AUSTRALIAN PETROLEUM PRODUCTION & EXPLORATION ASSOCIATION LIMITED

19 September 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 6247 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 3220 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 9321 9778

INTERNET
www.appea.com.au

EMAIL
appea@appea.com.au

Mr Philip Weickhardt
Commissioner
Productivity Commission
Locked Bag 2
Collins Street East
Melbourne VIC 8003

Dear Commissioner Weickhardt,

REVIEW OF REGULATORY BURDEN ON THE UPSTREAM PETROLEUM (OIL AND GAS) SECTOR

The Australian Petroleum Production & Exploration Association (APPEA) represents the upstream oil and gas industry in Australia. APPEA member companies currently produce approximately 98 percent of Australia's oil and gas.

Please find attached APPEA's submission in response to the Productivity Commission's Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector Issues Paper. It was a pleasure for APPEA to host you and your team's recent visit to the industry's operations to the North West Shelf region. We trust that this visit highlighted the high degree of current activity within the industry, but also emphasised the importance of regulation reform in realising the full potential of Australia's upstream oil and gas industry.

APPEA looks forward to continuing to engage with the Productivity Commission and other stakeholders in the completion of the Commission's review. As always, if you require any further information, or assistance in gaining a better understanding of the industry, please do not hesitate to contact APPEA's Deputy Chief Executive – Policy and External Relations, Mr Mark McCallum.

Yours sincerely

Belinda Robinson
CHIEF EXECUTIVE

Encl.

- *APPEA Submission*

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 PRODUCTIVITY COMMISSION REVIEW OF THE REGULATORY BURDEN ON THE UPSTREAM PETROLEUM (OIL AND GAS) SECTOR.

APPEA SUBMISSION

SEPTEMBER 2008

TABLE OF CONTENTS

1. INTRODUCTION

1.1 Australian Petroleum Production & Exploration Association

The Australian Petroleum Production & Exploration Association represents the upstream oil and gas industry in Australia. APPEA member companies produce around 98 per cent of Australia's oil and gas. More than 70 members explore for and/or produce Australia's oil and gas resources and a further 140 companies supply a vast range of goods and services to these explorers and producers.

Reliable, secure and competitively priced energy is crucial to industry, our communities and our households. It underpins Australia's economy and industrial structure. Within this framework, oil and gas plays a key role. At present, petroleum (oil and gas) accounts for more than 50 per cent of Australia's primary energy needs and is expected to increase.

Just as importantly, the industry creates significant wealth for the country, including through the employment of many Australians, underpinning the revenue collections of governments and generating valuable export revenue for the Australian economy. A strong, vibrant and growing industry is essential to the on-going health of the Australian economy.

1.2 Economic significance of the oil and gas industry

Oil and gas currently accounts for 33 per cent and 21 per cent respectively of Australia's primary energy consumption (ABARE 2006). In 2006 the estimated value of Australian oil and gas production was $22.7 billion, while tax and royalty payments to the Australian, State and Territory governments amounted to more than $8.1 billion (Wood Mackenzie Global Economic Model).

Petroleum (oil and gas) is Australia's 3rd largest mineral and energy export currently valued at $17 billion (March Quarter 2008 – ABARE). Local production of oil and gas is also a source of highly skilled employment, education, training and research.

1.3 Structure of the Australian industry

There is a diverse spectrum of participants in the upstream industry, ranging from small and medium-sized companies to super majors. Some of the smaller companies have a small amount of production but most are reliant on the equity market to fund exploration in Australia and, increasingly, in the United States and other parts of the world.

A number of medium to large-sized Australian companies typically have producing assets that fund further onshore and offshore exploration. Many of these are also expanding overseas in pursuit of more attractive opportunities in terms of prospectivity, product prices and time to first revenue.

The super-majors, whose Australian interests represent a very small part of their global portfolios, are predominantly focused on offshore exploration for large gas opportunities underpinned by LNG exports. Global competition for investment capital is increasing and Australia must constantly monitor its overall competitive position for investment.

1.4 Growth potential of Australia's oil and gas industry

Through the Upstream Oil and Gas Industry Strategy, industry has – with the support of the State, Territory and Australian Governments – set itself a number of growth targets over the next decade, including that by 2017:

- exports of LNG will reach 50-60 million tonnes per year (Mtpa), up from around 15½ Mtpa currently;
- natural gas used in resources processing will double; and
- in a competitive electricity market, 70 per cent of all new electricity generation capacity installed in Australia over the next decade is gas-fired.

Reaching the aspirational targets would also have significant economic and social benefits for Australia. Economic modelling commissioned from economic consultants CRA International[1] and conducted by Access Economics utilising their Access Economics General Equilibrium Model (AE-GEM) shows that if Australia achieves the aspirational targets set out in the *Platform for Prosperity* report over the period to 2017, then Australia can expect:

- an increase of between $13 billion and $55 billion in GDP in net present value terms which is equivalent to adding between 0.24 and 0.31 percentage points to Australian GDP growth in 2017;
- an increase in real consumption of between $500 million and $21 billion in net present value terms over the period to 2017;
- an increase in Australian exports leading to an improvement in our trade balance of $1.6 billion by 2017;
- the generation of new jobs in the oil and gas and construction industries – in 2012 at the height of the construction boom expected to be associated with the strategy 52,000 new jobs will be generated;
- the diversification of Australia's energy economy with increased penetration of gas in the domestic manufacturing industry; and
- a major boost to remote regional economies particularly in Western Australia, Queensland and the Northern Territory.

The magnitude of our natural gas reserves means that, with the right policy and fiscal settings, Australia's LNG industry is capable of growing from our current production of around 15½ million tonnes per year to 50-60 million tonnes over the next decade. This could make Australia the world's third largest LNG exporter. Realising this potential would:

- avoid more than 120 million tonnes of CO_2-e per year in the Asia-Pacific Region:
    - every million tonnes of LNG that replaces coal-fired power generation is equivalent to taking more than 500,000 cars off the road;
    - If the targets are met, global emissions avoided could total at least 180 Mt CO_2-e a year by 2017 compared with an alternative of coal being used to meet the energy requirements of Australia's LNG customers (at least 120 Mt) and the growth in energy demand in Australia's industrial and electricity generation sectors (around 60 Mt); and
    - This is equivalent to more than one quarter of Australia's projected greenhouse gas emissions in 2017.
- deliver up to an additional $10 billion per year in Government revenues; and
- stimulate the development of natural gas production for domestic commercial, industrial and domestic use, thereby avoiding greenhouse emissions in Australia.

[1] CRA International (2007), *Implications of achieving the Upstream Oil and Gas Industry Strategy Targets*, April (available at www.appea.com.au).

1.5 Challenges for realising Australia's growth potential

Oil prospectivity in Australia is generally perceived to be poor with relatively low discovery rates and small average field sizes. Gas prospectivity, however, is good. Despite this, large gas fields remain undeveloped decades after discovery and new gas discoveries are often remote from markets and infrastructure and therefore difficult to commercialise. These undeveloped fields are referred to as 'stranded gas'.

To date Australia has been an attractive petroleum investment environment and developed a reputation as being a sound place to do business, encouraging global oil companies to direct a part of their activity and investment to Australia. But Australia's lower sovereign risk is accompanied by lower returns and margins. Australia ranks poorly for returns on exploration spending. Development risk in Australia is also increasing. Oil project developments have tended to be in deeper water and more technically challenging.

The large capital requirements, long construction periods and long payback periods associated with remote LNG projects also increase Australia's risk profile. In short, global competition for petroleum investment capital is increasing and there are many alternatives. Ensuring a competitive regulatory framework is a critical ingredient for maintaining and improving on Australia's overall global competitive position as an attractive investment destination.

The future contribution of the industry will largely be determined through a combination of factors, ranging from successful exploration, technological developments that will unlock the full potential of new and existing discoveries, the capture of new market opportunities, and most importantly, project delivery at a standard that exceeds society's expectations. In order to realise the industry's potential, challenges and opportunities must be grasped by governments (on behalf of the community) and industry alike.

The potential rewards available to Australia through efficient and timely development of the nation's petroleum resources are significant and will only result from the combined efforts of governments and industry. Industry must recognise the framework set by governments' policy parameters, and governments must understand the nature of commercial decision making that will result in Australia attracting the maximum and most timely investment interest.

Factors that will influence future growth of the industry in Australia include:

- the level of exploration in the vast, high-risk frontier regions of Australia at a time of greatly increased exploration costs;
- rapidly declining domestic oil production, with the consequent negative impact on the nation's trade position;
- growth in export opportunities for gas in an increasingly competitive and dynamic global supply market;
- the competitiveness of gas with other fuels and its ability to increase its penetration in domestic markets—particularly on the east coast;
- the increased national and global focus on climate change policy;
- more rigorous community expectations in relation to safety and environmental performance;
- the availability of skilled labour; and
- the need for, and funding of, a coordinated program of research and technology development to underpin future industry competitiveness.

1.6 Australia's competitive position – the importance of the regulatory framework

In establishing and setting policies, Australia faces a number of difficulties. Australia's remoteness pushes up the cost of mobilising essential equipment and personnel. Perceptions of low oil prospectivity are discouraging exploration, even though many of Australia's offshore and onshore areas are largely unexplored. Low domestic gas prices and limited success in attracting new gas-based processing industries have tended to slow exploration and development investment. Planning is under way for a number of new, high-cost gas projects, although some have been delayed and investment decisions—involving in each case many billions of dollars—are yet to be made. The reality is that Australia is competing with a variety of other nations where exploration risk, underlying economics and time to development can be more attractive.

To successfully meet the industry's expansion targets will, however, require a rapid and sizeable increase in exploration and new project development, including a three- to four-fold increase in frontier exploration and investment of tens of billions of dollars in new LNG projects. Australia has a number of important competitive advantages but has only a small share of the world's petroleum resources—0.3 per cent of proven oil reserves and 1.4 per cent of proven gas reserves. Major improvements across a number of other key determinants of competitiveness will be needed in order to attract the attention of globally focused petroleum investors and move Australia from a 'middle of the pack' ranking to a 'top five', 'must consider' investment destination.

The perception of Australia as an investment destination with a low level of sovereign risk must continue to be at the forefront of policy makers' attention. Historically, this characteristic has been presented as an important strength of investing in Australia, but the increasing complexity of Australia's regulatory regime is increasing investor uncertainty and weakening one of Australia's main competitive advantages. It is for these reasons that of all the challenges identified in meeting the industry's potential, more consistent and more efficient regulation was identified as one of the highest value priorities that must be addressed as quickly as possible in the *Strategic Leaders' Report: Platform for Prosperity.*

2. WHY REVIEW REGULATORY BURDEN ON AUSTRALIA'S OIL AND GAS INDUSTRY

2.1 Operations across more than one jurisdiction

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 the industry is adhering to sound, responsible operating practices.

Every step in the exploration, development and production of crude oil and natural gas is highly regulated. In every jurisdiction the industry must meet hundreds of requirements relating to timing, location, environment protection, worker and public safety, and management and extraction of the resources in a manner that best serves Australia's national interest.

In many instances Australia's oil and gas resources are found in Commonwealth waters and then brought onshore for processing in state/territory jurisdictions via pipelines crossing Commonwealth, then state, waters. For projects with resources in State jurisdictions, such as conventional oil and gas in the Canning Basin, or the extensive coal seam gas operations in Queensland and New South Wales, not only are there State regulatory controls, but local government approvals are also required.

In many of the States and Territories, there are often duplicated requirements that industry must follow for a given activity for each of these respective jurisdictions – Commonwealth, State, and local government. APPEA notes that the Issues Paper has specifically excluded coal seam gas operations from the remit of the review. However clearly these projects, like the vast majority of Australia's oil and gas industry, operate under more than one jurisdiction, and for completeness the Commission's review should not arbitrarily discount the effect of the regulatory burden on the international competitiveness of these projects. Coal seam gas and conventional projects onshore are no less prone to duplicative and unnecessary regulatory burdens than those accessing Australia's offshore resources. These projects confront similarly challenging regulatory frameworks.

While the development of the individual approval requirements may have been appropriate at the time, the compounding result is that proponents are frequently now required to navigate their way through hundreds of decision points and approvals required. In the eyes of investors, this translates into hundreds of opportunities for regulatory failure.

As well as improving the efficiency of regulatory and approvals processes, more fundamental reform is required to recognise the unique circumstances of the oil and gas industry in Australia, where a single project can often cross three regulatory jurisdictions. Clearly this multijurisdictional approval regime further compounds the regulatory complexity.

2.2 Council of Australian Governments Principles of Best Practice Regulation

The Council of Australian Governments (CoAG) has recognised that there is a public perception that rule makers too often concern themselves with effectiveness, ignoring efficiency issues — that is, existing or proposed regulation may achieve a particular policy goal but not necessarily be the 'best' or least cost means for doing so.

CoAG has stated that determining whether regulation meets the dual goals of 'effectiveness' and 'efficiency' requires a structured approach to policy development that systematically evaluates costs and benefits. The following provide a useful framework for considering regulations.

- The problem to be addressed and the related policy objective should be identified as first steps in the policy development process.
- Consideration be given to a range of options for achieving the objective (including a 'no action' or status quo option).
- An analysis of the likely economic, social and environmental consequences.
- The policy development process should ensure that the benefits to the community of any regulation outweigh the costs, and give some assurance that the option chosen will yield the greatest net benefits.

APPEA has particularly welcomed and strongly supports the vigorous application of COAG's agreement that all governments will ensure that regulatory processes in their jurisdiction are to be consistent with the following principles:

1. A case for action must be established before addressing a problem;
2. a range of feasible policy options must be considered, including self-regulatory, co-regulatory and non-regulatory approaches, and their benefits and costs assessed;
3. adopting the option that generates the greatest net benefit for the community;
4. in accordance with the Competition Principles Agreement, legislation should not restrict competition unless it can be demonstrated that:
    a. the benefits of the restrictions to the community as a whole outweigh the costs, and
    b. the objectives of the regulation can only be achieved by restricting competition
5. effective guidance to relevant regulators and regulated parties must be provided in order to ensure that the policy intent and expected compliance requirements of the regulation are clear;
6. regulation must remain relevant and effective over time;
7. consultation with affected key stakeholders at all stages of the regulatory cycle; and
8. government action should be effective and proportional to the issue being addressed.

2.3 Productivity Commission Review of the Regulatory Burden on the Upstream Petroleum Sector

APPEA welcomes the decision by the Council of Australian Governments (CoAG) to commission the Productivity Commission to 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. Depending on consequent decisions and action, this work has the very real potential for increasing Australia's prosperity through a more cooperative, efficient, outcomes-focussed approach to regulation and project approvals.

With around $100 billion worth of new projects currently under consideration, the Commission's review is vital to both large and smaller companies. It impacts on the capital investment, and the resources required to navigate through between 150 and 500 approval mechanisms over a period that can last up to five years.

In addition to the work of the Productivity Commission, APPEA has been working across the Commonwealth and State Governments to improve the operation of the regulatory framework, including regulations and approvals required, under:

- the *Offshore Petroleum Act 2006*;

- the 2007 review of the *Environment Protection and Biodiversity Conservation Act 1999;*
- the 2008 review WA *Environment Protection Act*;
- the 2008 review of the WA environment impact assessment processes;
- the 2008 review of the WA *Native Vegetation Clearance Act*
- the 2007 review of Victorian approvals regime for resources exploration and development through the Earth Resources Development Council (ERDC);
- the recently announced Victorian Competition and Efficiency Commission review of the existing framework of environmental regulation and
- the finalisation of the Queensland Code of Environment Practice.

3. APPEA RESPONSES TO SPECIFIC QUESTIONS RAISED BY THE PRODUCTIVITY COMMISSION ISSUES PAPER

Section 2 Questions - Existing Regulatory Arrangements

What constitutes a regulatory burden?

1. Which metrics should be used and are available to compare and monitor Australia's regulatory performance in this industry?

APPEA currently utilises a combined measure of the total number of approvals required, the total number separate regulatory agencies from which these approvals are required and a consideration of the time that it takes to obtain all the approvals required before a project or industry activity can proceed. Another measure used by APPEA and its members includes the number of days per year spent on ongoing reporting requirements.

APPEA has established a number of case studies, based on these metrics, and provided them for consideration by the Productivity Commission. APPEA will also provide the Commission access to the approvals registers strictly on a Commercial-in-Confidence basis. These case studies demonstrate that approvals for major oil and gas projects may take in excess of 5 years, can require over 500 separate approval requirements, and frequently engage with over a dozen and sometimes more than 20 regulatory agencies. In addition, once approvals have been granted some larger companies can spend over one third of the year reporting to various agencies.

2. Is the number of approvals required a useful indicator for inter-jurisdictional and international comparison?

In the absence of any other clear benchmarks, the duration required and total number of approvals could, in addition to other measures, provide an indication of how well Australia's regulatory regime compares with the regulatory regimes of its international competitors. The length and complexity of the multi-jurisdictional approvals regime that applies to Australia's oil and gas industry is clearly contributing to an international perception that Australia is a difficult place to invest in oil and gas exploration and development. Such a measure would also provide a useful inter-jurisdictional comparison as some jurisdictions definitely have a better handle on regulatory processes than others.

While geologic and economic evaluations are always requirements for exploration, in today's globally competitive economy where resource companies may be examining many options for investment, a region's policy and regulatory climate has taken on increased importance in attracting and winning investment. The latest Fraser Institute Survey of Mining Companies 2007-08 incorporates a *Policy Potential Index* that serves as a report card to governments on how attractive their policies are from the point of view of an exploration manager.

The Policy Potential Index is a composite index that measures the effects on exploration of government policies including uncertainty concerning the administration, interpretation, and enforcement of existing regulations; environmental regulations; regulatory duplication and inconsistencies; taxation; uncertainty concerning native land claims and protected areas; infrastructure; socioeconomic agreements; political stability; labour issues; geological database; and security.

The Fraser Institute's Report is highly regarded and in the latest rankings a number of Australian jurisdictions have slid down the list with this year's report for example showing

that Western Australia has dropped from a consistent presence in the top 10 jurisdictions, (last year placing 3rd), to now being in the middle of the pack at 27th out of 68 jurisdictions. Add to that the increasing difficulties in raising global capital. It is more important than ever for Australia to be seen to be open for upstream petroleum business.

Existing Regulatory Arrangements

3. What are the lessons from the recent legislative changes for future reform?

With consultation and cooperation it is possible to find smarter, faster and better ways for providing industry accountability to the community and governments. This can be achieved in a number of ways including the consolidation of regulatory requirements (OPA regulations) and organisational structures (National Offshore Petroleum Safety Authority) , and the provision of one-stop-shop approval facilitators (such as Primary Industry and Resources South Australia - PIRSA).

Few disagree that removing superfluous red tape and seeking to introduce a streamlined and whole-of-governments approach to regulation is a worthwhile objective. APPEA believes that the work of the Productivity Commission will give the necessary momentum to reform the current approvals processes across the regulatory spectrum drawing on a number of past and present reviews, including:

- the *OPA Regulations*. In October 2007 the federal Department of Resources, Energy and Tourism made 54 recommendations for reforming the regulations associated with the OPA. These were strongly supported by APPEA and its members;
- the extensive 2007 review of the *Environment Protection and Biodiversity Conservation Act 1999;*
- the 2008 review WA *Environment Protection Act*;
- the 2008 review of the WA environment impact assessment processes;
- the 2008 review of the WA *Native Vegetation Clearance Act*
- the 2007 review of Victorian approvals regime for resources exploration and development through the Earth Resources Development Council (ERDC);
- the recently announced Victorian Competition and Efficiency Commission review of the existing framework of environmental regulation and
- the finalisation of the Queensland Code of Environment Practice.

While all regulatory reviews have been welcomed by the industry, the review of the OPA regulations is particularly significant, given the significant number of separate approvals and consents currently required under these regulations, mirrored by additional regulations in State waters and some onshore jurisdictions. APPEA has particularly supported the intent to eliminate duplication and simplify the structure of the regulations by reducing the number of regulations to just three, namely Safety, Environmental and Resource Management. As part of the ongoing process we look forward to the repeal of the Pipeline Management Regulations, Diving Safety Regulations, Well Operations Regulations and the removal of any requirement for legal consents under the regulations. APPEA also supports the far reaching proposals to simplify and reduce the amount of reporting and the reinforcement of the distinction between regulations and guidelines.

While much of the report into OPA streamlining has been discussed between the industry and government over the past few years, there are a number of recommendations in the report requiring clarification or further consideration. While APPEA welcomes the intent of the reform process, there is also a desire to have an opportunity to comment on the wording of any proposed revisions to the regulations once they have been drafted. Should the intent of the Report be fully implemented, this will be the most significant reform

to the regulatory regime applied to the Australian petroleum industry in decades and the Governments responsible, both previous and current, are to be commended.

Of all the regulatory reviews currently being undertaken, a key lesson the industry has learnt is that the application of the CoAG Principles of Best Practice Regulation will draw out many opportunities for regulatory reform. The processes that work best are processes that make a case for action, assess a range of feasible options, assess their respective benefits and costs, and adopt the most effective option that is proportional to the issue being addressed. It has been the industry's experience that the prevailing challenge of most of these reviews is that they are a review of a single legal instrument, and all other applicable regulatory instruments and guidelines are not considered. This is one reason that APPEA has warmly welcomed the Commission's comprehensive review within and across all respective jurisdictions and their regulatory instruments.

4. Has the review of OPA regulations identified all the associated unnecessary burdens faced by the sector?

The Offshore Petroleum Act 2006 (OPA) and its associated Regulations, administered by the Commonwealth Government and Designated Authorities, form part of the total regulatory framework that applies to Australia's oil and gas industry. In addition to the OPA and the regulations, the industry is subject various other federal, state and local government legislation and regulations in relation to the following key subject areas:

- Environment;
- Climate change and carbon capture and storage (CCS);
- Safety;
- Taxation, customs and resource rent/royalty;
- Corporate;
- Land access (including native title); and
- Local government.

5. Would the proposed consolidation and changes to the regulations fully address the identified problems?

As stated above, the OPA and its associated regulations are only one part of the regulatory requirements faced by Australia's oil and gas industry. While the objective review of these regulations will reduce the regulatory burden on the industry, the dual levels of administration at the Commonwealth (Joint Authority) and states/NT (Designated Authority) levels increases the amount of compliance costs in keeping both arms of the regulator fully briefed on all operational, tenement and resource management aspects.

6. What are the most important areas requiring further reform in order to lessen unnecessary burdens on the sector?

The Issues paper has captured many of the important areas requiring further reform. As stated earlier, every step in the exploration, development and production of crude oil and natural gas is highly regulated by governments and regulatory agencies. In every jurisdiction of Australia the industry must meet hundreds of requirements relating to the operations of the industry covering the seven key subject areas identified under Question 4, including timing, location, environment protection, worker and public safety, and management and extraction of the resources in a manner that best serves Australia's national interest.

Consequently, APPEA believes fundamental reform is required to recognise the unique circumstances of the oil and gas industry in Australia, where a single project is faced with a highly complex and frequently duplicative multijurisdictional approval regime.

APPEA's submission to this Review focuses on the full range of suggested improvements to the most important areas of Australia's regulatory framework that includes:

- a consolidation of existing regulatory requirements;
- a number of options to improve consistency of administration through:
  - "one stop shop" facilitators,
  - consideration of a national regulator;
  - expansion of the environment assessors forum;
  - expanded use Memorandums of Understanding;
  - accreditation of assessment and approval processes across and within jurisdictions;
- increasing the adequacy of training, resourcing and retention of regulators; and
- ensuring that all future regulations are subjected to the CoAG test of regulatory principles.

Consideration and adoption of many of these suggestions across Australia's onshore and offshore jurisdictions would result in a more effective and efficient management of Australia's hydrocarbon resources in accordance with the interests of the nation and ensure the significant potential for growth of this industry are realised.

7. How do the regulatory burdens on onshore petroleum projects differ from those originating offshore?

While the objectives are similar across onshore and offshore jurisdictions, the minutiae of regulations administering the day-to-day operations of projects across jurisdictions are highly variable. This requires cross-jurisdictional projects to be familiar and compliant with the unique requirements of each jurisdiction. While offshore projects are primarily regulated through the Offshore Petroleum Act and associated regulations, onshore operations are also subjected to additional regulations relating to:

- native title
- cultural and environmental heritage;
- prescriptive safety and major hazardous facility requirements;
- resource and environmental access, including landholder negotiation requirements;
- building approvals and other local government zoning approval conditions; and
- differing obligations and processes for carbon capture and storage.

Throughout this submission, APPEA draws on the full range of these regulatory issues and the burden they bring for cross-jurisdictional projects. One detailed example of the differing onshore and offshore regulatory burdens not addressed elsewhere is the requirement to lodge petroleum data in each jurisdiction. The oil and gas industry is unique in its voluntary and legislated requirements for geological and geophysical data management. The legacy aspect of such data and its importance for future explorers has promoted the need for the industry to champion world standards in such data management.

The importance of geo-scientific data in opening up Australia's vast unexplored sedimentary basins is well recognised by the industry and the relevant state and federal geological institutions. The detailed requirements to lodge such data vary between jurisdictions. Inconsistent data lodgement requirements impact the industry and the nation in the following ways:

- Incompatibility of data, making it impossible to concatenate data across geographical boundaries
- Data management standards differ and therefore the data may not be maintained in a robust and secure medium for future access

- Data is not maintained and secured to best practice standards across the country, thereby affecting access; and
- Industry has to comply to the different needs, increasing the compliance costs of data lodgement.

Australia is well regarded for the quality of its precompetitive data packages that promote the country's geological prospectivity. For Australia to maintain its global competitive edge, common data management standards across the country are essential. Such a universal/national system may then lend itself to virtual data access and digital data management to support long-term and secure data management practices.

8. Are there lessons from either that could be used to improve future regulation?

Clarity and purpose of regulations is perhaps most evident in the South Australian onshore jurisdiction. In regulating the Cooper-Eromanga Basin, which has been producing for over 40 years, the South Australian *Petroleum Act 2000* is simple to follow and regulate. This principal legislation is 61 pages long and the subordinate regulations 41 pages in length.

While the length of the legislation may not be a critical factor in assessing the appropriateness of legislative frameworks, the ease of comprehension of the legislation and its purpose are discernable factors when reading the SA legislation. In comparison, Queensland accounts for some of Australia's longest pieces of legislation in relation to petroleum operations. Their legislation is far more prescriptive, accounting for over 1200 pages of principal legislation and subordinate regulations, under both *Petroleum Act 1923* and *the Petroleum and Gas (Production and Safety) Act 2004*.

Further, the impending amendments that propose the inclusion of a carbon capture and storage (CCS) framework neither lengthen nor complicate the readability of the SA legislation, thereby ensuring the integrity of the legislation is maintained over a considerably longer-term. The industry is yet to cite the corresponding Queensland legislation.

9. Which local government regulations, if any, produce unnecessary burdens or delays to upstream petroleum projects?

Additional delays to projects may occur when they are exposed to local council planning schemes. In Western Australia there is some evidence of local Councils requesting oversight roles in granting building approvals for structures such as domestic and export LNG trains, LNG storage tanks and other structures already regulated by the major hazardous facilities regulator. Obtaining these additional regulatory "building approvals" for these major hazardous facilities typically involve substantial payments, calculated as a percentage of the "building's" value which can be upwards of $1 billion.

In Victoria, grants of Planning Permits can be appealed to the Victorian Civil & Administrative Tribunal (VCAT). One disgruntled local resident appealing the grant of the Planning Permit by the local council to VCAT delays the project. Whilst this may be reasonable from a natural justice perspective, enforceable time frames to make decisions by such tribunals should result in a more expedient and cost effective processes. It is the time taken to progress through the regulatory and appeals process and the impacts this has on project financing that is the real cost to the industry. The actual dollars expended in ensuring compliance are insignificant in comparison.

Resource Management

10. What are the unnecessary costs and delays, if any, associated with resource management regulation?

The industry respects the crown ownership of resources and recognises that it is licenced to explore and develop these resources in the best interests of the Australian nation. The duplicative and tiered approach to resource management regulations, particularly in the offshore context needs careful consideration to ensure efficiency and timeliness of approvals.

While it is useful to have the regulator in state jurisdictions look after both onshore approvals on behalf of the state and for offshore approvals on behalf of the Commonwealth, a holistic approach is needed to ensure that overlapping jurisdictional issues are managed in a timely and effective manner. Delayed development of Australia's hydrocarbon resources impacts on Australia's ability to manage its trade deficits in relation to the import of petroleum and petroleum products.

While the industry does not agree that resource management regulation is unnecessary, it does seek to rationalise and streamline the regulations to ensure that the purpose and policy drivers for these regulations are clarified to both the regulator and the industry. This process of rationalisation will not only reduce the costs and delays for the industry but more importantly it will allow the regulator to invest resources in timely approvals for development and the growth of the industry in Australia.

The cost and delays associated with these project approvals is neither justifiable nor affordable. Small to mid-cap companies rely on "first development" cash flows and delays in project approvals can have an adverse impact on their commerciality. For larger companies, they can refocus their project portfolios, even considering taking investment overseas to meet their corporate aspirations.

11. Would further guidance on government resource management policy objectives simplify compliance and expedite negotiations?

In most jurisdictions the intent of government's resource management policy objectives are evident. Certain aspects of resource management, mainly in the reporting aspects and the need for duplicative approvals processes, would benefit from further clarification in both onshore and offshore jurisdictions. Clearer guidelines on the government's policy intent would also benefit to industry and regulators.

12. What are the tensions between commercial incentives on operations and resource management practices dictated or negotiated by government under 'good oil field practice'?

Good oil field practice is a well recognised terminology in the Australian offshore regulatory context. There are, however, various interpretations of its meaning and intent. Definitions of "good oilfield practice" where they do exist, can be vague. As a consequence undesired policy outcomes can arise when government and industry are not agreed on what the definition means.

Generally speaking the industry view of what good oilfield practice means is maximising economic return, while maintaining a safe workplace and minimising effects on the environment. Government may take a view that GOP ensures maximum hydrocarbon recovery. It must be noted that there are instances where this can have unexpected results - for instance the requirement for additional equipment can, as well as adding to capital costs, also add to running costs and accelerating abandonment, thus negatively affecting recovery.

Good oil field practice can be used to suggest an alternative depletion scheme for a field. Where this means the production of a marginal value oil rim underlying a gas zone, before the gas zone can be drained, it can have the effect of delaying the development of the major part of the resource at considerable opportunity cost. Hydrocarbon resources are limited and non-renewable. The commercial drivers to produce a profitable resource is counterbalanced by the industry's responsibilities to ensure that the residual and undeveloped resource and the inherent geology are left intact for future recovery.

13. Does the negotiation process under the current regime cause unnecessary delays and uncertainty and, if so, why?

Development approvals that do not have timelines and are open ended provide little confidence to the industry that is about to, or has already committed to, considerable amounts of investment. Negotiating an appropriate outcome for the development of a resource is critical as it has both commercial as well as long-term resource management implications. Reaching such a negotiated balance between competing priorities can in many circumstances delay projects and in some rare occasions defer projects for a considerable time.

While the industry prefers the negotiation process to a directive based process consideration should be given to the length of time for development and other critical approvals. The two-month timeline from submission of all data required in a Field Development Plan (FDP) to the offer of grant of Production Licence has, in the industry's experience, never been met, even for very high profile projects with both State and Federal facilitation support. The average timeline from submission of the preliminary FDP to offer of grant is typically 9 to 12 months.

Critical resource management/development approvals require the industry proponent to negotiate at both the state and federal level in the OPA context (JA and DA approvals). While the Commonwealth Minister holds the final power to grant approval for such projects, the iterative, and at times, iterative negotiations between industry – state; state – federal and industry – federal can cause inordinate delays to project commencement.

Adding even further complexity is the use of two independent technical advisors in the process – the DA at the state/NT regulator level and the other being Geoscience Australia (GA) at the Commonwealth level. While the industry regards the importance of impartial technical advice being provided to the policy arm of the DA/JA, for critical development approvals, consideration needs to be given to whether such internal procedures and technical advice could potentially delay the approvals process.

The timeframes for approvals should be efficiently managed within the DA/JA processes such that no additional time burden is imposed on the industry. A hypothetical example of this is when the technical advisors within the DA and JA are unable to reach an agreed consensus on an issue and the decision maker (ie the JA) is unable to approve the development in a timely manner. The technical advice mechanism between the DA and JA should be "hidden" and built-in to the approval timelines.

These negotiations are compounded by the need for the industry to comply with other non-OPA legislative approvals processes as mentioned in the answer to Question 4 in the section relating to "what constitutes a regulatory burden".

14. Do similar regimes operate more effectively overseas and, if so, in what ways?

Australia's management framework of its offshore resources is unique with the Joint and Designated Authorities approvals requirements. The only other similar jurisdiction in this regard is that of, "Canada where different legislation currently applies to different parts of the offshore under federal jurisdiction, depending on whether or not a federal –provincial accord has been concluded to regulate oil and gas operations, each of which covers broadly the same ground…with particularities of administration designed to reflect to joint federal-provincial interest in the area."[1] On balance, the industry supports the presence of state representatives on the JA as it establishes checks and balances in State/Federal system helping to moderate the potential for any extreme positions.

Occupational Health and Safety

15. What are the unnecessary compliance costs, if any, associated with offshore OHS regulation, such as delays, inconsistency, unnecessary prescription, regulatory creep and red tape?

The Australian offshore OHS regulatory regime has continued to evolve since the inception of the National Offshore Petroleum Safety Authority (NOPSA) in 2005, with greater efficiencies and effectiveness being achieved over the last three years.

NOPSA has worked hard to consult with industry to identify areas where lack of clarity around regulations has led to inconsistency and delays and to address these concerns, particularly in the area of the submission and assessment of safety cases. A recent independent review of NOPSA concluded:

> *NOPSA has made good progress in building a safety regulatory regime and authority of world class calibre, and, as expected, there are still some aspects of the regime that can be improved on to achieve best practice regulation.*

APPEA is working collaboratively with the Federal Government and NOPSA to consider and give effect to the Independent Review Recommendations as appropriate, particularly in the area of clarifying particular regulations. There are a number of areas where the legislation is not clear and interpretation has been inconsistent including Associated Offshore Facility and Scope of Validation.

One area of real concern for APPEA's members however, is a discernable trend to introduce 'guidelines' that add new requirements rather than clarifying existing requirements – recent examples being 'Offshore Accommodation Standards' and 'Helicopter Standards'. This 'prescription by stealth' is strongly opposed. Any 'guidelines' introduced by NOPSA should provide genuine guidance on existing requirements and their development should be done in full consultation with the industry and the workforce.

[1] Page 3, *A Comparative Study: Discretion in the Administration of Offshore Oil and Gas*, Terence Daintith, AMPLA, December 2005.

An associated area of concern is the practice of referencing Australian and other international standards in their entirety in these 'guidelines'. Such Standards cover a large amount of detail and not all of that detail will be relevant to the subject for which guidance is being developed. As a consequence, only the specific section of the Standard that addresses the issue at hand should be referenced.

APPEA and its members would be particularly concerned by any developments that resulted in a move towards a more prescriptive regulatory regime, away from the objective based risk assessment approach that applies to onshore and offshore regulation of petroleum exploration and production activities. We continue to strongly support the objective based regime.

Under this regime, it is the responsibility of the Operator to develop and implement the specific design, technology, processes and procedures used to meet broad objective based requirements to best fit the individual circumstances of the facility and operation. APPEA commends this approach to the Productivity Commission for possible application in a range of regulatory areas.

16. Does State and Territory OHS legislation for onshore facilities and activities cause unnecessary duplication in compliance and, if so, how?

The application of state legislation always carries the potential to result in discrepancies in regulatory requirements across jurisdictions and can result in prescriptive requirements for operators that are incompatible with an objective based safety case regime. It can also blur the lines of responsibility.

Without anticipating the findings of the independent investigation into the recent Varanus Island incident, there has been considerable public confusion around the respective responsibilities of the Federal and State Governments, and of State Departments, for overseeing regulatory inspections, assessments and approvals.

It is essential for effective and efficient regulation of critical supply industries, and for effective and efficient governance, that the public and other stakeholders are able to identify and have confidence in the responsible regulator.

17. Are there any significant differences in compliance burdens for similar offshore and onshore activities that are unrelated to the different operating locations?

There are a number of differences in the regulation of safety for the onshore components of petroleum projects. A number of jurisdictions utilise a safety case approach through a *major hazardous facilities* regulator for major projects such as the Longford Gas Plant or the North West Shelf LNG Joint Venture. With around $100 billion worth of new projects currently under consideration, the industry could potentially increase the number of these major hazardous facilities from three to over twenty in the next five to ten years. These facilities will be primarily located in Queensland, the Northern Territory and Western Australia.

At the same time some jurisdictions still rely on the use of prescriptive based safety regulation, administered through predominantly mining safety regulators. Up until the early 1990s, Australia's upstream petroleum industry was regulated by highly prescriptive legislation. The concern with a prescriptive regime is that too often the regulator was assumed to have responsibility for identifying what was safe or not for the industry. Rapid changes in technology and operations meant that legislation and regulation were always out of date or inadequate. Prescriptive legislation achieves a minimum compliance culture, rather than paying attention to the risks actually present in dynamic and ever changing workplaces.

As mentioned in response to Question 15, APPEA continue to strongly support the objective based regime. Under this regime, it is the responsibility of the Operator to develop and implement the specific design, technology, processes and procedures used to meet broad objective based requirements to best fit the individual circumstances of the facility and operation.

18. What benefits and costs, if any, have been achieved by a national approach to regulating offshore petroleum safety?

The responses to Questions 15 and 16 answer this question to a degree, but clearly the nature of Australia's offshore oil and gas operations is demonstrably unique, and APPEA and its members are strongly of the view that OHS regulation for this critical industry is best achieved by a national industry based approach.

Since the inception of NOPSA, the industry has been required to bear the full cost of regulation, in spite of the joint public and private benefits that are derived from third party oversight of the industry's operation. Under this full cost recovery system, the budget of NOPSA has expanded from just under $6 million per annum, to over $10 million in the 2008-09 financial year. This system of full cost recovery in addition to the $6 - $8 billion collected in other payments to the Australian taxpayer has long been a major point of contention.

This system of full cost recovery is unique to the oil and gas industry's safety regulation globally and within Australia. While the industry recognises the expansion of activity in the sector since 2005, there is no public oversight and very limited accountability to the industry in terms of the appropriate regulatory priorities, appropriate levels of regulator activity, appropriate levels of expenditure, and efficient program delivery.

Clearly the industry sees benefits in third party oversight of its operations and undertakes a number of third party audits by the likes of DNV or Lloyds of London at its own expense, supplemented by additional internal audits and audits by the National regulator. However it is the industry's very strong view that best practice safety administration also has a substantial set of public benefits including community oversight in relation to the environment and to ensuring the security and reliability of energy supplies.

With clear set of public benefits from the regulation of the industry, the application of a full cost recovery system contradicts the Productivity Commission's *Report into Cost Recovery by Government Agencies 2001.* In this report, the Commission supports the *Beneficiary Pays Principle,* which it defines as "the idea that those who benefit from the provision of a particular good or service should pay for it". With some public funding, APPEA strongly believes that this would be accompanied by a high degree of public oversight of all expenditures by NOPSA, a higher level of confidence in the case for the significant expansion in the NOPSA budget and a far lower level of reluctance by industry to accept any further regulatory functions being incorporated into a joint Commonwealth –State national regulatory body. Without a degree of public funding under a joint funding model that recognises the public benefit derived from regulation and the public oversight this brings, there will remain a high level of reluctance by industry to additional costs to fund a new regulatory regime, regardless of the benefits that nationally harmonised regulation will bring.

19. What, if any, administrative duplication and inconsistencies still exist?

The main area where APPEA believes reform is required is the administration of Well Operations Management Plans (WOMPs), subsea equipment and Pipeline Management Plans, where currently regulatory responsibilities are shared by the DAs and NOPSA. These activities carry risks that impact upon the integrity of the total petroleum systems. The interaction between the various activities is critical to the safety performance of operations and should be regulated by a single body.

The other key area requiring reform is the definition of Associated Offshore Facility and its application to various marine vessels. This area currently causes considerable confusion and duplication in regard to safety regulation and the interaction between the safety case regime and other internationally recognised regulatory controls.

20. Does NOPSA represent a sound model to consider replicating or expanding to encompass other upstream petroleum regulation?

Aside from the points already made above, APPEA believes that its support for NOPSA as a regulatory model needs to be clarified and qualified. APPEA and its members recognise that determination of appropriate administrative arrangements is largely a matter for government. Nevertheless these arrangements do have to be designed to ensure that the system acts as an independent verifier of the effective implementation of the industry's operating plans and that it supports the application of world's best practice throughout the industry.

If the NOPSA model was to be considered for application in other areas, a number of preconditions and key principles would need to be considered. These would include:

- transparent and open consideration of possible changes to the current regulatory regime and in defining transitional arrangements required in any move to a new regime;
- any new regime should recognise the need for consistency in the application of regulations across all jurisdictions and operations, and therefore apply to all offshore activity (State/Territory and Commonwealth waters);
- be cost effective and appropriately resourced by independent personnel, knowledgeable about the complexities of the oil and gas industry. For example:
  - staff should have a capacity to fully comprehend and promulgate best practice safety case management,
  - there should be adequate numbers of staff, adequate levels of skilling and availability of all appropriate types of skills able to provide timely and competent/practicable/informed/consistent feedback on industry approvals, and
  - That governments need to recognise and address the historical difficulty in attracting and retaining qualified and competent staff;
- drive continuous improvement consistent with "as low as reasonably practicable" principles;
- ensure that under-utilisation of resources and waste is avoided (and, for example, consideration needs to be given to appropriate ways of sharing scarce and occasionally used specialists);
- provide timely, certain, coordinated and efficient processes and, in particular,
  - in the interests of cost effectiveness, processes for the administration of safety must be fully coordinated and integrated with the other statutory processes for offshore resource management such as hydrocarbon resource planning and development, environmental management, etc;
- be seen to be independent of, and at arms length from, industry; and
- the system should provide some element that allows for the recognition of the company's past performance.

21. Should the COAG reform of OHS legislation encompass the offshore regime and any other petroleum-specific State and Territory legislation? What would be the benefits and costs of such a move?

APPEA believes the offshore regime has already achieved a best practice national approach. The goal setting, safety case regime is working extremely well in an industry where the potential for catastrophic events to occur has to be addressed through the rigorous application of the 'As low as is reasonably practicable' or 'ALARP' principal.

Whilst APPEA recognises the benefits to be gained for all, including the oil and gas industry, from working cooperatively with other industries, and with the Australian Safety and Compensation Commission to share lessons, strategies and solutions, APPEA is strongly of the view that the offshore oil and gas industry is fundamentally too different from the range of industries and organisations covered by the COAG reform.

Most importantly, the safety regulation of the offshore industry is critical to Australia in regard to ensuring the security and reliability of energy supplies and providing community oversight for environmental and social issues.

Environmental Regulation

22. What, if any, are the major sources of inefficiency and delays associated with environmental and heritage regulations?

Many of the levels of inconsistency of regulation have either already been reviewed (EPBC Act amendments of 2007) or are being currently reviewed (WA EIA process, 2008 and recently announced Victorian Competition and Efficiency Commission review of the existing framework of environmental regulation, 2008).

While the review of the EPBC Act resulted in real and substantial changes to Commonwealth environment regulation and associated procedures, other reviews have been slower to progress. Reviews in WA in particular have been running into delays and funding problems.

A further challenge is the prevalent use of environmental guidelines and policy statements – such as environmental offsets, vegetation clearance, seismic exploration interactions with whales, and the use of synthetic based drilling fluids to assist difficult and complex well design and facilitation to Australia's more inaccessible energy resources. Policy statements, guidelines and Codes of Conduct are increasingly being utilised by regulators to further increase the degree of control over the activities of industry. While many of these documents may have been prepared in consultation with Ministers, advisory boards, and/or industry, few have been tabled for debate in parliaments across the nation and none have been required to prepare a regulation impact statement. Requiring regulators to demonstrate that the proposed restrictions on operations are compliant with the clear standards put in place by the Office of Best Practice Regulation would remove a great deal of duplication and collateral regulation of the industry.

In addition is the duplication that occurs between the assessment processes associated with accessing resources in Commonwealth waters and bringing these resources into a State or Territory for processing. This can result in the industry requiring approvals and the provision of reports already provided to other regulators. For instance companies will frequently receive requests from Department of Environment, Water, Heritage and the Arts (DEWHA) for copies of reports submitted to the Western Australian Department of Industry

and Resources (DoIR) in their role as Designated Authority. Companies are not required to submit reports to both agencies and would normally only submit to DEWHA if there was a matter of national environmental significance. Whilst we clearly acknowledge the role that DEWHA has, informal requests such as this duplicates regulatory processes.

Finally there have been a number of instances where an appeals process can add over 12 months to a projects approval. In Western Australia this has resulted in some projects experiencing delays and inefficiencies when regulators add to the level of detail and information required during the assessment process. This is particularly the case if issues or impact agreed as being minor at the scoping phase are not dismissed later when they come for public review or appeal. Instead the project has to provide further information and potentially undertake further research on issues that are minor and were originally dismissed.

There is further uncertainty surrounding the Western Australian Appeals Convenor process in particular, whereby a decision by (or on behalf of the Environment Minister) is appealed for review and reconsideration by the same Minister . For some nationally significant projects, the Appeals Convenor process can effectively become another stand alone approvals process without any or the processes, timelines and checks that have been built into the original assessment process.

23. Are there examples of inconsistencies between or within jurisdictions that cause delays or uncertainties, or otherwise add to costs?

Uncertainties in regulatory processes are playing an increasing role in companies considering a range of options for development sites and technological solutions to overcome regulatory uncertainties. This regulatory uncertainty is a factor in a number of companies considering alternatives to bringing the vast gas reserves already found in the Browse Basin, some 100-200 km off the Kimberly coastline. The WA Northern Development Taskforce and the Commonwealth Strategic Environmental Assessment of the Kimberly commenced after companies had, in good faith, already undertaken detailed site selection, agreed guidelines and scoping for the Environmental assessment and had spent significant amounts of time and millions of dollars on studies.

This new process has put aside guidelines and scoping that had previously been established and placed the project in limbo for an indefinite period of time. For other projects, the uncertainty associated with the Strategic assessment and speculation regarding the timelines involved has resulted in serious consideration being given to multi-billion dollar floating facilities and, for other projects constructing pipelines over 900 km's in length to alternative processing sites away from the Kimberly region.

24. Are the objectives of environmental 'offset conditions' placed on approvals clear and consistent? Are the approval processes clear and transparent?

Environmental offset requirements are largely a matter of policy, not regulation and therefore have not been subjected to the same parliamentary scrutiny as regulations and legislation but could have at least as onerous an impact on the industry. This issue aside, environmental offsets can provide a more flexible approach to ameleriorating environmental impacts provided they are a substitute for a regulatory obligation rather than an additional condition.

However, it is for the reasons of inconsistency and lack of clarity that APPEA has requested the Ministerial Council on Mineral and Petroleum Resources (MCMPR) adopt a national approach across all jurisdictions on the issue of environmental offsets.

Currently each of the jurisdictions, including the Commonwealth, has adopted an environmental offsets policy and in some instances enshrined this policy as an additional legal requirement. Each policy comes with its own unique variations on interpretations, definitions and expectations of industry and those in government with the duty of assessing the merits of each environmental offsets package.

In working with the MCMPR, APPEA has sought to ensure that the National Offsets Policy recognises that:

- While there may be merit to biodiversity or habitat replacement offsets, the use of greenhouse offsets, with the imminent introduction of a national emission trading regime was inappropriate. Offsets should not be mandatory for all activities, and in particular exploration activities, and must only be applied on a case by case basis;
- Offsets need a solid policy framework that will give both governments and industry certainty in the process;
- The requirement to consider environmental offsets should not be applied retrospectively to existing operations, especially with respect to any requirements for licence renewals or revisions to approved environment plans;
- Agreement must be reached by governments to ensure that, for projects operating under multiple jurisdictions, that environmental offsets applied to meet the requirements of one jurisdiction would be recognised as satisfying the requirements for all other jurisdictions; and finally
- Governments must establish an independent appeals process to allow for a test of reasonableness of an environmental offsets package.

APPEA looks forward to continuing to work with the MCMPR and providing comment on the release of the draft policy towards the end of 2008.

25. Are there improvements that could be made to reduce conflicts between the work program requirements of exploration permits and the regulation of exploration activities imposed by separate legislation?

With recent amendments to the EPBC Act, the Commonwealth could consider utilising new provisions that allow the Commonwealth Environment Minister to recognise the environmental assessments undertaken on behalf of the Commonwealth by the Minister for Resources and Energy.

This should particularly be the case for exploration activities. Since the commencement of the EPBC Act, there have only been three decisions that a seismic exploration activity was a controlled action and required further assessment under the EPBC Act. The case for mutual recognition is even stronger for offshore exploration drilling activities. Each year the industry drills, on average, around 60 new exploration wells, refers a majority of these for assessment under the EPBC Act and for all but a few since the commencement of the Act, has received a "not controlled" determination.

The industry is also required to prepare extensive and detailed Environment Plans under the OPA's Management of Environment Regulations, for assessment by a team of dedicated, experienced and highly specialised regulators.

26. How effective has the EAF been in reducing environmental regulation burdens?

The Environment Assessors Forum has made significant in-roads to addressing inconsistent application of the law. The EAF includes representatives from all jurisdictions, and seeks to remove inconsistent interpretation of regulations and find pragmatic solutions to regulatory issues, while preserving the intent and integrity of the regulation.

Having the right, skilled, trained and professional people in place is an essential ingredient for an efficient and effective process. Certain key individuals, especially within the Designated Authorities, actively facilitate industry through the approvals process, reducing time and stress for all parties. However, the approvals process should not have to rely on the good will of key individuals to achieve the desired outcomes. A simplified process with clear process flow charts and guidelines would help to reduce the need for government facilitators.

In spite of the regular bi-annual meetings of the EAF, there remains a degree of inconsistency in interpretation and application of the regulations, which in many cases, appears to be due to a personal interpretation of the legislation/regulation rather than an organisation/Australia wide policy decision. Such inconsistencies between Designated Authorities may be resolved through discussions at the EAF or the Upstream Petroleum & Geothermal Sub-Committee. Even within NOPSA, state to state inconsistencies occur even when there is a hierarchal reporting structure to enforce the implementation of organisation wide policy decisions. Consistent decisions on the same issue throughout Australia would help to achieve certainty of process.

Unfortunately, while there is some degree of engagement with other Commonwealth Environment regulators, the EAF membership primarily comprises those agencies administering the Management of Environment Regulations under the Offshore Petroleum Act. In addition, unlike the NOPSA joint national authority model, all other regulatory agencies, including environmental are suffering from skills and staffing challenges prevalent across Australia. These challenges are described in more detail in the response under Question 47. The structure of NOPSA and consolidation of offshore safety regulators under the one joint statutory authority has allowed a unique remuneration structure that provides salaries for regulators that are attractive and very competitive with industry pay scales. A consolidation of the dispersed but highly qualified environmental regulators into a single regulatory authority may like NOPSA, reduce the prevalence of leakage of valuable regulatory skills and qualifications into the industry.

27. What could, or should, the EAF now focus on to further reduce unnecessary environmental regulatory burdens?

The EAF has primarily focused on addressing inconsistent application of the law and policies in offshore regulatory environments. With a successful and pragmatic model to follow, EAF could now consider the range of onshore environmental regulations affecting the international competitiveness of Australia's oil and gas industry, whilst ensuring environmentally responsible access and maintenance of the industry's environmental performance. This could include differing policies and regulations relating to environmental offsets, weeds management, control of contaminated sites, and rehabilitation requirements.

Native Title

28. What unnecessary compliance costs, if any, are faced by the upstream petroleum sector in developing resources on aboriginal controlled or owned land as well as land under native title claims?

The upstream oil and gas industry respects the rights of the native title and indigenous parties and aims at all times to work in consort with communities in achieving mutually acceptable outcomes. To this end, the industry does not consider the costs of compliance to be "unnecessary", however, there is some justification towards rationalising the process of land access and negotiation for the benefit of the indigenous people.

The *Native Title Act 1993* (NTA) has been in force for over 15 years. The NTA provides for 2 distinct processes to undertake 'future act' negotiations between the petroleum industry and the indigenous people, namely the Right to Negotiate (RTN) and the Indigenous Land Use Agreement (ILUA) processes. Petroleum legislation in Australia predominantly gives the explorer the right to be granted an approval to produce the discovered petroleum. This 'conjunctive' right, between exploration and production, is critical as it ensures the explorer is able to develop a discovered resource.

Many Australian onshore jurisdictions have recognized this need for conjunctivity between exploration and development and have ensured that native title agreements reflect such provisions that will avoid industry having to renegotiate terms of development after the exploration phase. Conjunctivity allows industry and the indigenous community to assess the long-term impact of industry's operations and reach a negotiated settlement for the exploration and development of Australia's petroleum resources. Jurisdictions should encourage such agreement as it reduces legal and administrative costs to all parties. Such agreements reduce the level of sovereign risk for the industry and provide long-term certainty to indigenous communities.

RTNs are project specific and limited to smaller sections of land, whereas ILUAs are negotiated on larger tracks of land and in many instances for multiple purposes (for example, mining, petroleum, forestry, farming etc). In the majority of circumstances, RTNs could be replaced by negotiating an ILUA over the large piece of land. Such an ILUA would reduce the level of costs associated with negotiations, provide a wider agreement and encompass a larger proportion of industry proponents and indigenous communities at the same time.

In many instances, negotiations require the petroleum project proponent to fund the negotiation costs (including travel and legal costs). Adequate resourcing of native title representative bodies would alleviate the fiscal pressures on small to mid-cap Australian onshore operators from having to fund agreement making processes. Some of these negotiations can last up to several months and it becomes unsustainable for industry to bear their own costs as well as those of the indigenous parties.

29. What further initiatives, if any, could expedite mutually acceptable outcomes in native title negotiations?

APPEA believes that the past 15 years of the operation of the Native Title Act has matured the thinking of all negotiating parties and there is sufficient precedent on agreement making to consider developing a model agreement under the Native Title Act.

APPEA recommends the government consider providing a model agreement by Regulation that does not preclude existing methods of negotiation, but in the interests of efficiency provides another alternative approach. Variable provisions to such a model agreement could be completed in a Terms Sheet (typically negotiated commercial

terms). Sign-off of the Terms Sheet and the model agreement could result in an ILUA. This model agreement is not suggested in any way to detract from procedural fairness that the NTA provides through the existing various negotiation mechanisms. Instead, it recognises that in many places now, the form of documentation in use has become settled, with negotiations between experienced parties resolving commercial terms only.

Such a model agreement will provide ease of use, reduce expense (legal and travel), flexibility in managing cultural priorities and a streamlined approach. It will also foster better relationships between the industry and the community. It could also reduce demands on funding, accelerate exploration and provide an earlier income stream. A workable precedent of this nature may be able to extend to other ILUA areas in due course.'

30. Are delays caused by protracted native title negotiations, or complying with other regulations, leading to suboptimal investment decisions and thereby reducing international competitiveness? What examples are there of such delays and what were their costs or other consequences?

APPEA has been advised by some of its small to mid-cap members that the length of time required for native title and land access agreements has moved these companies to invest overseas for the sake of ensuring a commercial portfolio of projects. While it is true that the initial phases of native title legislation in the mid to late 1990s saw protracted negotiations between industry and indigenous parties, more recently both parties have noticed a level of maturity in the process and have accordingly expedited negotiations in more timely and efficient manner.

While there are some exceptions to the possibility of delay in relation to specific negotiations, if governments were to adequately resource the management of native title future acts processes within the states/NT, such delays could be minimised further.

Indigenous Heritage Processes

In addition to Native Title processes, indigenous heritage issues can cause delay (and potentially denial) to project schedules. This is exacerbated by the multiplicity of legislation that companies are required to comply with in relation to indigenous heritage. In Western Australia, where proponents deem there is a risk of impacting Aboriginal heritage sites as a result of executing their proposed activities, they must apply for consent to conduct those activities from the Minister for Indigenous Affairs under the Western Australian Aboriginal Heritage Act 1972. In addition the WA Environmental Protection Act considers aboriginal heritage where it is classed as a significant environmental factor, sometimes resulting in two sets of heritage management conditions. It is also not beyond the power of the WA Heritage Act to consider Aboriginal heritage issues.

In addition to State legislation Aboriginal people can apply for emergency and permanent protection orders under the Federal Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (ATSIHPA) . There are examples in WA where projects cleared to proceed under the state Act are still required to close out the same application under the federal Act. It is becoming increasingly common for applicants to use both Acts in an attempt to delay or deny construction activities. This impacts project schedules and imposes additional cost and uncertainty, especially where a project commences work after state approval only to find an application made under the federal Act.

The worst of this impact could be ameliorated if the Federal Minister had the capacity under the ATSIHPA to take into account a ruling by the State in applications that are substantially the same.

CCS Legislation

31. What concerns are there and what safeguards are necessary to ensure that unnecessary burdens are not created for the petroleum sector by new Australian Government or State and Territory carbon sequestration regulation?

APPEA's Views on Carbon Sequestration Regulation

APPEA's detailed views on carbon sequestration regulation are set out in our submissions to the House of Representatives Standing Committee on Primary Industries and Resources Inquiry and the Senate Economics Committee Inquiry. In making these comments to the Commission, APPEA's reference are to the *Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008* introduced into the Parliament on 18 June 2008 (and currently before the Parliament). In commenting on the Bill to these Inquiries, APPEA made the following key points relevant to this question (noting issues relating to inter-actions between petroleum operators and carbon sequestration project proponents is considered in Question 32 and project approval requirements are considered in Question 33).

APPEA comments on the Commonwealth's Bill are framed against the industry's carbon sequestration policy objective, which is to ensure that the carbon sequestration policy framework and associated legislative and regulatory framework:

- does not impede the exploration and development activities of the upstream oil and gas industry in Australia;
- provides an efficient and effective regulatory framework for oil and gas project proponents seeking to store greenhouse gases as an integral component of their operations; and
- ensures nationally and internationally consistent regulations are developed for carbon sequestration activities.

The process of considering the appropriate policy framework for carbon sequestration projects in Commonwealth waters in a manner underpinned by the November 2005 *MCMPR Regulatory Guiding Principles for Carbon Capture and Geological Storage* is welcomed. It is vital that a 'fit for purpose' and consistent legislative and regulatory framework across all Australian jurisdictions is developed.

The level of Ministerial discretion contemplated in the Bill is expansive. While some of the discretion may be clarified by future regulations and guidelines, the intent of such power in the legislation seems unwarranted and requires clarification. Otherwise they could act as a disincentive for investments in both future petroleum operations and carbon sequestration operations.

The Bill also contemplates certain third party access rules for carbon sequestration operations, to be determined by the Minister. Initial discussions had indicated that the third party access regime would only apply to carbon dioxide pipelines but the amendments in the Bill appear to apply to all aspects of carbon sequestration activities. APPEA notes the full extent of such powers remains unclear in the Bill, with the detail to be left to regulations and from a upstream oil and gas industry perspective (the third party access rules do not apply to petroleum facilities) it is of considerable concern that such powers are being considered for carbon sequestration facilities.

APPEA also concerned, that the Bill does not directly confirm that holders of petroleum production licences would continue to have the ability that they currently have (subject to obtaining normal regulatory approvals) to do whatever is necessary in the licence area for the purpose of recovering petroleum in the licence area, including injecting methane and/or carbon dioxide in the licence area for gas recycling or enhanced petroleum

recovery and subject to approval) injecting for disposal in the licence area methane or carbon dioxide stripped from the petroleum stream that is recovered in the licence area.

The activities currently (or in some cases, proposed) to be undertaken by the holders of petroleum production licences to recover petroleum represent common and long-standing industry practice utilised by the upstream oil and gas industry to enhance hydrocarbon activities from operating oil (and natural gas) fields. The industry does not contest that carbon sequestration activities unrelated to petroleum production should be regulated by the amendments proposed in the Bill and be subject to the licensing and regulatory regime. The amendments in this area should not, however, impinge on or apply new governing standards to long-standing and legitimate petroleum recovery activities.

The defining of long-term liabilities and management of post-closure responsibilities for the long-term underground storage of carbon dioxide is a key carbon sequestration regulatory priority. APPEA notes the key issue in considering long-term liabilities is to adopt an approach that balances industry certainty and community concerns. The approach adopted in the Bill is that following site closure, proponents have discharged their statutory liabilities but may still be found liable for breaches of generally applicable statutory and common law.

Whether such an approach provides sufficient certainty for carbon sequestration project proponents is unclear. The proposed amendments would leave the project proponent open to common law liabilities for as long as they exist. This may be a barrier to the uptake of carbon sequestration projects and may not be consistent with the approach taken in other jurisdictions, such as the United States and the European Union. With this in mind, APPEA recommends that the conditions and requirements for the injection phase and immediate post injection monitoring phase (including periods of monitoring) prior to site closure be established with certainty up-front and as long as the assumptions made as to the behaviour of the carbon dioxide plume prove to be correct, those conditions and requirements not change in any material way during the monitoring phase or at site closure time. This will mean a carbon sequestration proponent can, with a degree of certainty as to the costs of the project, make upfront commercial decisions as to whether the project is viable.

The commencement of the amendments contained in this Bill will fundamentally change the legislative and regulatory framework facing the petroleum exploration and production industry, introducing a range of new regulatory requirements. The new framework must be developed and administered in a manner that facilitates the ongoing activities of the upstream oil and gas exploration and production industry in Australia. APPEA is concerned sections of the Bill will provide an on-going disincentive to future upstream oil and gas activity through a dilution of legal certainty for oil and gas producers compared to the level of legal certainty associated with pre-commencement activities.

The legislative amendments include as an offence unauthorised exploration for a potential carbon storage formation or a potential carbon gas injection site in an offshore area. APPEA notes that many of the methods used to explore for petroleum will be the same as will be used to explore for a greenhouse gas storage formation. Given this, APPEA recommends the Bill be amended to clarify that a petroleum exploration lease holder cannot be deemed to have committed an offence simply because that explorer was undertaking petroleum exploration activities that could reveal a potential carbon storage formation or a potential carbon injection site.

32. Are industry concerns in relation to access regulation of carbon sequestration in oil and gas fields adequately reflected in government policy and proposed legislation?

A fundamental starting point for the industry in assessing any carbon sequestration legislative and regulatory framework is the preservation of the rights of pre-existing title holders (referred to in the as pre-commencement title holders). APPEA is of the very strong view that any carbon sequestration-related legislation and regulation should protect the rights of pre-existing title holders and provide for the future growth and development of the Australian upstream oil and gas industry:

- APPEA has recommended to every jurisdiction (including the Commonwealth during the development of its discussion papers in 2006 and to the House Standing Committee on Science and Innovation *Inquiry into Geosequestration Technology* in 2006 and 2007) that governments carefully consider the way in which they will protect the rights of pre-existing title holders and provide for the future growth and development of the upstream oil and gas industry;
- APPEA notes that to do anything that alter rights entered into in good faith would introduce an unprecedented level of sovereign risk into the regulation of the upstream oil and gas industry in Australia.

APPEA has long recommended any legislation should provide a framework where carbon sequestration or other activities in an area only proceed if they do not impact on existing oil and gas operations or they permit an existing titleholder and a carbon sequestration proponent to enter into commercial negotiation so that agreements between pre-existing title holders and carbon sequestration proponents can be struck.

As APPEA understands it, the responsible Commonwealth Minister must not approve "key operations" if there is a "significant risk of a significant adverse impact" on petroleum operations unless the petroleum title holder has agreed to the carbon sequestration operations and terms of the agreement are not contrary to the (undefined) "public interest". The Bill provides these "protections" through:

- imposition of conditions on assessment permits and holding leases;
- Ministerial directions to title holders;
- limitations on the circumstances in which injection licences are granted/ refused;
- the treatment of petroleum discoveries in certain circumstances; and
- certain provisions regarding injection licensee remedial works.

APPEA's consistent view has been that the best way to ensure such conflicts do not arise is to in general[2] avoid overlapping access leases or licences (for example, through the carbon sequestration acreage release process). Simultaneous operations of carbon sequestration operations and oil and gas production can create significant problems which may present significant risk and integrity issues.

In addition, concerns remain around the issue of renewal of pre-commencement titles and whether or not the grant of carbon storage titles that overlap such pre-existing titles would be prevented going forward or would the acreage be effectively shared between the two regimes. The levels of sovereign risk increase from exploration through to production phases. While there is an indication in the Bill that petroleum production licences will be given precedence, the exploration and appraisal expenditures undertaken need recognition in petroleum titles going forward.

[2] Recognising there may be situations some petroleum operators may find the need to apply for titles over parts of their existing licences. The Bill should cater for these situations.

An important aspect of the Bill provides protection for new petroleum discoveries (that is, discoveries made after a injection licence is in place) in areas where a injection licence overlaps the area of a pre-commencement petroleum title held by a person other than the injection licensee. As APPEA understands it, where the petroleum is commercially viable, or likely to become commercially viable at some time in the future and there is a significant risk that injection and storage operations under the title will have a significant adverse impact either on recovery of the petroleum or on its commercial viability and the petroleum title holder has not agreed in writing to the carrying on of the injection and storage operations.

APPEA supports these provisions that require the Minister to give a direction to the injection licensee for the purpose of eliminating the risk, or where it is not possible to eliminate the risk, give a direction to the injection licensee for the purposes of mitigating, managing or remediating the risk or suspend, either for a specified period or indefinitely, all or any of the rights conferred by the injection licence or cancel the injection licence.

In addition, APPEA notes the Bill requires a carbon sequestration proponent to advise the Minister of any hydrocarbon discovery but is not clear as to the Minister's obligation to advise the petroleum title holder with respect to any find. Given that a carbon sequestration proponent has no legal right to explore for petroleum, the intellectual property in the discovery should not reside with the proponent and should be made available to the holder of any existing petroleum title over the acreage. Should no petroleum title holder exist, intellectual property rights should revert to the Commonwealth. These data submission and release provisions should mirror the requirements that currently exist under the OPA for the petroleum industry to allow for the ease of access to the community and other interested parties in the future.

33. Are requirements for upstream petroleum projects to sequester associated carbon dioxide emissions or otherwise offset greenhouse emissions negotiated consistently? What approach would improve these processes?

No. Different projects face different requirements and various levels of regulatory burden. As the Commission has itself argued (in its submission to the Garnaut Climate Change Review), the introduction of an Australian emissions trading scheme (through the proposed Carbon Pollution Reduction Scheme), means that greenhouse gas abatement requirements that may be (or have been) imposed as part of State environmental approval processes should be removed. Such requirements are redundant in the face of an emissions trading scheme (which directly places a price on carbon).

Third Party Access Arrangements

34. Is third-party access a relevant issue to this review? If so, what burdens could third-party access impose on pipeline and infrastructure owners and access seekers?

Third party access to upstream facilities relates to the ability to gain access to spare capacity of upstream natural gas facilities, such as gathering lines, platforms, processing plants, and storage facilities.

Upstream facilities are designed for specific purposes, which may differ markedly from facility to facility, particularly with respect to the processing of liquids and the removal of contaminants. Importantly, hydrocarbons vary considerably in their chemical composition. As a result unlike many other commodities and activities, one party's use of a facility can significantly impact on that of another party. The richness and impurities associated with different gas streams in what can often be adjacent producing fields can present significant technical challenges for access systems. Considerable redundancy

can be built into these facilities to provide for continuity of supply of gas while some processing units are shut-in for maintenance. APPEA notes that spare capacity as a concept is not directly translatable from pipeline transportation systems.

Commercial negotiation provides the least cost and most effective method for achieving third party access to upstream facilities and has resulted in a number of access arrangements being successfully negotiated. Examination of competition pressures and outcomes in the upstream industry has not revealed evidence of a failure of market forces to operate efficiently with respect to processing of third party gas streams. The upstream industry therefore has a very clear preference for commercial negotiation to arrive at mutually agreed arrangements for such third party access.

Accordingly, APPEA has developed key principles to guide how commercial negotiations for third party access should be conducted. A copy of these principles is attached for the Commission's reference. APPEA member companies cover the whole spectrum of exploration and production activities, usually working in joint ventures to share the high costs and high capital risks associated with these activities.

Given this range of activities, APPEA member companies, whether large or small, can at times be operators of upstream facilities and at times be seeking of access to these facilities. There are clear benefits for operators and access seekers in having guiding principles for the commercial negotiation of access arrangements to create a clearer understanding on both sides of the issues requiring consideration. APPEA promotes the following guiding principles for commercial negotiations on third party access to upstream facilities:

- respond in a timely manner to bona fide applications for access consistent with the information and service sought;
- grant access on fair and reasonable terms to capacity in excess of that committed for security of supply and reasonably anticipated future requirements;
- negotiate in good faith;
- existing contractual commitments including security and reliability of supply to be honoured;
- provide for continuing safety, efficiency and integrity of the facility;
- maintain environmental standards and obligations;
- recognise the legitimate business interests and investments of facility owners and access seekers; and
- recognise that parties are at liberty to inform relevant authorities that access negotiations are in progress.

APPEA strongly endorses commercial negotiation as the mechanism for establishing access to upstream services. APPEA notes that failure to agree on the terms and conditions, including price, does not in itself indicate the failure of commercial negotiations as the most appropriate mechanism.

35. Is there any evidence of the threat of such third-party access rights changing the behaviour of upstream petroleum investors in a manner that reduces international competitiveness or overall efficiency?

APPEA is not aware of any evidence of such behaviour.

Decommissioning

36. Is the regulation concerning the decommissioning of offshore facilities a relevant issue to this review? If so, what concerns do businesses have about the current or mooted arrangements?

The regulation concerning the decommissioning of offshore facilities is a relevant matter for consideration under this review as clearly there is the potential for levels of duplication, inconsistency and regulatory overlap that will affect the international competitiveness and economic performance of the industry.

Like all activities in Australia's oil and gas industry, the process of facility decommissioning is likely to face just as many areas of duplication and regulatory overlap. To circumvent this potential, APPEA has encouraged the Ministerial Council on Minerals and Petroleum Resources to develop a nationally consistent policy for decommissioning offshore facilities. To date this process has consulted broadly with many regulators at the State and Commonwealth level, stakeholders, other ocean users and Australia's oil and gas industry. This has culminated in the release of a Discussion Paper by the Department of Resources, Energy and Tourism in March 2008.

APPEA strongly supports the development of a Commonwealth decommissioning policy, and the open and transparent consideration that is being given to assessing the merits of all available decommissioning options. The comprehensive approach by the Department in engaging all stakeholders very early in the development of new and critical policy, assessing the existing legal framework and then basing regulations on the best available science is commended by the industry.

The Discussion Paper provides a comprehensive and substantial background to oil and gas operations and the legal framework that applies to decommissioning options in Australia. This is important as it should ensure an improved level of understanding for all stakeholders involved in the discussion around decommissioning options, particularly those who may not be familiar with the industry.

APPEA broadly agrees with the objectives outlined in the Discussion Paper. APPEA and its members support the principles of ecologically sustainable development, and agree with the Discussion Paper's assessment that the full range of environmental, economic, safety and social factors must be integrated into the decommissioning policy, as stated in the Discussion Paper. APPEA also welcomes the inclusion of its suggestion for further reference to the Intergovernmental Agreement on the Environment, and specifically the consideration that measures adopted should be cost-effective and not disproportionate to the significance of the environmental problem being addressed.

37. Are State and Territory regulations which apply to the decommissioning of upstream petroleum onshore facilities creating any unnecessary burdens?

With the development of a nationally consistent approach, the potential for regulatory burdens specific to the states and territory's will be limited. In the development of a nationally consistent decommissioning policy, however, APPEA is seeking further clarity on a number of issues including:

- clarification of ongoing monitoring requirements;
- increased emphasis on the importance of safety in considering the viability of decommissioning options;
- recognition that the application of decommissioning bonds to the offshore petroleum industry is unnecessary and very expensive;
- clarification that liability is largely an issue that relates to criminal or negligent actions and is addressed through the judicial system at common law; and

- recognition that there is minimal value in the early provision of detailed decommissioning plans at the commissioning and approval phase of a project.

Limitations to Monitoring Requirements

APPEA believes that there should be no (or limited) ongoing monitoring and remediation requirements placed on industry. The application of such conditions seems to be unreasonable and inconsistent with similar onshore activities and unnecessary. In practice, at the end of a decommissioning program both the regulator and the operator should be able to sign off that the installation has been decommissioned in line with the decommissioning plan.

The industry should only propose (and expect that governments will only accept) decommissioning options that are robust and have demonstrated an acceptably low level of ongoing risk to the marine environment and to other ocean users. Once the operator has completed the decommissioning operation as agreed in the decommissioning plan it may be appropriate for short term monitoring via visual observation (such as use of ROV cameras) to verify to the satisfaction of the regulator the completion of the process.

In the unlikely event that issues arise a number of years after the decommissioning activity, liability for remediation work (if any) should rest with the joint venture only if it is found to have been fraudulent or negligent in its assessment and decommissioning activities. A requirement for long term monitoring would imply that the industry has proposed, and that governments have agreed to, higher risk and less stable decommissioning options. APPEA and its members believe that there should be no specific requirements in legislation for ongoing long term monitoring once the decommissioning process has been completed and verified to the satisfaction of governments.

Importance of Safety Considerations

APPEA believes that the length and detail of discussion relating to safety in the Discussion Paper does not fully reflect the importance of safety as a consideration in the decision making process. While technically feasible, many decommissioning options are actually high risk operations in themselves and need to be very carefully considered. In assessing decommissioning options, workforce safety must be at the front of the decommissioning planning process.

In addition, with changing safety standards and practices, design options that were provided for at commissioning of a facility may no longer be satisfactory or appropriate and may preclude decommissioning approaches envisaged at commissioning. A good example of this change in design standards relates to structural integrity and lifting required during decommissioning. Many of the current design codes for lifting points, safety factors and allowable stresses will no longer allow decommissioning methods to be used which were previously considered feasible.

Application of decommissioning bonds

Australia's offshore oil and gas sector is a mature, highly capital intensive industry. Given the immense costs involved in decommissioning, providing bonds to cover the decommissioning of every installation could potentially cost the industry tens of millions of dollars every year, year on year. The issue of financial security to cover decommissioning liabilities is already comprehensively addressed through the governments' oversight of the licensing and transfer processes.

APPEA believes that the requirement for performance bonds to cover financial security for decommissioning addresses a non-existent issue in Australia's offshore waters and that it would result in no different an environmental outcome.

During the granting of exploration licences, retention leases and production licenses, governments already undertake a rigorous assessment process of the financial *bona fides* of the companies involved to assure themselves that those companies have the financial resources required to construct, commission, operate and decommission the project. This assessment is not limited to the initial award of a title and governments also ensure the financial *bona fides* of any new party making an application to acquire a title through the transfer process. In addition, financial reporting and accounting standards ensure that decommissioning costs are factored into companies' balance sheets and that they are transparently accounted for during the sale of any assets.

While governments may wish to assess the rigour and adequacy of existing financial assurance procedures, APPEA believes that the application of decommissioning bonds to the offshore petroleum industry is totally unnecessary to achieve the desired policy outcome and could be very expensive.

Liability should be a matter for judicial review

The issue of liability is not something that is unique to the issue of decommissioning. Liability is an issue that is subject to judicial review under common law and is not something that can be predetermined. Liability for remediation work (if any) should rest with the joint venture only if it is found to have been fraudulent or negligent in its assessment and decommissioning activities. APPEA believes that if all project conditions have been met, Government then accepts surrender of the site and forward liabilities, except in cases of negligence.

Consequently APPEA believes that in developing nationally consistent decommissioning policy, there should not be preconditions or guidelines that presuppose the outcome of any judicial review. Any claims for compensation by third parties arising from damage caused by an installation after decommissioning has been completed will be a matter for the affected parties and is governed by the common law. In APPEA's view, the issue of post decommissioning liabilities should not result in a policy outcome that mandated total removal and site clearance as the only acceptable decommissioning option in spite of the stated desire to balance environmental, safety and economic considerations.

Requirements for early decommissioning plans

APPEA considers that it is appropriate for the industry to incorporate decommissioning considerations into early project design. At this point in the project however, these plans should only consider what is technically feasible. Approval to install a facility should only require a brief explanation of the ability to ultimately remove the entire structure (as required under IMO Guidelines adopted in 1989 under Resolution A. 672(16) for the *Removal of Offshore Installations and Structures on a Nation's Continental Shelf or its Exclusive Economic Zone*).

Requiring a company at this stage to provide a detailed assessment of the costs, technologies and safety considerations that might apply in twenty to fifty years time would be impractical, expensive and relatively pointless given the potential for technical advances and changes to costs. The detail of these considerations should come much closer to the time of decommissioning.

Section 3 – The sources of regulatory burden

Unclear policy intent

38. Is the purpose and policy intent of upstream petroleum regulations sufficiently clear in legislation or guidance material?

The policy intent of upstream petroleum regulations has largely been given effect since 1969 through the Offshore Petroleum Act, its predecessor and its associated regulations. While the intent of the legislation is largely sufficiently clear, the promulgation of new regulations, guidelines, schedules and policy statements that duplicate existing requirements is the primary source of unnecessary regulatory burden.

39. What problems are directly or indirectly attributable to a lack of clarity in policy intent?

See response above.

Redundant requirements and excessive prescription.

40. What aspects of the current relevant regulations are redundant?

APPEA strongly supports the Commonwealth's proposal to remove specific consents to operate and construct pipelines/facilities where licences, giving approval to proceed, are set in legislation. Licences, such as the pipeline licence and production licence are the ultimate requirements. Consents are essentially a legal authority that deems that you have a legal authority to undertake an action and are therefore highly duplicative and should be removed.

41. Which regulatory requirements, if any, are overly prescriptive?

A good example of overly prescriptive requirements is the recently amended Queensland Petroleum Legislation. The amended Queensland Petroleum Act 1923 and the new Petroleum and Gas (Production and Safety) Act 2004 and respective regulations contain very prescriptive and detailed processes for the submission of approvals for various activities. A large amount of paperwork is required to be submitted for the simplest of tasks such as the completion of an oil well. Rarely do the submissions seem to add value to the operation or receive any review or comment from the regulatory authority. For example, Later Development Plans are required to be submitted to the Queensland Department for the renewal of a production licence. In many cases a 20 plus page report is prepared by industry to address the development plans for upcoming years for a field which has few remaining reserves and whose development plans may quickly change depending upon commercial influences.

The provisions of the SA Petroleum Act 2000 regulating the daily approvals for oil and gas activities are much simpler for industry to deal with due to its objective based, rather than prescriptive approach. One drawback with the objective based approach is that this allows the department or individuals within a department to use their authority to delineate how operating objectives are achieved which in our experience can result at times in an overly prescriptive approach depending on the preferences of the administrators at that time. The SA Department has tried to address this by being transparent about policy objectives in administering the Act but the industry's experience is that requirements to satisfy what we consider to be at times unnecessarily detailed matters can be imposed in practice even though it may not be possible to anticipate these requirements prior to the time applications for various activities are made.

42. Is there a case for rationalising the multiplicity of approvals and consent orders for pipeline projects?

APPEA supports the view that that Pipeline Management Plans and Pipeline Safety Management Plans be dropped and safety requirements for pipelines be incorporated into the safety case. Other requirements should be incorporated into resource management regulations. APPEA has been highly involved in the integrity working group and strongly supports the amendments to remove the duplicative pipeline management requirements. While the pipeline licence requirement is still required to be administrated by the DA, this could easily be covered within the resource management regulations.

However, abolishing individual pipeline management plans and pipeline safety management plans and combining them with facility safety cases would require additional work from the operator. For example, in the case of the North West Shelf assets the PMP comprises an integrated family of documents. There would be a significant amount of work to "unbundle" the family and merge parts into the respective safety cases for North Rankin A Platform, Cossack Pioneer FPSO, Goodwyn A Platform and Karratha Gas Plant. The integrated design of the PMP also presents a problem of duplication if we rebadge the PMP as the Pipeline Safety Case and add it as an addendum to each of the facility safety cases. Following this suggestion, the same documents would appear in the safety cases for North Rankin A Platform, Cossack Pioneer FPSO, Goodwyn A Platform and Karratha Gas Plant, and this would complicate any future updates to the suite of PMP docs.

The above issues could be overcome however if the revised safety regulations allowed for pipelines to be either integrated into facility safety cases or, where appropriate, be covered by a stand alone safety case specific to pipeline systems (i.e. existing or new PMPs are rebadged as a pipelines safety case but not merged into facility safety cases). Stand alone safety cases for pipelines may be beneficial in situations where an Operator operates multiple pipelines as part of a network under a management system common to each pipeline.

APPEA has long stated that because the oil and gas industry, and in particular its pipelines, frequently cross 3 to 5 jurisdictional boundaries, that pipelines should be covered by one PMP, end to end. Proposed WA legislation for onshore pipelines will require a safety case with requirements slightly different to those required for pipelines in state and commonwealth waters.

With regards to pipeline consents, and consents for all other activities in general, APPEA strongly supports the removal of consents as they are essentially a legal authority that deems that you have a legal authority to undertake an action. Consents are highly duplicative and APPEA supports the approach to remove specific consents to operate and construct pipelines/facilities where licences, giving approval to proceed, are set in legislation. Licences, such as the pipeline licence and production licence are the ultimate requirements.

Complexity that adds uncertainty on how to comply

43. Which regulations are believed to be excessively complex?

APPEA does not have a research or information provided by members to enable us to respond to this question of complexity. It would appear on the face of it that complexity may not be the main issue.

Overlap and compliance duplication

44. Which regulations across and within jurisdictions overlap and require similar information to be submitted to a number of agencies?

APPEA has long stated that the oil and gas industry is unique because it frequently crosses 3 to 5 jurisdictional boundaries. APPEA believe that given this uniqueness, traditional regulatory models may not be the most efficient means of meeting the community's regulatory expectations on industry. APPEA supports a consideration in developing a joint system whereby only one approval process is required.

As stated in response to Question 1, APPEA has established a number of case studies and provided them for consideration of the Productivity Commission on a Commercial-in-Confidence basis. These case studies demonstrate that approvals for major oil and gas projects may take in excess of 5 years, can require over 500 separate approval requirements, and frequently engage with over a dozen and sometimes more than 20 regulatory agencies.

A Case Study in Duplication of Reporting on Energy Consumption

Under the *Energy Efficiency Opportunities Act 2006*, companies in an Australian joint venture are required to go through a process of obtaining written nominations of the operator of a joint venture as the nominated reporting entity for the Act to avoid the consequence of each member of the joint venture needing to count and report on energy consumption of that joint venture. For exploration joint ventures in particular this is a time consuming exercise requiring companies to chase responses from smaller joint venturers who may not be subject to the requirements of the Act due to low energy consumption levels.

Under the new *National Greenhouse and Energy Reporting Act 2007*, companies have to go through another round of nominations of the operator of each Australian joint venture in a different format including the additional step of lodging nominations with the regulator. A process of deeming the operator of a joint venture as the nominated reporting entity unless otherwise agreed in writing by the joint venturers would be a preferable method of regulating the collection of the required data from the joint ventures.

In addition, although some amendments have been made to the Energy Efficiency Opportunities Act 2006 intended to streamline the reporting requirements post introduction of the NGER Act, there is still a requirement for ongoing duplicate nominations, dual registrations once the thresholds are reached and 2 sets of reporting requirements for companies to understand and comply with the requirements of each Act going forward.

To further complicate the reporting regime, there are State government reporting requirements as well. In Victoria the EPA has launched Energy and Resource Efficiency Plans (EREPs) that require a duplicate of EEO but with the EPAs slant (including mandatory implementation of projects with less than 3 years payback). Theoretically companies were supposed to have been able to apply for an exemption if already participating in EEO but the regulations require your EEO assessment (which is a 5 year program) to have already been completed to get the exemption.

45. Which activities are potentially subject to differing requirements and interpretation across and within jurisdictions?

The Offshore Petroleum Act and all its associated regulations are in place to ensure that Australia's oil and gas resources are accessed in a safe and environmentally responsible manner, and in accordance with the national interest. There are many other instruments of regulation in addition to the OPA and the regulations. As a result of the multi-jurisdictional requirements, in addition to the OPA and its regulations, the industry is subject various other federal, state and local government legislation and regulations in relation to:

- Environment;
- Climate Change and Carbon Capture and Storage (CCS);
- Safety;
- Taxation, customs and resource rent/royalty;
- Corporate;
- Land access (including native title); and
- Local government.

Inconsistent administration

46. What examples are there of inconsistent administration between similar projects and over time?

In the case of seismic exploration activities referred for assessment under the *Environment Protection and Biodiversity Conservation Act 1999*, there are a number of examples of very similar proposals experiencing very different regulatory treatment. The industry has referred dozens of seismic surveys under the EPBC Act in full accordance with the *Seismic interaction guidelines* with, until recently, the only controlled action determination applying to a proposal for seismic survey 100 km to the east of the Great Barrier Reef Marine Park.

However, in the past twelve months, two seismic surveys planned off the west coast of Victoria were assessed as having, or likely to have a significant impact on matters of national environmental significance, and designated a "controlled action", requiring formal assessment under the EPBC Act.

While one of these proposals was resubmitted with substantial revisions, the other survey was cancelled and it is unlikely that another seismic vessel will be in this area for another 12-18 months. In neither instance was there any indication that the regulator was acting on any new science becoming available or what factors in this survey, made it any different to the 55 other surveys the industry has run in the region since 2001 with no known environmental incidents.

Inadequate resourcing of regulatory administration

47. Are relevant agencies adequately resourced with appropriately skilled and experienced staff to process approvals efficiently and expeditiously?

The increasing levels of industrial activity in the Australian economy and the ageing of the Australian workforce has led to a skills shortage that is being felt across all sectors of the Australian economy, including Australia's oil and gas industry and its regulators. Increasing community demands on regulators with few staff with the necessary skills and knowledge required to regulate this complex industry is further increasing the skills challenge.

The establishment of the National Offshore Petroleum Safety Authority saw a consolidation of regulatory requirements, administered by those who had the technical capacity and qualifications to provide a vital community assurance role and capacity to assess the industry's performance. The structure of NOPSA and consolidation of offshore safety regulators under the one joint statutory authority has allowed a unique remuneration structure that provides salaries for regulators that are attractive and competitive with industry pay scales.

A consolidation of the dispersed but highly qualified regulators into a single regulatory authority may like NOPSA, reduce the prevalence of leakage of valuable regulatory skills and qualifications into the industry. However, in the context of financing Government's administrative costs for the administration of regulations affecting the industry, it remains APPEA's position that best practice administration has a substantial set of public benefits (including in relation to the environment and aspects of reliability of energy supplies) and, as such, a degree of public funding should be available for the cost of an administrative system reflecting this community public benefit. APPEA could not endorse a full cost recovery regulatory funding model, as has been adopted in NOPSA that fails to recognise this significant public benefit and ignores the substantial fiscal returns already generated by the industry.

There are of course other models of regulation enforcement that could be investigated to overcome the skills shortage. The Environment Protection Agency (EPA) in Victoria for instance has a system of accredited environmental auditors to conduct audits. Another example is currently being debated in Western Australia, with industry seeking agreement to use of an accredited panel of experts/consultants to assist the EIA process. One issue to be resolved is a lack of faith in accreditation and the possible conflicts such an approach may create. Another issue seriously being considered is the potential for industry funding of the Environment Protection Agency Service Unit to better manage the assessment workload and improve service delivery during the current period of high demand. Options they present include a fee for service system, a one-off injection of funds and use of industry funded secondees. This will also require further discussion, but both the Victorian and Western Australian models could be applicable in other areas of petroleum regulation.

Regulatory Creep

48. To what extent are some burdens attributable to regulatory creep?

Policy statements, guidelines and Codes of Conduct are increasingly being utilised by regulators to further increase the degree of control over the activities of industry. Examples of these would include environmental offset policies, accommodation standards, guidelines on restricting the use of synthetic based drilling fluids seismic, guidelines for minimising the introduction of marine pests, vegetation clearance guidelines, and exploration and whale guidelines, amongst a plethora of others.

While many of these documents may have been prepared in consultation with Ministers, advisory boards, and/or industry, few have been tabled for debate in parliaments across the nation and none have been required to prepare a regulation impact statement. Requiring regulators to demonstrate that the proposed restrictions on operations are compliant with the clear standards put in place by the Office of Best Practice Regulation would remove a great deal of duplication and collateral regulation of the industry.

Fiscal incentives for regulation

49. Do fiscal incentives and disincentives, if any, faced by State and Territory governments contribute to resourcing or other problems and, as a result, delays associated with approvals for onshore processing of upstream petroleum?

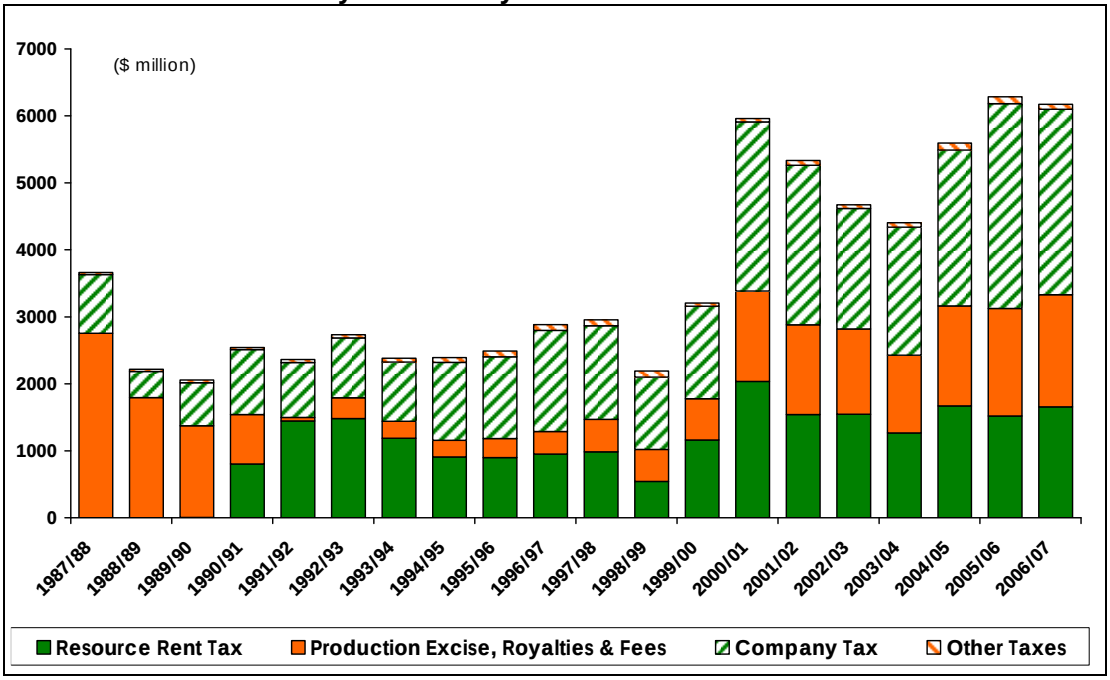
One example of a fiscal incentive for regulation relates to approval conditions that may bind a project to long term environmental research. In some cases this research is to improve the general baseline knowledge about an environmental aspect, frequently with little or no direct relation to the operational effects of the project. Government funding for long term environmental research is very limited (the Commonwealth for instance only funds approximately $1 million annually for marine mammal research, compared with several million dollars by the Australian oil and gas industry).

Because of limited government funding, scientific researchers seek long term scientific research from the industry. In some instances regulators have tied a commitment to long term research to project approvals, which as a result can significantly delay projects. In addition, as this approach to research is ad-hoc and dependent on linkages to project approvals, the research is not incorporated into broader strategic research programs, which can then result in significant amounts of money being spent on an issue, while other far more important strategic priorities receive substantially less funding.

Another example of a fiscal incentive for regulation and conditions on approval relates to the requirements for provision of environmental offset packages. In several jurisdictions, once all mitigation measures to reduce impacts to as low as reasonably practicable have been agreed, companies are then required to provide for a package of environmental and social programs to "offset" any residual impacts. While some jurisdictions such as Victoria and New South Wales have defined a formula to determine appropriate levels of offsets, other jurisdictions rely on a negotiated outcome between the proponent and regulator and have resulted in offset provisions worth tens of millions of dollars.

Overall, the upstream oil and gas industry currently contributes taxation payments of in excess of $6 billion per annum to governments in Australia (source: APPEA Financial Survey). In 2006/07, APPEA estimates that $1.7 billion was attributable to the petroleum resource rent tax and $1.67 billion to production excise/royalties.

Estimated Petroleum Industry Taxation Payments



Source: APPEA

Resource taxation receipts are shared as follows:

- PRRT collections are retained wholly by the Federal Government;
- crude oil production excise receipts are retained wholly by the Federal Government;
- royalties collected under Federal Government legislation are shared with the WA Government in a manner such that approximately one-third is retained by the Federal Government and two-thirds is paid to the WA Government; and
- State/territory royalties are generally retained wholly by the relevant jurisdiction under which they are collected. A portion of royalties collected under the WA coastal waters legislation is shared with the Australian government as a result of arrangements arising from the Offshore Constitutional Settlement.

While the majority of revenues are directed to the Federal Government, Western Australia, South Australia and Queensland generate significant petroleum royalty revenues. The extent to which state/territory governments have resource constraints as a result of the fiscal terms will need to be viewed on a case by case basis and is largely dependent on the quantum and location of the resources being administered. The Commonwealth Grants Commission also considers royalty payments in its fiscal equalisation processes.

APPEA is unable to comment directly on the ability of the states/territories to effectively administer approvals and regulatory processes, however the total quantum of taxation payments made by the industry should allow governments to ensure that adequate funding is made available or shared to undertake administrative activities on an efficient basis. The question of the actual sharing of revenues between governments would more appropriately be addressed at a governmental level.

Section 4 - What are the impacts of regulatory burdens

Compliance Costs

50. Are there any estimates of the costs relating to staffing and overheads associated with gaining approval for an upstream petroleum project? If so, what is the proportion of these to total project costs?

Contained within the eight case studies on the regulatory complexity face by the industry is a summary of some estimates relating to staffing and overheads associated with gaining approval for an upstream petroleum projects. The case studies presented in this submission illustrate that dedicated teams of up to 90 personnel are required to prepare approval documents for a number of years. Even for smaller projects, approval requirements generate workloads in excess of six man years and several million dollars in overheads.

As the sums associated with investments in projects often exceed many billions of dollars, the percentage proportion of staffing and overheads associated with gaining approvals for petroleum projects is very small. The real costs are the delays connected with project start-ups that reduce project net present values (and therefore project returns). This is particularly the case for gas projects where project revenues are often evenly spread over long lives, but large development costs must be incurred upfront prior to the commencement of production. Importantly, projects must also compete with alternative investment opportunities and delays resulting from regulatory requirements can lead to funding being delayed or lost.

51. How does this compare with international experience or experience in other Australian jurisdictions?

APPEA does not have independent research or information provided by members that would allow us to respond to this question at this stage. Perhaps this is something the Commission would consider independently commissioning, but as illustrated in response to Question 50, it is the time taken for approvals that reduces project net present values (and therefore project returns).

52. How does the time taken in Australia in the exploration–development– production cycle compare with experience in the industry elsewhere?

As discussed in responses to Questions 50 and 51, it is the time taken to move through the exploration – development – production cycle that is critical to project returns and a projects net present value. Most companies will seek to have a spread of investments across the risk–return spectrum, and Australia fits into that part of the spectrum offering lower risk than many other parts of the world. For this reason some international comparisons rank Australia relatively highly for petroleum investment. But Australia's lower risk is also accompanied by lower returns. Wood Mackenzie (2004) evaluated exploration performance and returns for 60 regions to which international oil companies had access between 1994 and 2003. On the basis of discovery success rates, average discovered field sizes, development costs and government take, offshore Australia ranked poorly—38 out of 60—for returns on exploration spending.

Part of this can be attributed to regulatory approvals and the time taken to move through the exploration – development – production cycle. It is the experience of APPEA members that gaining an approval in Australia often takes significantly more time than many other jurisdictions, such as onshore United States or Gulf of Mexico, and as a result companies

are increasingly choosing to invest their exploration budgets overseas rather than wade through Australia's regulatory maze.

This trend was clearly evident during the recent *Good Oil* Conference, held in September 2008 in Fremantle. Of the 22 oil and gas companies exhibiting at this conference, 3 were promoting Australian and overseas prospects, 6 were promoting solely Australian prospects and 13 were promoting solely overseas prospects. Of the 43 companies presenting at the Conference, 18 each had Australian and overseas interests, while 7 had interests both in Australia and overseas (5 are APPEA members).

Of those that attended the Good Oil Conference, the number one prevailing theme was regulation for access and environment approvals. While delegates noted the efforts of South Australian regulators as the exception, the consensus was that due to regulatory requirements there is a great difficulty to acquire acreage and undertake activity to get results in a time-frame that is acceptable to investor expectations.

53. Are there Australian regulations or standards that unnecessarily restrict the use of internationally accepted inputs, processes, equipment or technologies, resulting in deviations from internationally accepted best practice? If so, what are some examples of these and the costs associated with such restrictions?

The regulatory regime that predominantly applies to Australia's oil and gas industry is primarily objective based. Under such a regime the operator must demonstrate that that it can meet the government's regulatory objectives and that the risks have been identified, assessed and reduced to as low as reasonably practicable (ALARP).

Up until the early 1990s, the offshore petroleum industry in Australia was regulated by legislation that largely prescribed specific laws to be complied with and specific standards to be met. Too often the regulator was assumed to have responsibility for identifying what was best for the industry. The experience of the industry is that prescriptive legislation too often achieves a minimum compliance culture, with the focus on meeting the bare minimum requirements rather than paying attention to all existing and emerging risks actually present in dynamic and ever changing workplaces.

There is no diminution of standards under an objective based regime. In the case of pipeline management for instance, the operator should demonstrate the standard being applied and how the risk is being reduced to ALARP. In practice, the industry would refer to for example, an appropriate Australian or International Standard (in this case AS2885 (Part 1 issue 1997)) but go beyond this minimum standard and reduce the risk to ALARP. It is for all the reasons above that we support objective based regulation, the flexibility this gives to choose the most appropriate global standards and do not support any move backwards to a prescriptive approach to managing such complex facilities and operations.

54. Are there any significant unnecessary administrative costs and red tape involved in calculating petroleum resource taxes, crude oil excise and royalties?

Petroleum resource taxes are levied under the following legislative provisions:

- Petroleum resource rent tax under the Petroleum Resource Rent Tax Assessment Act 1987;
- Crude oil excise under the Excise Tariff Act 1921;
- Federal royalty under the Offshore Petroleum Act 2006;
- State/territory royalties under the applicable state/territory legislation

Petroleum Resource Rent Tax

PRRT is broadly a profits 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 or operating costs that relate to the petroleum project, and are deductible in the year they are incurred. Deductible expenditures include exploration, development, operating and closing activities;
- expenditures which are 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.

There are varying degrees of uncertainty associated with the above provisions. In terms of PRRT, of concern to industry is the uncertainty created surrounding key interpretive aspects of the regime. A range of issues have been encountered over recent years that have led to litigation and/or protracted disputes with the ATO. The administration of PRRT (which is broadly a tax based on economic principles) by the ATO had led to uncertainty in relation

to key operative provisions. Important issues such as the definition of eligible expenditures, the scope of exploration related costs and the nature of indirect administrative costs has created uncertainty for a range of taxpayers.

APPEA sees a role for policy agencies (such as Treasury) to become more involved in determining the policy framework for key operative provisions of the PRRT regime to assist in setting the direction for the ATO to more effectively administer the regime. In 2002, APPEA provided the government with a comprehensive list of proposed modifications to the regime to improve it's clarify and effectiveness. Some of these issues remain to be resolved while new areas of uncertainty are being encountered.

A recent example of this uncertainly surrounds accounting for PRRT as Income Tax. The Australian Accounting Standards Board recently issued a formal interpretation 1003 regarding the treatment of Petroleum Resource Rent Tax (PRRT) as a tax under AASB 112 with effect from 1 July 2007 that effectively means that PRRT is accounted for as income tax. This creates an anomaly with respect to the manner of reporting Australian PRRT diverging from the way in which some global resource companies approach the accounting treatment of PRRT. There is no standard practice as to how PRRT should be accounted for and in particular there is no industry approach to how PRRT is treated on acquisition and disposal of an interest in an asset that has PRRT attached to it.

There are some aspects of the administration of the petroleum royalty and crude oil excise regimes that can impose administrative burdens on taxpayers, although they are generally more clearly understood than the PRRT provisions.

International competitiveness

55. Is there evidence of significant adverse regulatory impact on the sector's productivity, profitability and international competitiveness compared with relevant operations in comparable overseas countries? Is it likely that these adverse regulatory impacts adversely affect other Australian industries and consumers through inter-industry linkages? If so, in what ways?

Yes there is evidence that Australia's regulatory system is having a significant impact on the sectors international competitiveness. The oil and gas industry is very capital intensive, and tens of billions of dollars of capital will be needed 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, for example, from 19.5 mtpa (once the current North West Shelf expansion is completed in 2008) to the industry target of 50-60 mtpa by 2017 will require new capital investment of at least $40 billion.

Although the geological knowledge base is far from complete, Australia is generally perceived to offer low prospectivity for oil, with relatively low discovery rates and small average field sizes. Gas prospectivity is good, but Australia already has many large undeveloped gas fields, and new gas discoveries are often remote from markets and difficult to commercialise. In the past Australia has offered a reasonably attractive petroleum investment environment and developed a reputation as being a sound place to do business. Low sovereign risk, transparent legal and regulatory processes, a stable political and economic environment, competitive markets and solid investment in pre-competitive geoscience research are significant advantages, encouraging global oil companies to direct a part of their activity and investment to Australia.

Most companies will seek to have a spread of investments across the risk–return spectrum, and Australia fits into that part of the spectrum offering lower risk than many other parts of the world. For this reason some international comparisons rank Australia relatively highly for petroleum investment. But Australia's lower risk is also accompanied by lower returns. Wood Mackenzie (2004) evaluated exploration performance and returns for 60 regions to which international oil companies had access between 1994 and 2003. On the basis of discovery success rates, average discovered field sizes, development costs and government take, offshore Australia ranked poorly—38 out of 60—for returns on exploration spending.

Development risk in Australia is also increasing. Oil project developments have tended to be in deeper water and more technically challenging. The large capital requirements, long construction periods and long payback periods associated with remote LNG projects also increase Australia's risk profile. In short, global competition for investment capital is increasing, and there are many investment alternatives. To optimise the value of its petroleum industry, Australia must constantly monitor its overall competitive position for investment.

Ensuring a competitive regulatory framework is a critical ingredient for maintaining and improving on Australia's overall global competitive position as an attractive investment destination. The perception that Australia's regulatory system is negatively impacting on Australia's international competitiveness as an investment destination 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. Gaining unnecessary approvals causes delays that can be costly and inefficient for both industry and government, and has the potential to drive investment overseas, from both Australian companies and international companies with Australian operations.

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 hundreds of decisions required to be taken. These smaller offshore exploration companies are frequently seeking to access Australia's higher-risk frontier areas and are increasingly choosing to invest their exploration budgets overseas rather than wade through Australia's regulatory maze.

Returns on investment

56. What are the most significant impacts of unnecessary regulatory constraints on investment returns?

Investments in the upstream petroleum industry commence in the exploration phase and generally end at the point of decommissioning. Regulatory constraints that delay or defer investments during all stages of the exploration, development, production and decommissioning processes can have a direct impact on project returns.

As the sums associated with investments in projects often exceed many billions of dollars, delays connected with project start-ups reduce project net present values (and therefore project returns). This is particularly the case for gas projects where project revenues are often evenly spread over long lives, but large development costs must be incurred upfront prior to the commencement of production. Importantly, projects must compete with alternative investment opportunities and delays resulting from regulatory requirements can lead to funding being delayed or lost.

57. What are some examples of consequential losses that are due to unnecessarily extended delays and uncertainties associated with approvals?

These consequential losses are extremely hard to quantify. However the anecdotal evidence that APPEA have gathered would suggest that extended delays and uncertainties result in significantly higher project costs and consequential losses than the actual costs expended in seeking approvals and ensuring compliance. By way of example, delays and uncertainties with approvals have recently resulted in:

- Resulted in several millions of dollars in rescheduling costs and delays of up to two years in drilling or seismic acquisition;
- Downtime worth millions of dollars waiting for marine pest inspections and clearances on critical vessels and infrastructure; and
- A relatively minor delay in Customs approvals to import vessels that may contain asbestos, that amounted to a cost of almost $10 million.

A more specific example would be a relatively simple gas field project tying into existing infrastructure that has taken over two years and cost over A$1million. Whilst it could be argued that this is a relatively small percentage of the total project cost, the capital cost of the project has increased by about 50 percent during this period. This has a significant impact on a small to medium company that is raising debt and equity finance to develop the project.

58. By relevant international comparisons, are upstream producers in Australia facing increased financial project risks as a result of unnecessary regulatory delays? What are some examples and where are the greatest opportunities for improvement?

The length and complexity of the multi-jurisdictional approvals regime that applies to Australia's oil and gas industry is clearly contributing to an international perception that Australia is a difficult place to invest in oil and gas exploration and development. As stated in response to Question 2, in today's globally competitive economy resource companies are examining many options for investment and a region's policy and regulatory climate has taken on increased importance in attracting and winning investment.

The evidence of this is well documented in the latest Fraser Institute Survey of Mining Companies 2007-08 incorporates a *Policy Potential Index* that serves as a report card to governments on how attractive their policies are from the point of view of an exploration manager. The latest rankings a number of Australian jurisdictions have slid down the list with this year's report for example showing that Western Australia has dropped from a consistent presence in the top 10 jurisdictions, (last year placing 3rd), to now being in the middle of the pack at 27th out of 68 jurisdictions.

Clearly an influencing factor in this global regulatory comparison is the relatively unique structure of the Australian Federation and the largely equal strength of all three levels of government, all with a significant role in the regulation of cross-jurisdictional projects. While APPEA won't comment on the Federation, establishing a joint single national regulatory authority for the upstream oil and gas industry represents a great opportunity for a significant improvement to international regulatory competitiveness.

59. Do unnecessary regulatory delays and costs materially increase barriers to entry for small- to medium-sized upstream petroleum businesses? To what extent does this affect competition and what are the greatest opportunities to mitigate such impacts?

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 hundreds of decisions required to be taken. These smaller companies are frequently seeking to access Australia's higher-risk frontier areas. Gaining an approval in Australia often takes significantly more time than other jurisdictions, such as onshore United States or Gulf of Mexico, and as a result these companies are increasingly choosing to invest their exploration budgets overseas rather than wade through Australia's regulatory maze.

As mentioned previously in response to Question 52, this trend was clearly evident during the recent *Good Oil* Conference, held in September 2008 in Fremantle. Of the 22 oil and gas companies exhibiting at this conference, 3 were promoting Australian and overseas prospects, 6 were promoting solely Australian prospects and 13 were promoting solely overseas prospects. Of the 43 companies presenting at the Conference, 18 each had Australian and overseas interests, while 7 had interests both in Australia and overseas (5 are APPEA members).

Of those that attended the Good Oil Conference, the number one prevailing theme was regulation for access and environment approvals. While delegates noted the efforts of South Australian regulators as the exception, the consensus was that due to regulatory requirements there is a great difficulty to acquire acreage and undertake activity to get results in a time-frame that is acceptable to investor expectations.

60. Are there any estimates of the impact of unnecessary regulatory delays on overall government tax revenues?

Delays in project decisions will cause delays in project proponents commencing production and therefore the generation of taxation revenues for governments. This clearly has a cost in net present value terms.

In addition, under the PRRT regime, funds expended on eligible exploration and general project activities can be compounded forward at defined rates. The nature of the compounding provisions, which are set a rates between the long term bond rate (LTBR) plus five percentage points (general project costs) and LTBR plus 15 percentage points (exploration costs) can see a real increase in deductions that translates into lower government revenues.

Section 5 - What legislative and administrative reforms are required?

Streamlining approvals

61. How effective are current 'one stop shop' arrangements aimed at streamlining approvals?

The South Australian Department of Primary Industries "one Stop Shop" model is highly effective in streamlining the approvals processes in onshore operations. This service facilitates managing the inevitable complexity surrounding the granting of exploration and mining approvals and the periodic introduction of new legislation, regulations and guidelines.

The department established the "one stop shop regime" in recognition that companies have a great need for clarity, transparency, and a simple system for obtaining all necessary approvals, licenses and permits - together with assistance from properly qualified and experienced officers on how best to process and lodge necessary paperwork. It is also crucial to provide a service which crosses departments to simplify lodgement processes:

South Australia contends that the PIRSA's one-stop shop approach is critical to investment attraction and retention in the industry and if South Australia does not provide such a clear system there is a danger that investment will move to other jurisdictions which do. Unfortunately for the industry there is little risk of this occurring as no other State provides a similar well resourced service to facilitate the industry through approval requirements.

62. What improvements can be made to the provision of guidance information and on-line application lodgement and approval tracking?

Increased use of electronic systems by regulators would potentially improve approval timeframes and increase awareness of approval requirements. Electronic approval systems would also ensure that any new requirements or removal of existing regulatory requirements are kept up to date. This would provide some degree of assistance in managing the myriad of approval requirements.

63. To what extent could approval processes be further streamlined under existing arrangements, such as by eliminating redundant requirements?

Of all the regulatory reviews currently being undertaken, a key lesson the industry has learnt is that the application of the CoAG Principles of Best Practice Regulation will draw out many opportunities for regulatory reform. It is the industry's experience that processes that make a case for action, assess a range of feasible options, assess their respective benefits and costs, and the adopt the most effective option that is proportional to the issue being addressed.

It has been the industry's experience that the challenge of many of these reviews is that they are undertaken in isolation from reviews of all other applicable regulatory instruments and guidelines within and between respective jurisdictions. A solution to this would be to work towards the establishment of a single joint regulatory authority who should then be tasked with ensuring that the CoAG principles are applied and that opportunities for streamlining are identified and redundant requirements are eliminated.

64. To what extent could joint responsibilities under the OPA be further rationalised?

Given that the recommendations for significant change to the OPA are yet to be given any legal effect, there is great potential for improvements to the OPA. This could be further improved through the establishment of a single joint regulatory authority, administering a nationally consistent regulatory framework, yet answerable to each respective Minister across each of the jurisdictions.

65. In what ways might the performance of relevant administrative agencies be improved?

Mandatory timeframes for government response during the approvals process would provide for certainty and allow better planning on both sides of the process. Some aspects of the approvals process, especially in the safety aspect under NOPSA, have a specified time frame to make a decision. Currently however, there are very few timeframes that must be adhered to by Government although timeframes can be dictated to industry by Government.

Many other aspects, especially in the final stages of the approvals process with the Designated Authorities, do not have timeframes associated with them. This issue is compounded in related legislative approvals, such as State planning systems (E.g. Environment Effects Statements, Victorian Civil and Administrative Tribunal (VCAT)) and the Commonwealth Environment Protection and Biodiversity Conservation (EPBC) Act. As mentioned previously, the concept of statutory time frames to make specific decisions throughout the regulations should result in a more expedient and cost effective process.

In some cases timeframes exist that have no real impact. For example, the WA Environmental Protection Act 1986 states that the EPA must set a level of assessment and inform the proponent within 28 days of receiving all of the relevant information, however the Act is silent on what occurs if this timeframe is not met. This has the effect of rendering the timeframe meaningless.

In addition, while there may be timelines provided for, in many instances there is also a stop the clock provision available. In Western Australia for instance, the decision to invoke a stop the clock provision is at the discretion of the regulator, and there is a lack of clarity around the circumstances when the clock can be stopped and when it is re-started again. This creates further regulatory uncertainty about the time required for approval and provides further risk for delays. This is not to say that there should not be a provision to allow regulators to request further information. Without this provision, regulators have been known to rely on the appeals process to address issues that could have been addressed early in the process.

The complexity of the various approvals required for the range of possible projects is highly variable; hence it is difficult to make a general statement on how long the approval process should take. However, a period of four weeks for a decision by Government and/or Ministers to progress to the next stage in the process would be a reasonable benchmark to aim for.

66. Could governments more efficiently achieve their policy intent by reducing the number of agencies involved in issuing approvals for upstream petroleum projects through administrative agreements and memoranda of understanding?

There is significant potential for increased regulatory efficiencies through mutual recognition of other agencies regulatory processes. One successful model is identification of levels of environmental assessment required for operations in WA's state waters through an MoU between the Department of Industry and Resources and the Department of Environment and Conservation.

The gamete of MoU's established between NOPSA and bodies such as the Australian Maritime Safety Authority and the Civil Aviation Safety Authority is another good example of improved regulatory efficiency.

Unfortunately however these arrangements are the exception. Other areas that would benefit from rationalisation are environmental controls, including exploration drilling and seismic approvals under the EPBC Act and OPA. Another example would be the vegetation clearance approvals in Western Australia under both the Petroleum Act, which requires a decision within 28 days and *Environmental Protection (Clearing of Native Vegetation) Regulations 2004.*

In relation to the Native Vegetation Regulations, one company applied for a very minor amount of clearing on (0.7 hectares maximum) to undertake an activity already controlled under the Environment Impact Assessment process. The official approval clock did not start until the application for clearance was advertised almost a month later. On receipt of several objections due to the high profile and public nature of this project, the company was advised that this would add 2 months to the process. A string of information requests from the Department were forthcoming (including for information that was provided in the application) despite the fact that a detailed botanical report commensurate with the size of the clearing had already been provided. A single request would have been simpler and quicker as would a proper reading and account taken of the information originally provided.

In this particular instance, the process from start to finish took in excess of 200 days for a process that is generally held to be a 90 day process and is in addition to the similar requirement under the Petroleum Act, requiring a decision to be made within 28 days. Similar excessive requirements have been reported by the industry in seeking approval to remove weeds from a helicopter landing zone and utilise a weed trimmer to clear vegetation from the vicinity of accommodation and control rooms.

Harmonisation

67. Where could the greatest benefits be delivered to the sector through reduction in regulatory burden by harmonisation?

Clearly in the previous 66 questions, the industry has made the case in a large number of areas where there would be significant potential benefits that would result from harmonisation, streamlining and consolidation of the regulatory regime that applies to Australia's oil and gas industry. These benefits would be derived across the sector as well as by those with the regulatory duties, but scarce resources, to oversee the activities of the industry.

APPEA's submission to this Review focuses on the full range of suggested improvements to the most important areas of Australia's regulatory framework that includes:

- a consolidation of existing regulatory requirements;
- a number of options to improve consistency of administration through:
  - "one stop shop" facilitators,
  - consideration of a national regulator;
  - expansion of the environment assessors forum;
  - expanded use Memorandums of Understanding;
  - accreditation of assessment and approval processes across and within jurisdictions;
- increasing the adequacy of training, resourcing and retention of regulators; and
- ensuring that all future regulations are subjected to the CoAG test of regulatory principles.

Consideration and adoption of many of these suggestions across Australia's onshore and offshore jurisdictions would result in a more effective and efficient management of Australia's hydrocarbon resources in accordance with the interests of the nation and ensure the significant potential for growth of this industry are realised.

A national regulator – extending the NOPSA model

68. What would be the key institutional features of an effective and efficient national upstream petroleum regulator?

See response to Question 20.

69. What are the strengths and weaknesses of NOPSA as a national regulatory model?

See response to Questions 18 through to 21.

70. Would an extended NOPSA, or a number of NOPSA-like regulators, be a suitable basis to nationally regulate the upstream petroleum sector as a whole?

See response to Questions 18 through to 21.

71. What changes might be considered?

See response to Questions 18 through to 21.

72. What governance arrangements would be necessary to maximise the effectiveness and efficiency of a national regulator?

See response to Questions 18 through to 21.

73. What can be learnt from similar arrangements in Australia and overseas to assist in the successful establishment of such a model?

See response to Questions 18 through to 21.

74. Are the potential advantages of nationally harmonised legislation and a national regulator sufficient to counterbalance any potential disadvantages, such as loss of competitive tensions between the regulatory regimes of different jurisdictions?

Possibly, but APPEA and its members recognise that determination of appropriate administrative arrangements is largely a matter for government. Nevertheless these arrangements do have to be designed to ensure that the system acts as an independent verifier of the effective implementation of the industry's operating plans and that it supports the application of world's best practice throughout the industry.

However APPEA and its members will not comment at this preliminary stage on a preferred institutional model. It is a matter for government to put its case to industry as to the most appropriate institutional structure that will meet the needs of the industry, workforce, governments and the community.

For APPEA to support this case a number of preconditions and key principles must be met for a national regulator model or any other proposals for change to the regulatory regime. Without these preconditions and principles being considered during the transparent and open development of any new arrangements for regulation of the offshore petroleum industry, industry will not be able to support proposed changes.

75. How might a single national regulator be kept efficient and effective?

A single national regulator would be kept efficient and effective through ensuring accountability to both industry and the public. APPEA strongly believes that there should be a high degree of public oversight of all expenditures of a single national regulator to ensure that:

- the regulator is focused on appropriate regulatory priorities;
- there are appropriate levels of regulator activity;
- expenditure levels are appropriate to deliver identified regulatory priorities , and
- there is an efficient and effective delivery of regulatory responsibilities.

With a high degree of public oversight of all expenditures, industry would have a higher level of confidence in the case for any significant expansion or change to regulatory requirements. As a result there would also be a far lower level of reluctance by industry to accept any further regulatory functions being incorporated into a joint Commonwealth – State national regulatory body. Without a high degree of public oversight, there will remain a high level of reluctance by industry to consider a new regulatory regime, regardless of the benefits that nationally harmonised regulation will bring.

76. What changes to the OCS might be required to harmonise the relevant regulations?

With the establishment of NOPSA as a joint statutory authority, there was no requirement to amend the Offshore Constitutional Settlement (OCS). If this joint statutory model was also chosen for a single national regulator for Australia's upstream oil and gas industry, then it is possible that there still would be no need to make any changes to the settlement. If alternative models were chosen, then changes to the OCS may need to occur to give effect to these arrangements, but this is largely something for the consideration of governments, in consultation with the industry.

4. EIGHT CASE STUDIES OF THE REGULATORY COMPLEXITY FACED BY A RANGE OF PETROLEUM DEVELOPMENT ACTIVITIES

Through the process of consultation with its members, APPEA has brought together a number of case study examples demonstrating the current regulatory burden faced by the Australian oil and gas industry, including:

- Two major LNG development proposed for an existing industrial region and sensitive environment;
- a small domestic gas project and associated offshore infrastructure;
- n unmanned oil facility, connected via a pipeline through State and Commonwealth waters to an onshore processing and distribution facility;
- a tie in gas development, connecting a gas new resource to existing gathering and processing infrastructure;
- a stand alone Floating Production, Storage and Offloading (FPSO) oil field development located in Commonwealth waters;
- a pipeline development project connecting a major development in Commonwealth waters to gas processing infrastructure located on State Lands; and
- a green-fields sub-sea gas development in Commonwealth waters, with associated pipeline and onshore processing and distribution infrastructure.

APPEA has summarised each of these eight case studies, and considers the total number of approvals required, the total number separate regulatory agencies from which these approvals are required and a consideration of the time that it takes to obtain all the approvals required before a project or industry activity can proceed. APPEA is also willing to provide the approvals registers for each of these projects for consideration of the Productivity Commission on a Commercial-in-Confidence basis.

While it may be a point of debate as to how best measure the regulatory burden applied to industry, and specifically Australia's upstream petroleum sector. APPEA currently utilises a combined measure of the total number of approvals required, the total number separate regulatory agencies from which these approvals are required and a consideration of the time that it takes to obtain all the approvals required before a project or industry activity can proceed. Another measure used by APPEA and its members includes the number of days per year spent on ongoing reporting requirements.

In the absence of any other clear benchmarks, the duration required and total number of approvals could, in addition to other measures, provide an indication of how well Australia's regulatory regime compares with the regulatory regimes of its international competitors. The length and complexity of the multi-jurisdictional approvals regime that applies to Australia's oil and gas industry is contributing to an international perception that Australia is a difficult place to invest in oil and gas exploration and development.

For the purposes of the Productivity Commission review, these case studies do clearly demonstrate that approvals for major oil and gas projects may take in excess of 5 years, can require over 500 separate approval requirements, and frequently engage with over a dozen and sometimes more than 20 regulatory agencies. In addition, once approvals have been granted some larger companies can spend over one third of the year reporting to various agencies.

It is clearly the case that to develop any of these projects requires extensive teams of potentially dozens of highly trained people to shepherd the approvals through the company, engage with government, engage with scientists, engineers and other specialist contractors and of course engage in consultation with local communities.

Case Study 1

LNG Development in Commonwealth waters with onshore processing

Australia has identified a number of conventional gas resources with the potential for commercialisation into both domestic and export liquefied natural gas (LNG) developments. Reserves of conventional gas identified by Geoscience Australia are estimated to be 146 trillion cubic feet, or some 110 years supply at current production rates.

LNG projects are high cost and take a long time to construct and deliver a return on investment. Project costs for LNG projects are now in the tens of millions of dollars, take 2 to 5 years to construct and once operational can take up to 10 years before an LNG project starts making a positive return on capital. On the other hand, LNG projects once fully operational provide long term benefits for the economy. While considerable emphasis is placed on the jobs and work created during the initial construction period, these are far outweighed by the whole of life benefits accruing over a 20-50 years operational life.

This case study involves accessing gas resources located in Commonwealth waters, with pipeline infrastructure bringing the resource through State waters onshore for processing, liquefaction and export via shipping.

This project is estimated to provide economic benefits to Australia:

- $11 billion initial investment over the next 20 years;
- Payment of $17 billion in company tax and Petroleum Resource Rent Tax by the joint venturers (plus $2 billion in tax generated from the additional economic activity);
- Additional export income of $2.5 billion a year;
- Permanently adding 6000 direct and indirect jobs to national employment, 1700 of which will be in Western Australia
- Expansion of existing services and industries, and attraction of new ones
- Underpinning the development of new technologies and skills, such as CO2 sequestration and subsea technology, creating regional capacity for future growth.

This project:

- required some 390 regulatory considerations and requirements; from
- 26 separate regulatory agencies, of which 10 were Commonwealth and 12 were State/Territory, 3 Local Government, and one joint statutory authority.

More specifically the total number of regulatory requirements included:

- 32 relating to general project approvals and preliminary survey requirements;
- 140 relating to the upstream investigation, construction, commissioning and operation in offshore waters; and
- 218 relating to the downstream investigation, construction, commissioning and operation of onshore facilities;

Case Study 2

LNG Development in Commonwealth waters with onshore processing

This case study involves accessing gas resources located in Commonwealth waters, with pipeline infrastructure bringing the resource through State waters onshore for processing, liquefaction and export via shipping. This development involves capital expenditure of $6-10 billion and will create up to 3000 direct jobs during construction and up to 200 jobs during operations from 2010. A further 3000 indirect jobs will also be created, mostly in the State, with an expected to boost the State economy by at least A$28.6 billion over the life of the project.

This project:

- required some 277 regulatory considerations and requirements; from
- 19 separate regulatory agencies, of which 9 were Commonwealth and 10 were State/Territory.

More specifically the total number of regulatory requirements included:

- 64 relating to general project approvals and preliminary survey requirements;
- 53 relating to offshore drilling, installation, construction and diving requirements;
- 49 relating to offshore pipeline design, construction, installation, commissioning, and operations;
- 7 relating to the decommissioning;
- 30 relating to shore crossings and shipping facility requirements;
- 52 for the storage, loading and processing facilities; and
- 22 relating to other general approvals for accommodation, gas connections and permit administration.

One of the challenges on this development has been the impetus to develop this export LNG project to take advantage of favourable global market conditions. As a result of the great importance of market timing a range of development options were under consideration and therefore the need to prepare approval documents for many of these different options.

The resources allocated, both internally and externally, to steer through the regulatory requirements for this project included:

- 1 fulltime approvals coordinator;
- 1 offshore environment approvals coordinator;
- establishing 30 focal points within the operator to coordinate all of the 277 individual applications, with each focal point requiring 2-3 people;
- preparation of several of the approval documents are out-sourced, such as the Public Environment Report and Field Development Plans at significant cost but still requiring high degrees of oversight and coordination by the operator; and
- several meetings interstate to Commonwealth regulators in particular (at the early stage of environment approvals and field development plan there were weekly visits for several personnel each time).

Case Study 3

Commonwealth waters oil development with onshore processing

Some smaller offshore resources are increasingly being accessed via not-normally manned facilities with a pipeline connecting the platform to onshore processing facilities. In this case study, a jack-up installed, unmanned, remotely operated wellhead platform was connected by two pipelines to onshore processing facilities. The platform sources oil reserves from eight production wells and incorporates two water re-injection wells, with the total cost for the development and construction of this operation exceeding $320 million.

This small unmanned facility located in Commonwealth waters required:

- 163 separate regulatory considerations and requirements; from
- 22 separate agencies, of which 8 were Commonwealth and 14 were State Government.

More specifically the total number of regulatory requirements included:

- 17 relating to the requirements for petroleum titles and licensing;
- 47 relating to the construction, installation, commissioning, operations and decommissioning of the offshore facility;
- 61 relating to pipeline approvals;
- 18 relating to drilling operations; and
- 45 relating to the construction, commissioning and operations of the onshore facilities.

The resources allocated, both internally and externally, to steer through the regulatory requirements for this project included:

- approximately 6 man years overall for the internal management by the operator of all 163 approvals and regulatory requirements;
- 54 man months of the internal management and coordination of all health, safety and environmental approvals; and
- engagement of contractors for the drilling and pipeline approvals totalling over $100,000.

Case Study 4

Commonwealth waters gas development

Smaller gas reserves may not be commercial in their own right, but when tied into existing gas processing infrastructure, can become commercial and add significantly to the diversity of Australia's domestic gas supplies.

A gas development located entirely within Commonwealth waters and tying into existing onshore gas processing infrastructure and requiring no construction for onshore processing required:

- 83 separate regulatory considerations and requirements; from
- 17 separate agencies, of which 14 were Commonwealth and 3 State Government bodies.

More specifically the total number of regulatory requirements included:

- 24 relating to the drilling design, construction and operation phase;
- 7 relating to obtaining a production licence;
- 46 relating to the pipeline design, construction, installation, commissioning and operations phase; and
- 6 relating to the decommissioning phase.

The resources allocated, both internally and externally, to steer through the regulatory requirements for this project included:

- Environmental approvals (EPBC and PSLA) that have cost approximately $200,000 in environmental consultants fees as well as 5 man-months of time from the operator;
- Production licence, Field Development Plan, Pipeline Management Plans, Pipeline Licence that have required about 8 man-months of time from the operator to prepare;
- Installation Vessel Safety Case Revision, Dive Management Plan and supporting HSE management plans and procedures for installation that have cost around $200,000 in consultancy fees; and
- HSE assessments in design for the operation have cost a further $300,000 in consultancy fees.

Case Study 5

Commonwealth waters gas development

In this large domestic gas project, the operation will comprise offshore production, a subsea pipeline of at least 100 kilometres length to shore, and onshore gas processing infrastructure. A host platform is likely to be located in shallower waters of about 50 to 70 metres, with flowlines running down to production wells in deeper water.

This domestic gas development project has required:

- 127 separate regulatory considerations and requirements; from
- 35 separate regulatory agencies, of which 13 were Commonwealth and 20 were State/Territory, one Local Government, and one joint statutory authority.

More specifically the total number of regulatory requirements included:

- 69 relating to state and local government requirements; and
- 58 relating to Commonwealth government requirements.

Case Study 6

Commonwealth Waters Floating Production, Storage and Offloading Facility Oil Development

To access smaller oil and condensate reserves that do not warrant the construction of immense traditional steel jacket or concrete gravity infrastructure designed to last decades, the industry is increasingly using Floating Production, Storage and Offloading (FPSO) technology. In this case study the development involves a subsea development and an FPSO facility which will be used to process, store and offload oil to export tankers, with an estimated economic field life of approximately 10 years. The vessel will be disconnectable, double hulled and be able to process approximately 80,000 barrels of liquids a day. Project costs for the development and construction of this operation are approximately US$600 million.

This stand alone FPSO development in Commonwealth waters identified 44 broader scale approval requirements from 6 separate agencies. Significantly this development did not include any pipeline regulatory requirements, which in the previous three case studies accounted for 49, 61 and 46 approvals respectively. Of the 44 approvals that were required for this stand alone FPSO development:

- 18 related to subsurface and drilling operation requirements;
- 14 related to validation, environmental, health and safety approvals;
- 6 related to installation and diving requirements; and
- 6 related to standards of design, testing and recovery of petroleum.

Case Study 7

Pipeline Design, Construction, Installation and Operation

In this case study, the operator identified that the approvals required just for the pipeline connecting gas wellheads to onshore processing facilities included 55 approval points or considerations to just the National Offshore Petroleum Safety Authority and the State Designated Authority. This project will produce around 180 terajoules of gas per day and 850 barrels of condensate per day, from three production wells producing to an unmanned platform. Project costs for the development and construction of this operation are approximately $300 million.

Of the 55 approvals that were required just for the pipeline of this project:

- 9 related to the initial development and project proposal;
- 11 related to the pipeline design;
- 14 related to the pipeline construction;
- 13 related to the pipeline operation; and
- 8 related to consents or notices required.

Case Study 8

Subsea Near-Shore Gas Development and Onshore Processing Facility

Another example of developing Australia's gas resources is through the use of sub-sea wells without the need for any top-side development. These sub-sea wells are then typically connected to an onshore processing facility via pipelines through Commonwealth and State waters. In this instance the pipelines connected the production wells offshore to an existing stabilisation and processing facility. However the cost to develop and construct this project still exceeded $200 million.

This facility located in Commonwealth waters, with pipeline access to existing onshore processing infrastructure required 144 separate regulatory considerations and requirements, of which again the largest percentage related to pipeline requirements (over 25 percent).