
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).

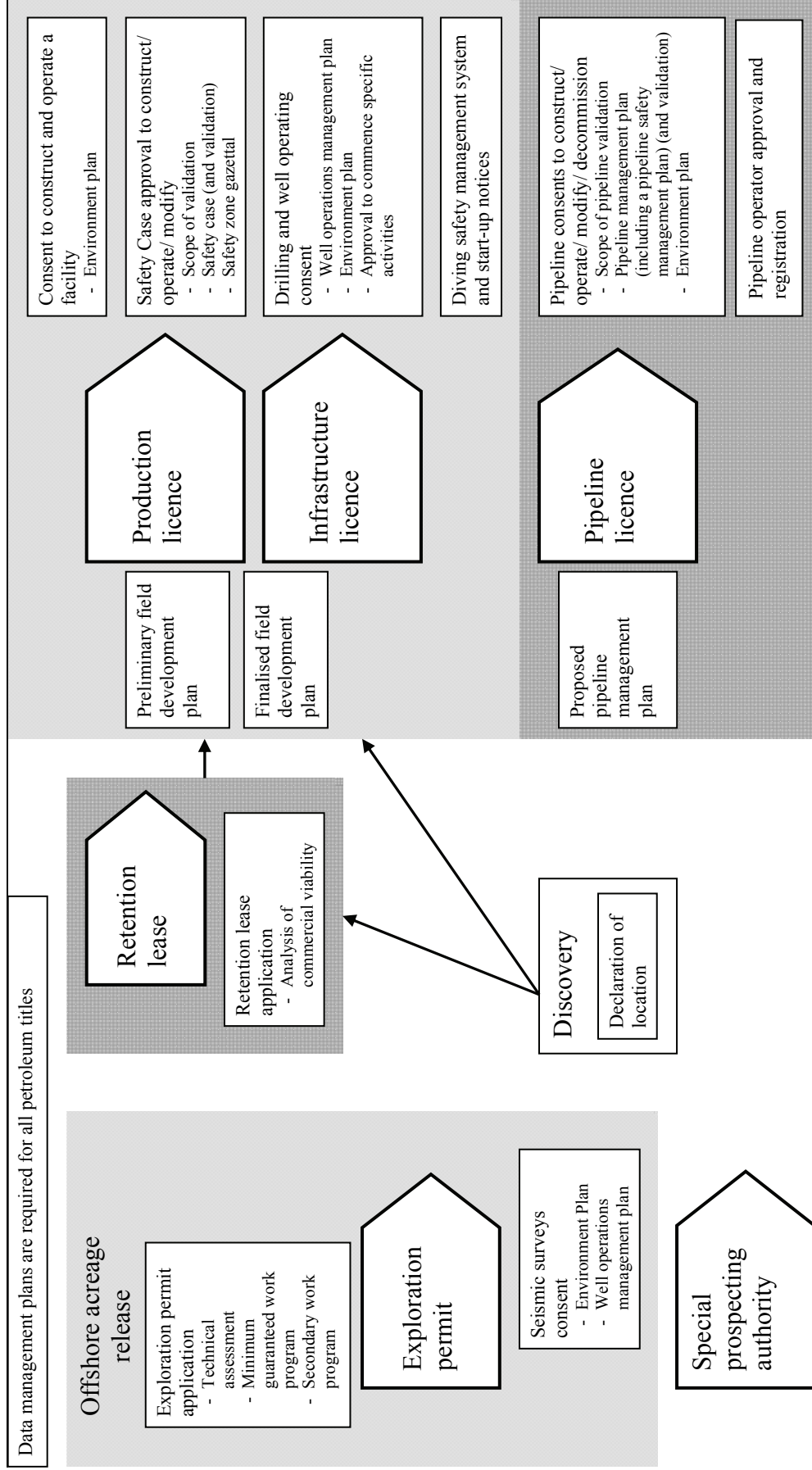
A stylised illustration of the key regulatory processes is presented in figure 5.1. Each type of petroleum title is shown, as well as specific application requirements and associated consents.

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* (Cwilt) 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

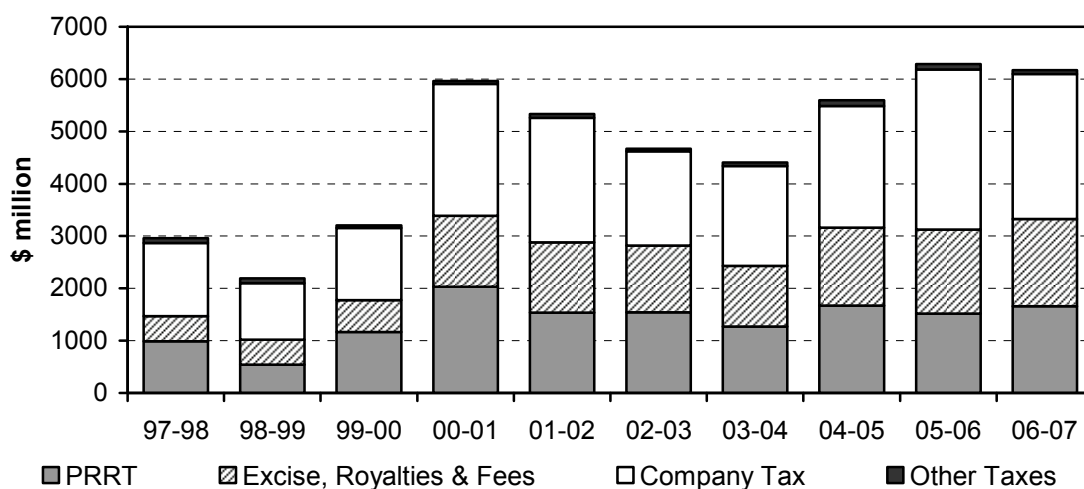
<i>Tax</i>	<i>Location of resources</i>	<i>Taxation authority</i>	<i>Value of tax</i>
Petroleum Resource Rent Tax (PRRT)	Commonwealth waters (beyond 3 mile limit)	Commonwealth	40 per cent of the difference between assessable receipts and allowable deductions, excluding an allowance for normal profit
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**

<i>Jurisdiction</i>	<i>Policy</i>
Commonwealth	<p>Native title legislation <i>Native Title Act 1993</i></p> <p>Land rights legislation <i>Aboriginal Land Rights (Northern Territory) Act 1976</i></p>
Victoria	<p>Policy documents Information regarding the processing of petroleum tenements under the <i>Native Title Act 1993</i></p>
QLD	<p>Land rights legislation <i>Aboriginal Land Act 1991</i> <i>Torres Strait Islander Land Act 1991</i> <i>Land Act 1994</i></p> <p>Policy documents Petroleum and Gas Exploration — Exploration laws explained Petroleum and Gas Exploration — A guide for landowners and occupiers</p>
WA	<p>Land rights legislation <i>Aboriginal Communities Act 1979</i> <i>Aboriginal Affairs Planning Authority Act 1972</i></p> <p>Policy documents Working with Aboriginal Communities — A practical approach</p>
SA	<p>Land rights legislation <i>Anagu Pitjantjatjara Yankunytjatjara Land Rights Act 1981</i> <i>Maralinga Tjarutaland Rights Act 1984</i> <i>Aboriginal Lands Trust Act 1966</i></p> <p>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)</p>
NT	<p>Land rights legislation <i>Aboriginal Land Act 1978</i> <i>Cobourg Peninsula Aboriginal Land, Sanctuary and Marine Park Act 1981</i> <i>Nitmiluk (Katherine Gorge) National Park Act 1989</i> <i>Parks and Reserves (Framework for the Future) Act 2004</i></p> <p>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</p>

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- 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.