
8 What impact are impediments having?

Key points

- The overall performance of Australia’s regulatory regime in the upstream petroleum sector appears to compare favourably by international standards — however, there is scope and capacity for regulatory improvement in all, but especially in lagging, jurisdictions.
- Improved regulatory arrangements could help reduce regulatory costs and offset Australia’s natural disadvantages of low oil prospectivity and geographical remoteness.
- There is considerable evidence linking regulatory burdens to lengthy and complex approval processes — particularly for pipelines — and onerous reporting requirements.
- The perceptions of regulatory performance in individual jurisdictions of Australia are affected by differences in the intensity of regulatory activity, as well as government initiatives undertaken to improve regulatory outcomes.
- Significant regulatory costs are associated with approval delays that potentially lead to increased project expenditures, reduced flexibility for responding to market conditions, inflated capital costs, increased difficulty of financing projects, and reduced present value from resource development.
- Expediting the average approval process by one year could increase the net present value of projects by 10–20 per cent simply by bringing forward income streams. Given the sector contributes 2 per cent to GDP, the potential income gains for Australian residents could be in the billions of dollars each year.

The Commission has in earlier chapters identified a number of unnecessary regulatory burdens impacting on the upstream petroleum sector. In this chapter, evidence is provided about the magnitude of these burdens, with efforts to quantify them where possible.

Section 8.1 presents a series of case studies highlighting the major burdens encountered by upstream petroleum businesses. Section 8.2 presents observations on comparative regulatory performance across the various jurisdictions in Australia. Section 8.3 presents evidence on the economic costs associated with regulatory

burdens. Section 8.4 discusses the implications of regulatory burdens for investment attractiveness of the upstream petroleum sector.

8.1 Evidence of unnecessary regulatory burdens

Industry participants have provided evidence of unnecessary regulatory burdens attributed to two major problems, namely lengthy and complex approval processes and onerous, sometimes duplicated, reporting requirements.

Lengthy and complex approval processes

Table 8.1 includes a number of (de-identified) case studies, drawn from a submission from the Australian Petroleum Production and Exploration Association (APPEA), to outline the number of approvals required, the complexity of the approval process and the number of government agencies involved in various types of projects.

Understandably, large projects typically face considerably more approval hurdles than smaller projects. Nevertheless, the number of approvals required for smaller projects can be significant, especially given that their proponents often have relatively constrained capacity to deal with compliance requirements. Case study 1 indicates that up to 390 approvals were required for a large liquefied natural gas (LNG) project. By comparison, a small project operating within a single jurisdiction (case study 4) still required over 80 approvals.

Most regulatory agencies involved are at the State and Territory level, except for projects solely located in Commonwealth waters. Even in the latter case, three or more State level agencies can be involved (such as in case study 4). Concerns about local government involvement, as noted as an issue by APPEA (sub. 16), are generally associated with large LNG facilities and some domestic gas projects.

Complexity typically increases as the number of government agencies involved in approvals increases. For example, the approvals for building a gas production facility in case study 5 involved 35 separate agencies operating at the Commonwealth, State and local government levels. Even the construction of production wells in case study 4 — which required no new infrastructure outside of Commonwealth waters — involved approvals by 17 government agencies.

Pipeline approvals form a substantial proportion of the total project approvals required. Among the case studies presented in table 8.1, the proportion of approvals dedicated to pipeline works ranges from 18 per cent to 69 per cent. For example, case study 7 — which refers to the standalone approval process for a pipeline —

required 55 approvals. These included 38 approvals for design, construction and operation; 9 general approvals; and 8 approvals for consents or notices required. By contrast, case study 6 — which did not include any pipeline works — required 44 approvals in total, the fewest for the case studies examined.

Another example of approval process complexity is the Longtom gas field, which is currently being developed by Nexus in the Gippsland Basin. This project involves building a subsea wellhead and a pipeline in Commonwealth waters.

Nexus (sub. 3) considered the Longtom project to be straightforward. Nevertheless, the approval process included a series of environmental, pipeline, health and safety, exploration, installation and production approvals that were interrelated (figure 8.1). Further, approvals often required to be pursued sequentially rather than concurrently. Prior to obtaining consent to construct a pipeline, Nexus had to apply for a pipeline licence and also prepare a pipeline management plan, a pipeline barge safety case, an environmental management plan, an emergency response plan, and an oil-spill contingency plan for approval by different authorities.

The environmental approval process also delayed, and ultimately may have changed the location of, Inpex's proposed LNG plant in the Kimberley, Western Australia. Inpex initially applied for approval of the facility in May 2006 on Marat Island. Twenty months later — in February 2008 — the Commonwealth Environment Minister and the WA Acting Minister for State Development announced the decision to undertake a strategic assessment of the Kimberley. Subsequently, Inpex has announced an intention to relocate their proposed plant to Darwin (Garrett and Kobelke 2008; Inpex 2006, 2008a, 2008b).

Resource requirements

Project proponents have to commit significant resources to approval processes as a result of complex compliance requirements. This is confirmed by the resource requirements in a selection of case studies presented in table 8.2. For example, the LNG project in case study 2 required involvement of up to 90 people at various stages of the approval process, and incurred significant consultancy costs for processing approval applications. Applications for environmental approvals alone in case study 4 incurred expenses of 5 person-months of staffing and \$200 000 for hiring external consultants.

Table 8.1 APPEA's case studies of regulatory approvals for upstream petroleum projects

| | Case study 1 | Case study 2 | Case study 3 | Case study 4 |
|---|---|---|--|--|
| Description of projects | Natural gas in Commonwealth waters, pipeline through coastal waters and onshore processing, liquefaction and export | Natural gas in Commonwealth waters, pipeline through coastal waters and onshore processing, liquefaction and export | Jack-up installed, unmanned wellhead platform in Commonwealth waters, pipelines to onshore processing facilities | Natural gas in Commonwealth waters connected to existing onshore processing infrastructure |
| Regulatory agencies involved | 26 | 19 | 22 | 17 |
| • Australian Government | 10 | 9 | 8 | 14 |
| • State/Territory Government | 12 | 10 | 14 | 3 |
| • Local government | 3 | – | – | – |
| • Joint statutory authority | 1 | – | – | – |
| Regulatory approvals required | 390 | 277 | 163 | 83 |
| • General project approvals and preliminary requirements | 32 | 64 | 17 | – |
| • Drilling approvals | – | 53 | 18 | 24 |
| • Pipeline approvals (including design, construction and operation) | – | 49 | 61 | 46 |
| • Decommissioning approvals | – | 7 | – | 6 |
| • Other approvals ^a | 358 | 104 | 92 | 7 |
| | (including 140 for offshore investigation, construction, commissioning and operation; and 218 for onshore investigation, construction, commissioning and operation) | (including 30 for shore crossings and shipping facility requirements; 52 for storage, loading and processing facilities; and 22 for accommodation, gas connections and permit administration) | (including 47 for offshore construction, installation, commissioning, operations and decommissioning; and 45 for onshore construction, commissioning and operations) | (for a production licence) |

(Continued next page)

Table 8.1 (continued)

| | Case study 5 | Case study 6 | Case study 7 | Case study 8 |
|---|--|--|--|---|
| Description of projects | Offshore production, incorporating a subsea pipeline and onshore gas processing infrastructure | Subsea development and a floating production storage and offloading facility in Commonwealth waters | A pipeline network connecting three gas wellheads to onshore processing facilities | Subsea wells in Commonwealth waters, with pipeline connection to existing onshore processing infrastructure |
| Regulatory agencies involved | 35 | 6 | – | – |
| • Australian Government | 13 | – | – | – |
| • State/Territory Government | 20 | – | 1 | – |
| • Local government | 1 | – | – | – |
| • Joint statutory authority | 1 | – | 1 | – |
| Regulatory approvals required | 127 | 44 | 55 | over 144 |
| • General project approvals and preliminary requirements | – | – | 9 | – |
| • Drilling approvals | – | 18 | – | – |
| • Pipeline approvals (including design, construction and operation) | – | – | 38 | over 36 |
| • Decommissioning approvals | – | – | – | – |
| • Other approvals ^a | 127 | 26 | 8 | 108 |
| | (including 69 relating to State and local governments; and 58 relating to the Australian Government) | (including 14 for project validation, environmental, health and safety approvals; 6 for installation and diving requirements; and 6 for design, testing and recovery of petroleum) | (for consents or notices required) | (for unstated requirements) |

^a Possibly including general, drilling, pipeline or decommissioning approvals in cases where no breakdown of such approvals has been provided. – Zero or not available.

Source: APPEA (sub. 16).

Table 8.2 APPEA’s assessment of business expenses for project approvals

| | <i>Case study 2^a</i> | <i>Case study 3^a</i> | <i>Case study 4^a</i> |
|----------------------------|--|---|---|
| Internal staff | <ul style="list-style-type: none"> • Up to 90 people required at various regulatory focal points • 1 full-time approvals coordinator • 1 offshore environmental approvals coordinator | <ul style="list-style-type: none"> • 6 person-years for all regulatory requirements • 54 person-months for health, safety and environmental approvals | <ul style="list-style-type: none"> • 5 person-months for environmental approvals • 8 person-months for production licence, field development plan, pipeline management plan, and pipeline licence |
| Outsourced tasks and costs | <ul style="list-style-type: none"> • Public environmental report, field development plans and other approvals (significant cost) | <ul style="list-style-type: none"> • Drilling and pipeline approvals (over \$100 000) | <ul style="list-style-type: none"> • Environmental approvals (\$200 000) • Installation vessel safety case revision, dive management plan, and supporting health, safety and environmental plans and procedures (\$200 000) • Health, safety and environmental assessments in design (\$300 000) |

^a Case study numbers align with those in table 8.1. See table 8.1 for project descriptions.

Source: APPEA (sub. 16).

The approval process can also consume considerable government resources. This is particularly the case under the Joint Authority–Designated Authority (JA–DA) regulatory framework, because it typically requires numerous iterations of paperwork processing between departments or agencies over protracted turnaround times (table 8.3).

Table 8.3 Features of approval processes under the JA–DA framework

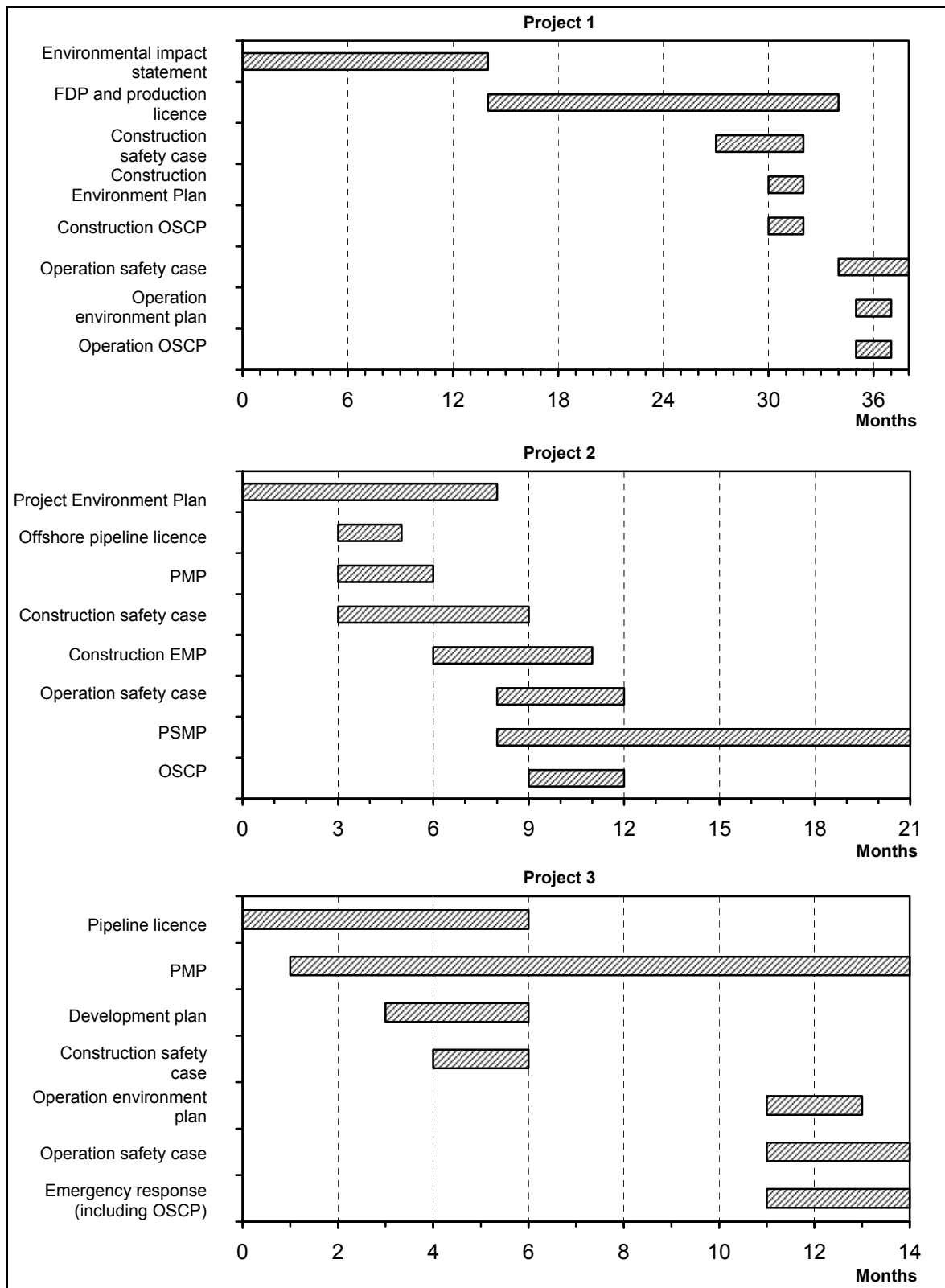
| <i>Type of approval</i> | <i>Time taken</i> | <i>Iterations of paperwork processing</i> |
|---------------------------------------|-------------------|---|
| | months | number |
| Production licence | at least 12 | 50–60 |
| Pipeline licence | 3–9 | 20–30 |
| Suspension and extension of pipelines | 3–6 | 12–20 |

Source: Victorian Government (sub. 7).

Delays

Lengthy and complex approval processes can also result in project delays. Figure 8.2 provides examples of timelines for certain key approvals for upstream petroleum projects. These timelines span from submitting a request to the relevant agency granting an approval. Depending on the scope of the project, approval times ranged from 14 months for a pipeline, to 38 months for a major project.

Figure 8.2 Project approval timelines



Acronyms are as follows — FDP: Field Development Plan; OSCP: Oil–Spill Contingency Plan; PMP: Pipeline Management Plan; EMP: Environmental Management Plan. PSMP: Pipeline Safety Management Plan.

Source: Commission estimates (based on information obtained from APPEA).

Although delays for some projects can be reduced through the use of a facilitating agency, this can result in increased delays to other projects unless there is an improvement to underlying approval processes. For example, the Pluto LNG development on the Burrup Peninsula, with assistance from the WA facilitating agency, the Office of Development Approvals Coordination, achieved approval within 18 months. However, according to the WA Auditor General, this was only accomplished by diverting agency resources, at the expense of approvals for other projects:

The Pluto experience has not resulted in any improvements to existing approval processes. Agencies participating in the Pluto review unanimously agreed that the experience would be difficult to replicate as the shorter than usual timeline was achieved by re-prioritising agency resources. Agencies advise that the effect of prioritising Pluto approval processes was that other development proposals were delayed. (Auditor General for Western Australia 2008, p. 28)

Some participants indicated that approval delays represent a substantial impediment to oil and gas projects, which could lower returns and make it potentially difficult to obtain finance for projects. Such delays could cost businesses more than the direct costs of complying with approval requirements. APPEA submitted:

... the percentage proportion of staffing and overheads associated with gaining approvals for petroleum projects is very small. The real costs are the delays connected with project start-ups that reduce project net present values (and therefore project returns) ... Importantly, projects must also compete with alternative investment opportunities and delays resulting from regulatory requirements can lead to funding being delayed or lost. (sub. 16, p. 42)

In some cases, regulatory delays add to direct costs because of the need to hire equipment on standby. Such costs can be substantial, as the Victorian Government indicated:

According to industry figures, current standby rates for semi-submersible drilling rigs are up to \$1.1 million per day. (sub. 7, p. 4)

In addition, where costs are rising over time, delays can lead to higher overall project costs. Participants have told the Commission of capital cost increases of between 25 and 30 per cent per annum in Western Australia over recent years. BP (sub. 15) stated labour costs for upstream oil and gas projects in Western Australia increased by around 20 per cent per year in the four years to January 2008.

BP further observed:

... independent analysis shows that cost escalation due to WA labor costs stands out on a global basis for upstream oil and gas projects. (sub. 15, p. 1)

Nexus's Longtom gas field project provides another example of substantial cost increases due to approval delay. To date, approvals for this project have taken more than two years, and cost the company in excess of \$1 million. Nexus (sub. 3) identified this direct cost as being a small percentage of the total cost, but noted that the delay caused increases in the capital cost, which affected their ability to secure financing for the project. In addition, the cost of establishing and maintaining undrawn credit facilities during this period also added to costs.

Regulatory creep

Some participants claimed that new environmental protection guidelines issued under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act) increase compliance burdens. One such guideline restricts the practices of seismic surveys, in particular in areas where there could be a risk of whales being encountered (APPEA, sub. 16; DEWHA, sub. 8). However, the Department of Environment, Water, Heritage and the Arts (DEWHA) countered that they believed the guidelines would not necessarily add to actual regulatory burdens. DEWHA cited that:

Of 124 offshore seismic surveys referred under the EPBC Act, 120 have operated in accordance with the measures detailed in the Guidelines, and which companies committed to, with only four surveys, planned for highly sensitive marine environments, requiring any further assessment (of which, one, was re-referred for a period when whales were less likely to be present and two were withdrawn). (sub. 8, p. 7).

Since the release of the draft report, DEWHA has said:

The Department disagrees that decision-making on seismic surveys has been inconsistent and asserts that the seismic guidelines provide good guidance to proponents on actions that are likely to require further assessment. The Department appreciates the efforts of the Productivity Commission to put forward both viewpoints but feels it would be useful to emphasise the fact that most seismic operations are conducted in accordance with the guidelines and do not encounter approval delays. (sub. DR35, p. 3)

In general, industry welcomes guidelines that clarify responsibilities under the EPBC Act. However, there is a perception that DEWHA is taking an increasingly interventionist role regarding seismic surveys. Seismic surveys are viewed as a routine activity by the upstream petroleum sector, and some participants therefore saw the requirement for further assessment of *any* surveys as indicating that the guidelines were heavy handed and not achieving their intended purpose.

Duplicated reporting requirements

The duplication of reporting requirements is another burden faced by the sector. This has arisen when businesses are regulated under multiple policy programs with similar objectives.

ExxonMobil, for example, has been required to report similar information in slightly different formats under a number of greenhouse and energy policy programs at both the Commonwealth, and State and Territory levels. The related requirements involved providing different program administrators with the same information, of which some is also used for corporate reporting (table 8.4).

Table 8.4 ExxonMobil's reporting requirements for greenhouse and energy programs

| <i>Jurisdiction</i> | <i>Program</i> | <i>Energy</i> | <i>Climate change</i> | <i>Annual reporting</i> | <i>Public reporting</i> | <i>Energy audit</i> | <i>Action plan</i> |
|-----------------------|--|---------------|-----------------------|-------------------------|-------------------------|---------------------|--------------------|
| Australian Government | Greenhouse Challenge | ✓ | ✓ | ✓ | ✓ ^a | | ✓ |
| | Greenhouse Challenge Plus | ✓ | ✓ | ✓ | ✓ | | ✓ |
| | Energy Efficiency Opportunities | ✓ | | ✓ | ✓ | ✓ | ✓ |
| | National Greenhouse and Energy Reporting | ✓ | ✓ | ✓ | ✓ | | |
| Victorian Government | Greenhouse Gas Action Plan | ✓ | ✓ | ✓ | | ✓ | ✓ |
| | Energy and Resource Efficiency Plans | ✓ | ✓ | ✓ | | ✓ | ✓ |
| Corporate reporting | Environmental Performance Reporting | ✓ | ✓ | ✓ | | | |
| | Environmental Business Planning | ✓ | ✓ | ✓ | | | ✓ |

^a Contributing to sector aggregate data.

Source: ExxonMobil (sub. 13).

The costs of compliance reporting increase when businesses are required to reprocess information to suit different content or reporting frequency requirements. For example, the Victorian Government's Energy Resource and Efficiency Plan has a shorter timeline than the Australian Government's Energy Efficiency Opportunities program, creating difficulty for participants in setting durable energy strategies.

ExxonMobil commented:

... the short timeline of [the Energy Resource and Efficiency Plan] is likely to encourage a focus on superficial and premature solutions. The consequence may well be that work will then need to be redone over the next 2 years under [Energy Efficiency Opportunities]. (sub. 13, p. 7)

APPEA stated that efforts to avoid duplicative reporting requirements under the two programs are flawed:

In Victoria the EPA has launched Energy and Resource Efficiency Plans (EREPs) that require a duplicate of EEO [Energy Efficiency Opportunities] but with the EPA's slant (including mandatory implementation of projects with less than 3 years payback). Theoretically companies were supposed to have been able to apply for an exemption if already participating in EEO but the regulations require your EEO assessment (which is a five year program) to have already been completed to get the exemption. (sub. DR29, p. 22)

APPEA also highlighted the problems confronted by joint venture partners when reporting against government programs. For example:

Under the Energy Efficiency Opportunities Act 2006, companies in an Australian joint venture are required to go through a process of obtaining written nominations of the operator of a joint venture as the nominated reporting entity for the Act to avoid the consequence of each member of the joint venture needing to count and report on energy consumption of that joint venture. For exploration joint ventures in particular this is a time consuming exercise requiring companies to chase responses from smaller joint venturers who may not be subject to the requirements of the Act due to low energy consumption levels. (sub. DR29, p. 21)

Woodside has said that government agencies frequently request annual or summary data that has already been provided under regulatory reporting requirements:

For example, in recent months Geoscience Australia and the Northern Territory Government have requested summary well and seismic data for 2007 and 2008. However, it is our view that with few exceptions, that data has already been provided to Geoscience Australia as part of our reporting requirement as each activity is undertaken. (sub. DR33, p. 2)

FINDING 8.1

There is considerable evidence of unnecessary regulatory burdens affecting the upstream petroleum sector, resulting in lengthy delays and substantial resource demands being placed on sector participants. These burdens can be overwhelmingly attributed to two major problems, namely lengthy and complex approval processes, and onerous and in some cases duplicated reporting requirements.

Pipelines

Given their often cross-jurisdictional nature, pipelines are often subject to particularly complex licensing and approval processes. With most of Australia's oil and gas reserves being located offshore, production frequently involves the use of pipelines that pass through multiple jurisdictions. Pipelines typically pass through Commonwealth waters, coastal waters and State or Territory onshore jurisdictions.

They are therefore subject to multiple licensing and approval processes in areas such as safety, integrity, the environment, and pipeline construction and operation. APPEA noted:

APPEA has long stated that because the oil and gas industry, and in particular its pipelines, frequently cross 3 to 5 jurisdictional boundaries, that pipelines should be covered by one PMP [Pipeline Management Plan], end to end. Proposed WA legislation for onshore pipelines will require a safety case with requirements slightly different to those required for pipelines in state and commonwealth waters. (sub. 16, p. 36)

In addition, in reference to its Gippsland project, ExxonMobil stated:

The Gippsland project includes offshore facilities that recover oil and gas from reservoirs located under Commonwealth waters, oil and gas pipelines that transport petroleum across Commonwealth submerged lands, State submerged lands and then finally State controlled lands before arriving at onshore processing plants located in a State jurisdiction (in this case Victoria). This mixture of jurisdictions has given rise to a large number of duplicated requirements that must be satisfied within the authority of the respective jurisdictions. While Federal and State responsibilities individually dictate the extensive approval requirements in each respective jurisdiction, given the multi-jurisdictional nature of most petroleum projects the result is that there are multiple duplicated approvals processes. (sub. 13, p. 4)

The existence of multiple regulators for a single piece of infrastructure also raises interface issues. That is, there is a real risk of blurred lines of responsibility between the various regulators and regulatory gaps appearing when responsibilities are not clear.

This point was highlighted by APPEA:

The application of state legislation always carries the potential to result in discrepancies in regulatory requirements across jurisdictions ... It can also blur the lines of responsibility.

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

It is essential for effective and efficient regulation of critical supply industries, and for effective and efficient governance, that the public and other stakeholders are able to identify and have confidence in the responsible regulator. (sub. 16, p. 18)

While Apache noted:

Devil Creek is a new domestic gas processing project located east of Cape Preston in the Pilbara region of WA. Devil Creek is an onshore project connected to an offshore gas field (Reindeer) in Commonwealth waters by means of a pipeline ... different regulators have overlapping areas of influence and responsibility (the gas supply

pipeline is the responsibility of the Department of Industry and Resources (DOIR) offshore and of the Department of Consumer and Employment Protection (DOCEP) onshore). (sub. 14, p. 3)

(Regarding the comment from Apache, from January 2009 the WA Government formed a new Department of Mines and Petroleum, combining the previous mining and petroleum regulatory role of the Department of Industry and Resources (DoIR) and the resource safety responsibilities from the Department of Consumer and Employment Protection.)

FINDING 8.2

The often cross-jurisdictional nature of pipelines means they are typically subject to particularly complex licensing and approval processes. Their licensing and regulation is covered by multiple jurisdictions and multiple regulators, which leads to duplication of processes, and delays. The presence of multiple jurisdictions and regulators also raises concerns in regard to interface issues and blurred lines of responsibility between regulators.

8.2 Inter-jurisdictional comparisons

This section provides a comparative account of the regulatory performance across various jurisdictions in Australia. (International comparisons are discussed in section 8.4.) It seeks to identify relative strengths and weaknesses of the regulatory arrangements in different jurisdictions. It does not provide a definitive ranking of the jurisdictions (although it discusses some surveys that have attempted to do so). The JA–DA arrangements, as discussed in chapters 4 and 5, complicate inter-jurisdictional comparisons because many regulatory responsibilities are shared between the Australian Government and respective State and Territory Governments.

Regulatory performance varies between jurisdictions

The Commission has received some consistent messages about comparative regulatory performance in this study. A common message is that regulatory inconsistencies and duplications exist in virtually all jurisdictions in Australia. However, some governments have adopted apparently effective measures to reduce these problems.

Many participants observed that South Australia has a relatively straightforward approval system, and that its petroleum legislation can be considered a benchmark for other jurisdictions.

For example, APPEA commented:

Of those that attended the [September 2008] Good Oil Conference, the number one prevailing theme was regulation for access and environment approvals. While delegates noted the efforts of South Australian regulators as the exception, the consensus was that due to regulatory requirements there is a great difficulty to acquire acreage and undertake activity to get results in a time-frame that is acceptable to investor expectations. (sub. 16, p. 43)

In two recent international surveys, South Australia has consistently been rated by resource business executives as the most attractive Australian jurisdiction in which to invest (Fraser Institute 2008b; ResourceStocks 2008). Such a favourable assessment largely reflected the perceived effectiveness of SA Government policies towards resource development projects (box 8.1).

However, South Australia has no significant offshore upstream petroleum activity. Accordingly, there are likely to be fewer demands made of the upstream petroleum regulatory agencies in South Australia relative to those in some other jurisdictions, and fewer approval interactions with the Australian Government.

The Commission has also noted that South Australia's high ranking in survey comparisons could have been influenced by its Plan for Accelerating Exploration program. This program provides grants to businesses undertaking resource exploration in that State and is, perhaps not surprisingly, popular with the resources sector. In effect, it is an industry assistance program and does not relate to regulatory performance.

Some participants saw the Northern Territory as more proactive in dealing with business concerns about regulatory burdens than some other jurisdictions. The Commission has noted Inpex's plan to build a pipeline from offshore Western Australia to Darwin despite significantly increased project costs. There appears to be a widespread perception that there is less 'red tape' associated with investment in the Territory, particularly for major projects. The aforementioned global surveys confirmed this perception as the NT Government's policies towards resource development were also highly rated by survey respondents.

Box 8.1 Survey comparisons of regulatory performance

The Commission has drawn on three global surveys, each completed in 2008, for evidence on comparative regulatory performance across jurisdictions in Australia and elsewhere. These surveys reflect up-to-date opinions from a wide base of survey respondents representing mining and petroleum businesses around the world.

Two of the surveys (conducted by the Fraser Institute and the ResourceStocks magazine) canvassed mining company executives for their views on the attractiveness of government policies towards resource projects in general. They cover 68 and 76 jurisdictions respectively, including individual Australian States and the Northern Territory.

In both surveys, South Australia was Australia's highest-rated jurisdiction — ranking 15th and 2nd respectively. Tasmania and the Northern Territory were also rated highly.

The poorer performing Australian jurisdictions were Victoria, Queensland (ranked lowest of Australian jurisdictions in the Fraser Institute survey) and Western Australia (ranked lowest of Australian jurisdictions in the ResourceStocks survey). The ranking of Western Australia in the Fraser Institute survey fell to 25th in 2007-08 from 11th in 2005-06. Queensland's ranking of 30th in the 2007-08 Fraser Institute survey was in line with the state's relative performance in earlier years, except for 2006-07 when the state was ranked 8th.

In another survey conducted by the Fraser Institute, inter-jurisdictional comparisons focused on impediments to investment specifically in the upstream petroleum sector. Survey results for Australia were reported only at the national level. Australia was ranked 75th of the 81 jurisdictions compared in terms of posing *most* barriers to investment. In other words, Australia was assessed as one of the *most favourable* places for investment in petroleum exploration and development (ranked behind Thailand, New York, Denmark, Ohio, Saskatchewan and Azerbaijan).

Sources: Fraser Institute (2008a, 2008b); ResourceStocks (2008).

Feedback provided to the Commission suggested Victoria's petroleum regime was generally seen in a positive light by industry participants. It was suggested that project proponents are typically able to get approvals within a reasonable timeframe if they 'do their homework'. Further, the Victorian Government informally undertakes some regulatory activities on behalf of the Tasmanian Government in relation to the Well Operation Management Plans and environmental assessments within the Tasmanian offshore waters (Victorian Government, sub. 7). This arrangement helps promote consistent regulatory practices between the two States.

Less favourable comments on regulatory performance have been made about the regulation of upstream petroleum projects in Queensland. Queensland's petroleum legislation was seen as overly prescriptive. Further, concerns were raised about a lack of communication between the Queensland Environmental Protection Agency

and the Department of Mines and Energy. On the other hand, parts of Queensland arguably have a more fragile environment and a greater reliance on tourism than some other jurisdictions. These factors might have led to more stringent environmental requirements being applied to project approvals. The State ranked lowest of the Australian jurisdictions in the 2007-08 Fraser Institute survey of resource business executives, although it had performed relatively well in the previous year's survey results (Fraser Institute 2008b).

Many participants made negative comments about the regulatory burdens in Western Australia, where there have been considerable concerns about approval backlogs. In particular, these concerns were said to have led proponents of some major projects planned for Western Australia to consider the Northern Territory as an alternative investment destination. Western Australia was rated as the worst performing jurisdiction in Australia by the ResourceStocks (2008) global risk survey. That said, the recent rapid expansion of mining and petroleum activity in Western Australia is likely to have put WA regulators under greater resource pressures than those faced by their counterparts in most other jurisdictions.

In response to the draft report, the WA Department of Mines and Petroleum stated:

One of the major priorities of DMP in 2009 will be to significantly improve the approvals process for resources projects and the Department is taking the lead in the reform process. The aim is to ensure that elements of the approvals process within DMP's jurisdiction are acted on in a timely and efficient manner, beginning with several short-term measures to improve its performance and reporting against its key title and post-title approvals. (sub. DR22, p. 1)

The Commission has received mixed messages regarding the Australian Government's regulatory performance. Some concerns were expressed about regulatory duplication at the Commonwealth level, and about environmental regulation. On the other hand, recent initiatives to consolidate the *Offshore Petroleum Act 2006* (Cwlth) and recent reforms to the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) have received strong support from the petroleum sector.

The regulation of petroleum development in the Timor Sea takes place under the Timor Sea Treaty between the Australian Government and the Government of East Timor (chapter 4). No major concerns about the regulation of upstream petroleum activities in this area have been raised with the Commission, although there have recently been tensions between the Government of East Timor and Woodside over the location of a downstream processing plant for Woodside's Greater Sunrise project (Grigg 2008).

Some governments appear more proactive than others in adopting measures to improve regulatory practices. This appears to have been reflected by variation in perceptions by industry of regulatory performance for different jurisdictions.

8.3 Economic costs

The legal and administrative complexity that characterises the regulatory framework governing upstream petroleum projects in Australia imposes significant regulatory burdens on project proponents. These burdens can affect the economics of petroleum supply through the effects of increased compliance costs, delays in project development and completion, and increased uncertainty. This section focuses on estimates of costs for the first two categories, with measurement of the costs of uncertainty being much more difficult and not attempted here.

Compliance costs

The overall compliance cost for large and complex projects can amount to millions of dollars as project proponents go through lengthy and elaborate assessment and approval processes. This results in a non-trivial productivity loss in the petroleum supply process.

Nonetheless, compliance costs are typically modest relative to the total project cost. A number of case studies presented in table 8.2 indicate the magnitude of resource burdens on petroleum businesses in relation to approval processes. APPEA provided further evidence of such costs:

Dedicated teams of up to 90 personnel are required to prepare approval documents for a number of years. Even for smaller projects, approval requirements generate workloads in excess of six man years and several million dollars in overheads. As the sums associated with investments in projects often exceed many billions of dollars, the percentage proportion of staffing and overheads associated with gaining approvals for petroleum projects is very small. (sub. 16, p. 42)

Delay costs

Potentially much more significant are regulatory costs associated with project delays and uncertainties, including:

- increased project expenditures
- reduced flexibility to respond to market conditions

-
- inflated capital costs
 - increased difficulty of financing projects
 - reduced present value from resource development.

Increased project expenditures

Delays represent a substantial impediment to upstream petroleum projects because of the disruption caused to project plans. Project proponents can face significantly higher exploration and development costs as a result of delays for the approval of seismic survey and drilling activities. As noted in section 8.1, which quoted daily standby rates for semi-submersible drilling rigs at around \$1.1 million, an unexpected delay of even a few days in obtaining approval could cost the project proponent millions of dollars in operating expenditure.

Indeed, it is not always possible for project proponents to swiftly reschedule leases of mobile equipment such as drilling rigs and seismic vessels if the original booking is cancelled because of approval delay. This is particularly the case when the equipment is in high demand, or when the activity can only be carried out within a narrow time window because of regulatory constraints, such as seasonal whale exclusion zones.

Reduced flexibility for responding to market conditions

Industry participants emphasised the importance of timely and expedient approval processing for LNG projects. The financing of these projects typically depends on securing long-term contracts with gas purchasers. Given a typical decade-long contracting cycle, the time window for locking in a supply contract in the early project development stages is narrow. Consequently, even minor approval delays can restrict project proponents' ability to capture prevailing commercial opportunities.

Inflated capital costs

During periods of rapid cost inflation, approval delays can lead to substantial escalation of capital expenditures, increasing the difficulties faced by project proponents. This seems to have been the case in the period between 2005 and 2007, with offshore exploration and production costs surging by over 50 per cent. In particular, the cost of leasing offshore rigs increased by over 300 per cent during 2007 (Fowler 2007). As noted earlier, BP (sub. 15) stated that labour costs for

upstream oil and gas projects in Western Australia increased by around 20 per cent per year in the four years to January 2008.

The willingness of Inpex to spend an estimated additional \$700 million (Burrell 2008) to build a pipeline to Darwin — rather than face further delays associated with locating a hub in the Kimberley — for its Ichthys LNG project provides further evidence of the significance of potential delay costs. Affected by increasing construction and raw material costs, the total cost estimate for this project has been revised from around US\$10 billion to more than US\$20 billion in the past few years (Wong and Tsukimori 2008).

Increased difficulty of financing projects

Not all petroleum businesses have the financial capacity to afford lengthy and costly approval deliberations. Regulatory delays can severely restrict the ability of small and medium-sized businesses to raise project finance. In particular, those that rely on debt financing as a source of investment capital would have to bear the cost of having standby undrawn credit facilities during the period of delay. Nexus observed that the significant increase in capital costs as a result of approval delays:

... has a significant impact on a small to medium company that is raising debt and equity finance to develop the project. (sub. 3, p. 6)

Reduced present value from resource development

Regulatory constraints that delay or defer beneficial production start up during any of the stages of exploration, development and production can diminish project returns. In each case, the present value of realising economic benefits from petroleum production is reduced. Such an economic cost would be even larger when delays occur after the project proponent has already incurred the large sunk costs associated with exploration and development. As Apache noted:

Oil and gas companies undertake projects which last for decades. Consequently these companies evaluate costs and benefits on a Present Value (PV) basis using discounted cash flow calculations. The actual monetary cost consequent on regulatory compliance is commonly far less than the cost of delay in PV terms to a profitable project. (sub. 14, p. 1)

APPEA expressed a similar view but also pointed out the particular impact of delays on gas projects:

As the sums associated with investments in projects often exceed many billions of dollars, delays connected with project start-ups reduce project net present values (and therefore project returns). This is particularly the case for gas projects where project

revenues are often evenly spread over long lives, but large development costs must be incurred upfront prior to the commencement of production. (sub. 16, p. 46)

What is the cost of unnecessary delays?

The Commission's assessment of the case studies presented to this study, as well as the approval processes and related regulatory requirements, indicates that a streamlined approval process could significantly reduce project timelines (chapters 4 to 7). For example, the Victorian Government (sub. 7) suggested that the time taken to obtain a production licence could be halved to around 6 to 12 months if all approvals were handled by one agency, with similar reductions feasible for other licences. The Commission accepts, based on the evidence it has seen, that this is a reasonable objective. Since the draft report a number of regulators and industry proponents have also described this as a realistic and desirable objective, while also noting that it could only be achieved if there are significant changes that would eliminate many of the current approval processes between the JA and DA.

It is impossible to quantify precisely the aggregate cost impact of *unnecessary* regulatory burdens delaying and discouraging investment in the upstream petroleum sector. Principally, judgment is required about which procedures are necessary and which are not. Such an exercise also requires detailed financial data from specific projects — not all of which are publicly available — as well as proprietary or commercial-in-confidence information on investment returns and hydrocarbon prospectivities. Nevertheless, it is feasible to derive indicative estimates of delay costs and, hence, reform benefits.

The Commission has applied cash-flow discounting techniques to estimate the economic cost associated with approval delay under different scenarios. An illustrative case study was constructed using representative data and judicious assumptions relating to a project's capital and operating costs, internal rate of return, tax rate and output rate (box 8.2). Details of the case study and its data sources are in appendix E.

The Commission's estimates confirm that regulatory delays can impose significant economic costs (table 8.5). The long-run cost associated with a one-year delay in approval of exploration activity was estimated to be a 9 per cent reduction in the net present value (NPV) of the project. This cost estimate essentially reflects a one-year delay of the entire cash flow, based on a 10 per cent discount rate that was applied in the model to measure the opportunity cost of capital for the upstream petroleum sector.

Not surprisingly, a delay in production start-up (after exploration costs have been incurred) would cost more than a delay in exploration. In this case, the long-run cost of a one-year delay in project development was estimated to be an 18 per cent reduction in the project's NPV.

Box 8.2 Representative cash flows of Australia's economic fields

An illustrative case study was constructed to simulate cash flows over the exploration–development–production cycle of a representative economic field in Australia. The distribution of cash flows over the project life was estimated using aggregate data from a study by Mackenzie and Cai (1993) for all economic petroleum fields discovered in Australia up to 1987. It appears that no more up-to-date database is available.

By drawing on a comprehensive database, the case study captures the 'average' characteristics — particularly project size, cost structure and hydrocarbon prospectivity — of all petroleum operations in Australia. This provides a credible approximation of the 'relativity' between various cost and revenue flows — enhancing the robustness of cost estimates when they are expressed in relative terms.

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

Source: Mackenzie and Cai (1993).

The Commission also undertook sensitivity analyses for different discount rates (or values of the weighted average cost of capital (WACC)) (table 8.5).

Table 8.5 Sensitivity tests for different values of the weighted average cost of capital

| <i>Weighted average cost of capital</i> | <i>One-year delay in exploration approval</i> | <i>One-year delay in development approval</i> |
|---|---|---|
| % | % of NPV ^a | % of NPV ^a |
| 8 | -7.4 | -11.4 |
| 9 | -8.3 | -14.3 |
| 10 | -9.1 | -18.4 |

^a Net present value.

Source: Commission estimates.

Obviously the economic cost of approval delays increases as the WACC increases. Changing the WACC within a reasonable range has a small effect on the estimated NPV reduction for a delay in exploration approval, but a larger effect on the cost estimate of a delay in development approval. This higher sensitivity reflects

increased significance of the WACC in discounting delayed revenue flows after exploration costs have already been incurred.

The Commission's estimates are broadly consistent with the findings of some external studies with a similar focus on regulatory delay costs. For example, in a Canadian study undertaken by Jorgensen et al. (1996), the costs of regulatory delay were estimated for various types of mineral extraction projects to range from 6 to 90 per cent of the project cost in real terms for delay periods of between 6 and 18 months. Donze (1992) argued that the costs of project delays caused by environmental regulation in the United States amounted to 10 per cent of the capital cost.

The Commission's results are sensitive to changes in parameters over time, and to the changing nature of projects. For example, the economics underlying recent large scale export LNG projects may be somewhat different to those in the Mackenzie and Cai (1993) database drawn on by the Commission. However, these changes are unlikely to lead to lower estimates. Indeed, LNG projects are typically very large and highly capital intensive.

The cost of delays over time to the sector, and to the economy as a whole, obviously will depend on the number of projects delayed unnecessarily and the additional costs incurred. But given the size of individual projects and the pervasiveness of regulatory delays, costs are potentially significant. Indeed, given APPEA's estimate that around \$80 billion could be invested in new gas projects in the Pilbara and the Kimberley alone in the next decade, and that \$200 billion worth of projects are either in production, under construction or being planned in Australia's north-west or central Queensland (APPEA 2008), the cost of delaying production and revenues could total several billions of dollars each year.

In response to the draft report, the WA Department of Mines and Petroleum said:

In the Commission's estimation of the economic costs of project delays, the primary data source is based on petroleum fields discovered in Australia up to 1987. Also, the cash flow modelling employed appears to be based on simply 'time-shifting' the production profile of a petroleum project and it is not clear how the modelling accounts for changes in the time profile of capital and operating costs. These issues, combined with speculation on the appropriate discount rate and period of over which to discount the value of a project, brings into question the veracity of any values derived on the costs of regulatory impediments. (sub. DR22, p. 21)

The Commission agrees that its results are only broadly indicative of the costs of regulatory delay and, as noted earlier, are sensitive to a range of assumptions. However, the analysis highlights that delaying revenue streams, particularly once

significant expenditure has been incurred for large projects, reduces the NPV of a project significantly.

Moreover, the Commission's results reveal only a portion of the aggregate cost impact of unnecessary regulatory burdens delaying and discouraging investment. Just as significant, but harder to quantify, is the increased risk and uncertainty affecting individual projects. Affected businesses face impediments arising from inflated capital costs, increased difficulty of financing projects, and reduced flexibility in responding to market conditions.

It is likely that in times of economic downturn, the actual costs of delays (measured in dollars) may be reduced, because both revenue streams and the number of projects are likely to be lower. However, difficult economic times also create increased uncertainties and greater difficulties in financing projects, and may render some projects quite 'marginal' where they were previously envisaged as being highly profitable. In these difficult economic times unnecessary regulatory burdens may become pivotal for investment decisions.

The economic cost of regulatory delay would be manifested partly as a reduction in the present value of tax revenues received by governments. Arguably, a delay means a deferral of tax payments that will eventually be recouped in a future period. Although this might appear to cause no direct loss of tax revenue to governments, there is an economic cost associated with revenue streams being delayed when the time value of tax money is taken into account.

FINDING 8.4

Unnecessary approval delays cost the economy dearly. Project approvals are taking longer than a streamlined approval process would allow, potentially diminishing the present value of petroleum resource extraction in Australia by billions of dollars each year.

Difficult economic times might reduce this figure, as some projects might not proceed due to greater uncertainty, and delayed revenue streams are likely to be smaller. More projects are also likely to become 'marginal'. Unnecessary regulatory burdens could tip the balance for these marginal projects. Therefore, in difficult economic times it is equally, or even more, important to remove unnecessary regulatory burdens.

8.4 Impact on investment attractiveness

Compliance and delay costs arising from the regulatory regime reduce the sector's profitability and, hence, its ability to attract project capital. Nevertheless, it is

difficult to quantify precisely the effect on investment in upstream petroleum projects in Australia. Many factors other than cash-flow prospects influence the project performance and investment strategy of individual businesses.

Competition for global capital

The Australian upstream petroleum sector operates in a globally competitive environment where exploration and investment capital is highly mobile. The international competitiveness of Australia as a potential destination for global capital flows hinges on the sector's ability to obtain a return on investment that is commensurate with the risks, costs and efforts involved. Specifically, the sector's investment attractiveness is subject to numerous influences, including regulatory performance, sovereign risk, taxation, prospectivity, discovery costs, capital and operating costs, price volatility and infrastructure accessibility.

Regulatory performance

Regulatory performance — the key focus of this study — has significant implications for investment attractiveness in the upstream petroleum sector. As discussed above, the complexity and the time taken in satisfying regulatory processes adds uncertainty to a prospective project, making a material difference to its valuation and commercial viability. Moreover, regulatory inefficiencies potentially limit the ability of project proponents to respond to changing market conditions in a timely manner.

Delays increase operating expenditures and capital costs, giving rise to implicit costs associated with deferred or cancelled projects, forgone earnings and lost market opportunities. Project delays can also limit the availability of cash flows and loans to finance new exploration and development projects.

Sovereign risk

Sovereign risk primarily relates to the stability and credibility of a country's legal system. In particular, legal protection of property rights is essential for reducing the risk of asset expropriation facing investors (box 8.3). Other influences on the level of sovereign risk include industrial relations and exposure to terrorism activities.

The importance of sovereign risk to investment decisions is well recognised by petroleum businesses. For example, Woodside (2007) told its shareholders:

We believe risky places are getting riskier in the oil and gas industry. These include Russia, Bolivia, Ecuador, Angola and Venezuela, just to name a few.

We have been closely assessing these risks and will continue to do so. You can expect your company to make appropriate changes in its asset portfolio in recognition of worldwide risk trends. (Woodside 2007, p. 9)

Box 8.3 Risk of asset expropriation

Resource nationalism has occurred in various parts of the world, leading to the expropriation of private petroleum exploration and production assets by host countries.

Many asset expropriations occurred between 1959 and 1985, with the majority taking place in Middle-East countries including Kuwait, Libya, Qatar, Saudi Arabia, Egypt, Algeria, Iran and Iraq. Historically, asset expropriations also occurred in South American countries including Ecuador, Peru, Venezuela, Bolivia and Argentina.

Recently, there has been a re-emergence of resource nationalism in some countries. A number of petroleum businesses in Venezuela, Bolivia and Ecuador were nationalised in 2006 and 2007. Forced nationalisation also occurred in Russia in the mid-2000s.

Source: Guriev et al. (2008).

Australia has a stable legal system and a liberal policy approach to foreign investment. APPEA stated:

To date Australia has been an attractive petroleum investment environment and developed a reputation as being a sound place to do business ... But Australia's lower sovereign risk is accompanied by lower returns and margins. (sub. 16, p. 5)

While Australia is rightly seen as place of low sovereign risk, were stricter 'use it or lose it' approaches introduced for retention leases where regulators considered that resource extraction was commercial, there would be important sovereign risk issues to consider when implementing such changes (especially where leaseholders had previously spent considerable sums on exploration). This issue is discussed in more detail in chapter 5.

Taxation

In Australia, petroleum in its natural state is the property of the Crown. As such, governments are entitled to collect royalties on any petroleum extracted within their respective jurisdictions (table 5.1). Petroleum businesses are also subject to income taxes levied by the Australian Government.

Recent studies have indicated that Australian governments appropriate between 45 per cent and 66 per cent of the value of oil and gas produced, depending on the project location. Such tax rates (including resource rent tax, royalty payment and income tax) are substantially higher than those in Ireland, the United Kingdom and

New Zealand, but lower than those in Norway and many Middle-East countries (GAO 2007).

Prospectivity

Australia has a high level of geographical risk in terms of low petroleum prospectivity, according to Powell (2008). This reflects the absence of major oil discoveries comparable with those in other parts of the world such as the Middle-East and, more recently, Brazil. APPEA noted:

Perceptions of low oil prospectivity are discouraging exploration, even though many of Australia's offshore and onshore areas are largely unexplored. (sub. 16, p. 6)

Discovery costs

Australia is considered to be a high-cost place for upstream petroleum exploration and development (Powell 2008). As APPEA explained, in Australia:

... oil project developments have tended to be in deeper water and more technically challenging. (sub. 16, p. 5)

Moreover, the average offshore commercial field discovery in Australia is small by global standards — particularly for oil (APPEA 2006). This limits the opportunities for achieving economies of scale and scope through an expansion in upstream petroleum activities.

Price volatility

Petroleum businesses operating in Australia can barely affect world supply or demand and, therefore, are price takers in global crude oil markets. Unlike some national oil businesses, they cannot mitigate the risk of oil price fluctuations through strategic production decisions. According to APPEA:

... oil price volatility and the overall future trend in oil prices are among the most significant risks faced by the upstream petroleum industry. (APPEA 2006, p. 37)

Pricing of natural gas is more heavily influenced by transport costs and regional market structures. Gas prices in Europe and North America tend to align with oil prices; as do LNG export prices in Australia (AER 2007). However, the wellhead price of natural gas produced in Australia has been largely determined by domestic market conditions, often in isolation from gas market developments elsewhere. As exports of LNG from Australia increase, however, domestic gas prices for gas fields in proximity to LNG export facilities are likely to be more heavily influenced by international trends.

Infrastructure accessibility

The remoteness of oil and gas reserves underpins the importance of the cost and access to necessary infrastructure for upstream petroleum projects in Australia. The large size and low population density of Australia often make access to low-cost infrastructure unlikely. For example, the costs of building large LNG facilities in remote Western Australia are considerably higher than those required in some other parts of the world. APPEA stated:

... large gas fields remain undeveloped decades after discovery and new gas discoveries are often remote from markets and infrastructure and therefore difficult to commercialise. (sub. 16, p. 5)

In particular, major hydrocarbon discoveries in remote locations in central Australia and offshore Western Australia have raised a variety of infrastructure challenges. One such challenge is the need to build long-distance pipelines, such as the Dampier–Bunbury pipeline that stretches over 1800 kilometres in Western Australia (PC 2004d).

Similarly, transport costs reduce achievable returns on investment in areas where reserves are located far from key markets. This is often the case for supplying LNG, which is logistically difficult and expensive to transport. In this case, gas producers in Australia have a comparative advantage in selling to proximate markets such as Japan and China rather than distant markets such as Europe and North America.

Removing regulatory impediments to investment

The commercial viability of investing in the upstream petroleum sector is heavily influenced by the end product prices and overall costs. Oil and gas prices are volatile and hard to predict in the longer term. Governments cannot change some negative influences, such as low oil prospectivity and geographical remoteness. On the other hand, improving regulatory performance can be a key to reducing regulatory costs and offsetting those adverse influences on investment returns in the sector in Australia.

For highly profitable projects, the costs of unnecessary regulatory burdens are less likely to influence whether the investment proceeds. In such circumstances, the project could remain commercially viable and still be assessed by some businesses as an attractive investment despite a reduction in profitability as a consequence of unnecessary regulatory burdens. Nevertheless, even if the level of investment is unaffected, the resultant reduction and delay in profit and tax revenue would represent a significant welfare loss to local and foreign shareholders, and the Australian community.

For marginally profitable projects, approval delays and other regulatory inefficiencies and uncertainties can pose a crucial disincentive for businesses to invest. Typically for these projects, the proponent must consider a low rate of return, a protracted payback period, and accept the risk exposure of inevitable price fluctuations. The margin for error is low and even small increases in uncertainties can make projects non-commercial. Just one of these uncertainties is the assessment by the resource management regulator of what constitutes an acceptable overall recovery of the resource. Pressure from the regulator to invest additional capital or to slow extraction (to enhance overall recovery) may reduce returns further. Therefore, effective and efficient regulatory arrangements take on increased importance in improving investment outcomes.

In particular, approval timelines and their predictability stand to strongly influence project proponents' assessments of the time and capital commitments to move through the exploration–development–production cycle and their overall impact on project viability. APPEA reflected on the experience of its members in this respect:

... smaller companies are frequently seeking to access Australia's higher-risk frontier areas. Gaining an approval in Australia often takes significantly more time than other jurisdictions, such as onshore United States or Gulf of Mexico, and as a result these companies are increasingly choosing to invest their exploration budgets overseas rather than wade through Australia's regulatory maze. (sub. 16, p. 48)

FINDING 8.5

Improved regulatory arrangements hold the key to reducing regulatory costs and, thereby, improving international competitiveness and offsetting some of Australia's natural disadvantages in attracting exploration capital from international sources — particularly low oil prospectivity and geographical remoteness from gas markets and infrastructure.

Environmental approvals is one regulatory area considered by some participants to be a potentially significant impediment to attracting new investment in Australia. This view seems to be consistent with the findings of a study commissioned by the Canadian Environmental Assessment Agency (2000) to compare the environmental assessment regimes of eight countries (including Australia) in terms of their regulatory performance. Although not specific to upstream petroleum activities, this assessment was based on widely applicable criteria for best practice regulation, such as clarity, certainty, timeliness and institutional capacity.

Australia's environmental assessment regime was rated ahead of those of Canada and the United States for its relative capacity to minimise impacts on industry competitiveness for attracting investment. All these federal regimes, however, were seen to be generally more cumbersome than those of the non-federal countries

included in this study — namely, Chile, France, Germany, Japan and the United Kingdom. Such rankings were apparently influenced to a degree by the need to harmonise or coordinate environmental regulation at multiple jurisdictional levels within a federation.

In a more recent Global Petroleum Survey conducted by the Fraser Institute (2008a), Australia was rated as one of the most attractive places around the world for investment in petroleum exploration and production (box 8.1). This superior rating reflected survey respondents' overall favourable assessment of Australia against a broad range of factors affecting their investment decisions, including geopolitical risk, commercial environment and regulatory climate. In respect of regulatory performance (covering the cost of regulatory compliance, regulatory uncertainty and environmental regulation), Australia scored notably better than the US offshore, Chile, New Zealand, Norway, the United Kingdom, and Canada (except for the provinces of Manitoba and Saskatchewan).

It should be noted that such positive assessment of Australia's regulatory performance at the national level cannot be generalised across all Australian jurisdictions. Indeed, a contrary view was expressed by APPEA, pointing to:

... an international perception that Australia is a difficult place to invest in oil and gas exploration and development. (sub. 16, p. 10)

As noted in section 8.2, there are considerable variations in regulatory performance across the jurisdictions in Australia. Moreover, government initiatives undertaken to improve regulatory outcomes appear to be a key performance driver. These observations point to ample scope and capacity for regulatory improvement in many areas. With other international jurisdictions improving on their own regulation of the upstream petroleum sector, reducing regulatory impediments to investment in Australia could help deliver significant economic benefits for the nation.

FINDING 8.6

Global surveys have provided an overall favourable assessment of Australia's regulatory regime in the upstream petroleum sector. However, there is clearly scope for improvement. Environmental approvals is one regulatory area in which Australia appears to fall behind some other comparable countries in minimising inefficiencies and impediments to investment. More broadly, significant reform benefits for Australia can be achieved provided all jurisdictions undertake initiatives to adopt regulatory best practices identified in Australia and abroad.