western Australia in particular has gone from being consistently ranked in the top 10 jurisdictions, down to being in the middle of the pack. Add to that the significant tightening seen in raising global capital, and it is even more important for Australia to be seen to be open for business if we are to tap our vast resources.

The Strategic Leaders' Report set a target that *"by 2009 governments, in consultation with industry, reform numerous aspects of the approvals and regulatory framework that are significantly increasing project risks and costs and are becoming a major deterrent to timely petroleum exploration and development in Australia."*

The cross-jurisdictional regulatory maze for most oil and gas projects potentially has a much greater impact on smaller companies with fewer resources to dedicate to providing governments with the information they need for the often hundreds of decisions required to be taken. Smaller companies are frequently seeking to access Australia's higher-risk frontier areas and are increasingly choosing to invest their exploration budgets overseas rather than having to wade through Australia's regulatory maze.

As well as improving the efficiency of regulatory and approvals processes, more fundamental reform is required which recognises the unique circumstances of the oil and gas industry in Australia, where a single project can often cross three regulatory jurisdictions. Specifically, APPEA has argued that there is a need for the Australian Government to undertake an extensive review of the regulatory systems for petroleum activities across all jurisdictions (Commonwealth, state and territory), covering the following issues:

- a benchmark of the Australian petroleum regulation system with other provinces (such as the United States, Canada, the United Kingdom, Norway, Indonesia and Brazil);
- ensuring that the Prime Minister's Taskforce Principles for Good Regulation are fully adopted;
- consideration of opportunities for streamlining and removing a number of areas of duplication in petroleum regulation, whilst ensuring that governments are able to continue to regulate industry on the issues that matter to them to provide public assurance; and
- implement clear timeframes for approvals retained under the new system to further reduce the potential delays to projects arising out of regulatory requirements.

At the conclusion of its meeting in March 2008, the Council of Australian Governments (CoAG) agreed that the Productivity Commission would undertake a review on the regulation of crude oil and natural gas projects that involve more than one jurisdiction and report back to COAG by April 2009. The decision by CoAG means that all of the nation's leaders are now committed to clearing away regulatory impediments to investment in new oil and gas projects.

APPEA has warmly welcomed the CoAG announcement as the decision holds real promise of increasing Australia's prosperity through a more cooperative approach to regulation and project approvals. APPEA also strongly supports the Productivity Commission as the most appropriate body to undertake this review based on its independence and track record during past reviews in remaining objective.

With around $100 billion in significant new potential projects currently under consideration, the CoAG decision has the potential to significantly reduce the regulatory burden that will be faced by both industry in seeking to develop these projects and for governments in providing the important community oversight role. The impact of this decision is just as important, if not more so, for APPEA's smaller explorers and producers with fewer resources to navigate their way through between 150 and 500 approvals required over a period that can last up to five years. For a number of years the industry has seen an increasing trend of these small to medium Australian companies spending capital raised in Australia on overseas exploration and projects because it is just too hard to do so in Australia.

APPEA will work with all member companies, regulators and the Productivity Commission to ensure that the Australia takes full advantage of this unique opportunity for significant reform of the regulatory framework and enhance Australia's reputation as an attractive investment destination.

2.5 The Fiscal Framework

2.5.1 Impact of Taxation on Project Decisions

Investment decisions undertaken in the industry, whether they be exploration or development focused, must take into account the full life-cycle impact of the fiscal regime. High priority should be accorded to ensuring taxation settings are consistent with the encouragement of positive investment decisions. Such a focus will assist in increasing Australia's share of global exploration expenditure, facilitate the development of new projects, and extend the productive life of mature developments.

In order for Australia to be an attractive investment destination for petroleum activities, the fiscal regime must be competitive both globally and with competing fuels on a domestic basis. In an environment of rising project costs and a growing and aggressive presence of state-owned oil and gas companies, the incidence and timing of taxation payments takes on additional importance. Modified fiscal terms for petroleum developments can be used to improve project economics – such changes can also act as a catalyst to directly encourage increased exploration. Taxation is an important means by which Australia can compensate for those factors that may be acting to deter investment decisions such as our prospectivity or the geographic isolation of resources. Modifying fiscal terms in a manner that improves development economics will also directly assist both the attractiveness and relative ranking of competing investment options.

APPEA data indicates that taxation accounts for more around a third of the total costs incurred by the industry in Australia. As briefly discussed in section 1.6, the fiscal regime, as it applies to upstream petroleum operations in Australia, broadly operates at three levels:

- **Resource Taxation** – this covers charges such as PRRT, petroleum royalties and crude oil production excise;
- **Income (Company) Tax;** and
- **Taxes on Business Inputs**, covering charges such as tariffs, stamp duties, licence fees and fuel excise.

Decisions undertaken by companies investing in petroleum development projects must, to varying degrees, take into account all of the above charges. While their relative importance will inevitably vary on a case by case basis, APPEA member companies suggest the following relative impact on project economics:

- Income tax – high impact
- Petroleum resource rent tax – medium impact
- Other resource taxes – variable impact depending on the nature and level of the impost
- Other taxes – low to medium impact

The more significant impact of income tax reflects a number of factors, including the profits based nature of PRRT and the stronger emphasis within the income tax system on the concept of accounting based profits. The income tax regime can lead to the early payment of tax which naturally impacts on the economics of high cost, long term projects on a net present value basis. Australia's income tax depreciation regime presents a significant challenge in attempting to commercialise projects. See below.

2.5.2 Recent Taxation Reforms

Changes to the taxation settings, like many other cost or technical factors, may not alone lead to changes in project decisions. However, modified fiscal terms can improve the overall framework and they also represent one of the limited number of financial variables that are within the control of governments. The lower returns, longer lead times and generally higher risks associated with gas projects lend themselves to potentially greater economic improvements through taxation changes.

Since the early 1990s, there have been a number of taxation changes that have affected the upstream petroleum industry. The reforms have to varying degrees had both positive and negative influences on the sector.

Income tax:

- reduction in the company tax rate to 30 per cent — positive
- abolition of accelerated depreciation of five to seven years to one based on the life of plant and equipment — negative
- introduction of statutory caps for certain oil and gas assets in 2002 and an enhancement to the diminishing value rate for depreciation in 2006 — marginally positive
- introduction in 2004 of a foreign resident withholding regime associated with construction contracts entered into with non-residents — marginally negative
- modifications to the loss recoupment (and loss transferability) rules — marginally negative.

Resource taxation:

- introduction of the wider deductibility provisions to the PRRT regime for exploration costs in the early 1990s — positive for PRRT-paying companies with active exploration programs
- reduction in the uplift rate for general project expenditures — negative
- introduction of the designated frontier incentive for eligible frontier acreage — negligible impact
- transferability of exploration expenditure in the assessment of quarterly instalments and a range of technical enhancements — marginally positive.

The impact of the changes has considerably varied across individual projects, although it is arguable that the net result has ranged from marginally negative to slightly positive.

Importantly, the industry considers that on balance, the changes have not materially improved our position relative to competitor nations.

2.5.3 Modified Fiscal Terms for Gas Projects

APPEA believes that changes to the fiscal framework are needed to make it more responsive to the economic factors affecting investment in high cost, long life gas projects and to improve our global competitiveness to attract investment in these types of activities. The industry recommends the introduction a five-year company tax depreciation regime for capital invested in gas projects on the basis that Australia's write-off periods of up to 15 and 20 years for gas projects cannot effectively compete with the five to 10 year periods generally available to similar projects in competing jurisdictions.

As part of the Strategic Leaders' Report, APPEA examined both the taxation contribution made by a single large scale gas project and key corporate taxation settings that apply in competing jurisdictions. To review the underlying project economics of a large-scale gas project and the potential impact of modifying key fiscal parameters, a detailed case study was prepared.

Table 2: Estimated LNG Project Parameters and Sensitivities

	Project NPV $ million	Change from base $ million	Govt Revenue nominal $ million	Income Tax NPV $ million	PRRT NPV $ million	Project Return (%)
Base case	2 799	0	39 593	4 502	527	11.8
Income tax - 5-year depreciation	3 339	540	39 648	3 961	527	12.2
Income tax - 10-year depreciation	3 104	305	39 618	4 196	527	12.0
Base case, 10% capital cost increase	2 042	(757)	32 881	4 506	0	11.2
Base case, 10% reduction in LNG price	1 505	(1 204)	29 009	3 950	0	11.0

Source: APPEA

The underlying assumptions for a 'stand-alone' offshore LNG project were developed by Wood Mackenzie with a view to replicating the costs and revenues that realistically could be expected in the development of such a new project in Australia. The analysis was conducted in consultation with government stakeholders. The results are based on a two train LNG plant, serviced by an offshore platform and producing 10 million tonnes per annum of LNG over a 27 project life.

Simulations were conducted to highlight both the underlying economics of the project and the impact of changes in key fiscal parameters. For simplicity, it was assumed that there were no historical exploration costs (the PRRT results will naturally vary depending on the tax paying status of an individual company) and the project was assumed to be condensate dry (minimal associated liquids).

While a more detailed examination of the results can be obtained from pages 34 and 35 of the Strategic Leaders' Report, key findings can be summarised as follows:

- under the base case, a project internal rate of return of 11.8 per cent was generated (this highlights the margin nature of such projects);
- income and resource taxes account for 64 per cent of the total project returns - as measured by project NPV plus tax payments;

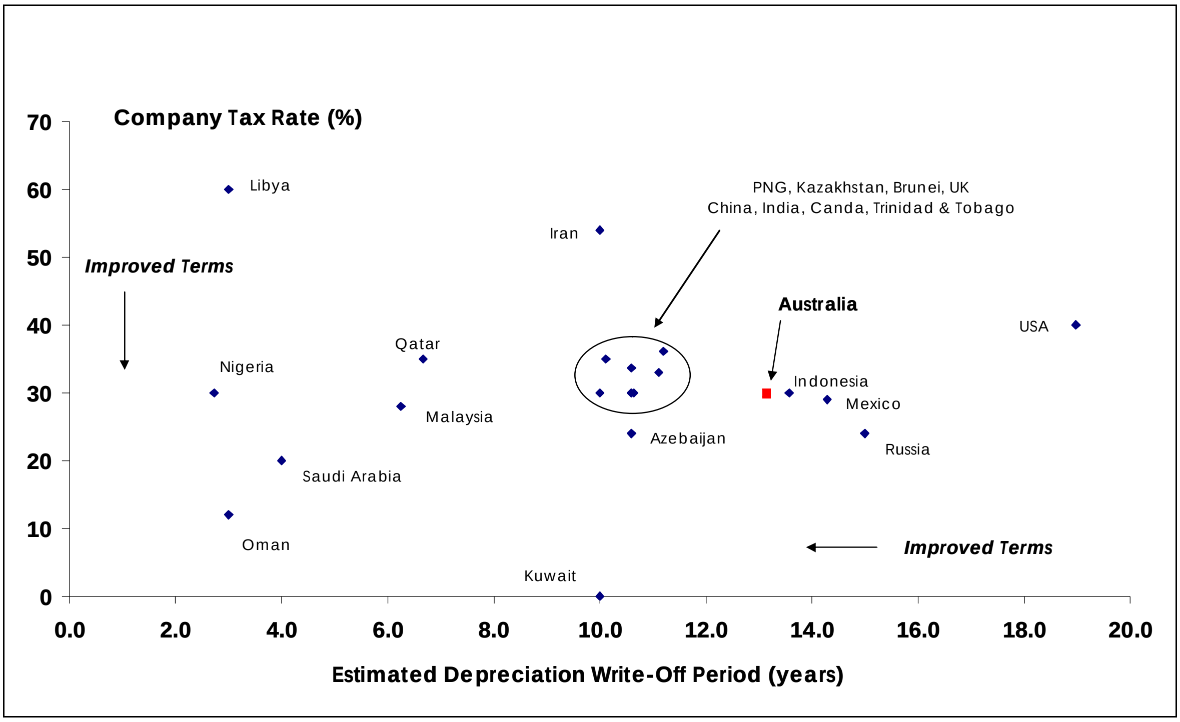
- nearly 90 per cent of the total tax paid is from company income tax; and
- government tax take in undiscounted terms approaches $40 billion over the life of the project (well in excess of $1 billion per annum).

A number of modifications to the fiscal parameters were also modelled, with a five year depreciation life leading to an improvement in project returns. In addition, modifying a number of key project variables can significantly impact the project outcomes. A 10 per cent increase in development costs or a 10 per cent reduction in gas prices were both modelled, with both leading to a significant fall in project performance.

2.5.4 An International Comparison – Company Tax Terms

As part of the Strategic Leaders' Report, a study was undertaken to compare key company tax provisions across a number of jurisdictions. The study covered a diverse range of gas producing jurisdictions. In drawing conclusions about Australia's relative competitive position, it is important to recognise that other taxes, whether they are resource charges or production sharing contracts in nature, will also play an important role. Taxation comparisons with other countries are often based on OECD examples – this is clearly inappropriate for gas based projects where most of Australia's direct competitors (particularly for LNG investments into the Asia-Pacific Region) are non-OECD countries.

Chart 9: Company Tax Rate/Depreciation Comparison – Gas Projects



Source: Strategic Leaders' Report

The depreciation comparison attempts to factor in the special incentives that have been introduced by some countries, including investment allowances or accelerated depreciation, or both, to encourage investment in gas plant and equipment. Chart 9 shows that Australia is clearly not a global leader in income tax terms. While we are around average in relation to the tax rate, we do not perform well in terms of depreciation.

2.6 A National Skills and Vocational Training Plan

The oil and gas industry has identified skills shortages as a major issue that will potentially threaten the long term growth of the sector. Some otherwise economic development opportunities could be lost or deferred, putting at risk the ability of the industry to meet local and export energy demand in a timely manner, thus forgoing significant national benefits.

In particular, the industry faces long-term shortages in the disciplines of petroleum engineering, geoscience and chemical engineering. It is also very short of technical personnel in oil and gas plant process operations and maintenance. In addition, new projects are taking longer to build and/or costing more as a result of the economy-wide shortage of tradespeople.

The Strategic Leaders' Report proposed the development and implementation of a long-term, multi-faceted skills, education and training strategy that takes into account the following elements:

- better understanding of the extent and nature of skills shortages and future trends;
- better resource planning and investment in training;
- improving community understanding of the industry and its attractiveness to potential employees; and
- working with governments to ensure that education and training budgets are directed to the areas of greatest need.

To achieve these outcomes, a variety of options and actions have been identified. For industry, employers will strive to recruit and train the staff required to deliver on their five-year business plans, increase industry information sharing and collaboration about indigenous training and employment programs and develop and implement programs for attracting greater female and indigenous participation in the industry.

As part of its election platform, the Government gave a high priority to the education and training needs of the Australian workforce, and announced a number of important initiatives to implement its vision, including:

- the development of a pilot mentoring program to encourage recently retired tradespeople to pass on their skills and knowledge to young Australians;
- establishing more around 450,000 additional training places over four years;
- creating a Fellowships Program for Australia's top researchers;
- implementing National Priority Scholarships for students in priority areas (including maths, science and engineering); and
- creation of Trades Training Centres within secondary schools.

These commitments will play an important role in addressing the challenges.

2.7 Harnessing the Environmental Benefits of Gas

2.7.1 The Benefits of Gas

Greater use of Australian gas, both domestically and overseas, as envisaged in the Strategic Leaders' Report, could result in the avoidance globally of 180 million tonnes of carbon dioxide equivalent a year by 2017 when compared with a coal alternative. This is equivalent to more than one quarter of Australia's projected greenhouse gas emissions in 2017. The Report pointed to a number of impediments that are constraining the growth of Australia's gas production including energy taxation distortions, subsidies for renewables, and regulations that distort price signals and investment decisions.

Greenhouse policies and programs can have a significant impact on natural gas development. Policies and programs developed around the country by State, Territory and national governments must be consistent and should aim to achieve maximum greenhouse gas abatement at least cost to industry and the community. However, this is not always occurring so the greenhouse benefits of natural gas are not being fully realised.

Unlike nuclear energy and the large scale adoption of renewable energy forms, the technology is available now for gas to be making a much larger contribution to reducing Australia's greenhouse gas emissions at a lower total cost.

One of the most immediate and beneficial greenhouse policies that could be introduced would be to remove subsidies (including preferential fiscal treatment) that produce distortionary effects and perverse outcomes, in relation to energy source decision-making. In particular, Australia has a number of different tax regimes facing the various energy sources, with offshore gas taxed differently (and often more heavily), than competing sources, particularly coal. This implies offshore gas could compete more effectively into domestic power generation on price if it was treated equally from a resource taxation standpoint.

2.7.2 Mandated Renewable Energy Targets

Renewable energy targets do not represent efficient or cost effective greenhouse response policies. Recent analysis, commissioned by APPEA from respected global economic consultants CRA International, found that a renewable energy target introduced alongside an emissions trading scheme is significantly less efficient than a pure emissions trading scheme in achieving a given level of emissions abatement[1].

2.7.3 Key Design Features of an Emissions Permit Trading System

The basic principles for judging 'good' greenhouse policy advocated by APPEA (and as the basis for assessing an emissions trading scheme (ETS), either in isolation or in comparison to possible alternatives) are:
- economic efficiency;
- environmental effectiveness; and
- equity.

The following considers how these principles apply and, importantly, how they can be appropriately 'operationalised' in the context of an ETS, such as the one proposed by the Australian Government's recently released Green Paper[2].

Economic efficiency

- competitive and economic distortions should be minimised through comprehensive sectoral and geographic coverage at a global level and by allowing temporal flexibility in policy design. In particular, distortions between energy sources (particularly those that disadvantage gas) should be removed;
  - as part of this, if comprehensive sectoral and geographic coverage at a global level cannot be achieved – as it the case currently – domestic greenhouse policies should seek to achieve outcomes consistent with those that would be

[1] A copy of the CRA International report, *Implications of a 20 per cent renewable energy target for electricity generation*, is available at www.garnautreview.org.au/CA25734E0016A131/WebObj/D0848328ETSSubmissionSupportingDoc-APPEA/$File/D08%2048328%20ETS%20Submission%20Supporting%20Doc%20-%20APPEA.pdf.
[2] See www.climatechange.gov.au/greenpaper/index.html for further information.

achieved if there were comprehensive sectoral and geographic coverage at a global level. This has important implications for the LNG industry;

- any revenue raised from an ETS should be recycled with a preference for measures that promote economic efficiency and investment in low emissions technology;

- the evolution of greenhouse policy, including an ETS, should depend on what is learned over time about the magnitude and impacts of climate change and be capable of adjustment in line with evolving scientific evidence;

- administrative costs should be minimised by avoidance of complex policy design;

- emissions mitigation and CCS can have equivalent effects on the climate and therefore should be encouraged; and

- greenhouse policy should incorporate both mitigation and adaptation components.

Environmental effectiveness

- a well-defined process is required to ensure that emission abatement is undertaken in all countries, including developing countries, if the aim is to stabilise the concentrations of greenhouse gases in the atmosphere;

- greenhouse policies should recognise the unique nature of natural gas as a low emissions technology source able to provide a significant and immediate greenhouse benefit to Australia and the region; and

- policies should not encourage the leakage of emissions-intensive production to regions with less stringent emission abatement policies.

Equity

- policy settings should avoid net windfall gains accruing to countries or within countries. Efforts should also be made to avoid unintended outcomes; and

- policies should facilitate the application and deployment of best practice and cleaner technologies, particularly gas-related technologies, across countries or sectors within countries.

2.7.4 Treatment of Emissions-Intensive Trade-Exposed Industries

A key issue in the development of an ETS is the treatment of emissions-intensive trade-exposed industries (EITEs).

Australia's LNG industry is in a unique position not only to contribute substantially to the economic development of the nation but also to help minimise the risks posed by global climate change. The vast reserves of natural gas located in close proximity to growing Asian markets make Australia well-placed to positively assist in meeting the global climate change challenge while substantially contributing to Australia's economic growth. It would be unfortunate if, by unnecessarily constraining Australia's LNG industry, the design of ETS were inadvertently to undermine the scheme's ultimate objective of helping the world to reduce emissions.

The industry is concerned that the Government's preferred position on the treatment of EITE industries, as presented in the Green Paper, is fundamentally at odds with the Government's pre-election commitments, including to *"ensure that Australia's international competitiveness is not compromised by Australia's response to climate change"; "ensure that Australian operations of emission intensive trade exposed firms are not disadvantaged by emissions trading";* and to *"consult with industry about the potential impact of emissions trading on their operations to ensure they are not disadvantaged."*[3]

Costs associated with a carbon price that are above those borne by our competitors, combined with the ability of our customer nations to substitute coal for natural gas, have the potential to cause our industry to fall short of its potential. Denying the Asia-Pacific region additional supplies of a cleaner burning fuel would not only lead to carbon leakage – the dominant consideration underpinning the Green Paper's treatment of EITE industries – it would also represent a lost opportunity for Australia to play its optimal role in addressing the global greenhouse gas emission reduction challenge.

Australia's LNG expansion projects face fierce global competition. Australia benefits from stable political and regulatory systems but recent analysis by Cambridge Energy Research Associates shows Australia is the highest cost location for new LNG projects supplying the Asia-Pacific market[4]. It is also the only nation with greenhouse gas emission reduction obligations supplying the Asia-Pacific region.

In summary (and while there may be different ways of achieving this), the industry believes that there is a compelling case for not having the Australian LNG industry bear an additional cost impact for as long as our competitors are not subject to a similar impost.

---

[3] Australian Labor Party (2007) *Labor's Plan for a Strong Resources Sector*: released 22 November 2007, p9, Chapter 8.
[4] CERA (2008), available at www.cera.com.

STIR SCIENCE SERVICES

policy – strategy – evaluation – management

Discovering Australia's Future Petroleum Resources: The strategic geoscience information role of Government

Dr Trevor Powell FTSE *

January 2008

STIR Science Services,
15 Jaeger Circuit Bruce, ACT 2617.
tpowell@actewagl.net.au
ABN 89 468 637 551

* Trevor Powell graduated with a BSc and PhD from the University of Newcastle-upon-Tyne, England. He retired in 2005 as Deputy Chief Executive Officer at Geoscience Australia (GA) where he has also held positions as Chief of Petroleum and Marine Division and Chief of the Onshore Sedimentary and Petroleum Geology. He is currently President of the Australian Geoscience Council and Chairman of the Advisory Board of the NCRIS Integrated Marine Observing System. He began his career with GA (then BMR) as a petroleum geochemist in 1969. He re-joined BMR in 1983 following 10 years with the Geological Survey Canada, Calgary where he was Head of the Petroleum Geology Program. His research interests have been mainly in petroleum geochemistry, petroleum resource assessment and environmental geochemistry. He holds the APPEA Lewis Weeks Gold Medal, a Medal of Merit of the Canadian Society of Petroleum Geologists and is a Fellow of the Australian Academy of Technological Sciences and Engineering.

Contents

Acknowledgements

Support for this study from the Australian Petroleum Production and Exploration Association and Geoscience Australia is gratefully acknowledged. I am also indebted to current and past government survey representatives who provided information and case histories for this study – Elinor Alexander, Clinton Foster, Arthur Morey, Marita Bradshaw and Greg Ambrose. These and members of the APPEA Exploration Committee provided comments on earlier drafts. The views expressed in this paper, however, remain the sole responsibility of the author.

Summary

Australia's production of oil is in steady decline. Given the maturity of the oil producing areas, only the discovery of a significant new oil province can arrest the long term decline in Australian production. Moreover, the increase in demand for clean energy and the location of Australia's major gas reserves means additional gas resources are also desirable. Many sedimentary basins both onshore and offshore are under-explored and are classed as exploration frontiers. Only Australian national, State and Territory governments, acting jointly or severally in partnership with the private sector, can ensure that the petroleum resource endowment of these frontiers is appropriately explored and developed to the benefit of the nation. As a nation, Australia needs to know the extent of this resource endowment.

A major barrier to the exploration of these frontier basins is the absence of sufficient basic geological information to allow exploration investors to make well-informed decisions. Understanding prospectivity is a primary consideration for explorationists, but such assessments are fundamentally dependent upon an infrastructure of geoscience data, concepts and knowledge which provide the framework of successful exploration. The absence of information means high risk and reduces the possibility of investment in exploration in frontier basins. For exploration frontiers the basic geological information collected by State and national geological surveys is fundamental to informed decision-making by exploration companies.

Australia competes with other nations for global exploration investment. Given the sovereign rights to the resource and the importance of oil and gas to the nation's economy and security, provision of pre-competitive geoscience information by government is an effective way of attracting exploration investment to Australia. However, the supply of pre-competitive geoscience data – which includes ready access to pre-existing industry data and information – is a strategic enterprise that must be maintained for many years if it is to serve the needs of the nation and the industry through the long lead and cycle times inherent in the exploration and production cycle. Promotion of successful exploration is dependent on the maintenance of a competitive exploration environment that includes the free flow of relevant information in forms that meet the need of all market players. Australia has excellent examples of strategies and

case histories where provision and promotion of geoscience information has been effective in attracting significant exploration investment.

Introduction

Australia's crude oil production and reserves are declining after 35 years where exports of domestic oil production have substantially offset imports of oil for domestic consumption. A key strategic policy question for the nation, therefore, is whether its assets of crude oil (Fig 1) have been largely discovered or whether there remains an opportunity to discover significant new resources of crude oil in Australia's large areas of relatively unexplored sedimentary basins – so called exploration frontiers (Fig 2). Only efficient and effective exploration of these frontiers is able to answer this key question.

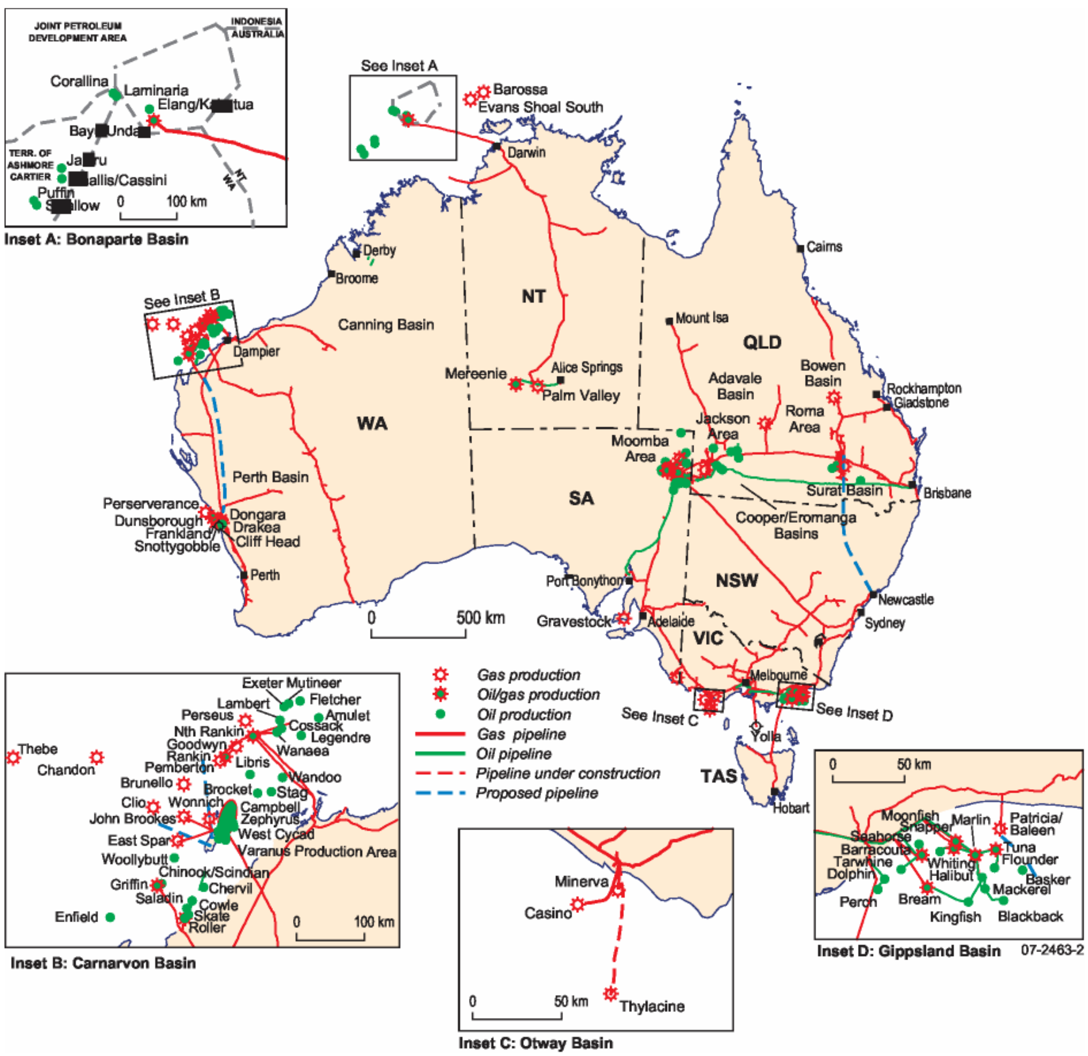


Figure 1 Australia's petroleum producing regions and pipeline infrastructure.

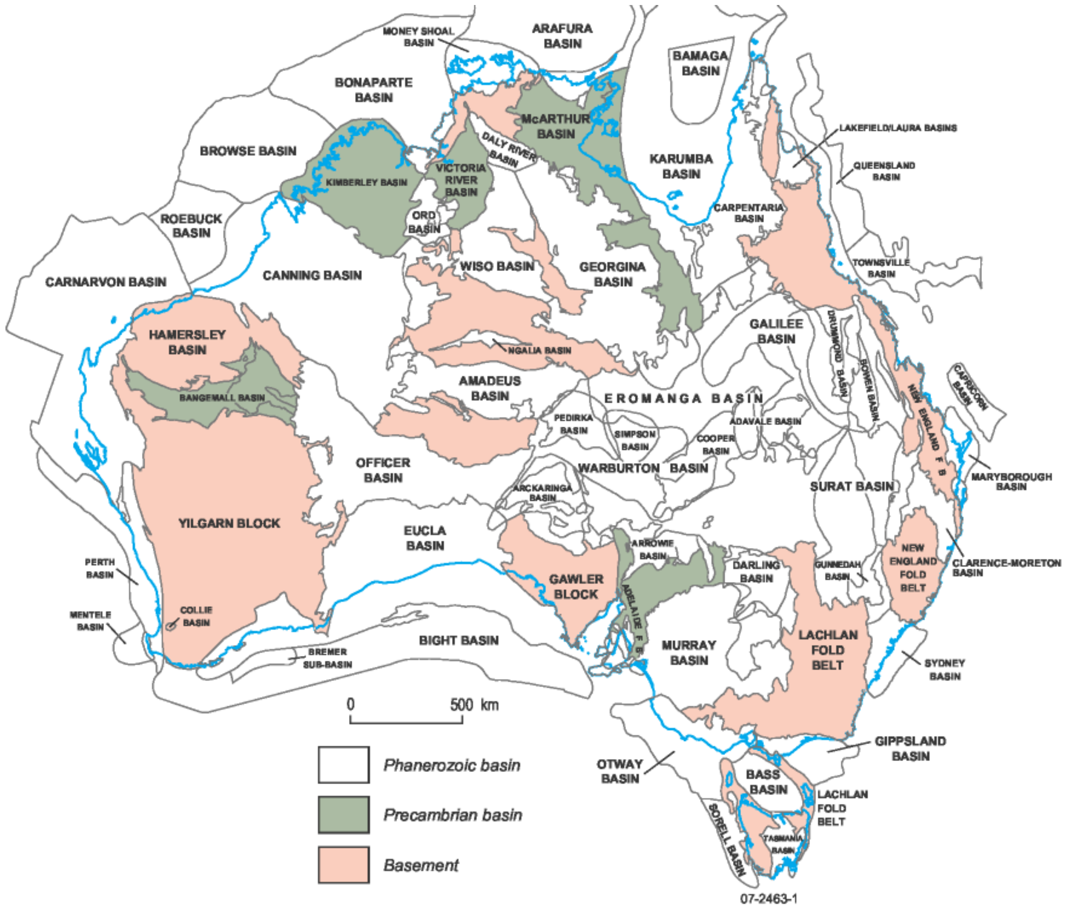


Figure 2 Australia's mainland sedimentary basins

Australia's remaining crude oil reserves peaked in 1995 at 325 gigalitres (2.046 billion barrels) with annual production peaking in 2000 at 35.1 gigalitres (221 million barrels) as the fields discovered in the mid 1990s were brought on stream (Geoscience Australia, 2006). Remaining crude oil reserves declined by 27 per cent to 237.7 gigalitres (1.495 billion barrels) as of 1 January 2005 – the latest figures available (Geoscience Australia, 2006) – but are anticipated to increase to around 260.7 gigalitres (1.64 billion barrels) when more recent discoveries in the Exmouth Sub-basin, offshore Western Australia (Fig 3), are taken into account (M. Bradshaw personal communication). Annual production in crude oil declined to 19.7 gigalitres (124 million barrels) in 2006. Crude oil production has been supplemented by production of condensate from developed gas fields. Production of 7.5 gigalitres (47million barrels) of condensate in 2006 enabled total liquids production to reach 27.2 gigalitres (171 million barrels) - some 35 per cent below the peak in 2000. Although a short-term increase in oil production is expected as the crude oil fields discovered in the Exmouth Sub-basin are brought on-stream (for example, Enfield, Vincent, Stybarrow, Van Gogh and Pyrenees fields), it is not anticipated that oil production will exceed the peak achieved in 2000 before the decline in production resumes at the end of the current decade (Geoscience Australia, 2006).

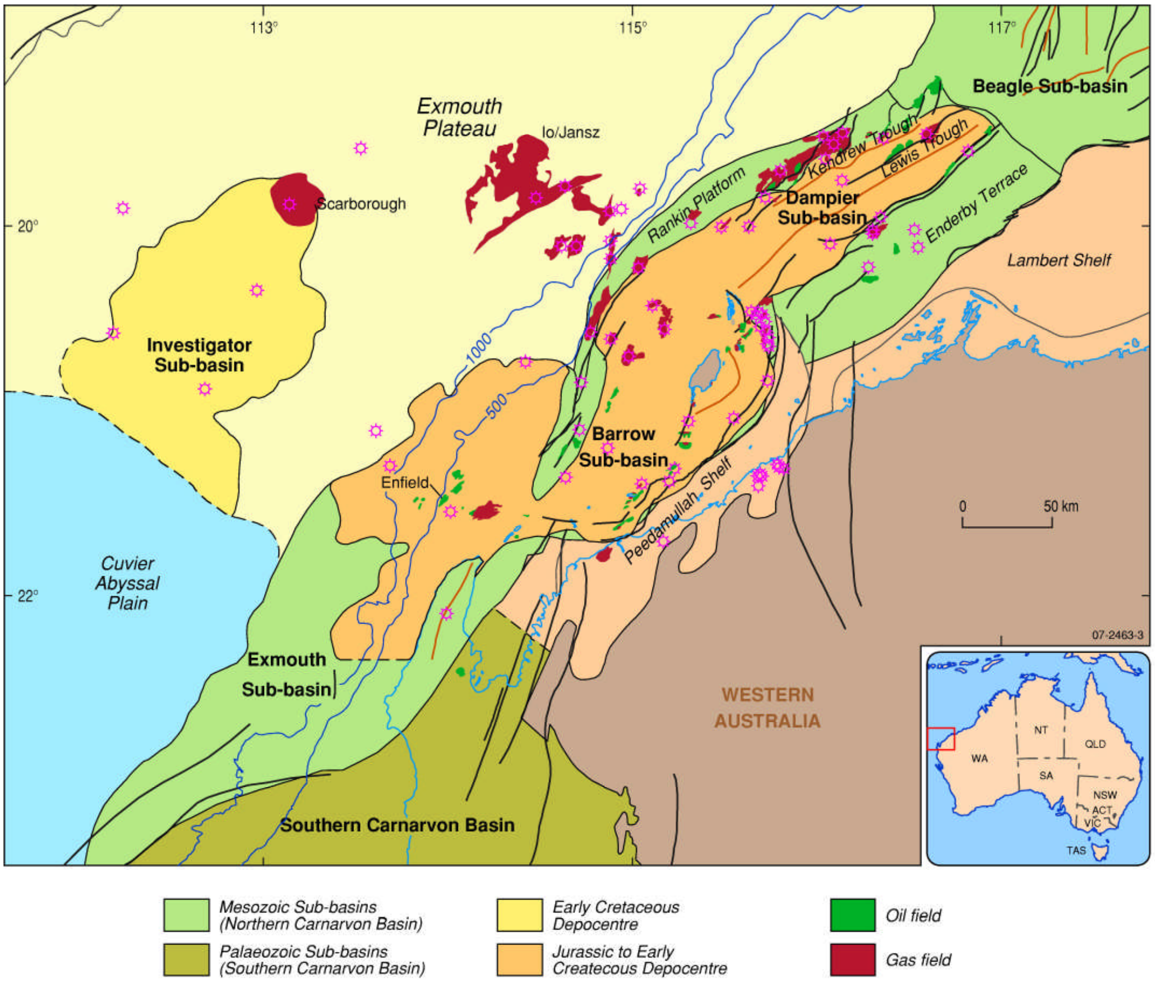


Figure 3 Oil and gas fields in the Northern Carnarvon Basin, north western Australia

Conversely, over the past 15 years Australia's remaining reserves of conventional natural gas have grown significantly as a result of further discoveries in northwestern Australia, with reserves standing at 4.05 trillion cubic metres (143 trillion cubic feet) as of 1 January 2005 with 344 gigalitres (2.165 billion barrels) in associated condensate. Only 19 per cent of gas reserves and 25 per cent of condensate reserves are presently in commercial production. Whilst condensate will continue to contribute significantly to

Australia's oil production over time, its rate of production will be insufficient to compensate for the decline in crude oil production.

The rate of discovery of new crude oil fields over the past decade has been insufficient to replace the oil reserves that have been produced (Fig 4) and the opportunities for major new sources of crude oil in producing areas are increasingly limited (Longley et al, 2001, 2002; Powell, 2001, 2004). If Australia is to maximize the opportunity to maintain production at similar levels to the present day, exploration effort will need to diversify to the frontier basins to locate a new oil province whilst the full potential of the known hydrocarbon basins continue to be explored. Whilst there is no substitute for a frontier discovery to stimulate exploration, there is an important role for Australian governments in facilitating exploration of these frontier areas by undertaking the pre-competitive geoscience work required to demonstrate their petroleum potential. Governments also have an important role in stimulating ongoing exploration by industry of all areas by providing access to exploration data collected by industry and submitted to government under legislation. This role is strongly endorsed by APPEA Strategic Leaders' Report (APPEA, 2007), which identified the need for governments to attract exploration investment by providing ready access to pre-competitive geoscience information and ongoing data acquisition and research.

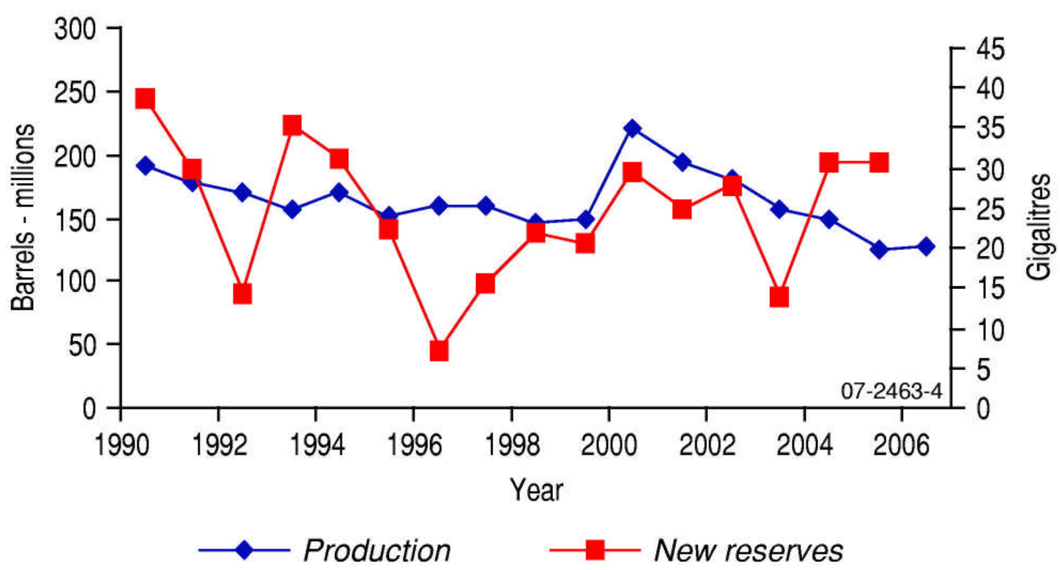


Figure 4 Australia's annual crude oil production and additions to reserves 1990 – 2005.

This paper outlines the rationale for supply of pre-competitive geoscience, information by government to facilitate industry exploration. It considers:

- the status of the discovery of Australia's hydrocarbon resources;
- the importance of and the uncertainty inherent in frontier exploration;
- the role of pre-competitive geoscience information in mitigation of risk and attraction of industry exploration investment; and
- the long term interest and the strategic role of government in ensuring exploration for and development of resources owned by the nation.

It also discusses the features of pre-competitive geoscience information and some typical examples of best practice in information provision.

Australia's hydrocarbon potential and its realisation

Established productive basins

Cumulatively, about 1113 gigalitres (7 billion barrels) of crude oil, 477 gigalitres (3 billion barrels) of condensate and 4.67 trillion cubic metres (165 trillion cubic feet) of natural gas have been found in Australia to 2005 (latest figures available – Geoscience Australia, 2006). Of these, 413 gigalitres (2.6 billion barrels) of crude oil, 334 gigalitres (2.1 billion barrels) of condensate and 2.5 trillion cubic metres (88.3 trillion cubic feet) of gas have been added to reserves since 1990. This includes both new discoveries and growth in reserves in already identified fields.

The discovery of crude oil reserves since 1990 has been consistent with the assessment of Australia's undiscovered hydrocarbon potential at that time. The Bureau of Mineral Resources Geology and Geophysics (BMR - predecessor organization to Geoscience Australia) estimated an additional 159 – 795 (mean expectation 381) gigalitres (1 – 5; mean expectation 2.4 billion barrels) of crude oil could be brought into production within 20-25 years (Powell et al, 1990). Added to the amount of oil already discovered by 1990, this gave a predicted total crude oil discovered in Australia at the end of the assessment period to be 874 – 1494 (mean expectation 1081) gigalitres (5 – 9.4; mean expectation 6.8 billion barrels). This compares favourably with the total of 1113 gigalitres (7 billion barrels) found by 2005. Industry assessments of Australia's crude oil potential at that time were broadly similar (Patterson 1985; Riva 1988)

However the details of the 1990 BMR assessment are not reflected in the exploration outcome. Australia's present hydrocarbon provinces (Fig.1) were all found to be hydrocarbon bearing by 1972. The history of hydrocarbon exploration over the past 35 years has been one of delineating the full potential of these basins. Just three – Gippsland, Carnarvon and Bonaparte Basins (Figs 1) – contain 90 per cent of Australia's crude oil reserves. As overall reserves have declined, the remaining reserves in the Carnarvon Basin have increased substantially – by 50 per cent since 1999 – so that currently the Carnarvon Basin represents two thirds of all Australia's crude oil reserves (Geoscience Australia, 2006). The recent rise in reserves in this basin is primarily due to the discovery of fields in the Exmouth Sub-basin – a deep water part of the Northern Carnarvon Basin (Fig 3) (Longley et al, 2002). This sub-basin was not included in the 1990 BMR undiscovered resource assessment and, at that time, the Bonaparte Basin was considered to have a higher crude oil potential than the Carnarvon Basin. This assessment was strongly influenced by the 1983 Jabiru discovery in the Bonaparte Basin resulting in a surge in exploration and optimism concerning the oil potential of the area now forming the Timor Leste – Australia Joint Petroleum Development Area (Fig. 5). Although substantial crude oil fields (for example – Laminaria) were discovered in the Bonaparte Basin, cumulatively they were not of the magnitude anticipated.

Thus, while the potential of known hydrocarbon provinces was underestimated, none or little of the oil resource potential identified in frontier basins in the 1990 BMR study has yet been realized as little relevant exploration has occurred. The potential of frontier basins remains highly uncertain and it is now understood there are limitations as to the ability of undiscovered resource assessments to predict longer term exploration outcomes (Powell 2001).

The situation for gas is quite different. Of the current national reserves of 4.05 billion cubic metres (143 trillion cubic feet), 3.74 billion cubic metres (132.2 trillion cubic feet) (Geoscience Australia, 2006) is in the Northern Carnarvon, Bonaparte and Browse Basins off northwestern Australia remote from the major population and industrial centres of eastern Australia (Figs 3 and 5). These reserves have lent themselves to large-scale developments for export markets of LNG and domestic use within western and northern Australia. There is now a growing demand for gas in the east, with a substantial part being met by resources of coal seam gas (CSG) from eastern onshore provinces.

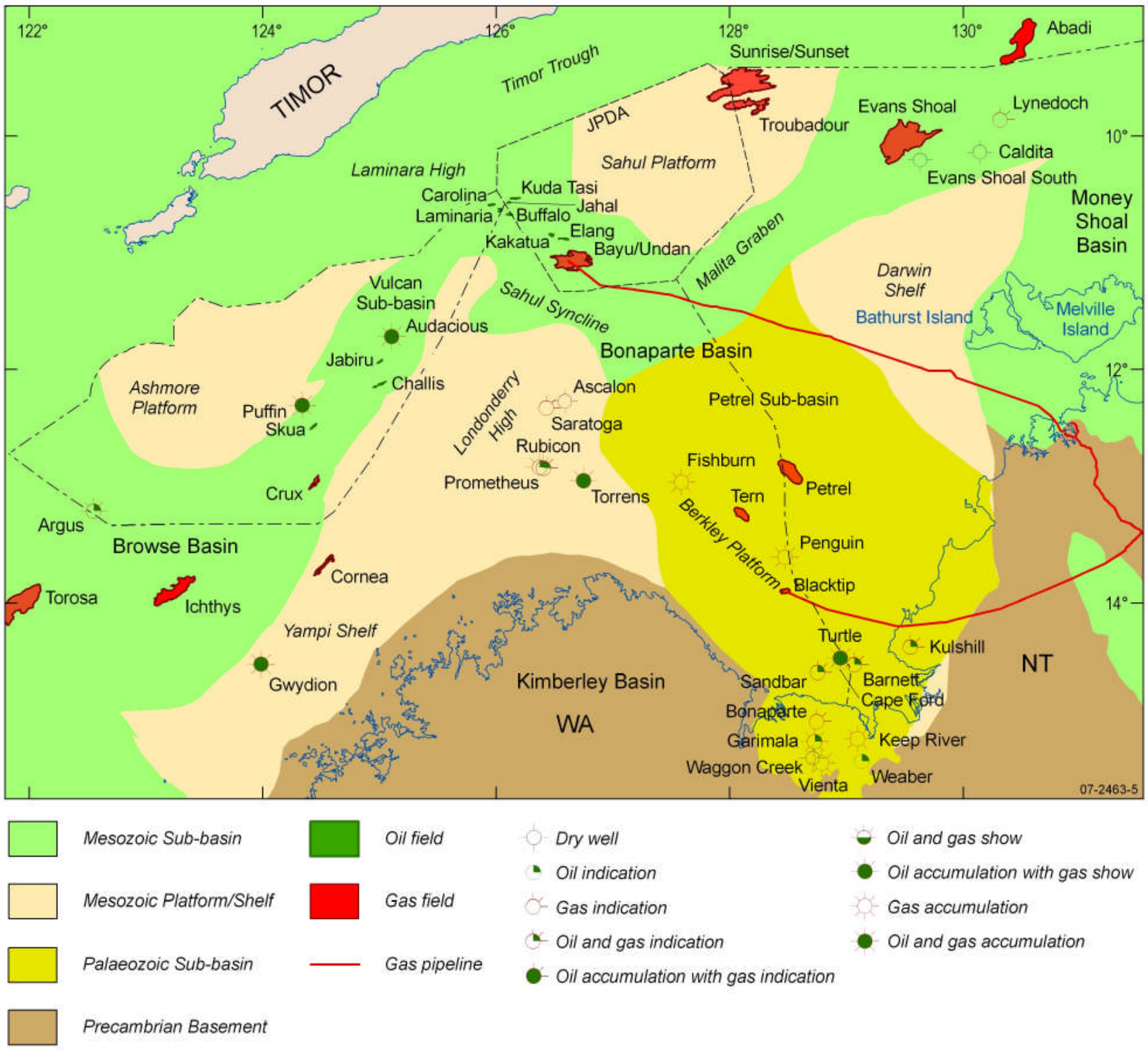


Figure 5 *Oil and gas fields in the Bonaparte and northern Browse Basins, northwestern Australia*

Historically the major suppliers to the eastern gas market have been the Gippsland, Cooper and Bowen Basins (Fig 1). With rapidly diminishing reserves in the Cooper Basin – reserves in 2005 were 44.7 billion cubic metres (1.56 trillion cubic feet) compared with 123 billion cubic metres (4.35 trillion cubic feet) in 2000 – and static but modest conventional reserves in the Bowen Basin (6.8 cubic metres (0.24 trillion cubic feet) (Geoscience Australia, 2006), increasing demand, maturation of contracts and greater pipeline interconnectedness are combining to make additional sources of natural gas desirable for a competitive market to meet future demand in eastern Australia.

The contribution of CSG is growing rapidly in Queensland and exceeded that of conventional gas as a contributor to State's gas production in 2006-2007 with production of 2.28 billion cubic metres (80.5 billion cubic feet) and 2P reserves in excess of 160 billion cubic metres (5.7 trillion cubic feet) (Brain and Randall, in press). In south-east Australia, Gippsland remains a major supplier for the foreseeable future (198.2 billion cubic metres - 7 trillion cubic feet; APPEA, 2007), with additional supplies coming from the Bass and Otway Basins (Fig 1), which held reserves of 14.7 billion cubic metres (0.52 trillion cubic feet) and 49 billion cubic metres (1.73 trillion cubic feet) respectively in 2005 (Geoscience Australia, 2006). Nonetheless, with use of natural gas for power generation potentially increasing in response to concerns regarding emissions of greenhouse gases from coal fired power stations and climatic conditions, the potential for competitive sources of gas in the longer term is apparent.

Role of the frontiers

The exploration of the Exmouth Sub-basin (Fig 3) and the north western margin of Australia more broadly (Longley et al 2002) illustrate an important point concerning the nature of hydrocarbon discovery. Once a new set of geological circumstances (play) with hydrocarbon potential is discovered, within a few years it is rapidly explored and the discovery rate associated with that play then diminishes. For example around 95 gigalitres (600 million barrels) of crude oil reserves were identified in the Exmouth Basin in the period 1998 – 2005, and apart from a potential reserve growth of around 25 per cent, the mean expectation now is that only 11.9 gigalitres (75 million barrels) will be found in the established plays in this sub-basin in the future (Geoscience Australia, 2005) This is referred to as the "creaming effect" or "large fields are found first". Because oil fields occur in clusters, locating the first field focuses exploration activity and makes others in the cluster easier to find. Exploration success may continue to be high but the volume of oil reserves discovered per well generally decreases and the strategic value of the play for new reserves diminishes (Powell, 2004). Reserves only increase substantially where a significant new hydrocarbon play is found. This can be the discovery of a major new play in a producing basin or discovery of a new geographic area or basin with hydrocarbon potential. It is the latter circumstance that has prevailed in Australia with the key basins being the Gippsland Basin (Fig 2); Barrow, Dampier and Exmouth Sub-basins in the Northern Carnarvon Basin (Fig 3) and the Vulcan Sub-basin and Sahul Syncline in the Bonaparte Basin (Fig 5) (Longley et al, 2001, 2002).

Given the maturity of Australia’s oil producing areas, only the discovery of a significant new oil province can arrest the long term decline in Australia’s reserves and production. Whilst crude oil will continue to be found in these mature basins, the impact on national reserves will be modest (e.g. recent discoveries in the Cooper-Eromanga and Perth Basins; Fig 1) although such discoveries will be commercially important for particular companies. These discoveries are not material in the overall national supply picture.

The search for petroleum in frontier basins is a prolonged process and, even when successful, would only impact production rates in 8-15 years from uptake of leases because of the long lead times in establishing new permits, undertaking exploration and establishing any production infrastructure (Powell, 2004). Major new sources of petroleum in Australia are likely to be located through extensions of known provinces into deeper water areas or the discovery of a new petroleum province in a frontier area. Exploration activity has already stepped out into deeper water offshore of the established petroleum provinces in the Carnarvon and Browse Basins (Figs 2 and 4). The recent discoveries in the Exmouth Sub-basin and the extension of the North West Shelf gas province into deeper water attest to the success of this strategy. This success, however, is already factored into Australia’s future petroleum supply.

The key challenge is to determine whether any of Australia’s under-explored sedimentary basins, both onshore and offshore, constitute a new hydrocarbon province. Offshore, these include the southern and southwestern continental margin, the Arafura Sea and parts of the northwestern margin and the remote eastern frontier regions such as the Faust, Capel and Fairway Basins of the Lord Howe Rise and the continental shelf area south of Tasmania, the South Tasman Rise (Figs 6). Onshore, they include the Lower Paleozoic Basins of central Australia (e.g. Canning, Georgina, Warburton and Darling Basins; Fig 2), which have hydrocarbon bearing analogues in North America and Upper Paleozoic and Mesozoic basins with similar attributes to the hydrocarbon-bearing Cooper and Eromanga Basins (e.g. Gunnedah, Pedirka and Simpson Basins Fig 2).

Despite the opportunities for hydrocarbon discovery presented by these vast sedimentary basins, a major barrier to their exploration is the absence of sufficient basic geological information to allow investors to make informed decisions.

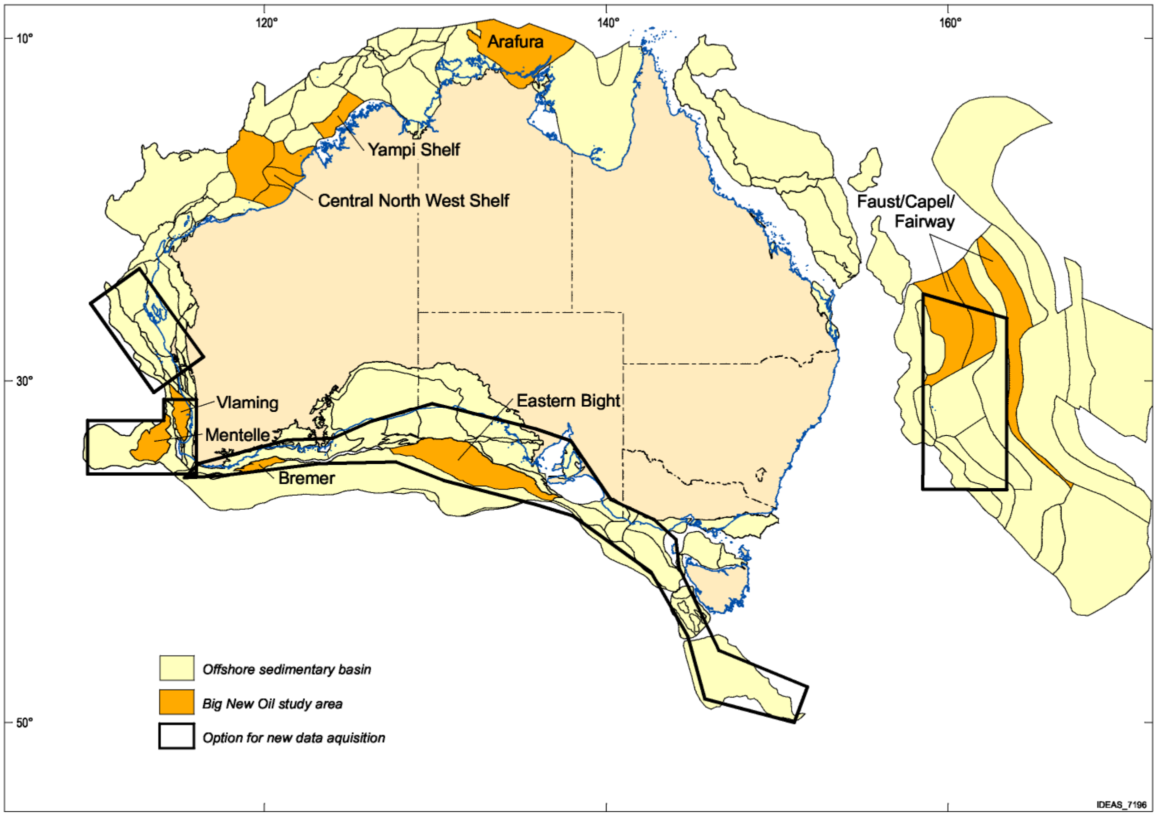


Figure 6 Australia's offshore sedimentary basins showing areas subject to Geoscience Australia's 'Big New Oil Program' (2003-2007) and options for new data acquisition by Geoscience Australia. (Foster, 2006)

Pre-competitive geoscience and its role in petroleum exploration

Petroleum Occurrence and Uncertainty

Petroleum occurs in sedimentary basins, but it is not evenly distributed between basins and many are barren of hydrocarbons. A disproportionate amount of the world's petroleum resources is distributed in relatively few basins. Only in a few basins are there the ideal combination circumstances for the accumulation of large reserves. Of the world's 260 producing basins, the top five (Arabian-Zagros, Middle East; West Siberia , Russia; Gulf of Mexico, Mexico, Volga-Ural, Russia; and Maracaibo, Venezuela) contain 65 per cent of all ultimately recoverable hydrocarbons. Moreover, in any given hydrocarbon basin, most of the reserves are contained in a few major fields. More than 70 per cent of the world's known recoverable petroleum occurs in about 500 giant fields representing less than two per cent of the total number of fields. The bulk of the world's petroleum is derived from a relatively small number of large fields in a few rich provinces.

The same general principles apply in Australia. The Gippsland, Carnarvon and Bonaparte basins accounted for in excess of 90 per cent of all Australia's discovered crude oil reserves, with the Gippsland Basin having had oil reserves more than 15 times larger than those in the Cooper, Eromanga, Bowen, Surat, Amadeus and Canning Basins combined (Fig 1). In the Gippsland Basin, the Kingfish field and the Halibut/Cobia/Fortescue field complex are much larger than other fields in the basin. Similarly in the Eromanga Basin, although the resources are not large in comparison with Gippsland, the Jackson field is much larger than the next largest field.

In Australia there are more than 50 sedimentary basins (Fig 2 and 6) of which 12 are currently oil or gas producing and 4 have currently non-commercial reserves. Many of the basins that could have hydrocarbons have not been drilled to any extent. Establishing a strategy to maximize the opportunity for discovery of a significant new hydrocarbon province amongst these under-explored basins is a critical task.

Little is known about the petroleum geology of poorly explored regions and there are a wide range of possible outcomes. Hydrocarbons in commercial amounts either do not exist or if they do exist they could range in size from very small to very large. In a collection of poorly explored basins there is a chance that one contains a large resource, but it will be uncertain as to which this may be. Paten's (1989) observations are pertinent in this regard. In 1977 at the first Queensland Exploration and Development Symposium, the Surat/Bowen, Cooper, Georgina, Galilee, Adavale and Pedirka Basins (Fig 2) were identified as having prospectivity. Thus the Eromanga Basin (onshore, mainly Queensland) was not widely regarded as having significant petroleum potential, but since that time it has become Australia's largest onshore crude oil producing region. Perceptions of prospectivity are critical. In a country as under-explored as Australia, the results of a single well may significantly change perceptions of the prospectivity. Three cases in point are the discoveries of the Fortescue oil accumulation in the Gippsland Basin in 1978, of the Jabiru oil field in the Bonaparte Basin in 1983, and of the Vincent and Enfield oil accumulations in the Exmouth Sub-basin in 1998-99. These finds significantly upgraded industry perceptions of the oil prospects of these areas and resulted in surges in exploration (Robertson, 1988; Longley et al, 2002)

The uncertainty of the exploration enterprise is illustrated by the search for crude oil in the Bonaparte Basin. Exploration discovered several medium (Petrel and Tern) and large sized gas fields (Sunrise and Troubadour) in different parts of the basin (Fig 5) (Barrett et al, 2004) between 1970 and 1974. Exploration languished in the late 1970s and early 1980s because gas discoveries could not be commercialized. In 1983, BHP Petroleum discovered the Jabiru field in Triassic reservoirs adjacent to a trough containing Jurassic source rocks in the Vulcan Sub-basin and it was originally estimated to contain in excess of 15.9 gigalitres (100 million barrels). This resulted in a surge in exploration interest. However, subsequent development of the Jabiru field was disappointing due to the complexity of the faulting of the trap and the difficulty in seismic imaging of the reservoir. Reserves were then significantly downgraded.

Although a few small oil fields were subsequently discovered in the Vulcan Sub-basin (Fig 5), exploration was generally disappointing. Many residual oil columns were found indicating accumulated hydrocarbons had leaked through faults. Nonetheless the discoveries prompted a search for plays elsewhere in the Bonaparte Basin – where the Jurassic source rock could feed traps which retained their integrity. The Sahul Syncline was identified as another oily sub-basin and the Laminaria Field (15.9 gigalitres -100 million barrels plus) was subsequently identified on the flanks of the Londonderry High. Again, exploration for crude oil in this part of the basin has subsequently been disappointing whilst production from the Jabiru Field has exceeded expectations with cumulative production close to the original reserve estimates and is reflected in the reserves growth shown by the difference between the backdated reserves and the initial reserves (Fig 7).

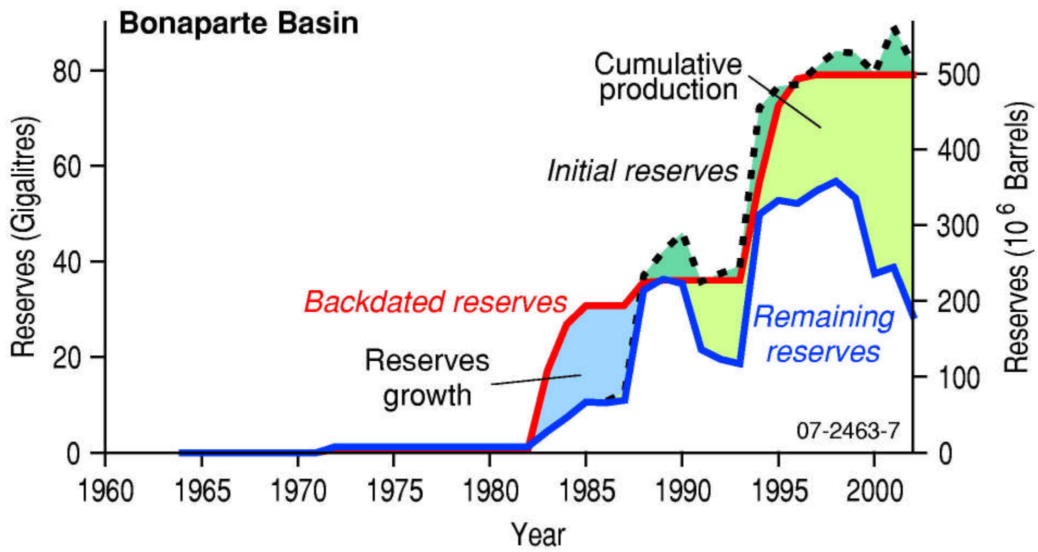


Figure 7 Crude oil reserves through time in the Bonaparte Basin (Powell, 2004). Backdated Reserves are the cumulative reserves backdated to the year of discovery of the host field; Initial Reserves represent the cumulative reserves known to have been discovered at a particular time; Remaining Reserves represents the identified reserves that remain to be produced. A decline in the graph of initial reserves represents re-evaluation downwards of previously recorded reserves.

The risks associated with exploration of the Vulcan Sub-basin have precipitated much research on the factors affecting leakage as well as on the history of oil accumulation and on seismic acquisition and processing parameters (Woods, 2004). This work has resulted in improved understanding of the factors affecting petroleum accumulation and underpins current exploration efforts and development of such fields as Crux, Montara and Talbot.

Expensive exploration ventures may also be inconclusive as exemplified by recent exploration in the Ceduna Sub-basin offshore South Australia (Fig 8). It has an area of 95000 km^2 and contains 15000m of Jurassic to Tertiary sediments, the bulk of which is represented by a Cretaceous delta complex of approximately half the size of the Niger delta. Prior to recent exploration by the Woodside JV (Somerville 2001, Tapley et al, 2005) only six wells had been drilled in this area during the period 1972-1993 in water depths of less than 270m. A non-commercial oil show was encountered in one of these wells. Following an extensive program of seismic acquisition and evaluation, the

Gnarleyknots-1A well was drilled in 1316m water depth and was the first test of the deepwater part of the basin. The most favourable weather conditions for offshore operations in the area occur in the summer months, but – due to delays in preceding work by the deep water drill rig – the well was not spudded until April 2003. The $53 million well was terminated early without penetrating two deep objectives due to deteriorating weather conditions. Excellent quality reservoir sands were penetrated and source rock potential can be inferred from geochemical data. Despite this exploration campaign, considerable uncertainty remains concerning liquids generation capability due to lack of well penetrations. A large number of untested hydrocarbon opportunities remains and the basin remains a significant frontier exploration target.

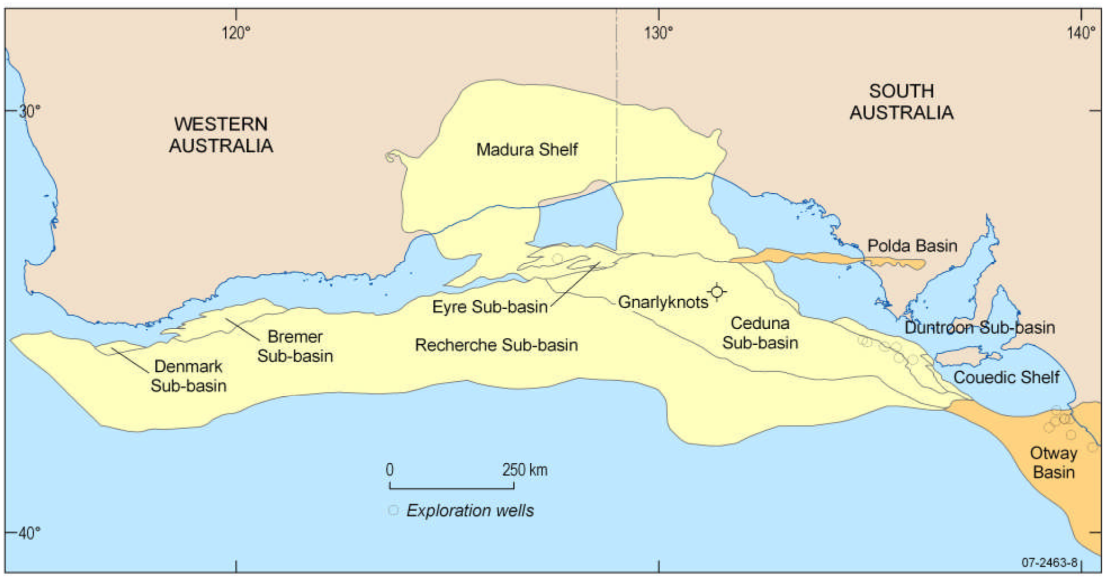


Figure 8 Location of the Bight Basin along Australia's southern margin, with component sub-basins and Gnarleyknots 1A location.

Risk management and pre-competitive geoscience

These examples illustrate the importance of risk management in petroleum exploration. The resources industry differs from many other forms of business enterprise because of the inherent uncertainty as to the outcome of exploration ventures. The petroleum industry is further differentiated by the very high cost of drilling particularly offshore and in deep water where well costs can exceed $50 million. Given historically average success rates of a 1 in 10 chance of discovering a commercial oil pool, the exploration effort represents a large sunk cost. Furthermore, exploration costs are extremely variable depending whether exploration is offshore or onshore and whether in remote or established exploration areas. As a result of this uncertainty, the oil industry has evolved sophisticated quantitative procedures for comparing the risk, potential returns and cost of exploration ventures. A portfolio approach is employed to reduce the overall risk of by diversifying over a number of separate ventures. Management of risk can therefore be regarded as a strategic consideration related to the financial goals of the exploration enterprise itself. Accordingly, a company will maintain a balanced portfolio of ventures that covers all aspects of the risk/reward scenarios commensurate with the objectives of the enterprise, but which does not leave it unnecessarily exposed to high risk. Companies may seek partners to explore a particular region (through farm out) to reduce their exposure to risk. They may also participate in other companies' projects (through farm in) to increase their overall chance of success. As a result, large petroleum companies operate world-wide whilst smaller companies may diversify by not confining their activities to a particular region.

Petroleum investment decisions are made around the world on the basis of geological prospectivity, sovereign risk and fiscal terms. Geological prospectivity is "the number one priority consideration" (Alexander, 2002). Geological risk incorporates all the elements of uncertainty related to prospectivity. It can only be fully assessed by acquiring a detailed scientific understanding of the factors which affect the generation, migration, entrapment and preservation of petroleum in the target area. This process provides the framework for effective exploration since for exploration to occur a company must feel that the reward potential justifies the risk within the framework of its overall strategy.

Successful discovery of petroleum resources clearly requires knowledge of what to look for and where to look. The industry uses publicly available pre-competitive information collected and made available through government geological surveys to select potentially prospective licenses in under-explored areas. An absence of such geological information renders frontier regions unattractive by increasing the risk in exploration. If a country or State wishes to actively develop and maintain its attractiveness for exploration investment, provision of relevant and up to date information on prospectivity is essential (Department of Industry Science and Resources, 1999). To maintain Australia's attractiveness for investment in petroleum exploration it is necessary to convince explorers that although this country is a relatively small producer in a global sense, there is good potential here for commercial discoveries of both oil and gas. Explorers must have easy access to major geoscientific datasets if they are to be convinced to invest in Australia. These include government-generated geoscientific maps and datasets, company reports of previous exploration. and other information defined as pre-competitive geoscience information. These typically could include geophysical surveys and information, geological information and samples, petroleum occurrences, resources, geological features tenement boundaries and basin and petroleum system studies. New geophysical surveys and new basin studies often trigger exploration interest.

Petroleum exploration is iterative – although it is usually possible to identify particular parts of a basin where conditions for petroleum accumulation appear suitable, it is rare for them to be accurately assessed immediately. Earth scientists improve their understanding of petroleum accumulation by successive approximations. Ideas drawn from the available data are eventually tested by the drill and often guided by new technological approaches. Paradoxically, and of vital importance to exploration is the assimilation and assessment of unsuccessful exploration attempts into the general body of knowledge, allowing a new and more accurate idea of where to look next. A recent example of this is the Longtom field in the Gippsland Basin (Lanigan, et al 2007). The Longtom field was discovered in 1995, but was deemed uneconomic by the then operator due to poor reservoir quality and the lack of liquid hydrocarbons. Re-examination of the exploration data and extensive seismic inversion work and well planning by the new operator Nexus Energy Ltd in the period 2002-2006 led to new exploration culminating in the drilling of a production well demonstrating sufficient lateral continuity and productivity in the reservoir to prove up a large gas accumulation. This provides new impetus for exploration in the lowermost strata of the Latrobe Group in the Gippsland Basin.

The demonstrated success of geoscientific concepts and new technological tools in reducing the risk associated with costly exploration ventures underlies the *modus operandi* of the exploration industry. In the early stages of exploration of a province the role of pre-competitive geoscience data is vital. It provides the basic framework for exploration groups to assess the potential for hydrocarbon occurrence both in the initial bidding for exploration rights, through assessment of farm-in opportunities and in attraction of newcomers after initial exploration has been unsuccessful. A discovery also creates the need for access to relevant information since it affects the exploration process: it adds geological knowledge and positive feedback and improves the perception of prospectivity leading to the need for reassessment of information in the light of drilling result to meet the needs of the increased level of interest by the exploration industry. Again, pre-competitive geoscience and information management by government is vital in assimilating the information and concepts and making it available to potential new players in a timely fashion.

Just as increasingly sophisticated exploration techniques and concepts are required to discover fields in different geological circumstances, so pre-competitive surveys and research are needed to develop to meet the needs of the ever increasing sophistication of exploration. Petroleum systems analysis, geochemical characterization of source rocks and crude oil and increasingly sophisticated geophysical and modeling techniques all now play their role in presenting the pre-competitive information to attract exploration investment. If it is to influence the decision making of potential investors on a global scale, such information must be provided in a digital format and in a cost effective and timely manner. Thus provision of pre-competitive geoscience data and ready access to pre-existing industry data and information is a strategic enterprise that must be maintained for many years – to serve the needs of the nation and the industry through the long lead and cycle times inherent in the exploration and production cycle. Promotion of successful exploration is dependent on the maintenance of a competitive exploration environment based upon free flow of relevant information in a readily accessible manner and in a form that meets the needs of all market players.

Government rationale for provision of pre-competitive geoscience information

Property rights to petroleum resources in Australia accrue to the nation through the national, State and Territory governments. Australia has proclaimed a 200-mile Exclusive Economic Zone (EEZ) around the continent and its territories in accordance with the United Nations Convention on the Law of the Sea (UNCLOS). Australia has claimed a further 3.3 million square kilometres of continental shelf beyond the EEZ. If accepted, Australia's full legal continental shelf will be more than one and a half times the size of the continent. It contains many under-explored sedimentary basins (Fig 6). The Australian Government exercises sovereign rights for petroleum exploration and production over this offshore area beyond three nautical miles by conferring exploration and development rights on companies through grants of title under the *Petroleum (Submerged Lands) Act, 1967.* Sovereign rights to the onshore and coastal waters to three nautical miles are controlled by the State and Territory governments.

Petroleum production projects are subject to a resource tax regime, which provides the Australian community with a fair return from the development of the nation's rights to the non-renewable petroleum resources. Because of this the national, State and Territory governments have a direct interest in seeing petroleum resources developed in a manner which optimises their long-term value to the community. Because of the uncertainty associated with petroleum exploration governments allocate a right to companies to explore for and develop resources in return for an economic rent or royalty upon production. Effective exploration and development of resources owned by Australia contribute to energy security and create wealth from the nation's endowment in resources. Governments, acting in the nation's interest, are best placed to evaluate and promote resource potential to maximize the benefits to the community.

Australia derives considerable economic benefit from local oil and gas production. The estimated value of Australian oil and gas production in 2006 was $22.7 billion while tax and royalty payments to the national, State and Territory governments amounted to more than $8.1 billion (APPEA, 2007). In addition to the net economic benefits arising from oil and gas production, Australia also gains a strategic and security benefit from having access to its own supplies of oil. If new, significant discoveries are to be made, frontier basins need to be explored more thoroughly. A new giant oil discovery in one of Australia's frontier basins would encourage major domestic and foreign investment and contribute to net economic benefits. However, there is a considerable lag time from collection of new pre-competitive data to any eventual development and production of petroleum from a new area. Hence expenditure on pre-competitive data acquisition today will typically take a minimum of 10 years to yield a stream of secondary taxation.

A similar policy objective (providing a fair return to the community from the use of its resources) is often pursued in other countries through national oil companies which undertake initial data acquisition and exploration in frontier areas. About 30 of the major producing countries have national oil companies (NOCs**)**. These are state-owned companies that carry out oil and gas activities on behalf of their governments, ranging from pre-competitive geoscience through to production and marketing. The geoscience activities that the Australian governments undertake through budget allocations are, in the case of NOCs, funded by the totality of the petroleum business in which they are engaged. For example, the initial exploration in Brazil's offshore basins was undertaken by Petrobras when it was a National Oil Company with a monopoly in the upstream and downstream petroleum industry in Brazil. This led to the discovery of the offshore Campos Basin in 1977. Today the Campos Basin produces 0.19 gigalitres (1.2 million barrels) per day, representing more than 80 per cent of the total oil produced in Brazil. The discovery of the Campos Basin and its deepwater extension has provided the incentive for other explorers to invest hundreds of millions of dollars in the open bid rounds since 1999, including the privatised Petrobras, now in competition with other international oil companies.

There is, therefore, a national interest in a vibrant and competitive exploration and production industry seeking access to prospective ground. However, companies are also seeking opportunities on behalf of their shareholders on a global basis to maximize the opportunity for exploration success for their investment. Australia is in competition with other countries for this investment. As indicated above, exploration of frontier basins suffers from market failure because there is insufficient information or access to information available to industry to adequately assess the prospectivity and risk of exploration leading to less than optimal, investment. It is therefore in governments' interests to mitigate this market failure by providing information on the basic geology of an area including information from past exploration. Companies can then make informed decisions as to potential within their own risk and reward framework.

Australia has around one per cent of worldwide petroleum reserves, and is estimated to have less than 0.5 per cent of the remaining undiscovered reserves – it was not mentioned in a compilation of potential exploration "hot spots" for oil in the 21st Century (Esser, 2001) As a result, it attracts a commensurately small portion of international exploration expenditure (around one per cent). Australia is a high cost and relatively high technical risk investment destination - and there are geological reasons why this is the case. It has a diverse and complex geology across a whole continent and also has older petroleum systems with a bigger preservation risk for the oil that is formed (risk of loss through seepage or conversion to gas). Australian acreage is regarded as gas prone and it is considered high risk for large oil discoveries. Wood Mackenzie (Latham, 2006) ranked Australia's North West Shelf (NWS) within the top four areas in the world to find gas. According to BHPBilliton, Australia does not rank in the first 50 countries for oil (Bell, 2002). The overall ranking of Australia, that includes all risk elements, referred to by BHPBilliton as "Global Materiality", shows that "Australia… not a place to rush to for oil". In spite of this pessimism, the past 50 years have shown that nationally significant reserves of oil are to be found to the benefit of Australia's economy and security of liquid fuel supply.

Capital for oil exploration is highly mobile. Large multi-nationals have merged to become super-majors and the size of the opportunity required to have a material impact on their balance sheet has increased. Whilst Australia remains highly attractive for gas exploration, larger companies seek exploration targets with higher probabilities of success for large oil reserves than are available in Australia's *producing areas*. Australian companies of all sizes are also diversifying their interests as they are subject to capital allocation discipline in line with their global strategies. Many explorers, including those that once had a strong Australian focus, are being driven by risk/reward assessments that discount factors that previously worked in Australia's favour. In particular, relatively low sovereign risk and regulatory transparency are now not sufficient to attract strong exploration interest in the face of countries which are more geologically prospective for oil.

The challenge for governments is to persuade the exploration industry to risk their exploration budgets in Australia rather than elsewhere in the world. Provision of pre-competitive information has contributed to the way that Australia has done this to date and to the reputation or "branding" Australia has promoted in order to attract explorers. However, increasing investment by other nations in promoting exploration opportunities (rather than letting proximity to discoveries promote themselves) requires still greater efforts to attract attention to Australia's frontier areas. Insufficient information available to the explorers will lead to Australia's failure to compete in this market.

While there is no certainty that industry will take up frontier areas for exploration, given the uncertain nature of prospectivity and risk reward balance, government engagement in pre-competitive geoscience ensures that data is acquired for the larger national good and shared equally between all potential and future explorers. This maximises the ability of government to attract national and international exploration investment. Alternative models such as issuing basin wide prospecting licenses or underwriting speculative surveys by private contractors tends to restrict information access and reduces the number of potential players by imposing substantial costs in prospectivity evaluation before a decision to invest is made. Not undertaking such pre-competitive work ensures that frontier remain unexplored or can introduce long delays and the risk of sub-optimal exploration effort. More importantly the nation cannot properly assess its resource endowment.

The amount of data available in and from Australia is highly regarded by industry and puts Australia in a strong position relative to its competitors (DPIE, 1997). Of all the factors that influence investment decisions, prospectivity is the principal determinant for defining interest. "Although there are other places in the world which may be more prospective than Australia, a key finding of the evaluation is that perceptions of petroleum prospectivity are driven principally by access to data and in this regard Australia has a competitive advantage." (DPIE,1997). This competitive advantage is enhanced where provision of ready access to information is accompanied by appropriate promotion because it forces new venture managers to consider the opportunity which they otherwise may not consider.

Features of pre-competitive geoscience information

The main role of geological surveys at national and State level has been the basic mapping of the continent and its offshore areas to provide fundamental knowledge for exploration and development of national resource assets. This was given impetus by the formation of the Bureau of Mineral Resources, Geology and Geophysics (BMR - a predecessor organization to Geoscience Australia) immediately after World War II when the need for basic geological mapping was recognized as a prerequisite for efficient resource exploration on a national scale. Basic geological mapping has been fundamental to the discovery of the minerals and fossil fuel wealth that underpins Australia's modern economic performance. Indeed much early geophysical exploration for petroleum was carried out by BMR and government polices such as the *Petroleum Search Subsidy Act 1957* underpinned the discovery of many of Australia's current petroleum provinces (Wilkinson 1991).

The geological survey function is basically that of a geoscience information business. Geological surveys undertake this role by conducting field research and surveys, by related laboratory research and by integration of information from university and industry activity into the national knowledge base from which needed information can be extracted as required. It is an important national resource – but it becomes outdated if not renewed as science advances and it does not regularly incorporate new information from industry activities. Australian governments have had a long–standing policy of requiring lodgment of all exploration and production data and its public release after a confidentiality period to encourage further exploration.

The challenge for modern geological surveys is to facilitate petroleum exploration and development in an aggressively competitive national and international market for investment with increasingly sophisticated requirements. This requires surveys to marshal a combination of new data acquisition, original research and synthesis of industry results, provision of access to basic data to meet the needs of a diverse customer base ranging from large multinationals, large independents, small independents and entrepreneurial start-up companies and consultants. Such data and information includes regional syntheses of petroleum basins, basic geophysical, geological and well data, analyses of petroleum systems and specialist studies related to specific influences on petroleum occurrence. This information has to be relevant, packaged, targeted and backed with basic data and made available and readily accessible in standard industry formats at an appropriate stage of the exploration cycle such as release of new acreage. Above all, it requires long term strategic planning, coordination and consultation with stakeholders and with petroleum administrative activities to achieve useful outcomes.

All Australia's jurisdictions (except the Australian Capital Territory) are engaged in this activity to a greater and lesser extent and the strategies and extent of their activities vary. The approach to provision of pre-competitive geoscience onshore differs from the offshore, for sound geological, logistical, financial and jurisdictional reasons. The offshore domain beyond three nautical miles (Fig 6) falls within the jurisdiction of the national government and has young sedimentary basins, which are prospective for large petroleum accumulations. In contrast, onshore basins fall within the jurisdictions of individual States and Territories (Fig 2). They are generally older, often with a complex geological history, and consequently have lower hydrocarbon potential than offshore basins. Many onshore and offshore basins are geographically remote and lack access to infrastructure.

New data acquisition for offshore areas is relatively expensive, but, once a commitment is made, the unit cost per line kilometer of data (e.g. 2D seismic) is relatively low compared with onshore, where the logistics of seismic operations render them very high cost. Alternative onshore geophysical survey options include airborne aeromagnetic surveys and gravity surveys. Offshore access to geological samples is difficult in the absence of petroleum wells. In certain circumstances samples can be obtained by dredging although sample sites cannot be located with any precision. Onshore, outcrops and shallow stratigraphic drilling can provide excellent samples although these tend to be from the margins of sedimentary basins which may not be representative of the deeper parts. Offshore, a variety of remote sensing technologies can be used for detection of seeps. Onshore, given the extensively weathered surface of the Australian land mass, seep detection is much more problematic.

Best practice in provision of pre-competitive geoscience information is illustrated through a series of examples. For the reasons outlined above, the onshore and offshore case histories are separated.

Provision of pre-competitive geoscience – onshore case histories

Overall strategy

There is considerable variation in the way different jurisdictions undertake their pre-competitive geoscience and information management activities particularly as it relates to the administration of petroleum exploration. As discussed previously, this linkage is critical if government geoscience is to be effective in attracting exploration interest. Two types of strategy are typically employed – ongoing geological studies directly linked to the petroleum administration process supplemented from time to time with additional funding for specific objectives such as South Australia, or application of a petroleum initiative with targeted expenditure over a number of years to fundamentally change perceptions of prospectivity. New South Wales is a recent example of this approach.

Petroleum and Geothermal Group, Primary Industry and Resources, South Australia (PIRSA) (Goldstein et al., 2007)

PIRSA's Petroleum and Geothermal Group continues to develop knowledge of prospective South Australian (SA) basins and maintain its reputation as a reliable and accurate source of information. The Group conducts, facilitates and manages research designed to address industry mind sets and knowledge gaps about prospective SA basins. SA basins have been ranked according to its view of their potential for large oil discoveries, and critical uncertainties identified through its knowledge and from industry feedback (via surveys). Examples of prospectivity studies include:

- Eromanga petroleum source rocks in the 1990s to address the paradigm that the underlying Cooper Basin is the sole source of oil;
- Petrophysical studies in the 1980s to develop more accurate oil and gas reserves methodology in the Eromanga, Otway and Cooper basins;
- A study of Cooper Basin gas economics in 1998 showed the minimum economic field size for stand alone gas developments in the lead up to opening the Cooper Basin to new operators;
- a review of the Jacaranda Ridge 1 oil discovery in 2005/6 which formed the basis for the successful acreage release in 2006 and recent gas-condensate discovery in Jacaranda Ridge 2; and
- Officer Basin new insights and new plays

Basin studies are not generally conducted at prospect scale (Jacaranda Ridge was an exception). Instead, work focuses on regional studies, addressing identified "market failures" and working up play trends.

In addition to in-house work, Adelaide University (Australian School of Petroleum – ASP - and the Geology and Geophysics Department) and others are used to conduct research via joint studies with academic staff and students and sponsorship of post-graduate theses. Joint studies with other State departments and Geoscience Australia under the National Geoscience Agreement are also important. PIRSA's significant financial support for the ASP is designed to generate new opportunities in SA and build a critical mass of oil and geothermal industry expertise in Adelaide.

Research results are widely disseminated to industry by papers in technical journals, articles in trade magazines, presentations at conferences, website, digital reports, publications and brochures, displays in promotional booths and via narrated PowerPoint™ presentations on DVD. The main publication providing information on petroleum in South Australia is the free annual *Petroleum and Geothermal in South Australia DVD (PAGSA)*. This comprehensive data-rich product contains GIS information, digital reports (including the PGSA series), statistics, summaries of each basin and information on geothermal exploration. The *Petroleum Geology of SA* (PGSA) series (now included on the PAGSA DVD and as chapter downloads on the website) provides a comprehensive review of the petroleum geology of the State's producing and prospective basins and included the latest research results. Basins featured in this series include the Otway (1995, 2nd edition in 2000); Eromanga (1996, 2nd edition in 2006); Officer (1997) and Cooper Basin (1998). The Bight–Duntroon has been partially published online.

An industry survey is conducted every two years to measure performance and gather information on industry views of SA prospectivity. Views are obtained by a consultant from a range of Australian explorers and consultants on promotional activities, research projects, regulatory issues, publications and data products, service provision and views of basin prospectivity. Results are processed in-house and acted upon by the various policy committees and branches within the Petroleum Group.

"Exploration NSW– Petroleum Program", Geological Survey of New South Wales (NSW Dept of Primary Industries, 2007)

A seven-year Exploration NSW Initiative to promote petroleum exploration commenced in 2000 and comprised the following principal elements:

- Petroleum Systems of the Sedimentary basins of New South Wales – presenting a series of petroleum system events charts of the major sedimentary troughs in

NSW to highlight the favourable and highly prospective elements and processes associated with these lightly explored basins.

- Oaklands Basin: 50 km km reconnaissance survey near Griffith to validate previous magnetic and gravity interpretation and modelling; a Passive Soil Gas Geochemical Survey established the presence of generation of hydrocarbons from the deep Permian - Triassic strata; A Petroleum Data Package reviews the coal seam methane and conventional petroleum prospectivity.
- Sydney-Gunnedah Basin Coal Seam Methane Modelling Project provides a detailed resource assessment.
- Eromanga Basin and Murray Basins; 80,800km^2 of high resolution aeromagnetic coverage; a SEEBASE™ (Structurally Enhanced View of Economic Basement) and structural GIS project was undertaken to investigate the effects of tectonism, basement geology and architecture on basin evolution; a Soil Gas Microseep Survey was undertaken for the Eromanga Basin.
- Darling Basin: Petroleum Package comprising a compilation of geological, geophysical, seismic , well, petrophysical, geochemical and cultural data; two seismic surveys have been conducted In the Wilacannia area to complement the existing 1600km of industry seismic and 20 wells, a SEEBASE™ Project integrating existing gravity, magnetic and seismic data generated depth to basement maps and a tectonic history was developed; a field investigation of Mid to Upper Devonian rocks provided information on reservoir, seal and source potential; two soil geochemical studies were undertaken along existing seismic lines and revealed anomalous amounts of ethane and propane.

Opening up an onshore frontier basin

Just as companies have to consider the various risks involved in selecting areas for petroleum exploration so must government agencies select areas that offer the best chance where new geoscience data or analysis may lead to an understanding of the key geological risks to petroleum occurrence. Consultation with industry at this stage is critical since it is most important that the work being undertaken maximises the opportunity to make a difference. In some cases acquisition of new data is fundamental but in other cases innovative analysis of existing data provides new insights. It is also important to acknowledge that, in some instances, the outcome is not positive. The following illustrates both outcomes:

Officer Basin, South Australia and Western Australia (Carlsen et al. 2003; Goldstein et al. 2007)

The Officer Basin represents one of the last remaining onshore frontier exploration areas where large petroleum discoveries may still be made. It is a large basin straddling the Western Australia (WA) and South Australia (SA) border (Fig. 2). It has close geological affinities with the productive Amadeus Basin in the Northern Territory, and with basins in the former USSR and Oman, both of which host giant oil and gas fields. Numerous oil shows are known in the Officer Basin from mineral and stratigraphic drill holes, although there has been little on-structure drilling for petroleum targets. Excellent reservoir quality and some source potential are proven. In eastern parts of the basin evaporites and salt tectonics are evident and may provide viable trapping and preservation mechanisms.

Exploration of the Officer Basin remained dormant from 1993 to 2003 with very little new data being gathered. In WA, the Geological Survey of Western Australia (GSWA) commenced a program of work to assess the petroleum potential of the western Officer Basin including the drilling of stratigraphic holes in the shallow parts of the basin in the Western Platform. No significant source rocks were encountered and structuring was limited. The similarities between two stratigraphic holes (Empress-1 and Lancer-1) drilled 260 kilometres apart showed that exploration attention would best be directed to the area of salt tectonics along the northeast margin of the basin where sequences and potential source rocks thicken considerably. The response to GSWA activity has been for applications for the areas surrounding GSWA Vines-1 near the SA border and WMC NJD-1 (a mineral exploration hole with a minor oil show) in the western part of the basin in WA (A.J. Morey – personal communication).

In SA, new aeromagnetic data was collected by PIRSA in 2003 and integrated with previous aeromagnetic data (Goldstein et al, 2007). These data were re-interpreted in conjunction with pre-existing seismic data using a modern workstation. A synthesis, including a new exploration play generated by this work, was then published within Australia in 2004 and internationally in 2005. This allowed the entrepreneurs who held an application to explore over the area, including the new play, to generate extra interest by investors and gain the required investment to turn their applications into petroleum exploration licenses (PEL). Canadian explorer Win Energy (through a newly formed affiliate, Officer Basin Exploration) was granted two PELs in the Officer Basin in July 2007. PEL 139 was granted in April 2007 to Dawnpark Holdings and Standard Oil (D&S), the operator of seven PELs in the Officer Basin.

Invigorating partially explored basins onshore - addressing questions of geological risk and prospectivity

Because of the continuity of knowledge and information available to them, it is not uncommon for geological surveys to be able to provide insights in petroleum potential that can reinvigorate exploration concepts in partially explored basins where exploration has faltered. This is the case in the following example:

Otway Basin, South Australia – is there oil in the Otway Basin? (Goldstein et al., 2007)

Uneconomic oil was discovered in several wells in the onshore Otway Basin (Fig 2) in1998, and in Jacaranda Ridge -1 in 1999 where 1950 barrels of oil were recovered. The area surrounding Jacaranda Ridge -1 was relinquished in 2005 at a time of high oil prices and stimulated PIRSA firstly to remap and document the undiscovered resource potential of the Jacaranda Ridge area, and then call for bids for OT2006-A in May 2006. The offer of PEL 255 on the basis of a guaranteed 3D seismic survey plus drilling is a measure of success for PIRSA's research and marketing efforts. In short, demonstrating the plausibility of an economic oil accumulation in the Jacaranda Ridge area may not just enrich the winning bidder, but also may re-vitalise parts of the onshore Otway Basin. All open-file information and an interpretation of the Jacaranda Ridge play are available on request on a free DVD from PIRSA. This includes an innovative approach to assessing the uncertainty of fault seals, which is a risk in the Otway Basin.

Provision of pre-competitive geoscience – offshore case histories

Overall strategy

In 2003 the Australian Government through Geoscience Australia (GA) embarked on a major four-year program of data acquisition to assist the petroleum exploration industry in the search for a new oil province. In 2006 this program was continued and accelerated, as part of the Government's Energy Security Initiative (Foster, 2006), for a further 5 years to support the annual offshore acreage releases. Under these programs, new pre-competitive information is provided at the cost of transfer to explorers so they can better assess investment opportunities in offshore frontier basins.

For the 2003-2007 program, GA developed a portfolio of potential projects (Fig 6) based on integrated programs of seismic acquisition, geological sampling and oil seep detection. Immediate priority areas for new data acquisition were identified in consultation with industry and were the shallow water Arafura Basin and the deep water frontier basins of the South West Margin. Other areas planned for data acquisition include the outer margin of the North West Shelf and the remote eastern frontier basins of the Lord Howe Rise. In the second phase a similar industry consultation process has been used to select deepwater frontier areas (Fig 6) from regions such as the Mentelle Basin, and offshore northern Perth Basin, off southwestern Australia (Fig 1); the Capel, Faust, Fairway, Gower and Moore Basins of the southern Coral Sea and Tasman Sea (Fig 6); and the Sorell Basin/South Tasman Rise region off western Tasmania (Fig 6) as well as possibly more complex basins in shallow waters of western and northern Australia.

Acquisition of new regional 2D seismic data in frontier basins is augmented by reprocessing of previously acquired seismic data, geological sampling and natural hydrocarbon seep detection. Technologies employed to sample and image the water column, seafloor and shallow subsurface, include coring and dredging, sub-bottom profiling swath mapping and side-scan sonar. Remote sensing data – synthetic aperture radar, Landsat and hyperspectral – have been collected to detect evidence of seepage on the sea surface, while the deep subsurface has been imaged with reflection and refraction seismic and gravity and magnetic data. Access to information is being improved by providing workstation ready seismic data packages covering new acreage release areas and by developing online or near online access to seismic data held by the organization. Industry access to seismic data, collected during earlier exploration phases and submitted by industry to government under legislative requirements, has been enhanced by the transcription over 4 years to high density media of a large volume of older seismic survey data. A new data room has been opened at GA to enable Australian and international petroleum companies to scrutinize, under confidential conditions, geological and geophysical datasets supporting the annual release of offshore acreages.

Of critical importance is that the timing of release and promotion of data packages is linked to the annual acreage release process managed by the then Department of Industry, Tourism and Resources and is illustrated by the following examples.

Opening up of an offshore frontier basin

Offshore Bremer Sub-basin - provision of new pre-competitive geoscience coordinated with acreage release and promotion (Geoscience Australia, 2005)

The Bremer Sub-basin (Fig 8) is a frontier area for petroleum exploration, with no wells drilled and, prior to this study, no exploration permits issued. Some seismic data were acquired in the 1970s by industry. The area was included in the 1993 Acreage Release but attracted no bids. GA's study of the Bremer Sub-basin commenced in February 2004 with a geological and geophysical survey, gathering geological samples from 45 sites by dredging a series of submarine canyons which have incised up to 1.5-2.0 km into the shelf margin and acquiring 6500 km of high-resolution swath data that was used to map the sub-marine canyons. In late 2004 a geophysical survey acquired 1300 km of industry-standard seismic data to complement the pre-existing industry seismic data, 2000km of which were re-processed to modern standards. All of this data acquired at a cost of $3.3 million were made available from the GA data repository at the cost of transfer. Geological and geochemical studies, integrated with interpretations from the new seismic data, indicate that the Bremer Sub-basin contains the essential petroleum system elements (source, reservoir and seal) and structures to generate and trap hydrocarbons

In April 2005, the Australian Government released two designated frontier blocks covering the full extent of the Bremer Sub-basin with water depths ranging from 70 – 4000m. The results of GA's study were presented to an explorers' workshop in October 2005. Data sets from the study were accessed by 18 petroleum exploration companies to assess the acreage release blocks. Bids for these blocks closed in April 2006 and two permits (WA-379 and WA 380-P) were awarded to Plectrum Petroleum PLC in August 2006 with an indicative exploration expenditure of $80 million - a 20:1 leverage on GA's investment - including a commitment to acquire 3,300km of new seismic data in year one, and an option to drill two wells in year five. Plectrum has recently been acquired by Capricorn Oil and Gas Ltd, a subsidiary of the Edinburgh-based Cain Energy PLC.

Invigorating partially explored basins offshore- addressing questions of geological risk and prospectivity

Blacktip Gas Field, Petrel Sub-basin offshore Western Australia (Geoscience Australia 2002)

Petroleum exploration drilling in the offshore Petrel Sub-basin (Fig 5) commenced in 1969, and the sub-commercial Petrel and Tern gas fields were discovered in 1969-1971. Oil (including gas) was first discovered at Turtle-1 and Barnett-1 in 1984-5, and was subsequently confirmed with significant oil and gas flows at Turtle-2 and Barnett-2 in 1989. Despite the early exploration success in the sub-basin, continued exploration failed to discover commercial quantities of gas, and no significant indications of oil.

In 1994-96 GA undertook an industry-sponsored study to analyse the paleogeographic controls on the petroleum systems in the Petrel Sub-basin and GA also undertook a major study to investigate the structural and stratigraphic evolution of the sub-basin, as well as an assessment of the petroleum systems active in the sub-basin. Collectively these studies identified three active petroleum systems in the sub-basin, including a newly recognised gas and possible oil-prone system sourced from Lower Permian strata, and suggested that exploration drilling had not adequately tested the petroleum potential of the region. The results of these studies were published as a series of scientific reports, journal papers and packages which were acquired by more than 30 exploration companies.

The results were used to promote additional offshore permit releases in 1997, 1998 and 2000. Subsequently Woodside was awarded Permits WA-279-P and WA-280-P in August 1998, and NT/P57 in January 1999, with a total exploration program valued at $82.6 million. In August 2001 Woodside discovered gas in multiple Lower Permian reservoirs at Blacktip-1. The Blacktip structure has estimated recoverable reserves of 1 trillion cubic feet (TCF). In September 2001 Woodside was awarded a further permit in the basin (WA-313-P, adjacent to the Blacktip-1 permit), with a total exploration program of $12.6 million. GA's research studies in the Petrel Sub-basin had greatly contributed to Woodside's initial interest in the area leading to their subsequent exploration program and discovery at Blacktip -1. Woodside have subsequently sold their interests in this area to ENI Australia Ltd.

Promotion – maintaining interest in Australian exploration opportunities

To maintain Australia's attractiveness for investment in petroleum exploration it is necessary to convince potential explorers that, although the country is a relatively small producer in a global sense, there is good potential here for commercial discoveries of both oil and gas. Promotion is both strategic and tactical. At the strategic level it is important to establish long term relationships and to persist over time. Targets include "supermajors" (e.g. ExxonMobil, ChevronTexaco) through to the single entrepreneurs. In the 10 year period to 2002, 154 companies either commenced or recommenced exploration in Australia, but over the same period 163 companies left. The external perceptions of Australia's exploration potential need to be understood so that negative views can be examined and corrected.

An example of a strategic approach is GA's long-standing relationship with Japanese exploration companies. In the early 1990s, GA began systematically marketing petroleum exploration opportunities to the Japan National Oil Company and associated private companies (Geoscience Australia, 2002). With the uptake of new leases, Japanese exploration investment in Australia gradually increased and represented the largest source of new exploration funds in the period 1996 – 2000. INPEX has been particularly successful and has discovered a gas-condensate resource off northwest Australia in the Ichthys Field in the Browse Basin representing about 10 per cent of Australia's currently defined reserves of gas-condensate. GA's study and promotion of the Browse Basin, backed with access to seismic data sets, was instrumental in attracting INPEX's interest there (Williamson and Foster, 2003). Whilst there are many factors involved in investment decisions, development of a long term promotion based on freely available data is one of the most effective ways to facilitate industry consideration of Australian exploration opportunities.

From a tactical perspective, the challenge is to get the relevant geoscience information in front of the exploration decision-makers in a relevant and timely manner. It is important to understand as far as possible the exploration strategies of companies. Potential field sizes, cost structures and portfolio balance are all key considerations which vary with company size and exploration strategy. It must be remembered that prior to the acquisition of an exploration lease, companies are unable to internalize the benefit of any work carried out in evaluation and the decision-making period is often time constrained. Appropriate data-based promotion at the right time in company decision making can be important in facilitating a company's decision to invest. An example is the promotion of the Bight Basin (Fig 8) (Geoscience Australia, 2002).

In 1998, GA initiated the Southern Margin Frontiers Project by first consulting widely with industry regarding scope and content of the study.

- In late 1998 to early 1999 GA acquired 8500 km of new seismic data in partnership with a seismic contractor, which provided the basis for GA's study.

- In early 1999 several research projects and joint ventures with universities, contractors and government agencies commenced to study aspects of the petroleum prospectivity of the area and the results communicated to a range of companies:

    - In early 1999, 11 exploration areas in the Great Australian Bight were released for bidding and GA presented initial results to an industry workshop attended by representatives of 16 international and Australian exploration companies.

    - In mid 1999, an acreage release promotional tour to Japan, the UK, Canada and the USA.

    - In late 1999 a study group comprised of Woodside Energy and PanCanadian Petroleum (now EnCana) acquired 5314 km of seismic data obtained by the GA/Seismic Australia joint venture. Smaller amounts of seismic data were purchased by other companies.

- In December 1999 GA presented its latest results and ideas to an industry workshop with representatives from nine exploration companies and representative of consulting/contracting companies.

- In April 2000 Anadarko joined the Woodside-led study group and purchased a license for the joint venture seismic data.

- In 2000 three new exploration permits (EPP 28 to 30) in the Great Australian Bight were awarded to a consortium of Woodside Energy, Anadarko Australia and PanCanadian Petroleum. The expected investment by the consortium was $88.8 million over 6 years.

In this case, the underwriting of the data acquisition was shared between government and the private sector and allowed a larger volume of data to be collected than would have been possible otherwise with the government funds available. Although the program met its primary objectives, in practice there are significant issues stemming from joint private/public underwriting and ownership of data. There is an inherent conflict between the aims of the contractor partner to maximize returns from sales and the objective of government to maximize exposure of the opportunity to the international oil industry in an environment of lack of information regarding prospectivity and market failure. There is also an obligation of government to make data collected by public funds readily available to interested parties who do not have the resources of the petroleum industry – for instance for research and other marine management purposes. Although joint underwriting can be a viable model in certain circumstances, in general, full government funding of data acquisition in frontier areas is required if the objective of attracting exploration investment is to be achieved.

Promotion of Australia's petroleum exploration opportunities overseas is best carried out in a coordinated manner. Since 1997 a "Team Australia approach" has been adopted for the annual conference of the American Association of Petroleum Geologists where GA coordinates a single large booth on behalf of the Australian, States and Northern Territory Governments. Within the booth each jurisdiction refers explorers to the relevant centres of infomation and expertise depending on their interest. Maintenance of a team approach whilst allowing individual jurisdictions to distinguish their own offerings remains particularly effective in getting the message across in the internationally competitive market for exploration investment.

Conclusions

Evaluation, promotion, exploration and development of Australia's petroleum potential is a long term strategic enterprise. It is now clear that new oil provinces must be found to sustain Australia's crude oil production. Therefore, exploration must be encouraged in frontier areas. It is essential that all Australian governments coordinate and renew their efforts to ensure that the information base and operating environment are in place to attract the necessary private sector exploration investment from the global market to these regions. Only the national, State and Territory governments can provide the basic pre-competitive geoscience information necessary to mitigate the high risk of exploration of the frontiers. This will not only facilitate discovery of petroleum resources owned by the nation and investment decision making by such companies, but also will improve Australia's attractiveness as an investment destination over countries where such data is not as readily available. As the Browse, Bight, Blacktip and Bremer examples outlined above illustrate,, investment by government in pre-competitive geoscience can result in significant exploration investment and can result in significant discoveries (Ichthys and Blacktip Fields). While this competitive advantage has been demonstrated in the past, it is important to appreciate that this information must be provided in a form compatible with industry business practices and decision making to be most effective. Active promotion of data and responsiveness to industry requests is fundamental to success. While some government organizations have performed this role — and some continue to so — it must be further developed and sustained by all jurisdictions if the opportunity to discover new oil provinces and thereby sustain Australia's oil production is to be maximised. The absence of such information will lead to less than optimal investment.

References

ALEXANDER, F.C. AND JONES, B. 2002- A Proposal for Annotated Upstream Petroleum Regime Model Form Provisions, Organisation of American States' SLA/OAS-CIDA Project White Paper. February 26th 2002, p11.

APPEA, 2007- *Platform for Prosperity, Australian Upstream Oil and Gas Industry Strategy*, Australian Petroleum Production and Exploration Association, Canberra 86p.

BARRETT, A.G., HINDE, A.L. AND KENNARD, J.M., 2004 – Undiscovered resource assessment methodologies and application to the Bonaparte Basin. In: Ellis, G.K., Baillie, P.W. and Munson, T.J. (eds). Petroleum Geoscience: Proceedings of the Timor Sea Symposium, Darwin Northern Territory, 19-20 June 2003. Northern Territory Geological Survey Special Publication 1. 353-372.

BELL, S.R., 2002 – Seeking diversity in exploration. APPEA Journal 42 (2), 40-45.

BRAIN, T. AND RANDELL, R. In press – Queensland's booming coal seam gas industry. Proc. APPEA Conference 2008,

CARLSEN,G.M., SIMEONOVIC, A.P. AND APAK, S.H. 2003 – Petroleum systems and exploration potential of the officer Basin, Western Australia. APPEA Journal, 43 (1) 473-494.

DEPARTMENT OF INDUSTRY, SCIENCE AND RESOURCES, 1999 - Australian Offshore Petroleum Strategy - a strategy to promote petroleum exploration and development in Australian offshore areas. Department of Industry, Science and Resources April 1999.

DPIE, 1997 - Department of Primary Industries and Energy Portfolio Evaluation of the Role of the Commonwealth in Offshore Petroleum Exploration and Development, October 1997, 2.

ESSER, 2001 - Discoveries of the 1990's: Were they significant? In Petroleum provinces of the Twenty First Century, eds Downey, M.W., Threet, J.C. and Morgan W.A. AAPG Memoir 74, 35-43.

FOSTER, C., 2006 - Extra $75m for offshore work – Energy Security Initiative boosts exploration. AusGeo News, 84. www.ga.gov.au/ausgeonews200612/offshore.jsp

GEOSCIENCE AUSTRALIA, 2002 – Submission to the House of Representatives Standing Committee Inquiry into Resources Exploration Impediments

GEOSCIENCE AUSTRALIA, 2005 – Bremer Sub-basin, Bight Basin. www.ga..gov.au/oceans/_Bremer.jsp

GEOSCIENCE AUSTRALIA, 2006 - *Oil and Gas Resources of Australia 2004*. Geoscience Australia, Canberra.

GOLDSTEIN, B.A., ALEXANDER, E., COCKSHELL, D., MALAVAZOS. M AND ZABWARNY,J., 2007 – The virtuous life cycle for exploration and production – lead and lag factors. APPEA Journal 47 pt 1, 363-377.

LANIGAN, K.P., BUNN, G. AND RINSCHWENTNER, J., 2007 – Longtom – Confirmation of a new play in offshore Gippsland. APPEA Journal 47 (1) 89–104.

LATHAM, A., 2006 – Exploration strategy and performance – Australia in a global context. APPEA Journal (2) 41-46.

LONGLEY, I.M., BUESSENSCHUETT, C., CLYDSDALE, L., CUBITT, C.J., DAVIS, R.C., JOHNSON, M.K., MARSHALL, N.M., MURRAY, A.P., SOMERVILLE, R., SPRY, T.B. AND THOMPSON, N.B., 2002—The North West Shelf of Australia—A Woodside perspective. In: Keep, M. and Moss, S.J. (eds) The sedimentary basins of Western Australia 3, Proceedings, PESA Symposium Perth WA, 27–88.

LONGLEY, I.M., BRADSHAW, M.T. AND HEBBERGER, J. 2001 - Australian petroleum provinces of the twenty first century. eds Downey, M.W., Threet, J.C. and Morgan W.A. AAPG Memoir 74, 287- 317.

NSW DEPARTMENT OF PRIMARY INDUSTRIES, 2007- www.dpi.nsw.gov.au/minerals/initiatives/exploration/Petroleum_prog.

PATTERSON, J.C., 1985 – International petroleum investment – Why Australia? The APPEA Journal, 25(1), 7-14.

POWELL, T.G., 2001 – Understanding Australia's petroleum resources, future production trends and the role of the frontiers. APPEA Journal 41 (1) 273-287.

POWELL, T.G., 2004 – Australia's hydrocarbon provinces – where will future production come from? The APPEA Journal 44 (1) 729-39.

POWELL, T.G., WRIGHT, D.J.AND NICHOLAS, E., 1990 – Petroleum Exploration and Development in Australia – A BMR Discussion Paper, Bureau of Mineral Resources Geology and Geophysics Record 1990/32 83p.

RIVA, J.P., 1988 – oil distribution and production potential. Oil and Gas Journal, 86(3), 58-61.

SOMERVILLE, R. 2001 – The Ceduna Sub-basin – A snapshot of prospectivity. APPEA Journal 41 (1) 321- 346

TAPLEY, D., MEE, B.C., KING, S.J. DAVIS, R.C. AND LEISCHNER, K.R. 2005 – Petroleum potential of the Ceduna sub-basin: impact of Gnarlyknots. APPEA Journal. 45(1) 365-380.

WILKINSON, R. 1991 - Where God Never Trod – Australia's oil explorers across two centuries. David Ell Press Pty Ltd, NSW, 482 p.

WILLIAMSON P. E. AND FOSTER, C.B. , 2003 – Access to Australian exploration and production data: a critical factor in attracting investment. The APPEA Journal, 43 (1), 693-704

WOODS, E.P., 2004 – Twenty years of Vulcan Sub-basin exploration since Jabiru - what lessons have been learnt? In: Ellis, G.K., Baillie, P.W. and Munson, T.J. (eds). Petroleum Geoscience: Proceedings of the Timor Sea Symposium, Darwin Northern Territory, 19-20 June 2003. Northern Territory Geological Survey Special Publication 1. 83-98.