Australian Government
Productivity Commission

Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector

Productivity Commission
Research Report

April 2009

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ISBN 978-1-74037-278-7

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An appropriate citation for this paper is:

Productivity Commission 2009, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, Research Report, Melbourne.

The Productivity Commission

The Productivity Commission is the Australian Government's independent research and advisory body on a range of economic, social and environmental issues affecting the welfare of Australians. Its role, expressed most simply, is to help governments make better policies, in the long term interest of the Australian community.

The Commission's independence is underpinned by an Act of Parliament. Its processes and outputs are open to public scrutiny and are driven by concern for the wellbeing of the community as a whole.

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Foreword

In 2008, the Council of Australian Governments (COAG) identified the upstream petroleum sector as one of many 'hotspot' areas where overlapping and inconsistent regulation threatens to impede economic activity, and agreed that the Productivity Commission should undertake a review.

The focus of the Commission's report is on measures that have the potential to reduce *unnecessary* burdens on the upstream oil and gas sector — in other words, regulatory burdens that can be removed without compromising desirable outcomes, such as relating to resource management, the environment, heritage, development, land access and occupational health and safety.

The report identifies significant unnecessary costs from delays and uncertainties in obtaining approvals, duplication of compliance requirements, and inconsistent administration of regulatory processes. The Commission finds that these burdens could be reduced through new institutional arrangements — principally the establishment of a national offshore regulator — as well as implementation of best practice regulatory principles in all jurisdictions.

In conducting its review, the Commission has drawn on information from submissions and consultations with a range of participants from industry and government. The Commission is grateful to the many people who have taken the time to contribute to this study, including those who provided feedback on the draft report.

The study was overseen by Commissioner Philip Weickhardt, with a staff research team from the Commission's Melbourne office.

Gary Banks AO
Chairman

April 2009

Terms of reference

Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector

Background

In its report on *'Annual Review of Regulatory Burdens of Business: Primary Sector*', the Productivity Commission recommended a broad review of the whole Australian onshore and offshore petroleum regulation framework.

Most of Australia's petroleum resources are in Commonwealth waters and are brought onshore for processing in State or Territory jurisdictions. As such, many petroleum projects cross numerous jurisdictions. Every step in the exploration, development and production of petroleum is regulated by various governments and regulatory agencies. For many petroleum projects, there are often duplicated requirements for a given activity for each of the jurisdictions involved.

This study will consider Australia's framework for upstream petroleum regulation and consider opportunities for streamlining regulatory approvals, providing clear timeframes and removing duplication between jurisdictions.

Scope of the review

The Productivity Commission is requested to undertake a research study on the regulation of crude oil and natural gas projects that involve more than one jurisdiction (but not the regulation of subsequent refining, distribution and wholesaling/retailing activities, coal seam methane or any other mineral resource). In undertaking the study, the Commission is to:

- assess the impact of the current regulatory framework on the international competitiveness and economic performance of Australia's petroleum sector and on the performance of the economy as a whole;
- report on regulatory impediments to improved performance, including inconsistencies and duplication across jurisdictions, and ways in which governments in Australia could address them; and
- consider options for a national regulatory authority (for example, along the lines of the National Offshore Petroleum Safety Authority model) to manage all regulatory approvals for the upstream petroleum industry as a means of addressing issues of regulatory duplication and inconsistencies.

In conducting the study and providing information to reduce unnecessary regulatory burdens on the upstream petroleum sector, the Commission is to:

- seek public submissions and consult with business, government agencies and other interested parties;
- have regard to any other current or recent reviews commissioned by Australian governments affecting the regulatory burden faced by businesses in the upstream petroleum sector; and
- have regard to the underlying policy intent of government regulation on the upstream petroleum sector.

The Commission is to report within 12 months of commencing the study and the Commission's report will be published and submitted to all Australian governments for consideration.

CHRIS BOWEN
Received 10 April 2008

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Abbreviations and explanations

Abbreviations

ABARE	Australian Bureau of Agricultural and Resource Economics
ALRA	*Aboriginal Land Rights Act 1976* (Cwlth)
APPEA	Australian Petroleum Production and Exploration Association
CCS	Carbon capture and storage
CMATS Treaty	Certain Maritime Arrangements in the Timor Sea Treaty
COAG	Council of Australian Governments
Cwlth	Commonwealth
DA	Designated Authority
DEWHA	Department of the Environment, Water, Heritage and the Arts (Australian Government)
DoIR	Department of Industry and Resources (WA Government)
DMP	Department of Mines and Petroleum (WA Government)
EAF	Environmental Assessors Forum
EEO	Energy Efficiency Opportunities
EIA	Environmental impact assessment
EP Act	Environment Protection Act
EPBC Act	*Environment Protection and Biodiversity Conservation Act 1999* (Cwlth)
ERA	Economic Regulation Authority (WA Government)
ESD	Ecologically sustainable development
GDP	Gross domestic product
ILUA	Indigenous land use agreement
IUA	International Unitisation Agreement for Greater Sunrise

JA	Joint Authority
JOA	Joint Operating Agreement
JPDA	Joint Petroleum Development Area
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MCMPR	Ministerial Council on Mineral and Petroleum Resources
MoU	Memorandum of Understanding
NES	National Environmental Significance
NGER Act	*National Greenhouse and Energy Reporting Act 2007* (Cwlth)
NOPR	National Offshore Petroleum Regulator
NOPR-CW	National Offshore Petroleum Regulator in Commonwealth Waters
NOPSA	National Offshore Petroleum Safety Authority
NPV	Net present value
NNTT	National Native Title Tribunal
NTA	*Native Title Act 1993* (Cwlth)
OCS	Offshore Constitutional Settlement
ODAC	Office of Development Approvals Coordination
OECD	Organisation for Economic Cooperation and Development
OHS	Occupational health and safety
OPA	*Offshore Petroleum Act 2006* (Cwlth)
OPGGSA	*Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth)
PC	Productivity Commission
PDO	Plan for Development and Operations
PIRSA	Primary Industries and Resources South Australia
PRRT	Petroleum Resource Rent Tax
PSLA	*Petroleum (Submerged Lands) Act 1967* (Cwlth)
RET	Department of Resources, Energy and Tourism (Australian Government)
RIS	Regulatory Impact Statement
RTN	Right to negotiate

UNCLOS	United Nations Convention on the Law of the Sea
WACC	Weighted average cost of capital
WOMP	Well Operations Management Plan

Explanations

Billion	The convention used for a billion is a thousand million (10^9).
Findings	*Findings in the body of the report are paragraphs highlighted using italics, as this is.*
Recommendations	***Recommendations in the body of the report are highlighted using bold italics with an outside border, as this is.***

Glossary

Appraisal well	A well or wells drilled to follow up a discovery and evaluate its commercial potential.
Barrel	Measure of crude oil equal to 42 US gallons, 35 Imperial gallons or 159 litres.
Basin	A dip in the earth's crust usually filled or being filled with sediment.
Coastal waters	The area between the territorial sea baseline (generally situated at the lowest astronomical tide line along the coast) and the line that is three nautical miles seaward of the territorial sea baseline as well as any waters landward of the baseline that are outside the limits of the States and the Northern Territory.
Commonwealth waters	The area between the outer limit of the coastal waters (three nautical miles from the territorial sea baseline) and the outer limit of the continental shelf.
Completion	The final preparations to ready a well for production.
Condensate	Hydrocarbons that are gaseous in a reservoir, but condense to form a liquid as they rise to the surface where the temperature is typically lower.
Continental shelf	The area extending from the outer limit of the territorial sea (12 nautical miles from the territorial sea baseline) for up to 200 nautical miles from the territorial sea baseline (subject to boundary delimitations with other countries). It can extend further if the physical continental shelf continues beyond 200 nautical miles in accordance with the United Nations Convention on the Law of the Sea.
Crude oil	Oil produced from a reservoir after associated gas has been removed.
Designated Authority (DA)	The Designated Authority for an offshore area of a State or Territory is constituted by the responsible State or Territory Minister. DA may also be used to describe the State or Territory government officials who assist the DA and have powers delegated to them by the DA.

Designated coastal waters	Coastal waters and any area between the territorial sea baseline and the coastline of the State and Territory that was, immediately before the commencement of the relevant State or Territory petroleum laws, the subject of an exploration permit under the repealed *Petroleum (Submerged Lands) Act 1967* (Cwlth) (when such an area no long has an exploration permit, retention lease or production licence under State or Territory petroleum laws, it is no longer part of designated coastal waters). This term is used for the purposes of Part 4.8 of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth), relating to the National Offshore Petroleum Safety Authority.
Downstream	Industry operations beyond the initial extraction and processing stages including refining and marketing — opposite to upstream.
Exclusive Economic Zone (EEZ)	The area extending from the outer limit of the territorial sea (12 nautical miles from the territorial sea baseline) for up to 200 nautical miles from the territorial sea baseline (subject to boundary delimitations with other countries).
Exploration licence	A licence to explore for oil or gas in a particular area issued to a company by the governing jurisdiction.
Hydrocarbons	Compounds containing only the elements of hydrogen and carbon. They may exist as solids (such as coal), liquids (such as crude oil) or gas (such as natural gas).
Internal waters	Australia's internal waters are the waters on the landward side of the territorial sea baseline. These waters can be divided between internal waters of the States and Northern Territory and internal waters of the Commonwealth. The internal waters of a State or Territory are those waters that fall within the Constitutional boundaries of that State or Territory, which may include bays, gulfs, estuaries, rivers, creeks, inlets, ports or harbours. All other internal waters are Commonwealth internal waters. For regulatory purposes they are treated as coastal waters.

Joint Authority (JA)	The Joint Authority of an offshore area of a State or Territory is constituted by the responsible State or Territory Minister and the responsible Commonwealth Minister. The term JA may also be used to describe the Commonwealth and State or Territory officials where those officials assist the JA.
Liquefied natural gas (LNG)	Natural gas that has been cooled to below 160 degrees Celsius thereby rendering it a liquid. This reduces its volume by over 600 times, making storage and transportation viable.
Liquefied petroleum gas (LPG)	A mixture of light hydrocarbons which is gaseous at normal temperatures and is liquefied by pressure for transport purposes. Consists mainly of propane and butane.
LNG train	A major processing facility, typically costing many billions of dollars. It is typically comprised of refrigeration stages (comprising compressor, condenser, pressure-expanding valve and evaporator) and purification stages to liquefy natural gas to form LNG. An LNG plant may comprise a number of LNG trains.
Natural gas	A mixture of light hydrocarbons (mainly methane) found naturally in the Earth's crust, often in association with crude oil.
Offshore area	The area extending seaward from the low tide mark on the coastline to the outer limit of the continental shelf. That is, it includes Commonwealth waters, coastal waters and some internal waters. (For the purposes of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth), the offshore area is defined as Commonwealth waters only.)
Onshore area	The area within the limits of a State or Territory including internal waters that are landward of the low tide mark, such as rivers and creeks.
Production	Phase of petroleum industry that deals with bringing the well fluids and gases to the surface and separating them.
Production licence	Licence to produce oil or gas in a particular area issued to a company by the governing state authority.
Seismic survey	A method of determining the sub-surface features by sending sound waves into the various buried rock layers in the earth and measuring the time they take to return to the surface.

Territorial sea	The area between the territorial sea baseline and the line that is 12 nautical miles seaward of the territorial sea baseline.
Territorial sea baseline	Generally is the line of lowest astronomical tide along the coast, but it also encompasses straight lines across bays (bay closing lines), rivers (river closing lines) and between islands, as well as along heavily indented areas of coastline (straight baselines) under certain circumstances.
Upstream	The upstream petroleum (oil and gas) sector encompasses exploration and appraisal, development and construction, and production. For natural gas and LPG, the definition of upstream includes processing and delivery to export terminals or domestic gas transmission pipeline in take.

OVERVIEW

Key points

- Oil and gas projects are large and complex. From the community's perspective, it is important that they meet reasonable requirements for the environment, heritage, land access, and occupational health and safety. It is also important to achieve these objectives without imposing unnecessary costs on companies or the broader community.
- Currently, duplication and overlap, and inconsistent administration of the 22 petroleum and pipeline laws and more than 150 statutes governing upstream petroleum activities impose significant unnecessary burdens on the sector.
  - Project approvals are taking longer than a streamlined approval process would allow, potentially diminishing the present value of petroleum resource extraction in Australia by billions of dollars each year.
- There is no simple, single answer to reducing the unnecessary regulatory burdens on the upstream petroleum sector. A suite of changes will be needed. The Commission's proposals fall into two broad groups: implementing regulatory best practice and reforming institutional arrangements.
- Key recommendations for improving existing regulatory arrangements include:
  - reducing unnecessary delays (particularly for environmental and heritage processes) through setting statutory timelines, ensuring legislative objectives are clear, promoting clear guidelines on information requirements, and introducing a 'lead agency' approach for approvals
  - clarifying and clearly articulating the objectives for intervention in resource management and ensuring the costs of intervention are the minimum necessary.
- To cut through regulatory duplication and overlap, the Commission proposes the staged establishment of a new national offshore petroleum regulator to undertake resource management, pipeline and environmental regulation in all Commonwealth, State and Territory waters (including islands).
  - The Australian Government initially would establish the new national offshore petroleum regulator in Commonwealth waters, and then provide State and Territory Governments, on a bilateral basis, the option of conferring their petroleum regulatory responsibilities. States and Territories would also have the option of conferring responsibility for regulating cross-jurisdictional onshore pipelines to this body.
  - The National Offshore Petroleum Safety Authority should remain a separate entity with an exclusive focus on occupational health and safety regulation, with its remit extended to offshore pipelines, subsea equipment and wells. Its geographical coverage should include all Commonwealth, State and Territory waters (including islands).

Many of the recommendations for 'best practice' regulation in this report repeat recommendations made by previous, yet for the most part, unimplemented, reviews. This simply reinforces that strong political will and leadership will be essential if meaningful improvement in the way this sector is regulated across multiple jurisdictions is to be successfully implemented, and sustained.

Overview

Upstream petroleum (oil and gas) projects bring substantial economic benefits to the Australian economy — contributing around 2 per cent of GDP. However, they inevitably pose complex, often multi-jurisdictional, environmental, safety and other challenges that must be managed. As for any industry, regulation of upstream petroleum projects ideally should be designed and implemented to promote community wellbeing without imposing unnecessary burdens.

In an international context, Australia's regulatory regime for oil and gas projects generally is regarded as good, although performance varies noticeably across jurisdictions. Nonetheless, there seems to be considerable room to expedite project approvals and to streamline regulatory requirements while at the same time delivering the policy intent of governments. This report outlines a number of measures to improve regulatory institutions, design and enforcement. If implemented, they would reduce unnecessary regulatory burdens and could deliver significant returns to Australian shareholders and the community more broadly through increased tax receipts. They should also improve Australia's attractiveness to investors in increasingly uncertain times.

About the study

This study is one of a number of reviews of regulatory burdens stemming from the report of the Regulation Taskforce in 2006. It reflects widespread concerns about delays and uncertainties in obtaining approvals for oil and gas projects, duplication of compliance requirements, and inconsistent administration of regulatory processes across jurisdictions.

The Commission has been asked to examine Australia's regulatory framework for upstream petroleum (oil and gas) projects involving more than one jurisdiction. It has been asked to identify ways to reduce *unnecessary* regulatory burdens on the sector — those burdens that could be reduced without sacrificing achievement of the policy intent of the regulation. It was also asked to consider options for a national regulatory authority to manage all regulatory approvals for the upstream petroleum sector, to address issues of regulatory duplication and inconsistency.

The Australian upstream petroleum sector

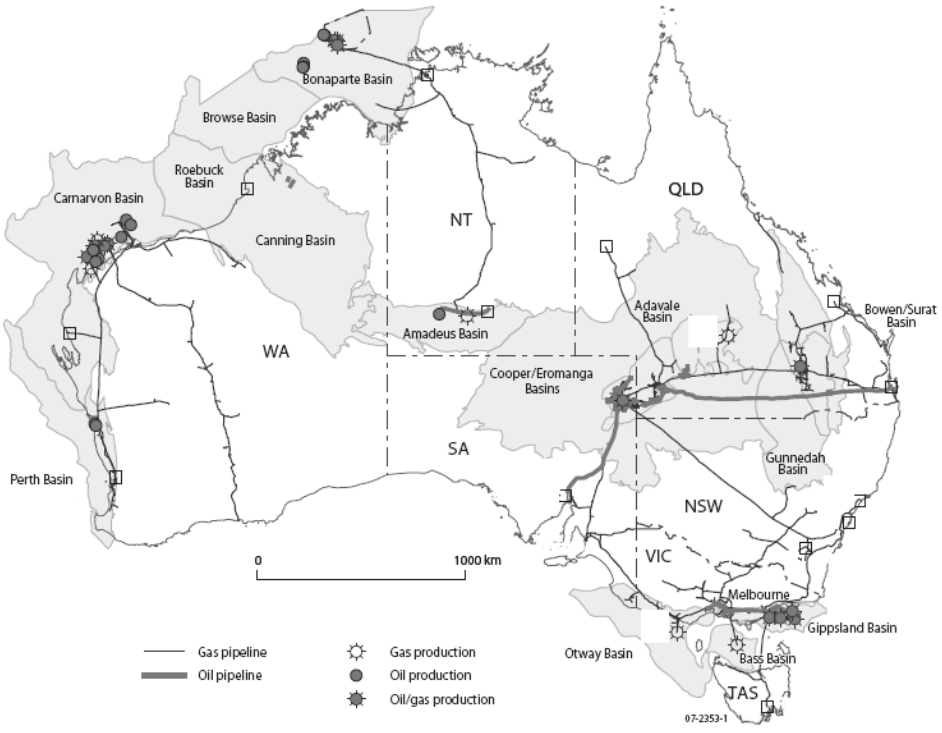
The upstream petroleum (oil and gas) sector encompasses exploration and appraisal, development and construction, and production. For natural gas and liquefied natural gas (LNG), the definition of upstream includes processing and delivery to export terminals or to the intakes of domestic gas transmission pipelines.

Over 80 per cent of Australia's gas reserves and over 95 per cent of oil reserves are offshore, with reserves concentrated in the Bonaparte, Browse, Carnarvon and Gippsland basins (figure 1).

The sector is dominated by international companies, including Apache, BHP Billiton, Chevron, ConocoPhillips, ExxonMobil, Santos, Shell and Woodside. The industry is also characterised by joint ventures; most onshore and offshore production licences are issued to multiple parties. For example, the North West Shelf Venture involves Woodside, BHP Billiton, BP, Chevron, Japan Australia LNG and Shell.

Projects in the upstream petroleum sector are often very large — an LNG development in Commonwealth waters with onshore processing can involve capital expenditure of $10 billion or more.

Figure 1 **Identified Australian oil and gas reserves, 2007**



Source: Geoscience Australia (pers. comm., 27 October 2008).

Current regulatory arrangements are complex

The regulatory framework governing the upstream petroleum sector reflects Australia's federal system, with powers shared between the Australian and the State and Territory Governments.

- The Offshore Constitutional Settlement established the States' rights over coastal and internal waters, and established joint regulatory authority over the Commonwealth waters adjacent to each State and the Northern Territory.
- The joint regulatory authority for each adjacent area consists of a 'Designated Authority' (DA) and a 'Joint Authority' (JA). The DA is the relevant State or Territory Minister and the JA is made up of the State or Territory Minister and the responsible Commonwealth Minister.

In addition to 22 petroleum and pipeline laws applying at both the Commonwealth and State and Territory levels, there are more than 150 statutes governing upstream petroleum activities in areas such as occupational health and safety (OHS), environmental and heritage protection, development, native title and land access (table 1). Well over 50 agencies at the Australian, State and NT Government levels regulate upstream petroleum activities.

Pipelines are subject to particular regulatory complexities, given their often cross-jurisdictional nature. They are likely to face significant regulatory overlap across jurisdictions and potential duplication, in some cases having to gain approval from four different authorities for the same pipeline.

The regulatory environment for the upstream petroleum sector has been undergoing reform — such as the consolidation of Commonwealth regulations under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA). Many reviews of regulation affecting the sector are currently being (or have already been) undertaken.

Unnecessary regulatory burdens impose significant costs

There is solid evidence that the current regulatory framework imposes a significant burden on the upstream petroleum sector. Although compliance costs are large (sometimes amounting to millions of dollars for a project), they are typically modest relative to the total project cost. *Delays* impose far more significant burdens, because they can increase project costs, reduce flexibility in responding to market conditions, impede financing of projects, and defer production and revenues.

Table 1 **Legislation affecting the upstream petroleum sector[a,b,c]**

Scope of legislation	*Onshore*[d]	*Offshore*[d]	
		Coastal waters	*Commonwealth waters*
Petroleum and pipelines	State onshore petroleum legislation **(8)**	*Petroleum (Submerged Lands) Act 1982* or equivalent **(7)**	*Petroleum (Timor Sea Treaty) Act 2003* (Cwlth)
	State pipeline-specific legislation **(4)**		
	Barrow Island Act 2003 (WA)[e]		
Occupational health and safety	*Occupational Health and Safety Act 1991* (Cwlth)		*Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth)
	State OHS or major hazard facilities legislation **(13)**		
Environment, heritage and development	*Environment Protection and Biodiversity Conservation Act 1999* (Cwlth)		
	Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cwlth)		
	other Commonwealth environment- and heritage-specific legislation **(4)**		
	State environment-, heritage- and development-specific legislation **(57)**		
	Local government legislation **(7)**		
Native title and land rights	*Native Title Act 1993* (Cwlth)		
	Aboriginal Land Rights (Northern Territory) Act 1976 (Cwlth) **(NT only)**		
	State native title, land rights and other land access legislation **(24)**		

[a] Although legislation is grouped according to primary scope, some laws may have a broader scope. [b] The numbers shown in brackets indicate the number of relevant statutes. [c] In this table, the use of the term 'State' also applies to the Northern Territory. [d] In this table, as most onshore legislation also applies to State and Territory internal waters, onshore includes State and Territory internal waters and offshore excludes such waters. [e] The *Barrow Island Act 2003* (WA) enables the State agreement — Gorgon Gas Processing and Infrastructure Project Agreement.

Sources: ComLaw; State and NT legislation databases; various departmental websites.

Consequently, reducing unnecessary approval delays can have significant payoffs. Some participants have suggested that cutting the time taken to gain approval for a major project by 50 per cent is possible. The Victorian Government considered a national offshore regulator could reduce the time taken for approving a production licence by about 50 per cent to around 6–12 months. If this regulator also regulated pipelines connecting offshore developments to onshore facilities, the Victorian Government considered approval times for pipeline licences and suspension and extension of pipelines (currently 3–6 months and 3–9 months, respectively) could also be reduced by 50 per cent. The Commission considers such reductions in approval times are a reasonable objective. Since the draft report, a number of regulators and industry proponents have also confirmed this objective, albeit noting that its achievement will depend on significant changes that eliminate many of the current iterative approval processes between the JA and DA.

The Commission estimates that expediting the regulatory approval process for a major project by one year could increase the net present value of returns by 10–20 per cent simply by bringing forward income streams (the approach used is summarised in box 1). Estimates of the benefits from reducing delays obviously are sensitive to the number of projects being delayed unnecessarily and the additional costs incurred as well as other parameters (such as the discount rate). But given the size of individual projects and the pervasiveness of regulatory delays, the potential benefits will be significant.

Box 1 **Estimating the economic cost of approval delay**

The Commission applied cash-flow discounting techniques to estimate the economic cost associated with approval delay. A delay was represented by a backward shift in the time distribution of cash flows from petroleum projects. The economic cost of delay was calculated as the difference between the net present value estimates obtained for a delay scenario and the base case (without the simulated delay).

The distribution of cash flows over the project life was estimated using aggregate data for all economic petroleum fields discovered in Australia up to 1987. By drawing on a comprehensive database, the model captures the 'average' characteristics of all petroleum operations in Australia — particularly their project sizes, cost structures and hydrocarbon prospectivities.

A discount rate of 10 per cent was used in calculating the present value of a stream of cash flows. This represents the weighted average cost of capital for the sector, comprising a risk-free rate and an equity risk premium commensurate with non-diversifiable project risks.

The Australian Petroleum Production and Exploration Association estimates that around $80 billion could be invested in new gas projects in the Pilbara and the

Kimberley alone in the next decade, and that $200 billion worth of projects are either in production, under construction or being planned in Australia's north-west or central Queensland. Given the significance of these projects, an 'across the board' one year reduction in total approval time for major projects — which many participants considered feasible — could generate future national income gains in the billions of dollars each year (some of which will accrue to foreign shareholders).

Not included in these calculations are losses from otherwise marginal projects where delays and other unnecessary regulatory costs have tipped the balance against them proceeding. Market uncertainty driven by recent falls in resource prices and escalation of capital costs will likely make regulatory imposts and delays even more critical in the future.

Identifying and reducing unnecessary regulatory burdens

There is no simple answer to the regulatory issues faced by the upstream petroleum sector. Oil and gas projects typically are large and complex, giving rise to unique and substantial environmental and other issues. Consequently, in addition to sector-specific petroleum and pipeline legislation, from the community's perspective it is important that these projects meet reasonable requirements relating to the environment, heritage, development, land access, and OHS.

In addition, most projects span multiple jurisdictions, adding a further layer of complexity. For example, Inpex's Browse Basin development (Ichthys) extends across Commonwealth waters, WA and NT coastal waters and will either come onshore in the Northern Territory or Western Australia (depending on final project arrangements). Woodside's Sunrise LNG development will extend into yet another jurisdiction, the Joint Petroleum Development Area (jointly managed by the Governments of Australia and East Timor).

Selected participants' views on the current overall regulatory system and scope for reform are summarised in box 2. Participants in this study also identified specific sources of unnecessary regulatory burdens in resource management and land access, environment and heritage, and OHS regulation, which are discussed in detail below.

The Commission has made over 40 findings and 30 specific recommendations on the current arrangements and possible improvements, so it is impractical to discuss each in this overview. Instead, key issues are highlighted. A full list of recommendations immediately follows the overview, and these are discussed in detail in the relevant chapters. Many of the issues raised and proposed solutions are not new. Various worthwhile recommendations have also been proposed in previous

reviews of the regulatory arrangements affecting the upstream petroleum sector, but many have yet to be implemented.

Resource management

Resource management regulation (under Commonwealth, State and Territory legislation) occurs throughout the upstream petroleum production process — from acreage release to exploration, extraction and transport of the resource. Proponents

Box 2 **Participants' views**

Many participants saw regulatory duplication and inconsistency as creating problems:

> Under the current JA–DA model there is substantial duplication in the administration and assessment processes for permit/licence grants. This duplication arises from the iterative processes carried out by both the Commonwealth and DAs for the same assessments … improvements in the efficiency of approvals processes have the potential to deliver real benefits to the sector. (Victorian Government, sub. 7, p. 4)
>
> There is a consistent lack of consistency in decision making between the regulatory authorities. (Nexus, sub. 3, p. 7)
>
> While Federal and State responsibilities individually dictate the extensive approval requirements in each respective jurisdiction, given the multi-jurisdictional nature of most petroleum projects the result is that there are multiple duplicated approvals processes and many opportunities for each regulator within the separate jurisdictions to take issue with a given proposal. (ExxonMobil, sub. 13, p. 4)
>
> 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. (APPEA, sub. 16, p. 7)

There was also widespread support for reform:

> A centralised upstream petroleum regulator has potential to increase consistency and timely decision making. Real gains in efficiency of the approvals process will only be gained if decisions are made by the one authority. (Nexus, sub. 3, p. 8)
>
> 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. (APPEA, sub. 16, p. 7)
>
> The Victorian Government supports in-principle the establishment of a national petroleum regulator for offshore activities. Further opportunities to improve efficiency through a nationally consistent model for regulating pipelines connecting offshore petroleum developments with onshore facilities should be explored. (Victorian Government, sub. 7, p. 2)

must apply to hold relevant titles including exploration permits, retention leases and production, pipeline and infrastructure licences. Title holders are subject to data reporting obligations at each stage in the process. In addition, regulators must approve various plans and give numerous consents to operate.

In its draft report, the Commission noted an absence of policy clarity and recommended that governments articulate the objectives of resource management regulations and periodically assess their benefits and costs.

Despite mixed, but mainly negative, reaction from participants across industry and government to its draft report recommendations relating to resource management, the Commission remains of the view that upstream petroleum resource management regulation falls short of best practice. To the best of the Commission's knowledge, the overall policy intent of governments in resource management has never been clearly articulated, and suggested rationales are often in tension.

While there are several legitimate roles for government in managing oil and gas resources — for instance, to provide information about the geology of an oil or gas field, and how one company's drilling proposal might affect another's operations — stated rationales, which go to overriding or second-guessing decisions of professionally-managed, for-profit businesses, appear less robust.

Provided they meet community environmental and other objectives, private companies generally will have appropriate incentives to extract oil and gas resources efficiently, such that profit maximisation and the community's interests coincide. Consequently, the basis for overriding commercial decisions — that is, the reason why commercial and public interests might diverge — should be clearly stated and the costs and benefits of intervening transparently assessed.

For instance, it has been suggested that governments seek to *maximise* rather than *optimise* resource extraction. Without proper account of the additional costs of doing so, intervention to maximise resource extraction would likely reduce profits and community welfare, and potentially discourage future exploration.

It has been put to the Commission that in the vast majority of cases, extraction plans proposed by companies are approved. If the ultimate justifications for intervention are spillover effects, or that there are some rare outlier cases where unprofessional or unethical companies can behave inappropriately to the community's detriment, to minimise unnecessary costs and delays it would seem better that, in the absence of spillovers, government intervention were focused on such outliers.

A particularly vexed issue is that of retention leases. Retention leases attempt to balance the need to give explorers some certainty of title over discoveries against

the desire of governments to encourage development of oil and gas reserves. Retention leases are not awarded or renewed if a discovery is deemed to be commercial. In this case, the lease holder must commence production or sell the lease to a company that will.

There has been some pressure to make commerciality tests more rigorous, especially for gas reserves, in order to increase domestic gas supplies. In the extreme, lease holders might be compelled to commence production or lose the resource title, regardless of differing views about commerciality (a strict 'use it or lose it' test).

Yet various reviews have not found any significant market failure justifying action to compel lease holders to sell or develop gas reserves — for example, competition was found adequate to ensure that individual businesses do not have an incentive to hoard reserves in order to influence prices. So it could be expected that companies generally will develop or on-sell their discoveries when they see the prospect of an adequate commercial return.

In the Commission's assessment, to minimise unnecessary regulatory burdens arising from the retention lease renewal process, and the commerciality test in particular, governments should clearly articulate the criteria they will apply and demonstrate how application of these criteria will promote the public interest. Compared with a bureaucratic assessment of commerciality (and competing claims of both leaseholders and rival businesses seeking to gain lease rights), market mechanisms, such as auctions with appropriately informed bidders, have the potential advantage of eliciting truthful valuations and reducing the risk of expropriation of exploration investments. Auctions could be considered as an option where there is disagreement between leaseholders and government.

But a more direct approach that could assist would be to remove impediments to voluntary, mutually beneficial lease transactions, including the current registration fee for transfers and dealings imposed on lease transactions. Equally effective would be a reduction in unnecessary regulatory burdens imposed by environmental and other regulations, which by reducing anticipated commercial returns, act to discourage field development.

Land access

Land access approvals are required prior to the undertaking of onshore petroleum exploration, and production and construction of onshore pipelines and onshore facilities. While there are no native title rights to minerals, petroleum or gas, land access must in many cases be negotiated with Indigenous people.

Under the *Native Title Act 1993* (Cwlth) there are two main avenues to deal with 'future act' (project) applications — the 'right to negotiate' (RTN) procedure and Indigenous land use agreements (ILUAs). The suitability of using the RTN procedure (which applies to a particular future act) or an ILUA (which applies to the use and management of an area of land) depends upon the circumstances.

There is evidence of delays in the processing by State Governments of future act applications through the RTN procedure. The RTN procedure can also take longer if parties cannot reach agreement and the National Native Title Tribunal is asked to arbitrate and determine the outcome of an application.

ILUAs provide a flexible alternative to negotiating land access approvals. They appear to have the potential to streamline the approval process, reduce the resources required for successive negotiations, take less time, and reduce costs in the long run for some large, complex projects, or where there are likely to be many future act applications in one area. Such agreements have been used successfully in South Australia. Governments should investigate whether greater use of such agreements is feasible, particularly as reducing unnecessary processing delays should lead to better outcomes for all parties.

Environment and heritage

Environmental regulation of petroleum activities covers petroleum-specific environmental approvals, and environmental and planning approvals that are required for any development activity. Upstream petroleum activities are potentially subject to four main areas of regulation:

- environmental regulation of offshore petroleum activities under OPGGSA regulations
- national environmental and heritage regulation under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act)
- State and Territory environmental, conservation and planning regulations
- Commonwealth, and State and Territory Indigenous heritage Acts.

Industry and other stakeholders raised various concerns about the design and administration of environment-related regulations required for the approval of petroleum activities. Significant efforts have been made to improve the operation of the EPBC Act. However, some concerns remain, including insufficient access to pre-existing information from government departments on relevant significant environmental risks prior to the release of new acreage. Also concerns were expressed about the interaction and overlap of environmental approvals by different governments, uncertainty about strategic assessment processes and alleged

inconsistency and increased intervention in decisions about seismic surveys under the EPBC Act.

Of greater concern to study participants were delays in State, Territory and local government approvals, particularly due to:

- inadequate resourcing of agencies responsible for approvals in some jurisdictions
- a lack of clear administrative arrangements between relevant agencies in some jurisdictions
- a lack of statutory or firm approval timelines
- insufficient public access to environmental data obtained either in previous assessment processes, or as a condition of previous approvals.

Some participants also considered the current process for establishing some environmental offsets (which are used by most jurisdictions as a condition of approval for some projects) to be arbitrary, open-ended and lacking in transparency.

A summary of recommendations to improve environmental and heritage regulation is presented in box 3.

Emerging issues include carbon capture and storage (CCS), greenhouse and energy consumption reporting, the proposed carbon pollution reduction scheme, and decommissioning of petroleum facilities. In order to establish a consistent framework for CCS regulation, the Australian and the State and Territory Governments have developed and apparently agreed on a common set of guiding principles. Despite this, each State and Territory now appears to be developing their own (differing) detailed CCS legislation, in some cases citing further principles that they consider important in their jurisdiction. Participants have expressed concern about the developing inconsistencies in CCS requirements. State and Territory Governments should mirror amendments resulting from the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008 in coastal waters, and consider implementing a nationally consistent framework for onshore carbon capture and storage.

Occupational health and safety

Regulatory arrangements for OHS differ for offshore and onshore operations. Regulation of most offshore activities has been harmonised with the creation of the National Offshore Petroleum Safety Authority (NOPSA), while onshore operations are regulated under the OHS regimes applying in each State and Territory. Although

Box 3 **Improving environmental and heritage approvals**

Unnecessary regulatory burdens on the upstream petroleum sector would be reduced by:

- improving the operation of the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) through:
  - ensuring the Department of Environment, Water, Heritage and the Arts manages and provides available information (such as information from previous assessments and relevant scientific studies) on significant relevant environmental risks to the Department of Resources, Energy and Tourism to be reported with new acreage releases and to proponents seeking approval for a new project (such as pipelines as well as associated onshore processing facilities)
  - expanding use of assessment bilateral agreements with States and Territories where a State or Territory has adequate local expertise and knowledge
  - where strategic assessments are used for particular regions, conducting these early according to clear timeframes
- identifying scope for streamlining onshore processes and associated regulations related to petroleum activities through the Environmental Assessors Forum
- governments appropriately managing and releasing information obtained by proponents as a condition of environmental approvals to enhance the public stock of environmental information and to assist in streamlining future approvals
- requiring that the Australian Government, in considering Indigenous heritage applications, take into account previous State and Territory government assessments and decisions about the same heritage site. The Commonwealth Act should also allow accreditation of State regimes that comply with a national set of minimum standards and should allow approvals under heritage Acts to be transferred with the title to a resource
- all governments introducing more transparent and timely environment offset processes to avoid the potential for arbitrary and inconsistent requirements, and open-ended negotiation processes. There may also be merit in introducing nationally consistent principles.

the establishment of NOPSA in 2005 significantly improved the efficiency and effectiveness of offshore petroleum regulation, study participants raised concerns about the unnecessary duplication arising from shared responsibility between NOPSA and the DAs in some areas. Particularly in Western Australia, there remains a complex position in regard to powers not being conferred on NOPSA for State internal waters and some islands (which in some cases contain upstream petroleum facilities that are contiguous with coastal waters that are the responsibility of NOPSA). This increases the risk of interface problems between safety regulators and can contribute to unnecessary regulatory burdens. Some also

raised concerns about a drift away from the desired objective-based regulation towards greater prescription in some OHS areas, such as through the release of prescriptive guidelines.

The Commission agrees with the views of most participants that the move to establish NOPSA and the use of safety cases has been a useful step forward, albeit that further improvements are possible and desirable. Such improvements include that the legislated coverage of NOPSA be extended to include the integrity of offshore pipelines, subsea equipment and wells.

Subject to the outcomes of the current Australian and WA Governments joint inquiry into the 2008 Varanus Island explosion, States and Territories should consider conferring powers to regulate OHS on NOPSA for all State and Territory waters seaward of the low tide mark, including islands in those waters. NOPSA should remain a focussed independent safety regulator.

Improving clarity and timeliness

The scope and complexity of most upstream petroleum developments inevitably makes the approval process complex and time consuming. Delays have been exacerbated by resourcing issues within agencies, regulatory 'creep' and uncertain timelines. Nonetheless, the Commission is also aware of cases where companies are responsible for project delays.

The Commission proposes a suite of changes that should help reduce the unnecessary delay in approval decisions, although none of them individually represent a 'cure all' solution:

- setting statutory timelines both for individual stages in decision making (with clear and transparent stop-the-clock provisions) and for overall timelines
- requiring agencies to report publicly on performance against these timelines can provide further incentives to improve timeliness
- ensuring legislative objectives are clear
- ensuring clear guidelines on information requirements and removing duplicated reporting requirements
- reviewing all the State and Territory petroleum regulations and, where necessary, revising them to be objective based and consistent with the conventions and definitions applying under the new OPGGSA
- ensuring that regulators are adequately resourced with appropriately experienced and skilled people
- exploring the feasibility of an electronic approvals tracking system

- introducing a 'lead agency' approach for approvals within each jurisdiction.

Under a lead agency approach (sometimes referred to as a 'one-stop-shop'), approval of most, if not all, aspects of an application would rest with the one agency. Primary Industries and Resources South Australia was widely seen as a model for other jurisdictions to emulate. A lead agency would manage all approval and licensing processes and provide companies with information on compliance requirements. It would maintain control of the process and, in most cases, would simply *consult* with other relevant agencies, such as an environmental agency, rather than formally refer the application to a separate agency for assessment.

Would a national regulator reduce unnecessary burdens?

Under the terms of reference, the Commission was asked to consider options for a national regulatory authority to manage all regulatory approvals associated with upstream petroleum activities. Desirable objectives for an institutional model that would minimise unnecessary regulatory burdens are summarised in box 4. Desirable characteristics for a national regulator are independence, accountability and clear objectives. These characteristics promote focus and are likely to reduce scope for the regulator to be captured by industry or other interests. The proposed suite of reforms also would allow responsibility for developing policy to be separated from regulatory approval and compliance functions. This is likely only to be practical if there is a rationalisation of the regulators currently involved. Another overarching issue is the need to weigh benefits from greater harmonisation against the benefits of diversity reflecting local conditions and preferences.

The main options for an expanded national upstream petroleum regulator include (figure 2):

- a *national petroleum regulator* with responsibility for both onshore and offshore petroleum regulation in all jurisdictions
- a *national offshore petroleum regulator* (NOPR) with responsibility for resource management, pipeline and environmental regulation in all offshore areas
- a *national offshore petroleum regulator in Commonwealth waters* (NOPR-CW) with responsibility for resource management, pipeline and environmental regulation in Commonwealth waters, with opt-in arrangements for States and Territories, on a bilateral basis.

Box 4 **Desirable objectives for an institutional model**

- Separating policy formulation and advice from regulatory administration, where practicable given issues of scale and capacity.
- Minimising multiple approvals or duplicate assessment requirements.
- Minimising overlapping administration by multiple agencies, or having clear administrative arrangements where multiple agencies are involved.
- Minimising inconsistencies in legislative requirements and decision making.
- Ensuring regulators have:
  - independence
  - accountability
  - clear regulatory objectives and do not face unnecessary conflicts of interest.
- Consolidating specialist expertise, efficiently using resources and enhancing the ability to retain specialist expertise. Adequate resourcing can reduce the potential that project approvals at peak times are at the expense of compliance monitoring.

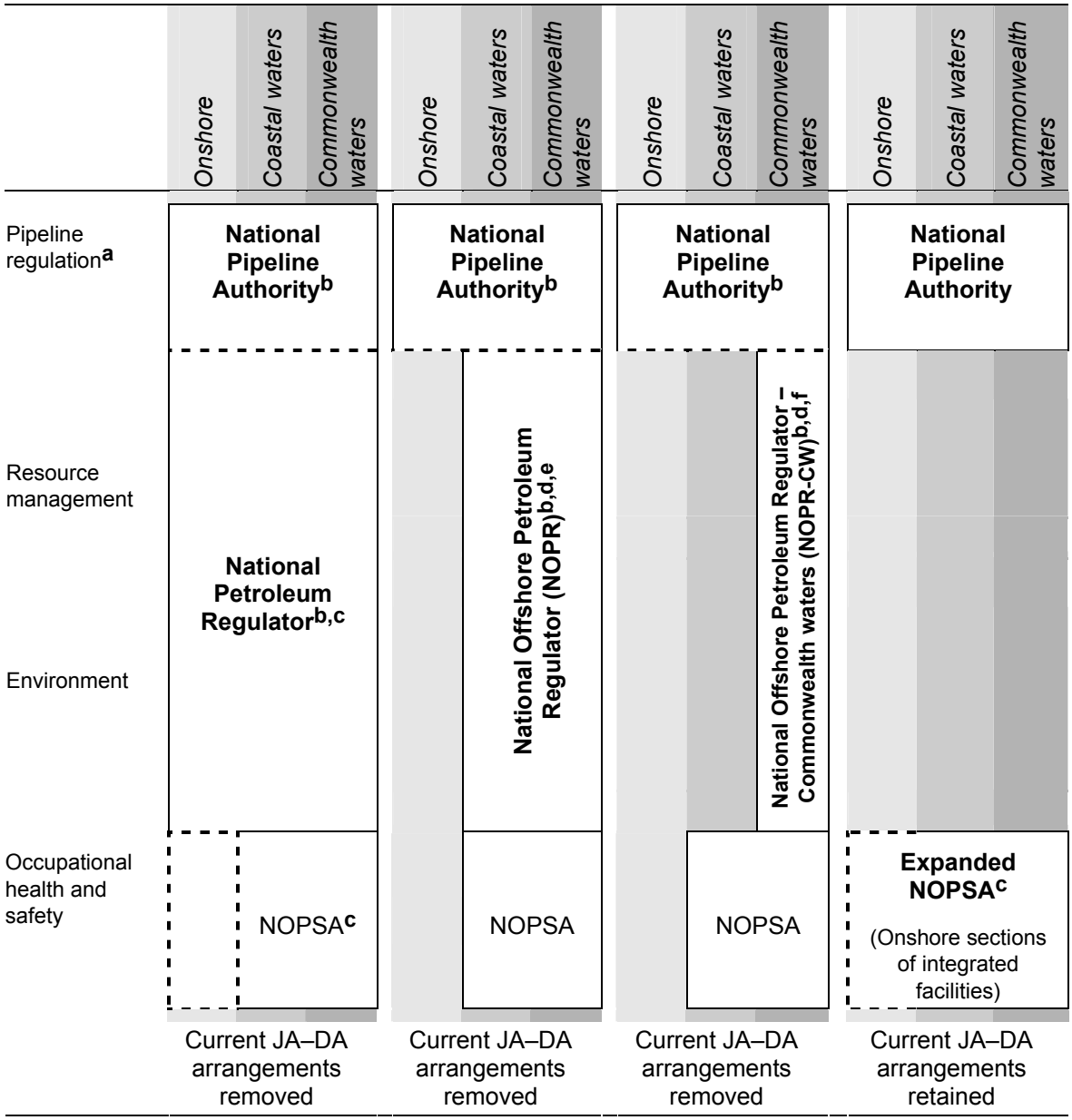
The Commission also considered a *national pipeline authority* with responsibility for approving cross-jurisdictional pipelines or coordinating such approvals, to be pursued separately or in conjunction with the above options.

These options presented relate to changing the institutions regulating the upstream petroleum sector and regulation. None of the options are intended to imply there should be any changes to existing resource rent tax and royalty arrangements imposed by the Australian, and State and Territory Governments.

A national petroleum regulator?

A national petroleum regulator for both onshore and all offshore areas would, in theory, provide cross-jurisdictional consistency, reduce duplication of regulatory requirements and potentially benefit from economies of scale. However, such a model would also appear to have significant weaknesses. Specifically, for activities located wholly onshore and within one jurisdiction, local agencies would appear better placed to undertake regulation due to their knowledge of local factors, issues and community concerns. On balance, and given the cost and difficulty of implementing this model, the Commission considers this approach not to be a practical option.

Figure 2 **Regulator options**



[a] Includes all aspects of pipeline regulation (including environmental and occupational health and safety aspects) in offshore areas, as well as onshore pipelines that cross two or more jurisdictions. [b] The National Pipeline Authority could be incorporated into the National Petroleum Regulator, NOPR or NOPR-CW. [c] In this model, the National Offshore Petroleum Safety Authority's (NOPSA's) responsibilities could be extended onshore to make it the national upstream OHS regulator. [d] In this model, the States and Territories retain responsibility for onshore petroleum regulation (excluding pipelines). [e] Ministerial reporting based on NOPSA model. [f] In this model, the States and Territories retain responsibility for regulation in coastal waters.

A national offshore petroleum regulator?

A national offshore petroleum regulator (NOPR) could undertake resource management, pipeline and environmental regulation in all waters seaward of the low tide mark, including islands in those waters, and administer both the OPGGSA

and its 'mirror' State and Territory petroleum Acts. Ideally, NOPR would perform the following functions in both Commonwealth and State and Territory waters seaward of the low tide mark, including islands in those waters:

- administration of exploration permits, production and pipeline licensing
- administration and approval of production, well construction and drilling, and pipeline consents (with NOPSA providing necessary approvals for safety-related issues)
- environmental approvals and compliance.

In its draft report, the Commission noted that under this model, NOPSA (preferably expanded as discussed earlier) could remain as a separate safety regulator with responsibility for OHS regulation in offshore areas or it could be brought within the umbrella of NOPR, but as a discrete structural unit. The Commission accepts the view put by participants that NOPSA should be retained as a separate independent entity, to maintain its exclusive focus on and accountability for OHS, avoiding any potential or perceived conflicts in regulatory objectives. Nonetheless, there should be good communication and information sharing between NOPSA and NOPR.

The effectiveness and efficiency of the NOPR model depend on the States and Territories agreeing to give NOPR responsibility for petroleum regulation in State and Territory waters seaward of the low tide mark, including islands in those waters (currently performed by petroleum and other agencies in each jurisdiction), with respective powers of the Commonwealth and State and Territory Ministers being similar to those applying to NOPSA. With such agreement, there are potentially useful economies of scale and reduced complexity.

The Commission proposes a staged approach to establishing a national regulator, given the limited likelihood of all States simultaneously agreeing to give NOPR responsibility for petroleum regulation in State and Territory waters seaward of the low tide mark, including islands in those waters and conferring final decision-making power on the Commonwealth Minister.

- As a first step, the Australian Government should establish a new national offshore petroleum regulator in Commonwealth waters (NOPR-CW), which would administer exploration permits, production and pipeline licensing, environmental approvals and compliance, and administer and approve production, well construction and drilling, and pipeline consents (with NOPSA's approval of relevant safety and integrity related issues). Even if reform only went this far, the Commission considers it would yield significant net benefits and should be pursued.

- The Australian Government should then provide State and Territory Governments, on a bilateral basis, the option of conferring existing petroleum-related regulatory responsibilities in State and Territory waters seaward of the low tide mark, including islands in those waters on this new regulator. To participate, the relevant State or Territory petroleum legislation would need to fully mirror the OPGGSA and its subordinate regulations (including provisions relating to pipelines) for such waters and islands. Under this model, NOPR and NOPSA would both regulate the same geographical limits.

The national regulator should be funded under a full cost recovery model, as for NOPSA.

There also appears to be a strong case for a more harmonised approach to cross-jurisdictional pipelines, following the Canadian example. Where States and Territories agree to confer their responsibilities for State and Territory waters seaward of the low tide mark, including islands in those waters (including pipelines) on the national offshore petroleum regulator, they should also have the option to confer responsibility for the regulation of cross-jurisdictional onshore upstream pipelines on this regulator. To participate, legislative provisions applying to pipelines onshore would need to be harmonised with the offshore OPGGSA regulations (as appears to be the case now in Victoria).

Although institutional and associated regulatory reform towards a 'national regulator' may provide a useful way forward, of itself, it will not remove all unnecessary regulatory burdens. Improving the regulatory framework requires political commitment from governments to implement best practice regulation and administration. Without this commitment, there is a risk of regulatory burdens persisting or even increasing.

Regardless of whether governments agree to implement a national offshore regulator for the upstream petroleum sector, implementing other recommendations should reduce the regulatory burden on the sector (table 2). Implementing a national offshore regulator, introducing a lead agency for petroleum approval processes and improving the transparency and accountability around approval process timelines and decision making are likely to achieve the greatest reduction in unnecessary regulatory burdens.

Many of the proposed solutions are not new, and have been raised in previous reviews. As elsewhere in the economy, reducing unnecessary regulatory burdens provides community benefits and is becoming increasingly important given the challenges facing the Australian economy.

Table 2 **A summary of the Commission's proposals[a]**

Current problem	*Proposed response*	*Main benefits of change*
Difficult, complex and time consuming approval processes	• Separate policy advice from regulation where practicable • Promote objective-based legislation where feasible • Make legislation consistent with the updated OPGGSA • Ensure approval processes are best practice and clearly defined • Provide clear guidelines on information requirements	• Promotes only that regulation necessary to achieve policy objectives • Improves the efficiency and effectiveness of approval processes • Reduces demands on government resources
Lack of clear and accountable processes and timelines	• Set statutory timelines for decision making • Measure and disclose performance against timelines • Implement an electronic approvals tracking system for individual regulatory areas and overall approval process	• Provides incentives to improve timeliness of decisions • Improves transparency and accountability of approval processes
Regulatory 'creep'	• Ensure that the intent of legislation is clearly defined at the parliamentary level • Clearly define the intent of guidelines and the powers of regulators to develop them	• Removes uncertainty regarding intent • Removes regulators' power to introduce overly prescriptive requirements
Multiple, overlapping and duplicative regulatory responsibilities	• Lead agency for petroleum approval processes	• Potential to improve timeliness
Overlapping local government laws, regulations and approvals	• State and Territory Governments should clarify the scope of local government's role	• Reduces duplication and overlap • Most appropriate agencies undertake regulatory tasks
Resource management		
Governments' role in managing the method and rate of extracting petroleum resources is unclear and needs to be articulated together with the totality of the resource management policy	• Clearly articulate the objectives of intervention and periodically assess benefits and costs. Ensure that this component of the resource management policy is administered in a manner consistent with the overall objectives of the policy	• Reduces costs and reduces chances of unintended consequences
Unnecessary burdens in reviewing retention leases	• Clearly articulate the objectives of intervention • Improve the clarity and transparency of the retention lease process	• Reduces costs and uncertainties and reduces chances of unintended consequences

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Table 2 (continued)

Current problem	*Proposed response*	*Main benefits of change*
Resource management (continued)		
Unnecessary burdens in reviewing retention leases (continued)	• Where there is disagreement over commerciality, consider options such as auctions	• Reduces regulatory error
	• Remove registration fee for transfers and dealings	• Reduces impediments to lease sales
Lack of consistency in carbon capture and storage requirements	State and Territory Governments should: • mirror amendments from the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008 in coastal waters • implement nationally consistent legislation for onshore carbon capture and storage	• Reduces costs
Complexity of the JA–DA model	• Establish a national regulator	• Reduces delays, duplication, iterations, inconsistency between DAs and gaming by proponents and government
Delays in updating 'mirror' legislation	• Update State and Territory legislation to mirror Commonwealth offshore legislation	• Minimises delays in approval processes and reduces costs to the sector
Land access		
Delays in processing future act applications for access to land subject to native title	• Investigate whether Indigenous land use agreements could be used more frequently	• Streamlines approval process, reduces resources for successive negotiations and takes less time
Environment		
Concerns about the operation of the EPBC Act: • Insufficient statutory timelines • Duplication from interaction with other environmental approvals • Limited information on environmental issues related to new acreage releases and development • Inconsistency in decisions • Uncertainty during strategic assessments	• Provide information from previous assessments and studies during acreage release and for new approvals • Use bilateral assessment agreements • Conduct strategic assessments early and according to timeframes	• Reduces approval uncertainty within new acreage and in areas of proposed development • Reduces duplication of assessment and approval processes • Streamlines assessment processes in regions with significant potential development activity

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Table 2 (continued)

Current problem	*Proposed response*	*Main benefits of change*
Environment (continued)		
Unclear environmental offset policies and processes	• Introduce transparent and timely environmental offset processes • Relate offsets directly to damage where possible • Where damage cannot be offset, explore other mechanisms such as an offset 'fund'	• Increases transparency • Reduces scope for time-consuming and ad hoc offset negotiation processes
Lack of public access to environmental data	• Actively manage and release information obtained as a condition of prior environmental approvals	• Streamlines approvals • Reduces risks and uncertainties for companies
Duplication between Indigenous heritage legislation at Commonwealth, and State and Territory levels	• Require consideration of previous decisions made by other jurisdictions • Amend Commonwealth Act to accredit State and Territory processes • Allow heritage approvals to be transferred to another operator	• Reduces duplication and delays
Lack of clear guidelines	• Enhance transparency of the Environmental Assessors Forum and provide it more support • Provide consolidated and consistent guidelines for cross-jurisdictional activities	• Enhances transparency and consistency of decision making
Complex and inconsistent administrative arrangements between environmental and petroleum agencies	• Review onshore environmental regulation to indentify scope for streamlining onshore approval processes	• Reduces complexity of State and Territory environmental approvals • Reduces overlap between and within jurisdictions
Occupational health and safety		
Shared responsibility for regulation of offshore pipelines, subsea equipment and wells	• Extend the legislated coverage of NOPSA to include offshore pipelines, subsea equipment and wells	• Removes ambiguity • Expands specialist knowledge • Increases efficiency
Duplication of regulation of vessels under the maritime and petroleum regulatory regimes	• Amend OHS regulations to ensure only necessary petroleum-related functions of vessels are regulated under the safety case regime	• Reduces duplication and ambiguity • Reduces compliance costs • Improves vessel choice for non-petroleum tasks

(Continued next page)

Table 2 (continued)

Current problem	*Proposed response*	*Main benefits of change*
Occupational health and safety (continued)		
Not all State and Territory waters or islands within those waters are regulated by NOPSA giving rise to potential interface problems	• Confer powers in State and Territory waters and islands to allow NOPSA to regulate entirety of offshore facilities for safety and integrity	• Removes ambiguity • Increases efficiency • Improves safety
Differing safety standards for equipment between jurisdictions	• Greater efforts to harmonise safety standards and their interpretation across jurisdictions • Provide appropriate recognition of compliance with international standards	• Reduces regulatory inconsistency • Reduces compliance costs • Increases equipment choice (improved cost and safety outcomes)
A national regulator		
Multiple approvals are required for cross-jurisdictional projects Inconsistencies in legislation and decision making across jurisdictions Under-resourcing of regulators	Establish a national offshore petroleum regulator for Commonwealth waters (NOPR-CW) and allow an opt-in by States and Territories for State and Territory waters and islands. It should be responsible for the regulation of resource management, pipelines and environmental impacts. It should have the following functions: • Administration of exploration permits, production and pipeline licenses • Administration of, and authority to, approve production, well construction and drilling, and pipeline consents (in conjunction with NOPSA for safety and integrity) • Retain NOPSA as a separate entity • Use a full cost recovery model to fund any new regulatory agency • Subject cost recovery models to regular review and appropriate governance	Main benefits of NOPR-CW model: • Reduces administrative inconsistencies • Removes the iterative and duplicative role between JAs and DAs • Improves governance arrangements by separating policy from regulatory roles • Some increase in administrative economies of scale and consolidates specialist resources and staff • Maintains local agency regulation of onshore, single-jurisdiction projects Benefits if States and Territories opt-in for State and Territory waters and islands: • Reduces inconsistencies between approvals in Commonwealth and coastal waters • Takes full advantage of harmonised arrangements • Increases economies of scale Full cost recovery model: • Improves funding arrangements for registration, monitoring compliance and issuance of exclusive rights

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Table 2 (continued)

Current problem	*Proposed response*	*Main benefits of change*
A national regulator (continued)		
Duplication and overlap caused by multiple jurisdictions and regulators for pipeline licensing and regulation	• Give NOPR-CW responsibility for regulating cross-jurisdictional onshore pipelines where States and Territories agree to confer their responsibilities and where they harmonise their onshore pipeline regulations with the OPGGSA regulations where relevant.	• Streamlines regulatory processes • Reduces duplication of licensing and other requirements
Shared responsibility for regulation of facilities and pipelines	• Continue State and Territory regulation of onshore production facilities and onshore pipelines	• Allows local conditions and community preferences to be considered

a Acronyms are as follows — DA: Designated Authority; EPBC Act: *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth); JA: Joint Authority; NOPR-CW: National offshore petroleum regulator for Commonwealth waters. NOPSA: National Offshore Petroleum Safety Authority; OHS: Occupational health and safety; OPGGSA: *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth).

Recommendations

There is no simple, single answer to reducing the unnecessary regulatory burdens on the upstream petroleum sector. The Commission has made a large number of recommendations covering regulatory best practice, institutional reform and specific regulatory areas to address the regulatory issues facing the sector. While all would contribute to reducing unnecessary regulatory burdens, the Commission has identified a number of key recommendations that will be essential to implement if a significant reduction in unnecessary regulatory burdens is to be achieved. These key recommendations are presented below, followed by further recommendations.

Key recommendations

The Commission's key recommendations can be broadly grouped into the following areas:

- improving regulatory practice
- institutional reform (establishing a national offshore petroleum regulator, extending the role of the National Offshore Petroleum Safety Authority and establishing lead agencies)
- environment and heritage
- resource management.

Improving regulatory practice

RECOMMENDATION 10.3

Governments should review and update all existing legislation to ensure it is consistent with the features of best practice regulation and good regulatory design. In particular, updated legislation and its administration should:

- ***separate policy advice from regulation where practicable***
  - ***where not practicable, for example due to scale particularly in smaller jurisdictions, reliance on appropriate checks and balances and transparency in policy and regulation making processes will be increasingly important***

- ***promote the use of objective-based legislation where feasible***
- ***ensure approval processes are best practice and clearly defined***
- ***set statutory timelines for individual regulatory decisions (any decision should include a 'stop the clock' mechanism). There should be two timelines: one excluding periods when the 'clock' is stopped and one including all time elapsed. There should also be disclosure of reasons for regulators requesting additional information, and measurement and public disclosure of their performance against these targets***
- ***measure and report overall timelines taking into account all stages of key regulatory processes (including scoping, advising, consultation and decisions)***
- ***be consistent with the definitions, format and approach of the updated Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth)***
- ***provide clear guidelines where feasible on information requirements to assist proponents in efficiently providing the necessary information to allow timely regulatory decisions***
- ***ensure reporting requirements are clear, justified, and avoid duplication and overlap with other mandatory reporting requirements.***

Institutional reforms

Establish a national offshore petroleum regulator

RECOMMENDATION 10.7

The Australian Government should establish a new national offshore petroleum regulator in Commonwealth waters, with regulatory responsibility for resource management, pipelines and environmental approvals and compliance. It should be an independent statutory authority and have the following functions:

- ***administration of exploration permit, production and pipeline licensing — it would process applications, prepare advice and make recommendations to the Commonwealth Minister for resources***
- ***administration and approval of production, well construction and drilling, and pipeline consents — it would have the authority to approve consents for these activities after receiving approvals from NOPSA for safety and integrity aspects of these activities***
- ***environmental approvals and compliance.***

The National Offshore Petroleum Safety Authority should remain a separate independent statutory authority for the regulation of offshore petroleum occupational health and safety.

RECOMMENDATION 10.8

The Australian Government should give State and Territory Governments, on a bilateral basis, the option of conferring their existing petroleum-related regulatory powers in State and Territory waters seaward of the low tide mark, including islands within those waters, on the new national offshore petroleum regulator and ultimately the Commonwealth Minister as relevant. The respective powers of the Commonwealth and State and Territory Ministers that would then apply should be similar to those applying to the National Offshore Petroleum Safety Authority.

For States and Territories that wish to opt-in, it would be a requirement that all their relevant State or Territory petroleum Acts fully mirror the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) and its subordinate regulations, including provisions relating to pipelines.

RECOMMENDATION 10.9

Where States and Territories have agreed to confer their powers in State and Territory waters seaward of the low tide mark, including islands within those waters and pipelines, on the national offshore petroleum regulator and ultimately the Commonwealth Minister as relevant, States and Territories should also have the option to confer responsibility for the regulation of onshore inter-jurisdictional upstream petroleum pipelines. For States and Territories that wished to opt-in, it would be a requirement that their legislative provisions applying to onshore pipelines were harmonised with the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) where relevant.

RECOMMENDATION 10.10

The current full cost recovery model used for the National Offshore Petroleum Safety Authority should be used to fund any new regulatory agency. As with the National Offshore Petroleum Safety Authority, the cost recovery model adopted for a new regulatory agency should be subject to regular review and appropriate governance arrangements. Only appropriately defined costs associated with regulating the upstream petroleum sector should be recovered by the new national offshore petroleum regulator. Implementation of this recommendation should be associated with the removal of the registration fee for transfers and dealings.

Extend the role of the National Offshore Petroleum Safety Authority

RECOMMENDATION 7.1

The legislated coverage of the National Offshore Petroleum Safety Authority should be extended to include the safety and integrity of offshore pipelines, subsea equipment and wells. If the National Offshore Petroleum Safety Authority is given these additional responsibilities, it would be necessary to ensure the authority was adequately resourced to carry them out.

RECOMMENDATION 7.2

Subject to the outcomes of the current Australian and Western Australian Governments joint inquiry into the 2008 Varanus Island explosion, States and Territories should consider conferring powers on the National Offshore Petroleum Safety Authority to regulate occupational health and safety matters for all State and Territory waters seaward of the low tide mark, including islands within those waters.

Establish lead agencies

RECOMMENDATION 10.6

Where not already implemented, States and Territories should consider establishing a lead agency for petroleum projects. Such an agency would manage an integrated approval process and would require a clear mandate for all relevant areas (for example, resource management, environment and heritage) and clear decision making powers over these areas except in exceptional circumstances. With appropriate governance, experience in South Australia suggests that such an agency can achieve an appropriate balance between enforcing legislative provisions and expediting approvals.

Environment and heritage

RECOMMENDATION 6.1

Specific measures to improve the operation of the Environment Protection and Biodiversity Conservation Act 1999 (Cwlth) include:

- ***ensuring the Department of the Environment, Water, Heritage and the Arts provides available information (such as information from previous assessments and relevant scientific studies) on significant environmental risks to the Department of Resources, Energy and Tourism to report with new acreage releases and to proponents seeking approval for a new project (such as pipelines) and in regard to potential processing facilities***
- ***developing bilateral assessment agreements between the Department of Environment, Water, Heritage and the Arts and the relevant State and Territory authorities to avoid the potential for duplication in environmental submissions and to streamline approvals for routine activities where a State or Territory has developed adequate local expertise and knowledge and that jurisdiction has appropriate legislation in place***
- ***State and Territory Governments should, at an early stage, undertake strategic assessment processes in particularly sensitive areas to identify suitable land to allow the development of probable major resource projects. All strategic assessments should be conducted early and according to clear timeframes.***

RECOMMENDATION 6.5

The Australian Government, in considering applications for a heritage protection 'declaration' under the Aboriginal and Torres Strait Islander Heritage Protection Act 1984, should take into account previous State and Territory government assessments and decisions about the same heritage site. The Commonwealth Act should also be amended to accredit State Indigenous heritage regimes that comply with a national set of minimum standards. In addition, heritage agreements should be transferable across operators when title ownership changes, providing the new operator is willing to adhere to the original work program, and the conditions of the original heritage approval.

Resource management

RECOMMENDATION 5.1

Governments should clearly articulate the objectives of intervention in approving the method and rate of petroleum extraction and periodically assess the benefits and costs to ensure such intervention is justified, and that if so, the costs of intervention are the minimum necessary to achieve the governments' objectives. Given that evidence suggests that intervention to revise extraction plans proposed by companies is rare, governments should focus their efforts on companies that are yet to establish a good track record, rather than imposing unnecessary burdens across all companies.

RECOMMENDATION 5.2

To promote regulatory certainty, governments should clarify and clearly articulate the objective/s and make transparent the criteria and processes used in both approving initial retention leases and renewing existing retention leases. In considering any changes to the retention lease system, governments should:

- ***assess the costs and benefits (including the possible effects on incentives to explore for petroleum, and any likely resulting gas supply outcomes)***
- ***ensure the costs of intervention are the minimum necessary to achieve the governments' objectives***
- ***consider more objective tests of commerciality, such as auction mechanisms, where disagreements about commercial assessments arise, to avoid inadvertent expropriation of exploration investments.***

RECOMMENDATION 5.3

Impediments to voluntary, mutually beneficial lease transactions should be removed. In this regard, Australian governments should abolish the registration fee for transfers and dealings as this may have the perverse outcome of inhibiting transfers that might otherwise improve the probability of discovered resources being commercialised expeditiously. This would also be consistent with cost-reflective charging arrangements.

Further recommendations

Listed below are further recommendations the Commission considers will reduce the unnecessary regulatory burden on the upstream petroleum sector**.**

Resource management and land access (chapter 5)

RECOMMENDATION 5.4

The Australian Government should subject any proposed changes to block graticulation to a full regulation impact statement process with careful consideration of the potential impacts on industry and only so amend the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) if the regulation impact statement clearly demonstrates a net benefit.

RECOMMENDATION 5.5

The WA Government should ensure its policy on securing domestic gas supplies is clear and transparent with appropriate guidelines and ensure this policy provides net community benefits.

RECOMMENDATION 5.6

State and Territory Governments should mirror amendments resulting from the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) in coastal waters, and implement nationally consistent legislation for onshore carbon capture and storage as originally endorsed by the Ministerial Council on Mineral and Petroleum Resources in 2006.

RECOMMENDATION 5.7

Governments should update legislation and its administration to ensure relevant offshore State and Territory legislation effectively 'mirrors' the Commonwealth offshore legislation as intended. To achieve this objective State and Territory governments should appropriately prioritise and resource legislative drafting processes.

RECOMMENDATION 5.8

In certain circumstances, Indigenous land use agreements have the potential to streamline the native title approval process and reduce the backlog of future act applications. State and Territory Governments should investigate whether such agreements could be used more frequently (including statewide, regional and conjunctive Indigenous land use agreements).

Environment and heritage (chapter 6)

RECOMMENDATION 6.2

The Ministerial Council on Mineral and Petroleum Resources should explore ways of enhancing the effectiveness and transparency of the Environmental Assessors Forum to further improve the consistency of offshore environmental approvals and decision making, particularly in relation to differences in interpretation by individual officials, without compromising the flexibility of the forum. In particular, the Ministerial Council on Mineral and Petroleum Resources should resource the Environmental Assessors Forum to develop consolidated and consistent environmental guidelines (with flowcharts and procedural information) for petroleum activities that are cross-jurisdictional, such as offshore pipelines.

RECOMMENDATION 6.3

Governments should actively manage and release information obtained by proponents as a condition of environmental approvals to enhance the public stock of environmental information and to assist in streamlining future approvals.

- ***Governments should improve the provision of baseline environmental information for new acreage releases or for new applications for project approvals in relevant areas. Notwithstanding this, governments should only require a company to provide information collected at its expense after that company has acquired its own appropriate approvals.***
- ***Governments should manage environmental data in a way similar to the current system for geophysical data: with all environmental data relating to Commonwealth, coastal and inland waters residing with Geoscience Australia and all onshore data with the relevant State and Territory agencies. All such information provided by companies at the request of governments should be publicly accessible in the same way as geophysical data, after an appropriate fixed period.***

RECOMMENDATION 6.4

The Ministerial Council on Mineral and Petroleum Resources should task the Environmental Assessors Forum to review the range of onshore environmental regulations to identify scope for streamlining onshore approval processes and associated regulations related to petroleum activities.

RECOMMENDATION 6.6

All Governments should introduce transparent policy principles for environmental offsets — especially the principle that offsets where practical should be directly related to the damage being offset. In situations where environmental damage cannot practically or sensibly be 'directly' offset, other transparent offset mechanisms should be explored — including, for example, the use of an offset 'fund', which could be devoted to the highest priority projects in the relevant jurisdiction under transparent and appropriate governance arrangements. There would be merit in introducing nationally consistent principles.

Occupational health and safety (chapter 7)

RECOMMENDATION 7.3

The Australian Government should clarify whether any significant regulatory uncertainty results from the decision that the Navigation Act would not apply to Australian registered vessels and floating production, storage and offloading vessels when these are operating under the safety case regime. If so, it should act to remove the uncertainty. Reapplication of the Act would impose an onerous regulatory burden and would be unlikely to result in net community benefits.

RECOMMENDATION 7.4

The Australian Government should clarify occupational health and safety regulations under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) to ensure that there is complete clarity about which petroleum-related sea going vessels must be regulated under the safety case regime. In determining which activities are petroleum related and pose sufficient risk to health, safety and the environment to warrant such inclusion, the Australian Government should liaise with the upstream petroleum sector, the National Offshore Petroleum Safety Authority and the Australian Maritime Safety Authority.

RECOMMENDATION 7.5

The Australian Government should consider whether it is still appropriate to have a Board for the National Offshore Petroleum Safety Authority and, if so, explicitly clarify the role of the Board and communicate this to all stakeholders.

RECOMMENDATION 7.6

State and Territory Governments should make greater efforts to harmonise safety standards, or the interpretation of those standards, for imported upstream petroleum equipment across jurisdictions, whilst giving recognition to appropriate prevailing international standards. Where the application of standards is more onerous than those prevailing in other jurisdictions or comparable countries, efforts should be made to ensure that the application of these more onerous standards provides net public benefits.

A way forward (chapter 10)

RECOMMENDATION 10.1

State and the Northern Territory Governments should make clear the scope of local government's role in the approval of upstream petroleum developments (and other major developments). Where aspects of these developments are already regulated by environmental agencies or major hazard facilities regulators, or when the regulation requires specialist industry knowledge, involvement by local government is not warranted.

RECOMMENDATION 10.2

The Australian Government should implement as soon as possible outcomes from the project to consolidate regulations under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth).

RECOMMENDATION 10.4

To support the system of objective-based legislation and to minimise regulatory creep governments should:

- ***ensure that the intent of legislation is clearly defined at the parliamentary level, including through clear explanatory memorandums and/or objects clauses that are clearly defined***
- ***clearly define the powers of regulators in developing guidelines and the intent and style of those guidelines.***

RECOMMENDATION 10.5

The Australian Government should explore options for the introduction of an electronic approvals tracking system to improve the timeliness, accountability and transparency of approval processes. Such a system should allow for tracking of individual regulatory areas (for example, resource management and environment) as well as the overall approval process. In exploring options, the Australian Government should consider whether additional features should eventually be included as part of the system (for example, licence payments and data submission).

To ensure the system is part of a best practice regulatory regime for the upstream petroleum sector, implementation of an electronic approvals tracking system should only commence once approval processes have been streamlined and are otherwise best practice.

Based on the proof and initial experience of this system, State and Territory Governments should, where possible, adopt the national tracking system.

1 What is this study about?

Key points

- In response to a request from the Australian Government, this study was undertaken to review Australia's regulatory framework for upstream petroleum activities.
  - Its objective is to identify ways to improve the regulatory arrangements and reduce unnecessary regulatory burdens on the upstream petroleum sector.
- This study is concerned with the regulation of conventional upstream petroleum projects that involve more than one jurisdiction.
  - The terms of reference exclude downstream activities, as well as coal seam methane and other mineral resource projects.
- This study focuses on burdens that may arise from deviation from best practice regulation, or from poor administration of regulatory arrangements.
  - Such burdens can result in delays and uncertainties in obtaining approvals, duplication of compliance requirements and inconsistent administration of regulatory processes, particularly affecting cross-jurisdictional projects.

On 10 April 2008, the Assistant Treasurer asked the Productivity Commission (the Commission) to undertake a research study of regulatory burdens on the upstream petroleum (oil and gas) sector. The Commission was given 12 months to prepare and submit a report for consideration by all Australian governments. The terms of reference are reproduced at the front of this report.

1.1 Background to this study

On 12 October 2005, the Prime Minister appointed a Taskforce on Reducing the Regulatory Burdens on Business (the Regulation Taskforce) to identify options to reduce the compliance burden on business from government regulation. The report of the Regulation Taskforce (2006) stressed the importance of continual reform to reduce regulatory burdens on business and the community. Since the release of this report, the Australian Government has focused its regulatory reform initiatives on addressing excessive, inconsistent or duplicative regulation. As part of this process, the Commission has been asked to conduct a series of reviews of burdens stemming from the regulatory requirements of the Australian Government.

In 2007, the Commission undertook a review of regulatory burdens on business in the primary sector, including upstream petroleum. In response to this review, the Australian Petroleum Production and Exploration Association indicated that significant burdens have resulted from delays and uncertainties in obtaining approvals, duplication of compliance requirements, and inconsistent administration of regulatory processes across jurisdictions. The burdens were claimed to be particularly large for cross-jurisdictional projects (APPEA 2007b, 2007c).

The Commission concluded that there was scope for improving the regulation of upstream petroleum activities, but that this required an examination of the totality of regulation, not just that of the Australian Government (PC 2007a). Consequently, the Commission recommended a broad review of the whole Australian onshore and offshore petroleum regulatory framework.

Governments in Australia have taken some steps to harmonise relevant legislation and streamline administrative arrangements governing upstream petroleum operations. However, COAG has recognised that there is scope for further improvement in this area.

In its meeting on 26 March 2008, COAG agreed to a far-reaching regulatory reform agenda, with the upstream petroleum sector identified as one of the numerous 'hotspots' where overlapping and inconsistent regulation threatens to impede economic activity (box 1.1). The present study was commissioned to assist Australian governments to identify ways of improving the regulation of upstream petroleum activities and reducing regulatory burdens on the upstream petroleum sector.

1.2 What the Commission has been asked to do

The Commission has been asked to review Australia's framework for regulating upstream petroleum activities, and consider opportunities to streamline regulatory approvals, provide clear timeframes and remove duplication between jurisdictions. Specifically, the terms of reference require the Commission to:

- assess the impact of the current regulatory framework on the international competitiveness and economic performance of Australia's petroleum sector and on the performance of the economy as a whole
- report on regulatory impediments to improved performance, including inconsistencies and duplication across jurisdictions, and ways in which governments in Australia could address them

Box 1.1 **COAG's regulatory reform agenda**

In February 2006, COAG launched a National Reform Agenda that included a stream of reform commitments aimed at reducing regulatory burdens on business and the community. Ten areas were originally identified for reform, namely: rail safety; occupational health and safety; trade measurement; chemicals and plastics; development assessment arrangements; building regulation; business regulation; environmental assessment and approval; personal property security; and product safety.

In December 2007, COAG established the Business Regulation and Competition Working Group to devise strategies and implementation plans for accelerating and broadening the regulation reduction agenda. The Working Group proposed to include 27 areas in an expanded reform agenda, which COAG subsequently endorsed at its 26 March 2008 meeting. These reform areas were prioritised as follows:

- Top priority — occupational health and safety.
- Requiring early action — environmental assessment and approval bilaterals; payroll tax administration; trade licences; Health Workforce Intergovernmental Agreement; national trade measurement; rail safety; consumer policy framework; product safety; trustee companies; mortgage credit and advice; margin lending; and non-deposit taking institutions.
- Accelerating progress — development assessment; building regulation; chemicals and plastics; Australian Business Number and business name registration; and personal property security.
- New reforms — standard business reporting; food regulation; mine safety; electronic conveyancing; upstream petroleum (oil and gas); maritime safety; wine labelling; directors' liabilities; and financial service delivery.

Sources: COAG (2008); PC (2006a).

- consider options for a national regulatory authority (for example, along the lines of the National Offshore Petroleum Safety Authority) to manage all regulatory approvals for the upstream petroleum sector as a means of addressing issues of regulatory duplication and inconsistencies.

Under the terms of reference, the Commission is required to have regard to:

- any other current or recent reviews commissioned by Australian governments affecting the regulatory burden faced by businesses in the upstream petroleum sector
- the underlying policy intent of government regulation on the upstream petroleum sector.

In addition, the *Productivity Commission Act 1998* (Cwlth) underpins broad policy guidelines to which the Commission must have regard in conducting this study. Those guidelines oblige the Commission to, among other things, adopt a community-wide perspective, promote reducing unnecessary regulation, encourage the development of efficient and internationally competitive Australian industries, and ensure that Australian industry develops in an ecologically sustainable way.

1.3 Scope of the study

This study is concerned with all forms of regulation governing conventional upstream petroleum projects that involve more than one jurisdiction (excluding coal seam methane and other mineral resource projects). Emphasis has been placed on regulatory arrangements that are potentially inconsistent and duplicative, or create burdens in their own right.

What *regulation* is within scope?

A broad definition of 'regulation' is adopted in this study, referring to any laws, government policies and rules that are intended to control or influence specific aspects of the regulated activity. Such regulation encompasses a range of legal instruments including statutes, subordinate legislation (regulations) and ministerial orders, as well as less formal instruments such as standards, guidelines and codes of conduct for which there is a reasonable expectation of compliance on the part of business (box 1.2).

Moreover, regulation can be implemented by contractual agreements between businesses and governments that provide the basis for governing business conduct. Under this approach, contract terms are negotiated with governments — possibly involving community stakeholders — on a facility- or project-specific basis. Such negotiated agreements are legally binding although they may or may not be codified into law.

What *activities* are within scope?

The Australian upstream petroleum sector produces a range of products including crude oil, condensate, natural gas, liquefied natural gas (LNG) and liquefied petroleum gas. The terms of reference explicitly exclude coal seam methane projects and other mineral resource projects such as oil shale extraction.

Box 1.2 **Business regulation in various forms**

Formal regulation involves governments exerting control or influence over business conduct through legal requirements, monitoring or inspection programs and, in the case of non-compliance, punitive sanctions. This form of regulation is generally based on:

- primary legislation — which consists of Acts of Parliament that set out the regulation-making authority
- subordinate legislation — which comprises laws and rules made by authorities under the delegated powers of the legislature to spell out details of policy decisions embodied in primary legislation, as exemplified by statutory rules, ordinances, by-laws, and disallowable instruments
- administrative decisions or discretions — which are requirements imposed by public officials entrusted with the relevant powers and duties
- international treaties and agreements — which can be ratified with legislative backing.

Apart from formal regulation, governments can influence business conduct by means of *quasi-regulation*. This encompasses policies, rules, standards and other instruments that do not have the force of law but effectively impose compliance requirements on business through government involvement in their development. Examples include government-endorsed industry codes of practice, government-issued guidance notes, government–industry agreements, and national accreditation schemes. Quasi-regulation is also implicit in licensing and government procurement requirements.

Further, business conduct can be subject to *co-regulation*. This involves industry and other non-government stakeholders jointly developing and administering particular codes, standards or rules, with government providing legislative support for the enforcement of those arrangements.

Sources: Banks (2001); Commonwealth of Australia (1997); OECD (2003).

In line with the terms of reference, the study has been confined to the upstream activities of the oil and gas supply chain — namely, exploration, development and production. These are distinguished from downstream activities associated with the refining, distribution, wholesaling and retailing of petroleum products.

Specifically, the delineation of upstream activities extends from the exploration for hydrocarbon deposits to the production and on-site storage of marketable crude petroleum commodities. In the upstream production stage, crude oil, condensate or gas is delivered from the wellhead, typically by pipeline, to a processing plant for primary purification or processing. These processes remove unwanted chemical compounds, making the petroleum products suitable for shipment to a refinery.

They sometimes take place on a floating export terminal for offshore projects. In the case of LNG, the upstream stage is taken to include the LNG purification and liquification trains and all activities up to the export terminal for LNG.

The regulation of a range of onshore and offshore project activities is examined in this study. A project can involve the development of a new single hydrocarbon reservoir or field, or an incremental development of an existing producing field. The integrated development of a group of several fields and associated facilities also constitutes a project (World Petroleum Council 2008). Regulated project activities include conducting exploration and seismic surveys, drilling wells (both for exploration and later for production), laying pipelines, constructing oil and gas extraction equipment and subsequent processing equipment, operating transport and storage facilities, and eventually decommissioning end-of-life installations.

For the purpose of this study, there are four classes of jurisdiction which are relevant — namely: (i) local governments; (ii) State and Territory Governments; (iii) the Australian Government; and (iv) the Joint Petroleum Development Area established under the 2002 Timor Sea Treaty between the Australian Government and the Government of East Timor. Accordingly, the Commission has considered a range of circumstances in which a project could be identified as cross-jurisdictional. These include, but are not limited to, cases where a project:

- crosses from Commonwealth waters into a State or Territory area (including coastal waters) such as in building a pipeline to bring gas onshore
- takes place wholly within a State or Territory but is subject to regulation by different levels of government, which could include federal, state or local government
- is subject to legislation jointly administered by agencies or departments at different levels of government
- crosses from the Joint Petroleum Development Area into Commonwealth waters.

1.4 Approach of the study

The Commission has reviewed the regulatory framework by considering the questions of whether it is achieving policy objectives and whether the resulting burdens are the minimum necessary to achieve those objectives. Where it is clearly articulated, the Commission has taken the underlying policy intent as given and, on that basis, sought to identify and distinguish between:

- the extent to which particular policy objectives explain the significance of regulatory burdens — that is, the policy creates a burden in its own right

- the extent to which particular policy objectives might be attained with a reduction in burden through improving the design and/or administration of regulation.

In some instances, however, the Commission has commented on the lack of clarity regarding the underlying policy intent of regulation. Lack of clarity in this respect creates uncertainty and, sometimes, inconsistency as different regulators put their own interpretations on what the policy is intended to achieve. All these contribute to unnecessary regulatory burdens.

In line with the broad definition of regulation outlined earlier, the regulatory framework has been reviewed as a collection of:

- policies
- laws and rules
- incentives
- decision-making processes
- licensing conditions
- compliance mechanisms
- administrative procedures
- institutional arrangements.

The Commission has drawn on broad principles of best practice regulation and governance when assessing the regulatory framework. Best practice regulation depends on rules and laws that have clear objectives, and are well designed, properly administered and duly enforced. Moreover, it requires the support of robust and adequate governance arrangements — a set of institutions, processes and systems by which policy decisions are made, roles and responsibilities are assigned, regulatory tasks and functions are carried out, and the relationships of authorities within and between jurisdictions are organised.

In addition, the Commission has examined the regulatory frameworks governing petroleum resource development in a selection of overseas countries. Identifying key similarities and differences in the form and content of regulation from an international perspective has been aimed at shedding light on the scope and focus of reforms that might bring improvement to the Australian regime.

The Commission has examined both the practice of regulators and the reaction of businesses to the regulation of project activities. To this end, empirical and anecdotal evidence has been obtained from meetings with petroleum companies, industry bodies, government departments and regulatory agencies.

Particular attention has been paid to how regulators act on and interpret their regulatory mandates. This behavioural aspect is important because any rule or law has an impact on business that is influenced by the way the regulators choose to interpret and apply that regulation.

The Commission also recognises the importance of appropriate resourcing to the organisational and administrative efficiency of regulation. Difficulties in attracting and retaining appropriately skilled and experienced staff to carry out regulatory functions has been frequently cited by participants in this study.

The Commission, in its issues paper, called for credible evidence and quantification of unnecessary regulatory costs borne by the upstream petroleum sector. Some participants provided information on burdens and associated costs, although the evidence presented was largely anecdotal or qualitative in nature with limited empirical data on burden indicators or costs. This qualitative information helped identify particular priorities and reveal the complexity of certain regulatory challenges.

1.5 The conduct of this study

On receipt of the terms of reference on 10 April 2008, the Commission advertised in major newspapers and issued a circular announcing the study to interested parties.

The Commission held informal discussions in Adelaide, Brisbane, Canberra, Darwin, Karratha, Melbourne and Perth with various interested parties, including representatives from petroleum companies, industry associations, government departments and regulatory agencies, as well as researchers with expertise in the regulation of petroleum projects.

In July 2008, the Commission released an issues paper to assist those preparing submissions. A total of 20 submissions were received in response to the issues paper. A draft report was released in December 2008, to enable participants to provide comments on the Commission's preliminary analysis through a further round of public submissions. Following the release of the draft report, a further 15 submissions were received.

In October 2008 the Commission held two roundtables, in Canberra and Perth, to elicit views on key issues relevant to the Commission's study. Further roundtables were held in February 2009, in Melbourne and Perth, following the release of the draft report.

All individuals and organisations consulted, roundtable attendees, and submissions received are listed in appendix A.

1.6 Report structure

The structure and economic significance of the upstream petroleum sector in Australia is described in chapter 2. Chapter 3 discusses the rationales for regulating upstream petroleum activities, as well as the general causes and implications of unnecessary regulatory burdens. Chapter 4 provides an overview of the regulatory framework, including its historical background, existing legislative and institutional arrangements, and recent and current reviews of those arrangements.

The next few chapters are devoted to detailed discussion of regulatory arrangements and issues in specific areas: resource management and land access (chapter 5); environmental and heritage protection (chapter 6); and occupational health and safety (chapter 7). This is followed by an empirical assessment of unnecessary regulatory burdens in chapter 8. Models for a national regulator are examined in chapter 9. Finally, the way forward on future regulatory arrangements is presented in chapter 10.

2 The upstream petroleum sector

Key points

- The upstream petroleum sector encompasses: (1) exploration and appraisal, (2) development and construction, and (3) production. For natural gas (including liquefied natural gas), the definition of upstream includes processing and delivery to export terminals or domestic gas transmission pipeline in-take.
- The Australian upstream petroleum sector is small by global standards.
- The upstream petroleum sector added $15.3 billion to Australian GDP, and contributed over $5.5 billion in taxes to governments in 2004-05.
- Australia's oil and gas reserves account for 0.1 per cent and 0.5 per cent of world totals respectively (excluding coal seam methane). Reserves are predominantly concentrated offshore in the Bonaparte, Browse, Carnarvon and Gippsland Basins.
- Australian natural gas production has increased steadily since 1970, while production of naturally occurring liquefied petroleum gas has remained stable. Crude oil production declined from 2000-01 to 2005-06, and increased in 2006-07.
- The Australian upstream petroleum sector has many international participants, with many engaged in joint ventures. Downstream customers are both domestic and international.

This chapter contains a discussion of the upstream petroleum sector in Australia, including the sector's economic significance, the quantity of Australian reserves, and the size and structure of the sector in a global context. It also contains a summary of the upstream elements of the oil and gas supply chain and an analysis of industry structure.

2.1 Oil and gas in Australia

The upstream petroleum sector represents a major component of the Australian economy. In terms of industry value added, oil and gas extraction contributed $15.3 billion to the Australian economy in 2004-05 (ABS 2008a). This represented approximately 2 per cent of GDP in 2004-05.

Australia is a net importer of crude oil. Indeed, crude oil has been Australia's largest import in dollar terms since 2006 (partly reflecting high global oil prices), accounting for $14.6 billion (6.2 per cent of total imports) in 2007 (DFAT 2008a). Australian crude oil exports also increased to $8.7 billion in 2007 (ABARE 2008a). Imports of crude oil are forecast to increase until 2027, with domestic consumption growth outstripping domestic production (Geoscience Australia 2008).

Australia is a significant net exporter of liquefied natural gas (LNG), with exports of $5.2 billion in 2006-07 (ABARE 2007b). No LNG is imported; however some natural gas from the Timor Sea brought onshore in Australia for processing is classified as imported. Liquefied petroleum gas (LPG) is also exported, accounting for $1 billion in 2006-07, more than 50 per cent higher in nominal terms than in 1999-2000 (ABARE 2001; 2007b).

Including company taxes, the upstream petroleum sector contributed over $6 billion in taxes to governments in 2006-07. Crude oil tax excise and royalty revenue to Australian governments was $3.3 billion in 2006-07, of which the Petroleum Resource Rent Tax contributed $1.7 billion (APPEA 2007a). A significant portion of petroleum royalties accrue to States and Territories. For example, the WA Government received around $737 million in petroleum royalties in 2007 (DoIR 2007b), reflecting that Western Australia accounts for 69 per cent and 67 per cent of Australian gas and oil production respectively (DoIR, sub. 18). Taxation of the sector is discussed further in chapter 5.

The upstream petroleum sector in Australia employs around 15 000 people (RET 2007) — less than 0.2 per cent of the total labour force at July 2008 (ABS 2008c). Wages and salaries in the sector totalled over $1.3 billion in 2006-07 (ABS 2008b).

Australia's oil and gas reserves

Oil and gas discoveries yet to be extracted are termed 'reserves'. However, prior to full extraction the size of oil and gas discoveries is always uncertain. The sector classifies reserves as 'proved' (greater than 90 per cent probability of existence), 'probable' (between 50 per cent and 90 per cent probability) or 'possible' (between 10 per cent and 50 per cent probability). The more general term 'resources' encompasses reserves, oil and gas that is yet to be discovered, and oil and gas that is uncommercial or technically infeasible to extract.

Australia has substantial reserves of gas, and was one of the world's top 20 gas-producing countries in 2006. It is currently ranked 24th in the world in terms of proved gas reserves. Nonetheless, proved reserves amounted to only 0.5 per cent

of the world total at 1 January 2008 (excluding coal seam methane), with worldwide reserves being concentrated in Russia, Iran and Qatar (PennWell 2008).

Australia's oil reserves are less extensive, comprising 0.1 per cent of the world total at 1 January 2008 (PennWell 2008). However, Australia has many under-explored sedimentary basins and may have considerable oil and gas resources yet to be discovered (Powell 2008).

Most of Australia's oil is light crude (box 2.1). Light crude is more valuable than heavy crude, as it is used for premium products such as gasolines. Most of the heavy crudes used for fuel oils, lubricating oils, and bitumen in Australia, are imported (Wilkinson 2006).

Proved and probable reserves of oil and gas are highly concentrated in a few areas off the coast of Australia (figure 2.1). In particular, most reserves are located in the

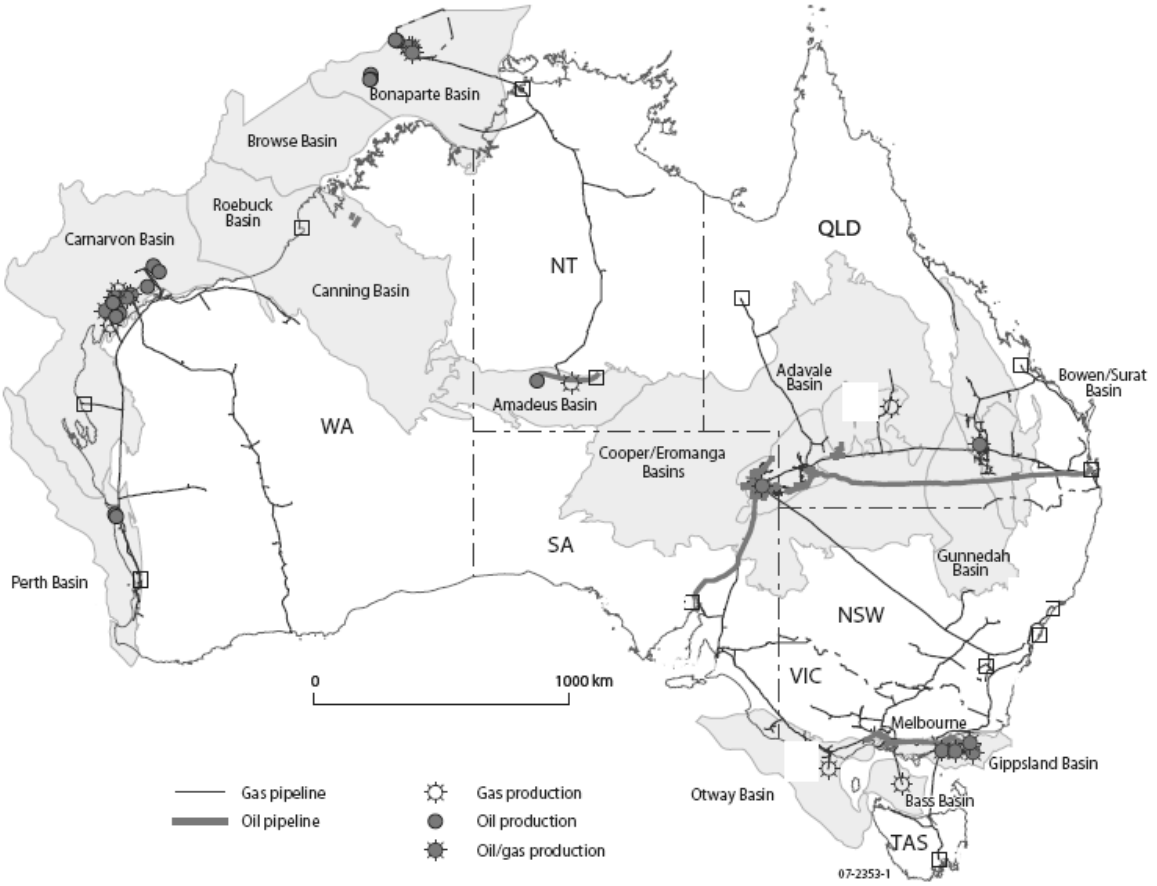
Box 2.1 **Types of oil and gas product**

The types of oil and gas products depend partly on the natural structure of the hydrocarbons, and partly on the post-extraction production processes.

- *Crude oil* — comes in three types depending on its chemical structure, which also determines its density:
  - *Paraffin-based crudes* — are mostly composed of paraffin molecules. These tend to have a low density, and are generally referred to as *light crudes*.
  - *Asphalt-based crudes* — are mostly composed of napthene molecules. These tend to have a high density, and are generally referred to as *heavy crudes*.
  - *Mixed-base crudes* — contain paraffins, napthenes and aromatic hydrocarbons. These are heavier than paraffin-based, but lighter than asphalt-based crudes.
- *Condensates* — are hydrocarbons that are gaseous in reservoirs, due to the high temperatures. At surface temperatures and atmospheric pressure they condense into a light oil. The term 'crude oil' is often applied to both crude oil and condensate.
- *Natural gas* — is mainly methane. It is treated before sale to remove the propane, butane, other liquid hydrocarbons and impurities it often contains in its crude form.
- *Liquefied natural gas (LNG)* — is natural gas cooled to below -160 degrees Celsius, thereby rendering it a liquid. This reduces its volume by over 600 times, making storage and transportation viable.
- *Liquefied petroleum gas (LPG)* — consists of propane and butane. It is found in gas and oil reservoirs, and is also a refinery by-product. LPG liquefies under slight cooling and compression, and is used as motor, domestic and industrial fuel.

Sources: Gary et al. (2007); Wilkinson (2006).

Figure 2.1 **Identified Australian oil and gas reserves, 2007**



Source: Geoscience Australia (pers. comm., 27 October 2008).

Bonaparte, Browse, Carnarvon and Gippsland Basins (table 2.1). The Bass Basin contains Australia's fifth largest reserves of LPG. Smaller reserves of oil have been found in the Perth Basin; and the Otway Basin contains small reserves of gas. By comparison, onshore Australian reserves make up 4 per cent of total oil reserves and 17 per cent of total gas reserves (RET 2007). The most substantial onshore petroleum reserves are located in the Cooper and Eromanga Basins.

Over time, the location of known Australian reserves has changed. Production of early oil and gas discoveries in the Cooper, Eromanga and Gippsland Basins have reduced the significance of the reserves in these basins. By contrast, newer discoveries in the Bonaparte, Browse and Carnarvon Basins that are yet to be fully exploited have increased the importance of these basins to Australian revenues.

Most of Australia's oil and gas reserves (78 per cent of crude oil and 92 per cent of natural gas) are located off the coast of Western Australia, in the Bonaparte, Browse, Carnarvon and Perth Basins (table 2.1).

Table 2.1 **Estimated oil and gas reserves, 1 January 2006[a]**

Basin	*Location*	*Crude oil*	*Condensate*	*LPG*	*Natural gas*[b]
		GL	GL	GL	bm^3
Adavale	Onshore	–	–	–	0.36
Amadeus	Onshore	0.73	0.18	0.03	6.79
Bass	Offshore	2.11	6.88	9.31	14.78
Bonaparte[c]	Offshore	21.32	100.44	58.14	792.61
Bowen	Onshore	1.26	0.38	0.45	11.15
Browse	Offshore	2.16	100.00	69.67	831.88
Canning	Onshore	0.02	–	–	0.18
Carnarvon	Offshore and onshore	180.56	168.22	121.95	2 315.86
Cooper	Onshore	2.03	2.61	4.50	38.77
Eromanga	Onshore	8.11	0.08	0.07	0.74
Gippsland	Offshore and onshore	44.24	20.82	27.80	208.10
Gunnedah	Onshore	–	–	–	0.30
Otway	Offshore and onshore	–	2.67	–	54.25
Perth	Offshore and onshore	6.35	1.79	–	39.13
Surat	Onshore	0.03	0.01	0.01	0.90
Total[d]		**268.93**	**404.05**	**291.93**	**4 315.80**
Total in PJ[e]		**8 914**	**14 130**	**8 012**	**160 816**

a Includes estimates of proved and probable reserves both from fields that are commercially viable and fields that have not yet been declared commercially viable. **b** Sales quality natural gas (refined to the specification of sales contracts). **c** Estimates for Bonaparte Basin include total reserves in the Joint Petroleum Development Area. **d** Totals may not add due to rounding. **e** Estimates based on conversion factors of 37 MJ/L for crude oil and condensate, 26.5 MJ/L for liquefied petroleum gas and 40.5 MJ/L for natural gas (1 m^3 natural gas is equal to 1000 L) (ABARE, pers. comm., 17 October 2008). – Nil or rounded to zero.

Sources: ABARE (2008a); Geoscience Australia (2006, 2008); Commission estimates.

Basins often cross more than one jurisdiction, particularly where they extend more than three nautical miles offshore. Moreover, the Bonaparte Basin straddles both Western Australia and the Northern Territory, as well as Commonwealth waters and the Joint Petroleum Development Area with East Timor. (Definitions reflecting Australia's maritime boundaries are presented in chapter 4.) Similarly, some onshore basins (such as the Cooper Basin) also straddle more than one jurisdiction.

Petroleum is a non-renewable resource. As Australian petroleum resources decline, the economic contribution of oil and gas production could also decline. However, to the extent that this occurs in conjunction with a decline in global resources, higher prices will increase the economic significance of oil and gas consumption and remaining Australian production. Higher prices are also likely to stimulate exploration and the discovery of new reserves.

As Tina Hunter observed:

> Once Australia exploits its petroleum resources, it liquidates the petroleum asset and will no longer have the revenue from these resources. That is because like any other asset, once the petroleum is extracted and sold, it is permanently lost. This creates an enormous challenge for the Australian government: to create a regulatory framework that generates appropriate and adequate revenue, whilst at the same time establishing appropriate incentives so oil companies are attracted to the petroleum province to develop the resources. (sub. DR28, pp. 3–4)

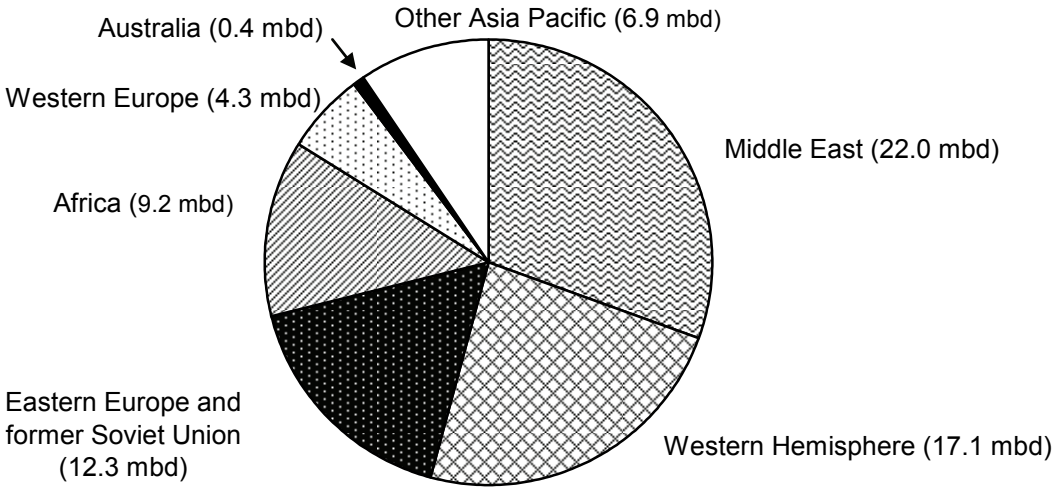
2.2 Structure and size of the sector in a global context

Australian oil and gas production represents a very small proportion of world production, with Australian reserves also small by global standards. Australian crude oil production (445 000 barrels per day) represented less than 1 per cent of worldwide production in 2007 (figure 2.2).

The Australian oil and gas market is also small by global standards. Specifically, ABARE (2008b) noted:

> … the domestic market for natural gas in Australia is presently characterised by a small number of producers, a small number of large consumers and limited depth in consumption. (ABARE 2008b, p. 32)

Figure 2.2 **Estimated world oil production, 2007[a]**



a Production expressed in million barrels of oil per day (mbd).

Source: PennWell (2008).

Over 100 companies (excluding wholly-owned subsidiaries) and individuals across Australia hold interests in oil and gas production permits. However, the industry is

dominated by a few large businesses, including BHP Billiton, Chevron, ExxonMobil, Santos and Woodside, which together accounted for approximately 58 per cent of oil production in 2006 (EnergyQuest 2007). As the upstream petroleum sector in Australia is open to competition from domestic and foreign businesses, it attracts investment from other large international businesses, including Apache, BP, ConocoPhillips, ENI, Inpex and Shell.

The exploration sector comprises over 270 companies and individuals holding interests in exploration permits (Commission estimates based on ENCOM 2008). This reflects the lower cost of the exploration phase compared with the production phase, with lower barriers to entry existing for the participation of smaller businesses. For example, Bow focuses on exploration activities such as data collection, and retains a small interest in any discoveries. The bulk of their interests is passed to larger businesses — with better access to capital — for exploration drilling and field development (Bow 2007).

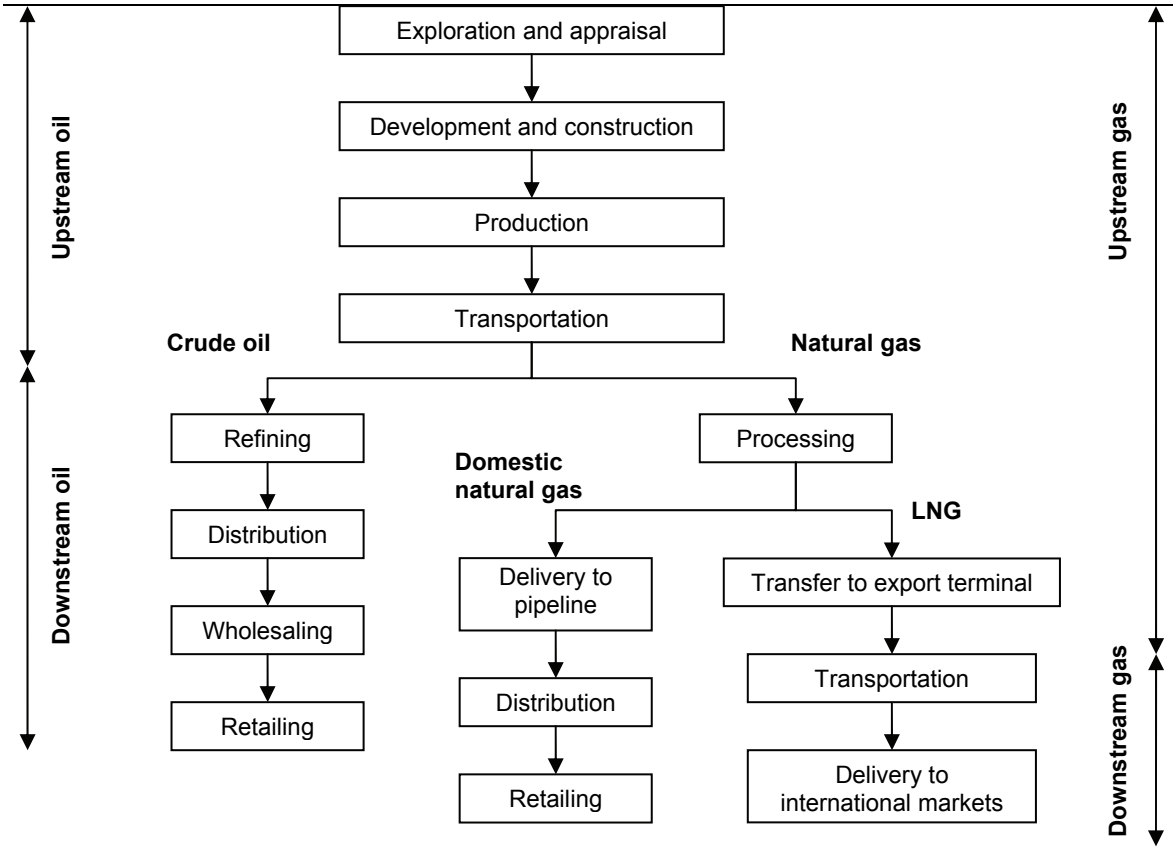
The number of industry participants has decreased slightly in recent years, with 163 companies ceasing exploration activities in Australia between 1993 and 2002, while 154 companies commenced or recommenced exploration during that period (Powell 2008).

Overall, the Australian upstream petroleum sector has shown after-tax returns on assets ranging between 5.1 per cent and 12.6 per cent in the 20-year period 1987-88 to 2006-07, with an average return of 8.6 per cent over the same period. (Commission estimates based on APPEA 2007a). These returns are below the 11.7 per cent average return on assets obtained by the top 200 American-owned upstream and downstream oil and gas companies in 2006 (PennWell 2008).

2.3 Exploration, development and production

The oil and gas supply chains contain a number of distinct stages. The upstream petroleum sector encompasses three of these stages: (1) exploration and appraisal; (2) development and construction; and (3) production. The downstream activities usually include refining, distribution, wholesaling and retailing. For natural gas (including LNG), the definition of upstream includes processing and delivery to export terminals or to domestic gas transmission pipeline in-take (figure 2.3).

Figure 2.3 **Stylised supply chain for oil and natural gas**



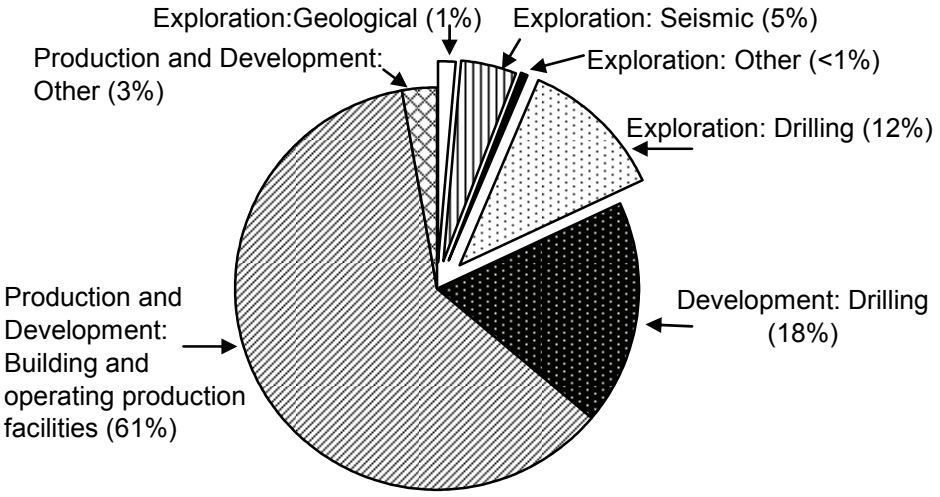
Total upstream project expenditure is dependent on a variety of factors at each stage of the supply chain (figure 2.4). The costs incurred at each stage also depend on the activities conducted in prior stages.

Exploration and appraisal

The primary focus of the exploration and appraisal stage is information gathering. This stage involves the use of a number of scientific techniques as well as drilling activities. Exploration expenditure tends to be lumpy, and occurs long before development. Consequently, it varies substantially from year to year as a proportion of total expenditure. In 2005, it comprised approximately 17 per cent of total expenditure, however, overall exploration accounted for about 28 per cent of total expenditure by the upstream petroleum sector in Australia over the period 1980–2005 (Geoscience Australia 2008).

A scientific approach is applied to select an appropriate area of the chosen sedimentary basin in which to explore. This includes a variety of non-seismic techniques, such as satellite imagery; gravity, magnetic and geochemical surveys; radiometric surveys and controlled electro-magnetic surveys (Wilkinson 2006).

Figure 2.4 **Breakdown of total upstream petroleum expenditure, 2005**



Source: Geoscience Australia (2008).

More detailed techniques are then applied in order to pinpoint a location in which to place a 'wildcat' well (that is, a search well placed in a previously undrilled area). Seismic surveys are the principal method used for obtaining data on subsurface geological structures. This entails sending sound waves through the earth, and collecting data from the reflections of those sound waves in order to compile a cross-sectional image of the subsurface geology. Surveys can be two- or three-dimensional. Three-dimensional surveys provide more detailed imagery, but are more costly and time consuming (Wilkinson 2006).

Collecting, processing and analysing the exploration data obtained from these procedures accounts for only a small proportion of the upstream sector's total annual expenditure. Exploration expenditure is high-risk and will not generate any revenues if oil and gas are not found. Even the discovery of oil or gas does not guarantee a return, as the resources may be marginal or non-commercial.

If geological information suggests a reasonable likelihood of oil or gas discovery, then a wildcat well is drilled to determine whether an oil or gas deposit exists (Wilkinson 2006). The number of wildcat wells drilled in Australia has fluctuated over time, ranging from 48 wells in 2002 to 124 wells in 1998 (table 2.2). In 2005, 85 wildcat wells were drilled, around the annual average for the preceding 10 years. The proportion of wildcat wells that have been successful in locating an oil or gas deposit varies across years, from around one quarter in 2003 to over one half in 2004 (Geoscience Australia 2008).

Table 2.2 **Exploration activities**

Year	Wildcat wells[a]	Extension/ appraisal wells[b]	Seismic surveys		Wildcat success rate[d]
			2-dimensional[c]	3-dimensional[c]	
	number	number	line km	sq km	%
1995	88	58	161 174	na	34
1996	95	50	389 163	na	37
1997	110	69	529 529	na	43
1998	124	39	1 062 810	na	36
1999	69	27	523 410	na	34
2000	72	28	135 828	15 178	39
2001	94	37	65 024	21 779	44
2002	48	41	15 442	15 653	46
2003	66	33	15 837	7 305	26
2004	86	36	43 215[e]	14 778[e]	52
2005	85	60	44 119	24 606	35

[a] A 'wildcat' well is a search well placed in a previously undrilled area. [b] An 'appraisal' well is typically drilled as part of the process to determine the size of a discovery. Similarly, an 'extension' well is used to determine if a discovery extends beyond the known area. [c] Measures of 3 dimensional seismic surveys conducted prior to 2000 were converted to line km and included in the 2 dimensional seismic survey figure by Geoscience Australia. [d] Wildcat success rate is based on the number of wildcat wells and the number of new field discoveries (irrespective of commerciality). [e] Figures may include reprocessed data. **na** Not available.

Sources: Geoscience Australia (2006, 2008).

Should oil or gas be found, the extent of the discovery is appraised for commercial viability by drilling appraisal wells. Combined with seismic mapping, appraisal wells are used to determine the nature and size of the discovery (Wilkinson 2006).

The cost of extraction and the marketability of both oil and gas in part depend on their chemical make-up. This is determined through testing prior to development and production.

The nature of an oil or gas deposit, as well as the subsurface geology, also determines recovery estimates. Not all of the hydrocarbons in a reservoir are extractable. Production of an oilfield usually extracts between 10 and 40 per cent of estimated resources, but up to 80 per cent in some circumstances. Between 75 and 90 per cent of estimated resources can usually be extracted from gas fields (Favennec 2004).

Development and construction

Infrastructure to support production is established in the development and construction stage. In addition to drilling production wells, this includes

constructing field infrastructure, on-site production and processing facilities, and transmission facilities to connect the field with downstream refineries and distribution systems.

The capital expenditure incurred in the development and construction phase forms a large proportion of the total costs of a project, with the development drilling component alone accounting for 18 per cent of total upstream petroleum expenditure in 2005 (figure 2.4). Development costs are influenced by the information gathered during the exploration and appraisal phase. Insufficient or inadequate information may lead to a poorly designed production system, which can increase overall project costs.

Development costs include drilling and constructing a gathering network, well testing facilities, on-site processing plants and pipelines. In addition, offshore plants may require an offshore processing platform. Much of this equipment is imported from the United States, the United Kingdom, Germany, Denmark, Sweden and Japan. Supplies from Asia, including China and India, are increasing (US Commercial Service 2008).

Development of LNG and domestic gas plants account for a large proportion of total project expenditure. For example, the construction of the North West Shelf Venture's fifth LNG train and production facility cost $2.6 billion (ASX 2008).

Delays in bringing proven reserves to commercial production are inevitably costly, due to significant sunk costs of exploration. At the development and construction stage delays are even more costly, due to the direct costs of placing construction on hold and the opportunity cost of idle capital equipment already in place.

Development drilling

Development drilling establishes the production wells. Drilling is generally a step-by-step process (particularly for onshore fields), thereby allowing the developer to revise the development plan based on the outcome of each well drilled. Successful onshore exploration wells may also be used as production wells (Wilkinson 2006).

The step-by-step process is often not possible for offshore fields, because economic design of production facilities requires the location of all wells to be known prior to development commencing. In this case, the optimal number and location of wells must be determined prior to drilling (Wilkinson 2006).

Development wells tend to be drilled more quickly than exploration wells and the costs are easier to control. This is because drilling in the area becomes a repetitive

process, with drill times and costs declining with the number of wells. However, development drilling forms a significant proportion of total expenditure (figure 2.4).

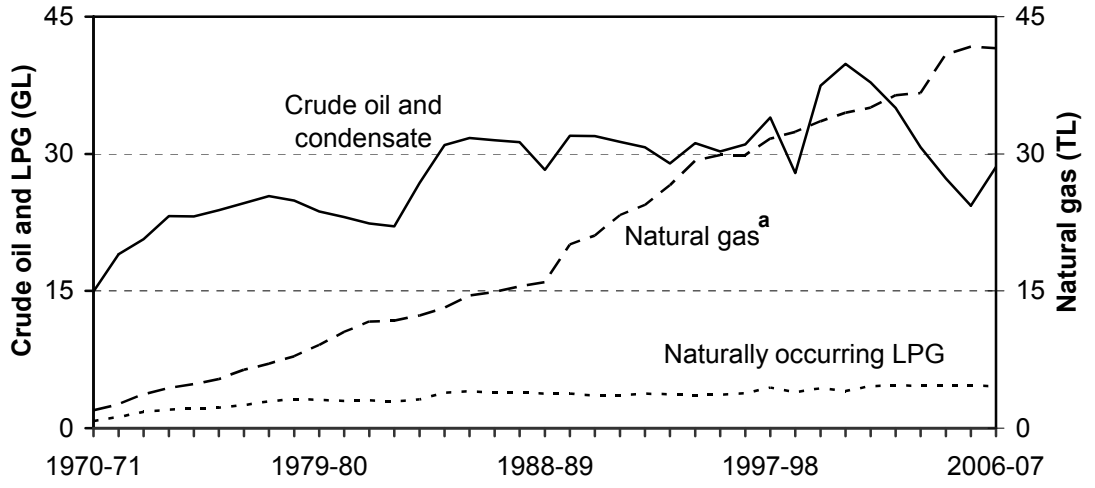
Production

The production stage commences after a field has been developed. Production activities commence with the recovery of petroleum from the reservoir using primary, secondary and tertiary methods. The recovered hydrocarbons are then processed, and finally transported to refineries and distribution systems.

The production stage involves higher operating expenditure and lower ongoing capital expenditure. Two thirds of on-site operating cash costs (excluding those related to LNG or domestic gas treatment facilities) are incurred in the areas of general support, well and surface operations, maintenance and logistics. Personnel costs form a substantial proportion of the costs in these areas (Favennec 2004).

Australian natural gas production has increased steadily since 1970, while production of naturally occurring LPG has remained more stable. Crude oil and condensate production increased from 15 GL in 1970-71, and peaked at 40 GL in 2000-01, before declining to 24 GL in 2005-06 (figure 2.5).

Figure 2.5 **Australian annual production, 1970-71 to 2006-07**



a 1 TL natural gas = 1 billion m^3. Litres refer to gas volume, and are not equivalent to liquefied natural gas (LNG) volume. Natural gas includes gas that is later converted to LNG, but excludes liquefied petroleum gas.

Source: ABARE (2008c).

Recovery

Primary recovery refers to the initial extraction of petroleum, using the natural pressure in the reservoir. This natural pressure forces the oil and gas to the top of the wellhead. Generally, 25 to 30 per cent of oil, or 80 per cent of gas can be recovered using this method (Favennec 2004).

Secondary recovery extends natural flow through artificial methods, such as injecting water or gas into the reservoir. This maintains the pressure in the reservoir and flushes the oil into the production well. Alternatively, pumps can be used to extract the oil. Tertiary (or enhanced) recovery alters the chemical properties of the remaining oil, to make it flow into the well. Techniques include injecting various fluids and gases, such as complex polymers and carbon dioxide (Wilkinson 2006).

Processing and transportation

Preliminary processing occurs on-site in conjunction with recovery. Processing involves dividing the hydrocarbon mix into separate streams of oil, water and gas. Both oil and gas are further treated to remove any remaining water.

Treated crude oils and condensates are transported by pipelines, tankers or trucks to refineries, where they are converted into commercial products. Refining represents the first stage of the downstream petroleum sector.

Natural gas also requires additional processing prior to its distribution. Therefore gas is transported (usually by pipeline) to gas processing plants. There, inert gases, liquid hydrocarbons, and sulphur and other impurities are removed from the gas, leaving a commercial form of gas that is mostly methane. This is then sold to retailers or large end users.

In order to make natural gas easier to transport and store, gas can be converted to LNG. The gas from the production field is transported to an LNG processing plant (train), generally located near port facilities. There it is processed, purified and cooled to below -160 degrees Celsius to convert it to liquid form. The LNG is then loaded onto a special LNG shipping tanker, and exported.

LPG is classified as either naturally occurring, as is 77 per cent of Australian LPG production (RET 2008d), or artificial. Naturally occurring LPG is sourced from gas fields and oilfields, while the artificial variety is a by-product from refineries.

Naturally produced LPG is separated from natural gas and condensate at the LNG or gas processing plant. It is then compressed, and transported in pressurised tanks to domestic or export markets.

2.4 Industry structure

The upstream petroleum sector is characterised by a number of international oil businesses, many of which participate in joint venture agreements. Petroleum products are then sold to downstream customers, such as oil refineries, gas retailers, and overseas markets.

Ownership structure

Many of the key businesses in the Australian upstream petroleum sector are subsidiaries of multinationals. For example, Apache, ConocoPhillips, Chevron and ExxonMobil have US parent companies, while BP, ENI, OMV and Shell have parent companies in Europe.

Some large Australian businesses are now engaged in overseas exploration and production. Woodside represents the largest independent Australian upstream petroleum company in terms of both market capitalisation and proved plus probable reserves, reflecting the large scale of some of Woodside's projects (table 2.3). Beach Petroleum, Origin and Santos have equity holdings in a large number of oil, gas and coal seam methane production permits in Australia.

The industry structure is complicated by the prevalence of joint ventures. Most onshore and offshore production licences are issued to multiple parties, with a single business designated as the 'operator'. For example, the North West Shelf project involves a joint venture between Woodside, BHP Billiton, BP, Chevron, Japan Australia LNG and Shell. Santos has joint interests with over 40 other producers, including Beach Petroleum, BHP Billiton, Chevron, ExxonMobil and Origin. A substantial proportion of exploration permits is also issued to joint ventures.

Joint ventures are important in the petroleum industry, as they facilitate risk sharing, and allow businesses to specialise and still accomplish the maximum development of a given field. Joint ventures also allow smaller businesses to be involved in production without raising the large quantities of capital required to develop a field alone.

Table 2.3 **Major Australian-listed oil producers**

Company	*ASX code*	*Market capitalisation at 1 January 2008*	*Reserves*		*Production permits in Australia 2008*
			Proved	*Proved plus probable*	
		A$ billion	mboe[a]	mboe[a]	number[b]
Arc Energy	ARQ	0.4	5.7	17	16
Australian Worldwide Exploration	AWE	1.6	na	39	3
Beach Petroleum	BPT	1.4	na	4.3	308
BHP Billiton	BHP	128.3	275	551	43
Cue energy Resources	CUE	0.1	5.1	47	–
Oil Search	OSH	5.2	132	1 193	–
Origin (upstream and downstream)	ORG	7.6	na	378	316
Petsec Energy	PSA	0.2	na	5.7	–
ROC Oil	ROC	0.9	13.0	17	2
Santos	STO	8.4	348	643	413
Tap Oil	TAP	0.3	na	19	9
Woodside	WPL	35.2	951	1 294	27

a Million barrels of oil equivalent. **b** Includes permits issued to wholly-owned subsidiaries. – Nil. **na** Not available.

Source: ABARE (2008a); Commission estimates based on ENCOM (2008).

Downstream customers

Once treated, crude oil, natural gas (including LNG) and LPG are either sold to domestic customers, or exported. The proportion of domestic production that is exported has increased significantly since the early 1990s (figure 2.6).

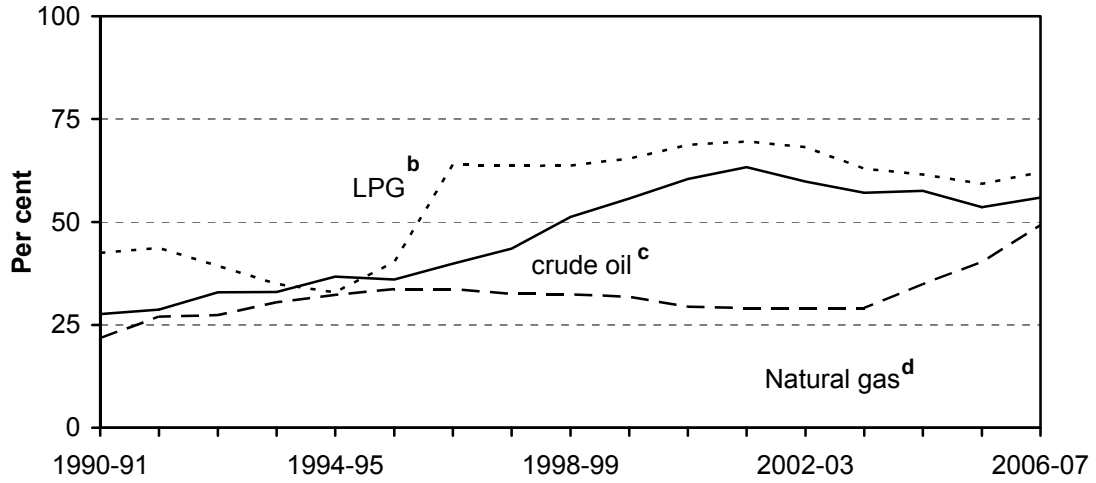
Tina Hunter noted:

> The export of petroleum was the second largest [export] income earner in 2006, behind coal. Importantly, LNG exports are increasing rapidly, from $5 billion in 2006 to an estimated $8.5 billion by 2011. As a source of import expenditure, crude oil is Australia's largest import in dollar terms, approximately 6.2% in 2006. (sub. DR22, p. 2)

Crude oil and condensate

Treated crude oil is not in a form that can be used as fuel — it must be refined. Consequently, the main customers of upstream crude oil producers are refineries, although intermediaries may also purchase crude oil and then sell it to the refineries. Australia has seven refineries, operated by BP, Caltex, ExxonMobil and Shell (PennWell 2008).

Figure 2.6 **Exports as a percentage of oil and gas production, 1990-91 to 2006-07[a]**



a Original measurements of production and exports are in PJ. **b** Liquefied petroleum gas (LPG) is equal to total LPG exports as a percentage of naturally occurring LPG produced. Production data for artificial LPG are not available. **c** Crude oil is equal to exported 'crude oil and other refinery feedstock' divided by produced 'crude oil and condensate'. **d** Natural gas includes LNG.

Sources: ABARE (2008b, 2008c); Commission estimates.

Although Australia is a net importer of crude oil, approximately 56 per cent of Australian-produced crude oil and condensate was exported in 2006-07, following a peak of 63 per cent in 2001-02 (Commission estimates based on ABARE 2008c). This partly reflects the fact that production from north-western Australia is mostly exported, whereas local refineries import crude oil in order to supplement declining production in south-eastern Australia (ABARE 2008a).

Over 68 per cent of Australia's crude oil exports went to the Asian region in 2005-06 (IEA 2008). The largest export markets for crude oil in 2007 were the Republic of Korea, Japan, Singapore, Thailand and Papua New Guinea (DFAT 2008a).

Natural gas and LNG

Once extracted, natural gas is transferred (usually by pipeline) to a gas processing plant. A number of domestic gas processing plants exist in Australia, most of which are located in southern Queensland, the Northern Territory, coastal Victoria and in the Carnarvon and Perth Basins in Western Australia (ABARE 2008b).

Processed natural gas can be sold directly to the end user, which is common with large users. However, natural gas is usually sold to a retailer, who generally has third party access to the transmission and distribution pipelines used to deliver the

gas to customers, including households. Major Australian gas retailers include AGL, AlintaGas, Allgas, Country Energy, Origin, TXU and Wesfarmers (PC 2004d).

Natural gas in its standard form is not exported, as its large volume makes transportation uneconomical. However, a substantial proportion — 49 per cent in 2006-07 (figure 2.6) — of Australia's natural gas is exported after being converted to LNG. This currently occurs in two LNG processing facilities, located in the Pilbara and in Darwin, and operated by Woodside and ConocoPhillips respectively. The majority of exported Australian LNG is purchased by Japan, Republic of Korea, China and Taiwan (Roarty 2008).

Although domestic natural gas consumption is forecast to increase by 86 per cent over the 25 years to 2029-30, production is forecast to grow at a faster rate, resulting in strong growth in LNG exports (ABARE 2007a).

LPG

Naturally occurring LPG must be separated from natural gas streams in an LPG extraction plant. A number of LPG extraction plants exist in Australia, including two in Western Australia, operated by the North West Shelf Joint Venture and Wesfarmers.

Around 60 per cent of Australian production of naturally occurring LPG is exported, primarily from Western Australia (figure 2.6). The largest export markets are Japan, the Republic of Korea and China (RET 2008d). Exports are forecast to increase until at least 2029-30 (ABARE 2007a).

Although Australia is a net exporter of LPG, eastern Australian States import LPG, amounting to 18 per cent of Australian consumption (RET 2008d). This reflects demand for particular gas mixes. While exports of LPG contain a mixture of propane and butane, demand in the eastern States is primarily for propane.

Domestic LPG consumption totalled 4038 ML in 2006-07, more than half of which was for automotive use (RET 2008e). Domestic consumption of LPG is forecast to increase by over 44 per cent between 2006-07 and 2029-30. However, production is forecast to increase by a greater amount, resulting in an increase in exports (ABARE 2008b).

3 What is an unnecessary regulatory burden?

Key points

- Governments regulate the upstream petroleum sector to define property rights, address spillovers and information gaps, and address concerns about monopoly infrastructure.
- Good regulatory design is important to minimise unnecessary burdens on business and the community. Best practice regulation maximises net benefits to the community by imposing the lowest burden necessary to achieve the policy goals underlying the regulation.
- The potential for unnecessary regulatory burdens can arise from problems with regulations themselves, poor enforcement or administration, and unnecessary duplication and inconsistency.
- The compliance costs associated with regulation and regulatory uncertainty can reduce investor returns and increase risk, reducing the incentive to invest in upstream petroleum projects, especially if regulatory requirements are seen as less onerous in other countries.
- Unnecessary compliance costs and delays add to the already significant barriers to entry for small- to medium-sized businesses, reducing competitive pressures and potentially innovation in the sector.

As noted in chapter 1, this study focuses on 'unnecessary' burdens that signify deviation from best practice regulation. This chapter discusses what constitutes an unnecessary regulatory burden, and how such burdens can be prevented.

3.1 Why regulate the upstream petroleum sector?

Government regulation of industry is ideally designed to address perceived market failures in a way that maximises net community benefits (box 3.1). Rationales generally relate to 'public good' characteristics, externalities, information problems or concerns about monopoly infrastructure (PC 2001a). All these apply in the upstream petroleum sector.

Box 3.1 **Rationales for government regulation**

Public goods exist where provision for one person means the product is available to others at no additional cost. Public goods are characterised by being non-rivalrous in consumption (that is, consumption by one person will not diminish consumption by others) and non-excludable (that is, it is difficult to exclude people from benefiting from the good). Given that exclusion would be physically impossible or economically infeasible, the private market is unlikely to provide these goods to a sufficient extent. The nature of public goods makes it difficult to assess the extent of demand for them. Common examples include flood-control dams, national defence and street lights.

Externalities or **spillovers** occur where an activity or transaction has positive or negative effects on others who are not direct parties to the transaction and these effects are not fully accounted for in the transaction outcome. An example of a positive spillover is disease immunisation, which protects the individual, while also lowering the risk of disease for the rest of the community. Governments often subsidise activities that have significant positive spillovers. Negative spillovers may include pollution, or a large building that blocks sunlight to its neighbours.

Public goods and spillovers are similar analytically — spillovers have public good characteristics in that they are non-rivalrous and non-excludable (Brown and Jackson 1990).

Information failures occur where there is insufficient or inadequate information about matters such as price, quality and availability for businesses, investors and consumers to make informed decisions. In some instances, markets can address these problems through intermediary products (for example, advisory services). But where the issues are highly technical, government may perceive a role to complement or verify market-supplied information — for example, providing information to employers in the area of occupational health and safety, and licensing, registration and labelling regulations for chemicals and pharmaceuticals.

Natural monopoly occurs where it is more efficient for one business to supply all of a market's needs than it would be for two or more businesses to do so. It arises where there are significant economies of scale resulting from fixed costs that are large relative to the variable costs of supply. Regulation or government ownership is often adopted to avoid excessive pricing that can arise from monopoly provision. Regulation to allow third-party access is sometimes used to promote competition in areas characterised by infrastructure monopolies.

Sources: Brown and Jackson (1990); Adapted from PC (2001a).

- For example, the information obtained from petroleum exploration has *public good* characteristics, and incentives to undertake exploration would be poor if other companies could 'free ride' off those who made initial discoveries. One response to this problem is for governments to establish a system of property rights, such as exclusive retention or exploration licences for particular areas (possibly following a competitive bidding process) (PC 2001a). Governments

may also need to regulate to deal with disputes relating to property rights, such as to clarify ownership when resources are found on land owned by private individuals, or on land subject to native title.

- Examples of possible *externalities* (or spillovers) relating to upstream petroleum would be pollution or environmental damage, damage to heritage places, or threats to public and/ or employee safety.
- To deal with *information problems*, governments typically provide maps and data to upstream petroleum businesses to assist with exploration, and often require provision of data about exploration activities or oil and gas discoveries. The public good nature of much of this information makes governments more likely to regulate on this basis.
- *Natural monopoly* concerns could apply to upstream petroleum assets such as pipelines, and — where specific exemptions from access claims do not apply — they may be subject to third-party access provisions.

Even where market failure is not present, governments sometimes regulate to change market outcomes. For example, resource management regulation is said to be intended to maximise the return to Australia on its petroleum resources (ownership of which is vested in the Crown). Governments typically seek to influence rates of exploration, and subsequent development and production (Hossain 1979). As Tina Hunter observed:

> A major objective for Australia is to increase petroleum production to ensure that it does not have [to] continue to import high levels of petroleum to meet domestic energy needs. To meet this objective, Australia needs to recover the greatest amount of petroleum as possible, since the greater the recovery of resources, the greater the economic contribution of the petroleum sector to Australia. This concept, known as value creation, means that the extraction of petroleum resources are directed by the State to ensure that the greatest value and benefit of the petroleum resources are extracted for the benefit of society. (sub. DR28, pp. 2–3)

Where there are differences between government perceptions of the national interest and the commercial interests of petroleum companies, government demands may conflict with the commercial imperatives of the companies. In particular it is not always the case that the greater the recovery of resources the greater the economic contribution to either Australia or to the company concerned. Increasing recoveries beyond a certain point may be technically or theoretically possible but, from an economic perspective, the additional resources gained may not justify the expenditure involved. The costs of recovery may exceed the benefits. This issue is discussed in chapter 5.

Governments may also regulate to ensure ongoing provision of services seen as especially important to the community (often labelled ‘essential services’). In the

event of shortages, this regulation may take the form of rationing. Western Australia has a policy that up to the equivalent of 15 per cent of liquefied natural gas production for export gas projects in that State should be provided to the domestic market. (Currently, average domestic gas prices, excluding transport costs, are significantly lower than those prevailing for export liquefied natural gas). While such policies may be in the short-term interests of domestic gas consumers, pipeline owners and retailers, they could represent a disincentive to invest in gas reserves by limiting potential returns. This issue is further discussed in chapter 5.

The other major area of regulation affecting the upstream petroleum sector is occupational health and safety (OHS). OHS regulation seeks to safeguard the health, safety and welfare of workers and the general public, thereby reducing the personal and economic costs of work-related fatalities, injuries and illnesses (PC 2004b). While employers would have an incentive to provide a duty of care to employees in the absence of regulation, this is considered unlikely to be sufficient in all cases to ensure levels of safety that meet community expectations. Weaknesses in the common law system mean that governments generally consider this to also be inadequate in ensuring adequate levels of safety (PC 2008b). Governments may also provide information to employers on OHS issues.

3.2 Sources of potential unnecessary regulatory burdens

The potential for unnecessary regulatory burdens arises from a number of sources. However, they can typically be categorised under three broad headings: (1) problems with regulations themselves, (2) poor enforcement and administration, and (3) unnecessary duplication and inconsistency.

Problems with regulations themselves

Regulations can unnecessarily increase regulatory burdens in several ways:

- *Unclear or questionable objectives*: a lack of clarity provides uncertainty about what is expected of both those being regulated and those regulating. Moreover, it increases the potential for regulators to use their own discretion in determining the intent and priorities of legislators and can lead to inconsistency between regulators interpreting the same piece of legislation. Regulatory uncertainty acts as a disincentive to invest, as well as potentially increasing compliance costs.
- *Conflicting objectives*: sometimes regulations (possibly enforced by different regulators) can have objectives that are conflicting. Examples might include

safety considerations, that suggest generous spacing, and environmental regulations that seek to minimise a facility's 'footprint' and hence its environmental impact.

- *Overly complex regulation*: complex laws are likely to require legal interpretation and therefore compliance is more costly and more time consuming. They also make it harder to determine the expectations of regulators.
- *Excessively prescriptive regulation*: prescriptive regulation is typically more complex and onerous than objective- or performance-based regulation, is less flexible, can stifle innovation, and may not allow businesses to deliver the policy outcome at least cost.
- *Redundant regulation*: regulation may remain in force despite being overtaken by changed circumstances. While providing no benefits, such regulation will still involve compliance costs and could overlap with more recent legislation, causing regulatory confusion.
- *Regulatory creep*: regulations that influence more areas and activities than were originally intended or warranted. This can stem from the use of subordinate legislation, and regulatory guidelines.

Poor enforcement and administration

Poor enforcement and administration of regulation can arise from a number of sources:

- *Excessive reporting or recording requirements*: requirements beyond the minimum required to enforce a regulation unnecessarily increase compliance costs.
- *Inadequate resourcing of regulators (including inexperience or lack of expertise)*: can delay the time taken for approvals, and potentially lead to poor regulatory decisions. It can also prompt regulators to seek additional, and potentially spurious, information because of a lack of experience or expertise, or to circumvent statutory time limits (where such limits exist).
- *Overzealous regulation*: can increase compliance costs and represents a disincentive to investment. Inadequate resourcing of regulators can lead to problems, but over-resourcing can also, if it results in imposing excessive regulation or micro-management of regulated businesses.
- *Regulatory bias or capture*: regulators may be 'captured' by particular interests that they deal with on a regular basis, and therefore make decisions favourable to those interests. Such interests could include the businesses being regulated (or a

particular business or businesses), or lobby groups such as environmental or community groups.

Unnecessary duplication and inconsistency

Regulatory duplication and inconsistency between jurisdictions is not inherently bad. It may stem from different circumstances between jurisdictions and, from a competitive federalism perspective, can lead to better overall outcomes. However, duplication and inconsistency can impose some costs:

- *Duplication of regulation*: the need to provide information to multiple regulators and go through multiple processes can add unnecessarily to compliance costs. The existence of multiple regulators also creates incentives for 'forum shopping', where participants may seek the forum in which they are most likely to obtain a favourable outcome. Further, it can create uncertainties regarding the boundaries of responsibility for each regulator. On the other hand, as discussed in chapter 9, regulatory duplication can also be seen as a desirable outcome of intergovernmental competition.
- *Inconsistency of regulation*: regulatory inconsistencies can occur within or across jurisdictions, and increase regulatory burdens. Inconsistency is likely to present particular problems for businesses operating in multiple jurisdictions.
- *Variation in definitions and reporting requirements*: variation can occur between regulators within jurisdictions, although it is typically a more significant problem for businesses operating in multiple jurisdictions. Such variation can increase compliance costs.

3.3 What is best practice regulation?

The overarching objective of regulation should be to achieve desired outcomes more efficiently than would be achieved by alternatives, including no regulation (PC 2002). In promoting government objectives, most regulation will also impose costs. The focus of this study is on *unnecessary* burdens. Best practice regulation imposes the least burden necessary to achieve the underlying policy goals, bringing the greatest possible net benefit to the community.

In its 2006 report *Rethinking Regulation*, the Regulatory Taskforce enunciated six principles of good regulatory practice (box 3.2), noting that the regulatory burden imposed by government would be reduced were the principles followed. The Australian Government has subsequently endorsed these principles (Australian Government 2006).

Box 3.2 **Principles of good regulatory practice**

Six principles of good regulatory practice were enunciated by the Regulatory Taskforce in its 2006 report:

- Governments should not act to address 'problems' through regulation unless a case for action has been clearly established. This should include evaluating and explaining why existing measures are not sufficient to deal with an issue.
- A range of feasible policy options — including self-regulatory and co-regulatory approaches — needs to be assessed within a benefit–cost framework, including analysis of compliance costs and, where relevant, risk.
- Only the option that generates the greatest net benefit for the community, taking into account all the effects, should be adopted.
- Effective guidance should be provided to regulators and regulated parties to ensure that the policy intent of the regulation is clear, as well as what is needed to be compliant.
- Mechanisms such as sunset clauses or periodic reviews need to be built in to legislation to ensure that regulation remains relevant and effective over time.
- There needs to be effective consultation with regulated parties at the key stages of regulation-making and administration.

Source: Regulation Taskforce (2006).

Good regulatory design

Good design of regulations is important to minimise unnecessary burdens on business and the community. Elements of good regulatory design relate to:

- clarifying objectives
- simplifying regulation
- reducing levels of prescription (unless this is necessary to clarify requirements or provide certainty about compliance, thereby potentially reducing unnecessary burdens)
- minimising reference to subordinate legislation
- minimising unnecessary inconsistencies between jurisdictions
- including review mechanisms
- completing regulatory impact statements (RISs)
- including sunset clauses — a sunset clause is likely to trigger a review or termination of a regulation, which may reduce unnecessary burdens (PC 2007b).

Regulatory impact statements and 'good' process

Since 1997, the Australian Government has mandated the preparation of RISs for significant regulation potentially affecting businesses or restricting competition. The RISs are prepared by the departments or agencies developing regulation, with compliance monitored by the Office of Best Practice Regulation. Some State and Territory Governments also mandate similar procedures.

The RIS process is designed to bring together key elements of good regulatory practice. The RIS should cover the problem or issue being dealt with, the objective of government in dealing with the issue, and a range of feasible options. There should be benefit–cost (box 3.3), impact and risk analyses for each option, together with justification for the preferred option. The RIS should also summarise the consultation process and feedback received, and address how the regulation will be implemented and what review mechanisms are in place (Regulatory Taskforce 2006).

Box 3.3 Importance of benefit–cost analysis

The use of benefit–cost analysis is an important part of the regulatory impact statement process. A proper benefit–cost analysis should account for all the effects of a regulatory proposal on the community and economy (not just direct or easily quantifiable effects). Benefit–cost analysis involves valuing the gains and losses relating to a regulatory proposal in monetary terms. Where the benefits exceed the costs, this suggests the regulatory proposal would bring net benefits to the community.

Benefit–cost analysis is an important part of the regulatory assessment process because it:

- provides decision makers with quantitative information about the likely effects of a regulatory proposal
- encourages decision makers to take account of all the positive and negative effects of a regulatory proposal, and discourages them from making decisions based only on the impact on a single group within the community
- quantifies the impact of regulatory proposals in a standard manner, thereby promoting comparability, and encouraging consistent decision making
- captures the various links between the regulatory proposal and other sectors of the economy
- helps discover cost-effective solutions to policy problems by identifying and measuring all costs
- makes clear and transparent the assumptions and judgments made in those instances where it is difficult to quantify some costs or benefits with precision (Australian Government 2007).

FINDING 3.1

Good regulatory design is important to minimise unnecessary burdens on business and the community. Unnecessary regulatory burdens can potentially arise from problems with regulations themselves, poor enforcement or administration, and unnecessary duplication and inconsistency. Best practice regulation imposes the least burden necessary to achieve the policy goals underlying the regulation, bringing the greatest possible net benefit to the community.

3.4 Objective-based regulation versus prescriptive regulation

Recent years have seen a general trend away from prescriptive regulation towards objective-based regulation. This means that governments have moved away from prescribing specific standards or procedures and, instead, have emphasised achievement of the objectives of legislation, leaving it to businesses to determine how objectives are to be achieved. Regulation of the upstream petroleum sector has, at least in part, followed this trend.

There have been two main drivers of this trend. First, in industries subject to rapid technological change, prescriptive regulation is likely to become quickly outdated, potentially becoming counterproductive in achieving greater safety or efficiency. Second, particularly in the area of OHS, there has been acceptance that where governments attempt to specify (through prescriptive legislation) appropriate measures to minimise risk, the government effectively accepts the role of risk minimisation for itself. Governments generally, including in Australia, see responsibility for risk minimisation as residing with businesses (DISR 2001).

There are, however, circumstances where prescriptive requirements or rules are unavoidable, or where prescription will reduce regulatory burdens by providing businesses with certainty about what they are required to do. Ultimately therefore, as noted by the Regulatory Taskforce (2006), the appropriate degree of prescription in legislative standards is a matter for assessment based on evidence and analysis.

Objective-based legislation inevitably leaves room for discretion by regulators, therefore potentially creating regulatory uncertainty. This problem can be somewhat alleviated by including objects clauses in legislation or clearly defining the objectives in an explanatory memorandum. This should tell regulators what balance is sought between conflicting objectives, and provide guidance on how this balance is to be achieved.

3.5 Costs of regulation

The major costs associated with regulation can be categorised as compliance costs (including the administrative costs to government); lobbying or 'gaming' costs; the costs of price distortions leading to consumption and production losses; and the related costs associated with potentially 'lost', delayed or suboptimal investment (figure 3.1).

Compliance costs

The costs of complying with (and administering) regulation are potentially significant. The compliance costs of regulation to businesses potentially include:

- management and staff time (including diversion of management attention from core business, and hiring of additional staff)
- payments to regulators
- purchase and maintenance of specially modified IT systems
- hiring of external expertise (such as consultants and lawyers)
- training costs.

The burden of these compliance costs falls initially on businesses, potentially reducing returns on investment and, therefore, possibly investment levels (in turn generating lower tax revenue). To the extent that higher costs are passed on to consumers in the form of higher prices or restricted consumer choice, the burden of increased compliance costs falls on consumers. Governments also incur significant costs in designing and enforcing regulation. Compliance costs are minimised when good regulatory practices are followed.

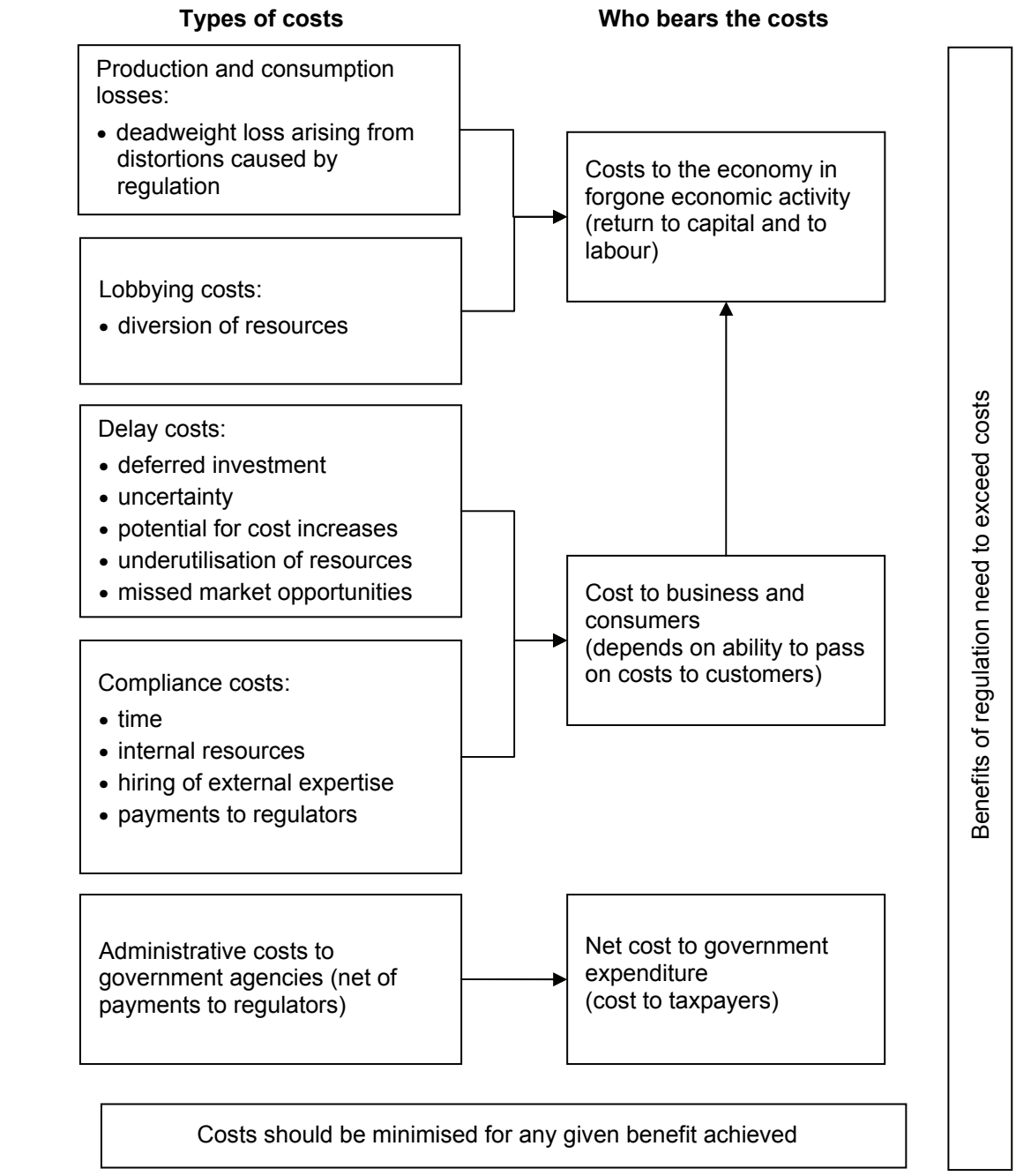
Lobbying costs

A further potential inefficiency stemming from regulation — particularly when regulatory outcomes are uncertain — is the diversion of resources into lobbying activity, both by businesses seeking to invest and other interested parties. The greater the discretion given to regulators, the greater the potential for lobbying activity to be employed in an effort to influence regulatory outcomes (PC 2004d).

In the context of the upstream petroleum sector, Nexus observed:

> Whilst regulatory approvals do happen in Australia without undue political interference, they often need guidance and lobbying to ensure they progress through the process in a timely and efficient manner. (sub. 3, p. 3)

Figure 3.1 **Costs of regulation**



Source: Adapted from PC (2008c).

Production and consumption losses

Regulation can potentially lead to price distortions resulting in production or consumption levels deviating from those that would occur in the absence of regulation. If unnecessary regulatory burdens result in increases in the prices of

upstream petroleum products, fewer will be produced or purchased, leading to efficiency losses. As discussed below, these distortions can also lead to reduced investment in the upstream petroleum sector.

Delays and the potential for 'lost' investment

The compliance costs and regulatory uncertainty associated with prospective projects can reduce investor returns and increase risk, lowering the attractiveness of upstream petroleum investments and potentially threatening their commercial viability. Costs associated with delays manifest themselves in many ways. Delays result in out-of-pocket expenses and implicit costs associated with deferred or cancelled projects, such as forgone earnings, lost market opportunities (sometimes quite significant as contracts can be of 10 to 15 years duration), the costs of standby financing facilities, and the costs of the funds already invested. These losses are compounded if capital costs are rapidly increasing (as has typically been the case in recent years). Further, project delays limit the availability of cash flows to finance new exploration and development projects.

Apache noted:

> The actual monetary cost consequent on regulatory compliance is commonly far less than the cost of delay in [present value] terms to a profitable project. (sub. 14, p. 1)

Similarly, Nexus observed:

> It is the time taken to wade through the process and the implications for project financing that is the real cost to a small to medium company, rather than the actual dollars expended in ensuring compliance. (sub. 3, p. 6)

The opportunity cost of projects that are delayed, reconfigured in a suboptimal way, or do not take place, represents one of the key potential costs associated with regulation. Australia's petroleum sector operates in a globally competitive environment where exploration and development capital is highly mobile. Petroleum exploration involves significant financial risk as it requires significant upfront capital investment, typically with a low likelihood of success in finding commercial oil or gas deposits. Those explorations that are successful are required to both offset the losses associated with failures, and to ensure investors earn an adequate return on capital.

Regulatory delays, or unnecessarily onerous regulatory requirements, reduce the incentive to undertake investment, especially if regulatory requirements are seen as less onerous elsewhere. Apache stated:

> Australia competes with all other nations to attract upstream oil and gas investment. At all times, irrespective of the level of oil and gas prices, this competition is fierce.

> Governments need to be aware that oil and gas companies factor in the costs and risks associated with the regulatory regime when allocating capital. (sub. 14, p. 2)

FINDING 3.2

The compliance costs associated with regulation, delays and regulatory uncertainty can reduce investor returns and increase risk, thereby reducing the incentive to invest in upstream petroleum projects. This is especially the case if regulatory requirements are seen as less onerous in other comparable countries.

Delay costs are discussed further in chapter 8.

Unnecessary regulatory delays can also impose fiscal costs on governments in two ways. First, production delays lead to reduced tax receipts and royalties. Second, and perhaps more importantly, the tax base could be reduced by under-investment in exploration and commercialisation (as projects that could otherwise have proceeded might not be developed).

Unnecessary compliance costs and delays can act as a deterrent to the entry of small- to medium-sized businesses, which already face high barriers to entry, as well as potentially dissuading foreign investment (by making Australia a less attractive country in which to invest).

APPEA noted:

> 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. (sub. 16, p. 15)

While the DomGas Alliance stated:

> The current approvals process and stringent demands placed on developments create significant barriers to entry for new players and serve to protect larger incumbent producers. (sub. DR24, p. 2)

FINDING 3.3

Unnecessary compliance costs and delays increase the already high barriers to entry for small- to medium-sized businesses.

4 Regulatory overview

Key points

- Recent changes to the regulation of the upstream petroleum sector reflect the general trend from a prescriptive to an objective-based regulatory environment over the past decade or so.
- The existing regulatory framework governing the upstream petroleum sector stems from Australia's federal system of government, with powers shared between the Australian and the State and Territory Governments.
- The Offshore Constitutional Settlement established the States' rights over coastal waters, and joint regulatory authority over the Commonwealth waters adjacent to each State and the Northern Territory.
  - The Settlement also outlined the division of responsibility between the Designated Authority in each State and the Northern Territory, and the Joint Authority in Commonwealth waters.
- In addition to various petroleum and pipelines laws, there is an extensive body of legislation governing upstream petroleum activities in areas such as the environment, heritage, development, native title and land rights, and occupational health and safety. A number of bodies across all levels of government have a role in regulating upstream petroleum activities.
- Many reviews of regulation affecting the sector are currently being (or have already been) undertaken.
- The Australian Government has signed several international treaties that affect upstream petroleum activities in offshore areas, mostly by giving certainty to Australia's maritime boundaries.
  - Specific arrangements relating to upstream petroleum have been agreed for the Timor Sea and the Torres Strait.

This chapter provides an overview of the regulatory environment of the upstream petroleum sector. It includes a discussion of the historical development of the existing framework and an overview of current legislative arrangements and regulators. It also contains a summary of current and recent reviews, and international agreements and treaties relevant to the upstream petroleum sector.

4.1 Historical development of the existing framework

Many of the regulatory arrangements currently in place for the upstream petroleum sector stem from Australia's federal system of government. The division of powers under the Australian Constitution gives the Australian Government some *exclusive* powers. Further, there are many areas under section 51 of the Constitution where the Australian Government can exercise powers *concurrently* with the States.

Much of the legislative and regulatory overlap that currently exists is not a recent phenomenon, but rather reflects historical factors and the development of institutional arrangements over a long period. The *Petroleum (Submerged Lands) Act 1967* (Cwlth) (PSLA) was the first offshore petroleum law to be enacted in Australia. However, its introduction did not resolve the conflict between the States and the Commonwealth over the power to legislate for the upstream petroleum sector (Hunter 2006). Frictions were intensified by the advent of the *Seas and Submerged Lands Act 1973* (Cwlth), which asserted the Commonwealth's sovereignty and sovereign rights over the territorial sea and the continental shelf (including the seabed and subsoil). This essentially implied that the States' powers ended at the low-water mark (Hunter 2006).

Consequently, the States challenged the Commonwealth's ability to make such assertions in *New South Wales v Commonwealth* (1975). The High Court ruled that sovereign rights to the territorial sea (including coastal waters) were vested in the Commonwealth (Attorney-General's Department 2007b). Notwithstanding this result, the conflict was not resolved and a series of negotiations was initiated between the States and the Commonwealth, which led to the Offshore Constitutional Settlement (OCS).

Offshore Constitutional Settlement

The OCS, completed in 1979, is an agreement between the Commonwealth, the States and the Northern Territory regarding jurisdiction over the territorial sea (which extends up to 12 nautical miles from Australia's territorial sea baseline — usually the low water mark). It includes arrangements for managing oil, gas and other seabed minerals (Attorney-General's Department 1980).

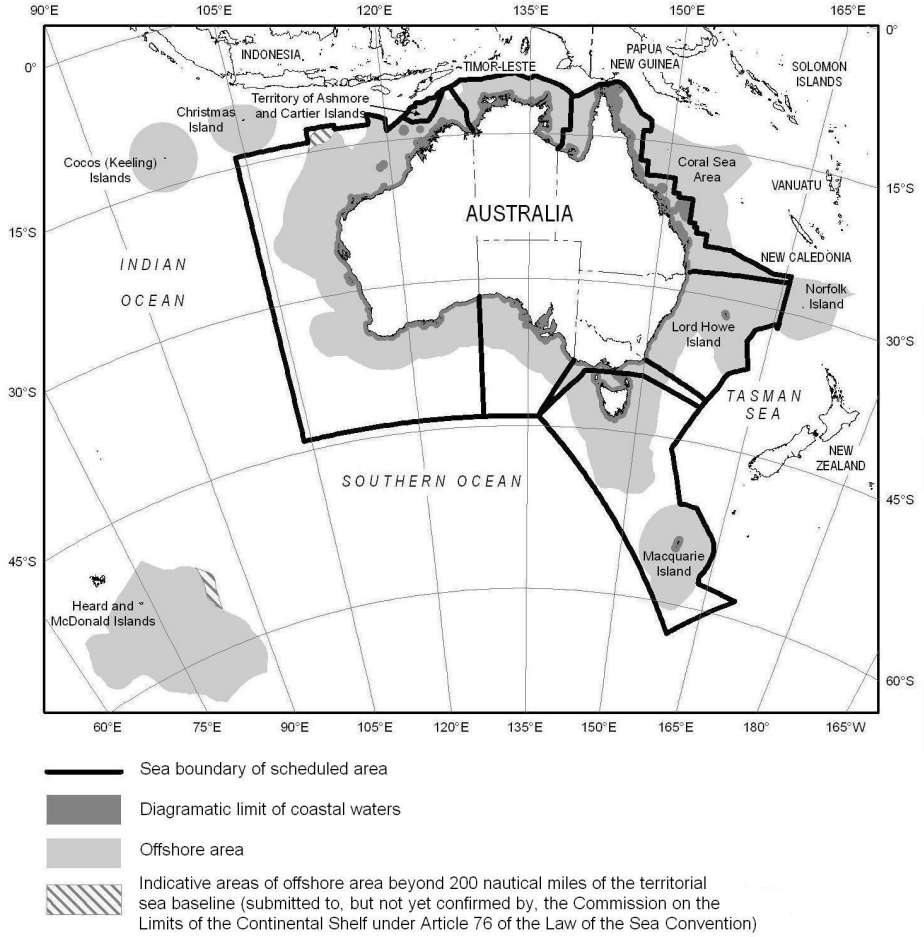
The OCS established the States' rights over coastal waters, which generally extend three nautical miles from the low water mark. Specifically, the Commonwealth agreed to give legislative powers over coastal waters (including the seabed) to the States, as well as proprietary rights and title in respect of the seabed. These rights were then enshrined in Commonwealth law — under the *Coastal Waters (State Title) Act 1980* (Cwlth) and the *Coastal Waters (State Powers) Act 1980* (Cwlth).

The Northern Territory was given the same title and powers under the *Coastal Waters (Northern Territory Title) Act 1980* (Cwlth) and the *Coastal Waters (Northern Territory Powers) Act 1980* (Cwlth).

Further, the OCS included agreements on offshore petroleum arrangements in both coastal and Commonwealth waters (box 4.1 defines Commonwealth, coastal and internal waters). These agreements formed the foundation of the existing regulatory framework, namely that:

- State and Territory petroleum legislation applies in coastal waters and is administered by State and Territory authorities
- Commonwealth legislation alone applies in Commonwealth waters. However, the Australian Government shares joint regulatory authority with the relevant State or Territory in the adjacent areas of Commonwealth waters (figure 4.1).

Figure 4.1 **Map of adjacent areas of Commonwealth waters**



Source: Geoscience Australia (pers. comm., 6 November 2008).

Box 4.1 Defining Commonwealth, coastal and internal waters

The Offshore Constitutional Settlement (OCS) provides for State and Territory jurisdiction over coastal waters. The definitions of Commonwealth, coastal and internal waters depend (at least in part) on the territorial sea baseline.

Territorial sea baseline refers to the line from which the seaward limits of Australia's maritime zones are measured. Generally it is the line of lowest astronomical tide along the coast, but it also encompasses straight lines across bays (bay closing lines), rivers (river closing lines) and between islands, as well as along heavily indented areas of coastline (straight baselines) under certain circumstances.

Commonwealth waters extend from the outer limit of coastal waters to the outer limit of the continental shelf.

The definition of *coastal waters* is a product of the OCS and has two elements. The first element is that area between the territorial sea baseline and the line that is three nautical miles seaward of the territorial sea baseline. The second element (where relevant) consists of any waters landward of the territorial sea baseline but outside the limits of the State and Territory.

Finally, to understand the split of regulatory responsibilities between the Australian Government and State and Territory Governments, it is also necessary to define *internal waters*. For the purposes of international law, internal waters are landward of the territorial sea baseline. These are divided into internal waters of the States and the Northern Territory and internal waters of the Commonwealth. *Internal waters of a State or Territory* are waters that are within the limits of the State or Territory, that is, they fall within their constitutional boundaries. The relevant constitutional boundaries were determined by the Letters Patent issued to State Governors at the date of Federation in 1901. *Commonwealth internal waters* are then all other internal waters — for the purposes of upstream petroleum regulation, these waters are treated as coastal waters. Identifying some State and Territory internal waters (for example, rivers and creeks) is relatively straightforward. There are others that are classified as internal given the Letters Patent, but are off the coastline and so might otherwise be seen as part of coastal waters.

Depending on the nature of the coastline and islands off that coastline, a State or Territory's coastal waters and internal waters could extend well beyond three nautical miles from the mainland. In reality, whether a body of water is classified as State and Territory internal, or coastal, is complicated by various exceptions and agreements made at the time of, and since, the Constitution.

For the purposes of this report, and particularly in relation to establishing a new national offshore petroleum regulator and clarifying the recommended areas that the National Offshore Petroleum Safety Authority should regulate, the Commission refers to petroleum activities in Commonwealth and State and Territory waters seaward of the low tide mark, including islands within those waters. It is recognised and intended that this definition includes some State and Territory internal waters.

Source: RET (n.d).

The joint regulatory authority for each adjacent area consists of a Designated Authority (DA) and a Joint Authority (JA). The DA is the relevant State or Territory Minister and the JA comprises the State or Territory Minister and the responsible Commonwealth Minister. In practice, the terms can also describe the government officials who assist the DAs and the JAs.

As agreed in the OCS, the DA is responsible for the day-to-day administration of petroleum activities, while the JA is concerned with major matters arising under the legislation. Examples of major matters are:

- determining areas to be open for applications for permits
- granting and renewing exploration permits and production licences
- approving instruments that create interests in permits or licences
- determining permit or licence conditions governing the level of work or expenditure.

As the Commonwealth ultimately has Constitutional power, in the event of disagreement within a JA, 'the view of the Commonwealth Minister is to prevail' (Attorney-General's Department 1980, p. 8).

Evans and Bailey (1997) consider that this joint decision-making structure promotes cooperative governance of offshore petroleum activities, despite constitutional constraint. It allows the Australian Government and the State and Territory Governments to set consistent policies for the development of petroleum resources in offshore areas. The cooperative multi-jurisdictional framework is discussed further in appendix C.

4.2 Current legislative arrangements

The upstream petroleum sector is subject to all Australian laws. In practice, the activities of the sector are governed by a large body of legislation. In this section, discussion of legislation is limited to areas that are considered the most relevant. The full list of legislation discussed in this chapter is presented in appendix B.

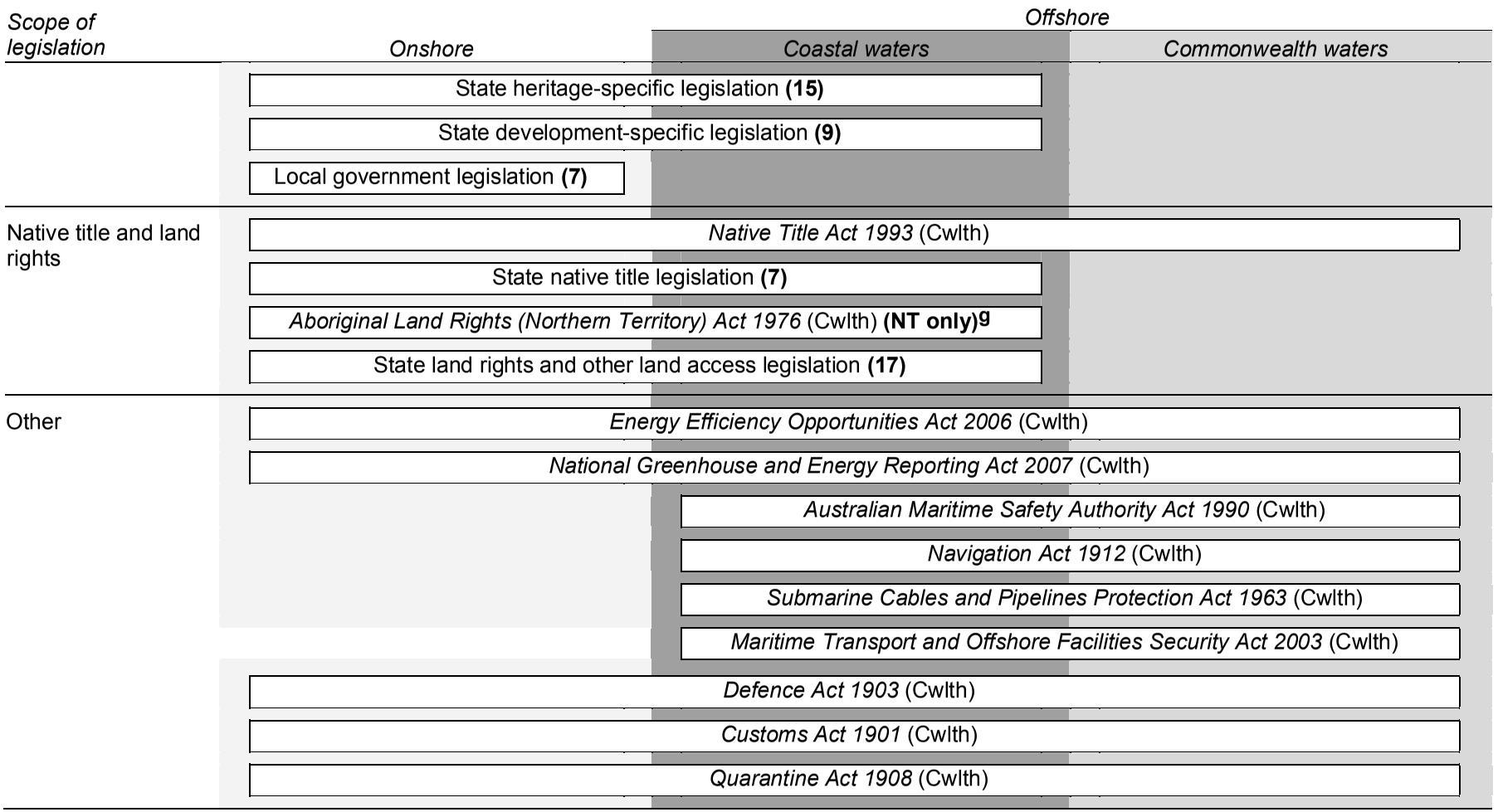
Table 4.1 shows an overview of legislation governing the upstream petroleum sector. It indicates whether the laws apply onshore (which for this table includes all State and Territory internal waters) or offshore (coastal waters or Commonwealth waters). (For the purposes of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth), offshore is defined as Commonwealth waters only.)

Table 4.1 **Legislation affecting the upstream petroleum sector[a,b,c]**

Scope of legislation	*Onshore*[d]	*Offshore*[d]	
		Coastal waters	*Commonwealth waters*
		Coastal Waters (State Title) Act 1980 (Cwlth)[e]	
		Coastal Waters (State Powers) Act 1980 (Cwlth)[e]	
Petroleum and pipelines	State onshore petroleum legislation **(8)**		*Petroleum (Timor Sea Treaty) Act 2003* (Cwlth)
	State pipeline-specific legislation **(4)**	*Petroleum (Submerged Lands) Act 1982* or equivalent **(7)**	*Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth)
	Barrow Island Act 2003 (WA)[f]		
Occupational health and safety (OHS)	*Occupational Health and Safety Act 1991* (Cwlth)		
	State OHS or major hazard facilities legislation **(13)**		
Environment, heritage and development	*Environment Protection and Biodiversity Conservation Act 1999* (Cwlth)		
		Environment Protection (Sea Dumping) Act 1981 (Cwlth)	
		Protection of the Sea (Prevention of Pollution from Ships) Act 1983 (Cwlth)	
		Great Barrier Reef Marine Park Act 1975 (Cwlth)	
	State environment-specific legislation **(33)**		
	Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cwlth)		
		Historic Shipwrecks Act 1976 (Cwlth)	

(Continued next page)

Table 4.1 (continued)



[a] Although legislation is grouped according to its primary scope, some laws may have a broader scope. [b] The numbers shown in brackets indicate the number of relevant statutes. [c] In this table, the use of the term 'State' also applies to the Northern Territory. [d] In this table, as most onshore legislation also applies to State and Territory internal waters, onshore includes State and Territory internal waters and offshore excludes such waters. [e] Similar laws have been enacted for the Northern Territory — the *Coastal Waters (Northern Territory Title) Act 1980* (Cwlth) and the *Coastal Waters (Northern Territory Powers) Act 1980* (Cwlth). [f] The *Barrow Island Act 2003* (WA) enables the State agreement — Gorgon Gas Processing and Infrastructure Project Agreement. [g] There are two other Commonwealth land rights laws — the *Aboriginal Land Rights (Lake Condah and Framlingham Forest) Act 1987* (Cwlth) and the *Aboriginal Land Grant (Jervis Bay Territory) Act 1986* (Cwlth).

Sources: ComLaw; State and NT legislation databases; various departmental websites.

Legislative arrangements for the sector are partly defined according to the distinction between onshore and offshore areas, and partly by jurisdiction. State and Territory laws generally extend to the limit of their respective coastal waters. However, petroleum, pipeline and occupational health and safety (OHS) regulation is different in coastal waters compared to State and Territory internal waters and onshore. Legislation has also been grouped according to scope — for example petroleum and pipelines, OHS, and environment, heritage and development.

FINDING 4.1

In addition to 22 petroleum and pipelines laws, there are over 150 statutes governing upstream petroleum activities in areas such as occupational health and safety, environmental and heritage protection, development, native title and land rights.

Petroleum and pipelines legislation

The *Offshore Petroleum Act 2006* (Cwlth) (OPA) was proclaimed on 1 July 2008, and replaced the PSLA. The OPA maintained the management regime and major policies of the PSLA, but was restructured and rewritten with a view to reducing compliance costs for industry and administrative costs for governments. The OPA was subsequently amended by the *Offshore Petroleum Amendment (Greenhouse Gas Storage) Act 2008* (Cwlth), with the new *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA) gaining assent on 21 November 2008.

The OPGGSA defines the roles of the DAs and the JAs, as well as the National Offshore Petroleum Safety Authority (NOPSA). The OPGGSA provides the legislative framework for petroleum titles (exploration, retention, production, infrastructure and pipelines), along with nine sets of subordinate regulations.

Despite the variation in regulatory arrangements between coastal and Commonwealth waters, it was agreed under the OCS that a 'common mining code' (part III of the PSLA) would be retained as far as practicable. In order to achieve this, State and Territory petroleum laws were enacted to mirror the Commonwealth legislation. Such legislation is titled the *Petroleum (Submerged Lands) Act 1982* in all States except New South Wales, where it has been renamed the *Petroleum (Offshore) Act 1982* (NSW). In the Northern Territory it is titled the *Petroleum (Submerged Lands) Act 1981* (NT). Although it was intended that the States and Territories would continue to modify their legislation to mirror changes to the Commonwealth legislation, in practice this has not always been the case (chapter 5).

Evans and Bailey (1997) consider that the use of mirror legislation contributes to the effectiveness of the Australian petroleum regime. It provides legal consistency

and continuity in different jurisdictions, enabling compatible resource titles to be granted for all offshore areas (appendix C).

This arrangement provides for common principles, rules and practices in regulating the exploration for, and extraction of, offshore petroleum. The Victorian Government commented that 'petroleum approvals required for Victorian waters are identical to those required for Commonwealth waters' (sub. 7, p. 4). Further, Western Australia maintains 'uniform petroleum legislation', meaning both their onshore and offshore petroleum laws employ the common code (box 4.2).

Box 4.2 **Western Australia's uniform petroleum legislation**

Western Australia uses a common petroleum code in its onshore and offshore petroleum laws. The *Petroleum and Geothermal Energy Resources Act 1967* (WA) applies onshore (including islands and internal waters) and the *Petroleum (Submerged Lands) Act 1982* (WA) applies in coastal waters. Both Acts use a similar petroleum code to the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth):

> The code varies little between the offshore and onshore, and only where it is necessary to recognise the requirement of other land tenures and usage. This commonality makes for more consistent and expedient administration and is far less confusing for explorers. (DMP 2008b, p. 1)

However, the benefits from maintaining a common petroleum code may be reduced (or eliminated) where mirror legislation is not updated (chapter 5).

Further, because Western Australia has not conferred powers to the National Offshore Petroleum Safety Authority for internal waters and islands, the regulation of occupational health and safety is not uniform.

Source: DMP (2008b).

New South Wales, Victoria, Western Australia and the Northern Territory have separate legislation governing pipelines, whereas the remaining States include pipeline licensing arrangements in their onshore petroleum legislation.

Australia has broadly adopted a 'sector-specific legislative system' for regulating petroleum projects, meaning the petroleum legislation sets out predetermined conditions under which the rights to explore for, and extract, petroleum resources are granted by means of standard licences or leases (Hossain 1979). A similar approach has been taken in Canada and the United States. In appendix C, the flexibility of this system is compared with a negotiation-based system (used in Saudi Arabia and Papua New Guinea) and a hybrid system (adopted in Norway and the United Kingdom).

Other legislation

A large proportion of the legislation affecting upstream petroleum activities is not petroleum and pipeline specific. Key areas are environmental, heritage, development and local government, and native title and land rights legislation.

Environmental legislation

Most environmental legislation in Australia has been enacted by the States and Territories. The Constitution does not provide the Commonwealth with the specific power to make laws relating to the environment. However, the Commonwealth has used its other constitutional powers — such as those relating to external affairs, corporations and taxation — to pass laws relating to environmental matters (Environmental Defender's Office New South Wales 2005). The *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) enacts Australia's obligations under several international treaties and is the key piece of Commonwealth legislation governing environmental issues (PC 2004a).

There are 33 State and Territory laws specifically concerned with protection of the environment in onshore areas and coastal waters. Some of these laws also contain heritage or development provisions. Although the number of laws varies significantly by jurisdiction, they cover roughly similar matters. For example, each State and Territory has laws that create reserve areas such as national parks, nature reserves and marine parks. In New South Wales, Victoria and South Australia, multiple departments are responsible for administering State environmental legislation.

Each State and Territory also has legislation giving effect to the *International Convention for the Prevention of Pollution from Ships*. These are listed in appendix B, but not in table 4.1.

Heritage legislation

Heritage protection legislation can take many forms. As well as several specific heritage statutes, there are provisions in some environmental, development and local government laws that allow for the protection of heritage places and objects.

The Department of the Environment, Water, Heritage and the Arts (DEWHA) considers that heritage includes:

> … places, values, traditions, events and experiences that capture where we've come from, where we are now and gives context to where we are headed as a community. (DEWHA 2008a, p. 1)

World heritage, which is defined as heritage of 'outstanding universal value', is protected under the EPBC Act according to criteria established by the *Convention Concerning the Protection of the World Cultural and National Heritage*. The EPBC Act also established the National Heritage List and the Commonwealth Heritage List. The National Heritage List includes natural, historic and Indigenous places considered to be of 'outstanding national heritage value' (DEWHA 2008a). The Commonwealth Heritage List comprises natural, historic and Indigenous places on Commonwealth lands and waters or under Australian Government control that have 'Commonwealth heritage values' (DEWHA 2008a).

Further, each State and Territory has enacted laws relating to heritage preservation. South Australia also has a separate law for historic shipwrecks.

The *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth) aims to preserve and protect areas and objects that are of particular significance to Aboriginals or Torres Strait Islanders in accordance with their tradition. In addition, there are seven pieces of State and NT legislation that are specific to Aboriginal or Torres Strait Islander heritage (but there is no specific law relating to Indigenous heritage in New South Wales).

Development and local government legislation

Development can refer specifically to the construction of a building or project, or more broadly to land use changes. Development regulation is closely associated with planning, and there is a large degree of interaction between environmental and development laws in Australia. In both New South Wales and Victoria, environmental assessment for new development is administered by the department responsible for planning under the *Environmental Planning and Assessment Act 1982* (NSW) and the *Planning and Environment Act 1987* (Vic) respectively. Separate planning legislation has been enacted in the remaining States and the Northern Territory.

The main effect of local government on the upstream petroleum sector occurs through planning procedures. Every State, and the Northern Territory, has enabled local governments to make and enforce local laws within their jurisdictions.

Native title and land rights legislation

All States and Territories are subject to the *Native Title Act 1993* (Cwlth) (NTA), which commenced on 1 January 1994. The NTA provides for the recognition and protection of native title. Most importantly for the upstream petroleum sector, it also establishes ways in which future dealings affecting native title may proceed.

Significantly, 'there are no native title rights to mineral, petroleum or gas' (NNTT 2006, p. 7).

All 'future acts' — mainly those after 1 January 1994 that affect native title — come under the sole jurisdiction of the NTA. 'An act affects native title if it extinguishes the native title rights and interests or if it is otherwise wholly or partly inconsistent with their continued existence, enjoyment or exercise' (NTA, s. 227).

In addition to the NTA, the States and Territories have all passed legislation to validate past and intermediate acts. Past acts are mainly acts done before the NTA commenced that were invalid because of native title. Intermediate acts occurred between the commencement of the NTA and the 1996 High Court decision in the *Wik Peoples v The State of Queensland*.

Although there is no national approach to resolving land rights claims in Australia, there are three Commonwealth land rights laws for specific areas — the Northern Territory, Jervis Bay (in New South Wales), and Lake Condah and Framlingham Forest (in Victoria). The *Aboriginal Land Rights (Northern Territory) Act 1974* (Cwlth) is the most significant, as it 'has resulted in the transfer of almost half of the Territory's land to Aboriginal ownership under inalienable freehold title' (Department of Families, Housing, Community Services and Indigenous Affairs 2008, p. 1). This is discussed further in chapter 5.

4.3 Regulators and other relevant bodies

Several bodies have been given specific responsibility for regulating the upstream petroleum sector. The Department of Resources, Energy and Tourism (RET) provides policy advice to the Commonwealth Minister for Resources. In cooperation with the States and the Northern Territory, RET is the regulator of offshore petroleum activities.

NOPSA is the offshore OHS regulator in both Commonwealth and coastal waters where States and Territories have conferred their powers (box 4.3). However, for onshore areas and for State and Territory internal waters, petroleum facilities and activities remain subject to each State and Territory's principal OHS legislation.

Box 4.3 **The National Offshore Petroleum Safety Authority**

On 1 January 2005, the National Offshore Petroleum Safety Authority (NOPSA) commenced operations as the responsible occupational health and safety (OHS) regulatory body for offshore operations. NOPSA's role is defined in the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA), and equivalent laws have been enacted by Victoria, Western Australia, South Australia and the Northern Territory. The mirror laws of New South Wales, Queensland and Tasmania are not yet fully in place.

In Western Australia, NOPSA has been conferred powers to act as the OHS regulator in coastal waters, but not for internal waters, nor for islands that contain upstream petroleum facilities (for example Varanus, Barrow and Thevenard islands). NOPSA in practice has historically acted under a number of service contracts with the WA Government to provide safety regulation services in some of these internal waters and island areas.

Offshore OHS legislation is now based on the safety case approach — requiring the applicant to develop a structured plan supported by a body of evidence for a compelling, comprehensible and valid case that a system is safe for a given application in a given operating environment. Extensive record keeping is involved and the regulatory authority has to be notified of changes in activity or circumstances. This is discussed further in chapter 7.

NOPSA's main functions include enforcing the OHS provisions of the OPGGSA (and equivalent State and Territory legislation), promoting OHS, developing effective monitoring and enforcement strategies, investigating and reporting on incidents, advising on safety matters and raising issues with Ministers.

Source: NOPSA (2008b).

Further, each State and the Northern Territory also has a department responsible for upstream petroleum regulation (table 4.2). These departments provide advice to the State Minister and act as the DA for the regulation of Commonwealth waters. The Victorian DA also undertakes some regulatory activity and environmental assessment in Tasmanian waters (for developments that are processed onshore in Victoria) (Victorian Government, sub. 7).

The activities of the upstream petroleum sector also fall under the jurisdiction of organisations with broader responsibilities. At the Commonwealth level, environmental and heritage issues are the responsibility of DEWHA. The National Native Title Tribunal has a role in native title issues as defined in the NTA. The Attorney-General's Department and the Department of Families, Housing, Community Services and Indigenous Affairs share responsibility for Commonwealth land rights legislation.

Table 4.2 **State and Territory departments responsible for upstream petroleum regulation**

Jurisdiction	*Department*
NSW	Department of Primary Industries
Victoria	Department of Primary Industries
Queensland	Department of Mines and Energy
WA	Department of Mines and Petroleum[a]
SA	Primary Industries and Resources South Australia
Tasmania	Department of Infrastructure, Energy and Resources[b]
NT	Department of Regional Development, Primary Industry, Fisheries and Resources

[a] Prior to 1 January 2009, the relevant department was the Department of Industry and Resources. [b] Mineral Resources Tasmania is contained within the Department of Infrastructure, Energy and Resources.

There are also a multitude of State and Territory departments with responsibility for the large body of legislation affecting the upstream petroleum sector. A snapshot of those responsible for environment, development, heritage and land access is shown in table 4.3. The full list of legislation in appendix B also cites the agencies responsible for implementation.

In addition, there are 565 local governing bodies in Australia, each with local planning responsibilities (Department of Infrastructure, Transport, Regional Development and Local Government 2008). Local governments also make land-use and environmental planning decisions, and are responsible for approving development applications (PC 2008a).

FINDING 4.2

Well over 50 bodies at the Australian, State, and NT Government level have a role in regulating upstream petroleum activities. In addition, local governments can also regulate activities within their jurisdictions.

Other relevant bodies

In addition to regulatory bodies, there are also advisory and policy bodies whose activities affect the upstream petroleum sector.

Geoscience Australia

Geoscience Australia — a prescribed agency within RET — conducts research and advises government and industry on Australia's petroleum prospects, reserves and potential. It provides pre-competitive (preliminary) geoscience information to attract petroleum exploration investment to offshore basins (DITR 2007a).

Table 4.3 **Key State and Territory regulatory bodies**

		Responsibility			
Jurisdiction	*Regulatory body*	*Environment*	*Heritage*	*Development*	*Native title and land rights*
NSW	Department of Planning	✓	✓	✓	
	Department of Environment and Climate Change	✓			
	Department of Aboriginal Affairs				✓
Victoria	Department of Planning and Community Development	✓	✓	✓	
	Department of Sustainability and Environment	✓			
	Aboriginal Affairs Victoria		✓		✓
Queensland	Environmental Protection Agency	✓			
	Department of Infrastructure and Planning			✓	
	Department of Natural Resources and Water		✓		✓
WA	Department of Environment and Conservation	✓			
	Environmental Protection Authority	✓			
	Department of State Development			✓	
	Heritage Council of Western Australia		✓		
	Department of Indigenous Affairs		✓		✓
SA	Department for Environment and Heritage	✓	✓		
	Department of Water, Land and Biodiversity Conservation	✓			
	Planning in South Australia			✓	
	Department of the Premier and Cabinet		✓		✓
Tasmania	Department of Environment, Parks, Heritage and the Arts	✓	✓	✓	
	Department of Premier and Cabinet		✓		✓
	Aboriginal Heritage Office		✓		
NT	Department of Natural Resources, Environment, the Arts and Sport	✓	✓		
	Department of Planning and Infrastructure			✓	
	Department of Justice			✓	
	Aboriginal Areas Protection Authority		✓		✓

Sources: ComLaw; State and NT legislation databases; various departmental websites.

Geoscience Australia has a role in assessing the technical merit of bids for exploration acreage in Commonwealth waters, as well as providing advice on environmental, cetacean, seismic and decommissioning issues. Geoscience Australia provides advice on production licence applications, including technical reviews of field development plans considered against national interest and good oilfield practice criteria. It also gives technical advice on retention leases and the 'commerciality' of a field (chapter 5).

Ministerial Council on Mineral and Petroleum Resources

The Ministerial Council on Mineral and Petroleum Resources (MCMPR), established by COAG in June 2001, consists of the Commonwealth Minister for Resources, Energy and Tourism, and State and Territory Ministers with responsibility for minerals and petroleum. The Ministers responsible for petroleum in New Zealand and Papua New Guinea have observer status (RET 2008f). The MCMPR's objectives are:

- to progress constructive and compatible changes to the basic legislative and policy framework
- to facilitate economically competitive development of the minerals and petroleum industries
- to improve coordination and, where appropriate, consistency of policy regimes
- to encourage new and expanded investment in competitive minerals and petroleum development opportunities
- to provide an opportunity for information and policy exchange.

Environmental Assessors Forum

The Environmental Assessors Forum (EAF), which focuses specifically on the environmental regulatory arrangements for the upstream petroleum sector, is responsible for reviewing legislation and administrative procedures, and facilitating communication between industry and government. The EAF was established in 2004 to promote interaction between environmental regulators, and help ensure there are robust systems in place to provide consistency of environmental processes over all jurisdictions (RET, pers. comm., 18 August 2008).

The EAF consists of representatives from RET, DEWHA, Geoscience Australia, and the State and NT DAs. Woodside stated that DEWHA's involvement is important as it 'allows the department to see how their delegated authority is implemented at a State regulator level' (sub. 11, p. 2). Recently the Environmental

Protection Agency Queensland has also been included. The EAF has no formal terms of reference and it reports to the MCMPR as required.

4.4 Recent Commonwealth, State and Territory reviews

A number of reviews and inquiries have been conducted by the Australian Government and the State and Territory Governments with an aim to improving regulation of the petroleum sector. The terms of reference for this study specifically require the Commission to have regard to current or recent reviews (commissioned by Australian governments) affecting the regulatory burden faced by businesses in the upstream petroleum sector. This section provides a brief overview of the most relevant reviews. However, there are many other reviews that cover related issues (box 4.4).

Current reviews

There are several reviews currently underway that will affect the regulatory environment of the upstream petroleum sector. The most significant of these is the Australian Government's review of the regulations under the then OPA (now replaced by the OPGGSA).

Consolidation of regulations under the OPGGSA

The Regulation Taskforce (2006) found that upstream petroleum businesses were concerned that similar information was required in multiple management plans under the various sets of regulations. In response, the Department of Industry, Tourism and Resources (now RET) commenced a project to consolidate the regulations under the PSLA (now replaced by the OPGGSA). The project, initiated in October 2006, aims to:

> … reduce the overall cost of regulatory compliance on industry through reducing duplicative requirements, streamlining processes and removing unnecessary or redundant reporting requirements, while protecting the safety of those working in the industry, protecting the environment, and protecting the valuable petroleum resource. (RET 2008g, p. 3)

The consolidation report, released in September 2007, made 54 recommendations, including that the current nine sets of regulations be condensed to three: (1) safety, (2) environment, and (3) resource management and reporting.

Box 4.4 **Government reviews[a]**

Many Australian governments have conducted (or are conducting) reviews and produced papers that relate to regulatory burden on the upstream petroleum sector. These include:

- National Offshore Petroleum Safety Authority Cost Recovery Review 2008 (current)
- Oilcode Review by the Department of Resources, Energy and Tourism (current)
- Carbon Pollution Reduction Scheme by the Department of Climate Change (current) (Green Paper released June 2008, White Paper released December 2008)
- Joint Commonwealth and Western Australian Government inquiry into the effectiveness of regulation for upstream petroleum operations with a focus on the incident at Apache Energy facilities on Varanus Island (current)
- Inquiry into matters relating to the gas explosion at Varanus Island, Western Australia by the Senate Standing Committee on Economics (November 2008)
- Garnaut Climate Change Review (October 2008)
- Review of Export Policies and Programs chaired by David Mortimer AO (September 2008)
- Quarantine and Biosecurity Review chaired by Roger Beale AO (September 2008)
- Strategic Review of Climate Change Programs chaired by Roger Wilkins AO (submitted to the Australian Government July 2008)
- Streamlining amendments to the Energy Efficiency Opportunities Regulations 2006 by the Department of Resources, Energy and Tourism (July 2008)
- Review of Approvals Processes for Earth Resource Development in Victoria, prepared by PricewaterhouseCoopers for the Victorian Department of Primary Industries (on behalf of the Earth Resources Development Council) (May 2008)
- Review of NT Exploration Investment Attraction Programs 1999–2007 and recommendations for future strategies and work, prepared by ACIL Tasman for the NT Department of Primary Industry, Fisheries and Mines (November 2007)
- Inquiry into Geosequestration Technology by the House of Representatives Standing Committee on Science and Innovation (August 2007)
- Australian Regulatory Guiding Principles for Carbon Dioxide Capture and Geological Storage developed by the Ministerial Council on Mineral and Petroleum Resources (November 2005)
- NT Indigenous Economic Development Strategy (May 2005)
- Review of the Native Title Claim Process in Western Australia chaired by Paul Wand (September 2001)
- WA Government Technical Taskforce on Processing of Mining, Exploration and Land Title Applications (November 2001).

a Unless otherwise noted, dates in brackets indicate the report release date.

Sources: Various departmental websites; Wong (2008).

The ensuing Regulatory Impact Statement (RET 2008h) advocated implementing most of the consolidation report's recommendations. The proposed changes include removing several reporting requirements, altering the requirements relating to reporting on discoveries and formalising some requirements by changing them from guidelines into regulations. Overall, the expected benefits from implementation include time savings, reduced compliance costs, reduced confusion, greater consistency and improved regulatory transparency. It is expected that the consolidated regulations will formally commence in 2009.

Development of new guidelines for decommissioning offshore oil and gas facilities

In conjunction with environmental regulators from the State and Territory DAs, RET is currently developing new guidelines for decommissioning offshore petroleum facilities. The existing guidelines only describe the approval process for decommissioning. The review aims to establish specific principles and guidelines for proponents and regulators.

RET released a discussion paper for comment in March 2008. It outlined decommissioning options (from finding an alternative use to full removal and disposal onshore) and possible criteria for deciding between them (such as environmental impact, cost, safety, and the interests of other users of the sea) (RET 2008a). Following the consideration of public submissions, and consultation with industry, a draft policy paper will be prepared and submitted to the MCMPR and the Natural Resource Management Ministerial Council for approval.

Review of retention leases

RET is currently conducting a mid-term commerciality review of petroleum retention leases as specified in the OPGGSA conditions. Further, RET will review the retention lease system for the MCMPR (Ferguson 2008a). Motivation for these reviews came from recommendations made by a joint working group of the Ministerial Council on Energy and the MCMPR that considered domestic gas supplies for existing and future markets (Joint Working Group on Natural Gas Supply 2007).

Review of the EPBC Act

On 31 October 2008, the Minister for the Environment, Heritage and the Arts appointed Dr Allan Hawke to conduct an independent review of the EPBC Act (in accordance with a statutory requirement for the Act to be reviewed every 10 years). The terms of reference require the review to examine the operation of the Act, the

extent to which the objects of the Act have been achieved, the appropriateness of current matters of National Environmental Significance and the effectiveness of the biodiversity and wildlife conservation arrangements. In doing so, the review must seek input from State and Territory Governments, members of the community and industry.

The discussion paper posed 44 questions on a range of topics, including the scope of the Act, assessment and approvals, protected areas, Indigenous involvement, compliance and enforcement and decision making (DEWHA 2008c). Public submissions closed on 19 December 2008 — with the review receiving 195 initial submissions. Further consultation with stakeholders is planned for March and April 2009, before an interim report is released in mid-2009.

Joint review into the effectiveness of regulation for upstream petroleum operations

On 3 June 2008, a series of explosions followed by fires occurred at the Apache operated facility on Varanus Island. Following the incident, the then WA Department of Industry and Resources (DoIR) requested NOPSA to undertake an investigation into the incident. The investigation was conducted jointly by DoIR (which was restructured on 1 January 2009) and NOPSA, and focused on the technical causes of the incident and not the regulatory systems or the actions of the regulators.

Following this investigation, the Commonwealth and Western Australian Governments announced in January 2009 a joint independent inquiry into the effectiveness of regulation for upstream petroleum operations with a focus on the incident at Apache's facilities on Varanus Island. The joint inquiry, expected to report by mid-April 2009, will consider the effectiveness of the OHS and integrity regulatory regime that applied to the Apache operations and facilities at Varanus Island, and the role of the then DoIR, NOPSA and the then WA Department of Consumer and Employment Protection.

It is anticipated that the proposed inquiry will take into consideration the *Petroleum Pipelines Act 1969* (WA), and interaction with other legislative instruments including the *Petroleum (Submerged Lands) Act 1982* (WA) and the OPGGSA.

The joint inquiry considering the Varanus Island incident will also look into two other significant incidents in upstream petroleum operations off the Western Australian coast during cyclone emergencies in December 2008, one of which involved a fatality. The inquiry will, to the extent practicable in the timeframe, consider the effectiveness of the regulatory regime for OHS and integrity that

applied to the vessels Karratha Spirit and Castoro Otto and the role of NOPSA and the Australian Maritime Safety Authority.

Current State and Territory reviews

Some State Governments are also undertaking reviews that will change the regulatory environment for the upstream petroleum sector within their jurisdictions. The WA Government currently has five reviews underway, including the Northern Development Taskforce (now absorbed by the Department of State Development) (box 4.5).

Box 4.5 **The Northern Development Taskforce**

The Northern Development Taskforce was established in June 2007 as a whole-of-government initiative to coordinate the issues relating to the development of Browse Basin gas in the Kimberley and the National Heritage Listing of the Burrup Peninsula. From 1 January 2009, the role of the Taskforce was absorbed into the newly established WA Department of State Development.

The scope of the Taskforce included negotiation and coordination of the issues associated with economic development, balanced against the wilderness, environmental, tourism and heritage values of the West Kimberley. Both the Burrup and West Kimberley components of the Taskforce report to the same Ministerial Committee.

The Taskforce released an interim report in June 2008, identifying nine potential sites 'considered worthy of further technical investigation and assessment related to Aboriginal heritage and cultural values and environmental constraints' (DSD 2008a, p. 4). A further two sites were reviewed at the request of traditional owners.

A site evaluation workshop was held in July 2008. Moreover, the WA Government released the Taskforce's site evaluation report on 15 October 2008 for a 28 day public consultation process. The report identified four sites that were considered technically viable for the purpose of gas processing — Gourdon Bay, James Price Point, North Head and Anjo Peninsula (DoIR 2008b).

In December 2008, the Taskforce released its Final Site Evaluation Report (Northern Development Taskforce 2008). The report recommended the James Price Point coastal area as the preferred location for a Kimberley liquefied natural gas processing precinct.

Sources: DSD (2008a); DoIR (2008a, 2008b); Northern Development Taskforce (2008).

The WA Government has established an industry working group to advise on ways to improve the State's exploration and development approval processes, as announced by its Minister for Mines and Petroleum on 17 November 2008

(Moore 2008). The review has a number of objectives, including identifying which impediments can be addressed through changes to government policies and administrative processes, and those which will require legislative change, and seeks to develop a framework to ensure better co-ordination across agencies to achieve quicker approvals. A final report is expected by the end of April 2009.

The WA Environmental Protection Authority is currently reviewing its environmental impact assessment processes. The review was announced in February 2008 and was expected to take six months (Templeman 2008b). The terms of reference stress that the assessment process should take a risk-based approach and involve setting outcome-based conditions (EPA WA 2008b). All upstream petroleum projects in Western Australia (onshore and in coastal waters) are subject to this assessment process. A final report is expected to be provided to the WA Minister for Environment shortly.

On 18 June 2008, the WA Environment Minister announced a review of native vegetation clearing legislation (Templeman 2008a) — the Environmental Protection (Clearing of Native Vegetation) Regulations 2004 (WA) and the relevant sections of the *Environmental Protection Act 1986* (WA). This legislation applies to upstream petroleum activities in Western Australia. The terms of reference require the review committee to consider any amendments to legislation, regulations and policies that would improve the effectiveness and efficiency of the regulation of clearing.

The WA Department of Housing and Works is currently reviewing the building regulatory environment and developing new building legislation. Benefits sought from the proposed reforms include clarifying the definition of a 'building' and exemptions from the building permit process (Department of Housing and Works 2008). New building legislation is expected to be passed during 2009 (Department of Treasury and Finance 2009).

The Victorian Competition and Efficiency Commission has recently been directed to undertake a review of the framework for environmental regulation in Victoria. It will submit a final report to the Victorian Government by 23 July 2009. An issues paper was released in August 2008, which identified areas with the largest potential regulatory burden. The remainder of the review will focus on 'the nature and magnitude of the administrative and compliance costs of those Acts with a major and moderate impact on businesses' (VCEC 2008, p. 15). Victoria's petroleum and pipelines legislation was initially classified as having a moderate impact on business, while the relevant environmental and development legislation was classified as having a major impact.

A draft report was released on 26 March 2009 (VCEC 2009) and, with regard to the regulation of petroleum and geothermal energy exploration and extraction, concluded:

> With the exception of matters requiring consideration by both the Commonwealth and Victorian Governments, the technical and regulatory assessment processes and decision criteria appear to work effectively and within justifiable timescales. [The Victorian Competition and Efficiency Commission] has been advised that cases of an applicant being deterred by the length or complexity of the approval process have been rare over the past decade. (VCEC 2009, p. 74)

The Environmental Protection Agency Queensland (2008) is currently developing a code of environmental compliance for low-impact petroleum activities, designed to streamline approvals. A draft code has been produced and is currently being finalised.

Primary Industries and Resources South Australia published a Green Paper on proposed changes to the *Petroleum Act 2000* (SA) in December 2006. Following the incorporation of submissions to the Green Paper, the Petroleum (Miscellaneous) Amendment Bill 2008 was released for public comment (PIRSA 2008). The key amendments in the Bill cover greenhouse gas storage provisions, licence applications and terms, royalty payments and notice of entry on land requirements. The Bill also introduced a Special Facilities Licence so third parties can construct and operate facilities for processing and storing regulated substances.

The Northern Territory Environment Protection Authority (2009) is undertaking a review of the *Environmental Assessment Act* (NT). The terms of reference for the review have been established and initial discussion papers are due to be released in April 2009. The review will examine how the environmental impact assessment process interacts with subsequent NT Government approval processes as well as interaction with the EPBC Act.

Past reviews

The actions taken, or yet to be taken, as a result of past reviews have altered, or have the capacity to alter, the regulatory environment for the upstream petroleum sector.

National review into model OHS laws

The Regulation Taskforce (2006) recommended nationally consistent standards for OHS. At the COAG meeting on 26 March 2008, it was agreed that the national harmonisation of OHS laws was ‘a top priority’ (COAG 2008).

Consequently, a national review into model OHS laws was announced on 4 April 2008. The terms of reference asked for a review of OHS legislation at both the Commonwealth and State and Territory levels, 'for the purpose of making recommendations on the optimal structure and content of a model OHS Act that is capable of being adopted in all jurisdictions' (Australian Government 2008d, p. 45).

The review panel received 242 submissions, and reported twice to the Workplace Relations Ministers' Council. The first report, released on 5 November 2008, contains findings and recommendations on matters requiring priority consideration — being duties of care, and the nature and structure of offences (including defences) (Australian Government 2008c). The second and final report, released on 13 February 2009, contains findings and recommendations on other specified matters, including scope and coverage, enforcement and compliance, and the role of OHS regulatory agencies in providing education, advice and assistance to duty holders (Australian Government 2009).

Review of NOPSA operational activities

An independent review of NOPSA's operations was tabled in Parliament on 12 June 2008 (RET 2008i). The review examined NOPSA's progress in improving OHS in the offshore oil and gas sector since the regulator commenced operations.

Many of the review team's 20 recommendations emphasised the need for clarity and consistency in order to improve safety outcomes, particularly in providing guidelines to legislation and regulation. The team also recommended that the safety case 'regime should be increased to cover the complete hydrocarbons production system' (RET 2008i, p. 3). This review is discussed further in chapter 7.

House of Representatives inquiry into resource exploration impediments

On 24 May 2002, the Federal Minister for Industry, Tourism and Resources asked the Standing Committee on Industry and Resources to inquire into, and report on, any impediments to increasing investment in mineral and petroleum exploration in Australia.

The final report, published in August 2003, made 28 recommendations on several themes — including corporate structure, capital raising and taxation; pre-competitive geoscience data acquisition; geoscience research and education; titles; exploration and native title; environmental and other approval regimes; and resources exploration and the community (HORSCIR 2003). Many of the recommendations related to consultation between Ministers and improved

collaboration with the States and Territories. A review of retention lease administration is currently underway, as recommended.

Review of the Aboriginal And Torres Strait Islander Heritage Protection Act

The Hon Elizabeth Evatt AC completed a review of the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth) in June 1996. The goals of the review included:

- ensuring that the Act fulfils its role as a measure of last resort by encouraging the States and Territories to adopt minimum standards for the protection of Indigenous cultural heritage as part of their primary protection regimes
- encouraging greater cooperation between the Commonwealth and the States and Territories, and avoiding duplication and overlap with State and Territory jurisdictions by recognising and accrediting their processes
- providing a process that operates in a consistent manner, according to clear procedures, in order to avoid unnecessary duplication, delays and costs
- resolving some of the difficulties of developers through better procedures that ensure early consideration of heritage issues in the planning process, effective consultation with Indigenous people and genuine mediation or other processes designed to avoid injury to, or desecration of, sites.

A principal recommendation was separating determination of the heritage significance of an area from decisions about proposed land use (which would remain a matter for ministerial discretion) (Evatt 1996).

The Aboriginal and Torres Strait Islander Heritage Protection Bill 1998 (Cwlth) was introduced to the House of Representatives in June 1998. Culvenor (2000) considered the introduction of this Bill would have limited Indigenous peoples' options for protecting valued sites. The Senate passed the Bill with substantial amendments that would have implemented the majority of the recommendations in the Evatt report (Culvenor 2000). However, the House of Representatives rejected several of the amendments. Consequently, the Bill never became law.

Reviews of the EPBC Act

The 2006 State of the Environment Committee commissioned a review of the EPBC Act (McGrath 2006). The review identified some negative aspects of the EPBC Act's framework and implementation, including the absence of a trigger point for greenhouse gas emissions and extensive time delays in listing many threatened ecological communities for protection.

In March 2007, the Australian National Audit Office conducted an audit of the Department of the Environment and Water Resources's (now DEWHA) compliance with the EPBC Act (ANAO 2007). The aim of the review was to assess and report on the administration of the Act in terms of protecting and conserving Australia's threatened species and ecological communities. The key factors constraining compliance identified by the audit were the scale of the task, the technical requirements involved and limited resources. This is discussed further in chapter 6.

Past State and Territory reviews

Several reviews into various aspects of the regulatory environment for the upstream petroleum sector have been conducted by State Governments. The most relevant of these are the Keating Review in Western Australia (box 4.6), and an inquiry into greenfields exploration in Western Australia.

Box 4.6 The Keating Review of the Project Development Approvals System

In September 2001, the WA Minister for State Development appointed Dr Michael Keating to chair an independent review committee to assess the project development approvals system. The Committee made 56 recommendations in its final report (Independent Review Committee 2002), including:

- greater use of timelines (including a 'stop the clock' mechanism) to improve levels of certainty and predictability for project approvals
- use of outcome-based conditions on approvals
- removal of overlap and duplication (particularly for environmental approvals and assessment)
- increased integration of State and Commonwealth legislation (in particular for environmental and Aboriginal heritage approvals)
- introduction of a single standard for offshore and onshore pipeline requirements
- government engagement in strategic planning for development sites on a regional basis
- an integrated approvals system for projects of 'state significance'.

Source: Independent Review Committee (2002).

Following the release of the Keating Review in 2002, the WA Government 'approved and funded a multi-agency response to the review's recommendations' (Auditor General for Western Australia 2008, p. 11). The WA Auditor General recently released a performance examination of improvements to the development approval process as a result of agencies' actions in implementing the Government's

commitments. It found that 'agencies have implemented the key initiatives, but so far they have not resulted in the intended improvements' (Auditor General for Western Australia 2008, p. 6).

Although the Ministerial Inquiry into Greenfields Exploration in Western Australia (Bowler 2002) mainly focused on mineral exploration, many of the report's 33 recommendations are also relevant to the upstream petroleum sector. Among the seven highest-priority recommendations were the need for increased government provision of pre-competitive geoscience information, improved heritage protection protocols and a review of the *Aboriginal Heritage Act 1972* (WA).

The Auditor General recently found that the Department of Indigenous Affairs' compliance with set times for approval processes has worsened following the introduction of the Office of Development Approvals Coordination (Auditor General for Western Australia 2008). Further, concerns persist regarding the Aboriginal Heritage Act. Apache argued the Act is 'complex, lacks transparency and accountability' (sub. 14, p. 3).

FINDING 4.3

Recognition of the regulatory burden on the upstream petroleum sector is evident from the various reviews that have been undertaken in the past. Several reviews (including this study) are currently underway due to ongoing problems with delays, duplication and overlap. Apparently worthwhile recommendations from past reviews appear not to have been successfully implemented.

4.5 International treaties and obligations

Ownership of, and access to, offshore resources (including petroleum) is outlined in the United Nations Convention on the Law of the Sea (UNCLOS). The Third United Nations Conference on the Law of the Sea began in 1973 and concluded with the adoption of UNCLOS in 1982. Australia ratified the Convention on 5 October 1994. The United States is notably absent from the list of 156 states or entities to have joined the Convention.

UNCLOS defines the territorial sea limits and the continental shelf as well as sovereignty over these areas. It also defines an Exclusive Economic Zone over which the state has:

> … sovereign rights for the purpose of exploring and exploiting, conserving and managing the natural resources, whether living or non-living, of the waters superjacent to the seabed and of the seabed and its subsoil. (UNCLOS Article 56.1(a))

Australia is a major beneficiary of the Exclusive Economic Zone regime due to its extensive coastline (United Nations 1998).

Where states have opposite or adjacent coasts, the delimitation of the Exclusive Economic Zone and the continental shelf can be effected by agreement on the basis of international law, or failing agreement, through the settlement disputes mechanism of UNCLOS. Australia has entered into six such treaties — with East Timor, Papua New Guinea, New Zealand, Indonesia, the Solomon Islands and France (regarding New Caledonia and Kerguelen Islands). However, the Torres Strait Treaty and agreements relating to the Timor Sea are the most relevant for the upstream petroleum sector.

A 10-year prohibition on mining and drilling in the Torres Strait Protected Zone was agreed in the Torres Strait Treaty with Papua New Guinea, which came into force on 15 February 1985. The moratorium on mining and drilling in this zone was extended for an indefinite period on 12 February 2008 (Smith 2008).

The Timor Sea

There are three agreements between the Governments of Australia and East Timor relating to resource use in the Timor Sea — the Timor Sea Treaty, the Treaty on Certain Maritime Arrangements in the Timor Sea (CMATS Treaty), and the International Unitisation Agreement (IUA) for Greater Sunrise.

The Timor Sea Treaty between the Government of East Timor and the Government of Australia was signed on 20 May 2002. It established the Joint Petroleum Development Area (JPDA) (figure 4.2). The treaty provides for petroleum produced from the JPDA to be shared: 90 per cent to East Timor and 10 per cent to Australia.

Until 30 June 2008, the Timor Sea Designated Authority administered the JPDA. However, the Autoridade Nacional do Petróleo took over this role on 1 July 2008. The Autoridade Nacional do Petróleo regulates and manages petroleum operations in the JPDA and Timor Exclusive Area, based on the legal regime of the JPDA and Timor Exclusive Area used under the Timor Sea Designated Authority (TSDA 2008).

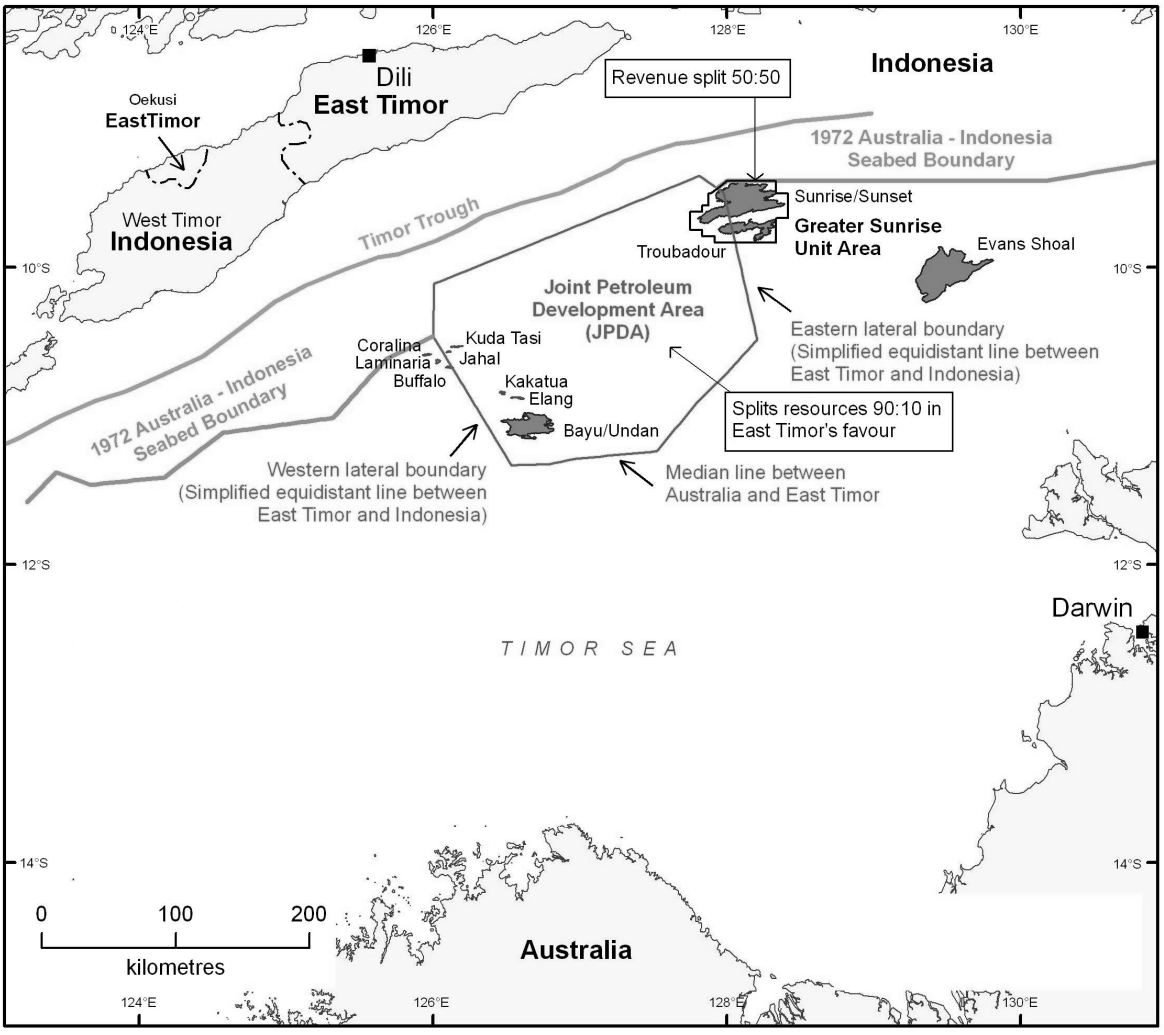
Petroleum activities in the JPDA are regulated by Production Sharing Contracts, which are signed by one or more oil and gas companies and the Autoridade Nacional do Petróleo (following approval by the Australia–East Timor Joint Commission).

As shown in figure 4.2, the Greater Sunrise Unit Area overlaps with the JPDA. The IUA, which was signed on 6 March 2003, provides the secure legal and regulatory

environment required for the development of the gas reservoirs in that area (DFAT 2008b). Under the Timor Sea Treaty, Greater Sunrise is apportioned geographically such that 20.1 per cent falls within the JPDA and the remaining 79.9 per cent falls under Australian jurisdiction.

The CMATS Treaty, which was signed on 12 January 2006, suspends maritime boundary claims between the two countries for 50 years. Although the formal apportionment of Greater Sunrise established under the IUA is retained, the CMATS Treaty states that Australia and East Timor will share equally the revenue derived from upstream petroleum activities in the Greater Sunrise Unit Area.

Figure 4.2 **Joint Petroleum Development Area**



Source: Geoscience Australia (pers. comm., 26 September 2008).

5 Resource management and land access

Key points

- Under Australian law, petroleum resources are owned by the Crown on behalf of the community. Governments play a 'stewardship' role in petroleum resource management.
- The overall objective of governments' resource management policies for petroleum resources is not clearly expressed and there are elements of the implied 'sub objectives' of this policy that appear in tension. If some sort of balance between the competing 'sub objectives' is intended, it will require a much clearer statement of how this is to be achieved.
- There are several legitimate roles for government in managing oil and gas resources including providing pre-competitive data and in preventing 'spillovers'.
- Rationales for overriding commercial decisions about the rate and method of resource extraction appear weaker because generally businesses will have adequate incentives to extract resources efficiently.
- The retention lease assessment process lacks clarity of policy intent and the commerciality assessment process lacks transparency.
- The current joint regulatory framework can cause delays in approval processes where permit and licence applications are assessed by both the Commonwealth and the States and Territories, particularly when technical advice is requested from both Geoscience Australia and the State and Territory equivalents.
- Land access approvals are required to undertake onshore petroleum exploration and production, and to construct petroleum pipelines and facilities such as liquefied natural gas trains. All levels of government, landowners and Indigenous people can be involved in negotiating and approving access arrangements with proponents.
- There is evidence of delays in the processing by State Governments of future act applications to explore for petroleum on land subject to native title.
- In Australia, most State and Territory Governments process applications for petroleum exploration in accordance with the right to negotiate (RTN) procedures outlined in the *Native Title Act 1993* (Cwlth). The exception is South Australia, where the preferred position of the Government is to negotiate through Indigenous land use agreements (ILUAs).

Regulatory arrangements for resource management (section 5.1) and land access (section 5.2) are discussed in this chapter. In each section, the relevant regulation is discussed, including key regulatory processes and requirements, and the sources of unnecessary regulatory burdens are identified. Environmental and heritage regulatory arrangements are discussed in chapter 6 and occupational health and safety regulatory arrangements are discussed in chapter 7.

5.1 Resource management

Under Australian law, petroleum resources are owned by the Crown and the rights to these resources are vested in government rather than private individuals. Government plays a 'stewardship' role in petroleum resource management, on behalf of the community. This involves balancing the exploitation of the resource, maintenance of occupational health and safety standards, and environmental and heritage protection.

Resource management regulation is neither precisely defined in Australia's petroleum legislation, nor clearly articulated in Commonwealth, State or Territory policy documents. However, it can be viewed as having four components:

- Collecting and disseminating data to assist explorers.
- Allocating secure title to the resources in order to instil confidence in investors in the upstream petroleum sector.
- Managing the timing and method of extraction of the resource.
- Ensuring an appropriate return to the community for extracting non-renewable resources through collecting resource rent taxes or royalties.

Resource management regulation takes place throughout the upstream petroleum production process — from acreage release to exploration, extraction and transport of the resource. The regulatory requirements include proponents applying to hold relevant titles — including exploration permits, retention leases and production, pipeline and infrastructure licences. Title holders are also subject to data reporting obligations and must seek approval from regulators for various plans and consents to operate. These requirements are specified under Commonwealth, State and Territory legislation.

Key regulatory processes and requirements

The resource management aspects of the key steps in the regulatory process are outlined in this section for Commonwealth and State and Territory resource management regulation.

Commonwealth resource management regulation

Petroleum resources located in Commonwealth waters are regulated under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA). The OPGGSA is administered by a Joint Authority (JA) and a Designated Authority (DA), where the JA comprises the relevant State or Territory Minister and responsible Commonwealth Minister, and the DA is the relevant State or Territory Minister.

The OPGGSA regulates the exploration for, and production of, petroleum resources, as well as infrastructure construction, through requirements to obtain titles in the form of exploration permits, retention leases, and pipeline, production and infrastructure licences. Special prospecting authorities and access authorities can also be allocated to allow for exploration activity (excluding the drilling of wells).

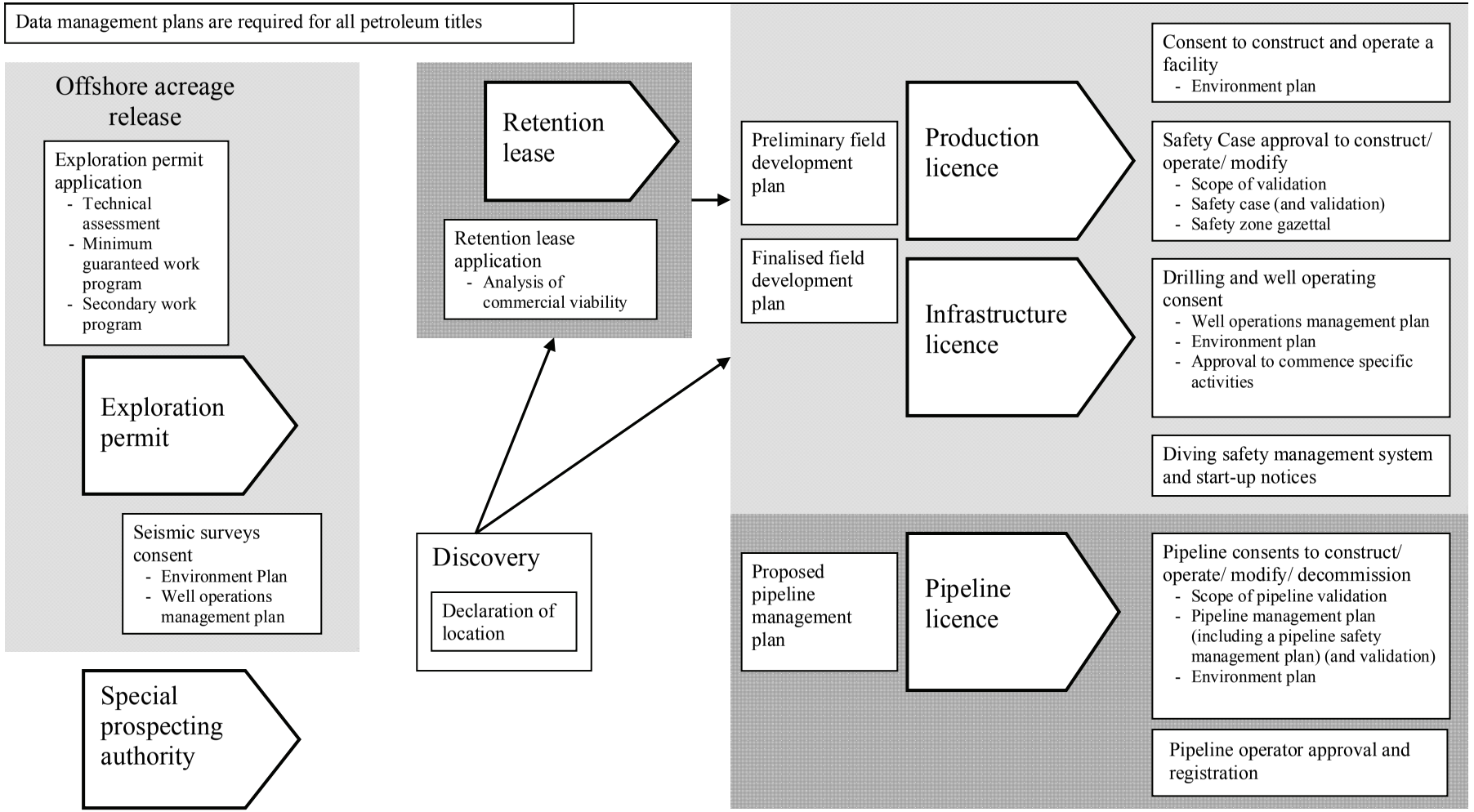
A stylised illustration of the key regulatory processes is presented in figure 5.1. Each type of petroleum title is shown, as well as specific application requirements and associated consents.

All titleholders must carry out operations in accordance with 'good oilfield practice', including carrying out operations in a manner that is safe and prevents the escape of petroleum into the environment. In order to retain title, titleholders must meet conditions of work and pay annual fees.

The OPGGSA also regulates key areas of resource management through a variety of regulations which the Australian Government, in consultation with the State and Territory Governments as well as industry, has been implementing since the early 1990s. The existing regulations cover well operations, safety on offshore facilities, occupational health and safety, diving safety, environment, pipelines, data management and fees.

The majority of the regulations under the OPGGSA, and its predecessor the *Petroleum (Submerged Lands) Act 1967* (Cwlth), are outcome focused and have progressively replaced the prescriptive *Schedule of Specific Requirements in the Offshore Petroleum Exploration and Production* (the Schedule), which applied under section 101 of the *Petroleum (Submerged Lands) Act 1967* (Cwlth) and the equivalent section 305 of the OPGGSA. However, the clauses in the Schedule relating to resource management are still current. In particular, clause 609 of the Schedule relates to approving the rate of recovery of petroleum. A current Department of Resources, Energy and Tourism (RET) review proposes consolidating and reducing the existing OPGGSA regulations and the draft resource management regulations to only three sets: (1) safety, (2) environment, and (3) resource management and reporting (DITR 2007b, p. 9) (chapter 4).

Figure 5.1 **Key steps in the regulatory process**



Sources: The *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) and subordinate regulations.

Acreage release

The Australian Government releases offshore acreage annually through a work program-based competitive bid process designed to award exploration permits to those applicants who commit to undertake the best assessment of the hydrocarbon potential of the area. The OPGGSA also allows for the use of a cash bid process, which requires a lump sum up front and is non-renewable if exploration drilling is not undertaken in the permit period. The work program permit requires expenditure commitments over a three-year period and is renewable if the program has been followed.

In addition to information about the application process, RET (2008b) publishes guidance notes for applicants on the impact of petroleum activities in the acreage areas on:

- environment and heritage protection
- navigation and maritime safety
- fishing activities
- defence activities
- submarine telecommunication cables
- insurance
- native title rights and interests.

Exploration permits

The JA approves exploration permit applications based on a report prepared by technical experts. A permit authorises the proponent to explore for petroleum and recover it on an appraisal basis (including operations and works required in the process) in the permit area for six years. Permits can be renewed for two further periods of five years, with 50 per cent relinquishment of the area at the end of each term (for a total of 16 years).

The JA grants exploration permits under the OPGGSA on the basis of a guarantee to complete the first three years of work without variation. This is also known as the dry hole system and means that the permit holder is required to fulfil the nominated commitment for those initial years, regardless of the circumstances, excepting force majeure. The second phase of the work program is negotiated on the basis of exploration results. However, if the proponent and the JA disagree on the extent of the program, then the initial work proposed when the application was initially made will prevail (DoIR 2007a).

Declaration of location

Upon discovery of petroleum, the exploration permit holder must notify the DA and provide details of the discovery. A *Declaration of Location* is nominated for approval by the DA over the block or blocks incorporating the discovery. The exploration permit holder may then undertake further exploration and appraisal activities within the location to determine more accurately the nature of the discovery.

Following a declaration, the permit holder must apply for a retention lease or a production licence within two years (although this may be extended for a further two years at the discretion of the relevant Minister).

Retention leases and production and infrastructure licences

The JA is the decision maker in granting retention leases for non-commercial petroleum discoveries. The applicant must demonstrate that the resource is not currently commercially viable, but is likely to become viable within the next 15 years. Retention leases are awarded for an initial five-year term and may be renewed for further five-year periods providing the resource remains uncommercial but is likely to become viable within 15 years. When a discovery is deemed to be commercial, the retention lease must be converted to a production licence. At any time during a five-year term, the Australian Government can request a review of the commercial viability of a field in the lease area.

A production licence provides the legal right to recover petroleum from an area. An infrastructure licence authorises the licensee to construct infrastructure facilities in an area and to operate infrastructure facilities. However, an infrastructure licence only applies for activities that cannot be covered by a production licence.

A field development plan is prepared during the production licence process. The stated objective of the plan is ensuring production satisfies so called 'good oilfield practice' albeit the definition of what constitutes good oil field practice is imprecise and subject to considerable judgement. Following the applicant submitting a preliminary field development plan, the DA and RET prepare a joint technical paper on the field development plan for the JA. RET seeks technical advice from Geoscience Australia. The proponent then prepares a finalised field development plan, taking into account the matters raised in the joint technical paper. Once production commences, considerable reporting must be undertaken for regulators, who have the power to require changes to the field development plan (DITR 2007b; DoIR 2007a).

Well operations management plans

All drilling operations are regulated. A titleholder of a retention lease, exploration permit, or production or infrastructure licence must have a well operations management plan that has been approved by the DA. The well operations management plan should include information on well drilling, testing, well completion, abandonment or suspension of a well, and well intervention.

The objective of a well operations management plan is to ensure the well is designed and managed in accordance with sound engineering principles and 'good oilfield practice', including identification of risks. A range of reporting on well operations is required, including daily drilling reports, monthly production reports and well completion reports (DITR 2007b; DoIR 2007a). As part of the consolidation of the OPGGSA, safety issues will be removed from well operations management plans. This will remove overlap with the safety case, and means such plans will now focus purely on resource management issues (RET 2008h).

Reporting requirements

Whenever a geophysical, geological or drilling activity is conducted under the OPGGSA, the operator must meet reporting requirements. Reporting requirements aim to ensure that work is conducted in accordance with the OPGGSA, as well as making information available to other interested groups to further the search for petroleum in the State, and offshore, in the most economical and efficient manner. All information and data submitted in accordance with the OPGGSA remain confidential until publicly released, as prescribed in regulation. Basic data are generally released after a period of two to three years, ranging up to 15 years for data from non-exclusive, three-dimensional seismic surveys. A five-kilometre two-dimensional grid extracted from three-dimensional non-exclusive seismic surveys is publicly released after five years (DITR 2007b; DoIR 2007a).

State and Territory resource management regulation

As agreed in the Offshore Constitutional Settlement, resource management regulation in the coastal waters of the States and the Northern Territory generally mirrors the requirements of the OPGGSA. However, not all requirements are the same and some difficulties have been encountered with maintaining mirror legislation (discussed below).

Onshore approvals vary across jurisdictions. As discussed in chapter 4, Western Australia aims to maintain consistency between coastal and onshore petroleum legislation, and Victoria's onshore approval process is virtually identical to the

offshore requirements. However, the onshore regulatory regimes in Queensland and South Australia differ substantially from their offshore regimes.

In South Australia, the *Petroleum Act 2000* represented a significant departure from the resource management requirements in the preceding *Petroleum Act 1940*, as well as from the OPGGSA and mirror legislation. Primary Industries and Resources South Australia (PIRSA) (sub. 20) stated that there were three main drivers behind the need for the new Act:

- changing community attitudes and expectations (particularly regarding environmental issues)
- competition policy reform
- the need for regulation to be more objective-based rather than prescriptive (making it more responsive to technological change).

Industry participants' feedback suggests that South Australia has a relatively straightforward regulatory system, which could be considered a benchmark for other jurisdictions (chapter 8). In total, the *Petroleum Act 2000* (SA) and subordinate legislation cover just over 100 pages. The Australian Petroleum Production and Exploration Association (APPEA) (sub. 16) considers the SA legislation to be simple to follow and administer. The Petroleum Act prescribes a limited role for government intervention in resource management:

> Other than for one section in the new Act where the government can force the cessation of operations of irresponsible or incompetent licensees, the new legislation does not prescribe in detail on any issue pertaining to resource management. (Malavazos 2001, p. 34)

Generally, the legislation is based on risk management principles. In particular, part 4 of the Petroleum Regulations 2000 allows for operators to carry out activities under low level official supervision, depending on the nature of the activities and the past performance of the operator.

In Queensland, it was intended that the *Petroleum and Gas (Production and Safety) Act 2004* would replace the *Petroleum Act 1923*. However, existing petroleum tenures likely to be affected by native title continue under the earlier Act (DME 2007). In total, the new Act and subordinate regulations cover just over 900 pages and the earlier Act and regulations almost 400 pages.

APPEA argued that the two onshore petroleum Acts and 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. (sub. 16, p. 35)

Petroleum royalties and taxation

The taxes levied on the upstream petroleum sector vary according to the jurisdictions in which they operate. The various tax and regulatory regimes are outlined in table 5.1.

Resources located in Commonwealth waters, with the exception of the North West Shelf, are subject to the Petroleum Resource Rent Tax (PRRT). The PRRT is assessed on an individual project basis, and is deductible for company tax purposes. Undeducted exploration expenditure incurred after 1 July 1990 is transferrable to a business's other profitable projects (ATO 2007). Instead of the PRRT, production on the North West Shelf Project is subject to crude oil excise tax, and an Australian Government royalty, which is calculated in the same manner as the WA royalty (Australian Government 2008a).

Production in all other areas (excluding Barrow Island in Western Australia) is potentially subject to the Commonwealth crude oil excise and State or Territory royalty provisions. The crude oil excise applies to condensate but does not apply to liquefied petroleum gas, natural gas and liquefied natural gas (LNG) (Australian Government 2008a). Royalties are calculated by taking a percentage of the value of petroleum at the wellhead, less deductible processing, storage and transport costs. The costs associated with the production field, including exploration, development and decommissioning, are not deductible (DoIR 2007a). Petroleum production on Barrow Island is subject to a State Agreement between Western Australia and the Commonwealth, which eliminates excise and State royalties. Instead, Barrow Island production is subject to the Resource Rent Royalty, which is modelled on the PRRT (APPEA 2007b).

Table 5.1 **Tax and royalty rates on petroleum production in Australia**

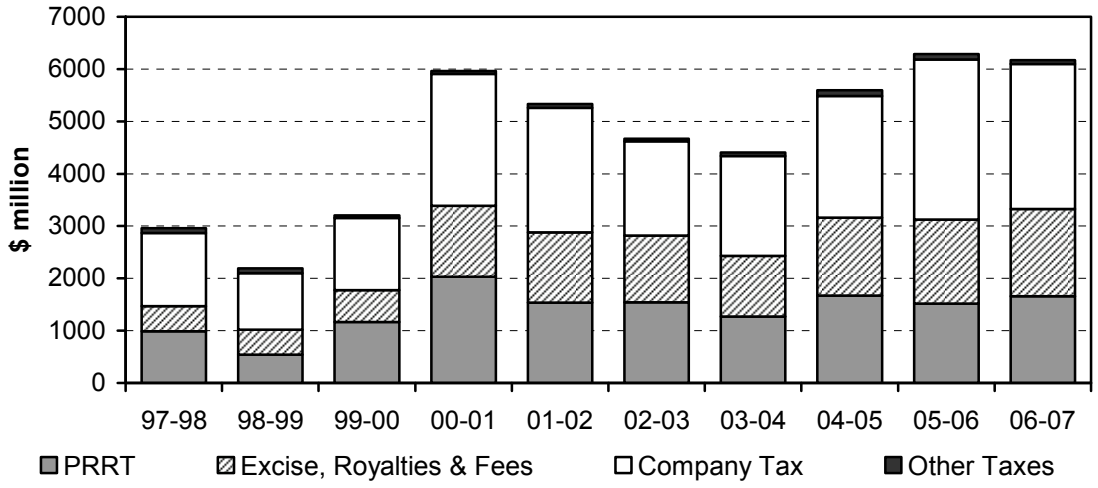
Tax	*Location of resources*	*Taxation authority*	*Value of tax*
Petroleum Resource Rent Tax (PRRT)	Commonwealth waters (beyond 3 mile limit)	Commonwealth	40 per cent of the difference between assessable receipts and allowable deductions, excluding an allowance for normal profit
Crude oil excise tax	Coastal waters	Commonwealth	Up to 55 per cent of volume weighted average of sale prices, increasing with production volume[a]
Company tax	All	Commonwealth	30 per cent of taxable income
Resource Rent Royalty	Barrow Island (Western Australia)	Commonwealth (75 per cent) and Western Australia (25 per cent)	40 per cent of net assessable receipts
Commonwealth royalty	North West Shelf	Commonwealth (approximately one third) and Western Australia (approximately two thirds)	10–12.5 per cent of wellhead value
State and Territory royalties	Onshore and coastal waters	New South Wales	10 per cent of wellhead value
		Victoria	10–12.5 per cent of wellhead value
		Queensland	10 per cent of wellhead value
		Western Australia	10–12.5 per cent of wellhead value
		South Australia	10 per cent of wellhead value
		Tasmania	10 per cent of wellhead value
		Northern Territory	10 per cent of wellhead value

a For oil discovered on or after September 1975, the maximum rate is 30 per cent.

Sources: APPEA (2007b, 2007d); ATO (2007); Australian Government (2008a); DME (2008); DMP (2008a, 2008c, 2008d); MRT (2008); Northern Territory Treasury (2006); DPI (2005); *Petroleum (Submerged Lands) Act 1982* (Vic); *Petroleum Act 1998* (Vic); PIRSA (2007).

Total government revenue from the Australian upstream petroleum sector has fluctuated over time, on an increasing trend (figure 5.2). In 2006-07, total royalties (including PRRT) constituted 54 per cent of total government petroleum-related revenue, while company tax represented 45 per cent (with the remainder consisting of 'other' taxes) (APPEA 2007a).

Figure 5.2 **Upstream petroleum taxation and royalties**



Source: APPEA (2007a).

The source of government revenue payments from the upstream petroleum sector has varied over the past two decades. Excise, royalties and fees as a proportion of total government petroleum-related revenue declined after the introduction of the PRRT in 1989-90, but their share has since increased to 27 per cent in 2006-07. PRRT revenues, as a proportion of government petroleum-related revenue, peaked at 61 per cent in 1991-92, and subsequently declined to a level roughly equal to excise, royalties and fees revenue in 2006-07 (APPEA 2007a).

Sources of unnecessary regulatory burden

Industry participants raised concerns about the appropriate role for government in resource management, and the associated lack of clarity of policy intent and definition of 'good oilfield practice', the retention lease assessment process, proposed changes to graticulation, the WA Government's domestic gas reservation policy and the lack of consistency of carbon capture and storage requirements. Concerns have also been expressed about duplication and overlap arising from current jurisdictional arrangements, resulting in delays in the approval process and issues with 'mirror' legislation.

The appropriate role for government in resource management

Participants focussed on government's role in resource management in two areas — collecting and disseminating geoscientific data, and approving the method and rate of resource extraction.

Collecting and disseminating geoscientific data

Governments as owners wish to attract private investment into exploring and developing petroleum resources. Frontier exploration is a high-cost high-risk activity, with a low probability of resulting in a commercial discovery. For this reason, the publicly-funded Geoscience Australia and State counterparts collect and disseminate data on frontier basins. RET and the State agencies make this 'pre-competitive' data available for free (or at nominal cost) and include it in the acreage release process.

The private sector uses this pre-competitive geoscientific data to identify potentially prospective areas in under-explored regions. This aspect of Geoscience Australia's role was supported by industry participants. Apache noted:

> [Geoscience Australia] has a crucial role in conducting regional studies on behalf of the Commonwealth designed to disseminate information regarding petroleum potential in frontier areas. [Geoscience Australia] also has important parts to play in guiding geoscience aspects of gazettals, in evaluating the national resource endowment and in representing the oil and gas industry to government. (sub. 14, pp. 2–3)

The Australian Government provides pre-competitive geoscientific data because it has public good aspects and this helps in attracting private investment to Australia.

FINDING 5.1

Geoscience Australia, and State and Northern Territory counterparts, by providing precompetitive data, play a valuable role in attracting private sector exploration investment in frontier areas.

Approving the method and rate of resource extraction

Most governments are involved in approving the method and rate of resource extraction, with approvals reliant on technical advice from Geoscience Australia, and its State and Northern Territory counterparts. However, South Australia, while retaining its right to intervene in exceptional cases, generally only requires operators to demonstrate good industry practice, reflecting a philosophy that:

> … through [the profit] motive alone, a company will seek to adopt appropriate practices and technologies to develop and produce the natural resource to an economically optimal level. (Malavazos 2001, p. 34)

Some industry participants suggested that Geoscience Australia's role in assessing the rate of resource extraction as part of the Joint Technical Report and Field Development Plan process may not add value.

Apache observed:

> Broadly, [Geoscience Australia's] contribution to commercial geoscience and reservoir engineering is superfluous; for instance its review of Field Development Plans tends to focus unnecessarily on inconsequential detail or to stray into commercial areas which are properly managed between the project proponents (and, in special cases, the DA). (sub. 14, p. 2)

The underlying rationale for government intervention in petroleum resource extraction seems to be a perceived divergence between private and public objectives based on an asymmetry of incentives, or of information, between industry and government or both. However, to the best of the Commission's knowledge, the overall policy intent of governments in the petroleum resource management area has never been clearly articulated. During the course of this study, various (and, in some cases, potentially inconsistent) rationales have been put forward (box 5.1), although the extent to which these reflect actual policy intent is unknown.

Box 5.1 Implied rationales for resource management intervention are often in tension

1. All upstream petroleum resources are owned by the Crown and should be extracted and taxed in a way that maximises net returns to the community and to future generations.
2. For-profit companies should be encouraged to actively explore for petroleum resources in Australia (and all its territorial waters).
3. For-profit companies should be encouraged to extract and commercialise all discovered petroleum resources, subject to a number of conditions that include:
   (a) The extraction methods should maximise the overall recovery of the total resource discovered, in a manner consistent with principles of intergenerational equity but such that the investor concerned will still make a commercial return. It is recognised that maximising overall recovery may involve additional capital, and may also extend the time taken to extract the resource. Both of these factors may reduce the economic returns to the company concerned.
   (b) Extraction of discovered resources should commence as soon as possible after discovery accepting that the investment required must be practical in terms of access to potential markets and must provide a commercial return to those making the investment.
   (c) All other government policies in terms of taxation, safety, environment, heritage etc must be satisfied.

Where a company which has discovered a resource is not prepared to make the investment to extract the resource (despite such extraction being judged by the regulator to be commercially viable) the company should either change its plans and develop the resource or sell its rights.

Some regulators claim government intervention is necessary because, left undirected, companies might employ extraction methods that could lead to reduced overall resource recovery. The remaining resource, unrecoverable in the future, is effectively 'sterilised' leading to losses for the community as the owner of the resource. The argument would appear to be that governments endeavour to prevent such resource sterilisation by requiring operators to comply with 'good oilfield practice'. However, 'good oilfield practice' appears to be highly situationally dependent and is inherently difficult to define rigorously. The OPGGSA references it by including safety and environmental matters and does not clearly delineate resource management requirements (box 5.2).

Box 5.2 **Defining 'good oilfield practice'**

Section 162 of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA) states that the Joint Authority has the right to direct the rate of extraction of petroleum, so long as it is not contrary to 'good oilfield practice'.

The OPGGSA (s. 6) defines the term as follows:

> ***good oilfield practice*** means all those things that are generally accepted as good and safe in:
>
> (a) the carrying on of exploration for petroleum; or
>
> (b) petroleum recovery operations.

However, this definition of 'good oilfield practice' is imprecise and therefore open to different interpretation by regulators and operators at different times:

> A central tenet of good reservoir management is the idea of 'good oilfield practice'. Generally speaking, parties have their own idea of what this entails and whilst in many cases government and industry representatives may have similar views, there will also be occasions where they differ. (Woodside, sub. 11, p. 5)

The lack of clarity of technical aspects of 'good oilfield practice' may be justified, as the term must be flexible enough to reflect changing and project-specific circumstances. However, a lack of definitional clarity can lead to differences in opinion between regulators and policy makers at various levels of government, as well as between government and industry participants. This can in turn lead to delays in approvals.

Perhaps more importantly, the term 'good oilfield practice' also lacks clearly delineated scope. It is unclear from the OPGGSA whether the term refers to safety, environment, resource security, extraction maximisation, other elements of petroleum exploration and production, or all of the above.

Source: Woodside (sub. 11).

Several participants expressed concerns with the definition of 'good oilfield practice'. Woodside commented:

> Since 'good oilfield practice' is never or consistently defined, and also appears to be evolving over time, there is scope for misunderstandings and differences to arise, especially when the parties have differing drivers. In our view to base a regulation on this idea is therefore potentially hazardous and likely to result in delays to approvals and the perception on the part of measures being demanded which are not in line with the achievement of maximum field depletion ... for example, in the case of a large gas field that has a marginal oil resource associated with it, the requirement to produce the oil resource first can defer the profitable gas production by many years at great opportunity cost. (sub. 11, p. 5)

It would seem reasonable to assume that through the commercial profit motive, industry would normally aim to employ the optimal *extraction technology* without direction from government. For governments to play a valuable role in approving resource extraction *methods* (thus avoiding resource sterilisation) suggests that the technical knowledge of government is superior to that of industry, or that industry is not taking into account all the social costs and benefits of its actions.

In its draft report the Commission considered it unlikely that government would systematically have better technical knowledge than industry and even if an individual company did not have expertise in this area, there was a range of oilfield services companies that can provide expertise to carry out activities as described in box 5.3. For example, Schlumberger provides services:

> … aimed at helping its customers increase oilfield efficiency, lower finding and producing costs, improve productivity, maximize reserve recovery, and increase asset value in a safe, environmentally sound manner. (Schlumberger 2008, p. 1)

The rationale for intervention in extraction methods is stronger when there is a risk of 'spillovers'. This can occur in two ways. One is where a single petroleum field encompasses two or more production licences held by different licensees and, the second is where depletion of one petroleum field affects the underlying aquifer (water table), which can potentially affect resource recovery from other oilfields in the vicinity of the aquifer. In both circumstances, there could be 'spillovers' where the actions of one operator affect the total amount of petroleum available to another operator. To the extent that any negative effects are not internalised by the individual licensee/operator, they will not have the incentive to adopt oilfield practice consistent with overall optimal depletion of the field.

Box 5.3 **Ultimate oilfield recovery**

The oil industry uses various methods to increase extraction rates and overall reservoir recovery rates. When oil prices are high, these methods become increasingly important.

Methods include enhanced recovery techniques and workovers (repairing or maintaining a well). The use of these techniques depends on the expected return:

> If oil prices are low, workover activity may be deferred until the cost can be justified by the price received for rejuvenated production. If prices stay low, workovers may be foregone altogether, and a well kept in production only as long as it produces a positive cash flow. (Wilkinson 2006, p. 152)

Once the marginal cost of producing petroleum from a given field exceeds the price that can be obtained, production ceases, and the field is shut-in (temporary) or abandoned (permanent). The point at which cost and revenues are equal is known as the economic limit:

> At the point of abandonment, the field still contains petroleum; it is just uneconomic to extract it. (Gluyas and Swarbrick 2004, p. 271)

The economic limit of a field is not fixed. A number of factors may cause the economic limit to change, allowing more oil to be extracted. These include:

> … changing fiscal regimes, increases in the oil price, the development of new technology and reductions in the operating cost … (Gluyas and Swarbrick 2004, p. 271)

A post-abandonment change in the economic limit may make a return to the field profitable. This is known as reactivation:

> Many oil fields are abandoned when the oil remaining in the ground is at least double what has been produced. The technology available to describe, drill into, and produce the oil today (or in the future) may be that much better than was available during the original life of the field. In consequence, the abandoned field may be selected for reactivation. (Gluyas and Swarbrick 2004, p. 13)

However, the costs of returning to a field can be high, as abandonment involves decommissioning a well. Consequently, the decision to abandon marginal oil fields will reduce resources available in the short run for production (even if the oil price increases), although in the long run this is not necessarily the case.

Sources: Gluyas and Swarbrick (2004); Wilkinson (2006).

In the first case, as the noted in the draft report, the Commission understands that in practice, rather than intervening using the OPGGSA, the DA encourages the licensees to develop a commercial unitisation agreement between them to optimally develop the field (RET, pers. comm., 17 November 2008). However, in the second case the Commission accepts that there may be a valid market failure, if the private incentives result in suboptimal depletion across the affected petroleum fields.

The WA Department of Mines and Petroleum (DMP) commented:

> In particular, the aquifer depletion example demonstrates that while industry may well have superior technical resources, Government agencies are better placed in terms of regional technical knowledge with unlimited access to regional data needed to regulate matters on a wide geographic basis. This enables Government to appropriately manage resources to encapsulate potential public good spillovers or externalities. Such issues are beyond the individual operator's control or interest. (sub. DR22, p. 4)

But intervention in resource extraction typically concerns more than addressing spillover issues. For instance, DMP further commented:

> The real issue is how industry or government agencies interpret technical issues according to their own economic incentives and policy drivers. (sub. DR22, p. 3)

This and other statements made to the Commission during this study suggest that the rationale for government intervention relates more to perceived differences between the objectives and time horizons for government and industry. For example, it has been argued that governments may wish to maximise rather than optimise resource extraction (potentially increasing costs and reducing profits), or to promote intergenerational equity and so prefer a longer time horizon for resource depletion reflected in a lower discount rate than adopted by industry.[1] Governments clearly have a role to foster objectives they consider are in the community's best interests. However, as highlighted by box 5.1, there does not appear to be any consistent statement of what those objectives are. Further, absent a clear statement of policy intent, policy implementation necessarily entails interpretation by regulators, leading to potentially inconsistent decisions. And, importantly, the absence of clearly stated objectives makes it difficult to assess the effectiveness of intervention.

For instance, as the Commission noted in the draft report, government views on the socially preferred time horizon are not unequivocally stated. The Australian Government appears to focus on the long-term recovery of the resource with RET (then the Department of Industry, Tourism and Resources) stating:

> The Commonwealth Government has a role in regulating the management of the resource to ensure that the recovery of petroleum is carried out in accordance with good oil-field practice in a way that is compatible with the long term recovery of the

[1] There is a range of views about the appropriate discount rate — all else given, the lower the rate, the greater the weight placed on future generations relative to the current generation. There is a strong argument that the discount rate should reflect the opportunity cost of using capital or savings in one activity compared with its next best use. As a rule of thumb, this is captured by the real market interest rate, adjusted for risk as appropriate. Whichever discount rate is used, sensitivity analysis should be reported to highlight the importance of the selected rate for overall results.

> resource. It is important to ensure that this objective is present in all associated petroleum regulations. (DITR 2007b, p. 24)

On the other hand, the WA Government seems to encompass both short-term and long-term perspectives.

> There are occasions when the interests of operators may diverge from those of regulators, and the community's best interests may not align exactly with those of the operating company. Under these circumstances, it is in the public interest to optimise both the long and short-term benefit to the Australian community. Therefore, there is a need for effective regulation that provides the required degree of assurance to all stakeholders. The concept of 'good oilfield practice' balances the competing objectives of maximising both net present value and ultimate recovery. (DoIR 2007a, p. 30)

Reflecting the lack of policy clarity, the Commission recommended in its draft report that governments clearly articulate their objectives and periodically assess the benefits and costs to ensure intervention in resource extraction is justified. Several participants endorsed this approach. APPEA stated:

> APPEA welcomes the call by the Productivity Commission for clarity on when government intervention is appropriate in determining the method and timing of petroleum extraction, and shares the Commission's views that there is rarely a divergence between private incentives and public interests. (sub. DR29, p. 5)

In similar vein, the SA Government noted:

> South Australia concurs with this recommendation and it supports the need for any government intervention in the area of regulating the extraction and management of the reservoir to be subject to the market failure test. The negative externalities referred to in the introduction of this submission need to be clearly identified through this test to justify any chosen regulatory intervention.
>
> It was through the application of this test when South Australia was developing its existing Petroleum Act that it realised that there was no or very little evidence to suggest that industry incentives to develop and extract resources to an optimal level would be contrary to the public interest. Hence it was decided to remove all prescriptive resource management requirements specified in the previous Act (SA *Petroleum Act 1940*) as this was acknowledged not to be an area of market failure requiring regulatory intervention. However, to cover the unlikely exceptional case, one clause was introduced in the Act to replace all the previous prescriptive provisions requiring industry to adopt good industry practice in carrying out its activities (which include resource extraction and development activities). (sub. DR23, p. 4)

The Commission remains of the view that, provided private companies meet community environmental and other objectives, they generally will have appropriate incentives to extract oil and gas resources efficiently, such that profit maximisation and the community's interests coincide. Consequently, the basis for overriding commercial decisions — that is, the reason why commercial and public

interests might diverge — should be clearly stated and the costs and benefits of intervening transparently assessed.

Moreover, the Commission understands that in the vast majority of cases, extraction plans proposed by companies are approved. If the ultimate justifications for intervention are spillover effects or that there are some rare outlier cases where unprofessional companies can behave inappropriately to the community's detriment, to minimise unnecessary costs and delays it would seem preferable that, in the absence of spillovers, interventions were focused on companies that are yet to establish a good track record. Companies that have established a good track record of appropriate behaviour, and demonstrated appropriate expertise, should have their plans subjected to quick confirmatory checking only.

FINDING 5.2

The underlying policy intent for and the regulatory objectives of government intervention in managing the method and rate of extracting petroleum resources is not unambiguously stated. The extent of the size of the divergence between private and public objectives is unclear. Consequently, it is not clear that the benefits from government intervention outweigh the costs, or even if they do, that they are the minimum costs possible to achieve the governments' policy objectives.

RECOMMENDATION 5.1

Governments should clearly articulate the objectives of intervention in approving the method and rate of petroleum extraction and periodically assess the benefits and costs to ensure such intervention is justified, and that if so, the costs of intervention are the minimum necessary to achieve the governments' objectives. Given that evidence suggests that intervention to revise extraction plans proposed by companies is rare, governments should focus their efforts on companies that are yet to establish a good track record, rather than imposing unnecessary burdens across all companies.

Retention lease assessment process

The policy rationale for retention leases is to protect property rights of companies investing in high-cost and high-risk exploration activity, albeit balanced against the desire of governments to have companies invest to develop resources. As outlined above, retention leases are awarded for non-commercial petroleum discoveries where the applicant can demonstrate that the resource, although not currently commercially viable, is likely to become viable within the next 15 years. Retention leases are awarded for an initial five-year term and can be renewed for further five-year periods, providing the resource remains uncommercial but is likely to

become viable within the subsequent 15 years. There is no maximum term prescribed in the OPGGSA but the DA can request a re-evaluation of the commercial viability of a discovery at any time in the lease period. Retention leases are not awarded or renewed if a discovery is deemed to be commercial. In this case, the leaseholder must commence production or sell the lease to a company that will.

The Australian Government, in consultation with the State and Northern Territory Governments, is currently reviewing the retention lease assessment process. The review scope was recommended in the final report of the Ministerial Council on Mineral and Petroleum Resources and the Ministerial Council on Energy Joint Working Group on Natural Gas Supply (2007):

> The [Joint Working Group] supports further investigation into improving the current acreage management process, in particular the granting and renewal of retention leases to ensure that processes are transparent and that tests of commerciality are rigorously applied and enforced. Proposed changes should be assessed in terms of the degree to which they are likely to have a positive impact on petroleum exploration and production in Australia. (Joint Working Group on Natural Gas Supply 2007, p. 32)

In its final report, the Joint Working Group (established in response to concerns about the price and availability of domestic gas) noted that a number of stakeholders believe the current acreage management system — in particular, retention leases — are creating barriers to domestic gas supply. Similarly, the Commission has received submissions suggesting that retention lease holders who obtain lease renewals may be deliberately withholding gas supply. Some gas users proposed what is effectively a strict 'use it or lose it' policy for retention leases. For example, the DomGas Alliance supported:

> … more stringent government assessment of Retention Leases to ensure that they are not used by producers to withhold domestic gas supplies. (sub. 1, p. 7)

The DomGas Alliance also proposed that governments reform the retention lease system to increase transparency:

> … to ensure that gas fields that can supply the domestic market are developed and that producers do not withhold supply. Greater transparency in the process is also needed to promote opportunity and third party participation. (sub. 1, p. 4)

On the other hand, BP suggested that toughening retention lease criteria to encourage accelerated development of resources would be misguided, as the main driver of gas development is commercial conditions, not the regulatory system:

> For example, some commentators and submissions have pointed to the fact that some gas reserves, discovered more than thirty years ago, have yet to be developed. This is true, but to lay the blame solely at the door of the regulatory system is to ignore the commercial reality … gas prices over the last decade and a half … remained relatively stable (and low from the perspective of the costs of LNG production) until 2002, since

> when they have broadly doubled. It is this story which most accurately accounts for the relative lack of development in earlier periods, followed by the period of concerted development activity in recent years. We therefore contend that the case for regulatory change to seek to force companies to invest is misguided, and should be rejected by the Productivity Commission. (sub. 15, p. 2)

In its draft report the Commission observed that introducing a stricter 'use it or lose it' approach to increase gas supply (by attempting to bring forward resource development of both export LNG and domestic gas) could be counter-productive. If toughening retention lease criteria causes explorers to perceive a dilution of their property rights, it is likely to diminish their incentive to invest in exploration.

Indeed, the Commission noted that where companies had invested heavily in exploration, they would seem likely to be motivated to develop any commercially viable discovered resources. The vast majority of lease renewal applications have historically been granted, presumably either because the company and government have eventually agreed about commercial prospects, or alternatively where they have not, because governments have recognised the risks of being seen to effectively expropriate company assets. This outcome was an important factor underlying the Commission's recommendation in its draft report to extend the length of retention leases, because the same outcome could be achieved at lower regulatory cost.

It was proposed that the initial lease period be extended from the current five years to 15 years, and renewals for a period of ten years. However, while in favour of retention leases, the majority of study participants did not support this recommendation. For example, APPEA responded:

> Consistent with the Commission's finding, retention leases provide a level of assurance to the exploration industry that in the event of currently uncommercial fields, the industry will not have to 'walk away' from discoveries but will be given an opportunity to make good the exploration risks undertaken. Importantly, retention leases recognise the need for security of title, respecting the risks undertaken by the explorer through its initial exploration investment in making the discovery … [and] that the existing legislative and regulatory provisions underpinning retention leases are adequate and do not require any modification to increase the initial lease from five years to fifteen. (sub. DR29, pp. 5–6)

After consideration of feedback, the Commission has amended its recommendation on this issue. Nonetheless, the Commission remains of the view that lack of clarity and transparency in the retention lease renewal process imposes unnecessary regulatory burdens.

There has been some pressure to make commerciality tests more rigorous, especially for gas reserves, in order to increase domestic gas supplies. In the

extreme, lease holders might be compelled to commence production or lose the resource title, regardless of differing views about commerciality (a strict 'use it or lose it' test).

The Commission remains highly sceptical of the desirability of strengthening the criteria for retention lease renewal in a bid to encourage domestic gas production. It is not clear that any non-renewed retention lease would necessarily be converted to a production licence by another party. Governments cannot compel private businesses to invest and, if other companies have more optimistic views about the commercial viability than the current title holder, then a private transaction between these companies would seem to be a likely outcome.

This assessment is backed up by recent work prepared by consultants McLennan Magasanik Associates (2007) for the Joint Working Group on Natural Gas Supply. As noted by the Western Australian Economic Regulation Authority (ERA) in a comment on the final report of the working group:

> … the Authority is in agreement with the view expressed in the MMA report that there is no evidence of market failure in the gas supply situation in Western Australia … (ERA 2007, p. 1)

In particular, competition was found adequate to ensure that individual businesses do not have an incentive to hoard reserves in order to influence prices. Thus, it could be expected that profit-maximising companies will develop or on-sell their gas discoveries when they see prices rise generating the prospect of an adequate commercial return.

That said, different companies face different short-term constraints and opportunities and, at any one time, could have different assessments of commercial prospects. In this regard, the reviews have explored various mechanisms for more objectively testing commerciality and scope for lease sales, including market auction mechanisms. Particularly if governments were to apply stricter tests to lease renewal, compared with a bureaucratic assessment of commerciality (and competing claims of both leaseholders and rival businesses seeking to gain lease rights), market mechanisms, such as auctions with appropriately informed bidders, have the potential advantage of eliciting truthful valuations and reducing the risk of perceived expropriation of exploration investments. McLennan Magasanik Associates (2007) recommended consideration of the feasibility of an auction option. However, auctions are likely to be costly and challenging to design, suggesting that they should only be used in exceptional circumstances. For instance, they could be provided as an option where there is intractable disagreement between leaseholders and government.

A more direct option would be to remove impediments to voluntary, mutually beneficial lease transactions. In particular, the current 1.5 per cent registration or dealing fee imposed on all transfers of petroleum and geothermal energy resource permits, leases and licences not only imposes a significant charge for each transaction, but also creates delays and uncertainty because of the need to establish the value of the title or transfer as the base for the tax. The fee could be replaced by cost-reflective charges, and should be replaced were the Commission's preferred national regulator model to be adopted (chapter 10). Equally effective would be a reduction in unnecessary regulatory burdens imposed by environmental and other regulations, which by reducing the net present value of anticipated returns, act to discourage field development.

To minimise unnecessary regulatory burdens arising from the retention lease renewal process, and the commerciality test in particular, governments should clearly articulate the criteria they will apply and demonstrate how application of these criteria will deliver net community benefits. Such clarification should include the extent to which governments, once a production licence had been applied for, might then require companies to modify planned extraction methods to maximise overall resource extraction, which clearly has the capacity to alter views of commerciality. Further, in considering changes to the retention lease system, governments should assess the costs and benefits of any changes, including the possible effects on incentives to explore for petroleum, and any likely resulting gas supply outcomes.

FINDING 5.3

Given that companies have typically undertaken costly exploration work to discover resources, it would seem that a retention lease is a legitimate instrument when the discovery is not yet considered commercial. What is considered commercial involves a complex assessment of extraction methods (which optimise overall resource recovery), long term costs and realisations in resource markets, and comparisons with international investment alternatives. Governments wishing to encourage commercialisation as well as encouraging ongoing investment in exploration must carefully balance incentives, costs and rewards for the companies investing and for the community as a whole. An automatic 'use-it-or-lose-it' policy is a blunt instrument subject to significant risks of regulatory error and may result in the perverse long-term outcome of both reduced exploration and reduced commercialisation of resources.

FINDING 5.4

The retention lease process lacks clarity and transparency for both applicants and other parties wanting to participate in the process.

FINDING 5.5

The registration fee for transfers and dealings has the potential to slow the desirable transfer of the title to a discovery from one party unwilling to commercialise it to another party that is. Not only is the fee an inhibitor but the time taken to agree valuations and make transfers is a regulatory burden in its own right.

RECOMMENDATION 5.2

To promote regulatory certainty, governments should clarify and clearly articulate the objective/s and make transparent the criteria and processes used in both approving initial retention leases and renewing existing retention leases. In considering any changes to the retention lease system, governments should:

- ***assess the costs and benefits (including the possible effects on incentives to explore for petroleum, and any likely resulting gas supply outcomes)***
- ***ensure the costs of intervention are the minimum necessary to achieve the governments' objectives***
- ***consider more objective tests of commerciality, such as auction mechanisms, where disagreements about commercial assessments arise, to avoid inadvertent expropriation of exploration investments.***

RECOMMENDATION 5.3

Impediments to voluntary, mutually beneficial lease transactions should be removed. In this regard, Australian governments should abolish the registration fee for transfers and dealings as this may have the perverse outcome of inhibiting transfers that might otherwise improve the probability of discovered resources being commercialised expeditiously. This would also be consistent with cost-reflective charging arrangements.

Proposed changes to offshore block graticulation

Areas offshore under the OPGGSA are currently divided into blocks that are 5 minutes of latitude by 5 minutes of longitude (67 to 85 sq km depending on latitude). These blocks are used for retention leases and production licences following declaration of location from an exploration permit. Retention leases and production licences are awarded where the applicant can demonstrate that the most likely interpretation of the field boundary goes into a block.

The Australian Government has proposed to change the unit of area for administration of graticular blocks for new titles from 5 minutes to 1 minute. The

Upstream Petroleum and Geothermal Subcommittee of the Ministerial Council on Mineral and Petroleum Resources is currently considering this proposal and it has been discussed at a technical forum involving representatives from industry and Commonwealth, State and Northern Territory regulators. There is no intention to change existing title boundaries, including renewing existing titles, unless there is mutual agreement by all parties.

The Commission understands that the main reason for a move to smaller blocks of 1 minute graticulation is to enhance efficient resource management by improving the fit between title boundaries and petroleum pool boundaries. The aim is to achieve this by changing the probabilistic boundary of fields as well as the size of the blocks. Currently, 5 minute by 5 minute blocks are awarded where the 'P50' boundary of the field is demonstrated to lie within that block, meaning there is a 50 per cent probability that the resource is contained in the block. The Australian Government proposes that 1 minute by 1 minute blocks would be awarded where the 'P10' boundary is demonstrated, meaning there is 90 per cent probability that the resource is contained in the block. This would mean that any retention lease or production licence boundary would be more likely to contain the actual field (RET, pers. comm., 11 November 2008).

The Australian Government considers that by awarding smaller blocks, substantial acreage is not locked into retention leases and production licences and is therefore open to competitive exploration and development. Different explorers might have different approaches and technologies for exploration and development and this should increase the diversity and competition in the market (RET, pers. comm., 11 November 2008).

However, Woodside considered that this change will result in more cumbersome requirements and that the new system will not yield any obvious benefits:

> The proposed change is likely to lead to a vastly increased burden of documentation … Fields which are neighbouring, but not close enough to have contiguous one minute blocks, will require dedicated field development plans in support of individual production licences, whereas in the past they may have been covered under a single field development plan … Overall, in our view there will be a greatly increased administrative burden with no obvious advantage for any party. Woodside believes this proposal is worthy of further investigation by the Productivity Commission. (sub. 11, pp. 4–5)

In the draft report the Commission sought comments on the proposed change to graticular blocks in terms of creating unnecessary regulatory burdens. APPEA submitted a detailed response outlining the perceived disadvantages of the proposed change including: decreased sovereign certainty over petroleum titles, increased administration for both government and industry, increased complexity, and

inappropriate application to frontier areas. The Commission notes the concerns expressed by APPEA and other industry participants about the proposed change to 1 minute graticular blocks in Australia. The Commission notes that this is a complex issue with potential for unintended consequences and costs. However it finds it difficult to reconcile some of the concerns expressed by industry with the fact the Commission has also been told that a large number of overseas countries and their upstream petroleum industries apparently operate reasonably successfully with 1 minute blocks.

The Commission considers that governments should rigorously assess the potential costs and benefits from any change to the current graticular block system and only proceed with changes if it can be demonstrated that an overall net benefit would result, and that of all the options available, the proposed change is the least cost means of achieving the governments' objectives. A comprehensive Regulatory Impact process should be conducted and cover this ground.

RECOMMENDATION 5.4

The Australian Government should subject any proposed changes to block graticulation to a full regulation impact statement process with careful consideration of the potential impacts on industry and only so amend the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) if the regulation impact statement clearly demonstrates a net benefit.

The WA Government's domestic gas reservation policy

The WA Government released its *Policy on Securing Domestic Gas Supplies* in October 2006, following stakeholder consultation. The policy aims to ensure that 'sufficient supplies of gas are available to underpin Western Australia's long term energy security and economic development' (Department of the Premier and Cabinet 2006, p. 2). The policy requires LNG project proponents to set aside up to the equivalent of 15 per cent of LNG production from each export gas project for domestic gas supply. This is a condition of access to WA land for the location of processing facilities.

A number of participants raised this issue in submissions to this review. For example, the DomGas Alliance (sub. 1) and the then WA Department of Industry and Resources (DoIR) (sub. 18) (now DMP), supported the use of a reservations policy in Western Australia to secure long term domestic gas supply:

> In the absence of the DomGas Policy, Western Australia could find itself with insufficient gas supplies to meet future demand … The DomGas policy is therefore essential to ensure the future gas needs of Western Australia. (sub. 18, p. 7)

DoIR claimed the WA policy does not impose price conditions on the sale of domestic gas:

> The DomGas Policy is designed to ensure gas availability, and places no conditions on price, which is negotiated between producers and consumers on commercial terms. (sub. 18, p. 7)

The WA Domestic Gas Policy is not clearly defined and its application appears to be subject to individual negotiation on a project by project basis. As such it has the capacity to impose uncertainty and unnecessary regulatory burdens. Further the policy itself has the potential to reduce the overall returns from a particular gas project. It would seem that if a proponent considering an LNG project could achieve higher wellhead realisation by selling gas to domestic users rather than exporting LNG, there would be no need for a domestic gas reservation policy. Commercial imperatives would see the domestic market fully supplied. The claimed need for a domestic gas reservation policy suggests to the Commission that current domestic gas users are often unwilling to pay prices or to agree to contracts of sufficient length or certainty which would leave an LNG exporter indifferent between supplying the domestic market or exporting LNG. To the extent that project proponents are required to sell a proportion of their gas into the domestic market at whatever price a domestic user will pay suggests a subsidised domestic gas price. For highly profitable projects, this might not affect investment levels but for more marginal projects such a policy may result in lower investment in exploration and development of both LNG and domestic gas projects.

In response to the Commission's discussion of this issue in the draft report, DMP submitted:

> … that the Commission by commenting on the *Western Australian Policy on Securing Domestic Gas Supplies* and presenting a draft finding, has breached the term of reference set down for the Review … [since the policy] is a State policy on energy supply and resource extraction, not a regulation. (sub. DR22, pp. 5–6)

However, as discussed in chapter 1, in this study the Commission has applied a broadly-accepted definition of regulation that encompasses policies. Importantly, regulation or quasi-regulation will impose unnecessary burdens if it is not the most efficient means of achieving a desired objective. If the intent of the domestic gas reservation scheme is to promote access to cheaper gas for domestic users over time, it is not clear that compulsory reservation will be the most effective mechanism, in large part because of the potential unintended consequences of increasing risk for companies. Further, as yet there is no clear statement of how the policy will be implemented, creating additional uncertainty.

FINDING 5.6

The WA Government's policy on securing domestic gas supplies is intended to increase domestic gas supply, although the full guidelines under which this policy is intended to be implemented are not clearly articulated. This is a form of quasi regulation that may impact on projects of a multijurisdictional nature. Although such a policy itself might not impose a regulatory burden, in this case the lack of a comprehensive statement of the policy and its guidelines, has the potential to create uncertainty and be subject to varied interpretation and inconsistent application. It can also reduce the overall returns from a particular gas project. Consequently, in practice it might negatively affect exploration and development of both liquefied natural gas and domestic gas projects.

RECOMMENDATION 5.5

The WA Government should ensure its policy on securing domestic gas supplies is clear and transparent with appropriate guidelines and ensure this policy provides net community benefits.

Carbon capture and storage

Study participants raised concerns about proposed carbon capture and storage (CCS) regulations. These included concerns about the rights of current holders of petroleum titles, third party access rules, and post-closure responsibilities and liabilities.

The Commonwealth's Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008 was passed by the Senate on 10 November 2008 and resulted in the amended *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth). The amendments to the Act provide for a similar system of titles for CCS as currently exists for petroleum. It also includes a range of changes to the current system of petroleum titles to provide for overlapping property rights between petroleum title holders and CCS title holders.

It is unclear at this stage whether the new amendment will impose unnecessary burdens on the upstream petroleum sector. Under the amendment, the responsible Commonwealth Minister will approve CCS permits, while the DA remains responsible for petroleum permits. However, the responsible Commonwealth Minister will also be required to approve any *key petroleum operations*, that is, petroleum activities that may affect existing or future greenhouse gas storage titles. Petroleum approvals are to have regard for written agreements from greenhouse gas storage title holders, and the 'public interest' (with the relevant public interest tests

to be defined under the regulations and yet to be determined). The amendment is not intended to change the rights of existing petroleum title holders.

Consistency of carbon capture and storage requirements

The Ministerial Council on Mineral and Petroleum Resources endorsed the *Regulatory Guiding Principles for Carbon Capture and Geological Storage* in November 2006. The aim of the principles was to establish a nationally consistent framework for CCS. However, States and Territories have proceeded with developing their own individual CCS legislation.

Woodside (sub. 11) indicated that while the intention was that Commonwealth and State legislation would mirror each other, or be consistent, in practice this does not appear to be the case. Further, it noted that various jurisdictions are legislating for CCS through different mechanisms:

> South Australia has made minor amendments to their onshore petroleum legislation; Queensland and Victoria have stated that they will most likely draft standalone legislation; and Western Australia has drafted minor amendments to the definition of petroleum but they have not yet been enacted. (sub. 11, p. 3)

In addition, Woodside argued that these CCS requirements are not consistent with the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008 (which only applies in Commonwealth waters):

> All of these mechanisms are at odds with the Commonwealth proposed amendments to the *Offshore Petroleum Act 2006* via the introduction of a completely new set of greenhouse gas titles. (sub. 11, p. 3)

At the October 2008 COAG meeting, it was agreed that jurisdictions would expedite the introduction of nationally-consistent regulation of CCS, including the geological storage of carbon dioxide. The Commission endorses the desirability of nationally consistent requirements in this area to avoid further complicating the current petroleum regulatory arrangements.

In its draft report the Commission recommended consistency in CCS legislation across all jurisdictions, and most study participants support this recommendation. DMP stated it:

> … supports this recommendation and intends to mirror the Commonwealth's greenhouse gas storage regime in coastal waters covered by the State's *Petroleum (Submerged Lands) Act 1982*. DMP also intends to develop onshore greenhouse gas legislation as endorsed by the Ministerial Council on Mineral and Petroleum Resources in 2006. (sub. DR22, p. 10)

However, the Victorian Government responded:

> Victoria's onshore legislation is consistent with the high level regulatory principles endorsed by the Ministerial Council on Minerals and Petroleum Resources. However, a key difference exists between Victoria's onshore regulatory framework and the Commonwealth legislation in relation to the rights of current holders of petroleum titles.
>
> The Commonwealth Act includes … provisions [that] provide petroleum titleholders with an advantage over any potential non-petroleum CCS proponents when applying for an exploration permit … Victoria's position … is that legislation should provide a level playing field for both CCS and Petroleum proponents. (sub. DR26, p. 3)

The Commission considers that it is highly regrettable that despite the agreement between governments about the desirability of consistency, and a significant investment of time to agree on key principles in this area, it appears that consistency across all jurisdictions is unlikely to be implemented.

FINDING 5.7

Nationally-consistent regulation in the area of carbon capture and storage would minimise regulatory uncertainty and inconsistency, and avoid further complicating current petroleum regulatory arrangements. It is regrettable that despite significant attempts to reach national agreement on consistency across all jurisdictions, it would appear that not all States have committed to the principles which were 'agreed' and none have implemented, and others do not intend to implement, nationally consistent regulation.

RECOMMENDATION 5.6

State and Territory Governments should mirror amendments resulting from the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) in coastal waters, and implement nationally consistent legislation for onshore carbon capture and storage as originally endorsed by the Ministerial Council on Mineral and Petroleum Resources in 2006.

Duplication and overlap from current jurisdictional arrangements

Several study participants raised concerns that the current JA–DA arrangements involve substantial duplication in the administration and assessment processes for granting permits and licences.

In particular, the Victorian Government observed:

> … this duplication arises from the iterative processes carried out by both the Commonwealth and DAs for the same assessments, particularly during the processing and assessment of Field Development Plans and Joint Technical Reports. (sub. 7, p. 4)

More generally, APPEA highlighted the added complexity from having two technical advisors (the DA and Geoscience Australia):

> 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. (sub. 16, p. 16)

APPEA expressed concerns over the duplicative and tiered approach currently applied to resource management regulations (particularly in the offshore context). Further, it argued that 'a holistic approach is needed to ensure that overlapping jurisdictional issues are managed in a timely and effective manner' (sub. 16, p. 15), despite also acknowledging the benefits of having local expertise involved in the regulation of petroleum activities in onshore areas as well as coastal and Commonwealth waters.

Nexus argued current arrangements have led to a lack of consistency in decision making when dealing with the variety of agencies across various jurisdictions:

> In many cases, this 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 Upstream Petroleum & Geothermal Committee, but the Committee has limited ability to enforce contentious decisions. (sub. 3, p. 4)

In contrast, Woodside considered the JA–DA model in Commonwealth waters to be generally workable:

> It is of great benefit having a representative of the joint authority in the State capitals for ready access to discuss any technical and administrative issues. As approvals are required from State authorities … it is logical that the State authority is involved in the decision making and approvals within adjacent offshore areas. (sub. 11, p. 3)

In conclusion, although some industry participants may perceive some benefits to the current JA–DA system, it would appear the duplication and iterative processes associated with these arrangements do delay approvals.

FINDING 5.8

The current Joint Authority–Designated Authority arrangements can cause delays in approval processes, particularly where Geoscience Australia and the State equivalents duplicate technical advice on approving field development plans.

A national regulator would address the current issues with the JA–DA arrangements, such as delays in approval processes. Various models for a national regulator are discussed in chapter 9 and the Commission's preferred approach is discussed in chapter 10. Minimising the duplicative role of Geoscience Australia

and the State and Territory equivalents in approving field development plans would also reduce this source of regulatory burden.

Issues with mirror legislation

Under the Offshore Constitutional Settlement, State and Territory petroleum laws were to be enacted to mirror Commonwealth legislation to ensure that a consistent regulatory regime applied across Commonwealth and coastal waters. However, it is apparent that over time differing priorities and parliamentary schedules have caused variation between the State and Commonwealth petroleum submerged lands legislation. Some industry participants raised concerns that State and Territory offshore petroleum legislation does not fully 'mirror' the Commonwealth legislation.

Woodside submitted:

> Although the aim is for State offshore petroleum legislation to 'mirror' the Commonwealth offshore legislation for consistency, in reality this doesn't always occur. This can be due to differing priorities and parliamentary schedules. State legislation is often not entirely 'in-synch' with the Commonwealth offshore legislation. For example, the restriction on drilling within 300m of a title boundary was revoked from the Commonwealth legislation in 2000, but is still in force in the WA offshore legislation. (sub. 11, p. 4)

The Commission notes that varying Commonwealth, and State and Territory offshore legislation has the potential to add to regulatory compliance costs and create uncertainty for industry.

Further, the OPGGSA recently replaced the *Petroleum (Submerged Lands) Act 1967* (Cwlth) and consequently the States are still in the process of updating their offshore petroleum legislation. To date, no State has enacted an equivalent of the OPGGSA. In this regard, Apache commented:

> The OPA is welcome but not all predecessor mirror legislation has yet been repealed (e.g. the WA *Petroleum (Submerged Lands) Act 1982* is still in force). This has led to a complicated legal situation, requiring Apache to take costly legal advice and putting the company at risk of losing good title to its acreage. Legislation should be put in place to simplify this situation. (sub. 14, p. 5)

In its draft report the Commission concluded that where policy objectives are the same, 'mirror' legislation across jurisdictions facilitates consistent compliance requirements, with resulting lower costs for industry. Delays in updating 'mirror' legislation can impose increasing costs on industry, and undermine the potential benefits of such arrangements.

The NT Government supported this conclusion and noted it:

> … considers that to be effective; each jurisdiction would need to have appropriate levels of resources. Changes to the costing of administering legislation would be required to develop a 'cost recovery' culture for all petroleum and gas administration. (sub. DR32, p. 4)

DMP also supported the recommendation and noted that Western Australia had almost completed drafting the Petroleum and Energy Legislation Amendment Bill. The Bill covers the 'important common petroleum mining code amendments since 1994 to the State's three petroleum Acts up to, but not including, the Commonwealth's plain English rewrite' (sub. DR22, p. 10).

FINDING 5.9

Delays to updating State and Territory 'mirror' legislation can be costly and reduce the intended benefits from having it in the first place.

Some variants of a national offshore petroleum regulator to which individual States and Territories could delegate powers would address this issue by removing the need for duplicated processes between the Commonwealth, and the States and Territories (chapters 9 and 10). However, regardless of the establishment of a national offshore regulator, governments should review and update existing legislation to ensure consistency of 'mirror' legislation.

RECOMMENDATION 5.7

Governments should update legislation and its administration to ensure relevant offshore State and Territory legislation effectively 'mirrors' the Commonwealth offshore legislation as intended. To achieve this objective State and Territory governments should appropriately prioritise and resource legislative drafting processes.

5.2 Land access

In Australia, most production of oil and gas occurs offshore (chapter 2). Therefore, land access is not an issue for much of this stage of the supply chain. However, the majority of oil and gas is piped to onshore facilities. Consequently, land access approvals are required to construct pipelines passing through multiple jurisdictions and to construct onshore facilities such as LNG trains. Land access approvals are also required to undertake onshore petroleum exploration and production.

Access to land must in many cases be negotiated with Indigenous people who are registered native title parties, who own freehold land or who live on reserve land. In

other cases, approval to access public land will be granted by relevant government departments (Crown land) or local councils (for example, development on land within the boundaries of a town planning scheme in Western Australia).

In the case of access to private land, there is usually a legislative requirement to seek the consent of the owner, or occupier, of that land and pay compensation to access that land. For example:

- under the *Petroleum Act 2000* (SA) 'owners' of land (including native title holders) are entitled to compensation for damage to the land and deprivation or impairment from use of the land
- the *Aboriginal Land Rights Act (Northern Territory) 1976* (Cwlth) (ALRA) requires the payment of compensation for damage or disturbance caused to the relevant Aboriginal land, and to the traditional Aboriginal owners of the land, by exploration activities undertaken on the land.

The Australian, State and Territory Governments have established legislation, regulations and policy guidelines to facilitate access to land and adjoining coastal waters (table 5.2).

Overview of land access regulation

Native title

Where native title applies, the Commonwealth *Native Title Act 1993* (NTA) is the overarching legislation that governs the whole of Australia. All States and Territories adhere to the Commonwealth native title provisions. As discussed in chapter 4, all States and Territories have passed native title legislation to validate past and intermediate acts.

Native title may exist in places where Indigenous people continue to follow their traditional laws and customs and have maintained a link with their country, and where this connection has not been extinguished because of acts done, or allowed by government. It is an existing legal right to lands and waters in Australia and offshore. The areas where native title may exist include:

- vacant or unallocated Crown land
- some reserve lands such as national parks, forests and public reserves
- some types of pastoral lease
- some land held by, or for, Aboriginal people or Torres Strait Islanders

Table 5.2 Key Australian, State and Territory Government land access legislation, regulations and policy guidelines

Jurisdiction	*Policy*
Commonwealth	**Native title legislation** *Native Title Act 1993* **Land rights legislation** *Aboriginal Land Rights (Northern Territory) Act 1976*
Victoria	**Policy documents** Information regarding the processing of petroleum tenements under the *Native Title Act 1993*
QLD	**Land rights legislation** *Aboriginal Land Act 1991* *Torres Strait Islander Land Act 1991* *Land Act 1994* **Policy documents** Petroleum and Gas Exploration — Exploration laws explained Petroleum and Gas Exploration — A guide for landowners and occupiers
WA	**Land rights legislation** *Aboriginal Communities Act 1979* *Aboriginal Affairs Planning Authority Act 1972* **Policy documents** Working with Aboriginal Communities — A practical approach
SA	**Land rights legislation** *Anagu Pitjantjatjara Yankunytjatjara Land Rights Act 1981* *Maralinga Tjarutaland Rights Act 1984* *Aboriginal Lands Trust Act 1966* **Policy documents** Liaison Guidelines for Landholders and Petroleum Explorers in South Australia SA Indigenous Land Use Agreement (ILUA) Statewide negotiations Strategic Plan 2005–2009 (SA ILUA negotiating parties)
NT	**Land rights legislation** *Aboriginal Land Act 1978* *Cobourg Peninsula Aboriginal Land, Sanctuary and Marine Park Act 1981* *Nitmiluk (Katherine Gorge) National Park Act 1989* *Parks and Reserves (Framework for the Future) Act 2004* **Policy documents** A Guide to Exploration and Mining on Aboriginal Land Exploring Country — A guide to making an exploration agreement Guideline for the Application of a Petroleum Exploration Permit that attracts Native Title Guideline for the Application of a Petroleum Exploration Permit over Aboriginal Land

- beaches, oceans, seas, reefs, lakes, rivers, creeks, swamps, and other waters that are not privately owned.

In Australia, native title rights and interests (including claims) cover a significant proportion of the land. For example:

- native title claims exist over most of the land in South Australia, with the majority of pastoral lease land being under native title claim (PIRSA 2002)
- in Western Australia, registered and determined native title claims cover 98 per cent of the State, with some covering inter-tidal zones and sea (ONTWA 2008)
- in the Northern Territory, 50 per cent of the land is covered by pastoral leases and is possibly subject to native title (DPIFM 2005).

Under Australian law there are no native title rights to minerals, oil or gas (chapter 4). However, non-exclusive native title rights can be recognised over land and sea areas where oil or gas is located. Non-exclusive rights (no control of access to, and use of the area) include the right to live on the area; access the area for traditional purposes (camping and ceremonies); visit and protect important places and sites; hunt, fish and gather food or traditional resources like water, wood and ochre; and teach law and custom on country. In July 2008, the Australian Government announced that it would recognise non-exclusive native title rights can exist in territorial waters up to 12 nautical miles from the Australian coastline.

The NTA, among other things, sets out procedures which must be complied with by Australian, State and Territory Governments before future acts can be validly done. Future acts are proposed activities or developments such as the granting of exploration licences (including petroleum exploration permits), mining leases and some compulsory acquisitions, that might affect native title by extinguishing it or creating interests that are inconsistent with the existence or exercise of native title.

Specifically, the NTA provides for two main avenues to deal with future act applications — through the right to negotiate (RTN) procedure, or through an Indigenous land use agreement (ILUA). The RTN procedure has been in place since the commencement of the NTA in 1994.

ILUAs on the other hand are a recent development, which were introduced with amendments to the NTA in 1998. An ILUA is an agreement about native title and the use and management of land and waters made between one, or more, native title groups and others (such as miners, pastoralists or government). ILUAs can be made about matters such as petroleum developments, sharing land, exercising native title rights and interests, and compensation.

Indigenous land rights

There is no national Indigenous land rights legislation in Australia. However, land rights legislation does exist in various forms in most States and in the Northern Territory.

- The ALRA was the first attempt by the Australian Government to legally recognise the Aboriginal system of land ownership and put into law the concept of inalienable freehold title. This means that the land cannot be acquired, sold, mortgaged or disposed of in any way and title is held communally. Consent for access to land under the ALRA must be obtained from the traditional Aboriginal owners.
- Aboriginal land rights legislation does not exist in Victoria. Instead, title to various parcels of Victorian land has been granted to certain Aboriginal Trusts or organisations. Access to this land requires the consent of the relevant Aboriginal community, but some parcels of land may preclude the granting of a lease, licence, permit or other authority under the *Petroleum Act 1998* (Vic).
- The Queensland *Land Act 1994* makes provision for land to be set aside in the form of a reserve or a deed of grant in trust. The Aboriginal and Torres Strait Islander land Acts provide the basis on which Indigenous people can claim and be granted freehold or leasehold title to land, or a lease for a term of years. Under the *Petroleum and Gas (Production and Safety) Act 2004* (Qld), if a petroleum explorer requires access to land occupied by Indigenous people, the petroleum authority holder must personally deliver an entry notice to the occupier of that land.
- In Western Australia, the Aboriginal Lands Trust established by the *Aboriginal Affairs Planning Authority Act 1972* (WA), holds land in trust for Aboriginal people (almost 27 million hectares or 12 per cent of the State's land). Land tenure includes reserves (20 million hectares), leases and freehold properties (DoIA 2008). A special entry permit is required to access reserve land and permission must be obtained to enter Aboriginal freehold land, and land held as general or pastoral leases.
- In South Australia there are three main Acts that provide for a form of Aboriginal freehold title and impose strict conditions on land access. Around 20 per cent of freehold land is owned by Indigenous people (Government of South Australia 2005).

Pipelines and onshore facilities

In Australia, some jurisdictions (for example, Victoria, Western Australia and the Northern Territory) have separate legislation governing petroleum pipeline

licensing. Other states cover pipeline licensing in their onshore petroleum legislation.

A petroleum pipeline licence is required to construct and operate a pipeline and is issued on the condition that construction cannot proceed until the necessary land tenure has been obtained. Land tenure can be categorised as either accessing freehold or non-freehold land for the purposes of constructing a pipeline. Non-freehold land under the control of State or Territory Governments can include land subject to a lease, permit or licence, reserved for community purposes, dedicated as a road or subject to no tenure at all.

Title to freehold land is not absolute as State and Territory Governments are empowered to withhold certain ownership rights, such as the right to any minerals or petroleum. In addition, use of freehold land may be controlled by local government legislation. In Western Australia, access to freehold land to construct petroleum pipelines is accommodated by way of easements under the *Transfer of Land Act 1893* (WA). Similar arrangements are undertaken in other States and Territories.

Access to non-freehold land for pipeline construction is provided for in various State and Territory legislation. For example, in Western Australia the *Land Administration Act 1997* provides for the granting of easements over Crown land (including pastoral leases) and reserve land. Public authorities also have the right to grant easements and any land may be resumed under the *Public Works Act 1902* (WA) for the purpose of the pipeline.

Approval to access freehold or non-freehold land can also be subject to the NTA. Native title holders must be afforded the same procedural rights as holders of freehold title. For example, in Western Australia the *Petroleum Pipelines Act 1969*, requires an applicant for a petroleum pipeline licence to notify interested parties, which includes native title holders.

In Western Australia, if a pipeline is to be constructed on non-freehold land, and is the subject of a registered native title claim or determination, agreement must be reached with the native title parties concerning an easement, lease of land, or, alternatively, compulsory acquisition.

Indeed, to provide for industrial development in Western Australia, the Government compulsorily acquired native title rights and interests on the Burrup Peninsula and certain parcels of land near Karratha (referred to as the Maitland Estate). In particular, the Burrup and Maitland Industrial Estates Agreements allow major industrial development to proceed, while at the same time establishing a conservation estate and ensuring Aboriginal heritage is protected.

Key regulatory processes and requirements

Native title

The NTA clearly articulates the RTN procedures and establishes timeframes to negotiate conditions or an agreement regarding the proposed future act. The RTN process involves notification, negotiation and, if no agreement can be reached, arbitration, before the Government can validly grant petroleum tenements that will affect native title rights and interests. If the parties fail to reach an agreement, any party may refer the matter to the National Native Title Tribunal (NNTT) for determination by arbitration (box 5.4).

Alternatively, an ILUA allows developments on land to happen independently of any application for a determination of native title, or before a determination of native title is reached. Courts are not involved in the ILUA negotiation process — it is conducted entirely between the parties. ILUA negotiations have no set timeframes although it is recommended that up to 12 months be allowed for adequate consultation and registration of the ILUA (NNTT 2005). A registered ILUA is legally binding on the parties to the agreement, as well as all native title holders for that area. However, unlike the RTN procedure, when negotiating an ILUA, there is no provision for arbitration if parties do not reach agreement.

In Australia, most State and Territory Governments process future act applications for petroleum exploration in accordance with the RTN procedure specified in the NTA. However, at least two applications for petroleum exploration permits in the Northern Territory have been negotiated through an ILUA and registered with the NNTT (NNTT 2008a).

The exception is South Australia where the preferred position of the Government is to negotiate future acts through an ILUA. Instead of negotiating petroleum ILUAs on a case-by-case basis, as has occurred in the Northern Territory, the SA Government has developed a statewide framework. First initiated in 1999, the statewide ILUA process is designed to resolve native title matters in respect of all interests (represented by peak bodies) with the relevant native title bodies across the State.

The SA Government believes that:

> … this process is often a better way to achieve resolution of native title matters as an alternative to litigation as it is cheaper, creates less social division and stress, and establishes new, enduring relationships and agreements with enduring effect on the ground. (SA ILUA 2005, p. 5)

Box 5.4 **An overview of the right to negotiate procedures**

Right to negotiate procedures are complex. The summary provided here is intended to give an overview of the process only.

Under the right to negotiate procedures, the State or Territory Government publishes a notice that it wants to grant a tenement for a proposed development (a future act).

The notice is given by placing an advertisement in major newspapers. It must also be given directly to any native title parties (includes registered native title claimants and registered native title bodies corporate). People who claim to hold native title in the area, but have not yet made a native title claimant application, have three months from the date given in the section 29 notice to file a claim if they want to have the right to negotiate about the proposed future act (*Native Title Act 1993* (Cwlth)) (NTA). To obtain that right, they must also be registered within four months of the date given in the notice.

If there are objections to the proposed future act at the end of the three month period, the government, the developer and the native title party must negotiate 'in good faith' for at least six months about the effect of the proposed development on the registered native title rights and interests. The right to negotiate is not a right to stop or veto projects from going ahead, but it does give native title parties a right to have a say about the project. The aim is to obtain the agreement of the native title parties to the future act being done.

The parties can ask the National Native Title Tribunal (NNTT) to mediate during the negotiations. If the negotiations do not result in an agreement (the parties have six months to negotiate), then under section 35 of the NTA any party can ask the NNTT to make a determination under section 38 of the NTA as to whether or not the future act should go ahead, or under what conditions it should go ahead.

The NNTT is required to make a determination as to whether the tenement can be granted, and under what conditions as soon as is practicable (NTA, s. 36). Six months is allowed for the NNTT to make a determination. However, if a determination is not made within this time, then the NNTT must advise the Commonwealth Minister in writing of the reason for it not doing so, and include in that advice an estimate of when a determination is likely to be made (NTA, s. 36).

The NTA also allows for an 'expedited procedure' if a 'future act' has a minimal impact on native title, in which case there is no need for negotiations (unless there is an objection by native title parties).

Source: NNTT (2005).

Aboriginal land rights

The ALRA has transferred around 50 per cent of the Northern Territory's land to Aboriginal ownership under freehold title.

The *Petroleum Act 1984* (NT) and the ALRA regulate all applications for petroleum exploration permits over Aboriginal freehold land. The permit is granted by the Minister for Mines and Energy with the agreement of the appropriate Land Council and the Commonwealth Minister for Indigenous Affairs.

Under the ALRA, the granting of petroleum exploration permits on Aboriginal freehold land is subject to agreements made with the relevant Land Council. In the Northern Territory there are four land councils representing Aboriginal interests. The most significant are the Northern and Central Land Councils. Agreements cover a range of matters including work programs, sacred site protection procedures, compensation and environmental protection. They also record the Land Council's consent. Although agreements must be negotiated with the relevant Land Council, consent for access to land must be obtained from the traditional Aboriginal landowners.

The ALRA sets out the procedures to be followed, and specifies timelines for the parties to negotiate land access agreements. A key feature of the ALRA is that it gives traditional Aboriginal owners the right to withhold consent (that is, veto) exploration licence and petroleum permit applications for periods of up to five years.

Amendments to the ALRA in 1987 required exploration agreements to be conjunctive, that is, they must cover both exploration and production. In effect, this amendment removed a second veto that could block petroleum production once an exploration permit had been granted (HORSCIR 2003).

Sources of unnecessary regulatory burdens

APPEA noted that the upstream oil and gas sector respects the rights of the native title and Indigenous parties and aims to work at all times in consort with communities to achieve mutually acceptable outcomes. However, APPEA stated that:

> … there is some justification towards rationalising the process of land access and negotiation for the benefit of the Indigenous people. (sub. 16, p. 25)

The Commission also agrees that there appears to be scope for reducing unnecessary process delays, without affecting the rights of Indigenous title holders. In fact, reductions in unnecessary process delays should lead to better outcomes for all parties.

The nature of unnecessary regulatory burdens

There is evidence that the longest delays in gaining access to land occur in the Northern Territory. A recent review by ACIL Tasman (commissioned by the NT Government) found:

> The NT has the longest delays in access to the most prospective terranes of any State/Territory (up to 20 years) and delays of two years or more over large prospective areas. (ACIL Tasman 2007, p. ix)

In part, these delays may reflect the provisions in the ALRA, which can limit access to Aboriginal freehold land for periods of up to five years.

Native title

There is also evidence of backlogs in the processing of future act applications by State Governments, particularly in the resource rich states of Western Australia and Queensland (NNTT 2008b). Such backlogs can exacerbate delays in the processing of applications by the NNTT.

Delays in the processing of applications can also occur if the NNTT is asked to arbitrate and determine the outcome of a future act application under the RTN procedure, although as the NNTT observes, the process could take longer, or remain unresolved, without its involvement (sub. DR30, p. 10). In Western Australia, 25 future act applications for petroleum exploration permits have been determined by the NNTT from the commencement of the NTA until June 2008. Of these, 18 took longer than 16 months to approve, with two of these applications taking seven years to approve (NNTT 2008c). Under a normal RTN procedure (subdivision P of the NTA), 16 months to approve a future act includes three months for a native title party to register, six months to negotiate 'in good faith' and six months for a determination to be made by the NNTT (box 5.4).

The RTN process can also involve significant direct costs. The applicant must be prepared to meet their own costs of participating in the process such as any travel expenses, meeting costs, legal expenses and court fees. These costs will depend on the nature and length of the negotiations and whether the application is referred for determination. Where an agreement is not reached and the application is referred to the NNTT for determination, the applicant is required to pay any associated fees. The applicant may also be required to reimburse any costs incurred by government officers during the negotiation period, including but not limited to, travel and accommodation expenses.

APPEA noted that the cost to negotiate can be significant for small to medium Australian onshore operators:

> In many instances, negotiations require the petroleum project proponent to fund the negotiation costs (including travel and legal costs). 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. (sub. 16, p. 25)

Generally, Indigenous parties (including native title representative bodies) are not well resourced to undertake negotiations, particularly if they are in an area with a high level of future act activity, or are responding to other statutory or Federal Court timeframes. As a consequence, the proponents will often be asked to contribute resources either to the Indigenous party or to the native title representative bodies (Wade and Lombardi 2001).

To minimise the negotiating costs, APPEA suggested:

> 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. (sub. 16, p. 25)

DoIR (now DMP) also raised the issue of resourcing of native title parties and noted:

> Increased resourcing of native title parties is seen as integral to the success of both general native title agreements and Indigenous Land Use Agreements, and the Department of Industry and Resources would support any initiatives for this to occur. (sub. 18, p. 6)

The Commission discussed this issue in its *Annual Review of Regulatory Burdens on Business: Primary Sector* report (PC 2007a), noting that recent native title reforms to address this issue need to be given time to take effect. The report concluded:

> Recent Australian Government reforms to the native title system — aimed at building capacity for Native Title Representative Bodies and encouraging agreements — are being progressively implemented. They should be given time to take effect and then be subject to independent evaluation within five years of implementation. (PC 2007a, p. 196)

This has since been agreed to in principle by the Australian Government (2008b).

In some cases delays in land access approvals may have affected investment decisions. APPEA stated that for some of its small to medium members:

> … 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. (sub. 16, p. 26)

An ILUA has the potential in certain circumstances to streamline the approval process because it can include multiple projects in a single agreement, and avoid the need to negotiate on each new project or future act application, as is the case under the RTN procedure. The ability to cover multiple projects in one agreement can reduce the resources required for successive negotiations, and takes less time to negotiate than the RTN process.

Further, an ILUA has the potential to be less costly in the long run than the RTN process for large, complex projects, or where there are many tenement applications in one area. For Indigenous parties the benefits of native title are accessible without the need for an approved determination of native title and its associated legal costs. APPEA also emphasised the benefits of ILUAs:

> RTNs are project specific and limited to smaller sections of land, whereas ILUAs are negotiated on larger tracks of land … 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. (sub. 16, p. 25)

ILUAs provide a flexible alternative to negotiating land access approvals with Indigenous parties as they can be tailored to suit the needs of those involved and their particular land use issues. They also appear to be a faster way of resolving native title issues. On average, it takes about two years longer to pursue a native title claim through the courts than it does to negotiate a settlement (NNTT 2008d). However, there is no provision for arbitration if the parties fail to reach agreement.

The ability to negotiate conjunctive agreements, covering both exploration and production, can also streamline approval processes and avoid industry participants renegotiating the terms of development after the exploration phase. In February 2007, the SA Government initiated the first conjunctive petroleum ILUA in Australia. This agreement covers petroleum exploration and production in much of the Cooper Basin (Holloway 2007). APPEA strongly supported the use of conjunctive agreements and recommended:

> 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. (sub. 16, p. 25)

Given the potential benefits of ILUAs, there seems to be merit in encouraging greater use of them. However, ILUAs require that all potential native title holders are identified, informed of the ILUA and involved in the negotiating process. This requirement may limit their use in practice, particularly in Western Australia where there is a diversity of claim groups and native title representative bodies. It can therefore be more difficult to identify all potential native title holders.

The NNTT, in a response to the Commission's draft report, noted that ILUAs have some advantages, but the particular circumstances were critical:

> In the Tribunal's view and experience it is certainly correct that in some circumstances ILUAs can streamline native title approval processes especially where the ILUA involves conjunctive agreements covering the grant of exploration and production titles and/or future grants in a particular area or in relation to a particular project. ILUAs may also enhance long term relationships with the native title parties However, it is impossible to say overall whether ILUAs are a better method to progress a proposed future act unless all of the circumstances of the project, including the native title environment (such as whether there are competing claims over the area) are known. In some circumstances the RTN might be a better option for parties. (sub. DR30, p. 2)

This view is reinforced by Bowler (2002, p. 95), who observed that Western Australia's diversity 'make[s] the prospect of any state-wide ILUAs most unlikely'. Yet, Bowler (2002, p. 95) also noted that 'there is considerable potential for regional ILUAs to be developed'. However, as at 30 September 2008, no regional ILUAs had been negotiated. Further, of the 11 ILUAs negotiated on a case-by-case basis and registered with the NNTT, none are petroleum related (NNTT 2008a).

Nonetheless, the then DoIR considered that the development of ILUAs for upstream petroleum and strategic industrial planning activities could be used to improve land access processes. It indicated that it is:

> … currently working with the Office of Native Title and State Solicitors Office to develop Indigenous Land Use Area Agreements with the aim of facilitating low-impact exploration activities such as airborne magnetic surveys. (sub. 18, p. 6)

The Commission understands that this is a point of considerable frustration to some proponents in Western Australia, where significant delays can occur in order to conduct such low impact studies. These studies are necessary to understand whether certain land could be of potential interest or use in progressing a project. In South Australia, the use of statewide agreements has been effective in reducing their backlog of tenement applications, and these may have wider application in other jurisdictions.

FINDING 5.10

Both Indigenous land use agreements and the Right to Negotiate process have a role under the Native Title Act 1993 (Cwlth). Nonetheless, it appears that Indigenous land use agreements have the potential to streamline approval processes (including future act applications), reduce the resources required for successive negotiations, take less time, and reduce costs in the long run for large, complex projects or where there are many future act applications in one area.

RECOMMENDATION 5.8

In certain circumstances, Indigenous land use agreements have the potential to streamline the native title approval process and reduce the backlog of future act applications. State and Territory Governments should investigate whether such agreements could be used more frequently (including statewide, regional and conjunctive Indigenous land use agreements).

Aboriginal land rights

A House of Representatives Standing Committee report, tabled in August 2003, *Exploring: Australia's Future — impediments to increasing investment in minerals and petroleum exploration in Australia*, expressed concern '… at the amount of time expended by companies in obtaining exploration licences in the Northern Territory over land subject to the provisions of the *Aboriginal Land Rights (Northern Territory) Act 1976*' (HORSCIR 2003, p. 98). The Committee also noted 'that these delays amount to a significant deterrent to minerals and petroleum explorers' and that 'there is a need to address negotiation time frames and associated costs' (HORSCIR 2003, p. 98). The Committee accordingly recommended:

> The Minister for Immigration and Multicultural and Indigenous Affairs implement a simplified and accelerated process for granting exploration licences on land granted under the *Aboriginal Land Rights (Northern Territory) Act 1976* with a view to reducing the economic transaction costs emanating from the existing provisions of the Land Rights Act. (HORSCIR 2003, p. 48)

The Aboriginal Land Rights (Northern Territory) Amendment Bill 2006, sought to improve flexibility and streamline the exploration and mining provisions of the ALRA.

The extent to which these amendments have improved land access arrangements to Aboriginal freehold land is unclear. However, feedback provided to the Commission would suggest that there is further scope to streamline some administrative processes in the ALRA.

6 Environment and heritage

Key points

- In general, environmental regulation seeks to reduce harm to social, economic and natural environmental values, which can arise when development activities affect the natural or built environment.
- In each jurisdiction, environmental regulation of petroleum activities can include petroleum-specific environmental approvals and environmental approvals that are required for all development activities. Petroleum activities are potentially subject to four key areas of regulation:
  - environmental regulation of offshore petroleum activities under *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) regulations
  - national environmental and heritage regulation under the *Environment Protection and Biodiversity Act 1999* (Cwlth) (EPBC Act)
  - State and Territory environmental, conservation and planning regulations
  - Commonwealth, and State and Territory Indigenous heritage Acts
- There have been significant efforts to streamline and enhance the operation of the EPBC Act. Some concerns about its operation remain, such as:
  - insufficient information on environmental risks prior to the release of new acreage
  - the interaction and overlap of the EPBC Act with other environmental approvals
  - potential uncertainty generated by strategic assessment processes
  - recent perceptions by industry of greater intervention in, and inconsistency in, decisions regarding seismic surveys.
- There appears to be scope to enhance State and Territory environmental approval processes, particularly with regard to coordination and referral arrangements, approval timelines and agency resourcing.
- Other sources of potential unnecessary regulatory burden include:
  - overlap between Commonwealth, and State and Territory Indigenous heritage legislation
  - the potential for inconsistent interpretation and decision making for offshore environmental approvals
  - environmental offsets used as a condition of approval for some projects can appear arbitrary, open-ended and lacking in transparency.
- There are several emerging issues, including greenhouse and energy consumption reporting, the Carbon Pollution Reduction Scheme and decommissioning of petroleum facilities.

Australian, State and Territory Governments require that petroleum businesses conduct their activities in a manner that meets a high standard of environmental protection. In general, environmental regulation seeks to reduce harm to social, economic and natural environmental values, which can arise when development activities affect the natural or built environment.

6.1 Overview of environmental regulation

In each jurisdiction, environmental regulation of petroleum activities can include petroleum-specific environmental regulation, and environmental and planning regulation that applies to all development activities. Environmental protection regulation in most jurisdictions has the objective of promoting the principles of ecologically sustainable development (ESD) (box 6.1). The principles of ESD essentially seek to balance economic, social and environmental considerations in approving proposed development activities.

Box 6.1 **Principles of ecologically sustainable development**

Most jurisdictions through their environmental protection legislation have adopted *ecologically sustainable development* (ESD) as their guiding framework for environmental regulation. The guiding principles of ESD — consistent with the 1992 COAG agreement — require the effective integration of economic, social and environmental considerations in decision-making processes. ESD principles commonly adopted in environmental protection legislation include the:

- precautionary principle
- principle of intergenerational equity
- principle of conservation of biological diversity and ecological integrity
- principle of improved valuation, pricing and incentive mechanisms.

Further details on ESD principles are provided in appendix D.

Sources: *Environmental Protection Act 1986* (WA); *Environment Protection Act 1970* (Vic); *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth); RET (2008c).

The key environmental and heritage regulatory requirements for petroleum activities are based on the following Commonwealth, State and Territory Acts and regulations:

- In Commonwealth waters, petroleum activities must comply with the Petroleum (Submerged Lands) (Management of Environment) Regulations 1999 (Cwlth) under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA) (referred to as OPGGSA Environmental Regulations in this chapter).

- National environmental and heritage regulation under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act), the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth) and the *Historic Shipwrecks Act 1976* (Cwlth).
- Petroleum-specific environmental regulatory requirements in some States and Territories.
- State and Territory environmental, conservation and planning legislation applying to activities in areas under State and Territory jurisdiction — a list of specific Acts is provided in appendix B.
- State and Territory heritage and Indigenous heritage Acts.

6.2 Key regulatory requirements and processes

Petroleum activities assessed for environmental impact can include the full range of activities that are undertaken as part of a petroleum project. As defined under the OPGGSA Environmental Regulations, these activities include:

- seismic and other surveys and drilling
- facility construction, installation, operation, modification or decommissioning
- pipeline design, construction, operation, modification or decommissioning
- petroleum storage, processing or transport.

In all areas, environmental approvals for petroleum activities are required for 'operational' approvals — such as operational consents, planning and clearing permits, and works approvals. Further, onshore activities may also require environmental approvals for some 'licence' approvals, such as for onshore pipeline licences.

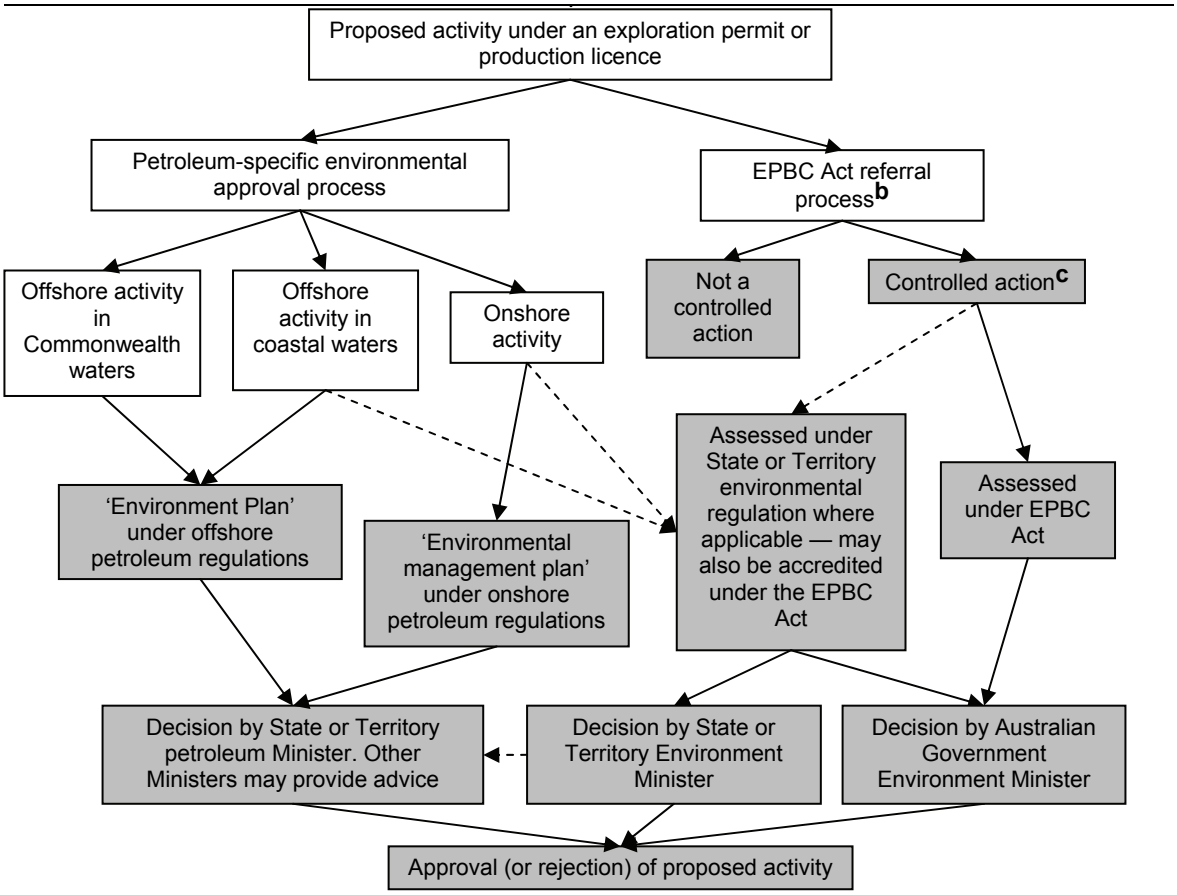
In general, petroleum projects that are likely to have a significant impact on the environment will be subject to an environmental impact assessment (EIA) in addition to petroleum-specific requirements. Depending on the nature and scope of the potential environmental impacts, EIAs will be conducted under State and Territory environmental (or planning) Acts, the EPBC Act, or in some cases both (see appendix D for further discussion of EIA processes and international comparisons).

There are several alternative or concurrent environmental and heritage approval processes that may be required for petroleum activities, including pipelines, depending on the magnitude of an activity's potential impact and its location.

Figure 6.1 provides an overview of the key Australian Government, and State and Territory Government environmental approval processes.

Figure 6.1 **Key environmental approval processes**[a]

Under petroleum and environmental regulation



[a] Shaded boxes indicate a specific regulatory requirement or decision stage and a dashed arrow indicates a decision stage that may not always be required. [b] The EPBC Act refers to the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth). [c] A controlled action is one that is likely to have a significant impact on a matter of National Environmental Significance under the EPBC Act.

The potential environment and heritage approvals for petroleum activities include:

- an approved Environment Plan for activities in Commonwealth waters under the OPGGSA Environmental Regulations — required to gain 'consents' for all offshore petroleum activities
- referral, assessment and approval requirements under the EPBC Act to undertake an activity that may potentially affect a matter of National Environmental Significance (NES). The EPBC Act applies to any upstream petroleum activity, regardless of jurisdiction
- approval of an 'environment plan' for activities in coastal waters under State and Territory offshore petroleum ('OPGGSA mirror') regulations or guidelines, or

alternatively, approval of an 'environmental management plan' for onshore activities under State or Territory onshore petroleum regulations or guidelines

- an environmental impact statement and approval under 'environment protection' legislation for those activities that are likely to have a significant environmental impact. Depending on the jurisdiction, the applicable assessment process defined under 'environmental protection' legislation can be defined by various forms of environmental related legislation (for example, environmental protection Acts, environmental assessment Acts, or planning Acts)
- relevant State and Territory or local government planning permits, planning scheme amendments and building approvals for onshore areas
- where an activity is likely to affect Indigenous heritage values or sites, an approval under State and Territory or Commonwealth Indigenous heritage legislation
- where an activity may affect non-Indigenous heritage sites or values, approval under the EPBC Act — for World, National or Commonwealth heritage sites — or under State and Territory non-Indigenous heritage legislation.

Australian Government environmental and heritage regulation

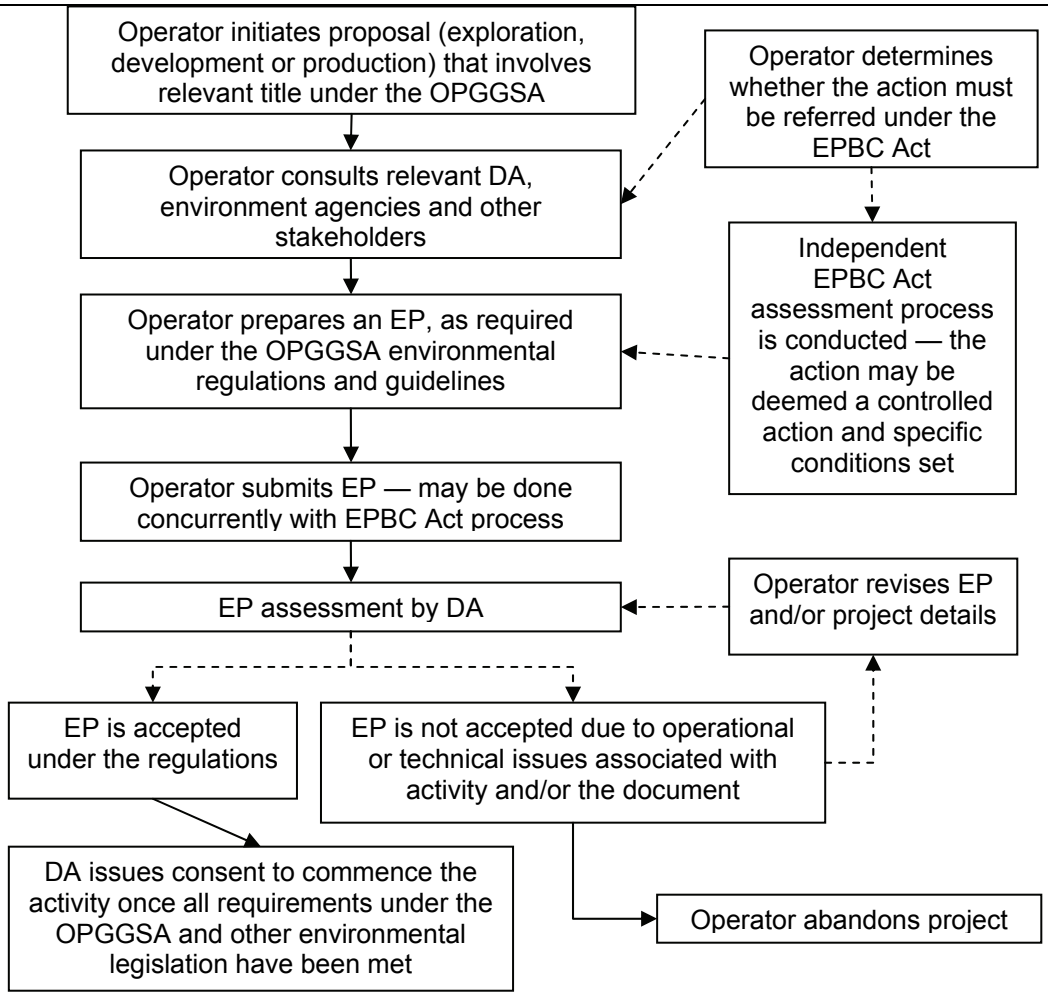
There are three main types of Australian Government environmental and heritage regulation applying to proposed petroleum activities: the requirements for Environment Plans under the OPGGSA's Environmental Regulations (for activities in Commonwealth waters), regulation under the EPBC Act and Indigenous heritage legislation, and regulation of offshore decommissioning.

Environment Plans under OPGGSA regulation

In Commonwealth waters, title holders (holders of exploration permits, production and infrastructure licences) require an approved Environment Plan under the OPGGSA Environmental Regulations before an operator carries out an activity in a permit or licence area. This approval is termed a 'consent' under the regulations. Environment Plans are submitted to the relevant Designated Authority (DA) for processing and approval (figure 6.2 provides an overview of the process).

Figure 6.2 **Overview of Environment Plan approval process**[a]

Process under the OPGGSA environmental regulations



[a] Acronyms are as follows — DA: Designated Authority; EP: Environment Plan; EPBC Act: *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth); OPGGSA: *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth).

Source: RET (2008c).

The Environment Plan may be submitted for one or more stages of the activity if the operator and the DA agree. For example, separate plans are generally submitted for seismic activities, the construction and operation stages of a production facility or pipeline, and drilling and well construction and operation. The plan must include the matters set out in the regulations. These include:

- corporate environmental policy
- applicable environmental legislation applying to the activity
- description of the activity
- description of the environment in which the activity takes place

- description and assessment of environmental risks
- environmental performance objectives and standards
- implementation strategy, including an emergency response plan and oil spill contingency plan
- reporting and compliance arrangements
- consultations with relevant stakeholders.

The DA has 28 days to accept or refuse the Environment Plan or request the operator to modify and resubmit it. An approved Environment Plan establishes the legally binding environmental management conditions that an operator of an offshore petroleum activity must meet (RET 2008c). An approved Environment Plan is required in addition to the submission of other statutory plans required for the same operating consents — specifically, the Well Operations Management Plan, Pipeline Management Plan and facility safety cases — and other relevant referrals and assessments under the EPBC Act.

The Plan must include details of consultation with relevant stakeholders, particularly those directly affected by proposed petroleum activities. For instance, some petroleum activities (such as seismic testing) can interfere with fisheries or fishing activities. The OPGGSA requires that the petroleum activities be carried out in a manner that does not interfere with fishing 'to a greater extent than is necessary for the reasonable exercise of the rights and performance of the duties' allowed under their permit or license (OPGGSA, s. 243).

While there are no specific requirements relating to fisheries, the guidelines for preparing an Environmental Plan recommend consultation with fisheries groups. The Australian Fisheries Management Authority also provides comment to the Department of Resources, Energy and Tourism (RET) on the proposed areas to be released for offshore petroleum exploration. Information is provided about the fisheries that will potentially be affected by exploration activity, and the times during the year when the effects would be greatest.

Environmental assessments under the EPBC Act

Proponents intending to undertake petroleum activities are obliged under the EPBC Act to consider whether those activities are likely to have a 'significant impact' on a matter of NES (appendix D) or on Commonwealth Heritage listed places. The EPBC Act places the onus on the proponent for ensuring an activity does not have significant impact on a matter of NES or on Commonwealth Heritage listed places — that is, it is not a 'controlled action' under the Act. If an action is a controlled

action it will not be able to proceed without the approval of the Commonwealth Environment Minister (RET 2008b).

Matters of NES include:

- World Heritage properties and National Heritage places
- wetlands of international importance
- listed threatened species and migratory species, and ecological communities
- Commonwealth marine areas
- nuclear actions (including uranium mining) (EPBC Act, chapter 2).

A proponent should 'refer' the proposed activity to the Environment Minister through the Department of Environment, Water, Heritage and the Arts (DEWHA) if they are unsure as to whether an approval is required. If a project is not referred but is considered likely to impact on matters of NES, the Environment Minister (or an 'interested person') may apply to the Federal Court for an injunction to stop a party from engaging in conduct that constitutes an offence or other contravention of the EPBC Act or regulations.

If an action referred by the proponent is classified as a 'controlled action', the action will go through the following two stages:

- Assessment of the proposed action — the proponent will be required to submit an environmental assessment in accordance with the particular assessment approach selected by the Commonwealth Environment Minister (there are five alternative forms of assessment available under the Act).
- Approval decision — the Commonwealth Environment Minister will consider the assessment and decide whether the controlled action can be approved, with or without conditions, under the EPBC Act (EPBC Act, chapter 4).

Several other environmental processes related to the EPBC Act might be relevant to proponents undertaking petroleum activities:

- Commonwealth marine reserves — there are currently 13 Marine Protected Areas in Commonwealth waters. In general, Marine Protected Areas restrict or exclude activities that extract resources at industrial scales. In addition, the South-East Commonwealth Marine Reserve Network, comprising 13 individual reserves, was established in September 2007 (DEWHA 2008b).
- Marine bioregional planning program — under this program, Marine Bioregional Plans will be developed in each of five marine regions in Commonwealth waters by 2012. The five marine regions are the South-East (predominantly offshore Victoria, Tasmania and eastern South Australia),

South-West and North-West (offshore western South Australia and offshore Western Australia respectively), North (offshore Northern Territory and western Queensland) and East (offshore eastern Queensland and New South Wales) (DEWHA 2008d).

- Strategic assessments — under the EPBC Act (Chapter 4, Part 10) the Commonwealth Environment Minister may agree to conduct a strategic assessment of potential actions under a policy, program or plan. These may include, but not be limited to, regional-scale development plans and policies, large-scale industrial development, infrastructure plans and policies (DEWHA 2008e).

Offshore decommissioning

Two Acts primarily govern decommissioning of petroleum offshore production facilities in Australia: the OPGGSA and the *Environment Protection (Sea Dumping) Act 1981* (Cwlth). Depending on the nature of the environment that the production facility is located in, decommissioning may also be subject to the EPBC Act (RET 2008b). The same is true of decommissioning of production facilities in coastal waters. State or Territory OPGGSA mirror legislation and the EPBC Act primarily govern these facilities.

Under the OPGGSA, decommissioning is subject to the OPGGSA Environmental Regulations and the Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996 (Cwlth). There is also a decommissioning guideline that describes the process for seeking approval for decommissioning production facilities based on international protocols and treaties. Under the OPGGSA regulations, production license holders are required to decommission a facility to the satisfaction of the DA.

State and Territory environmental regulation

State and Territory environmental regulation of petroleum activities includes petroleum-specific regulation applying to both offshore and onshore activities, and requirements under general State and Territory environmental and planning legislation — especially impact assessment requirements under environmental protection or planning Acts (appendix D).

Requirements for offshore petroleum activities

For petroleum activities (including pipelines) in coastal waters, the proponent is required to submit an Environment Plan (or 'Environmental Management Plan') for approval under the State and Territory Petroleum (Submerged Lands) Act. The department with responsibility for petroleum regulation in coastal waters in each jurisdiction is the same department as the DA under the OPGGSA.

In most States and Territories the scope of the Environment Plan or Environmental Management Plan for offshore activities is generally similar to the requirements under the OPGGSA for projects in Commonwealth waters. This includes Victoria Western Australia, South Australia, Tasmania and the Northern Territory. However, only Victoria, Tasmania and the Northern Territory have adopted environmental regulations that directly mirror those under the OPGGSA. The other States implement their regulatory requirements by departmental direction and guidelines. In Queensland, the Environmental Protection Agency has responsibility for granting 'environmental authorities' for offshore (and onshore) petroleum activities under the *Environmental Protection Act 1994* (Qld).

Requirements for onshore petroleum activities

A range of petroleum-specific environmental requirements exist for activities regulated under onshore petroleum Acts, subordinate regulations and departmental guidelines. In all jurisdictions, the approval of petroleum activities for 'medium or high risk' projects will generally require a detailed EIA to be conducted in accordance with environmental protection, environmental assessment, or development legislation. However, these processes vary significantly across States — reflecting differences in each jurisdiction's environmental regulation and use of memorandums of understanding (MoUs) and administrative agreements between State and Territory agencies.

Pipelines share most of the environmental approval requirements with other petroleum activities. While several States have separate onshore pipeline Acts, only Victoria has pipeline regulations that contain pipeline-specific environmental requirements. As with other petroleum activities, pipelines are also subject to the environmental legislation applying to all development activities within a State or Territory's jurisdiction.

Heritage regulation

The EPBC Act protects three types of listed values — World, National and Commonwealth List places (chapter 4). Emergency procedures, at the Minister's discretion, are also available where the heritage values of a site are 'under threat'. A referral must be made under the EPBC Act for actions that are likely to have a significant impact on heritage sites.

Further, there are two other Commonwealth heritage Acts that can affect petroleum activities:

- The *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth) allows for the responsible Minister to make an emergency declaration to preserve or protect an area from injury or desecration if satisfied that 'the area is a significant Aboriginal area' and there is a 'serious and immediate threat'.
- Under the *Historic Shipwrecks Act 1976* (Cwlth), the Heritage Minister can make a declaration to protect any historically significant wrecks or articles and relics that are more than 75 years old. The Act applies in Commonwealth waters and State and Territory waters to the low water mark. Currently 19 historic shipwrecks lie within protected or no-entry zones (DEWHA, sub. DR35, p. 3).

The Historic Shipwrecks Act is mirrored in State legislation in New South Wales, Victoria, Western Australia and South Australia (DEWHA, sub. DR35, p. 3).

Most States and Territories have both non-Indigenous and Indigenous heritage Acts. These Acts protect sites of non-Indigenous and Indigenous cultural significance, including archaeological, anthropological and historical sites. In general, it is an offence to alter a site in any way without the consent of the responsible Minister. As a result, each State and Territory Act will also contain 'emergency declaration' procedures to prevent proposed activities causing damage or interference with potential sites.

Environmental offsets

Although all jurisdictions may require proponents to undertake environmental offsets, there is no standard definition of an environmental offset across jurisdictions (appendix D). The Australian Government, for example, defines environmental offsets as actions taken outside a development site that compensate for the impacts of that development, including direct, indirect or consequential offsets (DEWHA 2007b).

In Western Australia, the Environmental Protection Authority expects proponents to put forward commitments for environmental offsets where a development is

predicted to have significant adverse residual impacts to the environment. For example, the Pluto liquefied natural gas (LNG) project on the Burrup Peninsula is subject to an offset package covering native vegetation, heritage and carbon dioxide emissions (EPA WA 2007). Environmental offsets can be imposed as conditions of regulatory approval or by legislative requirement. For example, the Pluto LNG project's offset package was negotiated between the WA Government and Woodside as part of the approval conditions, while the Gorgon project's offsets are outlined in the *Barrow Island Act 2003* (WA).

6.3 Sources of unnecessary regulatory burden

The potential for unnecessary regulatory burden arising from environmental regulation is not confined to the petroleum sector. As the Regulation Taskforce (2006) noted, there has been a proliferation of environmental and building regulations in recent years. Specifically, the Regulation Taskforce identified a number of other priority areas for reform of potential relevance to the petroleum sector:

- improving arrangements under the EPBC Act
- rationalising greenhouse gas and energy reporting
- enhancing native vegetation management
- promoting national consistency of building regulation and reducing local government variations.

In addition to the broad regulatory review of the Regulation Taskforce, a range of Australian, and State and Territory Government reviews have been completed or are currently in progress, which address environmental, planning or heritage issues of relevance to petroleum activities. Many of these reviews consider ways to streamline environmental and heritage regulation. Chapter 4 provides an overview of relevant completed and current reviews.

Further, the Commission's 2004 review of native vegetation and biodiversity regulations concluded that there was a heavy reliance on regulation that imposed substantial costs on many landholders who had native vegetation on their properties (PC 2004a). The Australian Government submitted their recommendations arising from this report at the June 2005 COAG meeting.

At its April 2007 meeting, COAG also identified environmental and assessment processes as one of the ten regulatory 'hotspots'. COAG agreed that the Commonwealth Environment Minister would develop a proposal with the States

and Territories for a more harmonised and efficient system of environmental assessment and approval as soon as possible (COAG 2007).

Although, progress has been made in some areas of environmental regulation as a result of these reviews, there are a number of outstanding issues. Industry and other stakeholders have raised a number of ongoing concerns regarding the design and administration of environment-related regulations required for the approval of petroleum activities. The Australian Petroleum Production and Exploration Association (APPEA) argued:

> 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. (sub. 16, p. 21)

In contrast, Woodside argued that while environmental approval processes may have some deficiencies, many of these can be managed, particularly by relatively larger companies, which have significant resources and experience with such processes:

> While environmental approvals are often the focus of concern by industry because of their potential for duplication, schedule risk and complexity, it is our experience that these can often be managed, albeit with an application of resource effort which would not be viable for smaller companies. (sub. 11, p. 2)

Key issues raised in this study include the operation of the EPBC Act, clarity and consistency of offshore approval processes, efficiency of State and Territory processes, duplication of Indigenous heritage requirements, and clarity and transparency of environmental offsets. These issues are discussed in the following subsections, with the Commission's findings and recommendations consolidated at the end of each subsection.

Operation of the EPBC Act

A number of initiatives designed to streamline and enhance the operation of the EPBC Act have been introduced in recent years. These include amendments to the Act in 2006 aimed at making it more efficient and effective through the use of, in part, strategic approaches to environmental issues, reducing the time and cost of processing, and stronger enforcement provisions (Parliament of Australia 2006). According to DEWHA (sub. 8), specific mechanisms to enhance the operation of the EPBC Act include:

- bilateral assessment agreements

- development of specific policy guidelines to clarify requirements under the EPBC Act
- introduction of strategic assessment processes
- development of marine bioregional plans.

On 31 October 2008 the Minister for the Environment, Water, Heritage and the Arts commissioned an independent review of the EPBC Act (chapter 4). The review will assess the operation of the EPBC Act and the extent to which its objects have been achieved. The review will be guided by key Australian Government policy objectives, including the Australian Government's deregulation agenda to reduce and simplify the regulatory burden on people, businesses and organisations, while maintaining appropriate and efficient environmental standards.

Potential issues identified in this chapter regarding the operation of the EPBC Act include efficiency of assessment processes, approval timelines, overlap with other environmental approval processes, and industry's concerns about a perceived lack of consistency of seismic approvals. The Commission's report on the primary industry sector also recently considered the efficiency of assessment processes under the EPBC Act (PC 2007a).

Assessment processes under the EPBC Act

The Regulation Taskforce (2006) noted that there appears to be considerable scope to streamline and improve the way the EPBC Act operates. A specific matter that concerned the Taskforce was the trigger for referral. Under the EPBC Act, a 'significant impact' on a matter of NES is not clearly defined in the Act itself or guidance material.

DEWHA (sub. 8) acknowledged that determining whether an action is likely to trigger the EPBC Act — because it is likely to have a significant impact on a matter of NES — requires judgment and consideration of the particular circumstances of each case. For this purpose DEWHA has developed a number of policy statements to assist proponents in understanding when an action is likely to have a significant impact on a matter of NES:

> *EPBC Act Policy Statement 1.1 Significant Impact Guidelines* provides generic guidance about what constitutes a significant impact for each matter of NES. These guidelines also include additional guidance on offshore exploration. Guidelines are also available for proponents working on or adjacent to Commonwealth land. (sub. 8, p. 7)

The House of Representatives inquiry report, *Exploring: Australia's Future*, also recommended that detailed sector-specific guidance should be developed and included in the existing guidelines on significant impact. This recommendation

endorsed the 2003 Australian National Audit Office's performance audit of the EPBC Act, which found that the current guidelines were not specific enough to particular sectors to allow proponents to make a decision on whether an action was likely to have a significant impact (HORSCIR 2003).

There are, however, specific guidelines on the conduct of seismic activities. In addition, DEWHA (sub. 8) believes there is potential to develop policy guidelines and statements for other offshore activities, such as laying pipelines and moving vessels.

Some in the sector have argued that there is also lack of information on environmental issues associated with new acreage releases to allow proponents to assess the likelihood of receiving Australian Government environmental approvals. Nexus stated:

> The government currently releases acreage in the annual gazettal process that has had very little scrutiny or checking from the Government's own environmental departments. Consequently, there is a reasonably high risk that a company could take on acreage and spend a considerable amount on exploration only to find that they can never obtain environmental approval to develop the field. (sub. 3, p. 5)

However, to provide information on potential triggers for referral, DEWHA provides advice to RET for incorporation into the annual release of acreage for petroleum exploration and development. According to DEWHA:

> This advice is included in the acreage information and highlights environmental sensitivities, if any, associated with specific acreage areas and informs the industry that activities in those areas may be subject to further assessment. Petroleum companies can factor environmental issues into their decision-making (whether to bid for acreage) and planning. (sub. 8, p. 2)

DEWHA further observed that information is available on its website on projects referred under the EPBC Act:

> All projects referred under the EPBC Act are publicly accessible by our website and all assessment documentation is publicly available. The Department's website also houses tools that allow anyone to search any area for the presence of matters of NES. In our experience, most proponents utilise these tools effectively in preparing their referral and assessment documentation. (sub. DR35, p. 4)

DEWHA identified strategic assessments as one way of streamlining environmental approvals. Under the EPBC Act a strategic assessment of a policy, plan or program allows the Environment Minister to 'pre-approve' classes of actions taken in accordance with these. These assessments are intended to provide greater certainty and efficiency where a number of people are planning to take similar actions within one region.

DEWHA suggested:

> Strategic assessments also encourage people to consider and address matters of NES early in the planning process and therefore avoid the need for project approvals late in the process. (sub. 8, p. 5)

In February 2008, the Australian and WA Governments signed an agreement to undertake a strategic assessment process to assist in the selection and management of a suitable site for a common-user LNG processing hub to service the Browse Basin gas reserves (box 6.2).

Box 6.2 **Strategic assessment of the Browse Basin**

The Northern Development Taskforce has worked with the Department of Environment, Water, Heritage and the Arts and the WA Department of Industry and Resources to coordinate the issues relating to the development of Browse Basin gas in the Kimberley, and the National Heritage Listing of the Burrup Peninsula. On 6 February 2008, the Commonwealth and the WA Government signed the Strategic Assessment Agreement, recognising the environmental and heritage values of the Kimberley, as well as the significant economic potential of the development of Browse Basin gas reserves. The agreement commits both Governments to undertake an assessment in two parts:

- A strategic assessment under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) for the potential hub site identified in the Plan for a Common User Liquefied Natural Gas Hub Precinct (the LNG Hub Plan) and its associated activities. To ensure the best sustainable and timely outcome, assessment of the Hub Plan aims to produce a set of reports that meet the requirements of both the EPBC Act and *Environmental Protection Act 1986* (WA).
- A strategic assessment of the broader regional land use issues and potential national heritage values in the West Kimberley.

The assessment will also consider issues such as social and community effects.

The LNG Hub Plan provides for the co-location facility with other operators on the Kimberley coastline based on a common-user LNG hub. The Browse Joint Venture are seeking a collocated hub at a site identified as acceptable to all key stakeholders. Should this option not eventuate then the joint venture would seek a stand-alone site. The Kimberley LNG hub would allow cost savings through the sharing of common pipeline corridors and LNG processing infrastructure.

Source: DSD (2008a).

DEWHA argued that the use of a strategic assessment in this case provides a more efficient approach to assessing environmental and heritage values:

> This process proactively addresses what would otherwise be the negative cumulative impacts and economic inefficiencies associated with piecemeal LNG-related

> developments and provide greater certainty to industry, government, and the community and secure long-term protection of the heritage and environmental values of the West Kimberley region. For this reason, the petroleum and LNG industry with an interest in the Browse Basin reserves are supportive of the approach. (sub. 8, p. 6)

The Commission understands that some participants consider that not all jurisdictions are sufficiently proactive in ensuring suitable land is available for major infrastructure projects. For example, in comparing Western Australia and the Northern Territory, Apache stated:

> It is evident that … [Western Australia] has not planned adequately for major resource projects and that it has not set aside industrial land for critical infrastructure projects such as Devil Creek. Land that has been set aside for industrial development … carry development risks that considered and appropriate strategic planning might have avoided … Suitable alternative development areas invariably require all of the heavy lifting on [native title] and Aboriginal heritage matters to be done by the project proponents … with the State only participating once the [native title] and heritage issues have been resolved … [Western Australia] could reduce the regulatory and administrative burden on project proponents markedly by better strategic planning, by taking on issues of sovereign risk … and by taking a more proactive approach to infrastructure projects. It has been pointed out that the Northern Territory has a more proactive approach in respect of securing land for industrial purposes. (sub. 14, pp. 4–5)

In July 2008, a meeting of the COAG Business Regulation and Competition Working Group agreed to identify further opportunities for strategic assessments under the EPBC Act to avoid unnecessary delays in development approval processes (sub. 8, p. 5).

In its draft report, the Commission recommended that State and Territory Governments should undertake strategic assessment processes early, in particularly sensitive areas to identify suitable land to develop major resource projects. APPEA supported this view:

> Industry has expressed its frustration at a perception that sensitive environments are very frequently identified following exploration and the identification of energy resources, and particularly once proposals for developing these resources in a region are put to governments.
>
> An alternative to identifying suitable land for development, as per the Commission's recommendation, would be the identification of any additional areas to be incorporated into the already extensive protected area network. These areas would then be off limits to incompatible developments and send a signal to project proponents that a much stronger case for compatibility of any proposed development would need to be mounted in these identified areas.

> Finally, the industry is of the very strong view that any State based strategic assessment must be recognised and operate in parallel with Commonwealth strategic assessment processes, and vice versa. (sub. DR29, p. 8)

The use of strategic assessments under the EPBC Act has potentially caused delays and uncertainties for some in the sector, and led some businesses to consider a range of costly alternatives for development sites and technological solutions to overcome regulatory uncertainties. For example, APPEA stated that the strategic assessment process being undertaken in the Kimberley is one example of a process leading to unnecessary regulatory costs for some operators:

> The WA Northern Development Taskforce and the Commonwealth Strategic Environmental Assessment of the Kimberley commenced after companies had, in good faith, already undertaken detailed site selection, agreed guidelines and scoping for the environment assessment and had spent significant amounts of time and millions of dollars on studies. (sub. 16, p. 22)

In addition, APPEA also indicated that the strategic assessment process has been perceived as creating a level of industry uncertainty:

> 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. (sub. 16, p. 22)

Although strategic assessments potentially offer a valuable mechanism to streamline approvals for activities in particular regions, it is paramount that such assessments are conducted early and in a timely manner to avoid unnecessary uncertainty. To improve the environmental information that DEWHA provides for new acreage release areas, proponents should have access to previous assessment information and information on specific 'high risk' locations, where approval of activities is unlikely to be obtained, or likely to have onerous approval conditions associated with it. It is also important when DEWHA provide environmental information about offshore exploration locations, that where possible it also provides environmental information about potential onshore locations that might be relevant to a future processing location for an offshore resource discovery.

In its draft report, the Commission recommended that where strategic assessments are proposed, these should be conducted early and according to clear time frames and they should not prevent proponents from pursuing approvals for existing projects. APPEA supported this recommendation (sub. DR29). DEWHA noted:

> The EPBC Act strategic assessments have the capacity to provide a significant degree of certainty to industry and other stakeholders and can result in substantial economic and efficiency dividends by streamlining environmental assessment processes and removing the need for proponents to undertake lengthy and expensive individual assessment processes.

> For example, under the Browse Basin strategic assessment agreement, the Western Australia and Australian governments have agreed to conduct a strategic environmental assessment of a plan for a common-user liquefied natural gas (LNG) precinct that will satisfy the requirements of both the EPBC Act and WA *Environmental Protection Act 1986*. …
>
> Under the EPBC Act, the strategic assessment provisions do not affect the Australian Government Environment Minister's ability to make approval decisions for individual projects and proposals referred during the strategic assessment process. Individual projects referred under the EPBC Act are assessed on their own merits. (sub. DR35, p. 4)

Another matter of NES relevant to those undertaking offshore petroleum activities is the Commonwealth marine environment. DEWHA (sub. 8) has cited the current marine bioregional planning program as another mechanism designed to streamline assessment and approval processes under the EPBC Act. DEWHA argued that these plans are intended to provide, among other things, strategic guidance for industry operations by:

> … assisting proponents and decision makers to determine whether or not proposals are likely to trigger the EPBC Act in terms of potential impacts on the Commonwealth marine environment … [and] provision of a regional context for national guidelines to help proponents consider whether their proposed action might result in a significant impact on matters of national environmental significance or conditions under which an activity might be conducted without necessitating a referral. (sub. 8, p. 6)

Clarifying what activities are likely to result in a significant impact on a matter of NES can be inherently difficult. Each project has its own specific characteristics that need to be taken into account, and ultimately this requires judgment of projects on a case-by-case basis. However, guidelines can assist in managing expectations by providing proponents with specific criteria that can be used to make an initial 'self-assessment' of proposed activities. It appears that there remains further scope to extend and enhance current guidelines, while also ensuring that such guidelines are not overly prescriptive in their approach.

Approval timelines

The statutory timeframes in the EPBC Act are relatively short. A decision on whether a referred action requires further assessment must by made within 20 business days of the referral being made. Depending on the type of assessment, the approval decision must be made within 20 or 40 business days of receipt of the final assessment report. According to DEWHA, approximately 90 per cent of these decisions were made within these timeframes for the 2007-08 financial year (sub. 8).

DEWHA argued that the time taken for environmental assessments varies and depends on the specific characteristics of the project and the need to gather information on environmental risks:

> The time taken for environmental assessments is generally commensurate to the complexity of the issues, the need to gather information on the environment and potential impacts and to develop the measures needed to protect the environment. Much of the time for environmental assessments is devoted to gathering this information. Much of this information gathering is the responsibility of the proponent and therefore any associated delays are outside the control of DEWHA. (sub. 8, p. 2)

In most cases the statutory time lines for decision making under the EPBC Act are met. In addition, most petroleum activities are not classified as controlled actions and so only require a referral decision rather than an approval by the Environment Minister. However, the main source of delays would appear to be when proponents are preparing referral information and — for those projects requiring assessment of a controlled action — assessment documentation. This part of the process under the EPBC Act is not subject to statutory timelines, as such, and DEWHA is able to make requests to proponents for further information without any time restriction.

Overlap between the EPBC Act, and State and Territory assessments

As discussed above, under the EPBC Act, a petroleum activity may require assessment and approval as a controlled action. In addition, all petroleum activities are potentially subject to State and Territory offshore and onshore petroleum-specific environmental requirements, and general requirements under environmental protection or development legislation.

Industry participants and some governments highlighted the potential for inefficiency and duplication in environmental assessments to arise from this regime. For example, the Victorian Government considered:

> … there is significant scope to improve the operational efficiency of the Environment Protection and Biodiversity Conservation Act and its interaction with State environment and planning approvals. (sub. 7, p. 6)

As previously discussed, the EPBC Act provides the ability to reduce duplication in environmental assessments and approvals via bilateral agreements between the Australian Government, and State or Territory Governments. Under these agreements, the Australian Government can effectively delegate assessment and approval powers to State and Territory Governments so that business has to undertake only one assessment and approval process, even where projects are likely to trigger the need for approvals under the EPBC Act.

The Regulation Taskforce (2006) recommended that the Australian Government seek to expedite the signing of bilateral 'assessment agreements' with all remaining States and Territories and that all bilateral agreements be extended to include the approval process. Since the Regulation Taskforce report, assessment bilateral agreements have been signed between DEWHA and the NSW, Queensland, WA, SA, Tasmanian and NT Governments. A draft Victorian assessment bilateral agreement has also been finalised.

The Commission's Review of Regulatory Burdens on the Primary Sector also recommended that DEWHA should, in consultation with the State and Territory Governments and other stakeholders:

> … identify specific aspects of the EPBC Act and State and Territory processes that are amenable to a bilateral agreement for approvals and set a timeframe for agreement. (PC 2007a, p. 202)

The Australian Government accepted this recommendation and noted COAG has agreed that the Commonwealth and State and Territory governments will work expeditiously and constructively to develop bilateral agreements where efficiencies can be achieved in meeting the requirements of the EPBC Act (Australian Government 2008b). DEWHA has worked with Western Australia to develop an approval bilateral agreement for the National Heritage-listed Dampier Archipelago and surrounding areas. However, DEWHA argued that in general the standards for approval bilateral agreements would need to be high:

> Given that approvals bilateral agreements effectively delegate all aspects of the approvals process under the EPBC Act to States and Territories for actions likely to have a significant impact on matters of national environmental significance, the standards to be met are necessarily rigorous. (sub. 8, p. 5)

While the scope to use approval bilateral agreements may be limited — especially given that the intent of the EPBC Act was to provide a final 'check and balance' on activities that may affect matters of NES — there would appear to be value in progressing such agreements for regions with well defined or limited environmental risks.

Overlap between EPBC Act and OPGGSA requirements

An issue of specific concern is the overlap in responsibilities between the environmental assessment requirements under the EPBC Act and those required under the Australian Government's OPGGSA Environmental Regulations. This overlap in responsibilities can result in duplication of regulatory requirements.

If a proponent is intending to undertake petroleum activity in Commonwealth waters, they are required to obtain approval of an Environment Plan prepared and submitted under the OPGGSA Environmental Regulations. In addition, there is an onus on proponents to ensure that their petroleum activities are not in breach of the provisions of the EPBC Act. If an activity is likely to affect a matter of NES, proponents can 'refer' the activity to DEWHA for a decision as to whether it is a controlled action under the EPBC Act.

Some study participants have argued that this is an unnecessary burden for two reasons. First, very few referrals to DEWHA in relation to offshore drilling or seismic survey activities have required further assessment or approval by the Minister as 'controlled actions' under the EPBC Act. For example, in relation to seismic surveys, APPEA indicated:

> 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. (sub. 16, p. 23)

Further, in relation to offshore drilling activities, APPEA stated:

> 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 [EPBC] Act, has received a 'not controlled' determination. (sub. 16, p. 23)

APPEA suggested that in relation to the EPBC Act, there should be improved clarity on the trigger for referral, and stated that its support for retaining the current arrangements associated with the EPBC Act is contingent on:

> … on a clearer expression of matters of national environmental significance, significant impacts on these matters, and the activities that are likely to cause significant impacts on these matters of national environmental significance.
>
> With the broadness of the Commonwealth Marine Environment Trigger, each and every activity by the industry in offshore waters potentially triggers the Act. The experience however is that of the several hundred referrals relating to oil and gas operations, only approximately a dozen have actually been deemed to be controlled actions under the Act. (sub. DR29, p. 9)

It would appear that many proponents refer activities for a determination under the EPBC Act — even if these activities are unlikely to be controlled actions — to minimise the risk that they are subsequently found to have breached the Act. However, as most referrals do not require additional assessment this may support the case for using Environment Plans as referral documents for EPBC Act purposes, rather than requiring proponents to submit additional documentation.

Second, industry participants agreed that an approved Environment Plan prepared under OPGGSA regulations for seismic survey or drilling activity in offshore areas should be sufficient for the DA to assess potential environmental impacts — both because of the level of detail required for these plans and the technical expertise of DA officials. For this reason, they considered it an unnecessary requirement that DEWHA requires additional referral information for the same activities for potential assessment under the EPBC Act. Specifically, APPEA noted that when a referral application is made to DEWHA:

> The industry is also required to prepare extensive and detailed Environment Plans under the [OPGGSA's] Management of Environment Regulations, for assessment by a team of dedicated, experienced and highly specialised regulators. (sub. 16, p. 23)

The WA Department of Industry and Resources, now the Department of Mines and Petroleum (DMP), also identified the potential for duplication in requirements under the EPBC Act and the Environment Plan under the OPGGSA:

> Once a proposal is referred, DEWHA, as part of its assessment, sets conditions which require the operator to submit detailed Environment Plans for ministerial approval prior to construction and operations. The conditions also require an Oil Spill Contingency Plan to be approved by the Commonwealth Minister. These conditions (referred to in the issues paper as 'quasi-regulation') are a direct duplication of the requirements under the petroleum environment regulations. (sub. 18, p. 5)

In addition, Woodside raised concerns with the duplication of information requests, sometimes in situations where there is no formal requirement under OPGGSA regulations. For example, it claimed that DEWHA sometimes requested information not formally required under the EPBC Act:

> We have received a number of requests from DEWHA in recent times for copies of reports submitted to the Western Australian Department of Industry and Resources in their role as Designated Authority. Under that system we 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. (sub. 11, p. 2)

The EPBC Act contains specific provisions that allow for the accreditation of environmental assessment processes required under other legislation. However, currently there is no bilateral assessment agreement under the EPBC Act between State and Territory DAs (the approval authority under the OPGGSA Environmental Regulations) and DEWHA. Amendments to the EPBC Act, which came into effect in February 2007, allow the Environment Minister to take into account the decisions made by other Commonwealth Ministers (PC 2007a). As a result there may also be potential for an 'approval' agreement between the Environment Minister and the DA (exercising the delegated powers of the Commonwealth Resources Minister under the OPGGSA).

APPEA argued:

> … 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. (sub. 16, p. 23)

In addition, to avoid duplication of environmental submissions under both the OPGGSA and EPBC Act, the WA Department of Industry and Resources endorsed an approach based on bilateral agreements:

> This situation could be addressed through a bilateral agreement between DEWHA and the individual designated authorities around Australia. (sub. 18, p. 6)

Further, currently if an activity is deemed to be a 'controlled action' and so requires formal assessment under the EPBC Act this does not eliminate the need for a proponent to submit an Environmental Plan under the OPGGSA regulations. However, RET have argued that this is unavoidable for two reasons:

> … there is not necessarily a neat link between the requirements in an environmental plan and the requirements in an [Environmental Impact Statement] or [Public Environment Report] nor in the timing between when an environment plan is due and when an activity needs to be considered under the EPBC Act. (DITR 2007b, p. 22)

The Commission concluded in its draft report that there would appear to be scope to streamline environmental approval arrangements under the OPGGSA and EPBC Act. Specifically, there appears to be significant duplication of information requirements and decision making for most petroleum proposals that are referred to DEWHA for a decision under the EPBC Act. The possible delegation of approval authority to the DA for some specific (relatively routine) offshore activities might further streamline approvals. In addition, the DA could act as a one-stop-shop for such referral decisions, with a single Environment Plan submitted to meet the regulatory requirements under both the OPGGSA and the EPBC Act.

The NT Government noted that there are already some bilateral arrangements between the NT Government and the Australian Government.

> The Commonwealth and Northern Territory Governments have arrangements in place to organise 'joint' assessments for projects which traverse Commonwealth and Territory waters. … For onshore projects, the Environmental Protection Biodiversity Conservation bilateral agreement between the Commonwealth and the Territory applies, which means that business and the public deal with a single impact assessment process. (sub. DR32, p. 5)

In its submission in response to the draft report, Nexus strongly supported reducing the duplication between the EPBC and the OPGGSA. It also noted:

> The industry is also required to prepare extensive and detailed Environment Plans under the OPGGSA Management of Environment Regulations … Recognition under the EPBC Act of the approval of these plans, as well as ongoing monitoring and reporting requirements by the Delegated Authority under the OPGGSA will reduce regulatory duplication. (sub, DR25, p. 3)

Seismic survey permit approvals

The EPBC Act places the onus on operators to refer a proposed action to undertake petroleum activities where there is a likelihood of encountering or interfering with whales — in particular, seismic surveys. Some see the approval process for referral to undertake seismic surveys as a potential source of unnecessary regulatory burden, particularly as it relates to claims by industry participants of inconsistency in decision making, which can generate uncertainty and additional compliance costs. APPEA considered:

> 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. (sub. 16, p. 38)

Consistent with best practice regulation, DEWHA has published guidance material — *EPBC Act Policy Statement 2.1 Interaction between offshore seismic exploration and whales* — for operators planning to undertake seismic exploration.

Specifically, DEWHA indicated that the policy statement:

> … was developed in consultation with industry and other stakeholders and provides guidance to people planning to undertake seismic exploration about their obligations under the EPBC Act. It also provides practical advice about best practice mitigation measures that can be used to ensure the seismic activity is not likely to cause a significant impact on a matter of NES. (sub. 8, p. 7)

In its draft report the Commission noted that there have been occasions where the regulations applying to seismic surveys have caused businesses difficulty in meeting the conditions of their permits. Specifically, APPEA noted that on two recent occasions seismic surveys have been assessed as likely to have a significant impact on a matter of NES, and therefore, were controlled actions requiring formal assessment under the EPBC Act.

APPEA regarded this decision as being inconsistent when compared with other similar surveys in the same region:

> 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. (sub. 16, p. 38)

In response to the draft report, DEWHA stated it:

> …disagrees that decision-making on seismic surveys has been inconsistent and asserts that the seismic guidelines provide good guidance to proponents on actions that are likely to require further assessment … most seismic operations are conducted in accordance with the guidelines and do not encounter approval delays. (sub. DR35, p. 3)

In practice, very few applications for permits to undertake offshore seismic activity would appear to have required further assessment under the EPBC Act. DEWHA (sub. 8) indicated that of the 124 offshore seismic surveys referred under the EPBC Act, 120 have operated in accordance with the measures detailed in the guidelines, with only four surveys planned for highly sensitive marine environments requiring any further assessment. One was re-referred for a period when whales were less likely to be present, and two were withdrawn. Detail on the approval of seismic surveys for offshore areas of south-eastern Australia is presented in box 6.3.

In the overwhelming majority of cases it appears that seismic survey applications are approved in a timely way where proponents undertake activities in a manner that is consistent with the guidelines. However, there is the potential for costly delays for proponents in situations where they schedule seismic operations in the expectation of receiving approval but find that approval is not provided.

The costs are significant on some occasions due to scheduling of seismic vessels — when demand for these vessels is high, so are their leasing costs. On occasions proponents might have difficulty balancing the potentially conflicting requirements of meeting their exploration work program commitments, gaining access to a suitable seismic vessel and satisfactory weather to undertake seismic work, against the need to avoid times when whales are present in an area.

To minimise the potential for costly delays it would appear prudent that where possible, proponents should seek approval for seismic surveys well in advance of the scheduled activity. Government officials, on the other hand, should ensure that decisions are being made in a timely and consistent manner.

Box 6.3 **Seismic surveys in south-eastern Australia**

The waters off Victoria and eastern South Australia contain critical feeding habitat for the endangered Blue Whale, and migration and calving habitat for the endangered Southern Right Whale. The area is also one of Australia's most prospective oil and gas provinces.

The *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) places the onus on petroleum companies to determine whether their exploration activities may have a significant impact on these (and other listed threatened and migratory species) and the Commonwealth marine environment. They are required to gain approval under the EPBC Act if this is likely to be the case.

Of the 15 seismic surveys planned to take place in this area between September 2007 and June 2008, and referred under the EPBC Act, over 90 per cent proceeded as planned by the individual companies. Of the 15 proposed surveys:

- 11 proceeded in accordance with the mitigation measures proposed by the proponents
- two proceeded in accordance with additional measures, agreed between the company and Department of Environment, Water, Heritage and the Arts
- one was determined to be a controlled action and required further assessment — the survey timing and location overlapped with Blue Whale feeding and Southern Right Whale calving
- one was withdrawn by the proponent.

Source: DEWHA (sub. 8).

FINDING 6.1

Many environmental and heritage issues associated with upstream petroleum projects will invariably be complex and sensitive. While effectively consolidating environmental and heritage approval processes would streamline those approval processes, there would also appear to be merit in retaining an independent decision maker of last resort, particularly in relation to matters of potential national environmental significance. This is consistent with the underlying rationale of the Commonwealth's Environment Protection and Biodiversity Conservation Act 1999 (Cwlth) and the Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cwlth).

FINDING 6.2

There has already been significant effort to improve the operation of the Environment Protection and Biodiversity Conservation Act 1999 (Cwlth) through use of bilateral assessment agreements, improved guidelines, early referral arrangements and the use of strategic assessment processes. However, some concerns about the operation of the Act remain:

- *While the Department of Environment, Water, Heritage and the Arts appears successful in meeting statutory timelines where they exist under the Act, not all elements of the approval process are subject to such timelines.*
- *In some cases limited information appears to be provided to bidders on relevant environmental risks related to new acreage for exploration and related potential production facilities.*
- *The interaction and overlap of the Act with other environmental approvals continues to cause some uncertainty and delays.*
- *Strategic assessment processes have been put forward as a mechanism to streamline some complex approvals, however, such assessments may also result in lengthy time delays and potential uncertainty while they are being completed. This emphasises the need for such approvals to be conducted early if they are to assist in reducing regulatory burdens.*
- *Recent perceived inconsistency by some industry proponents in decisions regarding seismic surveys.*

Consequently, there may be further scope, albeit limited, to further enhance the efficiency of the Act and its administration.

RECOMMENDATION 6.1

Specific measures to improve the operation of the Environment Protection and Biodiversity Conservation Act 1999 (Cwlth) include:

- ***ensuring the Department of the Environment, Water, Heritage and the Arts provides available information (such as information from previous assessments and relevant scientific studies) on significant environmental risks to the Department of Resources, Energy and Tourism to report with new acreage releases and to proponents seeking approval for a new project (such as pipelines) and in regard to potential processing facilities***
- ***developing bilateral assessment agreements between the Department of Environment, Water, Heritage and the Arts and the relevant State and Territory authorities to avoid the potential for duplication in environmental submissions and to streamline approvals for routine activities where a State or***

Territory has developed adequate local expertise and knowledge and that jurisdiction has appropriate legislation in place

- ***State and Territory Governments should, at an early stage, undertake strategic assessment processes in particularly sensitive areas to identify suitable land to allow the development of probable major resource projects. All strategic assessments should be conducted early and according to clear timeframes.***

Clarity and consistency of offshore approval processes

A potential source of regulatory inefficiency arises from environmental approval processes for offshore petroleum activities. While environmental objectives and requirements for offshore petroleum activities in Commonwealth waters are consistent — and are broadly similar to requirements in coastal waters — there is the potential for inconsistent interpretation and decision making by different DAs. The Environmental Assessors Forum (EAF) appears to have made a positive contribution towards addressing issues of inconsistency in decision making in particular. Participants considered the flexibility and responsiveness of the EAF as significant to its success. Woodside stated:

> Under strong leadership from RET the EAF has focussed on standardisation across the State jurisdictions. This has been valuable for companies that operate across multiple States. In particular we have seen a movement to a single approach in assessing environment plans for activities in the offshore environment. (sub. 11, p. 2)

However, APPEA also noted that the problem of inconsistent application of the law remains:

> 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/Australian wide policy decision. Such inconsistencies between Designated Authorities may be resolved through discussion at the EAF or the Upstream Petroleum & Geothermal Sub-Committee. (sub. 16, p. 24)

There is an important role for greater communication and coordination by regulatory officials to enhance the clarity of approval processes, but there also appears to be scope to improve the use of guidelines and flowcharts. These should provide clear outlines of the approval processes and detail on specific requirements for proponents. For instance, while APPEA regards the assistance provided by officials within a DA as being particularly important, clear guidelines would also be useful:

> 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. (sub. 16, p. 24)

In October 2008, national guidelines on preparing and submitting environment plans were released. DMP developed these guidelines in consultation with the EAF and other DAs. At the same time, the EAF announced national guidelines would be prepared for managing drilling fluids and decommissioning (DMP, sub. DR22, p. 13).

The EAF, with its cross-jurisdictional membership and objective to improve consistency of environmental processes and promote interaction across jurisdictions, would be well placed to develop consolidated and consistent environmental guidelines, including flowcharts and procedural information. Nonetheless, such a task should not compromise the flexibility of the forum. Governments should also ensure it is appropriately resourced to undertake this task.

The NT Government supported the EAF developing such guidelines, but cautioned 'as legislation differs in each State and Territory, the level of consistency that may be achieved through those guidelines may be limited' (sub. DR32, p. 5). DMP made a similar point (sub. DR22).

FINDING 6.3

The Environmental Assessors Forum is seen by stakeholders as a valuable, flexible and responsive approach to enhancing the consistency of environmental approvals for offshore areas. However, some concerns remain regarding the lack of consistency of decision making by officials within Designated Authorities, and the apparent complexity of current arrangements.

RECOMMENDATION 6.2

The Ministerial Council on Mineral and Petroleum Resources should explore ways of enhancing the effectiveness and transparency of the Environmental Assessors Forum to further improve the consistency of offshore environmental approvals and decision making, particularly in relation to differences in interpretation by individual officials, without compromising the flexibility of the forum. In particular, the Ministerial Council on Mineral and Petroleum Resources should resource the Environmental Assessors Forum to develop consolidated and consistent environmental guidelines (with flowcharts and procedural information) for petroleum activities that are cross-jurisdictional, such as offshore pipelines.

Efficiency of State and Territory processes

Within most States and Territories there has been a trend towards better defining and formalising administrative arrangements between agencies that administer different Acts requiring EIAs. The intention has been to reduce duplication of EIA processes. However, the EIA processes, particularly for large projects, can be complex and result in significant delays, particularly for projects such as pipelines.

Environmental and development approval processes

The WA Environmental Protection Authority is currently undertaking a review of their EIA process with a view to improving the efficiency of the system — eliminating unnecessary duplication and ensuring better use of agency resources. Woodside believe it is a valuable process and should benefit the industry:

> The review of environmental approvals processes by the Western Australian Environmental Protection Authority has picked up on a number of initiatives to increase certainty, reduce timelines, and simplify the approvals process. We support the work they are undertaking and believe it will be of real benefit to industry in WA. (sub. 11, p. 2)

Stakeholder forums as part of this review identified a range of inefficiencies in the WA Government environmental approval arrangements operating at the time (EPA WA 2008a). Some of the key issues raised in the review included:

- the lack of a strategic approach — this includes inefficient one-stop-shop arrangements, and a lack of regional and biodiversity mapping
- uncertain timelines — there is a need for greater certainty and timelines to build into project timetables. Scoping processes are too long and of less benefit (often lagging behind survey work in most cases), ministerial and appeals processes lack clear timelines, and greater rigour is required around 'stop the clock' processes to know when the clock has stopped and restarted
- complexity and duplication of processes — improved cross-agency cooperation is required. There are often several licences and decision-making authorities for each project (including for approval stages and compliance). MoUs are currently applied with little transparency and consultation with proponents, and there is a lack of consistency of activities requiring referral
- inadequate resourcing and expertise within environment agencies — need for user-pays to improve agency resourcing. Excessive detail is required in EIAs due to a very risk averse approach, a high turnover and lack of corporate knowledge amongst staff dealing with EIAs

- other issues — methodology and required quality of EIAs is rarely dealt with upfront. Assessments under EPBC Act bilateral agreements are resource intensive, offsets lack clarity, there is poor guidance provided on the EPA website, there is an unclear role for Office of Development Approvals Coordination (ODAC), appeals processes can be cumbersome, and there is a lack of consolidation of environmental information and data.

The WA Government's Independent Review Committee (the Keating review) undertook a significant review of the development approvals system in Western Australia in 2002 (Independent Review Committee 2002). Among other things, this review examined environmental approvals, including the *Environmental Protection Act 1986* (WA) (EP Act), integration of Commonwealth and State approvals, the linking of planning and environmental approvals, and petroleum legislation approvals. The Independent Review Committee found that the then current environmental assessment processes had a number of significant strengths:

> The EP Act has been under constant scrutiny since its inception, and has been favourably compared to other environment Acts by Wood and Bailey in 1994 and Wood in 1996. They compared the EP Act and its processes with similar processes in the USA, California, UK, Netherlands, Canada, Australia and New Zealand against 14 criteria. The EP Act was the only one to meet all the review criteria. (Independent Review Committee 2002, p. 41)

However, the review also identified several potential unnecessary regulatory burdens in relation to environmental and development approvals within the WA development approvals system (Independent Review Committee 2002). Key findings of the Keating review included:

- a local government authority may look to impose conditions that are additional to those that have emerged from the WA EP Act processes, or revisit issues covered in those processes
- earlier environmental approvals do not constrain later approvals, especially those involving local government
- approval processes in WA are notable for the lack of timelines in legislation. In addition, a feature of the timelines that do exist is that the start dates are not specific
- a lack of agency resourcing can cause significant delays and cost issues for proponents with critical time paths
- there can be fundamental inconsistencies in perspectives between agencies. Some agencies can appear to be relatively unconcerned about the need for State development.

In response to this review the WA Government introduced a range of measures to address these potential unnecessary regulatory burdens — including improved timelines, the introduction of an integrated project approvals system and the establishment of ODAC. However, the Auditor General for Western Australia, in a recent performance examination of these measures, found that many of the weaknesses identified in the Keating review have not been adequately addressed (Auditor General for Western Australia 2008). Specifically, there remains a lack of compliance with timelines, inadequate resourcing and a lack of effective coordination of processes.

The lack of specific timelines or lack of adherence to timelines also applies to a broad range of other approval processes of relevance to upstream petroleum development. Potential mechanisms to enhance the timeliness of upstream petroleum related approval processes (and compliance with existing timelines) are discussed in chapter 10.

Administrative procedures and resourcing

Referrals between petroleum agencies and environmental agencies may be an additional source of unnecessary delays. Some jurisdictions actively seek to avoid unnecessary referrals. In South Australia, the MoU between the petroleum regulatory agency and environmental agencies limits the circumstances for referral of proposals to those activities that are likely to have a 'high impact' on the environment. Further, environmental assessment requirements under the *Petroleum Act 2000* (SA) mirror those under environmental legislation.

In contrast, in other jurisdictions, such as Queensland and Western Australia, some proposals may require formal referral to an environmental agency for their consideration even if there is a low likelihood of significant environmental impact. Further, in Western Australia there are several environmental agencies that may be involved in an assessment process. The Keating review identified referral and consultation arrangements between agencies in Western Australia as a potential source of unnecessary burdens. For this reason, ODAC was introduced to improve coordination between agencies. However, the ODAC approach does not appear to have directly addressed the underlying weaknesses in referral and consultation arrangements that the Keating review identified.

In South Australia, businesses which have a sound track record of environmental compliance, are given a 'low supervision' operator status, providing more streamlined assessment and reporting requirements. The threat of losing low supervision status means that suitable incentives remain for proponents to maintain high environmental standards despite reduced regulatory requirements.

The administration and assessment of environmental management plans and impact assessments can be a highly specialised and time intensive task. A lack of specialised and experienced staff undertaking environmental approval processes has been highlighted as an area of potential inefficiency. This can result in delays in obtaining environmental approvals for petroleum activities. For example, Woodside stated:

> One underlying issue impacting on approvals processing in all environmental agencies is staff recruitment and retention. The availability of qualified and experienced decision makers significantly impacts a regulator's efficiency during peak workloads. (sub. 11, p. 2)

Appeal processes for environmental approvals can significantly extend approval process timelines. In some cases, issues that the regulator considered of minor importance at the beginning of an environmental assessment are then raised as a significant issue later in the assessment process. For example, APPEA argued that in some cases appeal processes can result in significant delays to a project:

> In Western Australia [the appeal process] 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. (sub. 16, p. 22)

A lead agency approach, such as that applied in South Australia, is one potential way of coordinating environmental assessments and streamlining referral arrangements. Such an approach potentially minimises formal referrals to other agencies except for activities with a 'high' level of environmental impact. The merits of lead agency arrangements are discussed further in chapter 10.

Conditions related to environmental research

Regulators often require proponents to undertake environmental research as a condition of Environment Plan approval, or as part of offset arrangements. Approval conditions related to research projects can cause delays for proponents and significant additional expense — in some cases without an obvious benefit to proponents or the community. For example, APPEA stated:

> 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. (sub. 16, p. 40)

It appears that under current arrangements, proponents are sometimes classifying environmental and scientific information obtained as a condition of approvals as 'commercial in confidence' or governments are not properly using information submitted as part of a broader research strategy. This information may be a valuable source of baseline information for new acreage releases, as well as being of general scientific benefit to the community. Indeed, if the petroleum information obtained is not of this type it is unclear as to whether it should be required to be gathered in the first place.

In its draft report, the Commission proposed governments actively manage and release information that proponents obtain as a condition of environmental approvals. Nexus supported this view, and observed:

> A certain amount of environmental information exchange already occurs between companies. If this can be more formalised, similar to the existing government managed geoscience data open file system, but in a simpler way without the requirement for complex data management plans, it should be encouraged. (sub. DR25, p. 3)

The NT Government also agreed, but noted the potential costs of managing such information:

> … if the intention is the development of a national repository of all States and Territory's environmental data, the development and ongoing management of a database and of the information is a considerable undertaking, which would require significant resources. (sub. DR32, p. 5)

DMP observed that implementation would depend on the willingness of proponents to release this information, and also noted that a national database of all environmental data would need substantial resources (sub. DR22, p. 14). DMP further noted that any proposal that has been formally assessed under the EPBC Act or by the WA EPA will have an impact assessment that is publicly available.

There may be issues of confidentiality in releasing information prior to proponents obtaining the approvals that the data relates to. Governments should require proponents to agree to the public release of such information but only after they have obtained the appropriate approvals.

In the Commission's view, managing and releasing environmental information should be handled in a way similar to that for geophysical data. Currently, under the OPGGSA, operators must meet reporting requirements whenever a geophysical, geological or drilling activity is conducted (chapter 5). All such information and data remains confidential until publicly released, with the period of confidentiality (prescribed in regulations) depending upon the type of data. The Commission believes that similar arrangements should occur for environmental information and

data that is obtained as a condition of environmental approvals or as part of an offset plan.

Inconsistencies between jurisdictions

There appear to be inconsistent regimes across States and Territories in relation to environmental approval processes for petroleum activities under onshore petroleum and environmental regulations. In addition to the inconsistencies in the approach taken to petroleum-specific environmental approvals, there appears to be inconsistent environmental assessment and planning regimes across jurisdictions. This includes inconsistent environmental offset arrangements, weeds management, control of contaminated sites and rehabilitation requirements (APPEA, sub. 16).

Although some States and Territories have adopted objective-based regimes for environmental approval of petroleum activities, some have a more prescriptive approach. Under petroleum regulation, Victoria and South Australia explicitly use a criterion of reducing environmental risks to 'as low as reasonably practicable' to assess these proposed plans. In contrast, Queensland uses a code of environmental compliance approach to petroleum regulation — to undertake low-risk petroleum activities (described as 'level 2' activities under the regulations) proponents must agree to conform with the detailed conditions outlined in the code of compliance. To obtain an environmental authority to undertake petroleum activities the Queensland Environmental Protection Agency assesses whether the operator has the capacity to comply with the conditions of the code.

There is also inconsistent use of mechanisms to streamline approvals, such as public MoUs, across jurisdictions. For example, in Western Australia and South Australia the resource and environmental agencies have detailed MoUs that are publicly available. In other jurisdictions, there are less transparent administrative arrangements for addressing coordination between agencies.

As discussed in chapter 4, the EAF was established to minimise inconsistencies in offshore environmental approvals. APPEA suggested that in the future the EAF should consider the range of onshore State and Territory environmental regulations:

> With a successful and pragmatic [offshore] model to follow, EAF could now consider the range of onshore environmental regulations affecting the international competitiveness of Australia's oil and gas industry. (sub. 16, p. 24)

The NT Government supported this suggestion (sub. DR32, p. 5).

The Commission endorses the EAF as a potentially valuable mechanism to streamline current environmental assessment processes across jurisdictions. However, if the EAF sought to address onshore environmental assessment

requirements it would need to actively engage with other State and Territory agencies, relevant inter-government committees and Ministerial council working groups.

FINDING 6.4

Environmental approvals under State, Territory and local government planning arrangements appear to be a significant source of delays and complexity. There are several issues of particular relevance to petroleum approvals:

- *The WA Government, in particular, has conducted a number of reviews of environmental and development approval processes, and made some efforts to streamline approvals, but these appear incomplete and there would appear to be inadequate resourcing of agencies responsible for environmental approvals of petroleum projects. To some extent this may reflect periods when there are a large number of new approval applications in the State.*
- *Not all jurisdictions have clear administrative arrangements between environmental and petroleum agencies, with publicly available administrative agreements or memorandums of understanding between agencies.*
- *There remains a lack of statutory or firm approval timelines in relation to many environmental approvals. Where there are firm timelines, there appears to be no consequence when regulators fail to comply with these timelines.*
- *There would appear to be insufficient public access to environmental data obtained either in previous assessment processes, or as a condition of previous approvals, or to information collected as part of an offset plan. It seems that although some information may be in the public domain, the management of the data, particularly between government agencies, can make it difficult to access. Access to other information is at times inhibited by companies or their consultants classifying it as 'commercial in confidence'.*

RECOMMENDATION 6.3

Governments should actively manage and release information obtained by proponents as a condition of environmental approvals to enhance the public stock of environmental information and to assist in streamlining future approvals.

- ***Governments should improve the provision of baseline environmental information for new acreage releases or for new applications for project approvals in relevant areas. Notwithstanding this, governments should only require a company to provide information collected at its expense after that company has acquired its own appropriate approvals.***
- ***Governments should manage environmental data in a way similar to the current system for geophysical data: with all environmental data relating to Commonwealth, coastal and inland waters residing with Geoscience Australia***

and all onshore data with the relevant State and Territory agencies. All such information provided by companies at the request of governments should be publicly accessible in the same way as geophysical data, after an appropriate fixed period.

RECOMMENDATION 6.4

The Ministerial Council on Mineral and Petroleum Resources should task the Environmental Assessors Forum to review the range of onshore environmental regulations to identify scope for streamlining onshore approval processes and associated regulations related to petroleum activities.

Duplication of Indigenous heritage arrangements

The overlap between Commonwealth, and State and Territory Indigenous heritage legislation is a potential source of unnecessary regulatory burden. APPEA considered the multiplicity of such legislation as being a significant source of potential delay and additional cost burdens:

> In addition to Native Title processes however, 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. (sub. 16, p. 26)

In Western Australia, for example, proponents undertaking petroleum activities that are perceived as likely to affect Indigenous heritage sites must apply for a consent to perform those activities from the Minister for Indigenous Affairs under the *Aboriginal Heritage Act 1972* (WA). Further, the Act in Western Australia can include Indigenous heritage considerations when classified as a significant environmental factor. Under the Commonwealth's *Aboriginal and Torres Strait Islander Heritage Protection Act 1984*, Aboriginal people may apply for an 'emergency declaration' of a potential heritage site. Chapter 2 of the EPBC Act also contains provisions protecting declared Indigenous heritage sites.

Specifically, APPEA raised concerns that the overlap in Indigenous heritage processes allows applicants to seek decisions under both the Commonwealth and State and Territory regimes, which can result in excessive delays and uncertainty:

> It is becoming increasingly common for applicants to use both [Commonwealth and State] Acts in an attempt to delay or deny construction activities. (sub. 16, p. 26)

Woodside (sub. 11) also raised the overlap between the Commonwealth Act and State heritage approvals, and the lack of a requirement for the Commonwealth

Minister to take State approvals into account. It indicated that this matter has previously been subject to review:

> In particular, applications under section 9 and section 10 of the [*Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cwlth)*] are frequently made by Aboriginal groups even when companies have complied with all relevant State heritage laws … This issue, and others, were explored by Elizabeth Evatt AC in her 1996 Review of the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984*, commonly referred to as the Evatt Review. (sub. 11, p. 3)

The Evatt Review found that delay and uncertainty had arisen because interaction between the Commonwealth, and State and Territory processes had not been clearly established — despite the intention that the Act be a last resort after the application of State and Territory laws (Evatt 1996). Further, the review observed:

> Since, in practice, applicants are expected to go through the State process before applying to the Commonwealth, most applicants seeking action at Commonwealth level have not been satisfied by the State or Territory process. The Commonwealth is asked to take a view different from that taken by the State or Territory government and, in effect, to override State law. The potential for both legal and political clash is obvious. State and Territory Governments have expressed concern that their decisions are subject to 'appeal' to the Commonwealth Minister. (Evatt 1996, s. 5.13)

The Commission in its report on the regulatory burdens on the primary sector (PC 2007a) also noted concerns relating to duplication and inconsistency in Aboriginal cultural heritage processes across Australia. In particular, the Commission noted that the absence of consolidated information regarding Aboriginal heritage sites listed by each jurisdiction could potentially add to the burdens on business by not providing access for information in a simple and timely manner. In response to a recommendation by the Commission, the Australian Government agreed that it would provide a single point of information about Indigenous cultural heritage places in all jurisdictions (Australian Government 2008b).

As the Evatt Review acknowledged, the Commonwealth Act was originally introduced to provide 'last resort' protection for Indigenous heritage sites in situations where State and Territory heritage legislation does not provide adequate protection. However, as this review also noted, the current overlap in Commonwealth, and State and Territory heritage Acts also leads to potential duplication and delays in approvals. The Evatt Review made a number of recommendations to address issues of overlap and duplication (box 6.4). Several of these recommendations were included in proposed amendments to the Act in 1999, although these were not subsequently passed by the Parliament.

In its draft report the Commission concluded that there was a case for requiring Indigenous heritage Acts in all jurisdictions to consider previous decisions by other jurisdictions about the same heritage site and including provisions in the Commonwealth Act that accredit State and Territory Indigenous heritage regimes that meet a certain minimum standard.

In general, study participants supported these proposals (for example, APPEA, sub. DR29). DMP observed:

> DMP supports this draft recommendation as it would streamline Indigenous heritage approval processes by reducing the duplication of functions between State and Commonwealth legislation regulating for the protection of Aboriginal sites. Furthermore, State accreditation by the Commonwealth under a national set of Indigenous heritage standards, would reduce the likelihood of appeals to Commonwealth for review of State Indigenous heritage approval processes in respect to consent for the use of land. (sub. DR22, p. 14)

Box 6.4 **Recommendations of the Evatt Review**

The Evatt Review made a number of recommendations to address the issue of overlap between Commonwealth, and State and Territory Indigenous heritage Acts.

Minimum standards for State and Territory Laws

The Australian Government should support and encourage the process of developing, in consultation with State and Territory Governments, the Aboriginal community, and other interested parties, agreed minimum standards as the basis for uniform or model laws on Aboriginal cultural heritage protection, for the States and Territories and the Commonwealth to adopt, where relevant.

Accreditation and referral

The Commonwealth should accredit, for the purposes of the Act, determinations and procedures under State and Territory laws that comply with minimum standards. It should provide, where appropriate, for the referral of matters to State and Territory agencies or bodies that meet minimum standards.

Recognition of decisions on significance

The Commonwealth should accredit or recognise, for the purposes of the Act, State and Territory Aboriginal cultural heritage bodies decisions concerning the significance of a site that meet the required standards and apply definitions comparable with the Commonwealth definition.

Source: Evatt (1996).

In contrast, DEWHA considered that it is not necessary to require Indigenous heritage agreements in all jurisdictions to consider previous decisions by other jurisdictions about the same heritage site:

> This is not needed. This proposal could apply when a State or Territory has made a decision about whether to protect a heritage site and the Australian Government also is asked to make a decision about protecting the area. While it could apply if the Australian Government has made a report before the matter was considered by the State or Territory, this would be unusual. It could not apply between States or Territories because their decisions can only apply within their separate (non-overlapping) jurisdictions.
>
> Under the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* the Australian Government Minister is required to seek the advice of the State or Territory Minister about whether the area is effectively protected under a law of the State or Territory (s. 13(2) also s. 14) before making a declaration to protect the area. The Minister cannot require the State or Territory to produce documents relating to State and Territory decisions about the area specified in the application and cannot require the State or Territory Minister to respond at all. The legislation permits the Australian Government Minister to make a declaration even he fails to elicit a response from the State or Territory Minister; otherwise the State or Territory Minister could frustrate action under the Australian Government legislation. In practice, States or Territories provide the Australian Government Minister with previous reports relevant to applications if these have not already been provided by the applicant or by another interested party. (sub. DR35, p. 5)

Nonetheless, participants have noted the duplication and delays caused by overlap between the Commonwealth and State and Territory Indigenous heritage Acts. Requiring the Australian Government, in considering Indigenous heritage protection applications, to take into account State and Territory government assessments and decisions about the same heritage site has the potential to reduce the duplication and delay.

The NT Government (sub. DR32, p. 6) and DEWHA (sub. DR35) supported the proposal to amend the Commonwealth Act to accredit State Indigenous heritage regimes that meet a national set of minimum standards. DEWHA observed it should reduce duplication of decisions and remove a source of uncertainty (sub. DR35, p. 5).

APPEA also proposed that heritage agreements be transferable in certain circumstances:

> … the industry believes that any heritage agreements should be transferable across operators when permit interests change, so long as the operations remain within the bounds of the original work program. (sub. DR29, p. 11)

The Commission sees merit in this proposal. As long as the new operator adheres to the original work program and the conditions of the original heritage approval, it appears an unnecessary regulatory burden to require another Indigenous heritage approval just because ownership changes.

FINDING 6.5

Duplication of Indigenous heritage approvals appears to be a source of delays and uncertainty. In some cases, proponents, who have obtained heritage approvals after lengthy processes under State and Territory Indigenous heritage legislation, are faced with further delays when there are applications for a heritage protection 'declaration' under the Commonwealth's Aboriginal and Torres Strait Islander Heritage Protection Act 1984.

RECOMMENDATION 6.5

The Australian Government, in considering applications for a heritage protection 'declaration' under the Aboriginal and Torres Strait Islander Heritage Protection Act 1984, should take into account previous State and Territory government assessments and decisions about the same heritage site. The Commonwealth Act should also be amended to accredit State Indigenous heritage regimes that comply with a national set of minimum standards. In addition, heritage agreements should be transferable across operators when title ownership changes, providing the new operator is willing to adhere to the original work program, and the conditions of the original heritage approval.

Clarity and transparency of environmental offsets

Some members of the sector considered the negotiation of environmental offsets between some governments and proponents as lacking clear and transparent processes. For example, APPEA indicated that some companies are of the view:

> 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. (sub. 16, p. 22)

However, some in the sector consider that the use of offsets has advantages. In particular, where they allow a more flexible regulatory approach rather than the reliance on more prescriptive regulatory solutions to environmental concerns. APPEA noted:

> … environmental offsets can provide a more flexible approach to ameliorating environmental impacts provided they are a substitute for a regulatory obligation rather than an additional condition. (sub. 16, p. 22)

One of the significant concerns with the current offset arrangements is the lack of consistency and clarity across jurisdictions. APPEA proposed that the Ministerial Council on Mineral and Petroleum Resources consider adopting a national and consistent approach across all jurisdictions on the issue of environmental offsets (sub. 16). The EAF is currently considering the issue of environmental offsets as part of its forward work program (RET, pers. comm., 18 August 2008).

In relation to offset requirements under the EPBC Act, DEWHA is developing a draft offsets policy (DEWHA 2007b). Environmental offsets should, in general, provide compensation for those impacts arising from development proposals that cannot be adequately reduced through avoidance and mitigation. DEWHA stated that the aim of the draft offsets policy statement is:

> … ensuring a consistent, transparent, equitable and effective approach to the use of offsets under the EPBC Act. The draft policy reflects the Department's current experience with offsets and the legal requirements of the EPBC Act and forms the basis for current administrative practices and procedures. (sub. 8, p. 8)

The WA policy guidelines on environmental offsets (appendix D) allows a wide range of information gathering, research and other 'contributing offsets' to be used. This would appear to be a potential source of some of the concerns about offsets, especially regarding their potentially arbitrary and open-ended nature.

DMP observed:

> … in Western Australia's jurisdiction, environmental offsets can be included in the Environmental Protection Authority's conditions of approval. The Department also understands that the Ministerial Council on Mineral and Petroleum Resources is aware of the importance in using environmental offsets and therefore, this Ministerial Council should be consulted in this regard. (sub. DR29, pp. 14–15)

It is the Commission's view that environmental offsets should be subject to more transparent and timely processes to avoid the potential for arbitrary and inconsistent requirements across different projects, and excessive delays from open-ended negotiation processes. For instance, in cases where direct ('like-with-like') offsets are not practical or sensible, an offset fund could be established where proponents make financial contributions as an offset condition. Such a fund would need to have transparent governance arrangements and would need to allocate funding to projects on a strategic rather than ad hoc basis. There may also be merit in considering the advantages of more nationally consistent offset policy principles to avoid the potential for unnecessary complexity and inconsistency that can arise from having different arrangements applying across jurisdictions.

In response to this proposal presented in the draft report, the NT Government noted it:

> … is in the process of developing approaches to offsets. There is no objection in principle to framing of national principles nor systems for identifying high priorities for offset arrangements, provided there is recognition of the limited value of strict like-for-like offsets in the Northern Territory situation. Subject to recognition of the need for some regional variation in approaches, the recommendation is supported. (sub. DR32, p. 6)

FINDING 6.6

The current process used in setting some environmental offset conditions appears arbitrary, open-ended and lacking in transparency. Offset conditions often seem to have little or no direct connection with the environmental damage they are intended to 'offset'. However, some industry participants regard offsets, despite their weaknesses, as a potentially flexible mechanism to mitigate environmental damage and overcome regulatory impediments to getting projects approved.

RECOMMENDATION 6.6

All Governments should introduce transparent policy principles for environmental offsets — especially the principle that offsets where practical should be directly related to the damage being offset. In situations where environmental damage cannot practically or sensibly be 'directly' offset, other transparent offset mechanisms should be explored — including, for example, the use of an offset 'fund', which could be devoted to the highest priority projects in the relevant jurisdiction under transparent and appropriate governance arrangements. There would be merit in introducing nationally consistent principles.

Emerging issues

Two key emerging environmental-related regulatory issues are the amendments to the OPGGSA on carbon capture and storage, and the establishment of the Australian Government's Carbon Pollution Reduction Scheme. These are likely to have a substantial future effect on the sector, consequently, these issues are a high priority for the industry. For example, a number of concerns were raised in submissions in relation to proposed carbon capture and storage policy arrangements — these include concerns about the rights of current holders of petroleum titles, third party access rules, and post-closure responsibilities and liabilities (chapter 5). Further, the Commission maintains its concern that this new area of legislation presented a real opportunity (which was missed) for regulatory burdens to be minimised by adopting mutually agreed nationally consistent legislation. Despite

attempts to achieve this it now appears that the outcome will be more of the same — disparate legislation in each State and Territory.

The Commission has previously considered a number of policy issues related to the potential introduction of a carbon pollution reduction scheme (or emissions trading scheme) (PC 2008d). Once a national emissions trading scheme is in place, other abatement policies generally change the mix, not the quantity, of emissions reduction. In many cases, retaining existing, or introducing new, policies to supplement the emissions trading scheme (such as energy efficiency initiatives) is not justified, as it imposes unnecessary costs on regulated businesses and the broader community.

In addition to legislation on carbon capture and storage, and the establishment of the Carbon Pollution Reduction Scheme, two other environment-related emerging issues were raised in submissions: the duplication of greenhouse and energy consumption reporting, and decommissioning of petroleum facilities.

Duplication between greenhouse and energy consumption reporting

The *Energy Efficiency Opportunities Act 2006* (Cwlth) (EEO Act) and the new *National Greenhouse and Energy Reporting Act 2007* (Cwlth) (NGER Act), require companies to report on energy consumption. In addition, there are State and Territory Government requirements for energy efficiency reporting. There appear to be some potential sources of duplication and unnecessary burdens under these arrangements.

Under the EEO Act, businesses in an Australian joint venture are required to obtain written nominations of the operator of a joint venture, as well as the nominated reporting entity. This is to avoid the potential requirement for each member of the joint venture to report separately on energy consumption. APPEA indicated that this has been a particularly resource-intensive exercise for some specific types of 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 [EEO] Act due to low energy consumption levels. (sub. 16, p. 37)

APPEA (sub. 16) claimed that under the new NGER Act, there has been a requirement for another round of nominations by joint venture operators. APPEA argued that although there were amendments made to the EEO Act — intended to streamline reporting requirements after the introduction of the NGER Act — it is still a potential source of unnecessary regulatory burden.

APPEA stated:

> There is still a requirement for ongoing duplicate nominations, dual registrations once the thresholds [for reporting] are reached and two sets of reporting requirements for companies to understand and comply with the requirements of each Act going forward. (sub. 16, p. 37)

However, the Minister for Resources, Energy and Tourism has recently announced amendments to the EEO Act subordinate regulations to streamline energy reporting with requirements under the NGER Act (box 6.5).

Box 6.5 National greenhouse and energy reporting system

Regulations governing the Australian Government's Energy Efficiency Opportunities (EEO) program were amended from 1 July 2008. This will enable participating companies to streamline energy use reporting with requirements under the new National Greenhouse and Energy Reporting System.

The National Greenhouse and Energy Reporting System will collect energy-use data, which will form the basis for a future emissions trading scheme. Streamlining the EEO with this system is designed to address concerns expressed by some businesses that energy-use reporting would be duplicated under the two systems.

Source: Ferguson (2008b).

In some cases, there are also State and Territory Government reporting requirements in addition to the energy efficiency reporting requirements under Commonwealth legislation. In Victoria, for example, under the Environmental Protection Authority's Energy and Resource Efficiency Plans there is apparently the potential for duplicate reporting with the requirements of the EEO Act. APPEA argued that while the Victorian process allows exemptions to avoid duplicate reporting, these are not well designed:

> 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. (sub. 16, p. 37)

ExxonMobil also highlighted duplication in reporting requirements for greenhouse and energy programs (sub. 13, quoted in chapter 8 of this report). Duplication of reporting requirements can contribute to unnecessary regulatory burdens. A recommendation that reporting requirements are clear, justified, and avoid duplication and overlap with other mandatory reporting requirements is presented in chapter 10.

Decommissioning

According to DEWHA (sub. 8), the decommissioning of petroleum facilities is a potentially significant future issue for Australia. Australia has two key petroleum provinces (Bass Strait and the North West Shelf), where many facilities will soon reach the end of their operating life.

APPEA has previously encouraged the Ministerial Council on Mineral and Petroleum Resources to develop a nationally consistent policy for decommissioning offshore facilities. RET has released a discussion paper on decommissioning regulation under the OPGGSA (chapter 4). APPEA (sub. 16) broadly supported the development of a consistent policy as proposed in the RET discussion paper. However, it raised two outstanding issues:

- Clarification of ongoing monitoring requirements.
- Recognition that there is minimal value in the early provision of detailed decommissioning plans at the commissioning and approval phase of a project.

Participants consider progressing the proposals of the RET discussion paper a priority to clarify future decommissioning arrangements.

Woodside stated:

> The discussion paper on decommissioning was a significant work, but within Woodside it is generally felt that the focus was heavily toward the environmental issues to the exclusion of technical and commercial requirements. In any event the process has been slow in moving forward with little progress being made toward an agreed guideline. (sub. 11, p. 2)

There is also potential duplication of requirements under the EPBC Act and the *Environment Protection (Sea Dumping) Act 1981* (Cwlth). However, DEWHA noted:

> The assessment of decommissioning activities to date has been coordinated so only one assessment is undertaken for both the EPBC Act and the *Environment Protection (Sea Dumping) Act 1981*. (sub. 8, p. 8)

Decommissioning is likely to be a growing area of regulatory activity, as facilities in a number of fields reach the end of their operating life. For this reason, governments should implement nationally consistent requirements — which also avoid any potential overlaps with other related processes — as a priority.

7 Occupational health and safety

Key points

- Regulatory arrangements for occupational health and safety (OHS) vary for onshore and offshore operations. Regulation of most offshore activities has been harmonised with the creation of the National Offshore Petroleum Safety Authority (NOPSA), while onshore operations are regulated under the OHS regimes applying in each State and Territory.
- The formation of NOPSA has led to improvements in the efficiency and effectiveness of OHS offshore petroleum regulation.
- To reduce regulatory duplication and uncertainty, the legislated coverage of NOPSA should be extended to include the safety and integrity of pipelines, subsea equipment and wells. If NOPSA were given these additional responsibilities, the authority would need to be adequately resourced to carry them out.
- To minimise potentially complex interface issues facing some projects, subject to the outcomes of the current Australian and WA Governments joint inquiry into the 2008 Varanus Island explosion, States and Territories should consider conferring powers on NOPSA to regulate OHS matters for all State and Territory waters seaward of the low tide mark, including islands within those waters.
- Cost recovery arrangements for NOPSA appear broadly consistent with regulatory best practice, and are likely to have assisted with staff retention.
- In view of the difficulties involved (including the potential creation of new regulatory overlaps and the possible loss of synergies for State and Territory based regulators), on balance the Commission does not see a case for extending NOPSA's responsibilities to include onshore integrated production facilities.

Regulatory arrangements for occupational health and safety (OHS) are quite different for offshore and onshore petroleum operations. The OHS regulation of offshore operations has been harmonised with the creation of a national offshore petroleum regulator. Onshore operations continue to be regulated under the OHS regimes applying in each State and Territory.

7.1 Offshore OHS regulation

Current offshore regulatory arrangements for petroleum safety reflect the recommendations of a review completed in 2000 by an international team of offshore safety experts. The review found that the regulatory arrangements prevailing at the time were complicated and insufficient to ensure effective regulation of offshore petroleum activity. In particular, the report found too many Acts, directions and regulations were in place, with problems stemming from legislative overlaps. State and Territory regulators were described as lacking skills, capacity and consistency when administering OHS regulations (DISR 2001).

The review recommended establishing a national petroleum regulatory body to oversee regulation in most Commonwealth waters. Subsequently, and in consultation with the State and Northern Territory Governments and various stakeholders, the Australian Government established the National Offshore Petroleum Safety Authority (NOPSA) on 1 January 2005 to regulate OHS in offshore areas.

NOPSA has regulatory responsibilities for offshore petroleum activities in both Commonwealth and coastal waters (box 7.1). It reports to the Australian Government, all State and Northern Territory Ministers with responsibility for the offshore petroleum sector, and to the Ministerial Council on Mineral and Petroleum Resources.

The major piece of OHS legislation for the offshore petroleum sector is the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA) — which is administered and enforced by NOPSA — in conjunction with the following Commonwealth regulations:

- Petroleum (Submerged Lands) (Occupational Health and Safety) Regulations 1993
- Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996
- Petroleum (Submerged Lands) (Pipelines) Regulations 2001
- Petroleum (Submerged Lands) (Diving Safety) Regulations 2002

These regulations will be superseded by one set of safety regulations, as part of the proposed consolidation of the OPGGSA.

Box 7.1 **Regulatory responsibilities of the National Offshore Petroleum Safety Authority**

Under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth), the National Offshore Petroleum Safety Authority (NOPSA) has occupational health and safety (OHS) regulatory responsibilities for offshore petroleum activities in Commonwealth waters and designated coastal waters where State and Territory legislation has conferred such powers. Designated coastal waters incorporate coastal waters as defined throughout the rest of this report, and any other areas that were the subject of an exploration permit under the repealed *Petroleum (Submerged Lands) Act 1967* (Cwlth) immediately before the commencement of the equivalent State or Territory Petroleum (Submerged Lands) Act (where either an exploration permit, retention lease, production lease or an application for a retention lease or production licence is still current).

States and Territories can also provide NOPSA with additional powers to regulate OHS in State and Territory internal waters, and for onshore facilities, by passing appropriate laws and agreeing on funding arrangements.

Source: *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth).

In addition to the Commonwealth legislation and regulations, there is, or — for some jurisdictions — it has been agreed there will be, OPGGSA mirror legislation or regulations in each State and the Northern Territory dealing with coastal waters (NOPSA 2008b).

Key regulatory processes and requirements

Regulation of offshore petroleum activities changed significantly following the 1988 Piper Alpha disaster in the United Kingdom sector of the North Sea. The Piper Alpha disaster claimed 167 lives, and led worldwide to a fundamental reassessment of how best to regulate the offshore petroleum sector.

Safety case regulation

The UK Committee of Inquiry into the Piper Alpha disaster recommended moving from prescriptive regulation to an objective-based 'safety case' regime. Following a 1991 Australian Government report, it was determined that Australia should embrace this trend. The *Petroleum (Submerged Lands) Act 1967* (Cwlth) was amended in 1992 to require safety cases to be developed for all offshore petroleum facilities. By 1996 the safety case regime was fully implemented with the completion of safety case regulations.

The 'safety case' regime entrenches the notion that ongoing management of safety at offshore facilities is the responsibility of operators and not governments or regulators (DISR 2001). The safety case presented must assure the regulator that operators are aware of potential safety problems, know how to manage them and how to deal with an emergency. Once a safety case is accepted, it forms the benchmark for compliance (box 7.2).

Box 7.2 **What is involved in a safety case?**

Occupational health and safety (OHS) laws contained within the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) require the operator of each facility to submit a safety case to the National Offshore Petroleum Safety Authority. The safety case must set out the facility operator's commitments to reducing risks to a level that is as low as reasonably practicable. It documents the arrangements for OHS that are to be observed by managers, supervisors and the workforce. The safety case must include a detailed description of the safety management system for a facility. The safety management system must provide for all activities occurring at the facility.

Once a safety case for a facility is accepted, the operator must comply with the commitments made in the safety case for reducing risk at the facility. All work on a facility must comply with the safety case and all people on a facility must comply with the safety requirements that apply to them.

Source: NOPSA (2008c).

While there is widespread agreement that the formation of NOPSA has simplified offshore petroleum regulation, a number of issues have been raised. Many of these were canvassed in a 2008 review of NOPSA's operational activities, the recommendations from which are now being considered by government (box 7.3).

The Australian and WA Governments announced at the beginning of 2009 a joint inquiry into the 2008 Varanus Island explosion. This inquiry is to also examine the effectiveness of NOPSA and offshore petroleum safety regulation more generally. The inquiry is being conducted by Kym Bills, the Executive Director of the Australian Transport Safety Bureau, and Dave Agostini, a former Woodside Petroleum executive (Ferguson 2009; Moore 2009).

Performance of NOPSA

Feedback provided to the Commission on the performance of NOPSA has typically been consistent with the major finding of the 2008 review of NOPSA's operations:

> 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. (RET 2008i, p. 1)

Box 7.3 **Independent review of National Offshore Petroleum Safety Authority operations 2008**

In line with legislative requirements for three-yearly reviews, in early 2008 a team of three independent safety experts conducted an independent evaluation of the operational effectiveness of the National Offshore Petroleum Safety Authority (NOPSA). The team comprised:

- Mr Magne Ognedal, Director General, Norwegian Petroleum Safety Authority
- Dr Derek Griffiths, Australian major hazards consultant
- Mr Bruce Lake, Managing Director of Vermilion Oil and Gas Australia.

The review team assessed whether NOPSA was delivering on its objectives and made recommendations to improve the overall operation of NOPSA, and the safety performance of the Australian offshore petroleum sector.

Overall, the panel found that NOPSA had made good progress, with the potential to improve in some areas. Specific recommendations of the review panel included:

- the need for NOPSA to develop guidelines in consultation with stakeholders to provide clarity and consistency to the process, which ultimately will result in better safety outcomes
- clarification that, particularly where it is unclear whether title holders or drilling contractors should be made responsible for demonstrating to NOPSA that drilling operations can be conducted safely, the party making all major decisions related to petroleum activities should bear this responsibility
- extension of NOPSA's legislative responsibility to cover the complete hydrocarbons production system from wells through to a custody transfer point or a reasonable physical/technical system boundary
- linking the initial acceptance of a new facility safety case to the inspection of a facility upon commencement of operations.

Source: RET (2008i).

The Australian Petroleum Production and Exploration Association (APPEA) noted:

> 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. (sub. 16, p. 17)

ExxonMobil expressed similar views:

> We believe that since the inception of the National Offshore Petroleum Safety Authority (NOPSA) in 2005 that the offshore OHS regulatory regime has continued to

> evolve with greater efficiencies and effectiveness. We have reviewed the recent independent report concerning NOPSA and generally support its findings and recommendations. We support the NOPSA concept in which a single regulator provides national coverage and the onus is placed on each enterprise to develop and implement processes that meet regulatory requirements. (sub. 13, p. 5)

APPEA has since stated to the joint Australian and Western Australian inquiry into offshore safety regulation:

> The regulatory approach and legislation for petroleum safety, both onshore and offshore in Australia, are working effectively and are consistent with world standards – resulting as they have from the findings of numerous national and international reviews over the past decade. There are inevitably, and always will be, room for improvement and many of these improvements have been well identified. (APPEA 2009, p. 4)

There has also been support for NOPSA's use of memorandums of understanding (MoUs) to minimise confusion over regulatory boundaries, and to promote cooperation with other agencies. NOPSA has entered into MoUs with 19 other agencies, including a number of Commonwealth and State and Territory departments, the Australian Maritime Safety Authority, the Civil Aviation Safety Authority and the Timor Sea Designated Authority.

APPEA suggested other agencies could learn from this approach:

> The gamut of MoUs 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. (sub. 16, p. 51)

The Commission encountered very few participants that were critical of NOPSA, although some observed that it was premature to state that the NOPSA model has yet been wholly successful.

On balance, the Commission agrees with major finding of the 2008 review of NOPSA's operations (as quoted above). The formation of NOPSA has led to improvements in the efficiency and effectiveness of offshore petroleum regulation.

Sources of unnecessary regulatory burden

A number of sources of potential unnecessary regulatory burdens were suggested to the Commission. Issues raised included the dual regulation of pipelines and wells, concern about a perceived shift towards prescriptive regulation, funding arrangements for NOPSA, regulatory resourcing issues, confusion regarding regulatory responsibilities in waters off the WA coast and a number of issues relating to marine regulation.

Dual regulation of wells and pipelines

At the time of NOPSA's formation, the Commonwealth, State and Northern Territory Governments agreed that NOPSA would regulate OHS matters, while the broader regulation of wells and pipelines initially would not be transferred to the new authority. The 2008 review of NOPSA's operations found this decision contributed to the authority's ability to establish its core corporate governance arrangements successfully (RET 2008i).

However, these arrangements could potentially lead to regulatory confusion. As APPEA stated:

> 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 [Designated Authorities] 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. (sub. 16, p. 20)

The 2008 review of NOPSA's operations said that some Designated Authorities (DAs) had stated they did not possess the expertise to review well operations management plans (WOMPs) or pipeline management plans:

> Most stakeholders supported the view that NOPSA should also regulate the integrity of pipelines and sub sea equipment. In particular the DAs advised that they no longer retain the necessary technical competence to assess the issues involved. They thought the current arrangement with both NOPSA and DAs having responsibility for integrity issues of parts of the petroleum offshore upstream industry made efficient regulation cumbersome to achieve.
>
> On the subject of who should regulate the safety and integrity of wells (WOMPs), the majority of stakeholders supported NOPSA taking on this role. The Western Australian DA indicated they still had the expertise to assess the issues involved and was neutral on who should regulate the safety of wells. The Victorian DA indicated they no longer had the necessary expertise and supported the regulation of wells by NOPSA. (RET 2008i, pp. 14–15)

The Victorian DA has indicated to the Commission since the draft report was published that Victoria does, in fact, still possess the expertise to regulate well integrity, and that it did not support NOPSA taking over this role. In response to the Commission's draft report proposal for NOPSA to take over regulation of the integrity of offshore pipelines, subsea equipment and wells, the Victorian Government said:

> The integrity of a well … depends on well design parameters … [that] are in the realm of resource management and therefore, currently in the realm of the DA. NOPSA's key role is occupational health and safety. While NOPSA has the requisite skills and

> expertise to regulate pipeline integrity, it does not have reservoir engineering skills required to assess well integrity. If well integrity were moved to NOPSA, then NOPSA would be required to acquire reservoir engineering skills just for well design … It would be an inefficient use of scarce skills. (sub. DR26, p. 2)

The Victorian Government indicated its concerns would be diminished if a new suitably resourced national petroleum regulator was formed incorporating the current activities of other federal and state regulators (and its concerns would be completely alleviated if the national regulator incorporated the current activities of NOPSA).

Other jurisdictions take a different view to Victoria. For example, the SA Government stated:

> South Australia concurs with the [draft report] recommendation for NOPSA to have coverage for all matters relating to safety in the offshore area. This will greatly assist in achieving greater efficiency through a one window to government for all matters relating to safety. South Australia also concurs that when extending NOPSA jurisdiction to include other offshore activities not currently under its ambit such as pipeline, seismic and other geoscientific exploratory activities, subsea equipment and wells, consideration needs to also be given to ensuring adequate resourcing. (sub. DR23, p. 10)

And APPEA has expressed a similar view:

> APPEA has long been working with NOPSA and the Commonwealth Department on the Integrity Working Group and has identified that regulatory requirements for wells and pipelines are largely a safety issue, with a small element of resource management. (sub. DR29, p. 11)

The Commission considers that shared responsibility for regulation of the safety and integrity of offshore pipelines, subsea equipment and wells creates unnecessary duplication. Moreover, in view of the importance of these areas to the safety of petroleum operations, clarification of responsibilities should be addressed as a matter of priority. With specific regard to well integrity, while there are resource management considerations, the Commission believes unambiguously clarifying responsibilities for safety issues is of paramount importance and the Commission believes NOPSA should take this role.

Steps proposed as part of the consolidation of the OPGGSA go some way towards reducing duplication in these areas. In particular, the proposed removal of safety issues from WOMPs (meaning the plans will concentrate on resource management issues), and the proposed removal of pipeline management plans represent positive steps in reducing regulatory overlap (RET 2008h).

However, the Commission considers the best solution is for the legislated coverage of NOPSA to be extended to include the safety and integrity of offshore pipelines, subsea equipment and wells. This effectively mirrors a recommendation of the 2008 review of NOPSA's operations. As this recommendation would add to NOPSA's responsibilities, it is important that it be adequately resourced for the additional tasks.

RECOMMENDATION 7.1

The legislated coverage of the National Offshore Petroleum Safety Authority should be extended to include the safety and integrity of offshore pipelines, subsea equipment and wells. If the National Offshore Petroleum Safety Authority is given these additional responsibilities, it would be necessary to ensure the authority was adequately resourced to carry them out.

Environmental compliance

At the time of NOPSA's establishment, the Ministerial Council on Mineral and Petroleum Resources also recommended consideration be given to expanding NOPSA's responsibilities to include environmental regulation (Wilkinson 2003). It was suggested that the Australian, State and Territory Governments could delegate responsibility for regulating environmental compliance in both coastal and Commonwealth waters to NOPSA.

It was envisaged that the relevant government in each jurisdiction would retain responsibility for setting environmental policy and approving development activity. NOPSA would then monitor and regulate compliance with the conditions set during the approval process. The DA and Joint Authority model would be retained, and the roles of the Department of Resources, Energy and Tourism (RET) and Geoscience Australia would be unchanged.

Governments decided that, at least initially, NOPSA should focus purely on safety. In the draft report, the Commission discussed whether NOPSA's responsibilities should be expanded to include environmental compliance, noting there are workable examples of petroleum agencies in other countries (including Canada, the Netherlands, the United States and Norway) undertaking environmental compliance in addition to other regulatory functions, including OHS.

Expanding NOPSA's role to include environmental compliance would increase the complexity of the agency's workload to a degree, but there would be benefits from combining activities associated with knowledge of offshore facilities, system auditing and inspection requirements. Wilkinson (2003) observed that a competent offshore petroleum regulatory organisation requires skills including operational and

engineering knowledge relevant to offshore technology, appropriate personal attributes and health and safety regulatory competencies. Adding environmental regulation to NOPSA's areas of responsibility could allow the agency's existing operational and engineering knowledge to be used in regulating environmental compliance.

There are also some important synergies. For example, engineering and operational aspects of pipelines related to safety and preventing emissions are likely to be relevant to preventing environmental damage. When NOPSA undertakes health and safety system audits of offshore facilities, it is likely there would be little additional difficulty in combining these with environment-related compliance checks of the same facilities.

However, the extent to which efficiency can be increased by combining OHS regulatory competencies and environmental compliance competencies is unclear. The Victorian Government suggested there were no real efficiency gains:

> While it is acknowledged that there are a number of synergies between safety and environment considerations associated with petroleum projects, joint audits carried out by NOPSA and the Victorian DA indicate there is no efficiency gain achieved by combining safety and environment considerations for audit purposes. Often, safety and environment considerations are competing for the same company personnel … which makes the audit process less efficient than if conducted separately. (sub. DR26, p. 2)

While the WA Department of Mines and Petroleum stated:

> Experience with combined safety and environmental audits has shown that it is far more efficient to split the agenda to ensure time is used most efficiently without excessively burdening a facility's personnel during the audit. Also, aspects of the environmental audit tend to become overshadowed by the safety matters. Consequently, the quality of the environmental inspection can be compromised, as can the quantity and quality of environmental information included in the report. (sub. DR22, p. 16)

Some participants saw greater synergies from keeping environmental assessment and compliance within the one agency. The Victorian Government expressed the view that:

> Environmental compliance is essentially about compliance with the environmental plan for a particular petroleum activity. Compliance typically requires understanding and knowledge of complex environmental issues. Separating environmental assessment from environmental compliance will require duplication of knowledge and understanding of the same issues. (sub. DR26, p. 2)

While the WA Department of Mines and Petroleum argued separating environmental assessment and compliance:

> … will result in double-handling of any amendments to projects and ongoing liaison due to the operator being required to advise both the approvals agency and the compliance agency of the amendment or additional information, thereby *increasing* duplication in the process. From the operator's perspective, rather than having one contact point within the Designated Authority for environmental matters, they would now conceptually have different contact points in different agencies for varying aspects of any one single proposal. This will increase the likelihood for miscommunication and errors in both the compliance and assessment stages of projects. (sub. DR22, p. 19)

There is also some potential risk, albeit probably low, that expanding NOPSA's role beyond OHS could diminish the emphasis on safety present in a single 'role' body. Some participants considered there was a greater risk that, given the importance of safety, giving NOPSA responsibility for environmental risk could result in a diminished focus on environmental issues. The WA Department of Mines and Petroleum stated:

> DMP would argue that the risk of diminished safety emphasis is extremely low. In fact … based on DMP's experience (prior to the formation of NOPSA), the real risk is in having environmental issues being overshadowed by safety issues. It is acknowledged of course that in all circumstances safety of personnel is paramount and always the first priority. However this ethos appears to affect resourcing available to environmental regulation. So even if there is any potential synergy in combining health, safety and environmental regulation, the tendency is for environmental matters to assume a lower priority in the organisation which could potentially result in compromised environmental outcomes. Therefore, any proposed recommendations to combine environment and safety regulatory functions should give detailed consideration to the structures in place to ensure environmental regulation is not compromised. (sub. DR22, p. 16)

On balance, the Commission considers NOPSA's responsibilities should remain solely focused on safety and integrity issues.

The issue of whether NOPSA's responsibilities should be further extended to all onshore OHS regulation for the upstream petroleum sector is discussed later in the chapter.

OHS regulation in coastal and inland waters

NOPSA was formed in large part to remove regulatory inconsistencies across jurisdictions and to reduce the number of regulators the upstream petroleum sector had to deal with. While NOPSA is able to exercise power in Commonwealth and coastal waters (and State and Territory internal waters subject to States and

Territories passing appropriate laws), the Commission has heard that there is still potential for regulatory confusion in some offshore areas.

The regulatory arrangements for Varanus Island at the time of the 2008 explosion can be used to illustrate this. At the time of this incident, Apache's operations on Varanus Island were regulated under the WA *Pipelines Act 1969*, with regulatory responsibility for OHS and integrity issues lying with the then WA Department of Industry and Resources (DoIR) (which was restructured in January 2009 and its regulatory responsibilities moved to the Department of Mines and Petroleum). NOPSA provided technical advice and contractor services to DoIR under a service contract.

Under the *Offshore Petroleum Act 2006* (Cwlth) and the WA *Petroleum (Submerged Lands) Act 1982*, NOPSA had OHS regulatory responsibilities for offshore platforms and pipelines feeding into the Varanus Island hub in Commonwealth waters, and in designated coastal waters where power was conferred on it.

The OHS and integrity issues relating to the mainland onshore operations of the pipelines were the responsibility of DoIR, with the WA Department of Consumer and Employment Protection providing regulatory services to DoIR for these pipelines under a memorandum of understanding (RET 2008d).

While the Commission is not suggesting these arrangements played any part in the Varanus Island incident, the arrangements do highlight that despite the formation of NOPSA, offshore regulatory arrangements can be quite complicated. Indeed, anecdotal evidence provided to the Commission has suggested projects could be subject to a number of OHS regulators (and alternate between regulators) if they went, for example, from Commonwealth waters, to onshore islands, to designated coastal waters, to State and Territory internal waters, to the mainland onshore.

The OPGGSA (and mirror legislation in the States and Territories) allows jurisdictions to confer powers on NOPSA in designated coastal areas and (subject to necessary laws being passed and funding arrangements being agreed with the Commonwealth) in State and Territory internal waters. It appears there would be a reduction in the unnecessary regulatory burden faced by the upstream petroleum sector if these powers were conferred on NOPSA more widely.

There would potentially be further benefits from giving NOPSA OHS regulatory responsibilities for islands located off the mainland States where offshore petroleum activity takes place.

FINDING 7.1

The complex interface issues facing some projects in offshore waters across Commonwealth waters, coastal waters, State and Territory internal waters and islands in terms of occupational health and safety is confusing and adds to the risk of poor regulation of safety and potentially adds to unnecessary regulatory burdens.

The Commission notes that the joint Australian and WA inquiry into the Varanus Island incident is considering these issues, particularly in the context of regulatory arrangements in Western Australia.

RECOMMENDATION 7.2

Subject to the outcomes of the current Australian and Western Australian Governments joint inquiry into the 2008 Varanus Island explosion, States and Territories should consider conferring powers on the National Offshore Petroleum Safety Authority to regulate occupational health and safety matters for all State and Territory waters seaward of the low tide mark, including islands within those waters.

Concern about prescriptive 'guidelines'

The upstream petroleum sector raised concerns about a perceived drift away from objective-based regulation towards greater prescription in some OHS areas. APPEA stated:

> 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 … 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. (sub. 16, pp. 17–18)

Following the release of the draft report, NOPSA disputed that the documents referred to by APPEA could be described as guidelines, and said they had been provided to the sector to obtain feedback.

In determining whether to accept proposed safety cases, NOPSA refers to internal standards and 'guidelines' for assistance. Many of NOPSA's published documents

appear to be these internal standards designed to guide NOPSA staff and supervisors. Such standards are particularly relevant in areas such as helicopter safety, which is unlikely to be an area of particular expertise for NOPSA staff. In these areas, the 'standards' are typically based on advice from other agencies, or consultants.

By making these 'standards' available to the sector, NOPSA could be seen as providing useful information to aid in completion of a successful safety case. (Moreover, sections of the sector have requested more guidelines and, as noted in box 7.3, the 2008 review of NOPSA's operations found a positive role for them.) However, publishing them means they could then be interpreted as being mandatory, thus partially undermining the objective-based regulatory regime.

Clear differences can be seen by the approach of NOPSA and, for example, the equivalent regulator in the United Kingdom, the Health and Safety Executive. While offshore petroleum safety regulation in both countries is based on safety case principles, the UK Health and Safety Executive publishes a wide range of safety alerts, information sheets and operations notices to guide industry.

FINDING 7.2

In those areas where the National Offshore Petroleum Safety Authority uses internal standards when assessing safety cases, there are likely to be net benefits from making these available to the offshore petroleum sector. However, it is important that the extent of use of, and the style of, such standards does not undermine the objective-based nature of the regulatory regime.

Marine issues

The Austral Chapter of the International Association of Geophysical Contractors, which represents seismic contractors, observed that the *Navigation Act 1912* (Cwlth) effectively requires Australian officers and seamen to take over from existing crews on seismic vessels before arriving in Australia. The organisation sees this restriction as creating particular problems given the shortage of qualified marine personnel in Australia:

> This procedure has resulted in undue burdens on the cost of exploration in Australia and has increased the risks of accidents as the Australian crews often have little or no experience of seismic operations or the complex vessels they are expected to man. This lack of experience is an increasing problem as there is an acute shortage of qualified marine personnel in Australia. Australia is the only country in which we operate which has the requirement to utilise local crews. We now are resorting to duplicating senior marine crew positions with our overseas experienced crew. (sub. 10, p. 1)

It saw the requirement as a disincentive for the seismic industry, and more broadly the oil and gas sectors, to invest in exploration in Australia.

In the draft report, the Commission sought further comment on whether requirements for Australian qualified marine personnel in the Navigation Act created unnecessary regulatory burdens. Relatively few comments were received. APPEA, however, submitted that the shortage or marine personnel was one of a number of skill shortages faced by the sector, and that it was important for the sector to develop appropriate responses:

> APPEA generally supports the views expressed by the Austral Chapter of the International Association of Geophysical Contractors in regard to the shortage of qualified marine personnel in Australia. APPEA's position would not however be to remove requirements to have Australian officers and seamen as a first position, but to develop a number of mechanisms to ensure the oil and gas industry is able to access the skills required in a timely and effective manner through, for example, developing strategies to increase availability of qualified marine personnel in Australia and specific immigration and visa arrangements to address short term shortages. This is consistent with the broad strategy adopted by the oil and gas industry to skills shortages. (sub. DR29, p. 20)

Given the limited evidence received stating that this is a significant unnecessary regulatory burden, the Commission considers major changes to the Navigation Act are not justified based purely on the regulatory burden faced by the upstream petroleum sector (particularly when weighed up against other government objectives). As suggested by APPEA, the sector will need to develop mechanisms to overcome any skill shortages stemming from the Act's application.

Another issue causing some confusion stems from the decision that the Navigation Act would no longer apply to Australian registered vessels and floating production, storage and offloading vessels when these are working under the safety case regime.

Currently NOPSA has jurisdiction over offshore facilities (whether floating or fixed) while they are in operation, being prepared for operation, or being decommissioned as an offshore facility. At other times, the Australian Marine Safety Authority has jurisdiction over vessels under the Navigation Act.

The Australian Marine Safety Authority stated that, to avoid a regulatory gap, in practice the Navigation Act requirements must be maintained so that a vessel can safely disconnect and sail away (RET 2008i). However, these arrangements provide for regulatory uncertainty during the transition phase.

The 2008 review of NOPSA's operations noted that it appears there are some unintended consequences arising from the changed regulatory arrangements. It further recommended:

> The consequences of the disapplication of the Navigation Act should be analysed, the actual consequences identified and unintended consequences addressed. The result of the analysis must be communicated to all stakeholders. (RET 2008i, p. 21)

The Commission agrees that if there is any regulatory uncertainty stemming from the decision to no longer apply the Navigation Act to Australian registered vessels and floating production, storage and offloading vessels working under the safety case regime, this should be clarified and resolved. However, given the highly prescriptive and all encompassing nature of the Navigation Act, reapplication of the Act to vessels would impose an onerous regulatory burden.

The current joint Commonwealth and WA inquiry into the Varanus Island explosion, which also is to focus on offshore petroleum safety regulation more broadly, is likely to consider this issue further.

RECOMMENDATION 7.3

The Australian Government should clarify whether any significant regulatory uncertainty results from the decision that the Navigation Act would not apply to Australian registered vessels and floating production, storage and offloading vessels when these are operating under the safety case regime. If so, it should act to remove the uncertainty. Reapplication of the Act would impose an onerous regulatory burden and would be unlikely to result in net community benefits.

The application of the safety case regime to 'associated offshore facilities' also has another consequence. Vessels require safety cases to be able to perform petroleum related work in Australia. This means vessels with safety cases are the preferred option for operators, even when they might not be the best or safest vessel available for a particular task. APPEA noted:

> 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. (sub. 16, p. 20)

The 2008 review of NOPSA's operations suggested that, from a practical viewpoint, if a vessel were regulated under a maritime regime, there is no point in duplicating this under the petroleum regulatory regime. It recommended that regulations (or their interpretation) should be changed to ensure that only petroleum-related functions representing a risk to people, environment and asset integrity of the petroleum facilities were regulated under the safety case regime (including collision or interaction risk) (RET 2008i). The Commission endorses this approach.

Following the release of the Commission's draft report, there was widespread agreement with the Commission's recommendation, although some participants wanted clarification of what would constitute a 'petroleum-related function' under such a regime. For example, the NT government said:

> The [Northern Territory Government] notes the draft recommendation, but considers that clarification of this recommendation is required to determine if pipeline laying vessels are classed as petroleum related vessels as the *Offshore Petroleum Act 2006* (Cth) also regulates gas. (sub. DR32, p. 7)

The Commission agrees clarification is important, and notes the 2008 independent review of NOPSA's operations attempted to define 'petroleum-related functions'. However, the Commission acknowledges it is not best placed to determine which functions are, or are not, petroleum related, and therefore considers the Australian Government should liaise with the upstream petroleum sector and the relevant regulators to determine which activities are petroleum-related and should therefore be regulated by NOPSA.

RECOMMENDATION 7.4

The Australian Government should clarify occupational health and safety regulations under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) to ensure that there is complete clarity about which petroleum-related sea going vessels must be regulated under the safety case regime. In determining which activities are petroleum related and pose sufficient risk to health, safety and the environment to warrant such inclusion, the Australian Government should liaise with the upstream petroleum sector, the National Offshore Petroleum Safety Authority and the Australian Maritime Safety Authority.

Funding arrangements

NOPSA is funded on a full cost recovery basis under the *Offshore Petroleum (Safety Levies) Act 2003* (Cwlth). Levies are calculated based on the Offshore Petroleum (Safety Levies) Regulations 2004 (Cwlth). The sector suggested that these arrangements fail to recognise that the activities of NOPSA benefit the wider public and not just the offshore petroleum sector.

APPEA stated:

> With clear … 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 [2001] 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. (sub. 16, p. 19)

In its 2001 Cost Recovery inquiry report, the Commission raised a number of concerns about applying the 'beneficiary pays' principle in the manner suggested by APPEA:

> There are three problems with this approach. First, funding regulatory activities from the budget would disguise the costs to consumers and producers of the regulatory activities deemed necessary to limit the risk of the spillover occurring. This could inappropriately encourage the regulated industry to expand, to the disadvantage of other industries where spillover effects are not as important and where regulatory costs are not as high. In addition, where consumption of regulatory activities is discretionary, regulated firms would not face the same financial discipline.
>
> Second, the benefits to the rest of the community result from costs foregone (that is, from not incurring a cost or not coming to some harm) and it may be argued on equity grounds that the community should not bear the expense of avoiding being harmed. Third, taxpayer funding creates other efficiency costs as a result of the impacts of taxes on the general community. (PC 2001a, pp. 28–29)

Moreover, the Commission viewed partial cost recovery as generally inappropriate, as this involved making subjective decisions about the degree of public and private benefits derived from regulation. The Commission found that, in principle, the prices of regulated products should incorporate all of the costs of bringing them to market, including the administrative costs of regulation.

Charges for goods and services consumed can provide important messages to users and consumers about the cost of resources involved in their production (PC 2001a):

> The case for recovering the costs of administering regulation is complex. Because some regulation is intended to reduce the likelihood of negative spillovers, the beneficiary pays principle does not universally apply. A more general principle that may apply is that where regulation is designed to minimise impacts on either consumers or third parties (that is, from spillover effects), the price of each regulated product should incorporate the efficient costs of its regulation. This approach has efficiency and equity advantages over the alternative of funding through general revenue. (PC 2001a, pp. 33–34)

The Commission notes there are potential downsides to regulatory cost recovery. While it can improve agency efficiency by instilling cost consciousness and promoting demand responsiveness, it can also weaken government scrutiny through normal budget processes. To the extent that agencies become effectively self-funding, there is less incentive for their respective portfolio departments and expenditure review processes to subject them to close scrutiny.

Cost recovery can also lead to regulatory creep (that is, additional regulation imposed without adequate scrutiny), gold plating (imposition of unnecessarily high standards) and cost padding (failure to seek efficiency savings, as costs can be readily recovered). Cost recovery may also encourage agencies to pay less attention to non-cost recoverable activities.

Cost recovery should not necessarily apply to all activities undertaken by regulatory agencies. In 2001, the Commission suggested that registration, monitoring of compliance and the issuing of exclusive rights would be potentially suitable candidates for cost recovery, while other activities would typically be funded from general taxation revenue (such as community education, investigation and enforcement, and policy development).

The Commission found that cost recovery charges should be linked as closely as possible to the costs of regulatory activities. This is best achieved by implementing fee-for-service arrangements reflecting efficient costs, although levies were also seen as appropriate albeit only where the basis of collection is closely linked to the costs involved. Further, cost recovery arrangements should apply to specific activities, rather than to agencies, and should avoid cross-subsidisation between groups.

Two of the three levies used to fund NOPSA appear to fit clearly within the guidelines laid down by the Commission and subsequently adopted by the Australian Government. These are the safety case levy (an annual levy to be imposed in relation to the safety case that is in force in relation to a facility) and the pipeline safety management plan levy (an annual levy to be imposed in relation to the pipeline safety management plan that is in force in relation to a pipeline).

The case for cost recovery of the third levy, the safety investigation levy (imposed on operators of facilities under investigation by NOPSA due to an accident or dangerous occurrence where the cost of an investigation exceeds $30 000), is more contentious. The levy is designed to quarantine these costs from the broader sector.

While the cost of investigations is typically met by taxpayers, it was argued in the Cost Recovery Impact Statement at the time the levy was introduced that:

> The prime beneficiaries of an efficient and consistent best practice safety regulatory regime are the owners and operators of offshore facilities. It is the owners who create the need for safety regulation and it is therefore appropriate to recover the costs of safety regulation. Investigations act as a safeguard of investment and revenue streams and do not undermine the objectives of safety regulation in the petroleum industry. (DITR 2004, p. 7)

The Cost Recovery Impact Statement also noted that the investigation levy is intended to cover incremental costs of major investigations only and that where an investigation leads to a prosecution, the investigation levy ceases on the day the brief of evidence is sent to the Director of Public Prosecutions. NOPSA can effectively waive the investigation levy in the event that the investigation identified that the operator had not been at fault or if the investigation had significant sector-wide implications. There are also appeal mechanisms for operators who believe the levy has been imposed unfairly.

The imposition of the safety investigation levy seems reasonable where major investigations are required given the safeguards in place.

Following the Commission's draft report finding that cost recovery arrangements for NOPSA appeared broadly consistent with regulatory best practice, a number of participants reiterated their disagreement with this position.

For example, APPEA stated:

> With a 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'. Clearly with the significant public benefits derived from regulation ensuring the secure provision of energy to meet the everyday life demands and expectations of the Australian public, there should be some degree of public funding in recognition of this public benefit. (sub. DR29, p. 19)

The Commission sees no contradiction between its position adopted with regard to NOPSA and the principles of cost recovery contained in the 2001 report. For the reasons outlined above, the Commission is still of the view that cost recovery arrangements for NOPSA appear broadly consistent with regulatory best practice.

FINDING 7.3

Cost recovery arrangements for the National Offshore Petroleum Safety Authority appear broadly consistent with regulatory best practice.

Some study participants have questioned why NOPSA has generated surpluses in recent years, given its cost recovery funding principles. NOPSA recorded a surplus of just under $2.9 million in 2005-06 (on revenue of $9.6 million), a smaller surplus of just under $1 million in 2006-07, and a surplus of $668 000 in 2007-08 (NOPSA 2008a). These surpluses do not, of themselves, indicate NOPSA has strayed from its cost recovery principles, although they may provide grounds for reviewing levy rates (particularly if maintained over time) or service levels. NOPSA attributes the surpluses to a high rate of growth in the petroleum industry (meaning

there were many new facilities), and to difficulties in attracting qualified staff. This meant that their collections through levies for a period exceeded their costs.

A scheduled three-yearly review of cost recovery arrangements for NOPSA was held in 2008. The review was to consider the principles laid down for cost recovery against NOPSA's actual activities, consider the effectiveness of monitoring of cost recovery by NOPSA, review cost recovery issues raised by stakeholders and recommend on whether there is a need for legislative amendments (RET 2008g). The review was well placed to consider issues relating to the surpluses generated by NOPSA and the levies charged. No outcomes from the inquiry have yet been made public.

There is further discussion of cost recovery principles, particularly in relation to how they might apply more broadly, in chapter 9.

Resourcing issues

As previously noted, one factor leading to the formation of NOPSA was concern about the capacity of earlier State and Territory regulators to adequately enforce OHS regulations. The Commission has heard concern about resourcing of regulatory agencies across a number of areas in the course of this study. In the case of offshore OHS regulation, however, the sector saw the creation of NOPSA as helping to ensure adequate resourcing. Indeed, it was considered that similar arrangements could assist elsewhere. APPEA considered:

> 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. (sub. 16, p. 39)

The Commission agrees that the consolidation of offshore OHS regulation into one agency is likely to have reduced resource pressures. The full cost recovery arrangements for NOPSA are likely to have assisted the agency in retaining staff by ensuring maintenance of competitive salaries.

Role of the NOPSA Board

NOPSA is overseen by a Board that provides advice to Commonwealth and State and Territory Ministers on policy and strategic matters, as well as providing advice and recommendations to the Chief Executive Officer of NOPSA about operational policies and strategies to be followed. The Board has six members with a mixture of industry, government and trade union experience. The Board members are appointed by the Commonwealth Minister, based on recommendations from the Ministerial Council on Mineral and Petroleum Resources.

The 2008 Review of NOPSA's operations found that while the NOPSA Board provided beneficial advice to NOPSA during its initial establishment phase:

> After NOPSA established itself and became operational the role of the Board became unclear to stakeholders. Some thought it was a governing Board, some looked at it as an access door to Ministers, and some did not see the need for a Board. The Board itself became more operational on a principal level engaging with stakeholders and maybe overlapped the responsibilities of the CEO of the independent NOPSA. (RET 2008i, p. 32)

The Commission agrees that, in practice, the role of the NOPSA Board is not entirely clear, and that there is potential for confusion and overlap between the Board and the Chief Executive Officer. The need for a board and, if such a need exists, the role of the Board, should be explicitly clarified and communicated to all stakeholders. The Commission is strongly of the view, however, that NOPSA should remain an independent statutory authority.

RECOMMENDATION 7.5

The Australian Government should consider whether it is still appropriate to have a Board for the National Offshore Petroleum Safety Authority and, if so, explicitly clarify the role of the Board and communicate this to all stakeholders.

7.2 Onshore OHS regulation

While offshore OHS regulatory arrangements have been harmonised, onshore activities are regulated under each State and Territory's OHS regime. Across jurisdictions, mechanisms for regulating onshore petroleum facilities vary, with some jurisdictions regulating via principal OHS Acts, some having industry-specific regimes, and some facilities being regulated principally via dangerous goods or major hazards legislation. OHS arrangements in the industry are governed by many pieces of legislation, with the major Acts shown in table 7.1.

Table 7.1 **Major onshore OHS legislation**

Jurisdiction	*Legislation*
New South Wales	*Petroleum (Onshore Act) 1991*
	Occupational Health and Safety Act 2000
Victoria	*Occupational Health and Safety Act 1985*
	Dangerous Goods Act 1995
Queensland	*Petroleum and Gas (Production and Safety) Act 2004*
	Petroleum and Gas (Production and Safety) Regulations 2004
	Dangerous Goods Safety Management Act 2001
Western Australia	*Occupational Safety and Health Act 1984*
	Mines Safety and Inspection Act 1994
	Petroleum and Geothermal Energy Resources Act 1967
	Petroleum Pipelines Act 1969
South Australia	*Occupational Health, Safety and Welfare Act 1986*
	Petroleum Act 2000
	Petroleum Regulations 2000
	Dangerous Substances Act 1979
Tasmania	*Workplace Health and Safety Act 1995*
	Dangerous Substances (Safe Handling) Act 2005
	Dangerous Goods Act 1998
Northern Territory	*Petroleum Act 1984*
	Petroleum (Occupational Health and Safety) Regulations
	Workplace Health and Safety Act 2007
	Dangerous Goods Act 1998

Onshore OHS issues

The Commission received relatively few comments about onshore OHS regulation. Those issues raised included whether a national model OHS Act could adequately regulate the onshore petroleum sector, regulatory inconsistency between State and Territory OHS regulations, and whether NOPSA should take over onshore OHS regulation.

General versus industry-specific OHS regulation

Study participants presented differing views on the relative merits of regulating OHS via principal Acts or industry-specific regimes. An Australian Government inquiry into national model OHS regulation recently reviewed the extent to which the current industry-specific Acts could be accommodated under a principal (model) OHS Act. The inquiry reported in January 2009 (Australian Government 2009), following a report on priority issues in November 2008.

Some industry participants expressed a preference for one model OHS Act across all industries, possibly supported by industry-specific regulation. Santos observed:

> When business is subject to OHS laws of both general and specific application, this creates a significant administrative burden for business that is required to report to two different regulatory bodies in the same State. The preferred Model Act should also promote single national OHS laws, with national industry specific regulation for the offshore and onshore oil and gas industry where required. This will ensure consistency and certainty for the offshore and onshore oil and gas industry across all jurisdictions. (Santos 2008, pp. 2–3)

BP suggested:

> Industry specific legislation should be abolished in favour of a streamlined and unified model OHS Act. Industry specific provisions should be addressed in comprehensive supporting regulations and codes of practice which would allow for effective transition. (BP 2008, p. 3)

However, others preferred maintenance of industry specific legislation, largely based on recent experiences with offshore regulation. The Australian Council of Trade Unions stated it:

> … strongly supports the retention of separate legislation for the offshore oil and gas industry … The same principles outlined in relation to shipping also apply to the offshore oil and gas industry, including the fact that it has its own regulator, NOPSA. (ACTU 2008, p.12)

APPEA also expressed doubts about whether model OHS legislation could adequately deal with petroleum related OHS issues:

> APPEA believes the offshore regime has already achieved a best practice national approach … 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. (sub. 16, p. 21)

The 2009 report on the national review of OHS laws saw a role for industry-specific laws, albeit a limited one. In discussing its preferred model (that is, separate and specific OHS laws for particular hazards or high-risk industries only where objectively justified), the review stated:

> … there may be understandable and valid reasons for there being … separate legislation. Many stakeholders have claimed that this is the case. Nonetheless, we consider that any such claims should be tested and periodically reviewed to determine whether the justification for that approach continues to exist. Where separate legislation was permitted, in the event of any overlap or inconsistency, the model Act should be paramount, other than in exceptional and specified circumstances. As far as possible,

> the separate legislation should adopt and apply the key requirements of the model Act (e.g. general duties of care). (Australian Government 2009, p. 12)

The review added that to have one single Act would assume there were no circumstances where separate legislation is warranted, and it was not clear that this was the case (Australian Government 2009).

With regard to offshore safety regulation, the Commission has heard overwhelming support for current arrangements. As APPEA reiterated in its response to the draft report:

> APPEA remains strongly of the view that the offshore regime has already achieved a best practice national approach and that the oil and gas industry is fundamentally different to other industries in terms of the environment and safety issues it faces. Notwithstanding this strong view, APPEA believes there may be opportunities for NOPSA and for the industry to work cooperatively with the national OHS regime to align common principles and to benefit where there are opportunities for joint initiatives. (sub. DR29, p. 20)

The Commission considers that the highly specialised (and high risk) nature of the upstream petroleum sector justifies separate OHS legislation in addition to that provided under one principal OHS Act. This is particularly the case for regulation of the offshore sector.

FINDING 7.4

The highly specialised nature of upstream petroleum operations (particularly offshore operations) would justify legislation for the upstream petroleum sector remaining separate from a principal (model) occupational health and safety Act.

A further issue is whether OHS legislation should incorporate a duty of care to the broader public, as well as to employees and contractors, and what that duty should entail. The 2009 report of the national review of OHS laws found general support for incorporating protection of public safety in OHS laws, noting that the only real disagreement among stakeholders was over how wide the protection should be. The review stated:

> We have kept in mind that the primary purpose of OHS laws is to protect people from work-related harm. In our view, the status of such people is irrelevant. It does not matter whether they are workers or have some other work-related status or are members of the wider public. They are entitled to that protection. At the same time, the OHS laws should not have an operation that affords such protection in circumstances that are not related to work. There are other laws, including the common law, that require such protection and provide remedies where it is not supplied. (Australian Government 2009, p. 19)

The review recommended that a model OHS Act should protect:

> … the health and safety of any person—including the wider public—from exposure to hazards and risks that are inherent in, or emanate from:
>
> a) the performance of work
>
> b) anything that is provided or used for or in the performance of work, or intended to be so provided or used; or
>
> c) a workplace, in its capacity as a workplace. (Australian Government 2009, p. 19)

The Commission broadly concurs with this view.

Regulatory inconsistency

Australia Worldwide Exploration (Western Region) (sub. 17) noted it was part of a group arranging for the import from the United States into Western Australia of a land based drill rig. Australia Worldwide Exploration (Western Region) stated that while the rig was built to US petroleum standards, additional requirements must be adhered to under WA regulations before the rig can be given approval to operate in Western Australia. It stated that as a consequence of the need to meet WA standards:

> The estimated cost and time for the rectification work for rig 826 is four weeks and more than one million dollars. (sub. 17, p. 7)

It also noted that there are also differences in standards between Australian States. For example, it suggested that requirements were more onerous in Western Australia than in Queensland. As a result of these differences, work must be done on a drilling rig before it can travel between States. Such differences create unnecessary regulatory burdens, and potentially limit options for using equipment deemed safe under standards prevailing in the United States and in other Australian States.

The WA Department of Mines and Petroleum disputed the facts in the example quoted by Australia Worldwide Exploration (Western Region), stating the drill rig in question did not meet Australian standards and would not have been approved in any Australian jurisdiction. It noted, however, that the zone compliance distances in Western Australia differ from other jurisdictions:

> … while Western Australia may have differing hazardous areas (zone compliance) distances, in the example cited the problems arose from the fact that the equipment and wiring simply did not comply — it was not a matter of zone compliance distances. (sub. DR22, p. 20)

The Commission is aware of efforts currently being made to harmonise safety standards for equipment across jurisdictions, and is supportive of these efforts. The

Commission's draft recommendation for greater harmonisation received widespread support. For example, the NT Government said:

> The [Northern Territory Government] supports the draft recommendation to standardise regulations across all jurisdictions with a view to developing nationally consistent guidelines and procedures. (sub. DR32, p. 7)

APPEA was also supportive:

> APPEA agrees with this recommendation and supports the Commission's call for clarity and harmonisation of standards across jurisdictions. (sub. DR29, p. 12)

Some jurisdictions highlighted that they are moving away from prescriptive safety regulations. In supporting the Commission's draft recommendation, the SA Government noted:

> … the focus of objective-based legislative regimes, such as the SA Petroleum Act, is for licensees to demonstrate achievement of desired outcomes. In line with the principles of efficiency and practicality, the aim of any such demonstration is that equipment is 'fit for purpose' rather than any strict compliance to the letter of onerous standards. (sub. DR23, p. 10)

Some study participants suggested to the Commission that some problems stemming from regulatory inconsistency between jurisdictions are due to differences in regulatory interpretation, rather than in the regulations themselves. There is potential for unnecessary regulatory burdens when regulators choose to interpret regulations in a manner that makes them more onerous.

RECOMMENDATION 7.6

State and Territory Governments should make greater efforts to harmonise safety standards, or the interpretation of those standards, for imported upstream petroleum equipment across jurisdictions, whilst giving recognition to appropriate prevailing international standards. Where the application of standards is more onerous than those prevailing in other jurisdictions or comparable countries, efforts should be made to ensure that the application of these more onerous standards provides net public benefits.

Should NOPSA take over regulation of onshore petroleum facilities?

There is broad agreement that the formation of NOPSA has reduced duplication and inconsistencies stemming from earlier offshore regulatory arrangements. Consequently, it may be worth examining whether there would be benefits in NOPSA taking over regulation of onshore sections of pipelines and integrated production facilities as well. This would further reduce duplication, and assist in alleviating confusion over regulatory responsibility for integrated facilities.

However, clear administrative agreements would be needed to prevent confusion over jurisdictional boundaries with an expansion to onshore OHS. Well defined MoUs would be required to assign responsibility between NOPSA and the relevant State and Territory safety and petroleum departments. For example, MoUs would be required between NOPSA and state OHS regulators (such as regulators of major hazard facilities).

The Petroleum and Gas Inspectorate of the Department of Mines and Energy in Queensland stated the NOPSA model was not appropriate for onshore OHS regulation:

> … the [Petroleum and Gas] Inspectorate does not consider that there is any significant duplication of requirements or addition compliance costs in regard to safety obligations … The NOPSA model is not considered an effective model for regulation of on shore upstream petroleum matters. The majority of production is conducted in only two States (South Australia and Queensland). In Queensland the majority of production is now coming from coal seam gas. Coal seam gas production activities require extensive drilling in stark contrast to similar production from conventional resources on shore and even more so from offshore resources. (sub. 5, p. 1)

In fact, it considered that moving to the NOPSA model involved removing some synergies:

> … there is significant overlap of issues with coal mining activities and the [Petroleum and Gas] Inspectorate works closely on safety matters with our mining colleagues in the Mines Inspectorate, including undertaking joint audits. Moving to a national body would remove these synergies … The [Petroleum and Gas] Inspectorate also regulates transmission pipelines, reticulation of gas, LPG industries including automotive LPG, and down stream industrial, commercial and domestic use of gas. Removal of any upstream component would reduce efficiencies gained from this one stop approach to petroleum and gas safety regulation in Queensland. (sub. 5, pp. 1–2)

The 2008 review of NOPSA's activities suggested that 'the definition of coverage for NOPSA needs to consider the relevant total petroleum systems rather than current statutory boundaries' (RET 2008i, p. 21). If safety cases were intended to include all risks affecting system integrity, including carbon capture, transport and storage, it therefore followed:

> Coverage of the regime should be increased to cover the complete hydrocarbons production system from wells through to the custody transfer point or reasonable physical/technical system boundary. (RET 2008i, p. 21)

The Commission recognises there would be some benefits of having one safety regulator within integrated (on and offshore) production facilities. However, in view of the difficulties involved (including the potential creation of new regulatory overlaps and the possible loss of synergies for State and Territory based regulators),

on balance the Commission does not see a case for extending NOPSA's responsibilities to include onshore integrated production facilities.

FINDING 7.5

On balance, the Commission does not see a case for extending the National Offshore Petroleum Safety Authority's legislated responsibilities to include onshore integrated production facilities.

That said, the Commission notes the OPGGSA enables States and Territories to empower NOPSA to regulate onshore facilities on a case by case basis. The Commission agrees such powers should be conferred in individual cases where it is mutually agreed that this would reduce unnecessary regulatory burdens and lead to improved regulatory outcomes.

The potential benefits and costs of applying the NOPSA model more widely are discussed in chapter 9.

8 What impact are impediments having?

Key points

- The overall performance of Australia's regulatory regime in the upstream petroleum sector appears to compare favourably by international standards — however, there is scope and capacity for regulatory improvement in all, but especially in lagging, jurisdictions.
- Improved regulatory arrangements could help reduce regulatory costs and offset Australia's natural disadvantages of low oil prospectivity and geographical remoteness.
- There is considerable evidence linking regulatory burdens to lengthy and complex approval processes — particularly for pipelines — and onerous reporting requirements.
- The perceptions of regulatory performance in individual jurisdictions of Australia are affected by differences in the intensity of regulatory activity, as well as government initiatives undertaken to improve regulatory outcomes.
- Significant regulatory costs are associated with approval delays that potentially lead to increased project expenditures, reduced flexibility for responding to market conditions, inflated capital costs, increased difficulty of financing projects, and reduced present value from resource development.
- Expediting the average approval process by one year could increase the net present value of projects by 10–20 per cent simply by bringing forward income streams. Given the sector contributes 2 per cent to GDP, the potential income gains for Australian residents could be in the billions of dollars each year.

The Commission has in earlier chapters identified a number of unnecessary regulatory burdens impacting on the upstream petroleum sector. In this chapter, evidence is provided about the magnitude of these burdens, with efforts to quantify them where possible.

Section 8.1 presents a series of case studies highlighting the major burdens encountered by upstream petroleum businesses. Section 8.2 presents observations on comparative regulatory performance across the various jurisdictions in Australia. Section 8.3 presents evidence on the economic costs associated with regulatory

burdens. Section 8.4 discusses the implications of regulatory burdens for investment attractiveness of the upstream petroleum sector.

8.1 Evidence of unnecessary regulatory burdens

Industry participants have provided evidence of unnecessary regulatory burdens attributed to two major problems, namely lengthy and complex approval processes and onerous, sometimes duplicated, reporting requirements.

Lengthy and complex approval processes

Table 8.1 includes a number of (de-identified) case studies, drawn from a submission from the Australian Petroleum Production and Exploration Association (APPEA), to outline the number of approvals required, the complexity of the approval process and the number of government agencies involved in various types of projects.

Understandably, large projects typically face considerably more approval hurdles than smaller projects. Nevertheless, the number of approvals required for smaller projects can be significant, especially given that their proponents often have relatively constrained capacity to deal with compliance requirements. Case study 1 indicates that up to 390 approvals were required for a large liquefied natural gas (LNG) project. By comparison, a small project operating within a single jurisdiction (case study 4) still required over 80 approvals.

Most regulatory agencies involved are at the State and Territory level, except for projects solely located in Commonwealth waters. Even in the latter case, three or more State level agencies can be involved (such as in case study 4). Concerns about local government involvement, as noted as an issue by APPEA (sub. 16), are generally associated with large LNG facilities and some domestic gas projects.

Complexity typically increases as the number of government agencies involved in approvals increases. For example, the approvals for building a gas production facility in case study 5 involved 35 separate agencies operating at the Commonwealth, State and local government levels. Even the construction of production wells in case study 4 — which required no new infrastructure outside of Commonwealth waters — involved approvals by 17 government agencies.

Pipeline approvals form a substantial proportion of the total project approvals required. Among the case studies presented in table 8.1, the proportion of approvals dedicated to pipeline works ranges from 18 per cent to 69 per cent. For example, case study 7 — which refers to the standalone approval process for a pipeline —

required 55 approvals. These included 38 approvals for design, construction and operation; 9 general approvals; and 8 approvals for consents or notices required. By contrast, case study 6 — which did not include any pipeline works — required 44 approvals in total, the fewest for the case studies examined.

Another example of approval process complexity is the Longtom gas field, which is currently being developed by Nexus in the Gippsland Basin. This project involves building a subsea wellhead and a pipeline in Commonwealth waters.

Nexus (sub. 3) considered the Longtom project to be straightforward. Nevertheless, the approval process included a series of environmental, pipeline, health and safety, exploration, installation and production approvals that were interrelated (figure 8.1). Further, approvals often required to be pursued sequentially rather than concurrently. Prior to obtaining consent to construct a pipeline, Nexus had to apply for a pipeline licence and also prepare a pipeline management plan, a pipelay barge safety case, an environmental management plan, an emergency response plan, and an oil-spill contingency plan for approval by different authorities.

The environmental approval process also delayed, and ultimately may have changed the location of, Inpex's proposed LNG plant in the Kimberley, Western Australia. Inpex initially applied for approval of the facility in May 2006 on Marat Island. Twenty months later — in February 2008 — the Commonwealth Environment Minister and the WA Acting Minister for State Development announced the decision to undertake a strategic assessment of the Kimberley. Subsequently, Inpex has announced an intention to relocate their proposed plant to Darwin (Garrett and Kobelke 2008; Inpex 2006, 2008a, 2008b).

Resource requirements

Project proponents have to commit significant resources to approval processes as a result of complex compliance requirements. This is confirmed by the resource requirements in a selection of case studies presented in table 8.2. For example, the LNG project in case study 2 required involvement of up to 90 people at various stages of the approval process, and incurred significant consultancy costs for processing approval applications. Applications for environmental approvals alone in case study 4 incurred expenses of 5 person-months of staffing and $200 000 for hiring external consultants.

Table 8.1 **APPEA's case studies of regulatory approvals for upstream petroleum projects**

	Case study 1	*Case study 2*	*Case study 3*	*Case study 4*
Description of projects	Natural gas in Commonwealth waters, pipeline through coastal waters and onshore processing, liquefaction and export	Natural gas in Commonwealth waters, pipeline through coastal waters and onshore processing, liquefaction and export	Jack-up installed, unmanned wellhead platform in Commonwealth waters, pipelines to onshore processing facilities	Natural gas in Commonwealth waters connected to existing onshore processing infrastructure
Regulatory agencies involved	**26**	**19**	**22**	**17**
• Australian Government	10	9	8	14
• State/Territory Government	12	10	14	3
• Local government	3	–	–	–
• Joint statutory authority	1	–	–	–
Regulatory approvals required	**390**	**277**	**163**	**83**
• General project approvals and preliminary requirements	32	64	17	–
• Drilling approvals	–	53	18	24
• Pipeline approvals (including design, construction and operation)	–	49	61	46
• Decommissioning approvals	–	7	–	6
• Other approvals[a]	358 (including 140 for offshore investigation, construction, commissioning and operation; and 218 for onshore investigation, construction, commissioning and operation)	104 (including 30 for shore crossings and shipping facility requirements; 52 for storage, loading and processing facilities; and 22 for accommodation, gas connections and permit administration)	92 (including 47 for offshore construction, installation, commissioning, operations and decommissioning; and 45 for onshore construction, commissioning and operations)	7 (for a production licence)

(Continued next page)

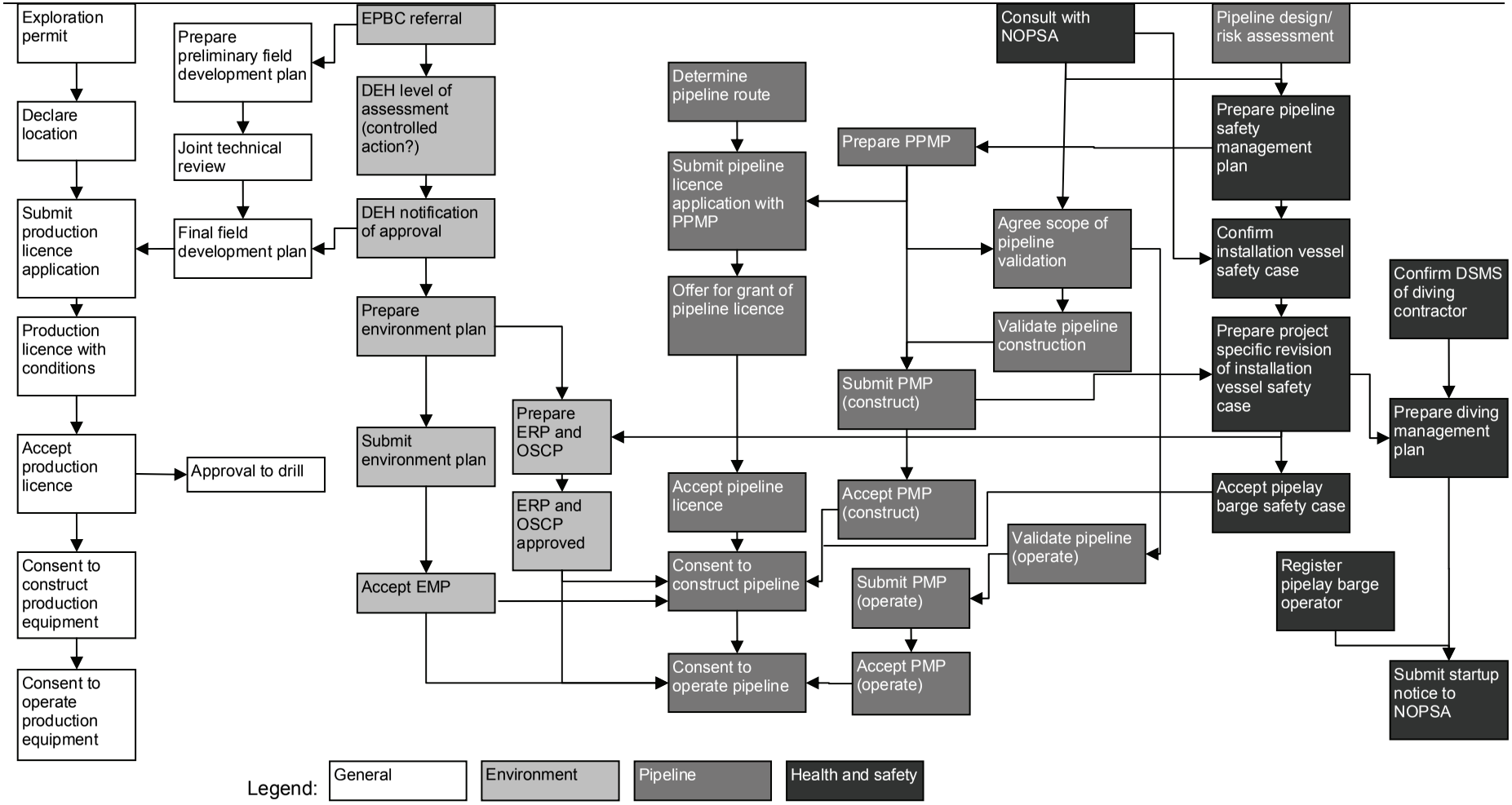
Table 8.1 (continued)

	Case study 5	*Case study 6*	*Case study 7*	*Case study 8*
Description of projects	Offshore production, incorporating a subsea pipeline and onshore gas processing infrastructure	Subsea development and a floating production storage and offloading facility in Commonwealth waters	A pipeline network connecting three gas wellheads to onshore processing facilities	Subsea wells in Commonwealth waters, with pipeline connection to existing onshore processing infrastructure
Regulatory agencies involved	**35**	**6**	**–**	**–**
• Australian Government	13	–	–	–
• State/Territory Government	20	–	1	–
• Local government	1	–	–	–
• Joint statutory authority	1	–	1	–
Regulatory approvals required	**127**	**44**	**55**	**over 144**
• General project approvals and preliminary requirements	–	–	9	–
• Drilling approvals	–	18	–	–
• Pipeline approvals (including design, construction and operation)	–	–	38	over 36
• Decommissioning approvals	–	–	–	–
• Other approvals[a]	127 (including 69 relating to State and local governments; and 58 relating to the Australian Government)	26 (including 14 for project validation, environmental, health and safety approvals; 6 for installation and diving requirements; and 6 for design, testing and recovery of petroleum)	8 (for consents or notices required)	108 (for unstated requirements)

[a] Possibly including general, drilling, pipeline or decommissioning approvals in cases where no breakdown of such approvals has been provided. – Zero or not available.

Source: APPEA (sub. 16).

Figure 8.1 **Nexus's mapping of the approval process for its Longtom project[a]**



[a] Acronyms are as follows — DEH: Department of Environment and Heritage; DSMS: Diving Safety Management System; EMP: Environmental Management Plan; EPBC: *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth); ERP: Emergency Response Plan; NOPSA: National Offshore Petroleum Safety Authority; OSCP: Oil-Spill Contingency Plan; PMP: Pipeline Management Plan; PPMP: Proposed Pipeline Management Plan.

Source: Nexus (sub. 3).

Table 8.2 **APPEA's assessment of business expenses for project approvals**

	Case study 2[a]	*Case study 3*[a]	*Case study 4*[a]
Internal staff	• Up to 90 people required at various regulatory focal points • 1 full-time approvals coordinator • 1 offshore environmental approvals coordinator	• 6 person-years for all regulatory requirements • 54 person-months for health, safety and environmental approvals	• 5 person-months for environmental approvals • 8 person-months for production licence, field development plan, pipeline management plan, and pipeline licence
Outsourced tasks and costs	• Public environmental report, field development plans and other approvals (significant cost)	• Drilling and pipeline approvals (over $100 000)	• Environmental approvals ($200 000) • Installation vessel safety case revision, dive management plan, and supporting health, safety and environmental plans and procedures ($200 000) • Health, safety and environmental assessments in design ($300 000)

[a] Case study numbers align with those in table 8.1. See table 8.1 for project descriptions.

Source: APPEA (sub. 16).

The approval process can also consume considerable government resources. This is particularly the case under the Joint Authority–Designated Authority (JA–DA) regulatory framework, because it typically requires numerous iterations of paperwork processing between departments or agencies over protracted turnaround times (table 8.3).

Table 8.3 **Features of approval processes under the JA–DA framework**

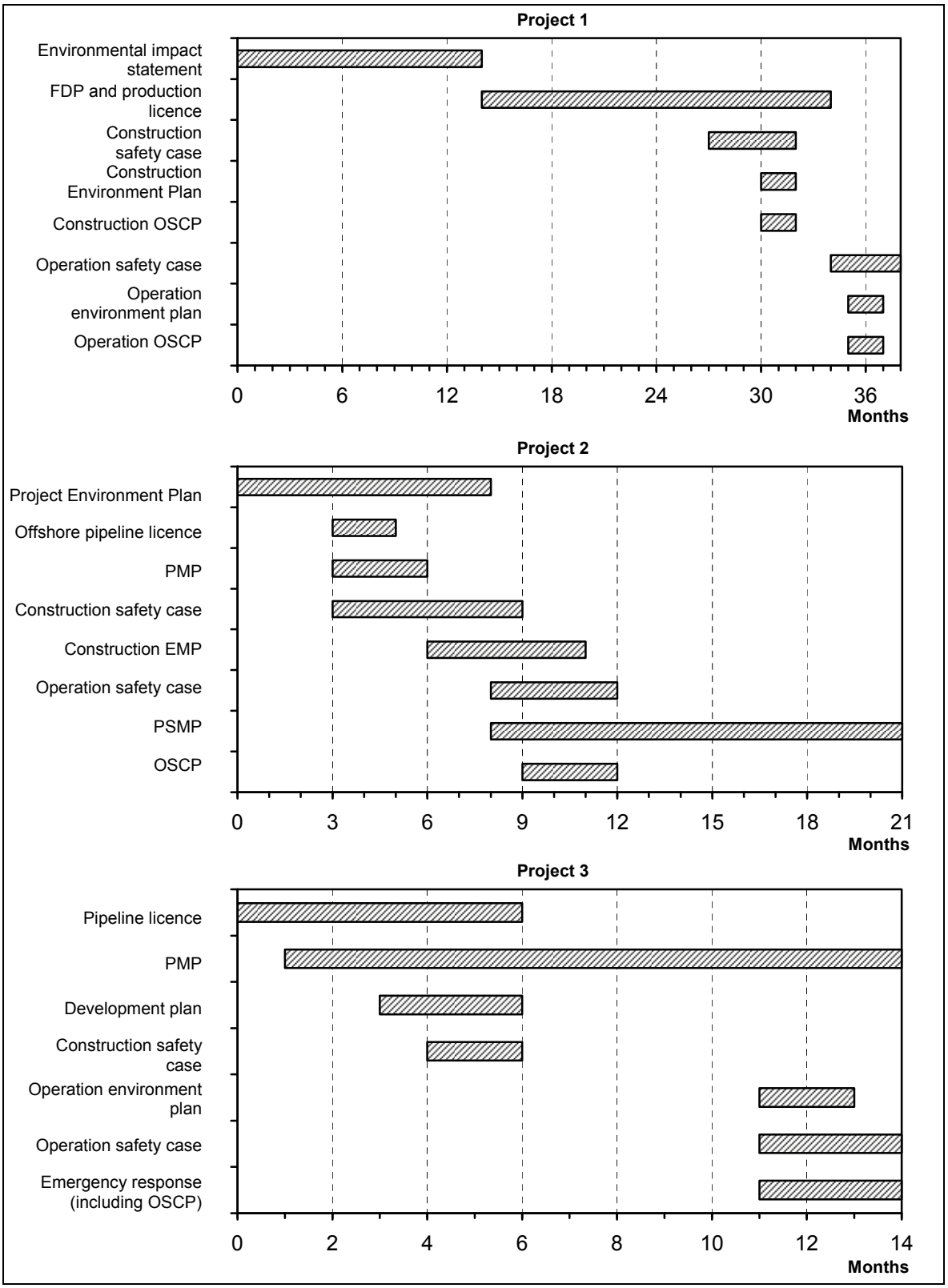
Type of approval	*Time taken*	*Iterations of paperwork processing*
	months	number
Production licence	at least 12	50–60
Pipeline licence	3–9	20–30
Suspension and extension of pipelines	3–6	12–20

Source: Victorian Government (sub. 7).

Delays

Lengthy and complex approval processes can also result in project delays. Figure 8.2 provides examples of timelines for certain key approvals for upstream petroleum projects. These timelines span from submitting a request to the relevant agency granting an approval. Depending on the scope of the project, approval times ranged from 14 months for a pipeline, to 38 months for a major project.

Figure 8.2 **Project approval timelines**



Acronyms are as follows — FDP: Field Development Plan; OSCP: Oil–Spill Contingency Plan; PMP: Pipeline Management Plan; EMP: Environmental Management Plan. PSMP: Pipeline Safety Management Plan.

Source: Commission estimates (based on information obtained from APPEA).

Although delays for some projects can be reduced through the use of a facilitating agency, this can result in increased delays to other projects unless there is an improvement to underlying approval processes. For example, the Pluto LNG development on the Burrup Peninsula, with assistance from the WA facilitating agency, the Office of Development Approvals Coordination, achieved approval within 18 months. However, according to the WA Auditor General, this was only accomplished by diverting agency resources, at the expense of approvals for other projects:

> The Pluto experience has not resulted in any improvements to existing approval processes. Agencies participating in the Pluto review unanimously agreed that the experience would be difficult to replicate as the shorter than usual timeline was achieved by re-prioritising agency resources. Agencies advise that the effect of prioritising Pluto approval processes was that other development proposals were delayed. (Auditor General for Western Australia 2008, p. 28)

Some participants indicated that approval delays represent a substantial impediment to oil and gas projects, which could lower returns and make it potentially difficult to obtain finance for projects. Such delays could cost businesses more than the direct costs of complying with approval requirements. APPEA submitted:

> … 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) … Importantly, projects must also compete with alternative investment opportunities and delays resulting from regulatory requirements can lead to funding being delayed or lost. (sub. 16, p. 42)

In some cases, regulatory delays add to direct costs because of the need to hire equipment on standby. Such costs can be substantial, as the Victorian Government indicated:

> According to industry figures, current standby rates for semi-submersible drilling rigs are up to $1.1 million per day. (sub. 7, p. 4)

In addition, where costs are rising over time, delays can lead to higher overall project costs. Participants have told the Commission of capital cost increases of between 25 and 30 per cent per annum in Western Australia over recent years. BP (sub. 15) stated labour costs for upstream oil and gas projects in Western Australia increased by around 20 per cent per year in the four years to January 2008.

BP further observed:

> … independent analysis shows that cost escalation due to WA labor costs stands out on a global basis for upstream oil and gas projects. (sub. 15, p. 1)

Nexus's Longtom gas field project provides another example of substantial cost increases due to approval delay. To date, approvals for this project have taken more than two years, and cost the company in excess of $1 million. Nexus (sub. 3) identified this direct cost as being a small percentage of the total cost, but noted that the delay caused increases in the capital cost, which affected their ability to secure financing for the project. In addition, the cost of establishing and maintaining undrawn credit facilities during this period also added to costs.

Regulatory creep

Some participants claimed that new environmental protection guidelines issued under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) increase compliance burdens. One such guideline restricts the practices of seismic surveys, in particular in areas where there could be a risk of whales being encountered (APPEA, sub. 16; DEWHA, sub. 8). However, the Department of Environment, Water, Heritage and the Arts (DEWHA) countered that they believed the guidelines would not necessarily add to actual regulatory burdens. DEWHA cited that:

> Of 124 offshore seismic surveys referred under the EPBC Act, 120 have operated in accordance with the measures detailed in the Guidelines, and which companies committed to, with only four surveys, planned for highly sensitive marine environments, requiring any further assessment (of which, one, was re-referred for a period when whales were less likely to be present and two were withdrawn). (sub. 8, p. 7).

Since the release of the draft report, DEWHA has said:

> The Department disagrees that decision-making on seismic surveys has been inconsistent and asserts that the seismic guidelines provide good guidance to proponents on actions that are likely to require further assessment. The Department appreciates the efforts of the Productivity Commission to put forward both viewpoints but feels it would be useful to emphasise the fact that most seismic operations are conducted in accordance with the guidelines and do not encounter approval delays. (sub. DR35, p. 3)

In general, industry welcomes guidelines that clarify responsibilities under the EPBC Act. However, there is a perception that DEWHA is taking an increasingly interventionist role regarding seismic surveys. Seismic surveys are viewed as a routine activity by the upstream petroleum sector, and some participants therefore saw the requirement for further assessment of *any* surveys as indicating that the guidelines were heavy handed and not achieving their intended purpose.

Duplicated reporting requirements

The duplication of reporting requirements is another burden faced by the sector. This has arisen when businesses are regulated under multiple policy programs with similar objectives.

ExxonMobil, for example, has been required to report similar information in slightly different formats under a number of greenhouse and energy policy programs at both the Commonwealth, and State and Territory levels. The related requirements involved providing different program administrators with the same information, of which some is also used for corporate reporting (table 8.4).

Table 8.4 **ExxonMobil's reporting requirements for greenhouse and energy programs**

Jurisdiction	*Program*	*Energy*	*Climate change*	*Annual reporting*	*Public reporting*	*Energy audit*	*Action plan*
Australian Government	Greenhouse Challenge	✓	✓	✓	✓[a]		✓
	Greenhouse Challenge Plus	✓	✓	✓	✓		✓
	Energy Efficiency Opportunities	✓		✓	✓	✓	✓
	National Greenhouse and Energy Reporting	✓	✓	✓	✓		
Victorian Government	Greenhouse Gas Action Plan	✓	✓	✓		✓	✓
	Energy and Resource Efficiency Plans	✓	✓	✓		✓	✓
Corporate reporting	Environmental Performance Reporting	✓	✓	✓			
	Environmental Business Planning	✓	✓	✓			✓

[a] Contributing to sector aggregate data.

Source: ExxonMobil (sub. 13).

The costs of compliance reporting increase when businesses are required to reprocess information to suit different content or reporting frequency requirements. For example, the Victorian Government's Energy Resource and Efficiency Plan has a shorter timeline than the Australian Government's Energy Efficiency Opportunities program, creating difficulty for participants in setting durable energy strategies.

ExxonMobil commented:

> … the short timeline of [the Energy Resource and Efficiency Plan] is likely to encourage a focus on superficial and premature solutions. The consequence may well be that work will then need to be redone over the next 2 years under [Energy Efficiency Opportunities]. (sub. 13, p. 7)

APPEA stated that efforts to avoid duplicative reporting requirements under the two programs are flawed:

> In Victoria the EPA has launched Energy and Resource Efficiency Plans (EREPs) that require a duplicate of EEO [Energy Efficiency Opportunities] but with the EPA's 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 five year program) to have already been completed to get the exemption. (sub. DR29, p. 22)

APPEA also highlighted the problems confronted by joint venture partners when reporting against government programs. For example:

> 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. (sub. DR29, p. 21)

Woodside has said that government agencies frequently request annual or summary data that has already been provided under regulatory reporting requirements:

> For example, in recent months Geoscience Australia and the Northern Territory Government have requested summary well and seismic data for 2007 and 2008. However, it is our view that with few exceptions, that data has already been provided to Geoscience Australia as part of our reporting requirement as each activity is undertaken. (sub. DR33, p. 2)

FINDING 8.1

There is considerable evidence of unnecessary regulatory burdens affecting the upstream petroleum sector, resulting in lengthy delays and substantial resource demands being placed on sector participants. These burdens can be overwhelmingly attributed to two major problems, namely lengthy and complex approval processes, and onerous and in some cases duplicated reporting requirements.

Pipelines

Given their often cross-jurisdictional nature, pipelines are often subject to particularly complex licensing and approval processes. With most of Australia's oil and gas reserves being located offshore, production frequently involves the use of pipelines that pass through multiple jurisdictions. Pipelines typically pass through Commonwealth waters, coastal waters and State or Territory onshore jurisdictions.

They are therefore subject to multiple licensing and approval processes in areas such as safety, integrity, the environment, and pipeline construction and operation. APPEA noted:

> 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 [Pipeline Management Plan], 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. (sub. 16, p. 36)

In addition, in reference to its Gippsland project, ExxonMobil stated:

> The Gippsland project includes offshore facilities that recover oil and gas from reservoirs located under Commonwealth waters, oil and gas pipelines that transport petroleum across Commonwealth submerged lands, State submerged lands and then finally State controlled lands before arriving at onshore processing plants located in a State jurisdiction (in this case Victoria). This mixture of jurisdictions has given rise to a large number of duplicated requirements that must be satisfied within the authority of the respective jurisdictions. While Federal and State responsibilities individually dictate the extensive approval requirements in each respective jurisdiction, given the multi-jurisdictional nature of most petroleum projects the result is that there are multiple duplicated approvals processes. (sub. 13, p. 4)

The existence of multiple regulators for a single piece of infrastructure also raises interface issues. That is, there is a real risk of blurred lines of responsibility between the various regulators and regulatory gaps appearing when responsibilities are not clear.

This point was highlighted by APPEA:

> The application of state legislation always carries the potential to result in discrepancies in regulatory requirements across jurisdictions … 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. (sub. 16, p. 18)

While Apache noted:

> Devil Creek is a new domestic gas processing project located east of Cape Preston in the Pilbara region of WA. Devil Creek is an onshore project connected to an offshore gas field (Reindeer) in Commonwealth waters by means of a pipeline … different regulators have overlapping areas of influence and responsibility (the gas supply

pipeline is the responsibility of the Department of Industry and Resources (DOIR) offshore and of the Department of Consumer and Employment Protection (DOCEP) onshore). (sub. 14, p. 3)

(Regarding the comment from Apache, from January 2009 the WA Government formed a new Department of Mines and Petroleum, combining the previous mining and petroleum regulatory role of the Department of Industry and Resources (DoIR) and the resource safety responsibilities from the Department of Consumer and Employment Protection.)

FINDING 8.2

The often cross-jurisdictional nature of pipelines means they are typically subject to particularly complex licensing and approval processes. Their licensing and regulation is covered by multiple jurisdictions and multiple regulators, which leads to duplication of processes, and delays. The presence of multiple jurisdictions and regulators also raises concerns in regard to interface issues and blurred lines of responsibility between regulators.

8.2 Inter-jurisdictional comparisons

This section provides a comparative account of the regulatory performance across various jurisdictions in Australia. (International comparisons are discussed in section 8.4.) It seeks to identify relative strengths and weaknesses of the regulatory arrangements in different jurisdictions. It does not provide a definitive ranking of the jurisdictions (although it discusses some surveys that have attempted to do so). The JA–DA arrangements, as discussed in chapters 4 and 5, complicate inter-jurisdictional comparisons because many regulatory responsibilities are shared between the Australian Government and respective State and Territory Governments.

Regulatory performance varies between jurisdictions

The Commission has received some consistent messages about comparative regulatory performance in this study. A common message is that regulatory inconsistencies and duplications exist in virtually all jurisdictions in Australia. However, some governments have adopted apparently effective measures to reduce these problems.

Many participants observed that South Australia has a relatively straightforward approval system, and that its petroleum legislation can be considered a benchmark for other jurisdictions.

For example, APPEA commented:

> Of those that attended the [September 2008] 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. (sub. 16, p. 43)

In two recent international surveys, South Australia has consistently been rated by resource business executives as the most attractive Australian jurisdiction in which to invest (Fraser Institute 2008b; ResourceStocks 2008). Such a favourable assessment largely reflected the perceived effectiveness of SA Government policies towards resource development projects (box 8.1).

However, South Australia has no significant offshore upstream petroleum activity. Accordingly, there are likely to be fewer demands made of the upstream petroleum regulatory agencies in South Australia relative to those in some other jurisdictions, and fewer approval interactions with the Australian Government.

The Commission has also noted that South Australia's high ranking in survey comparisons could have been influenced by its Plan for Accelerating Exploration program. This program provides grants to businesses undertaking resource exploration in that State and is, perhaps not surprisingly, popular with the resources sector. In effect, it is an industry assistance program and does not relate to regulatory performance.

Some participants saw the Northern Territory as more proactive in dealing with business concerns about regulatory burdens than some other jurisdictions. The Commission has noted Inpex's plan to build a pipeline from offshore Western Australia to Darwin despite significantly increased project costs. There appears to be a widespread perception that there is less 'red tape' associated with investment in the Territory, particularly for major projects. The aforementioned global surveys confirmed this perception as the NT Government's policies towards resource development were also highly rated by survey respondents.

Box 8.1 **Survey comparisons of regulatory performance**

The Commission has drawn on three global surveys, each completed in 2008, for evidence on comparative regulatory performance across jurisdictions in Australia and elsewhere. These surveys reflect up-to-date opinions from a wide base of survey respondents representing mining and petroleum businesses around the world.

Two of the surveys (conducted by the Fraser Institute and the ResourceStocks magazine) canvassed mining company executives for their views on the attractiveness of government policies towards resource projects in general. They cover 68 and 76 jurisdictions respectively, including individual Australian States and the Northern Territory.

In both surveys, South Australia was Australia's highest-rated jurisdiction — ranking 15th and 2nd respectively. Tasmania and the Northern Territory were also rated highly.

The poorer performing Australian jurisdictions were Victoria, Queensland (ranked lowest of Australian jurisdictions in the Fraser Institute survey) and Western Australia (ranked lowest of Australian jurisdictions in the ResourceStocks survey). The ranking of Western Australia in the Fraser Institute survey fell to 25th in 2007-08 from 11th in 2005-06. Queensland's ranking of 30th in the 2007-08 Fraser Institute survey was in line with the state's relative performance in earlier years, except for 2006-07 when the state was ranked 8th.

In another survey conducted by the Fraser Institute, inter-jurisdictional comparisons focused on impediments to investment specifically in the upstream petroleum sector. Survey results for Australia were reported only at the national level. Australia was ranked 75th of the 81 jurisdictions compared in terms of posing *most* barriers to investment. In other words, Australia was assessed as one of the *most favourable* places for investment in petroleum exploration and development (ranked behind Thailand, New York, Denmark, Ohio, Saskatchewan and Azerbaijan).

Sources: Fraser Institute (2008a, 2008b); ResourceStocks (2008).

Feedback provided to the Commission suggested Victoria's petroleum regime was generally seen in a positive light by industry participants. It was suggested that project proponents are typically able to get approvals within a reasonable timeframe if they 'do their homework'. Further, the Victorian Government informally undertakes some regulatory activities on behalf of the Tasmanian Government in relation to the Well Operation Management Plans and environmental assessments within the Tasmanian offshore waters (Victorian Government, sub. 7). This arrangement helps promote consistent regulatory practices between the two States.

Less favourable comments on regulatory performance have been made about the regulation of upstream petroleum projects in Queensland. Queensland's petroleum legislation was seen as overly prescriptive. Further, concerns were raised about a lack of communication between the Queensland Environmental Protection Agency

and the Department of Mines and Energy. On the other hand, parts of Queensland arguably have a more fragile environment and a greater reliance on tourism than some other jurisdictions. These factors might have led to more stringent environmental requirements being applied to project approvals. The State ranked lowest of the Australian jurisdictions in the 2007-08 Fraser Institute survey of resource business executives, although it had performed relatively well in the previous year's survey results (Fraser Institute 2008b).

Many participants made negative comments about the regulatory burdens in Western Australia, where there have been considerable concerns about approval backlogs. In particular, these concerns were said to have led proponents of some major projects planned for Western Australia to consider the Northern Territory as an alternative investment destination. Western Australia was rated as the worst performing jurisdiction in Australia by the ResourceStocks (2008) global risk survey. That said, the recent rapid expansion of mining and petroleum activity in Western Australia is likely to have put WA regulators under greater resource pressures than those faced by their counterparts in most other jurisdictions.

In response to the draft report, the WA Department of Mines and Petroleum stated:

> One of the major priorities of DMP in 2009 will be to significantly improve the approvals process for resources projects and the Department is taking the lead in the reform process. The aim is to ensure that elements of the approvals process within DMP's jurisdiction are acted on in a timely and efficient manner, beginning with several short-term measures to improve its performance and reporting against its key title and post-title approvals. (sub. DR22, p. 1)

The Commission has received mixed messages regarding the Australian Government's regulatory performance. Some concerns were expressed about regulatory duplication at the Commonwealth level, and about environmental regulation. On the other hand, recent initiatives to consolidate the *Offshore Petroleum Act 2006* (Cwlth) and recent reforms to the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) have received strong support from the petroleum sector.

The regulation of petroleum development in the Timor Sea takes place under the Timor Sea Treaty between the Australian Government and the Government of East Timor (chapter 4). No major concerns about the regulation of upstream petroleum activities in this area have been raised with the Commission, although there have recently been tensions between the Government of East Timor and Woodside over the location of a downstream processing plant for Woodside's Greater Sunrise project (Grigg 2008).

FINDING 8.3

Some governments appear more proactive than others in adopting measures to improve regulatory practices. This appears to have been reflected by variation in perceptions by industry of regulatory performance for different jurisdictions.

8.3 Economic costs

The legal and administrative complexity that characterises the regulatory framework governing upstream petroleum projects in Australia imposes significant regulatory burdens on project proponents. These burdens can affect the economics of petroleum supply through the effects of increased compliance costs, delays in project development and completion, and increased uncertainty. This section focuses on estimates of costs for the first two categories, with measurement of the costs of uncertainty being much more difficult and not attempted here.

Compliance costs

The overall compliance cost for large and complex projects can amount to millions of dollars as project proponents go through lengthy and elaborate assessment and approval processes. This results in a non-trivial productivity loss in the petroleum supply process.

Nonetheless, compliance costs are typically modest relative to the total project cost. A number of case studies presented in table 8.2 indicate the magnitude of resource burdens on petroleum businesses in relation to approval processes. APPEA provided further evidence of such costs:

> 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. (sub. 16, p. 42)

Delay costs

Potentially much more significant are regulatory costs associated with project delays and uncertainties, including:

- increased project expenditures
- reduced flexibility to respond to market conditions

- inflated capital costs
- increased difficulty of financing projects
- reduced present value from resource development.

Increased project expenditures

Delays represent a substantial impediment to upstream petroleum projects because of the disruption caused to project plans. Project proponents can face significantly higher exploration and development costs as a result of delays for the approval of seismic survey and drilling activities. As noted in section 8.1, which quoted daily standby rates for semi-submersible drilling rigs at around $1.1 million, an unexpected delay of even a few days in obtaining approval could cost the project proponent millions of dollars in operating expenditure.

Indeed, it is not always possible for project proponents to swiftly reschedule leases of mobile equipment such as drilling rigs and seismic vessels if the original booking is cancelled because of approval delay. This is particularly the case when the equipment is in high demand, or when the activity can only be carried out within a narrow time window because of regulatory constraints, such as seasonal whale exclusion zones.

Reduced flexibility for responding to market conditions

Industry participants emphasised the importance of timely and expedient approval processing for LNG projects. The financing of these projects typically depends on securing long-term contracts with gas purchasers. Given a typical decade-long contracting cycle, the time window for locking in a supply contract in the early project development stages is narrow. Consequently, even minor approval delays can restrict project proponents' ability to capture prevailing commercial opportunities.

Inflated capital costs

During periods of rapid cost inflation, approval delays can lead to substantial escalation of capital expenditures, increasing the difficulties faced by project proponents. This seems to have been the case in the period between 2005 and 2007, with offshore exploration and production costs surging by over 50 per cent. In particular, the cost of leasing offshore rigs increased by over 300 per cent during 2007 (Fowler 2007). As noted earlier, BP (sub. 15) stated that labour costs for

upstream oil and gas projects in Western Australia increased by around 20 per cent per year in the four years to January 2008.

The willingness of Inpex to spend an estimated additional $700 million (Burrell 2008) to build a pipeline to Darwin — rather than face further delays associated with locating a hub in the Kimberley — for its Ichthys LNG project provides further evidence of the significance of potential delay costs. Affected by increasing construction and raw material costs, the total cost estimate for this project has been revised from around US$10 billion to more than US$20 billion in the past few years (Wong and Tsukimori 2008).

Increased difficulty of financing projects

Not all petroleum businesses have the financial capacity to afford lengthy and costly approval deliberations. Regulatory delays can severely restrict the ability of small and medium-sized businesses to raise project finance. In particular, those that rely on debt financing as a source of investment capital would have to bear the cost of having standby undrawn credit facilities during the period of delay. Nexus observed that the significant increase in capital costs as a result of approval delays:

> … has a significant impact on a small to medium company that is raising debt and equity finance to develop the project. (sub. 3, p. 6)

Reduced present value from resource development

Regulatory constraints that delay or defer beneficial production start up during any of the stages of exploration, development and production can diminish project returns. In each case, the present value of realising economic benefits from petroleum production is reduced. Such an economic cost would be even larger when delays occur after the project proponent has already incurred the large sunk costs associated with exploration and development. As Apache noted:

> Oil and gas companies undertake projects which last for decades. Consequently these companies evaluate costs and benefits on a Present Value (PV) basis using discounted cash flow calculations. The actual monetary cost consequent on regulatory compliance is commonly far less than the cost of delay in PV terms to a profitable project. (sub. 14, p. 1)

APPEA expressed a similar view but also pointed out the particular impact of delays on gas projects:

> 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. (sub. 16, p. 46)

What is the cost of unnecessary delays?

The Commission's assessment of the case studies presented to this study, as well as the approval processes and related regulatory requirements, indicates that a streamlined approval process could significantly reduce project timelines (chapters 4 to 7). For example, the Victorian Government (sub. 7) suggested that the time taken to obtain a production licence could be halved to around 6 to 12 months if all approvals were handled by one agency, with similar reductions feasible for other licences. The Commission accepts, based on the evidence it has seen, that this is a reasonable objective. Since the draft report a number of regulators and industry proponents have also described this as a realistic and desirable objective, while also noting that it could only be achieved if there are significant changes that would eliminate many of the current approval processes between the JA and DA.

It is impossible to quantify precisely the aggregate cost impact of *unnecessary* regulatory burdens delaying and discouraging investment in the upstream petroleum sector. Principally, judgment is required about which procedures are necessary and which are not. Such an exercise also requires detailed financial data from specific projects — not all of which are publicly available — as well as proprietary or commercial-in-confidence information on investment returns and hydrocarbon prospectivities. Nevertheless, it is feasible to derive indicative estimates of delay costs and, hence, reform benefits.

The Commission has applied cash-flow discounting techniques to estimate the economic cost associated with approval delay under different scenarios. An illustrative case study was constructed using representative data and judicious assumptions relating to a project's capital and operating costs, internal rate of return, tax rate and output rate (box 8.2). Details of the case study and its data sources are in appendix E.

The Commission's estimates confirm that regulatory delays can impose significant economic costs (table 8.5). The long-run cost associated with a one-year delay in approval of exploration activity was estimated to be a 9 per cent reduction in the net present value (NPV) of the project. This cost estimate essentially reflects a one-year delay of the entire cash flow, based on a 10 per cent discount rate that was applied in the model to measure the opportunity cost of capital for the upstream petroleum sector.

Not surprisingly, a delay in production start-up (after exploration costs have been incurred) would cost more than a delay in exploration. In this case, the long-run cost of a one-year delay in project development was estimated to be an 18 per cent reduction in the project's NPV.

Box 8.2 Representative cash flows of Australia's economic fields

An illustrative case study was constructed to simulate cash flows over the exploration–development–production cycle of a representative economic field in Australia. The distribution of cash flows over the project life was estimated using aggregate data from a study by Mackenzie and Cai (1993) for all economic petroleum fields discovered in Australia up to 1987. It appears that no more up-to-date database is available.

By drawing on a comprehensive database, the case study captures the 'average' characteristics — particularly project size, cost structure and hydrocarbon prospectivity — of all petroleum operations in Australia. This provides a credible approximation of the 'relativity' between various cost and revenue flows — enhancing the robustness of cost estimates when they are expressed in relative terms.

A discount rate of 10 per cent was used in calculating the present value of a stream of after tax cash flows. This represents the weighted average cost of capital for the sector, comprising a risk-free rate and an equity risk premium commensurate with non-diversifiable project risks.

Source: Mackenzie and Cai (1993).

The Commission also undertook sensitivity analyses for different discount rates (or values of the weighted average cost of capital (WACC)) (table 8.5).

Table 8.5 Sensitivity tests for different values of the weighted average cost of capital

Weighted average cost of capital	*One-year delay in exploration approval*	*One-year delay in development approval*
%	% of NPV[a]	% of NPV[a]
8	-7.4	-11.4
9	-8.3	-14.3
10	-9.1	-18.4

a Net present value.

Source: Commission estimates.

Obviously the economic cost of approval delays increases as the WACC increases. Changing the WACC within a reasonable range has a small effect on the estimated NPV reduction for a delay in exploration approval, but a larger effect on the cost estimate of a delay in development approval. This higher sensitivity reflects

increased significance of the WACC in discounting delayed revenue flows after exploration costs have already been incurred.

The Commission's estimates are broadly consistent with the findings of some external studies with a similar focus on regulatory delay costs. For example, in a Canadian study undertaken by Jorgensen et al. (1996), the costs of regulatory delay were estimated for various types of mineral extraction projects to range from 6 to 90 per cent of the project cost in real terms for delay periods of between 6 and 18 months. Donze (1992) argued that the costs of project delays caused by environmental regulation in the United States amounted to 10 per cent of the capital cost.

The Commission's results are sensitive to changes in parameters over time, and to the changing nature of projects. For example, the economics underlying recent large scale export LNG projects may be somewhat different to those in the Mackenzie and Cai (1993) database drawn on by the Commission. However, these changes are unlikely to lead to lower estimates. Indeed, LNG projects are typically very large and highly capital intensive.

The cost of delays over time to the sector, and to the economy as a whole, obviously will depend on the number of projects delayed unnecessarily and the additional costs incurred. But given the size of individual projects and the pervasiveness of regulatory delays, costs are potentially significant. Indeed, given APPEA's estimate that around $80 billion could be invested in new gas projects in the Pilbara and the Kimberley alone in the next decade, and that $200 billion worth of projects are either in production, under construction or being planned in Australia's north-west or central Queensland (APPEA 2008), the cost of delaying production and revenues could total several billions of dollars each year.

In response to the draft report, the WA Department of Mines and Petroleum said:

> In the Commission's estimation of the economic costs of project delays, the primary data source is based on petroleum fields discovered in Australia up to 1987. Also, the cash flow modelling employed appears to be based on simply 'time-shifting' the production profile of a petroleum project and it is not clear how the modelling accounts for changes in the time profile of capital and operating costs. These issues, combined with speculation on the appropriate discount rate and period of over which to discount the value of a project, brings into question the veracity of any values derived on the costs of regulatory impediments. (sub. DR22, p. 21)

The Commission agrees that its results are only broadly indicative of the costs of regulatory delay and, as noted earlier, are sensitive to a range of assumptions. However, the analysis highlights that delaying revenue streams, particularly once

significant expenditure has been incurred for large projects, reduces the NPV of a project significantly.

Moreover, the Commission's results reveal only a portion of the aggregate cost impact of unnecessary regulatory burdens delaying and discouraging investment. Just as significant, but harder to quantify, is the increased risk and uncertainty affecting individual projects. Affected businesses face impediments arising from inflated capital costs, increased difficulty of financing projects, and reduced flexibility in responding to market conditions.

It is likely that in times of economic downturn, the actual costs of delays (measured in dollars) may be reduced, because both revenue streams and the number of projects are likely to be lower. However, difficult economic times also create increased uncertainties and greater difficulties in financing projects, and may render some projects quite 'marginal' where they were previously envisaged as being highly profitable. In these difficult economic times unnecessary regulatory burdens may become pivotal for investment decisions.

The economic cost of regulatory delay would be manifested partly as a reduction in the present value of tax revenues received by governments. Arguably, a delay means a deferral of tax payments that will eventually be recouped in a future period. Although this might appear to cause no direct loss of tax revenue to governments, there is an economic cost associated with revenue streams being delayed when the time value of tax money is taken into account.

FINDING 8.4

Unnecessary approval delays cost the economy dearly. Project approvals are taking longer than a streamlined approval process would allow, potentially diminishing the present value of petroleum resource extraction in Australia by billions of dollars each year.

Difficult economic times might reduce this figure, as some projects might not proceed due to greater uncertainty, and delayed revenue streams are likely to be smaller. More projects are also likely to become 'marginal'. Unnecessary regulatory burdens could tip the balance for these marginal projects. Therefore, in difficult economic times it is equally, or even more, important to remove unnecessary regulatory burdens.

8.4 Impact on investment attractiveness

Compliance and delay costs arising from the regulatory regime reduce the sector's profitability and, hence, its ability to attract project capital. Nevertheless, it is

difficult to quantify precisely the effect on investment in upstream petroleum projects in Australia. Many factors other than cash-flow prospects influence the project performance and investment strategy of individual businesses.

Competition for global capital

The Australian upstream petroleum sector operates in a globally competitive environment where exploration and investment capital is highly mobile. The international competitiveness of Australia as a potential destination for global capital flows hinges on the sector's ability to obtain a return on investment that is commensurate with the risks, costs and efforts involved. Specifically, the sector's investment attractiveness is subject to numerous influences, including regulatory performance, sovereign risk, taxation, prospectivity, discovery costs, capital and operating costs, price volatility and infrastructure accessibility.

Regulatory performance

Regulatory performance — the key focus of this study — has significant implications for investment attractiveness in the upstream petroleum sector. As discussed above, the complexity and the time taken in satisfying regulatory processes adds uncertainty to a prospective project, making a material difference to its valuation and commercial viability. Moreover, regulatory inefficiencies potentially limit the ability of project proponents to respond to changing market conditions in a timely manner.

Delays increase operating expenditures and capital costs, giving rise to implicit costs associated with deferred or cancelled projects, forgone earnings and lost market opportunities. Project delays can also limit the availability of cash flows and loans to finance new exploration and development projects.

Sovereign risk

Sovereign risk primarily relates to the stability and credibility of a country's legal system. In particular, legal protection of property rights is essential for reducing the risk of asset expropriation facing investors (box 8.3). Other influences on the level of sovereign risk include industrial relations and exposure to terrorism activities.

The importance of sovereign risk to investment decisions is well recognised by petroleum businesses. For example, Woodside (2007) told its shareholders:

> We believe risky places are getting riskier in the oil and gas industry. These include Russia, Bolivia, Ecuador, Angola and Venezuela, just to name a few.

We have been closely assessing these risks and will continue to do so. You can expect your company to make appropriate changes in its asset portfolio in recognition of worldwide risk trends. (Woodside 2007, p. 9)

Box 8.3 **Risk of asset expropriation**

Resource nationalism has occurred in various parts of the world, leading to the expropriation of private petroleum exploration and production assets by host countries.

Many asset expropriations occurred between 1959 and 1985, with the majority taking place in Middle-East countries including Kuwait, Libya, Qatar, Saudi Arabia, Egypt, Algeria, Iran and Iraq. Historically, asset expropriations also occurred in South American countries including Ecuador, Peru, Venezuela, Bolivia and Argentina.

Recently, there has been a re-emergence of resource nationalism in some countries. A number of petroleum businesses in Venezuela, Bolivia and Ecuador were nationalised in 2006 and 2007. Forced nationalisation also occurred in Russia in the mid-2000s.

Source: Guriev et al. (2008).

Australia has a stable legal system and a liberal policy approach to foreign investment. APPEA stated:

> To date Australia has been an attractive petroleum investment environment and developed a reputation as being a sound place to do business … But Australia's lower sovereign risk is accompanied by lower returns and margins. (sub. 16, p. 5)

While Australia is rightly seen as place of low sovereign risk, were stricter 'use it or lose it' approaches introduced for retention leases where regulators considered that resource extraction was commercial, there would be important sovereign risk issues to consider when implementing such changes (especially where leaseholders had previously spent considerable sums on exploration). This issue is discussed in more detail in chapter 5.

Taxation

In Australia, petroleum in its natural state is the property of the Crown. As such, governments are entitled to collect royalties on any petroleum extracted within their respective jurisdictions (table 5.1). Petroleum businesses are also subject to income taxes levied by the Australian Government.

Recent studies have indicated that Australian governments appropriate between 45 per cent and 66 per cent of the value of oil and gas produced, depending on the project location. Such tax rates (including resource rent tax, royalty payment and income tax) are substantially higher than those in Ireland, the United Kingdom and

New Zealand, but lower than those in Norway and many Middle-East countries (GAO 2007).

Prospectivity

Australia has a high level of geographical risk in terms of low petroleum prospectivity, according to Powell (2008). This reflects the absence of major oil discoveries comparable with those in other parts of the world such as the Middle-East and, more recently, Brazil. APPEA noted:

> Perceptions of low oil prospectivity are discouraging exploration, even though many of Australia's offshore and onshore areas are largely unexplored. (sub. 16, p. 6)

Discovery costs

Australia is considered to be a high-cost place for upstream petroleum exploration and development (Powell 2008). As APPEA explained, in Australia:

> … oil project developments have tended to be in deeper water and more technically challenging. (sub. 16, p. 5)

Moreover, the average offshore commercial field discovery in Australia is small by global standards — particularly for oil (APPEA 2006). This limits the opportunities for achieving economies of scale and scope through an expansion in upstream petroleum activities.

Price volatility

Petroleum businesses operating in Australia can barely affect world supply or demand and, therefore, are price takers in global crude oil markets. Unlike some national oil businesses, they cannot mitigate the risk of oil price fluctuations through strategic production decisions. According to APPEA:

> … oil price volatility and the overall future trend in oil prices are among the most significant risks faced by the upstream petroleum industry. (APPEA 2006, p. 37)

Pricing of natural gas is more heavily influenced by transport costs and regional market structures. Gas prices in Europe and North America tend to align with oil prices; as do LNG export prices in Australia (AER 2007). However, the wellhead price of natural gas produced in Australia has been largely determined by domestic market conditions, often in isolation from gas market developments elsewhere. As exports of LNG from Australia increase, however, domestic gas prices for gas fields in proximity to LNG export facilities are likely to be more heavily influenced by international trends.

Infrastructure accessibility

The remoteness of oil and gas reserves underpins the importance of the cost and access to necessary infrastructure for upstream petroleum projects in Australia. The large size and low population density of Australia often make access to low-cost infrastructure unlikely. For example, the costs of building large LNG facilities in remote Western Australia are considerably higher than those required in some other parts of the world. APPEA stated:

> … large gas fields remain undeveloped decades after discovery and new gas discoveries are often remote from markets and infrastructure and therefore difficult to commercialise. (sub. 16, p. 5)

In particular, major hydrocarbon discoveries in remote locations in central Australia and offshore Western Australia have raised a variety of infrastructure challenges. One such challenge is the need to build long-distance pipelines, such as the Dampier–Bunbury pipeline that stretches over 1800 kilometres in Western Australia (PC 2004d).

Similarly, transport costs reduce achievable returns on investment in areas where reserves are located far from key markets. This is often the case for supplying LNG, which is logistically difficult and expensive to transport. In this case, gas producers in Australia have a comparative advantage in selling to proximate markets such as Japan and China rather than distant markets such as Europe and North America.

Removing regulatory impediments to investment

The commercial viability of investing in the upstream petroleum sector is heavily influenced by the end product prices and overall costs. Oil and gas prices are volatile and hard to predict in the longer term. Governments cannot change some negative influences, such as low oil prospectivity and geographical remoteness. On the other hand, improving regulatory performance can be a key to reducing regulatory costs and offsetting those adverse influences on investment returns in the sector in Australia.

For highly profitable projects, the costs of unnecessary regulatory burdens are less likely to influence whether the investment proceeds. In such circumstances, the project could remain commercially viable and still be assessed by some businesses as an attractive investment despite a reduction in profitability as a consequence of unnecessary regulatory burdens. Nevertheless, even if the level of investment is unaffected, the resultant reduction and delay in profit and tax revenue would represent a significant welfare loss to local and foreign shareholders, and the Australian community.

For marginally profitable projects, approval delays and other regulatory inefficiencies and uncertainties can pose a crucial disincentive for businesses to invest. Typically for these projects, the proponent must consider a low rate of return, a protracted payback period, and accept the risk exposure of inevitable price fluctuations. The margin for error is low and even small increases in uncertainties can make projects non-commercial. Just one of these uncertainties is the assessment by the resource management regulator of what constitutes an acceptable overall recovery of the resource. Pressure from the regulator to invest additional capital or to slow extraction (to enhance overall recovery) may reduce returns further. Therefore, effective and efficient regulatory arrangements take on increased importance in improving investment outcomes.

In particular, approval timelines and their predictability stand to strongly influence project proponents' assessments of the time and capital commitments to move through the exploration–development–production cycle and their overall impact on project viability. APPEA reflected on the experience of its members in this respect:

> … 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. (sub. 16, p. 48)

FINDING 8.5

Improved regulatory arrangements hold the key to reducing regulatory costs and, thereby, improving international competitiveness and offsetting some of Australia's natural disadvantages in attracting exploration capital from international sources — particularly low oil prospectivity and geographical remoteness from gas markets and infrastructure.

Environmental approvals is one regulatory area considered by some participants to be a potentially significant impediment to attracting new investment in Australia. This view seems to be consistent with the findings of a study commissioned by the Canadian Environmental Assessment Agency (2000) to compare the environmental assessment regimes of eight countries (including Australia) in terms of their regulatory performance. Although not specific to upstream petroleum activities, this assessment was based on widely applicable criteria for best practice regulation, such as clarity, certainty, timeliness and institutional capacity.

Australia's environmental assessment regime was rated ahead of those of Canada and the United States for its relative capacity to minimise impacts on industry competitiveness for attracting investment. All these federal regimes, however, were seen to be generally more cumbersome than those of the non-federal countries

included in this study — namely, Chile, France, Germany, Japan and the United Kingdom. Such rankings were apparently influenced to a degree by the need to harmonise or coordinate environmental regulation at multiple jurisdictional levels within a federation.

In a more recent Global Petroleum Survey conducted by the Fraser Institute (2008a), Australia was rated as one of the most attractive places around the world for investment in petroleum exploration and production (box 8.1). This superior rating reflected survey respondents' overall favourable assessment of Australia against a broad range of factors affecting their investment decisions, including geopolitical risk, commercial environment and regulatory climate. In respect of regulatory performance (covering the cost of regulatory compliance, regulatory uncertainty and environmental regulation), Australia scored notably better than the US offshore, Chile, New Zealand, Norway, the United Kingdom, and Canada (except for the provinces of Manitoba and Saskatchewan).

It should be noted that such positive assessment of Australia's regulatory performance at the national level cannot be generalised across all Australian jurisdictions. Indeed, a contrary view was expressed by APPEA, pointing to:

> … an international perception that Australia is a difficult place to invest in oil and gas exploration and development. (sub. 16, p. 10)

As noted in section 8.2, there are considerable variations in regulatory performance across the jurisdictions in Australia. Moreover, government initiatives undertaken to improve regulatory outcomes appear to be a key performance driver. These observations point to ample scope and capacity for regulatory improvement in many areas. With other international jurisdictions improving on their own regulation of the upstream petroleum sector, reducing regulatory impediments to investment in Australia could help deliver significant economic benefits for the nation.

FINDING 8.6

Global surveys have provided an overall favourable assessment of Australia's regulatory regime in the upstream petroleum sector. However, there is clearly scope for improvement. Environmental approvals is one regulatory area in which Australia appears to fall behind some other comparable countries in minimising inefficiencies and impediments to investment. More broadly, significant reform benefits for Australia can be achieved provided all jurisdictions undertake initiatives to adopt regulatory best practices identified in Australia and abroad.

9 Models for a national regulator

Key points

- Institutional and associated regulatory reform could address weaknesses of the current regime in relation to duplication and complexity of requirements — particularly for cross-jurisdictional projects. It could also address delays arising from the administration of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth). Regulatory duplication and inconsistencies can lead to inefficiencies. However, from the perspective of 'competitive federalism', there may be some benefits from intergovernmental competition in regulatory regimes.
- Desirable objectives for an improved institutional model include:
  - separating policy formulation and advice from regulatory administration when practicable
  - minimising multiple approvals or duplicate assessment requirements
  - minimising administration by multiple agencies, or ensuring clear administrative arrangements where multiple agencies are involved
  - minimising inconsistencies in legislative requirements and decision making
  - ensuring regulators have clear regulatory objectives and do not face significant conflicts of interest
  - ensuring regulators are adequately resourced with appropriately skilled people
  - consolidating specialist expertise, efficiently using scarce resources and enhancing the ability to retain specialist expertise.
- Two key issues associated with an expanded or new regulatory authority are the scope of its activities and cost recovery mechanisms to fund those activities.
- Three options for an expanded national petroleum regulator include:
  - a *national petroleum regulator* with responsibility for both onshore and offshore petroleum regulation, although implementing this option would appear to face significant challenges
  - a *national offshore petroleum regulator* with responsibility for resource management and environmental functions in all offshore areas or, alternatively, limited to Commonwealth waters
  - a *national pipeline regulator* with responsibility for approving cross-jurisdictional pipelines or coordinating such approvals.
- The current full cost recovery model (with appropriate governance) as used for the National Offshore Petroleum Safety Authority appears to be the most appropriate for any new regulatory agency.

Under the terms of reference, the Commission was asked to consider options for a national regulatory authority — such as the National Offshore Petroleum Safety Authority (NOPSA) — to manage all regulatory approvals associated with upstream petroleum activities as a means of addressing issues of regulatory duplication and inconsistencies. Issues with the current regulatory framework are discussed in section 9.1.

Two key issues associated with an expanded or new regulatory authority are the appropriate scope of its activities and funding mechanisms for these activities. Possible models for assigning regulatory functions are outlined and assessed in sections 9.2 and 9.3, respectively.

Any new or expanded authority would need to be funded by government or the upstream petroleum sector, or a combination of both. Currently, NOPSA is fully funded by industry on a cost-recovery basis. However, the Australian Petroleum Production and Exploration Association (APPEA) raised concerns about the impact of cost recovery models given the sector's significant contribution to the community through taxes and royalties. If the regulator is to be funded by the sector, it will be important that there are appropriate 'checks and balances' to ensure the regulator is operating efficiently. Processes to determine funding levels must also be transparent. Cost recovery arrangements are discussed in section 9.4.

9.1 Issues with the current framework

As detailed in previous chapters in this study, the main burdens considered to be unnecessary arising from the current regulatory regime include the following:

- A lack of clear and certain administrative timelines contained in laws or regulations (chapters 5 and 6). Where timelines do exist for regulators there is a lack of compliance or enforcement mechanisms, and in many cases poor transparency and reporting of regulators' performance against legislative timelines.
- Duplication of administrative requirements, particularly where projects are cross-jurisdictional or where there is overlap of regulatory responsibilities. For example, environmental approvals are potentially required from both the Designated Authority (DA) under the Commonwealth's *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGSA) and the Australian Government Environment Minister under the Commonwealth's *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) (chapter 6), and often under other State and Territory Acts.

- The current approval process can be complex and generally involves multiple regulators. For example, production in Commonwealth waters will generally require separate approvals from the Joint Authority (JA), the DA and NOPSA (chapters 5 and 7).
- Regulatory agencies may be under-resourced and have difficulty retaining necessary expertise. Multiple agencies undertaking similar functions can result in competition for scarce resources and technical expertise (chapter 6).
- A lack of consistency in regulatory requirements and decision making over time and across jurisdictions or agencies. Onshore legislative frameworks differ and there are also inconsistencies in decision making, even where legislative requirements are the same (chapters 5, 6 and 7). Some decisions by the regulator (particularly in the case of resource management) are inherently judgemental. Examples include approval of field development plans and meeting the government's desire to maximise (within limits of what is judged commercial) overall recovery of the resource.
- There are examples where businesses have lost significant time and resources due to changes in government policy and a lack of timely information made available on environmental and other risks (chapter 8).

While regulatory provisions are harmonised for offshore areas under the OPGGSA and (in most) State and Territory petroleum Acts and regulations, projects that are cross-jurisdictional appear to experience significant regulatory impediments. According to Nexus:

> … where petroleum activities cross jurisdictions from offshore to State/Territory waters and into onshore facilities there is a significant increase in regulatory requirements and processes. (sub. 3, p. 4)

Therefore, there would appear to be scope for institutional and legislative reform to address duplication and complexity of requirements — particularly for cross-jurisdictional projects — and to address delays arising from the administration of the OPGGSA.

Constitutional issues

Much of the legislative and regulatory overlap that currently exists reflects historical factors and the development of institutional arrangements. Arguably given the preponderance of oil and gas resources found offshore in Australia, the most significant 'institutional arrangement' is the division of powers between the Australian Government and the State Governments as defined by the Australian Constitution.

Australia's federal model has a number of distinctive features. In particular, it has a relatively high degree of shared regulatory and legislative functions between governments. This has led to a diverse set of intergovernmental arrangements to handle the associated coordination challenges (PC 2006b). The Australian Government, through its external affairs and corporations powers and its ability to grant financial assistance to States and Territories on specific terms and conditions, can impose regulation in areas that might normally be expected to fall under the exclusive power of the States and Territories.

9.2 Models for assigning regulatory functions

There are a number of potential models for assigning regulatory responsibilities. These models can be used to assess whether the current overlaps and inconsistencies in regulation are justified in terms of effectiveness and efficiency.

National regulation or competitive federalism?

In the context of a federal system of government, the Subsidiarity Principle can sometimes provide guidance as to the most appropriate level of government for a particular function (box 9.1). In principle, subsidiarity would suggest that a central (or higher) level of government would perform only those essential tasks that (for reasons of scale, capacity or need for exclusive power) cannot be effectively undertaken at lower levels of administrative decision making (Head 2005).

One of the central elements of the Subsidiarity Principle is the notion of intergovernmental competition, also referred to as 'competitive federalism'. Inter-jurisdictional duplication and inconsistencies in regulation is generally viewed as an inevitable outcome of competitive federalism.

Nonetheless, a national or more consistent approach to regulation also offers advantages — often referred to as 'cooperative federalism'. Efficiency and effectiveness of regulation can be enhanced by assigning responsibility to the national government, where there are:

- limited differences in local conditions and risks. That is, where there are minimal or no local factors that might require a tailored approach to meet specific local circumstances or preferences
- significant inter-jurisdictional externalities or 'spillovers'. Regulation of a good or service in one jurisdiction can impose costs on other jurisdictions. Preventing these may require a cross-jurisdictional approach

- economies of scale and scope. There may be significant efficiency gains through consolidating administrative and technical functions
- scope for national markets. Diversity in rules or regulations is likely to lead to high transaction costs with insufficient offsetting benefits
- compliance leakages. Mobility of capital and people across jurisdictions can undermine the regulatory effectiveness of the sub-national level of government and may undermine efforts to secure effective policy outcomes in areas of agreed national significance.

Box 9.1 **The Subsidiarity Principle**

Under the Subsidiarity Principle, responsibility for a particular function should, where practicable, reside with the *lowest* level of government. This rests on four main considerations:

- Sub-national governments are likely to have greater knowledge of the needs of their citizens and businesses.
- Decentralisation of responsibility and decision making makes it easier to constrain the ability of elected representatives to pursue their own agendas to the disadvantage of the citizens they represent.
- Intranational mobility of individuals and businesses exposes sub-national governments to a reasonable degree of intergovernmental competition.
- Initial emphasis on the lowest level of government encourages careful consideration or testing of the case for allocating a function to a higher or national government and thereby guards against excessive centralisation.

Source: PC (2006b).

Any move in upstream petroleum regulation towards a national regulatory framework or authority would need to carefully weigh these potential advantages against the disadvantages of diminishing competition and diversity. The current regime takes a national approach to some areas of regulation where there are less likely to be differences in local preferences and risks (for example, NOPSA has responsibility for occupational health and safety (OHS) regulation).

Where there are multiple regulatory regimes, some project proponents might be able to avoid undertaking activities in jurisdictions with inefficient regulatory arrangements. This can provide an incentive for governments to improve their regulatory performance. However, the location of a large resource in one jurisdiction can mean that proponents may still decide to proceed with a project despite a relatively unfavourable regulatory regime. This means that the competitive

pressures in a jurisdiction to improve its performance are attenuated by the degree to which they are endowed with oil and gas resources.

Governance arrangements

Current regulatory reforms in many OECD countries emphasise the benefits from separating responsibilities for policy formulation from regulatory compliance, according to the principle of 'single-purpose organisations' (OECD 2002). Under this model, an independent agency is given autonomy to administer a regulatory regime within the limits of its legislative authority. This can limit opportunities for 'bureaucratic drift' away from the legislative mandate, improving credibility, stability and consistency in regulatory decisions.

Further, the model of regulatory governance advocated by the UK parliament (Select Committee on the Constitution 2004), for example, is founded on the following principles:

- independent regulators acting at 'arm's-length' from Ministers
- independent corporate boards directing statutory regulatory agencies
- ministers accepting overall responsibility and accountability for regulatory policy and associated regulatory framework, including the setting of environmental and social standards
- a whole-of-government perspective being used to coordinate roles played by different parties of a regulatory regime.

In Australia, regulators include both dedicated regulatory agencies and departments of state — where regulation is one of many tasks performed within a single department. As is the experience internationally, the credibility and effectiveness of regulation can potentially be improved through establishing a structural separation between policy development and regulatory administration. As the Commission has previously argued in the context of price regulation:

> The credibility and effectiveness of prices oversight can be enhanced if the entity that advises Government about whether regulation is needed is separate from the entity that implements the regulation. This will help avoid a conflict of interest that might exist if the regulator undertakes both functions — namely that it may tend to favour regulatory functions that expand its role. (PC 2001b, p. 107)

Where a department currently undertakes both policy and regulatory functions, the establishment of a separate regulatory agency, specifically a statutory agency, is one way of achieving greater separation between policy development — which would continue to be performed by the department and its Minister — and regulatory administration. However, the establishment of a statutory agency can also involve

transition and establishment costs, and higher ongoing operating costs (PC 2004c). The efficiency of a new statutory agency would be improved where:

- it has a broad range of regulatory responsibilities
- when established, resources are transferred from existing agencies and departments undertaking the same regulatory functions
- corporate and other support functions can be shared with other existing regulatory agencies undertaking similar functions.

Nonetheless, while the Commission supports the principle of separating policy advice and regulation, it also notes that, in some circumstances, this may not be practicable or desirable, for example in small jurisdictions. Primary Industries and Resources South Australia raised concerns with separating policy advice and regulation (see further discussion in section 10.1).

The adopted governance structure for Commonwealth statutory agencies was strongly influenced by the Uhrig Review, which took the view that effective governance arrangements should not lead to diminution of ministerial power to supervise these agencies (Uhrig 2003). Where separate regulators are established, the role of Ministers can be retained through their policy formulation role and, in some cases, through retaining specific statutory approval powers.

The governance arrangements for NOPSA (box 9.2) provide an example of a statutory agency undertaking regulatory administration and compliance that operates at arm's length from the policy makers. NOPSA has independence on operational decisions while policy makers, in the form of the Commonwealth and State and Territory Ministers, retain influence over policy through an ability to amend the relevant legislation and an ability to give the authority written advice on policy principles. In addition, there are other accountability and oversight mechanisms. These include the appointment of the Chief Executive Officer and Board members by the Commonwealth Minister (on advice of the relevant ministerial council), and State and Territory Ministers having an ability to formally request information.

As well as noting the governance arrangements for NOPSA, the Commission also notes the arrangements of other independent regulators such as the Australian Competition and Consumer Commission, the Australian Energy Regulator, the Independent Pricing and Regulatory Tribunal of New South Wales, and the Gene Technology Regulator, as well as other Commonwealth and State-based regulators. Many of these are established with a Commission or Tribunal (or other similar body) as the decision making body, with support being provided by a secretariat.

Box 9.2 **Governance arrangements for the National Offshore Petroleum Safety Authority**

Governance arrangements for the National Offshore Petroleum Safety Authority (NOPSA) are outlined in the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA). The broad governance arrangements are as follows:

- The Commonwealth Minister with responsibility for NOPSA may give the authority written advice about policy principles. In coastal waters, this can only be done with the agreement of the responsible State and Territory Ministers. In Commonwealth waters, the Commonwealth Minister is required to consult with State and Territory Ministers.
- NOPSA must comply with directions from the Commonwealth Minister relating to the performance of NOPSA's functions or the exercise of its powers generally (but the Minister cannot direct NOPSA in relation to the operation of a particular project).
- State and Territory Governments can pass laws to empower NOPSA with regard to coastal and internal waters. In the case of internal waters, NOPSA is not obligated to exercise these powers. These powers can only be exercised if there is an agreement over fees payable.
- The responsible Commonwealth Minister appoints the NOPSA Chief Executive Officer, but only on the recommendation of the Ministerial Council on Mineral and Petroleum Resources.
- The responsible Commonwealth Minister has the power to appoint and terminate board members in accordance with the OPGGSA. Functions of the board include to give advice and make recommendations:
  - to the CEO about operational policies and strategies to be followed
  - to the Commonwealth, State and Territory Petroleum Ministers, and the Ministerial Council on Mineral and Petroleum Resources, on policy and strategic matters relating to the occupational health and safety of persons engaged in offshore petroleum activities, and NOPSA's performance of its functions.
- The responsible Commonwealth, State or Territory Ministers can request reports about NOPSA's performance, or information about the exercise of its powers.
- The responsible Commonwealth Minister can give written advice about the performance of NOPSA's operations, or about its powers, but this must not relate to regulated operations at a particular facility. Responsible State and Territory Ministers may also request the Commonwealth Minister to provide such advice to NOPSA in regard to their own coastal waters. The Commonwealth Minister must use his or her best endeavours to make a decision on such requests within 30 days after receiving them. If the Commonwealth Minister rejects a request, written reasons for the rejection must be given to the State or Territory Minister concerned.

Source: *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth).

Consistent with this model, the Uhrig Review stated:

> Where statutory authorities undertake a narrow set of functions, delegation to an executive group, coupled with an appropriate framework of governance (not a board) will be the most practical and effective arrangement to achieve alignment between operations and the priorities of government. (Uhrig 2003, p. 8)

The Commission also notes the governance arrangements for the Civil Aviation Safety Authority (CASA), and the Australian Government's recent announcement to establish a small expert board for the Authority (Albanese 2009). As well as being a regulator, CASA also has a policy function in setting aviation safety standards and a research function. This mix of regulatory, policy and research functions is far broader than those planned for a national offshore petroleum regulator. Therefore the governance arrangements associated with independent regulators such as those noted above are of greater relevance for the establishment of a national offshore petroleum regulator.

The Commission also notes that the recent review of NOPSA's operational activities (RET 2008i) did make some observations about the role of NOPSA's Board, the clarity of its role, and its relationship with the independent regulator:

> After NOPSA established itself and became operational the role of the Board became unclear to stakeholders. Some thought it was a governing board, some looked at it as an access door to Ministers, and some did not see the need for a Board.
>
> The Board itself became more operational on a principal level engaging with stakeholders and maybe overlapped the responsibilities of the CEO of the independent NOPSA. (RET 2008i, p. 32)

Models for regulatory reform

The following models represent three distinct approaches to minimising regulatory duplication and inconsistency, each with a varying degree of shared regulatory responsibility and policy consistency:

- The *unified regulatory model* — a single agency or joint regulatory authority administering a common regulatory framework.
- *Regulatory harmonisation* — multiple regulators with harmonised legislation and regulation.
- *Cooperative regulation* — multiple regulators with clear regulatory boundaries and streamlined administrative arrangements.

A unified regulatory model — for example, a national regulator — could be established through combining inter-jurisdictional regulatory responsibilities into a single agency. This would require State and Territory regulatory powers to be

referred to the Australian Government, as has occurred, for example, in the regulation of corporations.

Regulatory harmonisation can be facilitated by a consistent set of legislative objectives, with separate regulators in each jurisdiction retaining operational control of the day-to-day administration — harmonisation can be achieved through template or model legislation (Leebron 1996). Such an approach has been applied recently in the case of the OPGGSA (and its predecessor the OPA).

Cooperative regulation is a regulatory framework in which different regulatory arrangements apply within or across jurisdictions, and unnecessary regulatory duplication and inefficiencies are mitigated by administrative and legal instruments.

These instruments vary according to whether the regulatory duplication and inconsistencies occur within or across jurisdictions:

- Intra-jurisdictional cooperation — pursued through whole-of-government processes, state agreements, memorandums of understanding (MoUs) (box 9.3), interagency committees, administrative arrangement agreements, information exchanges, and lead agencies and one-stop-shop approaches.
- Inter-jurisdictional cooperation — pursued through intergovernmental agreements, MoUs, statements of common principles, mutual recognition arrangements, and State and Territory flexibility within a national system by adopting 'core' and 'model' legislation.

Box 9.3 **Memorandums of understanding**

A memorandum of understanding (MoU) is a document that describes a bilateral or multilateral agreement between parties — often government departments or agencies. An MoU is not usually a legally enforceable agreement, but for it to be effective each party should have the ability under appropriate legislation to agree to the terms of the MoU. Further, an MoU should define the role of each party unambiguously.

For example, there is a MoU in place between the Environment Protection Authority and Primary Industries and Resources South Australia:

- The intent of the MoU is to 'achieve consistent and efficient environmental regulation of upstream petroleum and mineral resources … especially when the obligations of the parties under the Acts overlap' (PIRSA 2003b, p. 3).
- An administrative arrangement, prepared under the auspices of the MoU, sets out procedures and responsibilities for environmental approval of petroleum activities. In particular, it outlines under what conditions proposals are referred between agencies.

Sources: PIRSA (2003a; 2003b).

Australian and international regulatory approaches

This section discusses advantages and disadvantages of current institutional approaches used in Australia and internationally, to assess whether they can provide an appropriate model for enhancing the regulation of the upstream petroleum sector. Specifically, these approaches may provide practical examples or relevant learning of how to adapt or extend current regulatory arrangements in Australia to reduce duplication and improve efficiency.

Australian upstream petroleum occupational health and safety

An example of a 'unified regulatory model' can be found in NOPSA — the national regulator of petroleum sector OHS in most offshore waters (chapter 7). The rationale for a single-regulator model in this situation is outlined in box 9.4.

Box 9.4 **Assessing the National Offshore Petroleum Safety Authority model**

There are several arguments as to why a unified regulatory model is an appropriate regulatory approach for offshore health and safety:

- In health and safety matters, there is a significant degree of consistency and commonality in the purpose and objectives of regulation both at the state and national government levels. Regulation of occupational health and safety (OHS) can be relatively easily separated from other petroleum related regulatory activities, making it easier to achieve an agreement on common objectives. There is unlikely to be significant divergence in local and national preferences towards the level of protection of health and safety and the balance between competing interests.
- Significant economies of scale can be achieved by combining the specialist human resources and technical expertise required to regulate upstream petroleum OHS. This is true for both regulators and businesses required to comply with safety regulations. Duplication and inconsistency in compliance with OHS regulation in offshore waters is now lower than under the previous multi-regulator regime.
- Administrative clarity and focus of a specialist regulator of OHS may outweigh the additional administrative efficiency in combining health and safety regulation with other petroleum-related regulations (such as environmental and resource management).
- Variation in local conditions and risk factors affecting OHS in an offshore environment are minimal and any significant differences can be managed through the dedication of specific and localised resources within the single regulator.

State Agreements in Western Australia

State Agreements as used in Western Australia are contracts between the WA Government and proponents of major resources projects, that are ratified by an Act of the WA Parliament (box 9.5). Such agreements are an example of a cooperative intra-jurisdictional regulatory model. Since 1952, State Agreements have been used by successive WA Governments for resource development such as mineral, petroleum, and related downstream processing projects, together with essential related infrastructure investments. There are currently 72 Agreement Acts in force in Western Australia (DSD 2008b).

Box 9.5 **State Agreements in Western Australia**

State Agreements are Acts of Parliament that specify the rights, obligations, terms and conditions for development of projects, and establish a framework for ongoing relations and cooperation between the State and the project proponent. When entering into a State Agreement, the State's broad objectives are to:

- facilitate the efficient and effective development of the State's natural resources
- manage the development by ensuring it is consistent with State policies on issues such as land use, conservation, competition, infrastructure sharing, secondary processing development and maximising local content
- ensure that development provides economic and social benefits for the community.

State Agreement content

The contents of a State Agreement depend on what has been negotiated and agreed between the parties to it. All have similar general provisions, but, because they have been negotiated on a case-by-case basis, there are project-specific clauses that make each Agreement unique.

State Agreements have not generally been entered into for a specific term, but have been designed to operate through the life of the project. Provisions are also included to allow a developer to seek approval to modify, expand or vary its activities substantially beyond those specified in the approved proposals.

Development approvals

The Minister cannot approve proposals until all primary approvals have been finalised, such as environmental approvals, native title agreements, and heritage clearances. State Agreements usually now stipulate that environmental and native title clearances must be obtained before proposals can be approved. The development proposals, therefore, should specify all key approvals that have been obtained.

Source: DSD (2008b).

Many upstream petroleum developments require long term certainty, extensive or complex land tenure and are located in relatively remote areas. The ratification of the Agreement through legislation, and the fact that provisions can only be changed by mutual consent, potentially provides greater certainty, security of tenure and reduction of sovereign risk for such projects.

State Agreements could potentially offer significant flexibility for some projects. However, the ability of these agreements to streamline regulatory approvals would appear to depend on the timeliness of the agreement negotiation process, the specific conditions contained in the agreement, and the ability to reduce other related regulatory approvals. For instance, a State Agreement will usually only be approved by the responsible Minister once all 'primary approvals' have been obtained — primary approvals include environmental approvals, native title agreements, and heritage clearances.

Despite the fact that State Agreements have been used in Western Australia for many years, there still appears to be significant scope to enhance the timeliness and transparency of current development approval arrangements. Many State Agreement negotiation processes — such as that undertaken for the Gorgon project — continue to take a considerable time, do not eliminate the need to comply with a range of other complex approval processes, and do not necessarily contain consistent requirements. In addition, there has also been a lack of performance reporting and management of obligations under these agreements once they are in place (Auditor General for Western Australia 2004).

Canadian petroleum regulators

Canadian institutional arrangements are of particular relevance for Australia due to Canada's federal system of government. One regulatory model of relevance to this study is provided by the Canadian offshore petroleum boards, which are joint federal-provincial regulatory agencies responsible for the regulation of oil and gas development in offshore areas. (A Canadian Supreme Court decision found that, as in Australia, the federal government has jurisdiction over offshore areas seaward of the low tidal point.) There are currently two offshore petroleum boards with responsibility over offshore areas — Newfoundland and Labrador, and Nova Scotia. (Details on the Canada–Nova Scotia Offshore Petroleum Board are presented in box 9.6).

The Canada–Nova Scotia Offshore Petroleum Board and the Canada–Newfoundland and Labrador Offshore Petroleum Board regulate offshore exploration and production activities under separate, but broadly similar, Accord Implementation Acts. For each province, the Accord Implementation Acts include a

federal and provincial version of the same Act. Both offshore petroleum boards have broad regulatory mandates covering OHS, resource management and the environment. The federal government continues to regulate exports of crude oil and natural gas and interprovincial and international transmission pipelines.

Where the Board makes a 'fundamental decision', notice of that decision is transmitted to both the federal and provincial Governments before the decision becomes final. Both Governments then consider the decision and advise the Board whether its decision may stand and be put into effect, or whether either one or both governments disagree with the decision. 'Fundamental decisions' are decisions that affect the pace and mode of exploration and pace of production, or decisions primarily affecting the mode of development.

Box 9.6 **Canada–Nova Scotia Offshore Petroleum Board**

Established in 1990 as a result of the Resources Accord, the Canada–Nova Scotia Offshore Petroleum Board (the Board) is an independent joint agency of the Governments of Canada and Nova Scotia. It is the lead regulatory agency for all petroleum activities and resources in the Nova Scotia Offshore Area. The Board, under the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act 1988* (the Act), is responsible for:

- enhancing safe working conditions for offshore operations
- promoting the protection of the environment during offshore petroleum activities
- managing and conserving offshore petroleum resources
- ensuring compliance with the provisions of the Act with respect to employment and industrial benefits
- issuing of licences for exploration and development
- resource evaluation, and data collection and management.

The Board is also required to ensure effective coordination and avoid duplication of work and activities by concluding memoranda of understanding with federal and provincial agencies that also regulate aspects of petroleum activities.

The Board consists of five members: two appointed by the federal Government, two by the provincial Government and a Chairperson. The Chairperson is appointed jointly by the two levels of government and may also act as the Chief Executive Officer. The Board has the legal powers and capacities of a corporation incorporated under the *Canada Business Corporations Act*. It may be dissolved only by the joint operation of an Act of Parliament and an Act of the Legislature of the Province.

Source: *Canada–Nova Scotia Offshore Petroleum Resources Accord Implementation Act 1988.*

The Canadian Government also has regulatory power over interprovincial and international gas transmission pipelines. The Canadian National Energy Board

regulates these pipelines (box 9.7). The National Energy Board is responsible for approvals for the construction of proposed and existing pipelines, including in relation to environmental protection and OHS. The National Energy Board provides a working example of a national pipeline regulator within a federal system such as Australia.

Box 9.7 **Regulation of pipelines in Canada**

Pipelines are regulated at the federal level in Canada. Pipelines within the borders of a single province are regulated by that province's regulatory body.

In 1959, the National Energy Board was established as an independent federal agency to regulate international and interprovincial aspects of the oil, gas and electric utility industries (NEB 2008). The Board holds public hearings for pipeline projects exceeding 40 km in length (and any other pipeline proposals at the Board's discretion). It must approve the construction of all proposed and existing pipeline projects that cross provincial or international boundaries, including the environmental and safety aspects.

In order to meet its environmental protection responsibilities, the Board conducts environmental assessments before approval and carries out audits and inspections during construction, operation and abandonment. It is designated as a 'responsible authority' under the *Canadian Environmental Assessment Act 1992*.

Board staff are designated as Safety Officers for the occupational health and safety of pipeline company field staff. There is an agreement in place between the Board and Human Resources and Social Development Canada.

Other approval requirements depend on the type and ownership of the land to be disturbed by the pipeline. For example:

- timber clearing, disposal and salvage on Crown land must be approved by Natural Resources Canada
- stream, lake or river crossings must be approved by Environment Canada, the Department of Fisheries and Oceans and provincial environment departments
- archaeological and historic site crossings must be approved by Environment Canada and provincial environment departments
- plans for top soil stripping, erosion control, land reclamation, revegetation and reforestation must be approved by environmental regulators.

Sources: CEPA (2008); NEB (2008).

Norway

Norway provides an example of a national regulatory approach applying to upstream petroleum activities. As Norway does not have a federal system of government, a national regulatory approach is more feasible. In contrast to Canada's

offshore single joint regulatory agency arrangements, Norway's institutional framework is based on separate agencies that have differing regulatory responsibilities.

The two main regulatory agencies in Norway are:

- the Norwegian Petroleum Directorate (under the auspices and policy oversight of the Ministry of Petroleum and Energy), which is primarily responsible for resource management and licensing
- the Petroleum Safety Authority, which regulates OHS and environmental compliance.

In addition, the Petroleum Safety Authority also undertakes a coordination role in relation to the regulatory responsibilities of the Norwegian Pollution Control Authority and the Norwegian Board of Health where relevant.

The legislative and regulatory framework for upstream petroleum projects in Norway has a number of components which are established under the relevant petroleum Act and regulations. These components include exploration and production licences, approvals obtained under the Plan for Development and Operations (PDO), and a Joint Operating Agreement (JOA) (Hunter, sub. 9). For example, the two main regulatory agreements have the following functions:

- The PDO is a detailed plan required to obtain approvals for operational activities, that takes account of all aspects of a proposed project (such as production methods and environmental assessments) and is approved by the relevant Minister.
- The JOA provides the detailed rules and licence conditions for production that are consistent with the petroleum Act and regulations. The PDO forms the basis for the day-to-day operations of the licence and the allocation of earnings. The JOA is similar in nature to a joint venture agreement between private parties, except in this case, it is a contract between the Norwegian Government and the participants in a production licence.

Tina Hunter considered that the Norwegian model and the use of PDOs could provide a suitable model for streamlining Australia's regulatory arrangements:

> Experience in the Norwegian system demonstrates that the regulation of all petroleum activities by a single body, the Norwegian Petroleum Directorate, provides a seamless, cohesive regulatory body for petroleum development. (sub. 9, p. 46)
>
> … The Norwegian requirement for a PDO would be of use in the development of petroleum resources in Australia. It could streamline the regulatory system by concentrating all the regulatory requirements into a single application for production.

> This single PDO would address requisite regulatory, environmental, native title, decommissioning and competition law requirements in a single plan. (sub. 9, p. 48)

The PDO and JOA approach would appear to have some positive features in the Norwegian context. However, it is unclear whether Norway's regulatory framework would be feasible, or whether it would enhance the current regulatory arrangements as they operate in Australia:

- The main weakness of the unified regulatory approach, such as the Norwegian model, is the potentially significant degree of legislative and administrative reform required when adapting this model to a federal system of government which has separate regulatory powers and institutional arrangements in each State and Territory. The applicability of a unified national regulatory approach to the Australian upstream petroleum sector is considered in the next section.
- The large degree of direct government involvement in the petroleum sector (through direct 'joint venture' agreements between the Norwegian Government and private operators) would appear to be inconsistent with the current regulatory-based approach of governments in Australia to the development of the petroleum and resources sector.
- While the Norwegian petroleum Act itself is relatively short in length, the approval arrangements under exploration and production licensing, the JOA and the PDO, do not appear to eliminate the need for multiple and complex approval requirements and conditions.

United Kingdom

The United Kingdom provides an example of a unified regulatory approach that is similar to Norway's institutional framework. There are two main regulatory agencies:

- The Department of Business Enterprise and Regulatory Reform and its Energy Development Unit are responsible for policy development and regulation of upstream petroleum activities related to resource management and licensing, pipelines and offshore environment.
- The offshore division of the Health and Safety Executive regulates OHS. The Health and Safety Executive is the general regulator of OHS across all industries in the United Kingdom.

9.3 Assessment of institutional reform options

Institutional reform has the potential to reduce unnecessary regulatory burdens when it:

- streamlines regulation by reducing the need for multiple agency approvals and removes duplication of assessment and reporting requirements
- avoids, where possible, arrangements that involve multiple agencies and, where multiple agencies have to be involved, has in place clear administrative arrangements to avoid or minimise unnecessary overlap in regulatory functions
- avoids unnecessary inconsistencies in regulatory requirements or decision making within and across jurisdictions
- provides regulators with clear regulatory objectives and minimises unnecessary conflicts of interest
- consolidates specialist expertise and promotes efficient use of resources.

However, consolidation of regulatory functions raises issues about conflicts of interest and possible diseconomies of scale. For example, should a national regulator have both approval and compliance functions? NOPSA's current role spans approving safety cases and ensuring compliance. However, a regulatory body with both an industry and development support function (through the approval process), as well as a compliance role, might create conflicts of interest.

Splitting compliance and approvals might remove this conflict and might also help to prevent regulatory creep. Separating compliance and approvals may also increase compliance activity, by effectively placing a higher priority on compliance activity. However, in practice separating compliance and approvals and at the same time providing the necessary expertise and resources is problematic. In practice, it is likely to add to regulatory burdens, not reduce them. It is more important that policy making is separated from regulation rather than separating approvals and compliance.

Commenting on issues associated with separating environmental compliance and approvals, the Victorian Government stated:

> Separating environmental assessment from environmental compliance will require duplication of knowledge and understanding of the same issues. It would also result in additional briefings and clarification of environmental issues from the body responsible for environmental assessment (currently the DA) to NOPSA, where in many cases local knowledge is critical … joint audits carried out by NOPSA and the Victorian DA indicate there is no efficiency gain achieved by combining safety and environment considerations for audit purposes … For these reasons, keeping environmental

> assessment and environmental compliance together under the one authority is important. (sub. DR26, p. 2)

Similarly, the WA Department of Mines and Petroleum submitted:

> DMP strongly disagrees with the [draft] recommendation to expand NOPSA's role to include environmental compliance … this recommendation also implies splitting the current integrated role of Designated Authority environmental officers into separate roles for approvals (Designated Authority) and compliance (NOPSA). DMP cannot identify how this proposed recommendation would achieve any reduction in regulatory burden on the petroleum industry. (sub. DR22, p. 17)

Four possible models for institutional reform of regulation of the upstream petroleum sector are examined in this section (an overview of the scope of these models is provided in figure 9.1). This discussion assumes that the necessary legislative reform would be carried out by all relevant jurisdictions to make these changes possible and that current fiscal arrangements would remain unchanged. The possible models include:

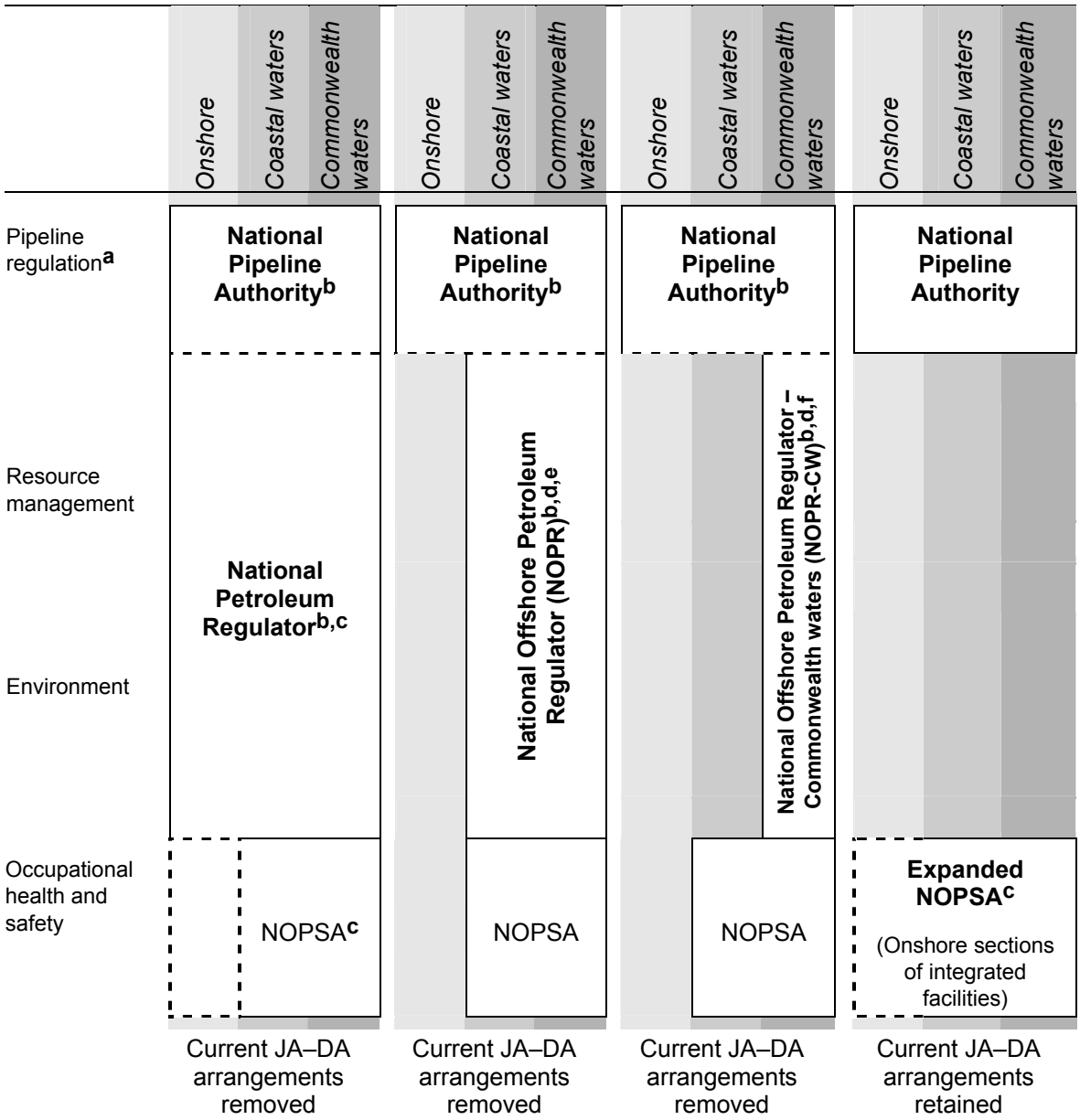
- A *national petroleum regulator* with responsibility for regulation of all upstream petroleum activities in both onshore and offshore areas. In this and all the options noted below it is recommended that a separate safety regulator (NOPSA) would also operate.
- A *national offshore upstream petroleum regulator* with responsibility for resource management, pipelines and environmental approval and compliance functions in all offshore areas.
- A *national offshore upstream petroleum regulator for Commonwealth waters*, which would take over the upstream petroleum regulatory functions for Commonwealth waters only.
- *A national pipeline authority* with responsibility for the coordination and the approval of all cross-jurisdictional upstream petroleum pipelines. This model could be pursued separately or in conjunction with the first three models.

In addition to these broad institutional reform options, chapter 7 also considers options for an expanded NOPSA (also outlined in figure 9.1) that can be pursued separately or in conjunction with these other institutional reforms. Potential options considered for an expanded NOPSA include safety and integrity of offshore pipelines, subsea equipment and wells, and OHS for onshore sections of integrated facilities, although the latter was, on balance, not recommended.

The following discussion assumes that the Joint Development Petroleum Authority for East Timor will continue to be separately regulated for the time being, although this may be considered later in relation to memorandums of understanding or

delegation. As the terms of reference for this study exclude coal seam methane projects, the Commission has not considered the effect of these on the workability of these models. Although coal seam methane projects could be considered a mining activity it would, in principle, seem quite possible that such projects could potentially be regulated under these models.

Figure 9.1 **Potential upstream petroleum regulator models**



[a] Includes all aspects of pipeline regulation (including environmental and occupational health and safety aspects) in offshore areas, as well as onshore pipelines that cross two or more jurisdictions. [b] The National Pipeline Authority could be incorporated into the National Petroleum Regulator, NOPR or NOPR-CW. [c] In this model, the National Offshore Petroleum Safety Authority's (NOPSA's) responsibilities could be extended onshore to make it the national upstream OHS regulator. [d] In this model, the States and Territories retain responsibility for onshore petroleum regulation (excluding pipelines). [e] Ministerial reporting based on NOPSA model. [f] In this model, the States and Territories retain responsibility for regulation in coastal waters.

A national petroleum regulator

A national petroleum regulator with responsibility for both onshore and offshore upstream regulation would have the theoretical advantage of providing greater consistency in decision making and regulatory enforcement across all jurisdictions. This should minimise duplication in requirements for proponents. This approach has the potential to consolidate existing petroleum expertise and should gain from significant economies of scale in administrative and support functions. However, this model would appear to have a number of significant weaknesses.

Primary Industries and Resources South Australia highlighted the benefits of retaining local State and Territory responsibility for onshore petroleum regulation and the practical difficulty of integrating the responsibilities of a national regulator with onshore regulatory frameworks:

> Each State has aligned its approach to onshore petroleum regulation to reflect its particular spectrum of petroleum resource prospectivity and stakeholders' concerns. Each State also has its own framework of legislation and interrelationship of petroleum legislation with other legislation. Therefore, it would be difficult to come up with a single national regulatory framework for onshore operations that would satisfy each State/Territory Government. (sub. 20, p. 8)

The Victorian Government acknowledged that a national regulator for both onshore and offshore would have substantial benefits, but it also expressed similar concerns regarding the difficulty of integrating offshore and onshore arrangements:

> This model has the greatest potential to reduce regulatory burden but would also be the most difficult to implement because of the degree of legislative reform required … Legislative reform would be particularly complex as various jurisdictions have included a range of activities in their onshore petroleum legislation (for example, [coal seam methane], geothermal and [carbon, capture and storage]). (sub. 7, pp. 8–9)

On balance, the Commission considers the option of a national petroleum regulator for both offshore and onshore areas is not practical at this stage for a number of reasons.

Onshore petroleum projects located wholly within one jurisdiction are unlikely to justify a national approach to regulation. Given the magnitude of the changes required there are not likely to be sufficient spillovers or commonality of local factors across all jurisdictions — especially in relation to local environmental and planning issues — to warrant a national approach. Clearly companies operating nationally would prefer a national regime but this looks difficult to justify.

Current petroleum regulators in each jurisdiction may be better placed to regulate onshore projects. Onshore regulatory regimes for petroleum projects will inevitably involve a range of local legislation and regulation that reflects State and Territory

community preferences and legislative powers in areas other than petroleum regulation. Local agencies, which are more familiar with the regimes in each jurisdiction, may be more efficient and effective in negotiating through the complexity of these processes.

Although this model would achieve improved consistency in regulation across jurisdictions, improved consistency could also be pursued through legislative harmonisation of onshore petroleum legislation across jurisdictions, without the need for a single regulator.

FINDING 9.1

A national petroleum regulator for both onshore and offshore areas would, in theory, provide greater cross-jurisdictional consistency, reduce duplication of regulatory requirements and benefit from economies of scale. However, such an agency would also appear to have significant weaknesses. Specifically, for activities located wholly onshore and within one jurisdiction, local agencies would appear to be better placed to undertake regulation due to their knowledge of local factors and community concerns. On balance, and also given the cost and difficulty of implementing a national petroleum regulator for onshore and offshore areas, the Commission considers this model not to be a practical option.

A national offshore petroleum regulator

A national offshore petroleum regulator (NOPR) would undertake upstream, petroleum resource management, pipeline and environmental regulation in Commonwealth and State and Territory waters seaward of the low tide mark, including islands within those waters, and would administer both the OPGGSA and its 'mirror' State and Territory Acts. Ideally, NOPR would perform the following functions:

- *Administration* of exploration permits, production and pipeline licensing. NOPR would prepare advice and make recommendations to the Commonwealth Minister. This is consistent with international practice, where ministerial power is retained for approvals relating to property rights such as exploration permits, production licences and retention leases.
- *Administration* and *approval* of production, well construction and drilling, and pipeline consents — NOPR would have the authority to approve consents for these activities in consultation with NOPSA for safety and integrity issues and, when relevant, with other responsible Australian Government and State and Territory agencies.

Implicit in the above is that NOPR would also have the functions of environmental approvals and compliance.

The NOPR model would effectively be an application of the 'NOPSA model' to other areas of offshore petroleum regulation. The responsibility for OHS regulation in offshore areas could be retained by NOPSA. As discussed earlier, the Canadian offshore petroleum boards provide an example of a single offshore regulator model — these boards undertake all regulatory functions, including OHS, resource management, and environmental approvals in offshore areas of their respective provinces. However, as noted in chapter 7, the Commission is now of the view it would be better to retain NOPSA as a separate institution, unlike in Canada.

NOPR would take on the regulatory functions from the Department of Resources, Energy and Tourism (RET) and Geoscience Australia and the DA's current delegated role in the approval of exploration permits, production licences and environmental approvals in Commonwealth waters. NOPR would be the one-stop-shop for regulation in Commonwealth waters rather than the DA and JA. The new agency would also be responsible for resource management and environmental regulation in State and Territory waters seaward of the low tide mark, including islands within those waters, and so would also take on the role currently performed by State and Territory agencies for these areas, but not for onshore areas.

A key finding of the Independent Review Team that established the NOPSA model was the need to reduce the confusing and overlapping legislation that applied to offshore facilities (DISR 2001). The Ministerial Council for Mineral and Petroleum Resources, in recommending the formation of NOPSA, were mindful of the need for effective and efficient coordination between the safety authority and other regulatory agencies. The OPGGSA requires NOPSA to cooperate with:

- other Commonwealth agencies having offshore petroleum operation functions
- State or Northern Territory agencies having functions relating to offshore petroleum operations
- the DAs of the States and the Northern Territory.

As with NOPSA, there would be significant benefits from NOPR establishing offices in each major petroleum producing State and Territory to retain local knowledge, and liaise with relevant State and Territory agencies with responsibility for other relevant regulatory functions for offshore activities — such as fisheries, shipping, conservation and environment. NOPR would also need to have clear administrative agreements and good communication with NOPSA.

In addition to other State and Territory agencies responsible for offshore regulation, the onshore–offshore interface would also need to be managed to ensure projects that move from offshore to onshore would have streamlined and coordinated regulatory requirements. The management of this interface would also depend on the arrangements eventually agreed for pipeline approvals. For example, a major pipeline in offshore waters and extending onshore may also require an environmental impact assessment under a State and Territory environmental protection Act — in addition to petroleum-specific environmental approvals under the OPGGSA and the mirror Acts, and on some occasions under the EPBC Act.

However, it may be possible to also include provisions within the State and Territory petroleum Acts to undertake environmental assessments under a common set of principles to minimise duplication of requirements and referrals to other State and Territory agencies. This sort of bilateral arrangement is in place for environmental assessments under the EPBC Act between the Commonwealth and the States and Territories.

If NOPR were to undertake pipeline approvals, rather than a separate pipeline regulator (see discussion on a national pipeline authority later in this section), it could also potentially have responsibility for the regulation of pipelines that extend onshore. This would reduce the overlap and duplication associated with the regulation of cross-jurisdictional pipelines.

An alternative model for a national regulator

In response to the Commission's draft report and recommendation on the establishment of a new national offshore petroleum regulator, APPEA put forward an alternative model for consideration:

> The industry would also expect that governments may also consider establishing a joint national statutory authority, whereby State Ministerial responsibilities were not divested to the Commonwealth Minister. Under this model, a single joint Statutory Authority would administer mirror legislation for the Commonwealth Minister in Commonwealth waters, and for the State Minister in State waters and for onshore pipelines. (sub. DR29, p. 16)

While such a model would produce some of the benefits associated with NOPR, the gains could be limited. First, the gains from removing the iterative JA–DA arrangements would likely be reduced under the APPEA suggestion. The NOPR model removes existing JA–DA arrangements and provides for seamless regulatory arrangements across Commonwealth and State and Territory waters seaward of the low tide mark, including islands within those waters. However, a joint national statutory authority regulating for both Commonwealth and State and Territory

Ministers would duplicate regulatory responsibilities in offshore areas and create the potential for inconsistent decision making and unnecessary delays.

Second, by maintaining regulatory roles for the Commonwealth and States and Territories in offshore areas, the suggestion has the potential to reduce efficiency gains and reduce the potential for streamlining of regulatory arrangements and resources required by governments. As with NOPSA today, the Commission's proposal for NOPR would allow State and Territory Ministers to provide policy input (through the Commonwealth Minister who would have to provide reasons if this were not passed onto NOPR). However, neither the Commonwealth or State and Territory Ministers can give NOPSA (or in this proposal, NOPR) instructions relating to a specific facility. The risk of having NOPR effectively report to both Commonwealth and individual State and Territory Ministers is that it might result in a more complicated environment than even the current JA–DA arrangements.

Relationship with NOPSA

In some other countries, such as the United Kingdom, the resource management and environmental regulation functions are performed by a different agency to the one undertaking OHS regulation.

The main advantage of retaining NOPSA as a separate entity is to maintain its exclusive focus on OHS regulation, therefore, avoiding potential or perceived conflicts in regulatory objectives or priorities — a single authority might create a potential conflict between its OHS objectives and its resource development role (that arises with exploration permit, production licence and other approvals). With NOPR and NOPSA as separate entities, NOPR could perform the role of the one-stop-shop for offshore proponents, and would refer OHS and safety integrity related approvals to NOPSA.

While NOPR could be established as a separate authority, there are also some potential advantages to combining it with NOPSA. Administrative efficiencies and improved communication could be achieved through having a single offshore petroleum regulator, through consolidating corporate support and other 'back-of-office' functions. Potential conflicts in regulatory objectives could be avoided, or at least minimised, through structural separation of the functions within the one agency. Further, strong review and oversight provisions may also identify potential regulatory conflicts or tensions before they become significant and affect performance, and allow these to be appropriately managed.

On balance, it is considered that the benefits of maintaining NOPSA as a separate entity outweigh the administrative efficiencies that would arise by combining NOPSA and NOPR.

Benefits of a national offshore petroleum regulator

Establishing NOPR would have a number of advantages. Specifically, it has the potential to:

- reduce inconsistencies and duplication in the administration of resource management and environmental regulation between Commonwealth and coastal and adjacent internal waters — reinforcing the intention of harmonised legislative arrangements under the OPGGSA and State and Territory petroleum (submerged lands) Acts
- remove the duplicative role of Australian Government and State and Territory agencies — under the current JA–DA arrangements — in Commonwealth waters
- improve governance arrangements by separating the regulatory role from the current policy role of the JA and DA agencies
- consolidate resources, and help to attract specialist expertise and staff.

The Victorian Government expressed support for a NOPR-like model to replace the DA's function:

> … the Victorian Government supports in-principle the establishment of a national petroleum regulator for offshore activities. (sub. 7, p. 2)

It stated also that establishing a national regulator would reduce unnecessary regulatory burdens on proponents:

> One national authority would allow significant improvements through streamlining processes and eliminating duplication. This would result in reduction of the regulatory burden placed on the upstream petroleum sector by reducing delays and uncertainty, while keeping a strong and functional regulatory system in place. (sub. 7, p. 6)

APPEA argued a single joint authority that is accountable to the respective Ministers (consistent with current JA arrangements) would appear to be a way of enhancing the operation of harmonised arrangements under the OPGGSA. Specifically, APPEA considered that the harmonised arrangements under the OPGGSA:

> … 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. (sub. 16, p. 50)

In support of a national petroleum regulator, Nexus argued that one of the main advantages is the potential to achieve greater consistency in the administration of current legislative arrangements and improve efficiency of administration:

> The centralised NOPSA model for a national upstream petroleum regulator has great potential to increase the consistent application of legislation and regulations. It will need to be adequately resourced with experienced, professional staff that are equipped with appropriate policy guidelines. This should assist in a consistent interpretation of the regulations.
>
> A staff reporting structure that encourages nationwide consistency should be more achievable in a central agency model than the current system where inconsistent application of regulations between DAs is attempted to be resolved at twice yearly committee meetings … Gains in efficiency with a centralised national upstream petroleum regulator will be achieved primarily if actions/decisions are made by the one authority rather than duplicating the current DA/JA process. (sub. 3, pp. 6–7)

Like Nexus, the Victorian Government also regard the NOPSA model as a useful example of the benefits and costs associated with establishing a national regulator:

> The success of NOPSA suggests further national regulation of the offshore petroleum sector may lead to gains in reducing regulatory burden for the sector. The experiences of NOPSA and areas identified for improvement in the review of NOPSA should be taken into account in the development of any national model. (sub. 7, p. 7)

Additional discussion and submissions following the Commission's draft report on a new national offshore petroleum regulator are presented in section 10.2.

The potential for improved economies of scale could particularly benefit jurisdictions with a small offshore petroleum sector with 'limited capacity to attract and retain appropriately skilled regulators' (Victorian Government, sub. 7, p. 7). Overall, the Victorian Government (sub. 7) identified three main benefits:

- A reduction in administration inconsistencies in administering the OPGGSA, providing greater clarity and certainty for proponents who operate across a number of jurisdictions.
- Streamlining of current approval and regulatory processes by having all approvals sent to one agency rather than between the Commonwealth and State and Territory members of the JA — resulting in a potential reduction in the time taken to obtain approvals to around six to 12 months (or around 50 per cent).
- Improving the position of government to attract a highly skilled workforce, especially if working under full cost recovery arrangements.

This model would also improve governance arrangements by establishing a structural separation between the current policy and regulatory functions of Australian Government and State and Territory petroleum agencies. Combining

policy and regulatory functions can potentially result in regulatory 'creep' — a gradual expansion of regulatory responsibilities. It would also provide a one-stop-shop for the vast majority of petroleum activities that are undertaken in offshore areas — including streamlining the regulation of petroleum activities that are undertaken in Commonwealth waters, which currently involves the State and Territory petroleum agencies in each jurisdiction.

Other advantages include:

- increased scope for mobilising more resources when major projects occur — these inevitably happen in a 'lumpy' manner and a larger national regulator is likely have more flexibility to cope with upswings in demand
- a well resourced regulator would also be in a better position to avoid the potential for resources being diverted from compliance activities to meet upswings in approval activities.

Weaknesses of a national offshore petroleum regulator

A NOPR would not eliminate the potential duplication and inconsistency in regulation between offshore and onshore areas. However, this would be difficult to eliminate under any regulatory framework, other than the fully national model. In addition, there may be some merit in such a separation.

Effectively integrating NOPR into the broader regulatory framework for State and Territory waters seaward of the low tide mark, including islands within those waters, in each jurisdiction is likely to require a significant reform effort. Weaknesses of the NOPR model include:

- It would remove the one-stop-shop that, in theory, exists with the DA for projects that extend from offshore to onshore. Although currently, even if the same DA staff are involved in the same project, once they move to the onshore environment they are operating under different legislation. For example, currently proponents undertaking a pipeline project are required to apply for offshore approvals via the DA under the OPGGSA, and onshore under relevant State and Territory petroleum regulations.
- A new authority would be required to replicate current, in some cases effective, administrative relationships that have been established between the DAs and other State and Territory regulatory agencies. For example, currently DAs are responsible for the environmental approvals under the OPGGSA in Commonwealth waters and administering environmental approvals in coastal waters and in some cases onshore environmental approvals — as a result there

are some established administrative arrangements between DAs and relevant State and Territory environmental agencies.

- NOPR would be competing for scarce technical expertise related to petroleum approvals and locally experienced upstream petroleum regulators with the States and Territories, who would also require some of these staff for onshore regulation.
- Potential efficiency gains from a national regulator may be reduced if a large unwieldy 'bureaucracy' were created, which might add to the regulatory burden. Or, alternatively, some smaller jurisdictions might feel a loss of local expertise if NOPR did not have local staff in their jurisdiction.

Some States and Territories might argue for retaining the current arrangements to ensure they continue to be formally involved in approving offshore activities that they believe have implications for State interests. In addition, APPEA have argued that continued Commonwealth and State and Territory involvement remains important to provide a point of appeal or moderation when proponents wish to refer decisions taken by one regulator. For example, APPEA argued:

> 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. (sub. 16, p. 17)

Inevitably, in all but the full national model, there will be an interface between regulators, whether it is the shoreline or the three nautical miles, that will require a clear division of regulatory responsibilities. However, the NOPR model would be most effective and efficient if all regulatory powers in relation to petroleum activities in State and Territory waters seaward of the low tide mark, including islands within those waters, were conferred on NOPR. This would include conferring final powers (but not influence) on the Commonwealth Minister responsible for making decisions regarding property rights in all offshore waters (including State and Territory waters seaward of the low tide mark, including islands within those waters). The arrangements used for NOPSA would appear to offer the appropriate model — under the NOPSA model, States and Territory Ministers and the relevant Ministerial council have a range of advice, consultation and information request powers (box 9.2).

While a case could be made by the States and Territories for retaining some approval powers, the efficiency gains of the NOPR model are largely dependent on the extent to which States and Territories are willing to confer final administrative and decision-making responsibilities in State and Territory waters seaward of the low tide mark, including islands within those waters, on NOPR and the responsible Commonwealth Minister. Otherwise NOPR might end up involved in many of the iterations that currently delay approvals under the JA–DA arrangement.

Some have argued that many of the gains possible under a NOPR might be achieved though improved agency resourcing and coordination.

For example, Apache were of the view:

> … more important than the organisational structure are (i) genuine local knowledge (ii) adequate staffing levels and competent personnel (iii) clear, distinct (i.e. not overlapping) responsibilities between departments and authorities and (iv) the ability to make approvals at an appropriate level and with transparency and accountability. (sub. 14, p. 6)

While many of these initiatives would improve regulatory arrangements, and are discussed further in chapter 10, experience with the current system suggests that without changing institutions and regulations these initiatives will not promote best regulatory practice. Feedback from industry and government participants at roundtables and meetings since the draft report suggests that the target of achieving a 50 per cent reduction in overall approval timelines is feasible, but is conditional on fundamentally reshaping the current JA–DA arrangements.

A single regulator for Commonwealth waters

It would be a significant challenge to gain the simultaneous agreement of all States and Territories for NOPR taking over all petroleum regulation in State and Territory waters seaward of the low tide mark, including islands within those waters, which is currently performed by petroleum and other agencies in each jurisdiction. An alternative, to the NOPR model, would be to establish a national offshore petroleum regulator for Commonwealth waters (NOPR-CW) which would be responsible for regulation in Commonwealth waters only. States and Territories could retain their existing responsibilities over State and Territory waters seaward of the low tide mark, including islands within those waters.

As with the NOPR model, NOPR-CW would take on the regulatory functions from RET and Geoscience Australia and would be a single point of contact for regulation in Commonwealth waters rather than the JA and DA. In this case, the DA's current administrative role in the approval of exploration permits, production licences and environmental approvals in Commonwealth waters would be taken over by the new authority. The main advantages of the NOPR-CW model would be to:

- reduce the potential for duplicative, iterative processes and delays that arises from the joint administrative role of the Australian Government and State and Territory Governments in Commonwealth waters under the OPGGSA

- improve governance arrangements by separating the regulatory role for Commonwealth waters from the policy role of the Australian Government and State and Territory petroleum agencies.

While it could be possible that the current JA powers might be retained, with NOPR-CW providing advice to both Commonwealth and State and Territory Ministers, the preferred option is that NOPR-CW would advise the Commonwealth Minister who would have exclusive responsibility for Commonwealth waters (as is the case with carbon capture and storage legislation). Removing the JA powers under a NOPR-CW model would provide greater jurisdictional clarity, with clear boundaries between Commonwealth and State and Territory responsibilities. This could potentially improve transparency and accountability for the regulatory performance and decision making performed by each jurisdiction.

However, this model would not take advantage of the harmonised legislative arrangements under the OPGGSA and (intended) mirror State and Territory Acts. Further, for the majority of projects that are cross-jurisdictional, regulatory inconsistencies and duplication between regulation of activities in Commonwealth waters and coastal waters would not be improved. In fact, regulation of offshore areas would be split between NOPR-CW, State and Territory petroleum regulators (the DA in each jurisdiction) and NOPSA — in contrast to the current arrangements performed by the JA, DA and NOPSA.

While in principle the NOPR model is preferred, the NOPR-CW model could also be used as a vehicle to establish a NOPR on a bilateral 'opt-in' basis with each State and Territory Government. Indeed, this is the process that led to the current form of NOPSA, with individual jurisdictions electing to opt-in and confer powers on NOPSA for their coastal waters at different stages. Specifically, the NOPR-CW could be established with the option being provided on a bilateral basis for each State and Territory to confer regulatory responsibilities for their waters seaward of the low tide mark, including islands within those waters, on NOPR-CW. This underscores that the NOPR model would be most effective and efficient compared to current arrangements if individual States and Territories were prepared to give NOPR clear responsibility for their current regulatory functions in their waters seaward of the low tide mark, including islands within those waters.

Issues of duplication and inconsistency appear to be primarily a problem where there are cross-jurisdictional activities, specifically pipelines. Therefore, regardless of the final views of governments in regard to NOPR and NOPR-CW, there may still be merit in focussing on improving the coordination of pipeline approvals.

FINDING 9.2

A national offshore petroleum regulator (with local offices in most States and Territories) could undertake resource management, pipeline approval, and environmental approval and compliance in all waters seaward of the low tide mark, including islands within those waters. The main potential benefits of the model include:

- *reducing administration inconsistencies between Commonwealth, coastal and internal waters and between different States and Territories*
- *removing the iterative and duplicative role of Australian Government and State and Territory agencies in Commonwealth waters under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth)*
- *improving governance arrangements by separating the regulatory role from the current policy role of the Australian Government and State and Territory agencies*
- *administrative economies of scale, consolidation of specialist resources and improved ability to attract and retain staff*
- *through appropriate cost recovery mechanisms, ensuring that the regulator has the necessary resources and expertise to provide a timely and efficient response.*

FINDING 9.3

An alternative would be to establish a national offshore petroleum regulator for Commonwealth waters (with local offices in most States and Territories) that would be responsible for upstream petroleum regulation. The main potential benefits of this model relate to removing the duplicative and iterative processes and delays from the current joint arrangements in Commonwealth waters. Such a regulator could be established independently by the Australian Government. The main weaknesses compared to the national offshore petroleum regulator would be:

- *the potential for inconsistencies between Commonwealth and State and Territory offshore areas*
- *not taking full advantage of the harmonised legislative arrangements*
- *reduced economies of scale due to its more limited scope.*

FINDING 9.4

The full effectiveness and efficiency of a national offshore petroleum regulator depends on the States and Territories agreeing to give it (and the Commonwealth Minister) the responsibility for petroleum regulation in State and Territory waters seaward of the low tide mark, including islands within those waters, currently performed by petroleum and other agencies in each jurisdiction. Without such an agreement there would be diseconomies of scale and greater complexity in replicating current administrative and decision-making arrangements with other State and Territory agencies.

Similarly, establishing a national offshore petroleum regulator that reports and advises the Commonwealth Minister when the particular project/decision is in Commonwealth waters, and reports and advises the State or Territory Minister when the particular project/decision is in State or Territory waters, would limit the gains from removing the Joint Authority–Designated Authority arrangements and streamlining of regulatory arrangements. This might increase regulatory burdens as the Commonwealth and States and Territories might duplicate regulatory resources.

Alternatively, a national offshore petroleum regulator for Commonwealth waters could be established with the option being provided by the Australian Government for each State and Territory to confer regulatory responsibilities, on a bilateral basis, for State and Territory waters seaward of the low tide mark, including islands within those waters, on this regulator.

A national pipeline authority

Many of the issues of overlap and duplication identified in this study thus far, arise from projects that are cross-jurisdictional in nature — this is almost always highlighted in the case of pipeline approvals. While there are clearly issues that could be addressed through expanding NOPSA's role, or establishing a national offshore regulator, there may be merit in considering specific ways of enhancing pipeline approval processes as distinct from other changes to upstream petroleum regulation. The current regulatory framework for pipelines consists of:

- licensing and consent approvals under the OPGGSA — including pipeline management and safety plans approved by NOPSA (for safety aspects of pipeline consents), the JA (for pipeline licence approvals) and the DA (for pipeline environmental consents)
- State and Territory petroleum Acts and regulations, which contain pipeline provisions for offshore areas covering pipeline licensing and technical approvals

- separate onshore pipeline Acts and regulations in several jurisdictions, which also cover pipeline licensing and technical requirements — in some jurisdictions pipelines are regulated under onshore petroleum legislation
- State and Territory environmental and planning Acts, which cover significant development projects such as pipelines.

There is an additional regulatory burden placed on cross-jurisdictional pipelines that arises from duplication in regulatory responsibilities across jurisdictions and resulting delays in obtaining multiple approvals. Therefore, there is potential for a significant reduction in approval timelines through the introduction of a single regulatory authority for cross-jurisdictional pipelines.

As the Victorian Government highlighted:

> Many petroleum projects involve pipelines running from offshore to onshore crossing a number of jurisdictions. In the case of the Woodside Otway project pipeline four jurisdictions (Commonwealth waters administered by both Victoria and Tasmania, Victorian state waters and Victorian onshore) were triggered. The time taken to grant a pipeline licence is currently between three to nine months and involves approximately 20 to 30 iterations between the DA and JA … As noted above for petroleum production licence approvals, there is potential to reduce approvals times by approximately half. (sub. 7, p. 8)

Under the current regulatory regime for pipelines there are significant inconsistencies between some jurisdictions, including between onshore and offshore requirements (chapter 5). Some States and Territories have introduced more harmonised pipeline arrangements. Specifically, the onshore pipeline regulations for Victoria are aligned with those offshore (which mirror the pipeline regulations under the OPGGSA):

> Although onshore pipeline regulatory processes and legislation generally vary markedly from state to state, in Victoria's case the *Pipelines Act 2005* is modern, objective based and in alignment with the principles of the offshore pipeline legislation. This allows offshore to onshore pipeline operations to be approved under the one operations plan, which meets the objectives of both onshore and offshore legislation. (Victorian Government, sub. 7, p. 8)

One option to address the duplication, delays and regulatory inconsistencies associated with cross-jurisdictional pipelines is the establishment of a national pipeline authority together with the necessary legislative harmonisation. Such a model could draw on the Canadian model for the regulation of cross-jurisdictional pipelines.

The national pipeline authority could be responsible for:

- the administration and approval of licences and works approvals for proposed pipelines crossing two or more jurisdictions — including the environmental and safety aspects. It could be designated as a 'responsible authority' under the OPGGSA (and mirror petroleum submerged lands Acts) and each State and Territory onshore pipeline (or relevant) Act
- environmental assessments before approval, and compliance audits during construction, operation and decommissioning. The national pipeline authority would also be accredited to undertake any environmental assessments required under the EPBC Act and State and Territory environmental Acts
- other approval requirements, depending on the type and ownership of the land to be disturbed by the pipeline. Administrative agreements would need to be established to coordinate other approvals that Commonwealth and State and Territory legislation may require.

A national pipeline authority could be established as a stand-alone authority or could be incorporated in an extended version of the NOPR discussed previously.

Benefits and costs of a national pipeline authority

A national regulator for cross-jurisdictional pipelines has the potential to provide more streamlined and consistent approval arrangements for such pipelines. In order to implement such a model there would need to be significant amendments to harmonise current State and Territory pipeline regulations — particularly requirements under onshore pipeline regulations that differ significantly across jurisdictions.

In addition to a more harmonised regulatory regime for pipelines across jurisdictions, the Victorian Government supported, at least in principle, a national pipeline authority model:

> Victoria would support the national regulation of pipelines based on the principles of the current offshore pipeline legislation. To introduce this model, the various jurisdictions would need to adopt similar pipeline legislation. It is also considered that it would be a relatively straightforward process to implement. (sub. 7, p. 8)

In addition, a national pipeline authority would address potential complications where pipelines cross between jurisdictions. In such circumstances, there is a risk that inefficient or unnecessarily restrictive regulatory regimes in one jurisdiction could affect the construction of the same pipeline in another jurisdiction — potentially imposing significant costs and lost economic activity as a consequence of delays or the imposition of approval conditions.

As with the national petroleum regulator model — applying to both onshore and offshore — concerns about this model stem from the degree of legislative reform required and the range of activities some jurisdictions have included in their onshore petroleum and pipeline legislation. In the case of Victoria, there are already harmonised regulatory provisions for pipelines, which could form the basis of a harmonised pipeline regime. However, other States and Territories may need to substantially amend their onshore — and in some cases offshore — pipeline regulations to enable a cross-jurisdictional pipeline regulator to operate.

Implementing a harmonised regulatory framework for pipeline licensing and other approvals could reduce inconsistencies in regulatory provisions and requirements. However, to minimise unnecessary duplication in approvals and inconsistent decision making a national pipeline authority is likely to be required. The advantages of such an authority in terms of streamlining cross-jurisdictional pipeline approvals would need to be carefully weighed against the potential disadvantages in relation to costs, particularly if the national pipeline authority is established as a stand-alone agency with responsibility only for cross-jurisdictional upstream petroleum pipelines.

If a national offshore petroleum regulator is not considered to be a feasible option, then there may not be sufficient efficiency gains from a single purpose pipeline regulator in comparison to the next alternative, which would be harmonised legislation between States and Territories and the OPGGSA. An alternative is to provide NOPR (or the NOPR-CW with conferred responsibility for State and Territory waters and islands within those waters) with responsibility for onshore pipelines that are cross-jurisdictional.

FINDING 9.5

Pipelines that cross two or more jurisdictions are likely to face significant regulatory overlap and potential duplication of regulatory requirements. In addition, for such pipelines there may also be significant negative effects from an inefficient regulatory regime in any particular jurisdiction. Consequently there appears to be a strong argument for a more harmonised approach to such cross-jurisdictional pipelines. The Canadian national pipeline regulator provides one apparently useful model for a cross-jurisdictional pipeline regulator in a federal system of government.

9.4 Cost recovery arrangements

Depending on the regulatory model there are a range of possible funding mechanisms. The Commission considered the issue of cost recovery for the

provision of government services more broadly in 2001 (PC 2001a). The funding of NOPSA is currently undertaken on a full cost recovery basis (box 9.8).

Box 9.8 **Cost recovery arrangements for NOPSA**

The National Offshore Petroleum Safety Authority is funded on a full cost recovery basis under the *Offshore Petroleum (Safety Levies) Act 2003* (Cwlth). Levies are based on the Offshore Petroleum (Safety Levies) Regulations 2004 (Cwlth). The levies include:

- a safety case levy: an annual levy to be imposed in relation to the safety case that is in force in relation to a facility
- a pipeline safety management plan levy: an annual levy to be imposed in relation to the pipeline safety management plan that is in force in relation to a pipeline
- a safety investigation levy: to be imposed on the operator of a facility in relation to the investigation, by NOPSA, of an accident or dangerous occurrence at that facility, above a set threshold of $30 000.

The Cost Recovery Impact Statement for NOPSA noted the following:

- The operator, not the regulator, must take full responsibility for the safety of its workforce (and its assets) and cost recovery of regulatory oversight and guidance is consistent with this.
- Imposing a dedicated safety levy was more efficient than the previous system because the charges will be directly linked to the service being provided, and will be reported in detail to industry.
- The prime beneficiaries of an efficient and consistent best practice safety regulatory regime are the owners and operators of offshore facilities. It is the owners who create the need for safety regulation and it is therefore appropriate to recover the costs of safety regulation from owners. Investigations act as a safeguard of investment and revenue streams and do not undermine the objectives of safety regulation in the petroleum sector.
- If there was no levy applied to the major incident investigations then all participants in the industry would have to be levied to recover the regulatory costs. This would be inequitable, is an unacceptable level of cross-subsidisation and would penalise good performers. Moreover, it was not proposed that the total cost of large investigations be passed on to industry. The investigation levy is intended to cover incremental costs only.

Source: DITR (2004).

The Commission concluded that: cost recovery should involve the use of fees for service where possible (at efficient cost); that cost recovery should apply to activities rather than agencies; and that cross-subsidisation between groups should be avoided. The Commission's principles enunciated in 2001 also suggested:

- partial cost recovery is generally inappropriate — either the costs of an activity or product are recovered in full or funded from general taxation revenue. Deviating from this rule involves making subjective decisions about the degree of public and private benefits involved. For example, the public should not have to pay to avoid being potentially injured as a result of the regulated activity
- registration, monitoring compliance and issuing of exclusive rights would be assessed for cost recovery, while other activities would typically be funded from general taxation revenue (such as community education, investigation and enforcement, and policy development).

In relation to the current cost recovery model for NOPSA, APPEA argued that a partial cost recovery model would be more appropriate:

> 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. (sub. 16, p. 19)

APPEA also argued that a partial recovery model would be most appropriate for the potential establishment of a new national regulator:

> 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. (sub. 16, p. 19)

APPEA and other industry participants reiterated their opposition to the full cost recovery model following the Commission's draft report. APPEA stated:

> APPEA strongly disagrees with this recommendation … Clearly with the significant public benefits derived from regulation ensuring the secure provision of energy to meet the everyday life demands and expectations of the Australian public, there should be some degree of public funding in recognition of this public benefit. (sub. DR29, pp. 18–19)

The Commission acknowledges that partial public funding might enhance public oversight of expenditure by NOPSA or a new national offshore petroleum regulator, and also reduce industry concerns about any new NOPSA-like model. Nonetheless, as previously found by the Commission, a partial cost recovery model is generally inappropriate due to the high degree of subjectivity involved in estimating the distribution of private and public benefits.

Using a full cost recovery model for a new national regulator is the Commission's preferred approach. Full cost recovery is most appropriate for the registration, monitoring compliance and issuing of exclusive rights (PC 2001a). Regulation of petroleum activities under the OPGGSA is consistent with these functions. In addition, many of the arguments in favour of full cost recovery in relation to NOPSA also apply to any new regulatory agency. Further, the advantage of a full cost recovery model is that NOPSA, or a NOPR, is then able to better attract and retain experienced and specialist staff required for them to be able to efficiently perform their regulatory function.

When compared with the arrangements for NOPSA, current charging and funding arrangements for regulatory arrangements under the OPGGSA are less than ideal. Currently, under the OPGGSA fees are payable to the Australian Government for activities including lodging applications, registering transfers and dealings (typically a fee of 1.5 per cent of the consideration of the dealing), annual fees to maintain a title and requests for data and material. These fees, particularly the registration fee for transfers and dealings, do not accurately reflect the costs incurred in administering these activities.

The Australian Government does not, in effect, retain the fees collected from activities in the offshore areas of States and Territories. Rather, amounts equivalent to the fees collected are paid to the State and Territory Governments for their administration of these areas on behalf of the Australian Government. Costs associated with Australian Government regulatory activities are not recovered. (RET and Geoscience Australia estimated that these unrecovered Australian Government costs for administrative and technical advice, policy advice, acreage release and data management, but excluding pre-competitive data acquisition, were about $13 million per annum (RET, pers. comm., 19 March 2009)).

Revenues collected by the Australian Government and passed to the States and Territories from offshore petroleum fees fluctuate significantly over time, more than doubling from $17 million to about $40 million between 2006-07 and 2007-08 (table 9.1), reflecting significant variability in transfers and dealings, not changes in the government costs of regulation. In contrast, NOPSA's revenue has been relatively stable — ranging between $9.6 million and $12.1 million in the past three years — and is directly linked to its activities.

Table 9.1 **Australian Government revenues from offshore petroleum fees**

Year	*Offshore areas of States and Territories*[a]	*Ashmore and Cartier Islands*	*Total*
	$'000	$'000	$'000
2004-05	16 868	1 978	18 846
2005-06	20 096	2 261	22 357
2006-07	15 180	1 534	16 714
2007-08	na	na	41 328

a These revenues are effectively passed back to the States and Territories**. na** Not available.

Source: RET (pers. comm., 19 March 2009).

Improvements to funding arrangements under the OPGGSA should be made with the establishment of a new national offshore petroleum regulator. As noted in chapter 5, the Commission recommends that the 1.5 per cent registration fee for transfers and dealings should be removed as a precondition to the full cost recovery model for NOPR being introduced.

As with the NOPSA funding model, if the regulator is to be industry funded it is important that there are appropriate 'checks and balances' to ensure the regulator is operating efficiently, and that related processes to determine funding levels are transparent. (With an appropriate cost recovery framework, and the efficiencies that a national regulator and the adoption of cost reflective pricing could promote, it is not certain that costs to industry would necessarily increase after the adoption of full cost recovery, particularly relative to peak years, such as 2007-08). Determination of funding arrangements should be determined by the relevant government department (currently RET), involve industry consultation and could also involve scrutiny through formal government budgeting processes. Importantly, clear and transparent funding arrangements for a new offshore petroleum regulator would provide greater clarity on what are appropriate costs to be funded by industry, compared to current arrangements where government employees may have various responsibilities, only some of which relate to regulation under the OPGGSA.

FINDING 9.6

The current cost recovery model for activities under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) could be significantly improved. Currently:

- *Australian Government costs associated with administering the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) are not recovered*
- *State and Territory costs are at least partially recovered, although charges to proponents do not reflect all the costs incurred by all relevant State and Territory regulatory agencies*

- *the registration fee for transfers and dealings is not cost reflective, can result in significant variation in annual fees and charges collected, and has other undesirable consequences.*

A full cost recovery model for a new national petroleum regulator is the preferred approach. Full cost recovery is most appropriate for the registration, monitoring compliance and issuing of exclusive rights. Regulation of petroleum activities under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) is consistent with these functions. Many of the arguments in favour of full cost recovery in relation to the National Offshore Petroleum Safety Authority also apply to any new national regulatory agency.

The process of setting the appropriate charges should be transparent, accountable, involve industry consultation and be subject to independent scrutiny and regular review. With the establishment of a new standalone national offshore petroleum regulator it should be easier to identify the costs of regulation.

10 A way forward

Key points

- Addressing the key issues identified in this study has the potential to significantly improve the efficiency and effectiveness of regulatory arrangements and reduce unnecessary regulatory burdens on the upstream petroleum sector.
  - Key issues include the number of regulatory requirements, environmental and native heritage approval processes, Joint Authority and Designated Authority arrangements, and pipeline licensing and approval processes. Reductions in approval timelines of major projects by 50 per cent should be a possible objective.
- Best practice regulation and good regulatory design should underpin government policy and regulation development.
- A number of prior and concurrent reviews have considered regulatory arrangements affecting the upstream petroleum sector, confirming that the problems associated with unnecessary regulatory burdens are not new.
- Improving the transparency and accountability around approval process timelines and decision making is fundamental to improving the timeliness of decisions.
  - Introducing clearer timelines, an electronic approvals tracking system and reporting on performance can improve transparency and accountability associated with approval processes and should lead to more timely decisions.
  - A lead agency with appropriate decision making powers should also improve the timeliness of decisions.
- Establishing a national offshore petroleum regulator with jurisdiction over Commonwealth waters will improve approval processes and the timeliness of decisions significantly.
  - States and Territories should have the option of conferring upstream petroleum regulatory powers for their waters (including islands within those waters), on this agency, and thus ultimately on the Commonwealth Minister. This option should also include powers relating to inter-jurisdictional pipelines in their waters.
  - They should also have the option of conferring regulation of onshore inter-jurisdictional upstream petroleum pipelines.

This chapter presents a way forward on future regulatory arrangements for the upstream petroleum sector. It focuses on solutions to overarching issues and problems that are relevant to the overall regulatory process affecting the upstream

petroleum sector. Solutions that focus primarily on implementing best practice regulation (section 10.1) and those that reshape the upstream petroleum regulatory architecture (section 10.2) are discussed.

10.1 Implementing best practice regulation

The principles of best practice regulation are well-documented and widely accepted by Australian governments. Previous reviews on regulation of the upstream petroleum sector have generally recommended ways to improve the regulatory environment, consistent with these principles (box 10.1). Yet in many cases, these recommendations have not been implemented.

Box 10.1 **Earlier reviews relevant to the upstream petroleum sector**

- Keating review on project development approvals system in Western Australia, completed in 2002 — recommendations included greater use of timelines, better integration of Commonwealth and State legislation, a single standard for offshore and onshore pipeline requirements, and an integrated approvals system for projects of 'state significance'.
- Evatt review of the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth), completed in June 1996 — aims included encouraging greater cooperation between the Australian, and State and Territory Governments and avoiding duplication and overlap by recognition and accreditation of State and Territory processes. A principal recommendation was the separation of determination of the heritage significance of an area from decisions about proposed land use (which would remain a matter for ministerial discretion).
- Bowler review into greenfield exploration in Western Australia, completed in 2002 — while focusing on mineral exploration, many recommendations relevant to the upstream petroleum sector, including improving heritage protection protocols and review of the *Aboriginal Heritage Act 1972* (WA).

Sources: Bowler (2002); Evatt (1996); Independent Review Committee (2002).

While a number of past reviews have considered approval processes and arrangements affecting the upstream petroleum sector, the reasons why relevant recommendations have not been progressed by governments is unclear. Even where governments have responded to previous reviews, issues and problems have not been fully resolved. The WA Government has responded to some of the Keating review recommendations, but the success of these reforms in improving approval processes has been limited (Auditor General for Western Australia 2008).

FINDING 10.1

Many of the issues and problems raised in this study have been considered in previous reviews. However, recommendations that could have removed unnecessary regulatory burdens have either not been implemented or have not been adequately implemented.

Best practice legislation and regulation

Previous chapters have highlighted a range of specific problems associated with the current regulatory framework for the upstream petroleum sector. This section highlights some pervasive regulatory shortcomings, which, if addressed, could significantly improve approval and other regulatory processes, reducing unnecessary costs and delays. This can be achieved without compromising — and most probably will promote — the achievement of the policy intent of governments.

Separating policy advice from regulation

As discussed in chapter 9, the issue of separation of policy formulation and advice from regulation is relevant when considering best practice regulation principles and regulatory and institutional reform. Separating policy advice and formulation from regulation is being emphasised in current regulatory reforms in many OECD countries, with key benefits including:

- improved credibility, stability and consistency of regulatory decisions
- creation of independent regulators acting at arm's-length from ministers.

Australian, and State and Territory Governments could attain these benefits now by separating out current policy and regulatory roles where practicable. However, by also considering broader reforms to regulatory institutions that rationalise existing agencies (section 10.2), net benefits from separating policy and regulation could be maximised.

In response to the Commission's draft recommendation that governments should separate policy advice from regulation, the SA Government observed:

> South Australia supports any initiative that will deliver legislation consistent with features of best practice regulation … South Australia submits that providing [best practice] principles are adhered to in the policy formulation and in the administration of the regulations for majority of circumstances there is little need to separate policy advice from regulation. South Australia holds the view, that in relation to the regulation of the upstream petroleum sector in particular, any such separation will in fact be counterproductive. In a highly technical industry such as this industry, any disconnect

between the policy-makers and those administering the legislation is very likely to foster many of the very deficiencies this review is seeking to address. (sub. DR23, pp. 11–12)

The Commission maintains the principle that ideally the functions of policy advice and regulation should be carried out by separate agencies. The benefits of this separation are increasingly being emphasised in reform initiatives both nationally and internationally. However, it is acknowledged that separation of policy and regulation may not always be practicable or desirable — for example, in smaller jurisdictions and where resourcing constraints exist. In such cases, reliance on appropriate checks and balances and transparency in policy and regulation making processes will be increasingly important and should be considered closely.

From prescriptive to objective-based legislation

Over recent years there has been a welcome trend towards objective-based legislation rather than prescriptive legislation (chapter 3). Industry participants support this change, for example, commending the relative simplicity of South Australia's objective-based petroleum regulations. The Australian Petroleum Production and Exploration Association (APPEA) commented:

> … 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. (sub. 16, p. 14)

The SA Government observed:

> Transparent, objective-based regulation ought to be the foundation for land access and activity proposals, and capturing co-regulatory approval requirements. (sub. DR23, p. 2)

Similarly, the WA Department of Mines and Petroleum (DMP) noted:

> DMP supports the use of objective based legislation where feasible and introduced the *Petroleum (Submerged Lands) Act 1982* safety regulations and drilling regulations based on the Commonwealth models in 2006–2007. Introduction of objective-based onshore petroleum safety regulations awaits finalisation of the drafting process. (sub. DR22, p. 23)

However, some State-based petroleum legislation remains highly prescriptive, particularly in Queensland. APPEA stated:

> … 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*. (sub. 16, p. 14)

It would seem a positive step if such legislation were made consistent with the definitions, format and approach of the updated *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA). This would enhance the ability of industry to understand and comply with this legislation as well as enhance the ability of regulators to implement it in a consistent and efficient manner.

A further issue raised is regulatory creep, whereby regulators issue guidelines which have the effect of adding to legislative requirements, rather than simply clarifying them. APPEA stated:

> … 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. (sub. 16, p. 39)

Clarity of approval processes

Clear approval processes assist industry participants to manage their investment and risk. APPEA noted:

> … 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. (sub. 16, p. 10)

Nexus also noted the importance of certainty of process for approval systems (sub. 3), while ExxonMobil commented:

> … regulations should also be clearly expressed so as to ensure that industry understands the requirements it is to meet, while giving the public confidence that industry is adhering to sound and responsible operating practices that are consistent with Australia's national interest. (sub. 13, p. 4)

Increasing involvement from local government is compounding approvals uncertainty. There is concern that local government may be becoming involved in areas beyond their expertise, possibly motivated to some extent by consequent large fees revenue. Apache observed in relation to its Devil Creek project in Western Australia:

> … Apache has been required to obtain numerous approvals from three tiers of government … Some of these bodies are attempting to undertake work which is clearly beyond their capabilities (e.g. the Shire of Roebourne is reviewing aspects of the gas

plant design based upon Building Council of Australia compliance requirements). (sub. 14, p. 3)

APPEA expressed similar sentiments:

> Additional delays to projects may occur when they are exposed to local council planning schemes … 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. (sub. 16, p. 14)

Local government has a legitimate role in some planning and development assessments. However, the Commission shares concerns about involvement from local government that adds to unnecessary regulatory burdens.

The Commission recommended in its draft report that State and NT Governments should make clear the scope of local government's role in the approval of upstream petroleum developments (and other major developments). This was strongly supported by DMP, who stated local government 'can stray beyond its level of expertise in the approval of upstream petroleum developments' (sub. DR22, p. 22). DMP suggested the following should be considered to clarify the role of local government:

- a draft standard Memorandums of Understanding (MOU) template could be developed by a government's lead approval agency to be utilised by petroleum developers and local government bodies responsible for the area of development. The MOUs would clarify roles and timelines for both parties and provide mechanisms for dispute resolution.
- Guidelines — resource and environment agencies, industry and local government [could] develop guidelines outlining the scope and role of all parties in the approval of upstream petroleum development. (sub. DR22, p. 23)

The Commission considers that the above suggestions could prove useful in defining respective regulatory roles for upstream petroleum projects. Such guidance should make explicit that areas that require specialist industry knowledge, or areas that are already regulated by other agencies, are out of scope for local government.

RECOMMENDATION 10.1

State and the Northern Territory Governments should make clear the scope of local government's role in the approval of upstream petroleum developments (and other major developments). Where aspects of these developments are already regulated by environmental agencies or major hazard facilities regulators, or when the regulation requires specialist industry knowledge, involvement by local government is not warranted.

Requirement for separate licences and consents

Another issue for approval processes is the need for proponents to obtain a range of separate approvals for the same component of a project — such as exploration permits, licences and consents to operate and construct. APPEA argued that where licences have been issued, additional approvals such as consents to operate and construct should not also be required:

> 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. (sub. 16, p. 36)

The inter-relationships and overlaps between licences and consents were discussed in the report on the current project to consolidate regulations under the OPGGSA (DITR 2007b). The report noted that companies, after getting production or pipeline licences, are still required to get consents for construction and operation. It observed that, in the most recent draft of the resource management regulations, it was not intended to retain any consents for construction and operation. The report recommended removing specific consents to operate and construct pipelines or production facilities where licences, giving approval to proceed, are set in legislation. However, it was also noted that the regulations should make it clear that an approved safety case, environment plan and field development plan would be a condition of approval for production or pipeline licences.

In relation to well operations, the report noted some duplication in the information required for a well operations management plan and the field development plan. The review proposed that where companies seek a production licence, the field development plan should cover all aspects of well operations, removing the additional requirement of a well operations management plan (DITR 2007b).

One challenge in reducing overlap between licences and consents, relates to the timing and detail required in obtaining them. In some cases, a licence can be obtained well before consents are sought and further detailed project development work is undertaken. To the extent that the information required to obtain both a licence and consent is brought forward to the licence application stage, it may increase the overall burden on proponents and also increase uncertainty until the combined licence and consent are granted. It may also impose unnecessary burdens. Where the licence might not have been granted, resources would have been wasted meeting all the requirements for the consent at the same time, compared with a situation where the licence and consents were sought consecutively. Further, where a proponent is an existing holder of a production licence, and only after some time

has elapsed proposes to expand, modify or decommission an existing facility, it does not seem practical to eliminate the need for consents for these subsequent actions, which would have been impossible to foreshadow with any precision at the time of the granting of the original licence.

For the reasons above, in some cases separate licences and consents are in fact desirable. The work on consolidating the regulations under the OPGGSA therefore did not attempt to eliminate all consents, but rather through consultation with industry and regulators identify those that could be eliminated. These changes should be implemented as soon as possible.

RECOMMENDATION 10.2

The Australian Government should implement as soon as possible outcomes from the project to consolidate regulations under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth).

Timeliness of approval processes

A key overarching issue raised in this study is the timeliness of approval processes. Timeliness has been raised in regard to resource management and Joint Authority (JA)–Designated Authority (DA) arrangements (chapter 5), environmental and native heritage approval processes (chapter 6) and pipeline approval processes (chapter 8). The Victorian Government commented on existing JA–DA processes and timelines, and the potential benefits of a national regulator:

> Under the current JA/DA model there is substantial duplication in the administration and assessment processes for permit/licence grants. (sub. 7, p. 4)
>
> [Potential benefits of a national regulator include] streamlining of current approval and regulatory processes [and] ameliorating delays associated with approvals and decisions being passed between the State and Commonwealth members of the Joint Authority. This could potentially reduce the time taken to obtain an approval to around six to 12 months, or by approximately 50 per cent. (sub. 7, p. 7)

The Commission considers that clear timelines and related processes form an important aspect of best practice regulation. However, it is not sufficient to simply apply timelines to regulatory decisions. For timelines to operate effectively, regulatory processes and decision making need to be transparent, and parties involved in the process need to be accountable for their actions.

With these objectives in mind, potential solutions include:

- statutory timelines and reporting of performance in meeting them
- ensuring legislative objectives are clear

- ensuring clear guidelines on information requirements are available to industry
- an electronic approvals tracking system.

Statutory timelines

Statutory timelines and public disclosure on timelines and progress should improve the timeliness of decisions. Wherever possible, statutory timelines should apply to decision makers. To promote transparency and accountability there should be public disclosure of reasons for regulators requesting additional information, while respecting commercially sensitive information. In addition, requiring regulators to inform or get permission from the relevant Minister to seek additional information from the proponent and extend timelines for a decision may provide further incentives for timely decision making.

Some participants considered that statutory timelines were useful in providing regulatory certainty. APPEA stated:

> … 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 [the National Offshore Petroleum Safety Authority], have a specified time frame to make a decision. (sub. 16, p. 50)

Nexus also stressed the importance of certainty of process and timelines:

> Certainty of process and timeframes are important aspects of any approval system, especially for small to medium companies such as Nexus to raise finance. (sub. 3, p. 3)

In some areas, statutory timelines exist and agencies must report their performance. The *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) has timelines for regulatory decisions. The Department of Environment, Water, Heritage and the Arts reports on its performance against these timelines, which they aim to achieve at least 90 per cent of the time (chapter 6).

Two statutory timelines could simultaneously be set: one excluding 'stop the clock' periods; and one including all elapsed time. The first would provide adequate time for regulators to make decisions once they are provided with the necessary information. The second recognises that use of the 'stop the clock' mechanism (legitimate or otherwise) may result in the overall elapsed time before a decision is made being far greater than the stated statutory timeframe. Timelines for key regulatory decisions (for example, environmental, native heritage and occupational health and safety approval processes, and the overall approval process) could be set, providing a useful target and benchmark to measure performance against.

Supporting measurement of performance against target timelines, the Auditor General for Western Australia recently stated:

> … reflecting on the business maxim, 'what gets measured gets managed' and Government's intention to streamline the approvals process, there needs to be better measurement of all parts of the approvals process. (Auditor General for Western Australia 2008, p. 22)

In its draft report, the Commission recommended that governments should set statutory timelines for regulatory decisions, and also measure and report on timelines taking into account all stages of key regulatory processes (that is, including scoping, advising, consultation and decisions), to highlight the overall time associated with regulatory processes. These draft recommendations received strong support, including from APPEA (sub. DR29), BP (sub. DR34), ExxonMobil (sub. DR31), the NT Government (sub. DR32) and Origin (sub. DR27). No submissions opposed the draft recommendations.

FINDING 10.2

A number of mechanisms could be implemented to promote timeliness and clarity of regulatory processes. Of fundamental importance is that steps are taken to improve the transparency and accountability of approval processes, including public disclosure and reporting of performance by the regulator against specified timelines.

Clear legislative objectives and guidelines

Clear objects clauses in legislation will provide greater clarity to regulators and industry on the objectives of the legislation, and should promote improved progress through the regulatory process and more timely decisions. Similarly, clear guidelines, where feasible, on information requirements will assist regulated entities in providing required information and should promote more timely decisions. Such guidelines should not add new requirements, but rather clarify existing ones.

In its draft report, the Commission recommended that to support the system of objective-based legislation, the intent of legislation should be clearly defined at parliamentary level and objects clauses should also be clearly defined. Regulators' powers in developing guidelines and the intent of those guidelines should also be clearly defined. In response, APPEA agreed with the broad recommendation, but observed:

> APPEA agrees with this recommendation, and while objects clauses are now rarely used, the intent of legislation should be provided through second reading speeches and ministerial statements. (sub. DR29, p. 15)

The Attorney-General's Department stated it supports well-expressed objects clauses (because it is valuable for the overall intention of legislation to be set out in this way) but notes that in practice they are unlikely to do more than provide general guidance in particular cases that might arise (pers. comm., 4 March 2009).

In contrast, DMP considered that if legislation is well drafted it is unnecessary to include objects clauses:

> DMP supports the importance of clearly defining the intent of the legislation at parliamentary level. DMP believes that if legislation is well drafted (both primary legislation and regulations) it is unnecessary to include objects clauses. It is therefore the practice in Western Australia to not include such clauses. (sub. DR22, p. 25)

The Commission agrees that well drafted legislation is important in promoting a clear understanding of its objectives, but clear objects clauses will provide additional benefits in terms of transparency and clarity. The Commission also considers that objects clauses are consistent with regulatory best practice. For example, objects clauses are consistent with effective guidance being provided to regulators and regulated parties to ensure policy intent is clear, and are important when legislation is periodically reviewed — that is, the objects clauses provide a benchmark against which the legislation can be reviewed.

Also, problems associated with movements in key personnel and changes in the interpretation of legislation and its application will be made worse where legislation does not include objects clauses.

In the absence of objects clauses, it may be possible to rely on explanatory memorandums to clearly understand the objectives of the legislation. Regardless, it is important that government can be confident that it has clearly communicated its legislative intent to both regulators and industry.

Timeliness and agency resourcing

Inadequate resourcing and a lack of expertise on the part of regulatory agencies can delay approvals, potentially leading to inadequate regulatory decisions (chapter 3). Study participants raised concerns about inadequate resourcing of regulatory agencies. Apache observed in relation to the previous Department of Industry and Resources (DoIR) (DMP now undertakes this role) in Western Australia:

> … DoIR's Perth office appears to be understaffed. More than half of the retention leases in WA are 'pending renewal' (i.e. they have expired and even though retention leases represent a key public policy issue no decision has been made either to grant or to refuse their renewal). Apache has a pipeline license which expired in 2005 for which we have sought approval but DoIR has not yet renewed it. (sub. 14, p. 5)

In response, DMP stated that the majority of these retention leases have only come up for renewal within the past six to seven months, analysis of retention lease renewals has become more complex, and renewal of Apache's pipeline licence is waiting for their submission of an environmental management plan (sub. DR22, pp. 22–23).

Woodside expressed similar sentiments to Apache:

> DoIR has suffered a diminished technical capability in the area of pipeline management since 2005. In general, pipeline expertise has been obtained through consultants. In our experience, the lack of in-house technical people has had some impact on DoIR's ability to process approvals. (sub. 11, p. 6)

However, problems were not confined to Western Australia. Nexus noted:

> … all government agencies that Nexus deals with are suffering to some degree from a lack of resources. Irrespective of the commitment of Government staff, delayed or poor decisions are often made due to this lack of resources. (sub. 3, p. 4)

Some have suggested that since the formation of the National Offshore Petroleum Safety Authority (NOPSA), staff shortages have diminished in the area of offshore health and safety. NOPSA has consolidated offshore occupational health and safety responsibilities and expertise, allowing a remuneration structure that is competitive with industry pay scales and thereby reducing loss of valuable regulatory skills and qualifications into the industry (APPEA, sub. 16).

A new national petroleum regulator (section 10.2) should provide similar benefits to the formation of NOPSA. In addition, the Commission's suggested reforms have the potential to improve resourcing arrangements and change the way regulatory agencies conduct their work. This was recognised as important by the Auditor General for Western Australia, who recently stated:

> Streamlining the approvals process will not happen unless agencies introduce new ways of conducting their work. (Auditor General for Western Australia 2008, p. 29)

Implementing the recommendations will not only see a reduction in unnecessary regulatory burdens affecting the upstream petroleum sector, but there is also potential for efficiency improvements within government and the effective 'freeing up' of existing resources. These resources are then able to better contribute to policy making and regulatory arrangements. This is important because regulators need to be able to cope with 'lumpy' demands on their time. As has been experienced over recent years, there has been significant activity, including new large projects, and this has resulted in significant demands on regulatory agencies. A rationalisation of regulators and increased ability to attract and retain experienced staff will assist in meeting such regulatory demands.

FINDING 10.3

There is no easy solution to the resourcing issues affecting regulatory agencies. However, the proposals in this report, by improving the efficiency and effectiveness of approval processes, should lead to a freeing up of government resources. Establishing a national offshore petroleum regulator and appropriate cost recovery measures should also assist, as appears to be now the case with the National Offshore Petroleum Safety Authority.

Reporting requirements

As discussed in chapter 8, duplication of reporting requirements adds to regulatory burden. Best practice legislation and regulation would support removal of this duplication and improved coordination between government agencies and different levels of government to ensure that requirements are not duplicated and that, overall, there are net benefits associated with the requirements. As noted in chapters 6 and 8, both ExxonMobil and APPEA have raised concerns in regard to the duplicated reporting requirements covering energy efficiency, greenhouse gases and related issues.

RECOMMENDATION 10.3

Governments should review and update all existing legislation to ensure it is consistent with the features of best practice regulation and good regulatory design. In particular, updated legislation and its administration should:

- ***separate policy advice from regulation where practicable***
  - ***where not practicable, for example due to scale particularly in smaller jurisdictions, reliance on appropriate checks and balances and transparency in policy and regulation making processes will be increasingly important***
- ***promote the use of objective-based legislation where feasible***
- ***ensure approval processes are best practice and clearly defined***
- ***set statutory timelines for individual regulatory decisions (any decision should include a 'stop the clock' mechanism). There should be two timelines: one excluding periods when the 'clock' is stopped and one including all time elapsed. There should also be disclosure of reasons for regulators requesting additional information, and measurement and public disclosure of their performance against these targets***
- ***measure and report overall timelines taking into account all stages of key regulatory processes (including scoping, advising, consultation and decisions)***

- ***be consistent with the definitions, format and approach of the updated Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth)***
- ***provide clear guidelines where feasible on information requirements to assist proponents in efficiently providing the necessary information to allow timely regulatory decisions***
- ***ensure reporting requirements are clear, justified, and avoid duplication and overlap with other mandatory reporting requirements.***

RECOMMENDATION 10.4

To support the system of objective-based legislation and to minimise regulatory creep governments should:

- ***ensure that the intent of legislation is clearly defined at the parliamentary level, including through clear explanatory memorandums and/or objects clauses that are clearly defined***
- ***clearly define the powers of regulators in developing guidelines and the intent and style of those guidelines.***

An electronic approvals tracking system

Performance against timelines, overall performance of the regulatory process and accountability might be improved with the introduction of an electronic approvals tracking system. An oil and gas portal, incorporating a tracking system, has been established in the United Kingdom (box 10.2).

Box 10.2 **UK oil and gas portal**

The UK oil and gas portal:

- allows businesses to apply for licence permits or consents
- covers a wide range of activities relating to exploration, development, production, decommissioning and protection of the environment
- allows businesses to retrieve, view and track progress of their application
- provides cross-government integration.

Establishment of the UK oil and gas portal was undertaken in a staged process, progressively implementing a drilling permit system, followed by production reporting and environment systems, and now a licensing system.

Sources: Fivium (2008) and UK Department of Energy and Climate Change (pers. comm., 6 January 2009).

An electronic approvals tracking system could be established to track a proponent's progress through the regulatory process, and be separated by regulatory area — for example, resource management, environment, heritage, occupational health and safety, land access and pipeline approvals. The system could also allow for overall tracking of the application, that is, total elapsed time.

A tracking system has the potential to apply a greater degree of accountability to decision makers and proponents, as it would be clear which party (if any) was the cause of delays. Such information would be useful in identifying problem areas and regulatory bottlenecks where processes should be reviewed, and over time may allow governments and industry to focus resources in those areas.

In support of electronic systems, APPEA stated:

> … 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. (sub. 16, p. 49)

In its draft report, the Commission proposed the Australian Government explore options for introducing an electronic approvals tracking system, and based on initial experience, State and Territory Governments should consider, where possible, adopting this system. DMP supported this approach:

> DMP supports this recommendation and welcomes the opportunity to further develop and enhance its local systems should a national tracking system be adopted. (sub. DR22, p. 25)

The Department of the Environment, Water, Heritage and the Arts also supported the proposal and suggested the system allow for proponents to report against their own timelines to help the regulator manage busy periods:

> Such a system is supported in principle and it is suggested this be extended to require reporting by proponents on the progress against their own timelines. For example, predicted timing of submission of draft assessment documentation. This would assist agencies planning and managing resources more efficiently, to cater for predicted peak periods of workflow. (sub. DR35, p. 7)

Electronic systems might be expanded beyond approvals tracking to cover a range of interactions between government and regulators on the one hand, and industry on the other. As well as the matters covered by the UK system, there might also be scope for an electronic system to cover licence and other payments and data submission.

However, any reform will only be successful if the new system captures relevant information, and appropriate incentives and arrangements are created to continually

improve performance. Supporting improved tracking of applications and timelines, the Auditor General for Western Australia recently stated:

> … resource projects cannot be tracked across government and agencies do not report on the time taken for the whole approvals process. Because of this, it is not possible to determine if overall timelines have improved.
>
> - Agencies are only required to report on set times for distinct parts of the process. They do not routinely measure overall timelines and where delays may be occurring in other parts of the process …
> - Agencies do not analyse the time data that are reported to identify opportunities for improving their processes or to assist Ministers to understand where improvements are needed. (Auditor General for Western Australia 2008, p. 6)

But the history of information technology projects, such as in the healthcare sector (PC 2005), suggests that inadequate implementation and overly ambitious scope can result in the costs outweighing the benefits. It might be prudent to start such a project for the upstream petroleum sector focused on Australian Government processes and, when this has been proven, to allow State and Territory Governments to adopt this system for their processes.

In addition, it would also be prudent to implement a tracking system only once approval processes had been fully reviewed and streamlined. This would ensure that the system was building upon what was identified to be an efficient and streamlined system, rather than attempting to fit a tracking system to processes that are duplicative and unclear.

FINDING 10.4

As now implemented in the United Kingdom, an electronic approvals tracking system has potential to improve the transparency and accountability of approval processes, and thereby improve the timeliness of decisions. However, implementation of an electronic approvals tracking system should only commence once approval processes have been streamlined and are otherwise best practice.

Further, the success of such a system will depend not only on what timelines are measured, and the transparency of who is responsible for progressing each stage of an approval, but also the commitment of government and industry to appropriately scope, implement and prove the system, and then to use the derived information to continually improve performance.

The establishment of a new national petroleum regulator (section 10.2) may provide an opportunity to implement an electronic approvals tracking system.

RECOMMENDATION 10.5

The Australian Government should explore options for the introduction of an electronic approvals tracking system to improve the timeliness, accountability and transparency of approval processes. Such a system should allow for tracking of individual regulatory areas (for example, resource management and environment) as well as the overall approval process. In exploring options, the Australian Government should consider whether additional features should eventually be included as part of the system (for example, licence payments and data submission).

To ensure the system is part of a best practice regulatory regime for the upstream petroleum sector, implementation of an electronic approvals tracking system should only commence once approval processes have been streamlined and are otherwise best practice.

Based on the proof and initial experience of this system, State and Territory Governments should, where possible, adopt the national tracking system.

The lead agency approach

Under a lead agency approach (sometimes referred to as a 'one-stop-shop'), approval of most, if not all, aspects of an application would rest with one designated agency. This agency would coordinate all approval and licensing processes and provide businesses with information on compliance requirements. It would maintain control of the process, and in most cases, would *consult* with other relevant agencies, such as an environmental agency, rather than formally refer the application to a separate agency for assessment. In some limited circumstances where impacts are considered to be significant, a formal referral may take place. By maintaining control of the approval process the lead agency approach is able to streamline approval processes and minimise time delays.

Some States already have such a lead agency (or 'one-stop-shop'), although their overall responsibilities and performance varies. Primary Industries and Resources South Australia (PIRSA) is widely seen as a model for other jurisdictions to emulate. As APPEA noted:

> 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 … no other State provides a similar well resourced service to facilitate the industry through approval requirements. (sub. 16, p. 49)

The WA Government until recently had sought to provide a 'one-stop-shop' service through the Office of Development Approvals Coordination (ODAC). However, ODAC, unlike PIRSA, did not grant licences or approvals, rather it had a facilitation, coordination and oversight role. (From 1 January 2009 ODAC was transferred to the WA Department of State Development. The WA Government is also currently reviewing the State's approval processes.) ODAC's lack of decision making power was a cause of frustration to some in the sector. Nexus stated:

> … whilst the Office provides great assistance in facilitating and mapping out the approvals process, its inability to enforce timely decisions by other government agencies causes industry frustration. (sub. 3, p. 7)

An October 2008 report by the Auditor General for Western Australia found only one ODAC coordinated project — Woodside's Pluto liquefied natural gas development — has so far completed all approval processes. (During the first half of 2008, 10 projects out of approximately 400 were receiving ODAC assistance.) That project is reportedly the first large development proposal to obtain all necessary approvals (subject to conditions) within 18 months. The Auditor General for Western Australia concluded:

> While there were some lessons learned about coordination between agencies, and between Commonwealth and State processes, the Pluto experience has not resulted in any improvements to existing approval processes. Agencies participating in the Pluto review unanimously agreed that the experience would be difficult to replicate as the shorter than usual timeline was achieved by re-prioritising agency resources. Agencies advise that the effect of prioritising Pluto approval processes was that other development proposals were delayed. (Auditor General for Western Australia 2008, p. 28)

The contrasting PIRSA and ODAC examples illustrate the importance and relevance of where decision making powers reside.

One potential criticism of the lead agency approach is that it may become 'captured' by industry, or be overly pro-development, leading to important issues being neglected. Such an outcome may be avoided by clearly defining legislative responsibilities, having clear and transparent regulatory processes, and consulting with other relevant agencies to gain additional expertise.

It is noted that issues of regulatory capture do not appear to have emerged in South Australia. PIRSA has a clear mandate, clear regulatory responsibilities, good processes to engage with other relevant agencies, and checks and balances that apply in high risk situations.

The SA Government commented:

> Guidelines for, and adherence to best practice consultation processes can foster efficiency without reducing stringent standards. (sub. DR23, p. 3)

FINDING 10.5

The lead agency approach has strong potential to improve the timeliness of approval processes provided the lead agency has adequate decision making powers. Ideally, the agency would maintain control of approval processes and consult with other relevant agencies. Only in limited circumstances would it be required to refer a decision to another agency.

In contrast, 'facilitator' agencies, which assist proponents through approval processes by providing a single point of contact within government and coordinating with decision making agencies, often have limited impact on streamlining the approval process and improving the timeliness of decisions.

Successful establishment of a lead agency for upstream petroleum approvals will require significant effort and cooperation within government, and the framework supporting the lead agency will significantly impact on its success. Key features of the lead agency approach include:

- strong support and commitment from government on the role of the lead agency and its decision making powers, and providing a clear mandate for all relevant approval processes — petroleum legislation should cover areas such as environment, heritage and pipelines, and the agency should have clear accountability for these approval processes
- not diminishing the policy intent in the areas to be covered within the petroleum legislation — that is, while under this proposal, areas like environment would be comprehensively covered in the petroleum legislation, criteria for approval in these areas would be unchanged (apart from now being the responsibility of the lead agency)
- memorandums of understanding or consultation arrangements with other relevant agencies to ensure appropriate expertise and knowledge is considered
- referral to other agencies or rights of other agencies to intervene only in limited circumstances.

Consistent with this, the SA Government noted:

> [A lead agency's] success depends on the extent to which the lead agency can attain the confidence and trust of other state regulatory bodies. To achieve such trust the lead agency must display genuine openness and transparency in its decision-making and engagement with the other agencies. (sub. DR23, p. 13)

While State- and Territory-based lead agencies will not remove interface issues with Commonwealth legislation and regulatory requirements, the fact that most upstream petroleum developments involve onshore facilities suggests that a lead agency would streamline existing approval processes significantly.

RECOMMENDATION 10.6

Where not already implemented, States and Territories should consider establishing a lead agency for petroleum projects. Such an agency would manage an integrated approval process and would require a clear mandate for all relevant areas (for example, resource management, environment and heritage) and clear decision making powers over these areas except in exceptional circumstances. With appropriate governance, experience in South Australia suggests that such an agency can achieve an appropriate balance between enforcing legislative provisions and expediting approvals.

10.2 Reshaping the regulatory architecture

This section considers solutions that focus on reshaping the regulatory architecture, specifically the establishment of a national petroleum regulator. Chapter 9 discussed possible models for a national regulator:

- a *national petroleum regulator*, covering both offshore and onshore activities
- a *national offshore petroleum regulator* (NOPR), covering offshore activities (Commonwealth and State and Territory waters seaward of the low tide mark, including islands within those waters)
- a *national offshore petroleum regulator*, covering only activities in Commonwealth waters (NOPR-CW).

It is important to note that in considering options for a national petroleum regulator, the focus is on the regulatory and institutional arrangements governing project approvals for the upstream petroleum sector. None of the options are intended to imply that there should be any changes to existing resource rent tax and royalty arrangements imposed by the Australian, and State and Territory Governments.

A new national regulator?

A national petroleum regulator for both onshore and offshore areas would in theory maximise the benefits associated with greater cross-jurisdictional consistency, reduced duplication of regulatory requirements and economies of scale. However, such a model also has significant weaknesses. On balance, and also given the cost

and difficulty of implementing this model, the Commission considers this approach not to be a practical option at this time.

Instead a more practical alternative discussed in chapter 9 is the establishment of NOPR. NOPR would undertake resource management, pipeline and environmental regulation in Commonwealth and State and Territory waters seaward of the low tide mark, including islands within those waters, and would administer both the OPGGSA and its 'mirror' State and Territory submerged lands Acts. Benefits include removal of duplication and delays associated with current JA–DA arrangements, and consistent regulation across offshore areas, including islands. However, the effectiveness and efficiency of the NOPR model is largely dependent on the States and Territories agreeing to confer ultimate administrative and decision making responsibilities in their waters on NOPR and the Commonwealth Minister as relevant.

A national regulator for Commonwealth waters only?

An alternative to NOPR would be to establish NOPR-CW that would be responsible for upstream petroleum regulation in Commonwealth waters only. The main benefit with NOPR-CW is removal of the duplicative and iterative role of the JA and DA, and that its establishment would only require a decision from one government (the Australian Government). However, the main weaknesses of this model compared to NOPR are:

- the potential for inconsistencies between Commonwealth and coastal waters
- not taking full advantage of the intended harmonised legislative arrangements
- reduced economies of scale due to its more limited scope.

To capture more of the NOPR benefits under the NOPR-CW model, States and Territories could be provided with the ability to individually opt-in and confer their upstream petroleum responsibilities for their waters seaward of the low tide mark, including islands within those waters, on NOPR-CW and ultimately the Commonwealth Minister, as relevant. Benefits of such an approach include:

- the capturing of significant benefits associated with removal of existing JA–DA arrangements for Commonwealth waters
- allowing States and Territories to individually opt-in — if NOPR-CW works efficiently then some States and Territories and businesses may see benefits in the delegation of authority in their waters seaward of the low tide mark, including islands within those waters, even if all States and Territories do not
- maintaining some of the benefits of competitive federalism — assuming that the NOPR-CW model works efficiently and as intended, States and Territories that

do not opt-in will effectively maintain an additional level of regulatory complexity and duplication. They will then come under pressure to streamline their processes in order to attract investment versus other jurisdictions that have conferred their responsibilities.

Overall, the Commission considers that the Australian Government should pursue the establishment of NOPR-CW. While the proposal falls short of what some regard as a national petroleum regulator, for example APPEA and the Victorian Government, the Commission sees significant benefits associated with the proposal when considered alongside other recommendations. The proposal also provides a staged process to the establishment of NOPR, as individual States and Territories choose to opt-in. This is similar to the evolution of NOPSA.

Participants generally supported the Commission's proposal in its draft report to establish such a new national offshore petroleum regulator (SA Government, sub. DR23 and Nexus, sub. DR25). Origin Energy recognised the benefits of a national regulator and States and Territories opting in, and stated:

> Origin believes the establishment of a national regulator is an important initiative and supports the Commission's recommendations in this regard. It would be hoped that a national regulator, which with co-opted powers granted to the Commonwealth by the States and Territories, could have jurisdiction over the Commonwealth waters and the coastal waters. (sub. DR27, p. 2)

Woodside also supported the proposal but acknowledged the importance of the agency being able to attract and retain quality staff and resources:

> Woodside can see considerable merit in this suggestion, although we note that the success of any such agency would be in its capacity to attract and retain high quality staff and access to sufficient resources. We agree with APPEA that more specific feedback cannot be provided without further detail on this proposal. (sub. DR33, p. 2)

Further, the Victorian Government restated its support:

> I reiterate the Victorian Government support, in-principle, for the establishment of a national offshore petroleum regulator (NOPR). A NOPR that adopts the regulatory functions of other federal and state agencies (including the Department of Resources, Energy and Tourism, Geoscience Australia and the Joint and Designated Authorities) and incorporates NOPSA presents the greatest opportunity to reduce regulatory burden on the upstream petroleum sector … A phased approach, whereby NOPR initially administers Commonwealth waters with the administration of State waters to be phased in at a later date, is a sensible option. (sub. DR26, p. 1)

However, not all submissions supported the establishment of a national regulator. DMP stated:

> DMP acknowledges that there could be benefits from establishing a new national offshore regulator. However, this recommendation is not supported. In terms of

> Commonwealth/State relations, this recommendation undermines the cooperative federalism model as represented by the Offshore Constitutional Settlement of 1979 and dismantles the Designated Authority/Joint Authority structure. (sub. DR22, p. 26)

Similarly, the NT Government did not support the creation of a national offshore petroleum regulator, noting that it and the State or Territory regulators could effectively double-up on resource requirements, or otherwise divide the resource pool available to each and therefore reduce the regulatory capability of the State or Territory (sub. DR32, p. 10).

Like NOPSA, the new national petroleum regulator would need to have local staff in key States and Territories in order to benefit from local knowledge and expertise. NOPR-CW would effectively be an application of the 'NOPSA model' to other areas of offshore petroleum regulation. Respective powers of the Commonwealth and State and Territory Ministers for NOPR-CW should be similar to those applying to NOPSA (chapter 9, box 9.2).

In regard to governance arrangements for a new national offshore petroleum regulator, the Commission has not attempted to recommend the details of a preferred model, except that it is clear this body, like NOPSA, should be an independent statutory authority. Existing Commonwealth and State-based independent regulatory agencies, and the Uhrig Review (Uhrig 2003), provide examples of what may be appropriate governance arrangements and factors that should be considered in determining those arrangements. Many independent regulators, such as the Australian Competition and Consumer Commission, the Australian Energy Regulator, the Independent Pricing and Regulatory Tribunal of New South Wales, and the Gene Technology Regulator, are established with a commission or tribunal, or an individual as the decision making body, with support from a secretariat. A similar model for NOPR would not be unreasonable, and would be consistent with the findings of the Uhrig Review. Conclusions from reviews of NOPSA should also be taken into account.

In its early stages, and separate from formal governance arrangements, there may be some benefit from an advisory or guidance mechanism to ensure the regulator receives feedback from stakeholders, including State and Territory governments. Such a mechanism could include an advisory council or formal feedback through the Ministerial Council on Mineral and Petroleum Resources.

Important in establishing the governance arrangements and any advisory mechanism is clearly defined roles and responsibilities that are well understood by all relevant parties. As illustrated in the review of NOPSA's operational activities, issues can arise when roles and responsibilities are unclear (RET 2008i).

Finally, NOPSA and NOPR should be maintained as separate entities.

FINDING 10.6

The Commission does not have a preferred governance arrangement model for a new national offshore petroleum regulator except it should be an independent statutory authority. Arrangements for existing independent regulators such as the Australian Competition and Consumer Commission, Australian Energy Regulator, Independent Pricing and Regulatory Tribunal of New South Wales and Gene Technology Regulator provide examples that are worthy of consideration, and which are consistent with the findings of the Review of Corporate Governance of Statutory Authorities and Office Holders.

In its early stages, and separate from formal governance arrangements, there may be some benefit from an advisory or guidance mechanism to ensure the regulator receives feedback from stakeholders, including State and Territory governments.

Roles and responsibilities in any such advisory arrangements should be clearly defined and well understood by all relevant parties.

RECOMMENDATION 10.7

The Australian Government should establish a new national offshore petroleum regulator in Commonwealth waters, with regulatory responsibility for resource management, pipelines and environmental approvals and compliance. It should be an independent statutory authority and have the following functions:

- ***administration of exploration permit, production and pipeline licensing — it would process applications, prepare advice and make recommendations to the Commonwealth Minister for resources***
- ***administration and approval of production, well construction and drilling, and pipeline consents — it would have the authority to approve consents for these activities after receiving approvals from NOPSA for safety and integrity aspects of these activities***
- ***environmental approvals and compliance.***

The National Offshore Petroleum Safety Authority should remain a separate independent statutory authority for the regulation of offshore petroleum occupational health and safety.

RECOMMENDATION 10.8

The Australian Government should give State and Territory Governments, on a bilateral basis, the option of conferring their existing petroleum-related regulatory powers in State and Territory waters seaward of the low tide mark,

including islands within those waters, on the new national offshore petroleum regulator and ultimately the Commonwealth Minister as relevant. The respective powers of the Commonwealth and State and Territory Ministers that would then apply should be similar to those applying to the National Offshore Petroleum Safety Authority.

For States and Territories that wish to opt-in, it would be a requirement that all their relevant State or Territory petroleum Acts fully mirror the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) and its subordinate regulations, including provisions relating to pipelines.

Regulation of pipelines

An important issue is pipeline licensing and approval processes. As most of Australia's oil and gas reserves are offshore, a significant proportion of production involves pipelines passing through multiple jurisdictions.

Current arrangements result in multiple regulators and multiple approval processes:

> 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 [Pipeline Management Plan], end to end. (APPEA, sub. 16, p. 36)

Having multiple jurisdictions and regulators inevitably leads to duplication and delay. The existence of multiple regulators also raises interface issues. That is, there is a risk of blurred lines of responsibility between the various regulators and regulatory gaps appearing when responsibilities are not clear.

NOPR-CW would create a single regulatory jurisdiction for developments in Commonwealth waters (extending to State and Territory waters seaward of the low tide mark, including islands within those waters, where a State or Territory opts-in), and could therefore benefit inter-jurisdiction pipeline developers. However, where a State or Territory does not opt-in, pipelines are likely to continue to face significant regulatory overlap and duplication.

Chapter 9 discussed establishing a national pipeline authority. In its draft report, the Commission considered that a standalone authority for upstream petroleum pipelines was not the best option. Ideally, States and Territories would confer relevant responsibilities on NOPR-CW, and this would provide a single regulator for pipelines in offshore areas. In addition, for pipelines only, NOPR-CW's jurisdiction could extend onshore where States and Territories confer such powers. As part of this process, States and Territories would be required to harmonise their

offshore and onshore legislative provisions for pipelines where relevant. Such arrangements would greatly improve regulatory processes for pipelines.

APPEA supported this approach:

> If States and Territories agreed to a national offshore petroleum regulator, APPEA would support a recommendation to also incorporate onshore pipelines into the remit of the national petroleum regulator. (sub. DR29, p. 18)

RECOMMENDATION 10.9

Where States and Territories have agreed to confer their powers in State and Territory waters seaward of the low tide mark, including islands within those waters and pipelines, on the national offshore petroleum regulator and ultimately the Commonwealth Minister as relevant, States and Territories should also have the option to confer responsibility for the regulation of onshore inter-jurisdictional upstream petroleum pipelines. For States and Territories that wished to opt-in, it would be a requirement that their legislative provisions applying to onshore pipelines were harmonised with the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth) where relevant.

Cost recovery

As discussed in chapter 9, NOPSA's functions are currently undertaken on a full cost recovery basis. It is acknowledged that partial public funding might enhance public oversight of expenditure by NOPSA (or a NOPR-CW) and reduce some industry concerns about any proposed expansion of NOPSA's role. Nonetheless, as previously found by the Commission (PC 2001a), a partial cost recovery model is generally inappropriate due to the high degree of subjectivity involved in estimating the distribution of private and public benefits.

A full cost recovery model for a new national regulator is preferred. Full cost recovery is most appropriate for the registration, monitoring compliance and issuing of exclusive rights (PC 2001a). Regulation of petroleum activities under the OPGGSA is consistent with these functions. In addition, many of the arguments in favour of full cost recovery in relation to NOPSA also apply to any new regulatory agency.

As noted in chapters 5 and 9, current cost recovery arrangements are less than ideal. The full costs of regulating the sector under the OPGGSA are generally not recovered, fees and charges are not cost reflective, and recovery can vary significantly from year to year given the nature of current charges. Improvements to arrangements are likely to result in a more stable and predictable recovery of costs

(with benefits to government and industry), as well as greater clarity and transparency around what are appropriate costs to be recovered from industry.

RECOMMENDATION 10.10

The current full cost recovery model used for the National Offshore Petroleum Safety Authority should be used to fund any new regulatory agency. As with the National Offshore Petroleum Safety Authority, the cost recovery model adopted for a new regulatory agency should be subject to regular review and appropriate governance arrangements. Only appropriately defined costs associated with regulating the upstream petroleum sector should be recovered by the new national offshore petroleum regulator. Implementation of this recommendation should be associated with the removal of the registration fee for transfers and dealings.

10.3 Concluding remarks

The upstream petroleum sector must make significant investments to explore and develop Australia's oil and gas resources. While the regulatory regime is only one of many factors influencing proponents' decisions to invest in Australia or overseas, the delays and time taken to negotiate regulatory requirements can have a significant impact on investment returns, with flow-on impacts to payments to government and economic activity. Further, the costs associated with current approval processes need to be considered alongside emerging issues that have the potential to add new regulatory requirements and costs on the upstream petroleum sector. Amongst these are the proposed Carbon Pollution Reduction Scheme and carbon capture and storage legislation.

This report sets out a suite of reforms to the regulatory regime which the Commission considers will reduce unnecessary regulatory burdens and establish more efficient and effective approval processes for the benefit of proponents, governments and the nation more broadly. Importantly, the proposed reforms have been developed with regard to maintaining the policy intent of governments and clarifying this where it is currently uncertain. Implementation of these proposals should allow a more efficient and improved balance between policy development, compliance regulation, and approval activities.

APPENDIXES

A Public consultation

Table A.1 **Submissions**

Participant	*Submission number*[a]
Apache Energy (Apache)	14
Australian Petroleum Production and Exploration Association (APPEA)	16, DR29
Australia Worldwide Exploration (AWE)	17#
BP Developments Australia (BP)	15, DR34
Chevron Australia (Chevron)	19
Department of Industry and Resources (Western Australia)	18
Department of Mines and Energy (Queensland)	5
Department of Mines and Petroleum (Western Australia)[b]	DR22
Department of the Environment, Water, Heritage and the Arts (Australian Government)	8#, DR35
Department of Water and Energy (New South Wales)	12
DomGas Alliance	1, DR24
ExxonMobil Australia (ExxonMobil)	13, DR31
Hunter, Tina	9, DR28
International Association of Geophysical Contractors Austral Chapter	10
Malek, Reza	6
National Native Title Tribunal	DR30#
Nexus Energy (Nexus)	3, DR25
Northern Territory Government	DR32
O'Donnell, Carol	2#, 4, DR21
Origin Energy	DR27
Primary Industries and Resources South Australia (South Australia)	20
South Australian Government	DR23
Victorian Government	7, DR26
Woodside Energy (Woodside)	11, DR33

[a] A hash (#) indicates that the submission includes attachments. [b] Created from a restructure of the previous Department of Industry and Resources and the Department of Consumer and Employment Protection in January 2009.

Table A.2 **Visits**

Participant (grouped by visit location)

Canberra

Australian Pipeline Industry Association
Australian Petroleum Production and Exploration Association
Department of Resources, Energy and Tourism (Australian Government)
Geoscience Australia (Australian Government)
The Treasury (Australian Government)

Melbourne

Department of the Environment, Water, Heritage and the Arts (Australian Government)
Department of Primary Industries (Victoria)
ExxonMobil Australia
Nexus Energy

Brisbane

Department of Mines and Energy (Queensland)
Environmental Protection Agency (Queensland)
Magellan Petroleum Australia
Origin Energy Australia

Adelaide

Beach Petroleum
Primary Industries and Resources South Australia (South Australia Government)
Santos

Perth

Australia Worldwide Exploration
BHP Billiton
BP Australia
Chevron Australia
Department of Industry and Resources / Department of Mines and Petroleum[a] (Western Australia)
Department of the Premier and Cabinet (Western Australia)
Department of Treasury and Finance (Western Australia)
DomGas Alliance
Eni Australia
Environmental Protection Authority (Western Australia)
Inpex
National Offshore Petroleum Safety Authority
Office of Development Approvals Coordination (Western Australia)
Vermilion Oil and Gas Australia
Woodside Energy

Darwin

ConocoPhillips Australia
Department of Regional Development, Primary Industry, Fisheries and Mines (Northern Territory)

(Continued next page)

Table A.2 (continued)

Participant (grouped by visit location)
Karratha & North West Shelf
Dampier Port Authority
Stag Platform (64 kilometres off Dampier, Western Australia; operated by Apache Energy)
Karratha Gas Plant (operated by Woodside Energy)
Pluto liquefied natural gas (LNG) project (Burrup LNG Park, Western Australia; operated by Woodside Energy)

[a] Created from a restructure of the previous Department of Industry and Resources and the Department of Consumer and Employment Protection in January 2009.

Table A.3 **Roundtables**

Participant
Canberra 16 October 2008
Australian Petroleum Production and Exploration Association
Department of Primary Industries (Victoria)
Department of Resources, Energy and Tourism (Australian Government)
Department of the Environment, Water, Heritage and the Arts (Australian Government)
ExxonMobil Australia
Geoscience Australia (Australian Government)
Magellan Petroleum Australia
Nexus Energy
Santos
Perth 23 October 2008
Australian Petroleum Production and Exploration Association
Chevron Australia
ConocoPhillips Australia
Department of Environment and Conservation (Western Australia)
Department of Industry and Resources (Western Australia)
Eni Australia
Inpex
Primary Industries and Resources South Australia (South Australian Government)
Woodside Energy
Melbourne 10 February 2009
Department of Infrastructure, Energy and Resources (Tasmania)
Department of Primary Industries (Victoria)
Department of Resources, Energy and Tourism (Australian Government)
Department of the Environment, Water, Heritage and the Arts (Australian Government)
Geoscience Australia (Australian Government)

(Continued next page)

Table A.3 (continued)

Participant (grouped by visit location)
Perth 16 February 2009
Department of Environment and Conservation (Western Australia)
Department of Mines and Petroleum (Western Australia)[a]
National Offshore Petroleum Safety Authority
Primary Industries and Resources South Australia (South Australian Government)
Perth 17 February 2009
Apache Energy
Australian Petroleum Production and Exploration Association
BHP Billiton
Chevron Australia
Eni Australia
ExxonMobil Australia
Inpex
Santos
Woodside Energy

a Created from a restructure of the previous Department of Industry and Resources and the Department of Consumer and Employment Protection in January 2009.

B List of legislation

The upstream petroleum sector is subject to all Australian laws. However, discussion of legislation in this study is limited to areas that are considered the most relevant to the activities of the sector. Table B.1 contains a list of all the legislation referred to in chapter 4. It is grouped according to primary scope (although some laws may have a broader scope) and jurisdiction. The relevant department or agency responsible for administering the legislation is also listed.

Table B.1 **Legislation relevant to upstream petroleum activities**

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Petroleum and pipelines	Commonwealth	*Offshore Petroleum and Greenhouse Gas Storage Act 2006*	Department of Resources, Energy and Tourism
Petroleum and pipelines	Commonwealth	*Petroleum (Timor Sea Treaty) Act 2003*	Department of Resources, Energy and Tourism
Petroleum and pipelines	NSW	*Petroleum (Offshore) Act 1982*	Department of Primary Industries
Petroleum and pipelines	NSW	*Petroleum (Onshore) Act 1991*	Department of Primary Industries
Petroleum and pipelines	NSW	*Pipelines Act 1967*	Department of Energy, Utilities and Sustainability
Petroleum and pipelines	Victoria	*Petroleum (Submerged Lands) Act 1982*	Department of Primary Industries
Petroleum and pipelines	Victoria	*Petroleum Act 1998*	Department of Primary Industries
Petroleum and pipelines	Victoria	*Pipelines Act 2005*	Department of Primary Industries
Petroleum and pipelines	Queensland	*Petroleum Act 1923*	Department of Mines and Energy
Petroleum and pipelines	Queensland	*Petroleum Submerged Lands) Act 1982*	Department of Mines and Energy
Petroleum and pipelines	Queensland	*Petroleum and Gas (Production and Safety) Act 2004*	Department of Mines and Energy
Petroleum and pipelines	WA	*Barrow Island Act 2003*	Department of Mines and Petroleum
Petroleum and pipelines	WA	*Petroleum and Geothermal Energy Resources Act 1967.*	Department of Mines and Petroleum
Petroleum and pipelines	WA	*Petroleum (Submerged Lands) Act 1982.*	Department of Mines and Petroleum
Petroleum and pipelines	WA	*Petroleum Pipelines Act 1969.*	Department of Mines and Petroleum
Petroleum and pipelines	SA	*Petroleum (Submerged Lands) Act 1982*	Primary Industries and Resources South Australia
Petroleum and pipelines	SA	*Petroleum Act 2005*	Primary Industries and Resources South Australia
Petroleum and pipelines	Tasmania	*Mineral Resources Development Act 1995*	Department of Infrastructure, Energy and Resources
Petroleum and pipelines	Tasmania	*Petroleum (Submerged Lands) Act 1982*	Department of Infrastructure, Energy and Resources
Petroleum and pipelines	NT	*Energy Pipelines Act 1983*	Department of Regional Development, Primary Industry, Fisheries and Resources
Petroleum and pipelines	NT	*Petroleum Act 1984*	Department of Regional Development, Primary Industry, Fisheries and Resources

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Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Petroleum and pipelines	NT	*Petroleum (Submerged Lands) Act 1981*	Department of Regional Development, Primary Industry, Fisheries and Resources
OHS	Commonwealth	*Occupational Health and Safety Act 1991*	ComCare
OHS	NSW	*Occupational Health and Safety Act 2000*	WorkCover NSW
OHS	Victoria	*Dangerous Goods Act 1995*	WorkSafe Victoria
OHS	Victoria	*Occupational Health and Safety Act 1985*	WorkSafe Victoria
OHS	Queensland	*Dangerous Goods Safety Management Act 2001*	Department of Emergency Services
OHS	WA	*Dangerous Goods Safety Act 2004*	Department of Mines and Petroleum
OHS	WA	*Occupational Health and Safety Act 1984*	Department of Commerce
OHS	SA	*Dangerous Substances Act 1979*	SafeWork SA
OHS	SA	*Occupational Health, Safety and Welfare Act 1986*	SafeWork SA
OHS	Tasmania	*Dangerous Goods Act 1998*	Workplace Standards Tasmania
OHS	Tasmania	*Dangerous Substances (Safe Handling) Act 2005*	Workplace Standards Tasmania
OHS	Tasmania	*Workplace Health and Safety Act 1995*	Workplace Standards Tasmania
OHS	NT	*Dangerous Goods Act 1998*	NT WorkSafe
OHS	NT	*Workplace Health and Safety Act 2007*	NT WorkSafe
Environment	Commonwealth	*Environment Protection and Biodiversity Conservation Act 1999*	Department of the Environment, Water, Heritage and the Arts
Environment	Commonwealth	*Environment Protection (Sea Dumping) Act 1981*	Department of the Environment, Water, Heritage and the Arts
Environment	Commonwealth	*Great Barrier Reef Marine Park Act 1975*	Department of the Environment, Water, Heritage and the Arts
Environment	Commonwealth	*Protection of the Sea (Prevention of Pollution from Ships) Act 1983*	Department of Infrastructure, Transport, Regional Development and Local Government
Environment	NSW	*Coastal Protection Act 1979*	Department of Environment and Climate Change
Environment	NSW	*Environmental Planning and Assessment Act 1982*	Department of Planning

(Continued next page)

Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Environment	NSW	*Marine Parks Act 1997*	Department of Environment and Climate Change
Environment	NSW	*Marine Pollution Act 1987*	NSW Maritime
Environment	NSW	*National Parks and Wildlife Act 1974*	Department of Environment and Climate Change
Environment	NSW	*Threatened Species Conservation Act 1995*	Department of Environment and Climate Change
Environment	Victoria	*Coastal Management Act 1995*	Department of Sustainability and Environment
Environment	Victoria	*Conservation, Forests and Lands Act 1987*	Department of Sustainability and Environment
Environment	Victoria	*Environment Effects Act 1978*	Department of Sustainability and Environment
Environment	Victoria	*Environment Protection Act 1978*	Environment Protection Authority
Environment	Victoria	*Flora and Fauna Guarantee Act 1988*	Department of Sustainability and Environment
Environment	Victoria	*National Parks Act 1975*	Department of Sustainability and Environment
Environment	Victoria	*Planning and Environment Act 1987*	Department of Planning and Community Development
Environment	Victoria	*Pollution of Waters by Oil and Noxious Substances Act 1986*	Environment Protection Authority
Environment	Victoria	*Wildlife Act 1975*	Department of Sustainability and Environment
Environment	Queensland	*Coastal Protection and Management Act 1995*	Environmental Protection Agency
Environment	Queensland	*Environment Protection Act 1994*	Environmental Protection Agency
Environment	Queensland	*Marine Parks Act 2004*	Environmental Protection Agency
Environment	Queensland	*Nature Conservation Act 1992*	Environmental Protection Agency
Environment	Queensland	*Transport Operations (Marine Pollution) Act 1995*	Maritime Safety Queensland
Environment	WA	*Conservation and Land Management Act 1984*	Department of Environment and Conservation
Environment	WA	*Environmental Protection Act 1986*	Department of Environment and Conservation
Environment	WA	*Pollution of Waters by Oil and Noxious Substances Act 1987*	Department for Planning and Infrastructure
Environment	WA	*Wildlife Conservation Act 1950*	Department of Environment and Conservation

(Continued next page)

Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Environment	SA	*Adelaide Dolphin Sanctuary Act 2005*	Department for Environment and Heritage
Environment	SA	*Coast Protection Act 1972*	Department for Environment and Heritage
Environment	SA	*Environment Protection Act 1993*	Environment Protection Authority
Environment	SA	*Marine Parks Act 2007*	Department for Environment and Heritage
Environment	SA	*National Parks and Wildlife Act 1972*	Department for Environment and Heritage
Environment	SA	*Natural Resources Management Act 2004*	Department of Water, Land and Biodiversity Conservation
Environment	SA	*Protection of Marine Waters (Prevention of Pollution from Ships) Act 1987*	Department for Transport, Energy and Infrastructure
Environment	SA	*River Murray Act 2003*	Department of Water, Land and Biodiversity Conservation
Environment	SA	*Wilderness Protection Act 1992*	Department for Environment and Heritage
Environment	Tasmania	*Environmental Management and Pollution Control Act 1994*	Department of Environment, Parks, Heritage and the Arts
Environment	Tasmania	*National Parks and Reserve Management Act 2002*	Department of Environment, Parks, Heritage and the Arts
Environment	Tasmania	*Pollution of Waters by Oil and Noxious Substances Act 1987*	Department of Environment, Parks, Heritage and the Arts
Environment	NT	*Environmental Assessment Act 1982*	Department of Natural Resources, Environment, the Arts and Sport
Environment	NT	*Environmental Offences and Penalties Act 1996*	Department of Natural Resources, Environment, the Arts and Sport
Environment	NT	*Marine Pollution Act 1999*	Department of Planning and Infrastructure
Environment	NT	*Territory Parks and Wildlife Conservation Act 1977*	Department of Natural Resources, Environment, the Arts and Sport
Heritage	Commonwealth	*Aboriginal and Torres Strait Islander Heritage Protection Act 1984*	Department of the Environment, Water, Heritage and the Arts
Heritage	Commonwealth	*Historic Shipwrecks Act 1976*	Department of the Environment, Water, Heritage and the Arts
Heritage	NSW	*Heritage Act 1977*	Department of Planning
Heritage	Victoria	*Aboriginal Heritage Act 2006*	Department of Planning and Community Development
Heritage	Victoria	*Heritage Act 1995*	Heritage Victoria

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Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Heritage	Queensland	*Aboriginal Cultural Heritage Act 2003*	Department of Natural Resources and Water
Heritage	Queensland	*Queensland Heritage Act 1992*	Environmental Protection Agency
Heritage	Queensland	*Torres Strait Islander Cultural Heritage Act 2003*	Department of Natural Resources and Water
Heritage	WA	*Aboriginal Heritage Act 1972*	Department of Indigenous Affairs
Heritage	WA	*Heritage of WA Act 1990*	Heritage Council of Western Australia
Heritage	SA	*Aboriginal Heritage Act 1988*	Department of the Premier and Cabinet
Heritage	SA	*Heritage Places Act 1993*	Department for Environment and Heritage
Heritage	SA	*Historic Shipwrecks Act 1981*	Department for Environment and Heritage
Heritage	Tasmania	*Aboriginal Relics Act 1975*	Department of Environment, Parks, Heritage and the Arts
Heritage	Tasmania	*Historic Cultural Heritage Act 1995*	Tasmanian Heritage Council
Heritage	NT	*Heritage Conservation Act 1991*	Department of Natural Resources, Environment, the Arts and Sport
Heritage	NT	*Northern Territory Aboriginal Sacred Sites Act 1989*	Minister for Indigenous Policy
Development	Queensland	*Integrated Planning Act 1997*	Department of Infrastructure and Planning
Development	Queensland	*State Development and Public Works Organisation Act 1971*	Department of Infrastructure and Planning
Development	WA	*Planning and Development Act 2005*	Department for Planning and Infrastructure
Development	SA	*Development Act 1993*	Department of Planning and Local Government
Development	Tasmania	*Land Use Planning and Approvals Act 1993*	Department of Justice
Development	Tasmania	*Resource Planning and Development Commission Act 1997*	Department of Justice
Development	Tasmania	*State Policies and Projects Act 1993*	Department of Premier and Cabinet; Department of Justice
Development	NT	*Lands, Planning and Mining Tribunal Act 1998*	Department of Justice
Development	NT	*Planning Act 1993*	Department of Planning and Infrastructure
Local government	NSW	*Local Government Act 1993*	Department of Local Government

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Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Local government	Victoria	*Local Government Act 1989*	Department of Planning and Community Development
Local government	Queensland	*Local Government Act 1993*	Department of Local Government, Sport and Recreation
Local government	WA	*Local Government Act 1995*	Department of Local Government and Regional Development
Local government	SA	*Local Government Act 1999*	Office for State/Local Government Relations
Local government	Tasmania	*Local Government Act 1993*	Department of Premier and Cabinet
Local government	NT	*NT Local Government Act 1994*	Department of Local Government and Housing
Native title	Commonwealth	*Native Title Act 1993*	Attorney-General's Department; Department of Families, Housing, Community Services and Indigenous Affairs
Native title	NSW	*Native Title (NSW) Act 1994*	Department of Lands
Native title	Victoria	*Land Title Validation Act 1994*	Department of Justice
Native title	Queensland	*Native Title (Queensland) Act 1993*	Department of Natural Resources and Water
Native title	WA	*Titles (Validation) and Native Title (Effect of Past Acts) Act 1995*	Department of Treasury and Finance
Native title	SA	*Native Title (SA) Act 1994*	Attorney-General's Department
Native title	Tasmania	*Native Title (Tas) Act 1994*	Department of Premier and Cabinet
Native title	NT	*Validation (Native Title) Act 1994*	Department of the Chief Minister
Land rights	Commonwealth	*Aboriginal Land Rights (Northern Territory) Act 1976*	Department of Families, Housing, Community Services and Indigenous Affairs
Land rights	Commonwealth	*Aboriginal Land Rights (Lake Condah and Framlingham Forest) Act 1987*	Department of Families, Housing, Community Services and Indigenous Affairs
Land rights	Commonwealth	*Aboriginal Land Grant (Jervis Bay Territory) Act 1986*	Department of Families, Housing, Community Services and Indigenous Affairs
Land rights	NSW	*Aboriginal Land Rights Act 1983*	Department of Aboriginal Affairs
Land rights	Victoria	*Aboriginal Lands Act 1970*	Department of Planning and Community Development
Land rights	Victoria	*Aboriginal Lands Act 1991*	Department of Planning and Community Development
Land rights	Victoria	*Aboriginal Land (Manatunga Land) Act 1992*	Department of Planning and Community Development
Land rights	Queensland	*Aboriginal Land Act 1991*	Department of Natural Resources and Water
Land rights	Queensland	*Land Act 1994*	Department of Natural Resources and Water

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Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Land rights	Queensland	*Torres Strait Islander Land Act 1991*	Department of Natural Resources and Water
Land rights	WA	*Aboriginal Affairs Planning Authority Act 1972*	Department of Indigenous Affairs
Land rights	WA	*Aboriginal Communities Act 1979*	Department of Indigenous Affairs
Land rights	SA	*Aboriginal Lands Trust Act 1966*	Department of the Premier and Cabinet
Land rights	SA	*Anangu Pitjantjatjara Yankunytjatjara Land Rights Act 1981*	Department of the Premier and Cabinet
Land rights	SA	*Maralinga Tjarutja Land Rights Act 1984*	Department of the Premier and Cabinet
Land rights	Tasmania	*Aboriginal Lands Act 1995*	Department of Premier and Cabinet
Land rights	NT	*Aboriginal Land Act 1978*	Department of Planning and Infrastructure
Land rights	NT	*Coburg Peninsula Aboriginal Land, Sanctuary and Marine Park Act 1981*	Department of Natural Resources, Environment, the Arts and Sport
Land rights	NT	*Nitmiluk (Katherine Gorge) National Park Act 1989*	Department of Natural Resources, Environment, the Arts and Sport
Land rights	NT	*Parks and Reserves (Framework for the Future) Act 2004*	Department of the Chief Minister
Other	Commonwealth	*Australian Maritime Safety Authority Act 1990*	Department of Infrastructure, Transport, Regional Development and Local Government
Other	Commonwealth	*Coastal Waters (Northern Territory Powers) Act 1980*	Attorney-General's Department
Other	Commonwealth	*Coastal Waters (Northern Territory Title) Act 1980*	Attorney-General's Department
Other	Commonwealth	*Coastal Waters (State Powers) Act 1980*	Attorney-General's Department
Other	Commonwealth	*Coastal Waters (State Title) Act 1980*	Attorney-General's Department
Other	Commonwealth	*Customs Act 1901*	Attorney-General's Department
Other	Commonwealth	*Defence Act 1903*	Department of Defence; Department of Education, Employment and Workplace Relations; Department of the Prime Minister and Cabinet; Attorney-General's Department

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Table B.1 (continued)

Scope	*Jurisdiction*	*Legislation*	*Responsible department/agency*
Other	Commonwealth	*Energy Efficiencies Opportunities Act 2006*	Department of Resources, Energy and Tourism
Other	Commonwealth	*National Greenhouse and Energy Reporting Act 2007*	Department of Climate Change
Other	Commonwealth	*Navigation Act 1912*	Department of Infrastructure, Transport, Regional Development and Local Government
Other	Commonwealth	*Quarantine Act 1908*	Department of Health and Ageing; Department of Agriculture, Fishing and Forestry
Other	Commonwealth	*Submarine Cables and Pipelines Protection Act 1963*	Department of Infrastructure, Transport, Regional Development and Local Government
Other	Commonwealth	*Maritime Transport and Offshore Facilities Security Act 2003*	Department of Infrastructure, Transport, Regional Development and Local Government

Sources: ComLaw; State and Northern Territory legislation databases; various departmental websites.

C International comparisons

The Commission has drawn on several external studies to examine structural and circumstantial influences on regulatory performance from an international perspective. Two issues of regulatory structure are identified as particularly relevant to this study, namely:

- the legal nature of the state–business relationship — specifically, the choice between rule-based and negotiation-based regulation (section C.1)
- the constitutional constraints that a federation places on designing a cooperative multi-jurisdictional regulatory framework (section C.2).

C.1 Introducing flexibility with negotiation-based regulation

The legal framework governing upstream petroleum activities can have crucial implications for the level of regulatory burden faced by project proponents. In particular, the question arises as to whether such framework should be defined by general legislation or based on *ad hoc* agreements between governments and individual businesses.

According to Hossain (1979), the regulation of petroleum projects in different countries falls broadly under three systems, namely:

- a sector-specific legislative system — with legislation predetermining conditions under which the rights to explore for and exploit petroleum resources are granted by means of standard licences or leases, including royalty taxes and other payments to be made by licensees or lessees
- a negotiation-based system — with the government granting the rights to explore for and exploit petroleum resources on the basis of individually negotiated agreements with petroleum businesses in the absence of comprehensive petroleum legislation
- a hybrid system — with general legislation setting out certain provisions and minimum standards or conditions for the grant of rights to explore for and exploit petroleum resources, but also providing for certain important matters to be settled by negotiation between government and individual businesses.

Australia primarily depends on a sector-specific legislative system for regulating upstream petroleum activities. In a few cases, contractual agreements have been negotiated and subsequently codified into legislation. Some others are based on 'major project' provisions of the legislation. Canada and the United States adopt a similar legal system.

Petroleum concessions were typically negotiated between host governments and multinational businesses in traditional petroleum provinces such as Saudi Arabia and some other Middle East countries. More recent examples include Indonesia and Papua New Guinea, where petroleum legislation lays down broad principles for contracting businesses in the private sector to develop petroleum resources, while leaving detailed terms and conditions to be determined through contract negotiation (Asmus 2000; Yalapan 2003).

The Netherlands, New Zealand, Norway and the United Kingdom are among the countries that have adopted a hybrid system to regulate upstream petroleum activities. Typically, these countries have legislation governing petroleum development activities that contains provisions enabling governments to negotiate with petroleum businesses on crucial contractual matters. For example, Norway's regulatory framework is outlined in box C.1.

A key advantage of a sector-specific legislative approach (from a government's perspective) is that the terms (including fiscal terms) can be varied by subsequent legislative changes. This helps avoid the situation where an individually negotiated agreement 'freezes' contract terms over the project life, without any legal recourse to enable adjustment to changing market conditions.

Another advantage of the legislative approach is that it allows policy objectives to be incorporated into the legal framework. Setting out overarching policy strategies for petroleum development in legislation can provide guidance on the design and administration of regulatory arrangements.

Further, minimum standards and basic conditions for the grant of rights of resource exploration and extraction can be laid down in legislation. This helps promote transparency and accountability in the administration of the regulatory regime. To leave such licensing standards and conditions to administrative discretion or negotiation could expose the regulatory agency concerned to undue pressure exerted by petroleum businesses individually or collectively.

On the other hand, to include excessive project details into legislation could lead to a lack of contracting flexibility. Moreover, including detailed rules into legislation can add to compliance obligations.

Box C.1 **The Norwegian regulatory framework**

The Norwegian petroleum resource management regime is characterised by the use of principle-based legislation, as currently reflected in the *Petroleum Activities Act 1996* (Norway). This law sets out framework conditions to guide the formulation of acceptable commercial incentives in concession contracts granted to private businesses for undertaking exploration and extraction.

Among the matters prescribed by the legislation are the initial duration of an exploration licence (3 years) and a production licence (10 years), as well as the mandatory obligation for project proponents to submit field development plans for approval by authorities before extraction activities can commence. The legislation also prescribes that '[t]he King may decide that the Norwegian State shall participate in petroleum activities' (*Petroleum Activities Act 1996* (Norway), s. 3.6).

A number of critical matters are determined by mutual agreement of the parties concerned, which often requires intensive negotiations. These matters include the size of the exploration program and the extent of state participation in the project. In effect, state participation involves negotiating a joint-venture agreement covering a number of contractual issues such as the percentage of equity to be held by each party, the management structure and control of operations, and the conditions under which the obligation to invest in resource development would increase.

Despite its contractual basis of regulation, the Norwegian petroleum regime includes mechanisms that enhance transparency through a set of criteria for reporting on concession terms and project incomes. For example, there is public information on the tax payments from individual businesses operating in the Norwegian continental shelf. Further, model contract terms are accessible to the public.

Sources: Hossain (1979); Norwegian Ministry of Foreign Affairs (2006); Tina Hunter (sub. 9).

Hossain (1979) suggested that the most effective way to introduce contractual flexibility would be to leave room for negotiation on matters for which some variation could be expected. Variation could stem from differences in location or other geological and geophysical features of petroleum projects. Consequently, this approach underpins a key advantage of the hybrid system.

Onorato (1995), while serving as the World Bank's principal advisor on petroleum development matters, suggested that best practice regulation in this area should involve integrating the legal, contractual and fiscal arrangements into a self-contained legislative framework. Further, Onorato argued that such an integral framework would give both the host government and the petroleum business a clear legal and contractual basis on which to negotiate mutually advantageous arrangements for developing petroleum resources. Under this approach, the regulatory framework comprises broad, and not overly detailed, petroleum law

complemented by enabling regulations and one or several variants of a model contract (box C.2).

According to a study by Daintith (2005), the Australian regulatory regime for upstream petroleum activities involves administrative rules embedded in legislation. The regime operates by prohibiting certain activities and then granting businesses the administrative authority to carry out operations under the relevant regulatory provisions.

In almost all other concession systems worldwide, the state concludes a contract with the business within a regulated environment on the basis of the state's complete sovereign rights to the petroleum resources (Daintith 2005). In the United Kingdom, for example, the state–business relationship is wholly expressed in a contractual form.

Box C.2 **An effective legislative framework for petroleum development**

According to World Bank practices of legal reform in the petroleum sector, an effective legislative framework for attracting investment should be comprised of a generic petroleum legislation, a set of subsidiary regulations, and a model contract.

The petroleum legislation would assert the state's property rights to petroleum resources. It would also identify an agency to be vested with the exclusive mandate to implement government policies for developing petroleum resources within its jurisdiction. This agency would represent the state in negotiating and contracting with investors, and subsequently in regulating and administering contract compliance activities.

To maintain its generic property, the petroleum legislation should be couched in terms of minimal permissive contents of a model contract — without including excessively detailed legal provisions. For example, the recommended practice in respect of environmental protection and safety is to include a comprehensive obligation for these policy goals in the petroleum legislation, and then to detail specific actions and requirements in the subsidiary regulations and the contract.

For regulating petroleum projects, a self-contained and coherent legislative framework is considered more appropriate than piecing together legislative provisions in both the petroleum legislation and other related and relevant laws such as those on taxation, land use and environmental protection. Accordingly, Onorato concluded that it is inadvisable to make petroleum operations subject to broad, general environmental protection law, except to the extent that the principles of law are applicable to specific practices of the petroleum sector.

Source: Onorato (1995).

In the 1960s, Australian governments avoided using a concession system to regulate oil and gas exploration and extraction, in part to avoid conflict between the

Commonwealth and States and Territories over resource rights (Daintith 2005). Australian governments maintained a non-contractual basis of petroleum laws even after the resource rights issue was resolved through the Offshore Constitutional Settlement in the late 1970s.

Tina Hunter argued that the history of Australia's offshore petroleum legislation produced 'a combination of painstaking detail and grand scale delegation' (sub. 9, p. 20). Daintith (2005) found the system of petroleum titles under the *Petroleum (Submerged Lands) Act 1967* (Cwlth), and the detailed rules surrounding them, limited the flexibility of Australia's petroleum regime to adjust to different or changing circumstances.

The Australian regime has been described as involving broad delegation of regulatory powers to government departments or agencies (Daintith 2005). These authorities are given appreciable discretionary powers, particularly in interpreting and determining regulatory requirements, although these administrative powers are sometimes exercised through the issuance of regulatory guidelines that confine the decision making of the authorities.

C.2 A cooperative multi-jurisdictional framework

Evans and Bailey (1997) found that the Australian offshore regime appeared to be effective in averting the potential conflicts of interest between jurisdictions. This was in contrast with the US framework, which is based on the traditional three-mile separation offshore of the state from federal authority. In the United States, the administration of the petroleum regime is largely entrusted to the Secretary of the Interior, with no delegation to state authorities and limited scope for federal–state joint decision making (Daintith 2005).

On the US west coast, for example, the tension between governments pursuing differing, or even conflicting, policy goals within their respective coastal zones was noted to have 'broken down' the offshore oil leasing program (the US petroleum acreage allocation process) (Evans and Bailey 1997). Such a problem reflects the asymmetric distribution of costs and benefits involved in developing petroleum resources — that is, the beneficial aspects of offshore development accrue mainly to the federal government as resource-driven revenues, whereas the costs of onshore infrastructure, environmental damage and disruption of lifestyle are incurred at a more localised level.

Evans and Bailey (1997) suggested that two factors contribute to the relative effectiveness of the Australian regime. First, the use of mirror legislation in different jurisdictions provides legal consistency and continuity, enabling

compatible resource titles to be granted for all offshore areas. Second, the joint decision-making structure promotes cooperative governance of offshore petroleum activities, allowing the Australian Government and the State and Territory Governments to set consistent policies for the development of petroleum resources in offshore areas.

Hunt (1990), after comparing the petroleum regimes of Australia and Canada, concluded that Australia's Offshore Constitutional Settlement has worked well in resolving the competing jurisdictional claims over offshore petroleum resources of the two levels of government (box C.3). Nevertheless, it was noted that common petroleum codes could be 'more an illusion than reality' in Australia because the *Coastal Waters (State Powers) Act 1980* (Cwlth) allows each State to alter its petroleum laws in its coastal waters without having to seek the agreement of other governments. Consequently, a lack of uniformity in petroleum laws could complicate the regulation of projects in cross-jurisdictional areas (chapter 5).

Box C.3 **Comparing the Australian and Canadian petroleum regimes**

The Australian and Canadian petroleum regimes are both characterised by federal–state (province) involvement in decision making about the development of petroleum resources in offshore areas. Nevertheless, they have some notable differences.

Australia has a multilateral inter-jurisdictional system covering all water areas adjacent to the States and the Northern Territory. By contrast, Canada has a bilateral system. This is represented by the 1985 Atlantic Accord and the 1986 Resources Accord signed between the Canadian Government and, respectively, the provinces of Newfoundland and Nova Scotia.

Further, unlike Australia's Offshore Constitutional Settlement, the Canadian Accords do not differentiate between the territorial sea and the continental shelf. For areas where no intergovernmental management arrangements have been agreed to, the Canadian Government has jurisdiction over the regulation of petroleum development.

Australia's regime has the advantage of a single Commonwealth statute governing the entire continental shelf. Yet, it also has the potential disadvantage of different State statutes governing the territorial seas.

Sources: Brownsey (2007); Hunt (1990).

The Australian regime, notwithstanding its strengths as discussed above, was viewed by Evans and Bailey (1997) as having a narrow focus on resource management, while giving less consideration to environmental issues. It is primarily based on the mandate for governments to manage the economic relationship between the jurisdiction (as resource owner) and the project proponent (as the entity entrusted with the development of petroleum resources), although this mandate also

includes broader responsibilities of government such as environmental protection and public safety. Reflecting this, there is scope for governments to pursue differing environmental policies within their own jurisdictions (chapters 4 and 6). This has led to different approaches to environmental regulation across Australia.

The absence of fully cooperative marine protection policy at different levels of government is not unique to Australia but also applies to other federations such as Canada (Bowal 2003). This is in large part because environmental protection law has been a relatively recent initiative. As a consequence, the legal jurisdiction over such issues has been interpreted and declared from a constitutional structure that did not foresee the natural environment as a discrete subject for regulation. In practice, the diverse nature of environmental protection renders it difficult to assign all relevant regulatory responsibilities to one level of government.

D Summary of environmental and heritage requirements

D.1 Principles of environmental regulation

The potential environmental impacts arising from petroleum activities are diverse and depend on the nature of the activity (including its scale, location and management). The environmental impacts of petroleum activities that are likely to be considered as part of an environmental management plan or assessment include:

- potential impact on marine species, including disturbance to fisheries and cetaceans (cetaceans include whales and dolphins)
- discharges to land or water — including 'drilling muds' and fluids, formation water, domestic water, and other discharges
- emissions to air — such as gas flaring, venting and fugitive gas emissions
- waste disposal and management
- noise pollution
- land and vegetation clearance, including disturbance to native flora and fauna and ecological processes — such as clearance for construction of production facilities and pipelines
- social and economic impacts — environmental impacts can affect local tourist and recreational activity, visual amenity and wilderness values
- impact on sites with cultural or natural heritage value.

Most jurisdictions through their environmental protection legislation have adopted ecologically sustainable development (ESD) principles. Some key ESD principles commonly adopted in environmental protection legislation include the:

- precautionary principle — if there are threats of serious or irreversible environmental damage, lack of full scientific certainty should not be used as a reason for postponing measures to prevent environmental degradation. Decision making should be guided by careful evaluation to avoid serious or irreversible damage to the environment wherever practicable, and by an assessment of the risk-weighted consequences of various options

- principle of intergenerational equity — the present generation should ensure that the health, diversity and productivity of the environment is maintained or enhanced for the benefit of future generations
- principle of conservation of biological diversity and ecological integrity
- principles of improved valuation, pricing and incentive mechanisms — persons who generate pollution and waste should bear the cost of containment, avoidance and abatement. In addition, users of goods and services should pay prices based on the full life-cycle costs of providing the goods and services. Established environmental goals should be pursued in the most cost-effective way by establishing incentive structures, including market mechanisms.

D.2 Requirements under the EPBC Act

The *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) is the Australian Government's main legislation dealing with environmental impacts. It provides a legal framework to protect and manage nationally and internationally important flora, fauna, ecological communities and heritage sites — defined in the Act as matters of National Environmental Significance (NES). Actions that are likely to significantly impact on those matters are prohibited, without the Commonwealth Environment Minister's approval under the EPBC Act.

The objectives of the EPBC Act are to:

- provide for the protection of the environment, especially matters of NES
- conserve Australian biodiversity
- provide a streamlined national environmental assessment and approval process
- enhance the protection and management of important natural and cultural places
- control the international movement of plants and animals (wildlife), wildlife specimens and products made or derived from wildlife
- promote ESD through the conservation and ecologically sustainable use of natural resources.

Under the EPBC Act, certain actions — projects, development, undertakings, activities or a series of activities, or an alteration to any of these — require an assessment under the EPBC Act and an approval from the Commonwealth Environment Minister.

Actions that may trigger assessment and approval processes under the EPBC Act include those that have, will have or are likely to have a significant impact on:

- a matter of NES
- the environment of Commonwealth land even if the action is taken outside Commonwealth land, and on the environment in general if the action is taken on Commonwealth land
- the environment, inside or outside of Australian jurisdiction, where the actions are undertaken by the Australian Government or its agencies.

Matters of National Environmental Significance

Matters of NES include (EPBC Act, Chapter 2):

- World Heritage properties
- National Heritage places
- wetlands of international importance
- listed threatened species and ecological communities
- listed migratory species
- Commonwealth marine areas
- nuclear actions (including uranium mining).

A proponent can refer the proposed activity to the Environment Minister through the Department of Environment, Water, Heritage and the Arts (DEWHA) if they are unsure as to whether an approval is required. If a referred action is likely to have a significant impact on a matter of NES, it will be considered a 'controlled action', and require approval by the Commonwealth Environment Minister under the EPBC Act, otherwise it cannot proceed. The proponent will be required to submit an environmental assessment for approval by the Environment Minister (box D.1).

There are five main forms of assessment (EPBC Act, Chapter 4):

- Accredited assessment — State and Territory or other assessment processes accredited under bilateral agreements with the Commonwealth.
- Assessment on referral information — decision based on the proponent's referral application.
- Assessment on preliminary documentation — decision based on the referral application form and additional information provided by the proponent.

- Assessment by Environmental Impact Statement or Public Environmental Report.
- Assessment by public inquiry.

Box D.1 **Approval processes under the EPBC Act**

There are three potential main stages in considering a matter of National Environmental Significance (NES) under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) — a 'referral decision' stage, an 'assessment' stage and a 'decision whether to approve' stage.

Referral decision stage

Before taking an action that may have a significant impact on a matter of NES, the proponent must submit a referral form to the Commonwealth Environment Minister via the department. The referral will then be processed according to the following steps:

- Following receipt of a valid referral the Minister has 20 business days to decide if the proposed action will require assessment and approval under the EPBC Act, including a 10 day period for public comment.
- If a significant impact is likely, the action is deemed to be a 'controlled action' and it will require assessment and approval under the EPBC Act. The proponent is informed of the referral decision and, if an assessment is required, the proposed method of assessment.

Assessment and approval stage

An assessment is prepared and submitted by the proponent. Depending on the assessment approach, the Minister will make a decision on the action in accordance with the following timeframes after receiving a completed report:

- Accredited assessment report — within 30 days of receiving a completed report.
- Assessment by referral information — the Department of Environment, Water, Heritage and the Arts has 30 days after the 'assessment approach' decision to finalise a recommendation report. A decision must be made within 20 days of receiving a recommendation report.
- For assessment by public inquiry, Environment Impact Statement, Public Environment Report or preliminary documentation — within 40 days of receiving the finalised documentation from the proponent.

The decision of the Minister will be either the approval of the controlled action, approval with conditions (including environmental offset conditions), or not to approve the controlled action.

Source: DEWHA (2007a).

An accredited assessment may be undertaken where there is a bilateral 'assessment' agreement in place between the Commonwealth and a State or Territory. In this

situation certain actions that require approval under the EPBC Act can be assessed under accredited State or Territory environmental assessment processes. At the completion of the assessment process, the State or Territory provides the Commonwealth Environment Minister with a report on the relevant impacts of the proposed action.

Definition of significant impact

The requirement to undergo assessment and approval under the EPBC Act applies when an action has a 'significant impact'. DEWHA has produced *EPBC Act Policy Statement 1.1 Significant Impact Guidelines,* which set criteria for judging whether the impact is likely to be significant. While the guidelines provide examples of actions that are, and are not, likely to have a significant impact, they are not exhaustive or definitive. For example, the guidelines state that an action is likely to have a significant impact on a 'critically endangered' or 'endangered species' when it:

- leads to a long-term decrease in the size of a population
- reduces the area of occupancy of the species
- fragments an existing population into two or more populations
- adversely affects habitat critical to the survival of a species
- disrupts the breeding cycle of a population.

Strategic assessments

Under section 146 of the EPBC Act, the Commonwealth Environment Minister may agree to conduct a strategic assessment of potential actions under a policy, program or plan. These may include, but are not limited to (DEWHA 2008e):

- regional-scale development plans and policies
- district structure plans
- local environmental plans
- large-scale industrial development
- fire, vegetation or pest management policies, plans or programs
- water extraction and use policies
- infrastructure plans and policies.

A strategic assessment happens early in the assessment process and is separate from the conventional approval process under the EPBC Act. A strategic assessment may

examine the potential cumulative impacts of actions in accordance with one or more policies, programs or plans. The main objective of strategic assessments is to streamline the approval process under the areas covered by providing:

- early consideration of national environmental matters in planning processes
- greater certainty to the local communities and developers over future development
- reduced administrative burden for proponents taking actions consistent with a policy, plan or program approved under a strategic assessment
- capacity to achieve better environmental outcomes and address cumulative impacts at the landscape level
- flexible timeframes commencing early in the planning process.

Commonwealth marine reserves and bioregional plans

There are currently 13 Marine Protected Areas in Commonwealth waters under the EPBC Act. Approval is required if an action is to be undertaken within an Marine Protected Area. In addition, the South-east Commonwealth Marine Reserve Network, comprising 13 individual reserves, was established in September 2007. All Marine Protected Areas are managed primarily for biodiversity conservation. Specific zoning and management arrangements allow for uses that are consistent with the management plan in operation for the area.

Further, the Australian Government has embarked on a program of bioregional marine planning that falls directly under the EPBC Act (DEWHA, sub. 8). Under this program, Marine Bioregional Plans will be developed in each of the five marine regions in Commonwealth waters by 2012. These plans will include the identification and establishment of representative Marine Protected Areas. Once in place, these marine regional plans will provide information to marine industries that will assist them to understand their obligations under the EPBC Act. It is intended that petroleum exploration and production activities will be allowed within some Marine Protected Areas subject to approvals under the *Offshore Petroleum Act 2006* (Cwlth) and the provisions of the EPBC Act (RET 2008b).

Seismic activities and cetaceans

Under Chapter 5 of the EPBC Act there is a process for obtaining a permit for any activity likely to impact on cetaceans, incidentally or otherwise, in offshore waters. Cetaceans include whales, dolphins and porpoises. The 2008 offshore petroleum

acreage release includes areas that are in recognised whale migration corridors and important aggregation areas (RET 2008b).

A policy statement on the interaction between offshore seismic exploration and whales has been developed by DEWHA — *EPBC Policy Statement 2.1 — Interaction between offshore seismic exploration and whales*. This document provides guidance on a proponent's obligations. Seismic surveys proposed in areas where there is a moderate to high likelihood of encountering whales are obliged to employ a range of mitigation measures, in addition to the standard management procedures under the policy.

A key component of the standard management procedure is a sequential 'ramp-up' of the acoustic source. This is considered to be industry best practice, as the slow increase in acoustic energy may alert whales in the area to the presence of the seismic activity. Additional mitigation measures may include:

- marine mammal observers
- whale spotting surveys during daylight — if undertaking seismic activity at night or in poor visibility
- spotter vessels and aircraft
- increased safety and buffer zones
- passive acoustic monitoring.

D.3 State and Territory environmental regulation

State and Territory environmental regulation of petroleum activities includes petroleum-specific regulation applying to both offshore and onshore activities. It also includes requirements under general State and Territory environmental and planning legislation — especially impact assessment requirements under environmental protection or planning Acts.

Specific requirements for onshore petroleum activities

A range of petroleum-specific environmental requirements exist for onshore petroleum activities regulated under onshore petroleum Acts, subordinate regulations and departmental guidelines. In Victoria, Western Australia, South Australia and the Northern Territory, detail on environmental impacts and risks of petroleum activities must be provided to the department responsible for petroleum regulation. In Queensland, and in associated coastal waters, a petroleum-specific environmental submission to the Environmental Protection Agency is required

under the *Environmental Protection Act 1994* (Qld). See box D.2 for specific requirements.

Box D.2 **State and Territory requirements for onshore activities**

- In Victoria, an operation plan covering environmental risks is required for onshore petroleum operations, and is provided to the Department of Primary Industries. This is required under the provisions of the Petroleum Regulations 2000 (Vic). Pipelines require an Environment Management Plan, and a rehabilitation bond, under the Pipeline Regulations 2007 (Vic).
- In Queensland, a proponent is required to submit an application for an 'environment authority' and, for medium-to high-risk activities, an Environment Management Plan to the Department of Mines and Energy, which is then forwarded to the Environmental Protection Agency for approval. The petroleum-specific environmental requirements are detailed under the *Environmental Protection Act 1994* (Qld).
- In Western Australia, an Environment Management Plan is required for petroleum activities, including pipelines, and is provided to the Department of Mines and Petroleum. The specific requirements for these plans are outlined under departmental guidelines only. The *Pipeline Act 1969* (WA) and Petroleum Pipeline Regulations 1970 (WA) do not contain specific environmental provisions.
- In South Australia, a proponent prepares an Environmental Impact Report and a draft Statement of Environmental Objectives for petroleum activities, including pipelines, and provides them to Primary Industries and Resources South Australia. These requirements are specified under the *Petroleum Act 2000* (SA) and the Petroleum Regulations 2000 (SA).
- In the Northern Territory, an Environment Management Plan is provided for production activities to the Department of Regional Development, Primary Industry, Fisheries and Resources. The requirements are set out in guidelines. As specified in the relevant guidelines, pipelines require the submission of an Environment Plan, as part of a Pipeline Management Plan under the Energy Pipeline Regulations (NT) or, for pipeline licence applications, a Notice of Intent.

Sources: DoIR (2006); RDPIFR (2008a, 2008b, 2008c).

Environmental assessment and referral arrangements

Box D.3 outlines environmental approval requirements in a number of States and Territories. Further, an environmental or planning agency, and community members in general, may also 'call in' or refer activities for consideration under environmental legislation.

Box D.3 **State and Territory environmental approval requirements**

The following is an overview of the key environmental approval requirements in the main petroleum-producing States and Territories.

New South Wales

All petroleum production projects, and most exploration activities, require environmental assessment under the *Environmental Planning and Assessment Act 1979* (NSW). The approval authority depends on the type and scale of the proposal. Although the NSW Department of Primary Industries is the assessment and approval authority for some exploration activities, in the majority of cases the authority will be the Minister for Planning under Part 3A of the Act. There is also major project legislation that allows a more coordinated and streamlined approach to approvals.

Victoria

An Environmental Effects Statement for petroleum activities may be undertaken by the environmental agency under the *Environmental Effects Act 1978* (Vic). Typically the Minister administering this Act will require a Statement to be undertaken when:

- there is a likelihood of regionally or State significant adverse effects on the environment
- there is a need for integrated assessment of potential environmental effects of a project and relevant alternatives
- normal statutory processes would not provide a sufficiently comprehensive, integrated and transparent assessment.

Petroleum exploration activities in coastal waters, unless in a marine sanctuary, are unlikely to require an Environmental Effects Statement. However, most petroleum production activities in coastal waters would generally require one. The Primary Industries Minister will receive advice from the Environment Minister in relation to the completed statement, and must consider their views in making a decision.

Queensland

The Environmental Protection Agency will assess all applications for petroleum-specific environmental approvals under the *Environmental Protection Act 1994* (Qld). There are two different assessment processes:

- 'Level 1' petroleum activities have a medium to high risk of causing serious environmental harm. Assessment is based on an application accompanied by an Environmental Management Plan. After receipt of the application, the Environmental Protection Agency may decide that the proponent is required to prepare an Environmental Impact Statement under the Act.
- 'Level 2' petroleum activities have a low risk of serious environmental harm. The assessment process for level 2 is based on whether the applicant can comply with the standard environmental conditions in the relevant code of environmental compliance in the case of a code-compliant authority.

(Continued next page)

Box D.3 (continued)

Western Australia

The Department of Mines and Petroleum will refer all offshore petroleum proposals that occur in coastal waters to the Environment Protection Authority for possible assessment under the *Environmental Protection Act 1986* (WA).

Onshore petroleum proposals will be referred to the Environmental Protection Authority depending on the location of the activity (for instance, if it located near a 'protected area', a 'Red Book' area, or a declared town-site or private reserve) whether it has the potential for a significant impact or if it involves clearing of native vegetation. Proposals are assessed formally where environmental effects are perceived to be 'significant' or where there is a high degree of public interest. There are five levels of formal assessment available to the Environmental Protection Authority.

Proposals that are considered not to warrant assessment under the Act are referred back to the department who assess and assign environmental conditions to the proposal upon approval of the environmental documentation.

South Australia

Primary Industries and Resources South Australia (PIRSA) will consult with relevant environmental agencies to decide on the required level of assessment for specific petroleum activities:

- A 'low risk' activity will be assessed internally by government between PIRSA, the Department of Environment and Heritage, the Department of Planning and Local Government and other relevant agencies, such as the Environmental Protection Authority. The Resources Minister will decide on the approval of the Environmental Impact Report and Statement of Environmental Objectives, on the advice of PIRSA.
- 'Medium risk' activities will be assessed under equivalent requirements of the public environmental report process under the *Development Act 1993* (SA). PIRSA will also seek comments from the Environmental Protection Authority and other relevant agencies on the Environmental Impact Report and the Statement of Environmental Objectives during the public consultation process. PIRSA will consider the assessment and advise their Minister whether to approve the activity.
- Only 'high risk' activities will be formally referred to the Department of Planning and Local Government for assessment under the Development Act. The Petroleum Minister will then make a decision based on the advice of the Planning Minister.

Northern Territory

The Environmental Management Plan will require review for referral to the Environmental Protection Agency for possible assessment under the *Environmental Assessment Act* (NT). If the proposed project is assessed under the Act, the proponent will also be instructed to prepare either an Environmental Impact Statement or a Public Environmental Report.

D.4 Heritage regulation

Heritage regulation includes Commonwealth heritage legislation — specifically, the EPBC Act, the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth) and the *Historic Shipwrecks Act 1976* (Cwlth) — and State and Territory Indigenous heritage Acts.

Commonwealth heritage requirements

The EPBC Act protects three types of listed values — World, National and Commonwealth List places. Anyone can recommend a place for National and Commonwealth listing, however there is an 'assessment cycle', which is defined in the EPBC Act (usually over a 12 month period). A delegate for the Minister decides whether the application meets the regulations and is in good faith (vexatious or frivolous applications may not be considered). There are emergency procedures under each section that are at the Minister's discretion where the heritage values are 'under threat'.

A referral must be made under the EPBC Act for actions that are likely to have a significant impact on the following matters protected by Part 3 of the Act:

- World Heritage properties (sections 12 and 15A)
- National Heritage places (sections 15B and 15C)
- the environment, if the action involves Commonwealth land (sections 26 and 27A).

The Aboriginal and Torres Strait Islander Heritage Protection Act applies in all States and Territories:

- Section 9 of the Act allows for the Minister to make an emergency declaration to preserve or protect an area from injury or desecration if satisfied that 'the area is a significant Aboriginal area' and there is a 'serious and immediate threat'.
- Section 10 of the Act allows for the Minister to make a declaration to preserve or protect an area from injury or desecration if satisfied that 'the area is a significant Aboriginal area' and that it is under threat. A declaration under section 10 has added requirements such as a written report must be submitted and the application must be published.

The Historic Shipwrecks Act protects shipwrecks and associated relics that are older than 75 years. The Minister for the Environment, Heritage and the Arts can also make a declaration to protect any historically significant wrecks or articles and relics that are less than 75 years old. The Act applies in Commonwealth waters and

State and Territory waters to the low water mark. Currently, 19 historic shipwrecks lie within protected or no-entry zones (DEWHA, sub. DR35, p. 3). These zones may cover an area up to a radius of 800 metres around a wreck site, and may be declared where circumstances place it at particular risk of interference. This declaration prohibits all entry into this zone in the absence of a permit.

The Historic Shipwrecks Act is mirrored in State legislation in Western Australia, Victoria, New South Wales and South Australia (DEWHA, sub. DR35, p. 3).

State and Territory heritage requirements

Each State and Territory has their own Indigenous heritage Act. These acts generally protect sites of Aboriginal cultural significance — these include archaeological, anthropological and historical sites. In general, it is an offence to alter a site in any way without the consent of the Minister. As a result, each State and Territory Act will contain 'emergency declaration' procedures to prevent proposed activities causing damage or interference with potential sites.

For example, under the *Aboriginal Heritage Act 1972* (WA) the owner of the land (which includes the holder of any right or privilege under the *Petroleum and Geothermal Energy Resources Act 1967* (WA)) wishing to undertake any activities that may damage, alter, destroy, or excavate a place or object must report to the Aboriginal Cultural Material Committee in writing:

- The Committee then (as soon as practicable) evaluates the significance of the site and gives a recommendation to the Minister.
- The Minister then makes a decision in the interest of the community and can give approval (with or without conditions), or decline consent.
- If the Committee does not submit the initial notice from the owner of the land with its recommendation, the Minister can require the committee to do so, as well as other actions, in order to expedite the procedure.
- The owner may apply to the State Administrative Tribunal for a review of any decision by the Minister.
- If the Committee is satisfied that it is practicable to do so, any objects can be removed from the land to a 'place of safe custody'.

The Committee can recommend to the Minister that an Aboriginal site should be declared to be a 'protected area' if it is considered to be of outstanding importance. The Minister must provide notice of this to anyone likely to be affected. Anyone aggrieved by the declaration can make a complaint in writing to the Minister, who

can then ask the Committee to consider their complaint. The Minister can then ask the Governor (by Order in Council) to declare it a protected area.

D.5 Environmental offsets

Although all jurisdictions may require proponents to undertake environmental offsets, there is no standard definition of an environmental offset across jurisdictions. For example:

- the Australian Government defines environmental offsets as actions taken outside a development site that compensate for the impacts of that development — including direct, indirect or consequential offsets (DEWHA 2007b)
- the Victorian Government defines an environmental offset as an action (or actions) to address an adverse environmental impact of resource use, a discharge, emission or other activity at another location to deliver net environmental benefit (EPA Victoria 2008)
- the WA Government defines environmental offsets as environmentally beneficial activities undertaken to counterbalance an adverse environmental impact, aspiring to achieve 'no net environmental loss' or a 'net environmental benefit' outcome — including *direct offsets* and *contributing offsets* (EPA WA 2006).

Direct offsets, as defined by the Environmental Protection Authority in Western Australia, are at least one of the following activities:

- Restoration (off-site) — includes restoring natural or historic functions, appearance and other characteristics of an existing ecosystem to near pre-impact condition.
- Rehabilitation (off-site) — may include increasing native vegetation, enhancing habitat value, weed or feral fauna eradication, or establishing buffers.
- Re-establishment — may involve forming a biodiversity corridor between two important ecosystems, or re-establishing ecosystems in areas of low representation.
- Acquisition of land for conservation — consists of purchasing the offset and transferring the land title into the conservation estate or establishing covenants with an approved organisation or legal tenure agreements.
- Sequestration — involves offsetting pollutant emissions by removing or locking up pollutants in the environment. It may be linked to activities associated with restoration, rehabilitation or re-establishment, or the use of banking or credit

trading mechanisms, deep well injection and capping, soil amendment or using other sequestration methods (EPA WA 2006).

Contributing offsets, as defined by the Environmental Protection Authority in Western Australia, are complementary activities that can improve knowledge, understanding and management leading to improved conservation outcomes. They may include:

- implementation of recovery plan actions — including surveys
- contributions to relevant research or education programs
- removal of threats — such as the eradication of feral animals, or exotic flora, removing pollutants, removing livestock or controlling the spread of disease such as dieback
- contributions to appropriate trust funds or banking schemes that can deliver direct offsets through a consolidation of funds and investment in priority areas
- on-going management activities such as monitoring, maintenance, preparation and implementation of management plans.

The majority of offset activities to date have addressed impacts on biodiversity and the natural environment. For example:

- the proposed Gorgon development on Barrow Island is subject to environmental offsets to protect its high environmental and unique biodiversity conservation values. In addition, under the *Barrow Island Act 2003* (WA) there was also an agreement to undertake the sequestration of carbon dioxide
- the Pluto liquefied natural gas development on Burrup Peninsula is also subject to an offset package covering native vegetation, heritage and carbon dioxide emissions (box D.4).

Policy documents

Offsets can be imposed as conditions of regulatory approval or by legislative requirement. Many Australian jurisdictions have implemented, or are in the process of implementing, environmental offset policies and some have enshrined offset schemes into legislation (such as New South Wales and Western Australia) (table D.1). However, very few jurisdictions have specific environmental offset policies for the upstream petroleum sector.

Box D.4 **Pluto liquefied natural gas development**

The Pluto gas field was discovered by Woodside in 2005. It is located in the Carnarvon Basin about 190 km north-west of Karratha in Western Australia. Woodside plans to develop the field by constructing offshore production facilities and the onshore Burrup Liquefied Natural Gas (LNG) park to process gas into LNG for export.

In August 2007, the Minister for the Environment approved the $12 billion Pluto project, with offsets for marine, native vegetation, heritage and carbon dioxide emissions.

Marine offsets

To offset the potential impact on coral during the dredging process, Woodside have contributed $7 million to support research that could be targeted to strengthen knowledge of the Mermaid Sound region to better predict and manage impacts from dredging on tropical coral reef communities.

Native vegetation offset

Woodside will commit $250 000 towards:

- rehabilitating previously disturbed areas that lie outside the proposed disturbance area, including the rehabilitation of weed infested areas in coastal sand dunes and drainage lines
- research (botanical surveys or taxonomic studies) on a number of flora species.

Woodside will also commit $100 000 to research into the taxonomy of *Rhagada* snail species.

Heritage offset

Located in the Dampier Archipelago, an area known for its rock art engravings, the Burrup LNG Park is being built in an industrial estate, established in 2003 by an agreement between the WA Government and the local Ngarluma, Yindjibarndi, Yaburara, Mardudhunera and Wong-Go-Tt-Oo Indigenous Groups.

Although the LNG plant was designed to avoid 95 per cent of all rock art engravings on the estate, 170 boulders with engravings had to be relocated to a nearby site. Heritage approvals were granted by the WA Government in February 2007, and a Cultural Heritage Management Plan is in place for the Pluto leases. In July 2007, Woodside signed a Conservation Agreement with the Australian Government. As part of the agreement Woodside will commit up to $34 million to identify, research and display the National Heritage Values of the Dampier Archipelago.

Woodside is also supporting studies on the potential impact of industrial emissions on rock art. CSIRO is leading this research.

Carbon dioxide emissions offset

Woodside is investing $100 million in a program to offset reservoir emissions from the Pluto gas field. The program involves a $25 million investment for mallee tree plantings in 2008 and 2009 with an option to undertake additional plantings for another three consecutive years.

Source: Woodside (pers. comm., 16 October 2008).

Table D.1 **Commonwealth, State and Territory offset policies**

Jurisdiction	*Policy/approach*
Commonwealth	The Australian Government has released a **Draft Policy Statement: Use of environmental offsets** under the *Environmental Protection and Biodiversity Conservation Act 1999* for comment in August 2007.
NSW	The NSW Department of Environment and Climate Change, has established the Biodiversity Banking and Offsets Scheme (BioBanking) under Part 7A of the *Threatened Species Conservation Act 1995*. BioBanking: • provides a systematic and quantitative approach for offsetting the impacts of development to achieve an 'improve or maintain' outcome for biodiversity values • involves developers purchasing offset (or biodiversity) credits produced by offset bankers.
VIC	The Environmental Protection Authority released a Discussion Paper on ***Environmental Offsets*** for comment in April 2008. The Department of Sustainability and Environment released **Native Vegetation Management: A Framework for Action**, in 2002. It was developed to implement the objectives of Victoria's Biodiversity Strategy and the National Strategy for the Conservation of Australia's Biological Diversity. The action plan: • establishes 'net gain' as the primary goal for native vegetation management in Victoria and incorporates the principle of offsetting as an option to achieve that goal • offsets are based on ratios that relate to the quantity and quality (habitat hectares) of the vegetation type to be cleared • applied in part through the Bushbroker scheme, which provides for the registration and trading of native vegetation credits.
QLD	Natural Resources and Water Queensland has released a ***Policy for Vegetation Management Offsets*** in September 2007, and ***ClimateSmart 2050 strategy*** (includes reference to Carbon Offsets Policy and Green Invest).
WA	The EPA released an ***Environmental Offsets Position Statement No. 9*****,** in January 2006 and ***Guidance for the Assessment of Environmental Factors No. 19***, in June 2007 (to complement the position statement). These documents establish the EPA's policy on offsets focusing on the goal of achieving a 'net environmental benefit'. The *Barrow Island Act 2003* specifies environmental offset requirements for the Gorgon project.
SA	The Department of Water, Land and Biodiversity Conservation released ***Guidelines for a Native Vegetation Significant Environmental benefit policy for the clearance of native vegetation associated with the minerals and petroleum industry***, in September 2005.
TAS	As reported by the Australian Government Department of the Environment and Water Resources, the Department of Primary Industry and Water have a draft offset policy.
NT	No offset policy.

Source: DEWHA (2007b).

E Estimating the economic cost of approval delays

This appendix presents the method used by the Commission to estimate the economic costs associated with approval delays in the upstream petroleum sector. Section E.1 sets out the design. Section E.2 describes the data sources. Section E.3 outlines some limitations of the method and potential areas for further development.

E.1 Design

Petroleum production can be viewed as a supply process transforming initially unknown oil and gas resources into marketable products through the stages of exploration, development and production. Under this approach, the economics of petroleum supply can be portrayed by the time distribution of cash flows associated with the discovery and operation of an economic field (figure E.1).

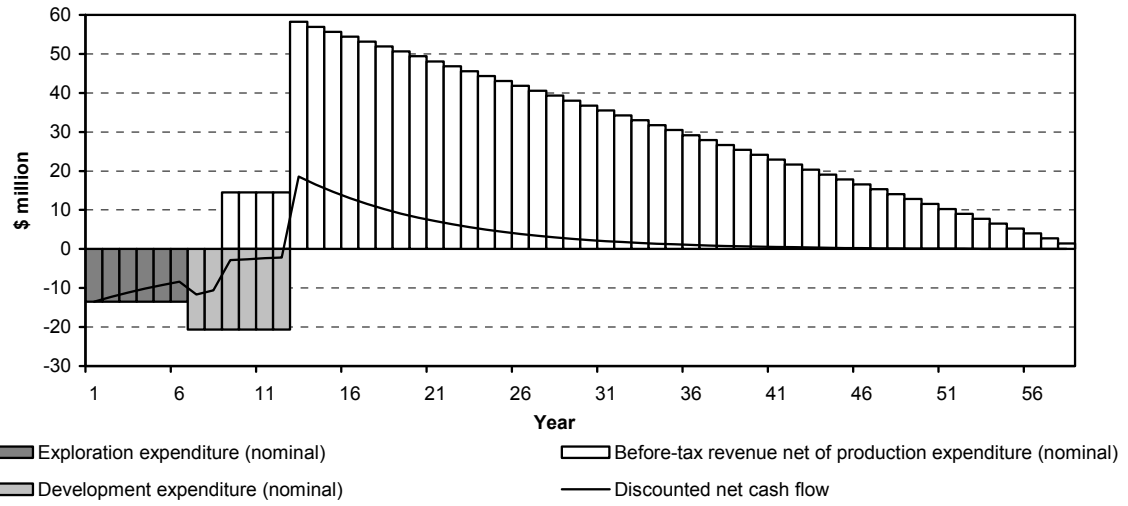
In practice, the value of resource extraction in a project can be assessed from different time perspectives. Specifically:

- the long-term value of exploration is evaluated prior to commencing exploration
- the medium-term value from successful exploration is evaluated from the start of field development, conditional on the exploration outcome.

For this study, the project value was evaluated from a long-term perspective and assuming full information on costs, petroleum prospectivities and output prices. This approach, though not fully consistent with the way petroleum businesses make sequential decisions on capital commitment, enables estimating the net value of an economic field over its entire exploration–development–production cycle.

Cash flows were estimated to represent output values and input costs at different points of time over the petroleum supply process. The evaluation of output values typically combines field-specific prospectivity assessments with petroleum price projections.

Figure E.1 **A stylised representation of cash flows from an economic field**



Data source: Commission estimates based on data in Mackenzie and Cai (1993).

Cost estimates were derived for each of the exploration, development and production stages. Exploration costs include expenditures for geological analysis, seismic surveys, drilling exploration and appraisal wells, and related overheads. Development costs include expenditures for drilling development wells, establishing field structures, and constructing pipelines, processing plants and other transmission and storage facilities. Production costs include expenditures for processing and delivering petroleum products, as well as field operating expenses.

All project costs were treated as current expenditures. This is appropriate for variable inputs such as operating expenses and the costs of hiring seismic survey ships. For durable project-specific capital inputs, however, it is a simplification to include the full expenditures as they are incurred.

A more rigorous way of estimating capital input flows is to, first, derive the capital stock as a cumulative sum of investment expenditures and then apply a rental price of capital to that capital stock estimate. Instead, the simplified treatment of capital costs avoids such computational complications involved in capital stock estimation.

An economic field adds value to the economy by generating greater output values than the input costs required over time. To account for the diminishing time value of money, the net present value (NPV) of resource supply was derived by discounting input–output cash flows in future periods with a measure of risk-adjusted cost of capital. In effect, the NPV converts the time distribution of cash flows for a project into an equivalent dollar value at the start of the petroleum supply process.

For cash-flow discounting, the cost of capital was set equal to an estimate of the weighted average cost of capital (WACC) for the upstream petroleum sector. The estimation of WACC is typically based on a capital asset pricing model with the assumption that debt and equity finance is allocated through complete and perfectly efficient capital markets.

Specifically, it was assumed that project proponents have access to portfolio diversification opportunities that eliminate non-systemic risks associated with individual projects. Under this assumption, the cost of capital comprises a risk-free rate (often proxied by a long-term government bond yield rate) and an equity risk premium reflecting extra returns commensurate with non-diversifiable project risks.

A uniform risk–return profile was assumed for the entire supply process. This enables using a constant WACC. In reality, capital risk tends to be higher in the exploration stage than in the development and production stages.

Algebraically, the NPV formula was expressed as:

$$NPV = \sum_{i=1}^{T} \frac{R_i - O_i - E_i - D_i}{(1+c)^{i-1}}$$

where:

R_i = revenue in year i

O_i = production expenditure in year i

E_i = exploration expenditure in year i

D_i = development expenditure in year i

c = weighted average cost of capital

T = project life.

Two types of delay were simulated: (1) delay in the approval of exploration activity; and (2) delay in the approval of development activity after exploration. For each type, a delay was represented by a backward shift in the time distribution of cash flows affected by the approval delay. A zero cash flow was assumed for the delay period, which is an oversimplification — in the real world companies will continue to incur costs during periods of delays.

The economic cost of delay was calculated as the difference between the NPV estimates obtained for the delay scenario and the base case (without the simulated delay). The estimated change in NPV was expressed as a percentage of the base case NPV.

E.2 Data

The primary data source is a study by Mackenzie and Cai (1993) that sought to evaluate the economics of all petroleum fields discovered in Australia up to 1987. The economics of these projects may be somewhat different from more recent large scale export liquefied natural gas projects. However, it appears that no other up-to-date database is available in published form.

The aggregate data on various expenditure items and production revenues for all economic fields identified were used to derive the corresponding average cash flows per field. These data enable the calculation of total undiscounted cash flows as shown in table E.1.

The time pattern of expenditure and revenue flows was constructed using the relevant cash-flow graph in Mackenzie and Cai (1993, p. 43) as a guide. As depicted in figure E.1:

- exploration expenditure was evenly distributed over a six-year period
- development expenditure was evenly distributed over a six-year period after exploration
- production expenditure was assumed to be a fixed proportion (27 per cent) of production revenue
- net production revenue was diminishingly distributed over a 50-year period, with annual flows tailing off towards a minimal positive net return.

Table E.1 **Key characteristics of an economic field**

Characteristic[a]	*Unit*	*Base case*
Time period:		
Exploration	years	6
Development (maximum)	years	11[b]
Production (maximum)	years	50
Undiscounted cash flows:		
Exploration expenditure	$m	81
Development expenditure	$m	124
Production expenditure	$m	538
Production revenue	$m	1 968
Weighted average cost of capital	%	10

[a] Based on the average characteristics of 184 economic fields. [b] The Commission assumed a period of six years for the development stage.

Source: Mackenzie and Cai (1993).

The WACC was set equal to 10 per cent, following Mackenzie and Cai (1993). In a more recent study, Antill and Arnott (2002) considered it reasonable to estimate the WACC for upstream petroleum businesses at around 8 per cent to 9 per cent.

Unsurprisingly, sensitivity tests confirm that the economic cost of approval delay increases as the WACC increases (table E.2). For a delay in exploration approval, changing the WACC within a reasonable range would have a small effect on the estimated NPV reduction. By comparison, the choice of WACC has a larger effect on the cost estimate of a delay in development approval. This higher sensitivity reflects increased significance of the WACC in discounting delayed revenue flows after exploration costs have already been incurred.

Table E.2 **Sensitivity tests for different values of the weighted average cost of capital**

Weighted average cost of capital	*One-year delay in exploration approval*	*One-year delay in development approval*
%	% of NPV[a]	% of NPV[a]
8	-7.4	-11.4
9	-8.3	-14.3
10	-9.1	-18.4

[a] Net present value.

Source: Commission estimates.

E.3 Potential for further development

The Commission has sought to produce indicative estimates of delay costs for plausible scenarios by using readily accessible data in conjunction with credible assumptions. Therefore, the approach has been kept relatively simple. However, several data and design issues arguably limit the scope and amount of detail. Addressing such issues is likely to offer possibilities for improved evaluation of the impact of approval delays on the sector. Specifically, potential improvements identified include:

- using up-to-date and disaggregated cash-flow data
- enriching the structure with additional variables
- modifications to account for regulatory risk and uncertainty.

The current aggregate cash-flow pattern of the sector may have changed from that applied in this study for two reasons. First, there have been considerable relative price and cost changes over the past two decades or so. Second, a number of recent discoveries and projects — particularly those in the North West Shelf — have

increased the economic significance of gas production relative to oil production and, in so doing, have greatly increased the capital costs involved (given the relatively expensive nature of export liquefied natural gas plants).

The accuracy of the cost estimation can be improved by using cash-flow data that reflect present cost structures and revenue potentials of all prospective and operating petroleum fields in Australia. Such data updating will provide a better representation of the 'relativity' between various cost and revenue variables, which is a crucial determinant of the cost estimates expressed in percentage terms.

Applying the approach to individual basins, instead of their aggregation as in this study, is another way to produce more accurate cost estimates. This could help capture variations in the cost structure and petroleum prospectivity between onshore and offshore operations across different basins. Using this approach, it is also possible to produce cost estimates for individual jurisdictions.

Additional variables could be introduced to enrich the descriptive and information structure. Incorporating details on taxation arrangements could improve the analysis relating to investment returns and government revenues. The impact of compliance costs, which has been omitted, could be analysed through adding relevant cost variables. Further, simulation results could become more accurate if decommissioning expenditures were included.

A key limitation of the present approach is related to its assumption of full information. This means that the estimated economic cost does not account for the adverse impact of approval delay on increased uncertainty and constrained flexibility for responding to market changes facing businesses.

It appears feasible to modify the approach in two ways to estimate the economic cost associated with increased regulatory risk and uncertainty. A risk premium could be incorporated in the WACC to account for the possibility that regulatory outcomes might be worse than expected or worse than the *status quo* from an industry perspective.

Alternatively, a real-option approach could be used to estimate economic costs associated with regulatory constraints that impede businesses from capturing market opportunities. In estimating such costs, the focus would be on the curtailment of upside potential amid uncertainty. Although uncertainty typically involves both upside and downside potential, downside risk can typically be managed by creating and exercising investment options based on incremental information gathering — as in the case of petroleum exploration and development. Regulatory delays and other compliance burdens diminish the probability of benefiting from such options, resulting in welfare losses to business and the community.

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