



REGULATORY REFORM

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14.1 Introduction

The regulation of the onshore petroleum industry and, in particular, hydraulic fracturing, has been a controversial matter in the NT since at least 2010 (see the discussion in Chapter 1). In order to address the community's concerns about the development of the industry, each of the last three NT governments has commissioned at least one inquiry or review into the onshore unconventional gas industry.

The design, implementation and enforcement of a robust regulatory framework is the principal way by which the Government can ensure that any onshore shale gas industry develops in a manner that protects the environment, is safe to humans, and meets community demands.

Where environmental risks and impacts are identified, it is generally legal regulation that provides the appropriate mitigation measure, whether by prescribing that an activity is prohibited, by prescribing that world leading practice standards and technologies are used, by mandating transparency and accountable decision-making, and/or by imposing rigorous monitoring and enforcement regimes and tough penalties for non-compliance.

During the public hearings, community forums and in the submissions the Panel received, the community expressed an acute lack of confidence in the current regulatory framework.¹ It is the Panel's view that this concern is justified and that the regulatory regime in the NT must be reformed to ensure that any onshore shale gas industry develops in accordance with community expectations and properly reflects and operationalises the principles of ESD.

14.2 Community consultations

The Panel heard from a variety of stakeholders, including many members of the public, that they did not trust the regulator, or the current regulatory framework, to adequately protect the environment from any adverse impacts of any onshore shale gas development. People noted several legacy mines that have not been properly rehabilitated, such as Mt Todd gold mine and Rum Jungle, as examples of the Government's failure in this regard.² People also pointed to the fact that 85% of the NT (including some national parks) is covered with exploration applications and granted tenements as evidence that the Government prioritises development above the environment.

Some key criticisms of the current regulatory framework are as follows:

- that when regard is had to other extractive industries (such as mining), the regulator has been unable to prevent environmental harm and has been unwilling to ensure compliance with title conditions, or has refused to take enforcement action in relation to non-compliance;³
- that it does not take into account the cumulative impacts of any industry, but assesses impacts on an activity-by-activity basis;⁴
- that baseline testing of groundwater, surface water, soil, sediment and air quality is not mandated, and adequate data does not exist;
- that there is no 'fit and proper person' test or other requirement that a gas company's environmental history be considered prior to any approval being granted;
- that it does not include third party merits review rights or provide any open standing for judicial review;
- that compensation for landholders is currently inadequate and that there are no statutory provisions requiring the negotiation of 'make good' agreements; and

1 M Haswell submission 183, p 14; EDO submission 213, p 36; NTCA submission 217, p 8; NLC submission 214, p 39; Mr Justin Tutty, submission 152 (J Tutty submission 152), p 2; Lock the Gate submission 171, p 68; ECNT submission 188, p 3; AFANT submission 190, p 7; C Roth, submission 191, pp 15-16; Coomalie Council submission 15; CDRC submission 76, p 1.

2 PAN submission 51, p 4; Ms Jean McDonald, submission 182 (J McDonald submission 182), p 5; Climate Action Darwin submission 151, p 14.

3 CLC submission 47, Appendix A, p 9.

4 CLC submission 47, Appendix A, pp 8-9.

- that there are no legislative requirements regulating access arrangements for gas companies to enter onto non-Aboriginal land.⁵

14.3 Overview of regulation of unconventional shale gas in the NT

14.3.1 Ownership of petroleum

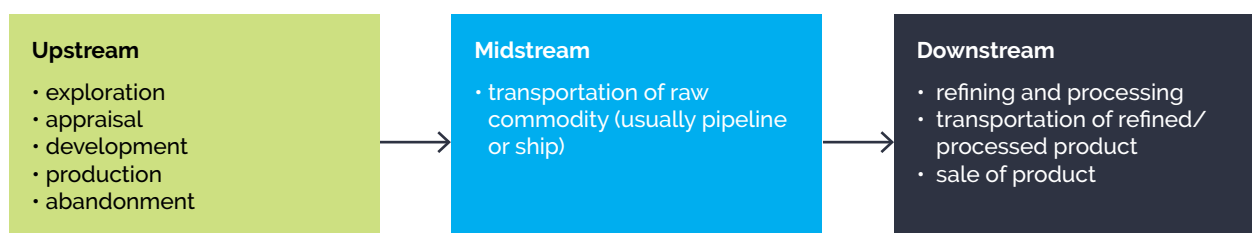
Like all other Australian jurisdictions, all petroleum resources in the NT, including shale gas reserves, are owned by the Government.⁶ While the Government owns all of the petroleum, it does not explore for or produce petroleum resources. To do so is risky and expensive and requires extensive technical expertise. Accordingly, like all other jurisdictions in Australia, the Government relies upon gas companies to explore for petroleum resources on its behalf. This shifts the exploration risk away from the Government (and the taxpayer). The gas companies that explore for, and develop, natural gas are typically large international petroleum companies that have the size, expertise and finances to navigate the risks and uncertainties associated with exploring for gas.

But it is nevertheless incumbent on the Government to create a policy and regulatory regime that strikes the right balance between, on the one hand, attracting gas companies to the NT to explore for, and produce, gas, and on the other hand, ensuring that such development is regulated effectively and in accordance with community expectations. Gas companies are more likely to invest in jurisdictions where the legal framework is certain and where they can be confident that they will get a return on their investment. Every year the Fraser Institute publishes the Global Petroleum Survey, which ranks jurisdictions around the world in terms of their attractiveness for gas companies. The Institute looks at all the reasons why a gas company would, or would not, invest in a particular jurisdiction, including tax rates, regulatory obligations, environmental regulations, and political stability. For many years, the NT was favourably included in the survey (except in 2016, when there was not enough data available to rank the NT).⁷

14.3.2 Phases of development

The development of onshore shale gas resources into products for use by consumers (for domestic and commercial use, such as air conditioning or manufacturing) is characterised by three distinct phases: the upstream phase, the midstream phase and the downstream phase.⁸

Figure 14.1: Phases of the development of petroleum resources. Source: Hunter.⁹



The 'upstream phase' comprises the following:

- **exploration:** which is the search for commercially viable petroleum resources. It comprises aerial surveys, seismic surveys and the drilling and hydraulic fracturing of exploration wells;

5 EDO submission 213, pp 9, 18; North Star Pastoral, submission 467 (**North Star submission 467**); Northern Territory Cattlemen's Association, submission 217 (**NTCA submission 217**), pp 2-4; CPC submission 218, p 4.

6 See s 69(1) of the *Northern Territory (Self Government) Act 1978* (Cth), whereby the Commonwealth vests all of its interests in petroleum in the Crown of the NT.

7 Fraser Institute 2016.

8 Hunter 2013, p 6.

9 Hunter 2013.

- **appraisal:** which is the process of confirming the size, quality and commercial potential of a petroleum resource. The appraisal phase may involve the drilling of appraisal wells near the exploration wells;
- **development:** which involves the declaration of a commercially viable petroleum reservoir, the planning process to exploit the petroleum, and the construction of production facilities;
- **production:** which involves the extraction of petroleum from the well; and
- **abandonment:** which involves the cessation of production, the plugging of wells and the decommissioning of field structures.¹⁰

The 'midstream phase' involves transport, storage and marketing. Pipelines are used to transport petroleum to a processing facility or to a tanker terminal for transport to a port that has a processing facility.¹¹

The 'downstream phase' involves the processing of petroleum and the marketing and distribution of petroleum products.¹²

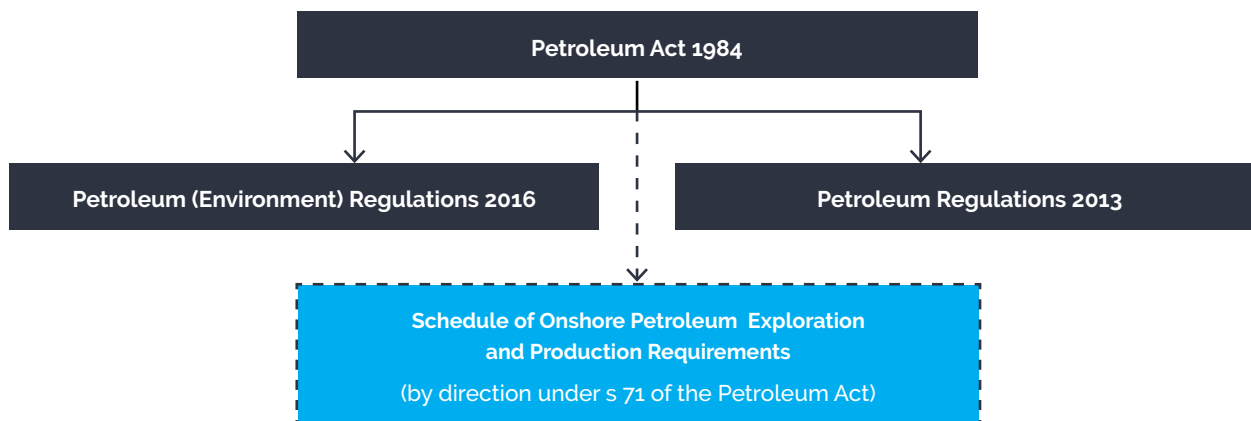
This Chapter will focus on the governance of the upstream phase only. It is this phase that has the greatest capacity for risk.

14.3.3 Overview of NT petroleum legislation

The Petroleum Act is the primary piece of legislation that regulates any onshore shale gas industry in the NT. It is supported by the Petroleum Regulations, the Petroleum Environment Regulations and the Schedule, as well as a series of non-enforceable guidelines and policy documents.

The Petroleum Regulations regulate fees in relation to petroleum activities.¹³ The Petroleum Environment Regulations require approvals from the Minister for Resources for all activities that may have an environmental impact. The Schedule contains many provisions that are generally found in regulations, including the regulation of drilling and well activities, reporting and data, production, and geological and geophysical surveying.¹⁴

Figure 14.2: Overview of NT petroleum legislation.



14.3.3.1 Petroleum Act

The Petroleum Act sets out a statutory regime for the granting of petroleum interests and titles for exploration, production and ancillary activities associated with exploiting any onshore shale gas, as well the assessment of proposed technical works programs within these titles. It also administers the reporting of data, collection of royalties and, to the extent reasonably practicable, the reduction of harm to the environment during petroleum exploration and production activities.¹⁵ In exchange for the exclusive right to produce and sell Territory gas, the Petroleum Act requires that gas companies pay 10% of the gross value of the petroleum at the wellhead back to the Government.¹⁶

¹⁰ Hunter 2013, pp 7-8.

¹¹ Hunter 2013, p 8.

¹² Hunter 2013, p 9.

¹³ DPIR submission 492, Attachment A, p 26.

¹⁴ 2012 Hunter Report, p 27.

¹⁵ Petroleum Act, s 3.

¹⁶ Petroleum Act, s 84.

The Petroleum Act does not set out a framework for the management of environmental risks and impacts associated with onshore petroleum activities. This is done in the Petroleum Environment Regulations (discussed below). The main provisions in the Petroleum Act that relate to the environment are:

- the environmental offence provisions, which make it an offence to release waste or pollutants into the environment causing a serious or material environmental harm (see s 117AAC); and
- s 58(c), which imposes a statutory obligation on all permit holders to “*cause as little disturbance as practicable to the environment*” (non-compliance with a condition of a permit is grounds for cancelling a permit).

14.3.3.2 Petroleum Environment Regulations

While the Petroleum Act does not, on its face, manage environmental risks and impacts, the Act allows the making of regulations for the protection of the environment. The Petroleum Environment Regulations were introduced in July 2016 for this purpose.¹⁷ The objective of the Petroleum Environment Regulations is to:

“set out a clear risk management framework for environmental aspects of petroleum activities and require the Minister to consider the principles of ecologically sustainable development (ESD), publish approved EMPs in full and ensure that risks and impacts are reduced to as low as reasonably practicable (ALARP) and acceptable levels. This requires that risks and impacts are identified and assessed, that stakeholders are engaged in setting objectives and outcomes as well as the elimination or mitigation of risks and impacts, with specific performance standards around the controls put in place and measurement criteria and reporting commitments of those performance standards.”¹⁸

The Petroleum Environment Regulations apply to any petroleum activity that has an environmental impact. This includes hydraulic fracturing because “*hydraulic fracturing*” is listed as a “*regulated activity*.”¹⁹ It is an offence to conduct hydraulic fracturing without an approved EMP.²⁰ A plan will be approved if the Minister is satisfied that certain approval criteria have been met. In particular, the Minister must be satisfied that the plan will reduce all environmental impacts and risks associated with the activity to levels that are both ALARP and acceptable. The Minister for Resources determines what an “*acceptable*” level of risk is by reference to the principles of ESD and any recommendations from the EPA. The Minister must publish reasons for his or her decision.

The Petroleum Environment Regulations implement many of the recommendations from the 2012 and 2016 Hunter Reports and 2014 and 2015 Hawke Reports. They:

- are objective-based;
- attempt to operationalise the principles of ESD by requiring the Minister to consider those principles as part of the decision-making process;
- ensure a level of transparency by requiring the public release of EMPs and the Minister's statement of reasons for approving a plan;
- require stakeholder engagement as a precursor to the submission of an EMP;
- require the Minister to consider any recommendations made from the EPA when making a decision about a plan; and
- operationalise the ALARP test in the decision-making process.²¹

17 DPIR submission 226, p 38.

18 DPIR submission 226, p 38.

19 Petroleum Environment Regulations, cl 5.

20 Petroleum Environment Regulations, cl 30.

21 Ensuring that a risk has been reduced ‘as low as reasonably practicable’ means weighing the risk against the reasonableness of the measure needed to further reduce it. The presumption is that the decision-maker should implement available risk reduction measures. To avoid having to implement the measure, the decision-maker must be able to demonstrate that it would be unreasonably or grossly disproportionate to the benefits of risk reduction that would be achieved. The process is not one of balancing the costs and benefits of measures, rather, it concerns adopting measures except where they are ruled out because they involve grossly disproportionate sacrifices.

14.3.3.3 The Schedule

The Schedule operates alongside the Petroleum Environment Regulations and the Petroleum Act to regulate certain petroleum activities, such as the design and construction of wells. The Schedule, by itself, is not enforceable.²² It is given legal effect by the Minister for Resources, who issues each interest holder (gas company) with a direction under s 71 of the Petroleum Act requiring the interest holder to comply with the terms of the Schedule.²³ The Schedule includes provisions relating to operational matters dealing with onshore petroleum activities, such as seismic surveys used in exploration, the construction and drilling of wells, and well integrity.

The Schedule has been described as an ineffective regulatory tool.²⁴ In its current form, it is highly prescriptive, which means that it focusses more on what gas companies must do rather than whether or not they have achieved specified environmental outcomes for a particular activity. Prescriptive regulation does not necessarily promote best practice and does not facilitate the development of new and effective ways to mitigate environmental risks. In addition, the Schedule is not subject to any type of regulatory assessment. While this type of regulation gives the Government significant flexibility (the Schedule can be amended immediately by the Minister), it is problematic, in the Panel's view, for the reasons set out in Section 14.7.3.2.

In both the 2012 and the 2016 Hunter Reports the phasing out of the Schedule was recommended.²⁵ DPIR has publicly committed to phasing out the Schedule and replacing it with exploration and production regulations, but this is yet to occur.²⁶

14.3.4 Process to explore for and produce any onshore shale gas

The process for gaining the rights to explore for, and produce, any onshore unconventional shale gas in the NT is set out in **Figure 14.3**. Before any exploration activity can occur in the NT, the Government must release the land for exploration (**Step 1**). Once land is released gas companies make bids for the land (**Step 2**) and the Minister for Resources selects the most meritorious application for consideration of the grant.²⁷ The requirements of the Native Title Act and Land Rights Act are then complied with (**Step 3**). The Minister grants the exploration permit to the gas company (**Step 4**). There is a non-statutory requirement to reach an agreement with pastoralists in respect of a proposed exploration program (**Step 5**) (see Section 14.6.1). For any activity that will have an environmental impact, the gas company must submit a draft EMP for approval by the Minister for Resources (**Step 6**), and the Minister makes a decision to either approve or not approve the plan (**Step 7**). Certain activities, such as drilling and hydraulic fracturing, will require the gas company to submit an application for approval under the Schedule (**Step 8**), and the Minister for Resources then issues an approval where appropriate (**Step 9**). In the event that a commercial shale gas reserve has been discovered, a gas company can apply for a production licence (**Step 10**), and provided that all conditions of the exploration permit have been met, the Minister for Resources may grant the licence (**Step 11**). Any production activity that will have an environmental impact must have an approved EMP in place, and certain activities, such as drilling, hydraulic fracturing and seismic surveys, will also require an approval under the Schedule (**Steps 12-15**).

22 2016 Hunter Report, p 15.

23 Petroleum Act, s 71.

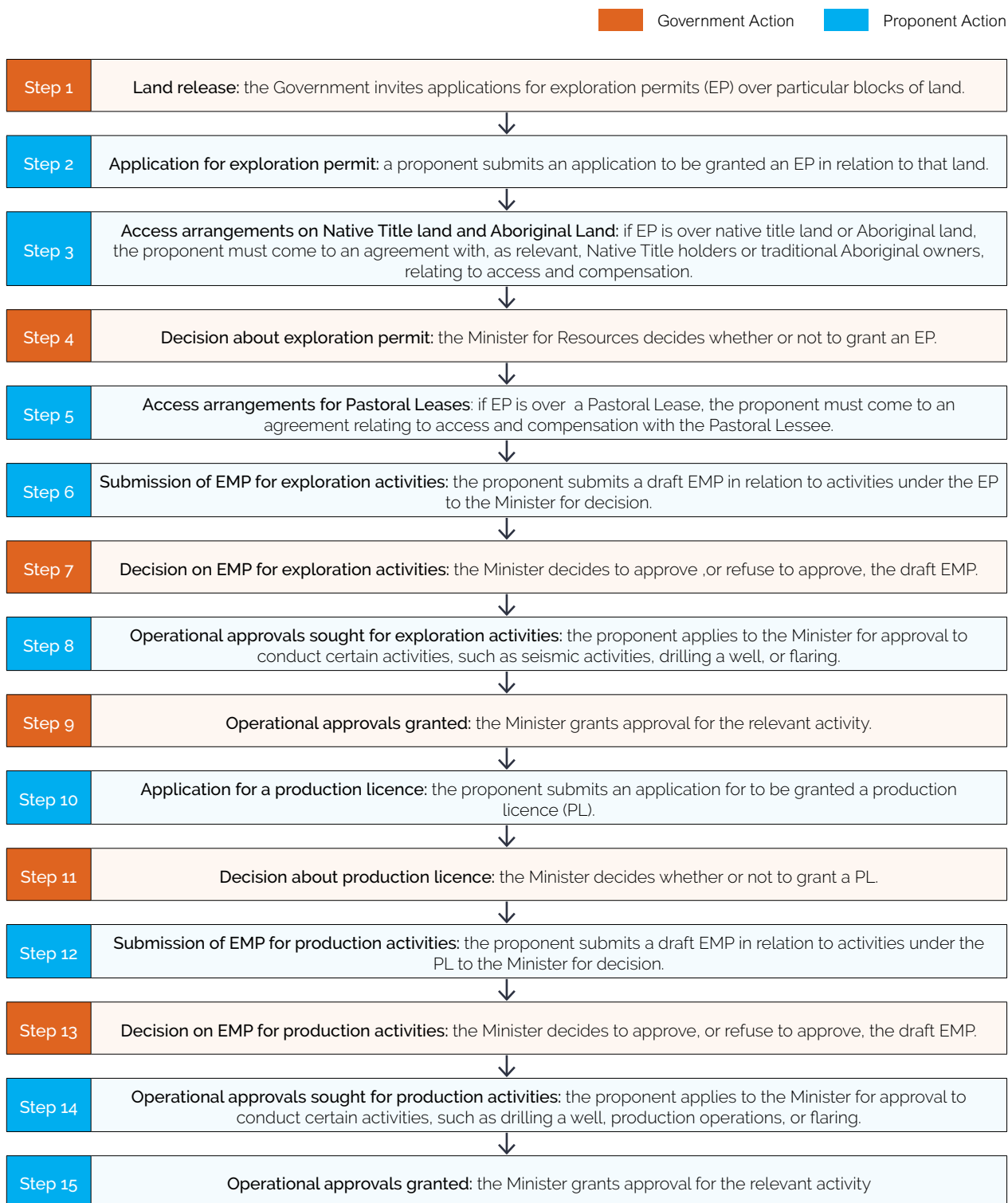
24 2016 Hunter Report, p 15.

25 2016 Hunter Report, p 15; 2012 Hunter Report.

26 DPIR submission 226, p 38.

27 DPIR submission 226, p 13.

Figure 14.3: Steps for the exploration and production of onshore unconventional gas in the NT.



14.4 The regulators

It is important to understand which Government departments and agencies administer the laws regulating any onshore unconventional shale gas development in the NT, and which departments and agencies have decision-making roles under those laws (see **Figure 14.4** and **Table 14.1**).

Figure 14.4: Departments and agencies that are involved in regulating onshore shale gas development in the NT.

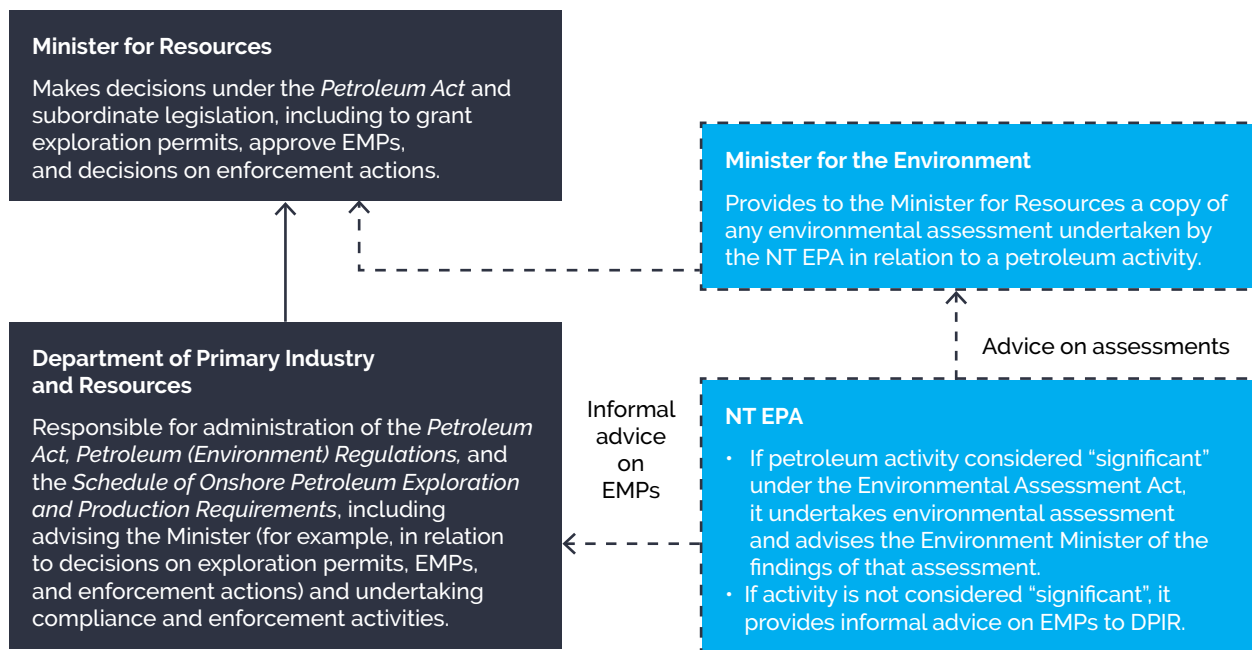


Table 14.1: Regulation of various aspects of onshore shale gas in the NT.

What is being regulated?	The regulators			What legislation applies?
	Who assesses?	Who approves?	Who does compliance and enforcement?	
Tenure; royalties; resource management; data management	DPIR	Minister for Resources	DPIR	Petroleum Act
Environment	DPIR	Minister for Resources	DPIR	Petroleum Environment Regulations
	EPA, but only if environmental impact is "significant"	No approval	N/A	EAA
	EPA	EPA	EPA	Waste Management and Pollution Control Act
	Department of the Environment and Energy (DoEE) and NT EPA under a bilateral assessment agreement	Federal Minister for the Environment	DoEE	EPBC Act (for matters of national environmental significance).
Process safety; reporting; well integrity; hydraulic fracturing; seismic surveys	DPIR	Minister for Resources	DPIR	Schedule

14.4.1 DPIR

The Minister for Primary Industry and Resources is currently the responsible Minister under the *Petroleum Act*, and officers in the Energy Division in DPIR administer that Act and are responsible for compliance and enforcement.²⁸

²⁸ See the current Administrative Arrangements Order under s 35 of the Interpretation Act 1978 (NT) at <https://legislation.nt.gov.au/en/Legislation/ADMINISTRATIVE-ARRANGEMENTS-ORDER>.

14.4.2 EPA

The EPA is an independent statutory authority established under the *Northern Territory Environment Protection Authority Act 2012* (NT). The EPA's functions include those associated with environmental assessments as conferred under the EAA and waste and pollution management as conferred under the Waste Management Act.

The EAA is relevant to the onshore shale gas industry because an activity that may have a "significant" environmental impact must be assessed by the EPA under that legislation. If an activity is assessed, the EPA gives an assessment report to the Minister for Environment and Natural Resources, who in turn provides that report to the Minister with responsibility for deciding whether or not the activity should proceed. In the case of petroleum activities, the responsible Minister is the Minister for Resources under the Petroleum Environment Regulations.

The Waste Management Act does not apply inside petroleum permits where all contaminants and wastes associated with an activity remain on the permit area.²⁹ The Waste Management Act requires gas companies to have a licence for the collection, transport, storage, treatment and disposal of "listed wastes",³⁰ many of which are chemicals used for hydraulic fracturing or that are found in wastewater. The EPA issues those licences.

14.4.3 Water Controller

The Water Act requires a person to have a permit to drill a water bore, interfere with waterways, pollute, build a dam, recharge an aquifer, dispose of waste underground by means of a bore, and extract water. The Minister for Environment and Natural Resources is the responsible Minister under the Water Act. The Minister appoints a person to be a Water Controller, who has functions under the Water Act, including to issue water extraction licences.

The Water Act currently exempts gas companies from the need to get a water extraction licence under that Act. The Government has committed to reforming this position³¹ and, given the large volumes of water required by any onshore shale gas industry in full production (see Chapter 7), the Panel has recommended that the Act be reformed to require gas companies to obtain and pay for a water extraction licence under the Water Act for the purposes of hydraulic fracturing (see *Recommendation 7.1*).³² This is to ensure that water use by any onshore shale gas industry is sustainably managed.

14.4.4 NT Worksafe

NT Worksafe has carriage of all work health and safety matters on petroleum permits as well as the transport, storage and use of dangerous goods in the NT. The legislation covers the use and transportation of hazardous chemicals and dangerous goods that are used in the petroleum sector.

While the regulation of occupational health and safety matters by a separate safety body is an accepted practice,³³ there is the potential for regulatory gaps and overlaps to arise.³⁴ Regulatory overlap has the capacity to erode the community's confidence in the regulatory framework because it creates uncertainty about who the regulator is. As noted by the Productivity Commission, regulatory overlap also means that information needs to be provided to multiple regulators and go through multiple processes, which can add to compliance costs.³⁵ Regulatory overlap is a form of regulatory burden and should be removed. The Panel has observed some regulatory overlap between DPIR and NT Worksafe, including requirements for spill contingency plans under work health and safety legislation as well as the Schedule.³⁶ While not the subject of a recommendation by the Panel, this overlap should be addressed by the Government.

²⁹ Waste Management Act, s 6.

³⁰ Waste Management Act, s 30(3).

³¹ DENR submission 230, p 7; NT Parliament 2016, p 145; DPIR and DENR submission 492, Attachment A, page 22.

³² There is universal support for this: see EDO submission 456, p 4; Origin submission 476, p 3.

³³ 2012 Hunter Report, p 29.

³⁴ 2012 Hunter Report, p 29.

³⁵ Productivity Commission 2009, p 34.

³⁶ See s 357 of the *Work Health and Safety (National Uniform Legislation) Regulations 2012* (NT) which requires a spill contingency system to be in place, and cl 214 of the Schedule, which requires actions to be taken in accordance with an "approved spill contingency plan" in the event of a petroleum or chemical spill.

14.4.5 Regulatory fees

A key component of a robust regulatory regime is an adequately resourced regulator.³⁷ As Dr Tina Hunter noted in her 2016 Report, the success of any regulatory framework depends on adequate resourcing of the regulator, and in this regard, *“as onshore petroleum activities increase, staffing levels at the Regulator will also need to increase.”*³⁸ One of the community’s main concerns about the regulation of any onshore gas industry in the NT was that the regulator would not be sufficiently resourced to have thorough oversight of the industry, especially having regard to NT specific factors such as its small population, its extensive geography, and the challenge of overseeing an often remotely operated industry.³⁹ Various stakeholders thought that DPIR was *“under resourced and under staffed”*, which jeopardised the ability of the agency to perform its statutory duties.⁴⁰ The EDO noted:

*“significant concerns about the ability of the Northern Territory government to adequately regulate a production-scale gas industry. The Northern Territory has difficulty attracting and retaining staff with adequate expertise and the small population and revenue base of the Northern Territory sees the [DPIR] and Northern Territory EPA compliance teams far smaller than those that exist in other states and territories.”*⁴¹

The NLC noted that it *“has doubts that existing Government, Regulatory and Land Management bodies in the Northern Territory currently hold sufficient capacity to adequately manage rapid development of the onshore oil and gas industry”*⁴² and that *“the Northern Territory Government may be insufficiently resourced to monitor the full extent of future environmental impacts posed by the development of the onshore oil and gas industry.”*⁴³

Regulatory bodies are generally funded either by the government through its budgetary process, or on a full cost recovery basis, where the regulated industry is required, through fees and levies, to fund all of the regulatory burden (known as full cost recovery). With the latter principle, the cost of governance of a particular industry is not borne by the public. In 2001, following an extensive inquiry, the Productivity Commission released Cost Recovery by Commonwealth Agencies which, among other things, concluded that, *“the prices of regulated products should incorporate all of the costs of bringing those products to market, including the administrative costs of regulation.”*⁴⁴

In 2002, the Australian Government adopted a general policy of full cost recovery. The most recent iteration of this policy, the 2014 Australian Government Cost Recovery Guidelines, states that *“where appropriate, non-government recipients of specific government activities should be charged some or all of the costs of those activities,”*⁴⁵ and moreover, that fees should generally be set to cover the full cost of the activities.⁴⁶ It is consistent with a user-pays, market-driven approach to regulation. It also operationalises the principles of ESD insofar as it is an aspect of the polluter-pays principle.

The regulation of the offshore petroleum industry has been considered by the Commonwealth to be appropriate for full cost recovery, with the National Offshore Petroleum Safety and Environmental Management Authority (**NOPSEMA**) operating on a full cost recovery basis.⁴⁷

DPIR has informed the Panel that it supports a full cost recovery model for the regulation of onshore shale gas development in the NT.⁴⁸ Any cost recovery mechanism must, however, be designed to:

- avoid fee duplication; and
- minimise gas companies avoiding fees through active non-compliance.⁴⁹

In the NT gas companies are currently required to pay regulatory fees for a number of approvals, including applications for exploration permits and production licences, applications to renew, vary

37 Hawke EPBC Act Review, pp 11, 16.

38 2016 Hunter Report, p 4.

39 See, for example: NLC submission 214, pp 39-40; NLC submission 471, p 25; CLC submission 47, Appendix A p 9.

40 Lock the Gate submission 171, p 69; Climate Action Darwin submission 175, p 14; NARMCO submission 186, p 9.

41 EDO submission 213, p 36.

42 NLC submission 214, p 39.

43 NLC submission 214, p 41.

44 Productivity Commission 2001, p xlii.

45 Cost Recovery Guidelines, p 5.

46 Cost Recovery Guidelines, p 6.

47 NOPSEMA cost recovery and levies; see also Productivity Commission 2009, p 265.

48 DPIR submission 424, pp 20-21.

49 Hawke EPBC Act Review, para 109, p 16.

or extend titles, and other annual fees. These fees are deposited into general Government revenue and then returned to DPIR as part of the budgetary process for use for regulatory activities.⁵⁰ These fees, however, would not cover the full costs of regulating any onshore gas industry.⁵¹

As **Table 14.2** demonstrates, fees payable in the NT, particularly in relation to production, are lower than those in SA and WA (where costs of regulation are similarly not fully covered by fees), NOPSEMA, British Columbia or Alberta, Canada (where the regulator is fully funded by industry fees and levies).

Table 14.2: Fees payable to unconventional gas regulators in different jurisdictions.⁵²

Activity	NT	SA	WA	NOPSEMA	BC	Alberta
Application for exploration permit	\$5,280	\$4,348	\$6,209	\$7,500	\$12,400 VND (for well permit-per well)	-
Application for renewal of exploration permit	\$2,080	\$2,175	\$6,209	\$7,500	-	-
Application for variation, suspension, or extension of exploration permit	\$875	\$2,175	\$6,209	\$7,500	-	-
Annual fees	\$92 per graticular block (approx. 80 km ²)	For the first term of the licence, \$3,678 or \$1.40 per km ² of the total licence area, whichever is the greater (\$112 per 80 km ²)	\$793.00 per graticular block	\$4,125 per well	-	-
Application for production licence	\$2,627	\$4,348	\$6,209	\$7,500	12,400 VND (for well permit-per well)	-
Application for renewal of production licence	\$2,627	\$2,175	\$6,209	\$7,500	-	-
Application for variation, suspension, or extension of production licence	\$875	\$2,175	\$6,209	\$7,500	-	-
Annual fees for production	\$13,225 per graticular block (approx. 80 km ²)	\$3,678 or \$676 per km ² of the total licence area, whichever is the greater (\$54,080 for 80 km ²)	\$16,532 per graticular block	\$4,125 per well	\$0.71 VND per 1,000 m ³ of marketable gas produced by the producer.	Administration fee of \$421.99-\$7,912.37 VND per well (depending on production volume) for 2017-18

What the table shows, in the Panel's opinion, is that there is scope for fee increases in the NT, to properly fund the regulation of any onshore shale gas industry. The Panel considers, given that the benefit of the regulatory activities goes primarily to an identifiable group, that is, the gas companies, that the regulation of any onshore shale gas industry in the NT should be conducted on a full cost recovery basis.

Recommendation 14.1

That the Government design and implement a full cost recovery system for the regulation of any onshore shale gas industry.

14.5 Release of land for the purposes of onshore unconventional shale gas development

Before any onshore shale gas activities can occur in the NT, land must be made available for exploration. The process of making land available is the 'land release process'. Once land is

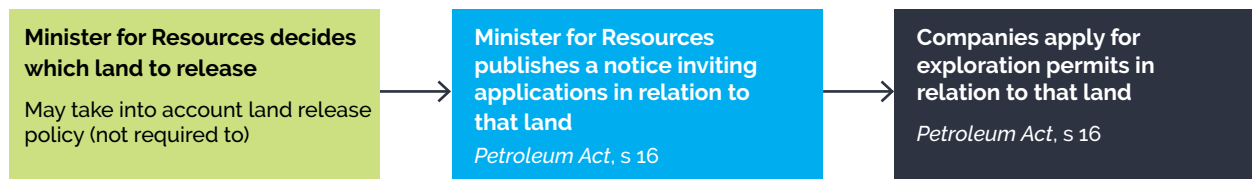
⁵⁰ DPIR submission 226, pp 26 and 186.

⁵¹ NT Agency Budget Statements 2017-18, pp 175, 185.

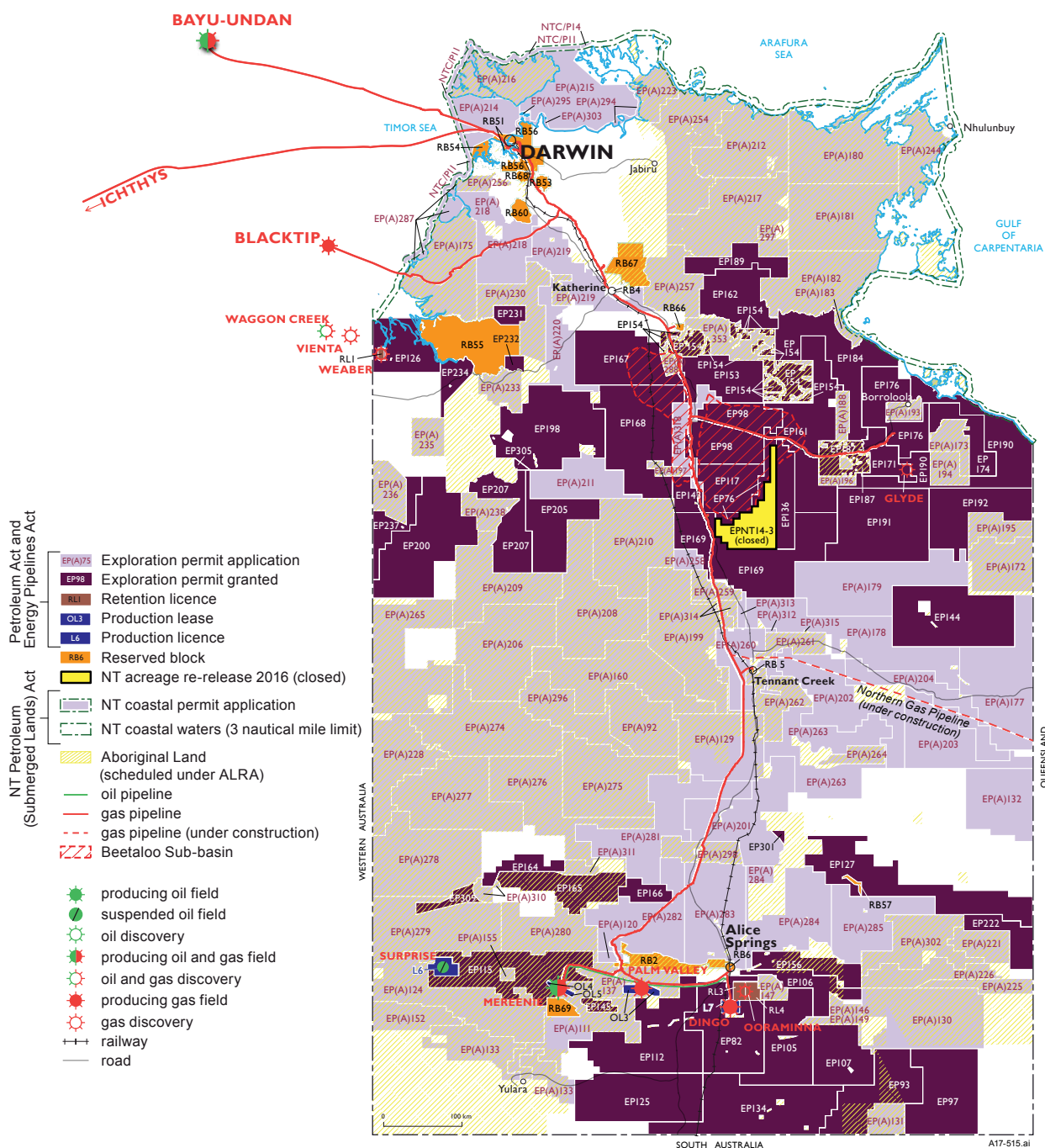
⁵² With respect to the latter three jurisdictions, care must be taken in any comparison, however, because the regulation of NOPSEMA offshore petroleum is a different to onshore petroleum, and the fees charged in the two Canadian jurisdictions are calculated on production volume rather than permit fees alone.

'released' by the Government, gas companies can apply for the grant of an exploration permit. Once an exploration permit is granted, a gas company has the exclusive right to explore for shale gas, subject to the requirement to obtain the other approvals discussed below in Section 14.7.

Figure 14.5: Current process for land release in the NT.



As shown below in **Figure 14.6**, approximately 85% of the NT land mass has already been released for exploration and is either subject to an application for, or is the subject of a granted exploration permit.



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Figure 14.6 has been used by those opposed to any onshore shale gas industry to argue that the Government prioritises economic development in the NT over the environment. Many of the areas covered by an application or granted permit are arguably areas with little or no prospectivity for petroleum resources, especially shale gas.

The reasons most of the NT is currently subject to an application for, or a granted, exploration permit are two-fold. First, prior to 1 January 2014, applications for a petroleum exploration permit were awarded on a 'first-in first-served' or an 'over-the-counter' basis.⁵³ All land was considered available, and gas companies could simply make an application over the counter for an exploration permit. Second, following the shale gas revolution in the US, gas companies were looking for areas that may be prospective for shale gas, and the NT was deemed to be a highly prospective area. This resulted in permit applications being made over 85% of the NT.⁵⁴

On 1 January 2014, the Petroleum Act was amended to enable the Government to invite applications from gas companies only over areas that had been 'released'. The amendments were arguably too late because most of the land was already under application. There is now very little land left to be 'released'. DPIR has advised the Panel that only two areas of land have been released since the 2014 amendments.⁵⁵

The new process (under the Petroleum Act) is that the Minister publishes a notice in a newspaper inviting gas companies to apply for an exploration permit on "*any of the blocks specified in the notice*".⁵⁶ The Petroleum Act does not provide any details on how the Minister decides which land is specified in the notice. DPIR has, however, established the following process. Before land is released, DPIR considers:

- the prospectivity of the relevant land for oil and gas exploration;
- the views of certain stakeholders, including Government agencies, Aboriginal Land Councils and local councils; and
- whether the land is in an area of intensive agriculture, high ecological value, culturally significant or an area of strategic importance.⁵⁷

The Minister is presently not required by law to consider any of the above matters when making a decision whether or not to release land. The Panel's view is that the Minister should be mandated to consider these matters. The "*Where oil and gas activities can occur*" guideline, produced by DPIR, states that the Minister for Resources will not release land or grant a permit over areas that are areas of intensive agriculture, high ecological value, cultural significance or areas of strategic importance, but the guideline is not enforceable.

To increase transparency and trust in the Government about which land should be released for any onshore shale gas exploration, the Panel recommends that the Minister be required to notify and consult with the community about the Minister's intention to release land for exploration. This will ensure that the community, and other stakeholders, have an opportunity to identify, on a case-by-case basis, areas of intensive agriculture, high ecological value, cultural significance, or other land uses that may be incompatible with any onshore shale gas development prior to the land being released. A statutory obligation on the Minister to publish and consult will ensure even greater transparency and accountability.

Recommendation 14.2

That the Minister publish any proposed land release for any onshore shale gas exploration.

That the Minister must consult with the community and stakeholders and consider any comments received in relation to any proposed land release.

That the Minister be required to take into account the following matters when deciding whether or not to release land for exploration:

- ***the prospectivity of the land for petroleum;***

⁵³ DPIR submission 492, Attachment A.

⁵⁴ DPIR submission 226, p 13; DPIR and DENR submission 492, Attachment A, p 11.

⁵⁵ DPIR and DENR submission 492, Attachment A, p 13.

⁵⁶ Petroleum Act, s 16(1); DPIR submission 226, p 18.

⁵⁷ DPIR submission 226, pp 18, 312.

- *the possibility of coexistence between the onshore gas industry and any existing or future industries in the area; and*
- *whether the land is an area of intensive agriculture, high ecological value, high scenic value, culturally significant or strategic significance.*

That the Minister publish a statement of reasons why the land has been released and why coexistence is deemed to be possible.

The Panel also recommends that the Government facilitate the withdrawal of all extant exploration permits and applications in respect of areas that are either not prospective for shale gas or that otherwise fall in the areas described above. This recommendation should be adopted notwithstanding the fact that some of the applications are presently subject to the negotiation processes set out in the Native Title Act and the Land Rights Act. Industry, Land Councils and traditional Aboriginal owners should work with DPIR in this regard. DPIR indicated that it has already commenced this process, with one applicant withdrawing 22 applications in 2016.⁵⁸

Recommendation 14.3

That Government consider mechanisms, including an amendment to the Petroleum Act, to ensure that applications that are currently extant are not granted in relation to areas that are not prospective for onshore shale gas or where coexistence is not possible. Consideration must be given to areas of intensive agriculture, high ecological value, high scenic value, cultural significance and strategic significance.

14.5.1 Reserved blocks

There are some areas of the NT that should never be released for exploration for onshore shale gas. Where an area of land is deemed to be permanently unsuitable for any type of exploration activity, the Minister for Resources can declare it to be a “reserved block” under the Petroleum Act. A reserved block is a ‘no go zone’, which means it cannot be considered by the Minister as part of the land release process and can never be subject to a petroleum permit.⁵⁹

The areas that are currently reserved blocks in the NT are shown in **Figure 14.7**. Some, but not all, national parks are reserved blocks (for example, Nitmiluk National Park and Watarrka National Park).⁶⁰ Petroleum exploration has occurred within at least one national park in the NT, namely, Limmen National Park.⁶¹

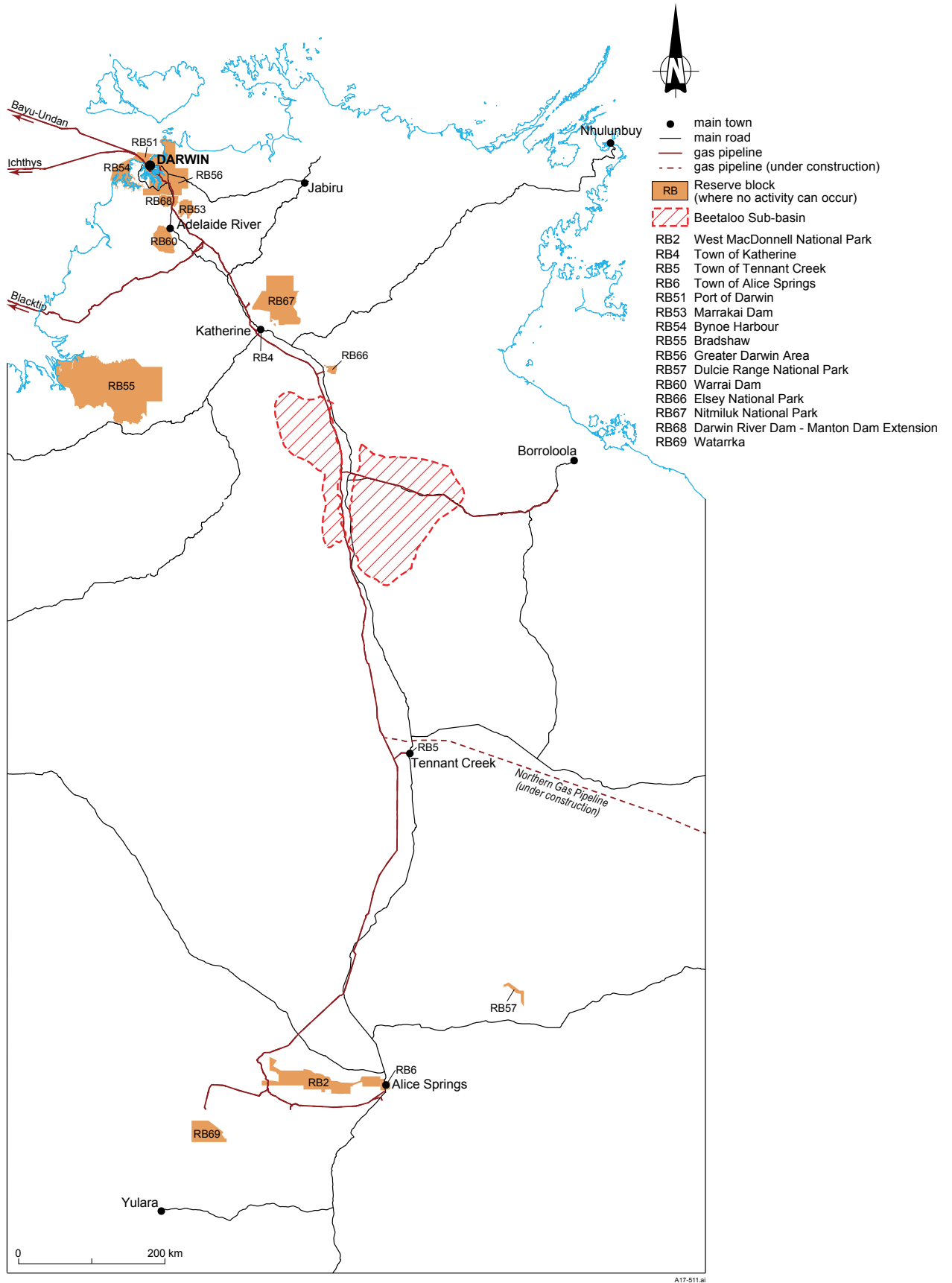
⁵⁸ DPIR submission 226, p 14.

⁵⁹ Petroleum Act, s 9.

⁶⁰ DPIR submission 226, p 14.

⁶¹ EDO submission 213, p 20.

Figure 14.7: Current reserved blocks in the NT. Source: DPIR.



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During consultations the Panel heard that more areas should be declared or reserved blocks or 'no go zones'. The Panel agrees that areas of high tourism value (for example, Mataranka Hot Springs), towns and residential areas (including areas that include assets of strategic importance to nearby residential areas), national parks, conservation reserves, areas of high ecological value and areas of cultural significance should be made reserved blocks under the Petroleum Act, because any onshore shale gas industry is unlikely to be able to coexist with these uses of land. This will ensure that these areas are never considered by the Minister to be potentially released as part of the land release process described above. The Panel notes that this is consistent with Government policy as set out in the "Where oil and gas activities can occur" guideline.⁶²

The Panel heard that land used for intensive agriculture should also be made a 'no go zone' or reserved block. But co-existence between the agricultural and any onshore shale gas industry may, in some cases, be possible. The possibility of coexistence between certain industries should be considered on a case-by-case basis. The land release process recommended above will allow landowners of intensive agricultural land to consult with Government about whether or not co-existence between current land use and any onshore shale gas industry is possible. If it is not then the Government should not release that land for exploration.

Recommendation 14.4

That the following areas must be declared reserved blocks under s 9 of the Petroleum Act, each with an appropriate buffer zone:

- **areas of high tourism value;**
- **towns and residential areas (including areas that have assets of strategic importance to nearby residential areas);**
- **national parks;**
- **conservation reserves;**
- **areas of high ecological value; and**
- **areas of cultural significance.**

14.6 Land access for onshore shale gas activities

The development of the onshore unconventional gas industry in Australia has, in many instances, caused tension between those with rights and interests in and above the surface of the land, such as pastoralists and traditional Aboriginal owners, and those with rights to enter, explore for and extract gas from underneath that land (that is, gas companies). The following types of land in the NT are relevant to the issue of land access for the purposes of carrying out any onshore shale gas activities:

- Aboriginal land under the Land Rights Act;
- land where native title rights and interests have not been extinguished and where the Native Title Act applies; and
- pastoral leases granted under the *Pastoral Land Act 1992* (NT) (**Pastoral Leases**).

A map showing the different types of land tenure in the Northern Territory is in Chapter 11 at **Figure 11.1**. The Figure shows that forms of land tenure can overlap. For example, a parcel of land can be subject to a petroleum exploration permit, a pastoral lease, and native title. This gives rise to a complex land access regime in the Territory. The issues surrounding land access management for Aboriginal land held under the Land Rights Act and the Native Title Act are dealt with in Chapter 11.

Table 14.3 shows the key features of the principal types of land tenure in the NT, including the presence, or not, of a landholder's right to veto access by gas companies to the relevant land.

62 NT Government 2015, p 9.

Table 14.3: Land tenure in the NT.

	Pastoral Lease	Native Title	Aboriginal Land	Freehold Land	Crown Land
Total area as a percentage of the land mass of the Northern Territory	44%	47%	48%	1%	4%
Percentage of the area that is subject to a petroleum interest (exploration or production)	53%	52%	6%	4%	37%
Type of interest	Leasehold interest granted under the <i>Pastoral Land Act 1992</i> (NT)	Native Title rights and interests are defined in s 224 of the <i>Native Title Act 1993</i> (NT).	Inalienable statutory freehold established under the Land Rights Act.	<i>Law of Property Act 2000</i> (NT)	<i>Crown Lands Act 1931</i> (NT)
Interest holder	Pastoralist	Native Title Holders or Prescribed Body Corporate	Aboriginal Land Trust	Title Holder	Crown
Where are the rules for land access by petroleum companies set out?	<i>Petroleum Act 1984</i> (NT); <i>Petroleum (Environment) Regulations 2016</i> (NT); Land Access Guidelines	<i>Native Title Act 1993</i> (NT); <i>Petroleum Act 1984</i> (NT); <i>Petroleum (Environment) Regulations 2016</i> (NT)	<i>Aboriginal Land Rights Act (Northern Territory) 1976</i> (Cth)	<i>Petroleum Act 1984</i> (NT); <i>Petroleum (Environment) Regulations 2016</i> (NT); Land Access Guidelines	N/A
Is there a veto right for Exploration Permits?	No	No – native title holders have a "right to negotiate".	Yes	No	N/A
Is there a veto rights for Production Licences?	No	No	No – arbitration provision in the Land Rights Act	No	N/A
Is there a statutory veto right for access to the tenement post grant?	No. The Land Access Guidelines require an access agreement to be reached.	No. There may be a contractual veto.	No. There may be a contractual veto.	No	N/A
Does the interest holder own sub-surface petroleum	No	No	No	No	All minerals are reserved to the Crown.
Is the interest transferrable? (i.e. can you sell it?)	Yes	No	No	Yes	N/A

14.6.1 Access to Pastoral Lease land

Gas companies require access to Pastoral Leases to exercise their statutory right to explore for and extract petroleum on the permit area.⁶³ Pastoral Leases are issued by the Crown under the Pastoral Land Act. The holder of the lease (**pastoralist** or **pastoral lessee**) must use the lease area for pastoral purposes.⁶⁴ The rights and obligations of pastoralists are set out in legislation, supporting regulations, and the lease document. Pastoralists do not own the land, and unlike the holder of a freehold interest, they do not have the right to exclusive possession of the Pastoral Lease area. A pastoralist must pay rent to the landowner (the pastoral lessor) in exchange for the rights given under the Pastoral Lease.⁶⁵ Pastoralists, like native title holders, Aboriginal land trusts, and owners of fee simple interests, do not own subsurface petroleum resources, such as shale gas.⁶⁶

⁶³ Petroleum Act, s 29(1).

⁶⁴ *Pastoral Land Act 1992* (NT), s 38(1)(d). There is a regime in the Act that allows pastoralists to use their leases for non-pastoral purposes.

⁶⁵ *Pastoral Land Act 1992* (NT), s 55.

⁶⁶ *Pastoral Land Act 1992* (NT), s 38(1)(b); Petroleum Act, s 6; regarding Aboriginal trust land see Land Rights Act, s 12(2), which reserves the rights to all minerals, including petroleum, to the Commonwealth, or the Territory, as the case may be. Most submissions acknowledged that minerals and petroleum are reserved to the Crown: see R Sullivan submission 18, p 2; DPIR submission 226, p 15; R Dunbar submission 75, p 1.

The rules governing access by a gas company to Pastoral Leases are set out in the Petroleum Act, Petroleum Environment Regulations and the *Stakeholder Engagement Guidelines Land Access (Land Access Guidelines)*.

Unlike many other jurisdictions in Australia, there is no statutory requirement in the NT for a gas company to enter into an access and/or compensation agreement with a pastoralist. Once a petroleum exploration permit is granted, a gas company has the exclusive right to enter and remain on the permit area to explore for gas.⁶⁷ The Petroleum Act does, however, require the gas company to, by agreement, compensate a pastoralist for any deprivation of use or enjoyment of the land or damage caused by the company.⁶⁸ If agreement as to the amount of compensation cannot be reached then either party can refer the matter to Northern Territory Civil and Administrative Tribunal (**NTCAT**).⁶⁹ The Act requires the gas company to give notice to the owner or occupier of the relevant land before commencing exploration.⁷⁰

14.6.1.1 Access under the Land Access Guidelines

DPIR has developed the Land Access Guidelines, which set out a process whereby petroleum companies can access Pastoral Leases. The Land Access Guidelines were the result of negotiations between DPIR, the NTCA and APPEA.⁷¹ However, no statutory amendments were made to formalise the agreed process. In other words, the process set out in the Land Access Guidelines has no legislative force. The Panel considers this to be a weakness of the present land access regime.⁷²

The Land Access Guidelines require the pastoralist and the gas company to reach an agreement prior to the commencement of an exploration program. The Land Access Guidelines do not stipulate what must be included in the agreement. The parties have 60 days to reach an agreement from the date the proponent sends the pastoralist a notice of intention to commence negotiations. If agreement cannot be reached within 60 days, either party may refer negotiations to an Arbitration Panel to make a determination over conditions of access. The Arbitration Panel is comprised of the Chief Executives of DPIR; DENR; the Department of Infrastructure, Planning and Logistics; and industry representatives.⁷³ The Arbitration Panel has 21 days to make its recommendations. If the parties do not agree with the decision of the Arbitration Panel, *"they retain the right to seek further review through the judicial system"*, which is likely to be protracted and costly.⁷⁴

14.6.1.2 Access under the Petroleum Environment Regulations

The Petroleum Environment Regulations do not require an access and/or compensation agreement to be negotiated between a gas company and a pastoralist. Nor do they give pastoralists the right to veto onshore shale gas activities. Rather, the Regulations set out a process for stakeholder engagement every time a gas company proposes to undertake a *"regulated activity"*, which is an activity that has or will have an environmental impact.⁷⁵ The Petroleum Environment Regulations require a gas company to consult with stakeholders about their proposed activity and give such stakeholders the opportunity to respond to the information prior to submitting an EMP to the Government.⁷⁶ Under the Petroleum Environment Regulations, *"stakeholders"* are people that may be affected by the regulated activity and include pastoralists.

67 Petroleum Act, s 29. The right to explore also includes the right to "use the water resources of the exploration permit area for his domestic use and for any purpose in connection with his approved technical works programme and other exploration": Petroleum Act, s 29(2)(d).

68 Petroleum Act, ss 81-82.

69 Petroleum Act, s 81(3).

70 Petroleum Act, s 81(2).

71 DPIR submission 226, pp 15, 180ff.

72 See also EDO submission 213, p 9; R Dunbar submission 75, p 3.

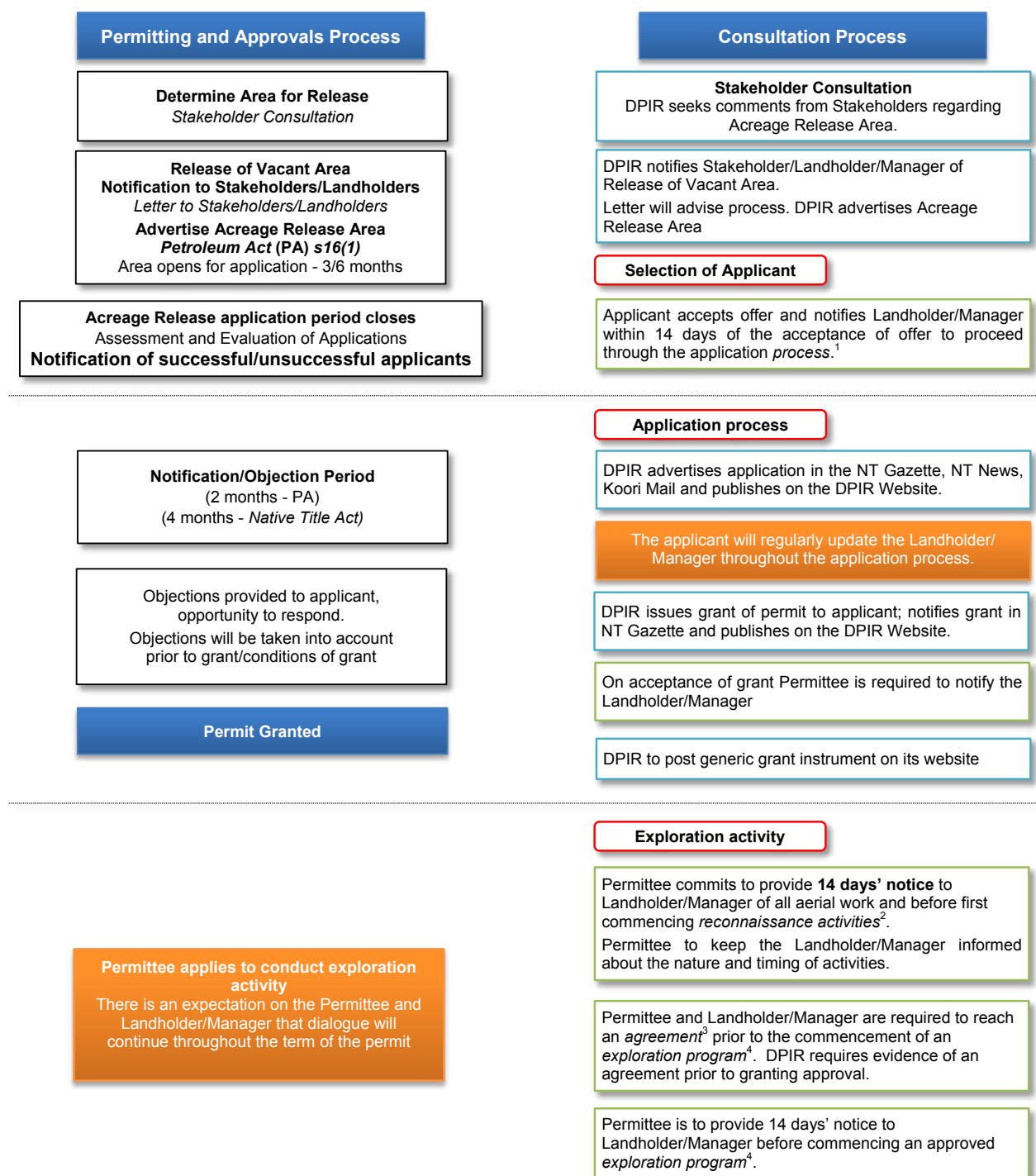
73 DPIR submission 226, p 184.

74 DPIR submission 226, p 184.

75 Petroleum Environment Regulations, cl 7. See Petroleum Environment Regulations, cl 5 for the definition of "regulated activity".

76 Petroleum Environment Regulations, cl 7(2)(b).

Figure 14.8: Overview of Pastoral Lease land access. Source: DPIR.⁷⁷



1. Section A and/or B of the *Notice of Application for the Grant of a Petroleum Exploration Permit*.
2. Reconnaissance activities are surveys, inspections and other activities that do not involve any disturbance to the land or vegetation and are undertaken before the commencement of an exploration program.
3. Once the Permittee notifies the Landholder/Manager of its intention to commence negotiations, the parties have 60 days to reach a land access agreement and associated conditions. See the Stakeholder Engagement Guidelines Land Access for further details about agreement and arbitration processes.
4. A group of activities (other than reconnaissance activities) forming an exploration program requiring approval by DPIR.

77 DPIR submission 226, p 144.

14.6.1.3 The land access regime does not facilitate a cooperative relationship between pastoralists and gas companies

There is an undeniably strong relationship between pastoralists and 'their' land, notwithstanding the absence of freehold title. Some pastoralists have been involved in the pastoral industry for many generations, raising families and building successful businesses in remote parts of the Territory.⁷⁸ It is plain that many pastoralists feel a deep and personal sense of belonging and control over their Pastoral Lease even though they do not own the land or have any rights in the sub-surface petroleum resources.

It was submitted by gas companies that, in general, the current land access regime facilitates agreement making and a cooperative relationship between pastoralists and gas companies.⁷⁹ Various gas companies cited the number of access agreements that they have entered into as evidence that the present land access regime works. APPEA noted that, "*over 50 pastoralists have land access agreements in place and are working collaboratively with our industry.*"⁸⁰ Origin stated that, "*negotiations with pastoralists have been undertaken openly and transparently with a strong focus on achieving mutually agreed outcomes and minimising impacts on pastoralists.*"⁸¹ Some pastoralists also thought that the current access regime was working effectively.⁸²

Origin, however, acknowledged that not all relationships with pastoralists have been harmonious. But it observed that the reasons for relationship breakdowns "*do not share any particular root cause, but rather reflect the complex external environment in which we are negotiating and operating under and the inherent uncertainty and challenges of person to company relationships.*"⁸³

Various submissions noted that the current land access regime gives more negotiating power to gas companies than to pastoralists.⁸⁴ One stakeholder opined that any "*power imbalance*" is the result of pastoralists' "*limited experience in undertaking such negotiations compared to explorers, who may have negotiated hundreds of such agreements; the asymmetry of information regarding the potential impact of the exploration activity; and an imbalance of power, as in most cases, rural land holders are legally required to allow explorers to access their land.*"⁸⁵

Other stakeholders raised concerns about pastoralists' limited access to independent and affordable legal advice, limited political influence, limited technical knowledge, and limited time to negotiate agreements.⁸⁶ Various submissions advocated for the establishment of an independent gas commissioner, similar to the Gasfields Commission in Queensland, to facilitate agreement-making between pastoralists and gas companies. Others proposed that there be a statutory requirement that all legal costs associated with agreement-making be paid for by the gas companies.⁸⁷ The Panel notes that this is usually agreed to by gas companies.⁸⁸

Central to the success of the negotiation process is adequate time to negotiate an access agreement, access to independent and affordable legal advice, and clarity on the legal (and other specialist advice) requirements of the agreement-making process. The Panel does not advocate the creation of a body such as the Queensland Gasfields Commission. That body has been criticised as having been subject to regulatory capture by the unconventional gas industry and failing to adequately protect the interests of landholders.⁸⁹ This has led to the creation of another regulatory body to deal with land access issues between the CSG industry and landholders, the Land Access Ombudsman.⁹⁰ Instead, the Panel is of the opinion that reform other than a creation of a separate regulator agency dealing exclusively with issues arising between pastoralists and gas companies must be considered. This is discussed further below in Section 14.12.2.

78 R Dunbar submission 75, p 4.

79 Pangaea submission 220; D Armstrong submission 180; Santos Ltd, submission 58 (**Santos submission 58**); Santos submission 168; Origin submission 153; Australian Pipelines and Gas Association and Energy Networks Australia, submission 101 (**APGA and ENA submission 101**); Roper Resources, submission 181 (**Roper Resources submission 181**); Oilfield Connect submission 174; B Sullivan submission 160; M Sullivan submission 166; APPEA submission 215; R Sullivan submission 243, pp 1-2.

80 APPEA submission 215, p 5; Origin submission 153, p 156; Santos submission 58, p 7; Pangaea submission 220, p 81. See also D Armstrong submission 180, p 7.

81 Origin submission 153, p 156.

82 B Sullivan, submission 160, p 7; R Sullivan submission 18, pp 1-2.

83 Origin submission 153, p 157.

84 NTCA submission 32, p 1.

85 North Star submission 155, p 5. The submission refers to the Productivity Commission's, *Mineral and Energy Resource Exploration, Inquiry Report No 65*, Canberra, 2013, pp 18, 133.

86 S Bury submission 189, p 4.

87 Armour Energy Ltd, submission 23 (**Armour submission 23**), p 3; Lock the Gate recommended a fully independent ombudsman be created to act as an umpire in disputes between landholders, traditional owners and gas companies, Lock the Gate submission 171, p 74.

88 Origin submission 153, p 156; Santos submission 168, p 115.

89 Gasfields Commission Review: Queensland Gasfields Commission 2017.

90 *Land Access Ombudsman Act 2017* (Qld).

14.6.1.4 Pastoralists should not have a statutory right of veto

One way to mitigate any power imbalance between pastoralists and gas companies is to enshrine a statutory right of veto to allow pastoralists to refuse access to Pastoral Leases. The NT does not give pastoralists a statutory right of veto to petroleum companies accessing Pastoral Leases to conduct petroleum activities. Various stakeholders told the Panel that pastoralists should have a right of veto.⁹¹ Those in support of a statutory veto right thought that it would fix the power imbalance between gas companies and pastoralists described above.⁹² This is the official position of the NTCA.⁹³ However, this view is not universally held among pastoralists and does not occur in other jurisdictions, as the table below demonstrates.⁹⁴

Table 14.4: Comparison of state protections for access to private land for exploration. Source: Senate Select Committee on Unconventional Gas Mining.⁹⁵

Protection	NSW	Vic	Qld	WA	SA	Tas
Land access arrangement agreed to with landholder before the explorer can access land	Yes	Yes	Yes	Yes	No ¹	No ²
Compensation available to landholder for loss or damage arising from exploration activity	Yes	Yes	Yes	Yes	Yes	Yes
Compensation for legal costs incurred by landholders in negotiating access agreements	Yes	No ³	Yes	Yes	Yes	No ³
Compensation for other costs associated with negotiating access agreements	No	No ³	Yes ⁴	Yes ⁵	Yes ⁶	No ³
Exploration prohibited within specific distances of buildings and other improvements	Yes	Yes	Yes	Yes	Yes	Yes
Landholder veto over exploration on agricultural land	No	No ⁷	No	Yes ⁸	Yes ⁹	No

1. Authorisation to enter private land can be provided through the written consent of the land holder or by serving the land holder a statutory form (Notice of entry on land) under the *Mining Act 1971* (SA).
2. No formal agreement is required between the landholder and the explorer before exploration commences. However, where exploration involves ground disturbance, officers from the Department of Infrastructure, Energy and Resources are generally involved in the oversight of exploration activities to ensure that these activities adhere to the work plan.
3. Although there is no specific reference to compensation for legal, or other, costs incurred by land holders in negotiations with explorers, the legislation does not 'rule out' the provision of such compensation.
4. The Queensland Land Access Code provides for the compensation of reasonable accounting and land valuation costs incurred by the landholder.
5. The *Mining Act 1978* (WA) provides for reasonable legal or other costs of negotiation for private land under cultivation.
6. The South Australian guidelines make specific reference to compensation for legal costs and the *Mining Act 1971* (SA) provides for the reasonable costs incurred by the landholder in connection with negotiations.
7. The Minister can have agricultural land excised from the licence where the economic benefit of continuing to use that land for agricultural purposes is greater than the work proposed in the licence.
8. This applies to mineral tenements, but not to oil and gas tenements.
9. Exploration on cultivated land requires landholder consent. Where agreement cannot be reached, the explorer has the option of seeking a determination through the courts.

There are a number of cogent arguments why pastoralists should not have the right to veto access by gas companies seeking to gain access to their land.⁹⁶ These arguments may be summarised as follows:

- granting a right to veto access by gas companies would be the same as giving pastoralists *de facto* ownership over shale gas reservoirs, which they do not own.⁹⁷ Furthermore, with approximately 25% of the Pastoral Leases in the Northern Territory under some form of foreign ownership, a *de facto* ownership right over gas resources would effectively give

⁹¹ See North Star submission 155; Lock the Gate submission 171; S Bury submission 189, p 4; NTCA submission 217, p 2, and submission 32, p 7; R Dunbar submission 75, p 2; C Dennison submission 5, p 2.

⁹² NTCA submission 32, p 1.

⁹³ NTCA submission 32.

⁹⁴ D Armstrong submission 180, pp 8-10; M Sullivan submission 166, section 5.1; R Sullivan submission 18, p 2.

⁹⁵ Senate Select Committee on Unconventional Gas Mining 2016, pp 24-25, citing Productivity Commission 2013, p 121.

⁹⁶ Mr Paul Brant, submission 71 (**P Brant submission 71**); Origin submission 153, p 154; D Armstrong submission 180; B Sullivan submission 160; M Sullivan submission 166; R Sullivan submission 18; Oilfield Connect submission 174; Roper Resources submission 181; Santos submission 58; AGPA and ENA submission 101.

⁹⁷ APPEA submission 215, p 94, quoting *Landholders' Rights to Refuse (Gas and Coal) Bill 2015*, Senate Standing Committee on Environment and Communications, Chapter 4, Commonwealth of Australia, 2015; see also Origin submission 153, p 155.

foreign investors the power to “stop Territorians benefiting from [their] resources”;⁹⁸

- a right of veto might mean that pastoralists could negotiate substantial payments in exchange for their consent, potentially reducing the amount of revenue that would go to the Government under any statutory royalty regime;⁹⁹
- a veto right might have an impact on the amount of rent that pastoralists are required to pay under the Pastoral Land Act, which is calculated on the unimproved value of the land;¹⁰⁰
- a right to veto could have an impact on the rate of economic development in the NT because it would be “a huge red flag to all investors to stay away from the Northern Territory, making this a clear ‘no-go’ place, as at any time someone can simply pull the rug from beneath your business, without the need to show cause”;¹⁰¹
- a right of veto might place pastoralists under potential “unfair and distressing” pressure from environmental activists.¹⁰² One stakeholder argued that there was “substantial pressure placed on Aboriginal people from activists as they have the right of veto, with scare tactics and misinformation”;¹⁰³
- traditional Aboriginal owners’ right to veto the grant of a petroleum exploration permit under the Land Rights Act (described in **Chapter 11**) does not justify giving pastoralists a similar statutory right. The policy reasons behind the exploration veto in the Land Rights Act are historical and complex. Various stakeholders pointed to the key differences between the proprietary nature of Aboriginal land under the Land Rights Act (inalienable freehold) and Pastoral Leases (transferable leasehold) to submit that pastoralists should not be afforded a veto right of the kind set out under the Land Rights Act;¹⁰⁴ and
- in any event, a statutory veto right ought not be necessary to negotiate fair access and compensation arrangements for pastoralists and that any power imbalance could be adequately addressed using other measures, such as, for example, a statutory requirement for all reasonable legal fees to be paid by the gas companies.¹⁰⁵

The Panel agrees that there should be no statutory right of veto for pastoralists. Nevertheless, the Panel does recommend the adoption by all relevant stakeholders of a set of principles similar to those adopted on 28 March 2014 in NSW contained in the *Agreed Principles of Land Access*.¹⁰⁶ Various submissions referred to the access agreement for CSG operations entered into between Santos, AGL, NSW Farmers, Cotton Australia and the NSW Irrigators Council in 2014, and subsequently the Country Women’s Association and Dairy Connect in September 2015, as a high water mark of land access arrangements in Australia. The gas companies that are a party to that document have agreed that farmers have the right to say ‘yes’ or ‘no’ to the conduct of CSG operations on their land.¹⁰⁷ The signatories agreed that:

- any landholder must be allowed to freely express their views on the type of drilling operations that should or should not take place on their land without criticism, pressure, harassment or intimidation, and any landholder is at liberty to say ‘yes’ or ‘no’ to the conduct of unconventional gas activities on their land;
- Santos and AGL confirmed that they will respect a landholder’s wishes and not enter a landholder’s property to conduct drilling operations where that landholder has clearly expressed the view that this activity would be unwelcome; and
- the parties will uphold the landholder’s decision to allow access for drilling activities, and not support attempts by third party groups to interfere with any agreed operations, and that the parties will condemn bullying, harassment and intimidation in relation to agreed drilling operations.

98 D Armstrong submission 180, p 8.

99 APPEA submission 215, p 94.

100 M Sullivan submission 166, p 5; see also B Sullivan submission 160, p 6; D Armstrong submission 180, p 8.

101 Oilfield Connect submission 174, p 45; Roper Resources submission 181, p 2.

102 Origin submission 153, p 165.

103 D Armstrong submission 180, p 9.

104 Ministerial consent is required for a transfer. See PLA, s 67(1). See also D Armstrong submission 180, p 9 and Origin submission 153, p 155.

105 D Armstrong submission 180, p 8.

106 NSW Land Access Principles, available at: <https://www.nswfarmers.org.au/_data/assets/pdf_file/0008/35567/Agreed-Principles-of-Land-Access-280314.pdf>.

107 EDO submission 213, p 27; North Star submission 155, p 5; CPC submission 218, p 7.

The principles, while not formalised by legislation or government policy, serve a powerful normative purpose and assist in building trust and acceptance (necessary components of any SLO. See Chapter 12) in the community for any onshore shale gas industry. While the Panel does not formally recommend that a similar agreement be adopted in the NT, major stakeholders should contemplate endorsing a similar proposal, and aspects of the agreement ought to be contained in improved land access arrangements (discussed in detail in the Section immediately below).

14.6.1.5 There must be a statutorily enshrined land access agreement prior to any onshore shale gas activity on any Pastoral Lease

It is the Panel's strong view that, prior to any access to a Pastoral Lease, a signed land access agreement (**statutory land access agreement**) must exist between the Pastoral Lessee and the gas company, and moreover, that the obligation to finalise such an agreement must be statutorily mandated.¹⁰⁸ As stated above, the Land Access Guidelines in existence in the NT are not binding.

As a further safeguard, any breach of the statutory land access agreement by the gas company should be a breach of that company's approval to undertake onshore shale gas activity, and therefore, a breach of the relevant legislation giving rise to, at the very least, civil sanctions, including revocation of the approval.

Recommendation 14.5

That prior to undertaking any onshore shale gas activity on a Pastoral Lease (including exploration), a land access agreement must be signed by the Pastoral Lessee and the gas company.

That the land access agreement be required by legislation.

That breach of the land access agreement will be a breach of the relevant approval giving rise to the petroleum activity being carried out on the land.

At a minimum, the statutory land access agreement must contain the following protections for Pastoral Lessees:¹⁰⁹

- minimum notice periods, given either orally or in writing, except in the case of emergencies;
- an obligation to conduct the onshore shale gas activities in a manner that minimises disturbance to livestock and property;
- an obligation to return any gates to their original position unless advised otherwise by the Pastoral Lessee;
- an obligation to obtain the Pastoral Lessee's consent prior to the erection of any gate, fence or other barrier on the land;
- an obligation to repair any gate, fence, grid or other barrier on the land damaged or harmed by the gas company or any subcontractor engaged in onshore shale gas activity on the land;
- agreement upon the location and size of any camps on the land necessary to conduct the onshore shale gas activities;
- notification to the pastoral lessee as soon as practically possible of all spills, incidents, harm or damage to the Pastoral Lease and its infrastructure and operation;
- a minimum amount of compensation payable for each well drilled (see the discussion in Section 14.6.1.6 below);
- 'make good' provisions for any damage or harm to the water (surface and ground), land, infrastructure, or operation of the Pastoral Lease. The onus of proof is to be reversed so that the obligation is on the gas company to demonstrate that the harm or damage was not caused by the onshore shale gas activities;

¹⁰⁸ NTCA submission 32, p 4.

¹⁰⁹ See the *Farming Land Access Agreement Template for Petroleum Exploration Activities under the Petroleum and Geothermal Energy Resources Act 1967*, October 2015 (WA); Department of Natural Resources and Mines, *Land Access Code*, version 2, September 2016 (Qld); Department of Industry, *Exploration code of practice: petroleum land access*, December 2016 (NSW); NTCA submission 217, pp 2-4.

- indemnification for any harm or damage caused by any third party engaged by the gas company or any of its sub-contractors to the water (surface and ground), land, infrastructure or operation of the Pastoral Lease;
- the provision of appropriate guarantees where the holder of the approval to carry out the relevant onshore shale gas activity is not the person or company undertaking the activities on the land;
- to the extent reasonable and permitted by law, a release by the gas company of the Pastoral Lessee for any death or personal injury to the gas company's personnel, damage to or loss of the gas company's property or consequential loss, including financial loss;
- a prohibition on the sale, assignment or transfer of any rights or obligation by the gas company;
- no confidentiality clause unless by mutual agreement of the parties. Any information of a personal nature obtained about the pastoral lease and its operations or the Pastoral Lessee, however, is to remain confidential;
- payment of all reasonable legal, financial and technical fees incurred in respect of the agreement must be borne by the gas company holding the approval for the activity;
- the payment of all duties and taxes payable in respect of the land access agreement;
- clear dispute resolution mechanisms;
- clear termination mechanisms;
- agreement on access points, roads and tracks prior to entering onto the lease;
- induction training for all employees or contractors of the gas company;
- an obligation to prevent the spread of weeds, feral pests and diseases;
- clear obligations with respect to rehabilitation and remediation, including the provision for the independent assessment of all rehabilitation and remediation;
- continuing liability in respect of all decommissioned wells to be the responsibility of the gas company; and
- the ability to renegotiate the land access agreement after a specified period of time, including post-exploration and pre-production.

Statutorily enacted minimum contractual protections assist in shifting any power imbalance back in favour of the Pastoral Lessee. In light of some of the adverse experiences between Pastoral Lessees and gas companies that the Panel was informed of during its trip to the Surat Basin in Queensland, such provisions are necessary. Their willing acceptance by any gas company seeking to engage in onshore shale gas activities in the NT may be seen as an aspect of the industry's acquisition of an SLO in the Territory. The experience of at least one Pastoral Lessee indicates that in the absence of such provisions, gas companies will seek to agree to minimum, not maximum, leaseholder contractual arrangements.¹¹⁰ The experience of some landholders in Queensland that the Panel consulted with validates this view. Having said this, any statutory land access agreement should contain both binding and non-binding terms to ensure a minimum degree of protection to the Pastoral Lessee while nevertheless ensuring maximum sufficient flexibility in any negotiations between the parties.

¹¹⁰ See the draft *Pastoral Land Access and Compensation Agreement (Petroleum Activity)* between Origin and Lexcray Pty Ltd attached to R Dunbar submission 75.

Recommendation 14.6

That in addition to any terms negotiated between the pastoralist and the gas company, the statutory land access agreement must contain standard minimum protections for pastoralists.



NT pastoral enterprise.

14.6.1.6 Compensation for onshore shale gas activities occurring on Pastoral Leases

In the absence of a right of veto, pastoralists should, however, be financially compensated for any onshore shale gas development on their land. Many submissions echoed the sentiment expressed by the Commonwealth Minister for Resources and Northern Australia, Senator the Hon Matthew Canavan, in his media announcement of 9 May 2017, regarding the Commonwealth's \$28.7 million investment in east coast gas security, *"our natural resources belong to all Australians, but it's only fair that the landholders who allow access to these resources on their land receive a fair return."*¹¹¹ Many stakeholders were generally in favour of the concept that pastoralists should receive a revenue stream to compensate for the impact of exploration on their Pastoral Lease. Some, however, expressed a contrary view, concerned that the payments (or other benefits) received by Pastoral Lessees would not be shared for the public good: *"if the cattle industry was to earn a large chunk of royalty from the Northern Territory public resources, how many schools, hospitals will they build, how many roads, bridges, water storage/drainage infrastructure will they construct?"*¹¹²

The Panel is of the opinion that absent a right of veto, it is not unreasonable for Pastoral Lessees to seek some form of financial benefit for the inconvenience and disruption imposed upon them by the development of any onshore shale gas industry. As one stakeholder said, *"a revenue stream for a pastoralist from oil and gas could underpin their cattle business; hence they have skin in the game with the end result they are a beef and cattle producer. They would therefore be more inclined to support the industry and be proactive in assisting its development."*¹¹³

The financial recompense could be in the following forms. First, a mandatory minimum compensation payment calculated by reference to the number of wells drilled on the Pastoral Lease and the area of land cleared and rendered unavailable to the Pastoral Lessee. The most transparent method of calculating this head of compensation is an annual fee by reference to the improved value of the land. As discussed above, reasonable fees for negotiating any statutory land access agreement should also be payable by the gas company.

¹¹¹ Canavan, media release, 9 May 2017.

¹¹² Oilfield Connect submission 174, p 46; see also APPEA submission 215, p 94.

¹¹³ D Armstrong submission 180, pp 7-8; R Dunbar submission 75, p 3.

Recommendation 14.7

That the Government consider implementing a mandatory minimum compensation scheme payable to Pastoral Lessees for all onshore shale gas production on their Pastoral Lease. Compensation should be by reference to the number of wells drilled on the Pastoral Lease and the area of land cleared and rendered unavailable to the Pastoral Lessee.

Second, and in the alternative, consideration could be given to a royalties payment scheme similar to the PACE Royalties Return Scheme in SA (which provides that 10% of royalties the SA Government collects goes back to the landowners whose property overlies a new petroleum field that is brought into production¹¹⁴), or the Royalty Return Scheme proposed by the Commonwealth's Department of Industry, Innovation and Science.¹¹⁵ This financial compensation can confer a tangible benefit upon landowners. This is important because, echoing the quote above, "community and landowner acceptance and agreement to host onshore gas activity is essential for the timely development of onshore gas".¹¹⁶

Having said this, there are arguments against the establishment of such a scheme, not the least of which is that it is not available to native title landholders, and moreover, the tenure of pastoralists, unlike the landholders in SA, is not freehold.

Recommendation 14.8

That the Government consider whether a royalty payment scheme should be implemented to compensate Pastoral Lessees for all new petroleum fields brought into production.

14.7 Exploration for onshore shale gas

Exploration is the phase in an unconventional gas operation where the gas company is looking for a commercially exploitable gas reserve. Exploration activities include any activities directed towards this purpose, for example seismic testing and other geophysical and geological surveys, drilling wells and hydraulic fracturing.

14.7.1 Exploration permits

Exploration for onshore shale gas is governed by the Petroleum Act, the Petroleum Environment Regulations and the Schedule. In order to explore for gas in the NT, a gas company must have an exploration permit, which is granted under the Petroleum Act. An exploration permit grants the proponent the exclusive right to explore for petroleum and to carry out such operations and execute such works as are necessary for that purpose in the exploration permit area.¹¹⁷

An application for an exploration permit may only be made in relation to land that has been released (see above Section 14.5). In order to apply for an exploration permit, a gas company must submit an application to DPIR containing, among other things:

- a proposed technical works program for exploration of the blocks during each year of the term of the proposed exploration permit;
- evidence of the technical and financial capacity of the gas company to carry out the proposed technical works program and to comply with the Petroleum Act;
- the name of the designated operator and evidence of the technical capacity of the operator to carry out the proposed technical works program; and
- the prescribed application fee.¹¹⁸

The Minister must publish notice of the application. The notice must include the name of the gas company, identification of the land over which the application applies, and a statement that a person who has an estate or interest in that land, or in land contiguous with that land, may, within two months, lodge an objection to the granting of the permit.¹¹⁹ Copies of any objections lodged in response to the notice must be provided to the gas company, and the gas company may lodge

¹¹⁴ Department of Industry, Innovation and Science, submission 299 (DIIS submission 299), section 2.3, p 4.

¹¹⁵ DIIS submission 299, p 6 and Department of Industry, Innovation and Science, submission 459 (DIIS submission 459).

¹¹⁶ DIIS submission 299, section 2.3, p 4.

¹¹⁷ Petroleum Act, s 29(1).

¹¹⁸ Currently set at \$5,280; Petroleum Act, s 16.

¹¹⁹ Petroleum Act, s 18.

responses to those objections within 30 days.¹²⁰ If the land under application is Aboriginal land under the Land Rights Act or is subject to native title, the processes set out in Chapter 11 must be complied with before the permit can be granted. In making a decision about whether to grant or refuse the exploration permit, the Minister must consider:

- the application;
- any objections to the grant of the exploration permit;
- any replies or other comments of the gas company;
- any other information that the Minister requested from the gas company; and
- any other matter that the Minister considers relevant to the application.¹²¹

If the Minister decides to grant the exploration permit, the Minister must give the gas company a notice setting out the conditions under which such a permit would be granted and a specified date (at least 28 days after the date of the notice) after which the application will lapse if the Minister has not received the gas company's acceptance of the conditions.

If the Minister receives written acceptance of conditions from the gas company, the Minister must grant the exploration permit subject to those conditions.¹²²

If the Minister decides to refuse to grant the exploration permit, the Minister must inform the gas company of this decision, provide reasons for the decision and notify the gas company that it may apply for review of the decision. The gas company may, if it is dissatisfied with a decision of the Minister to refuse to grant an exploration permit, seek a review of that decision.¹²³ The review is conducted by a panel appointed by the Minister, who will review the decision on its merits and make a recommendation to the Minister to confirm or revoke the decision.¹²⁴ The Minister may choose to accept or reject the panel's recommendation.

120 Petroleum Act, s 19.

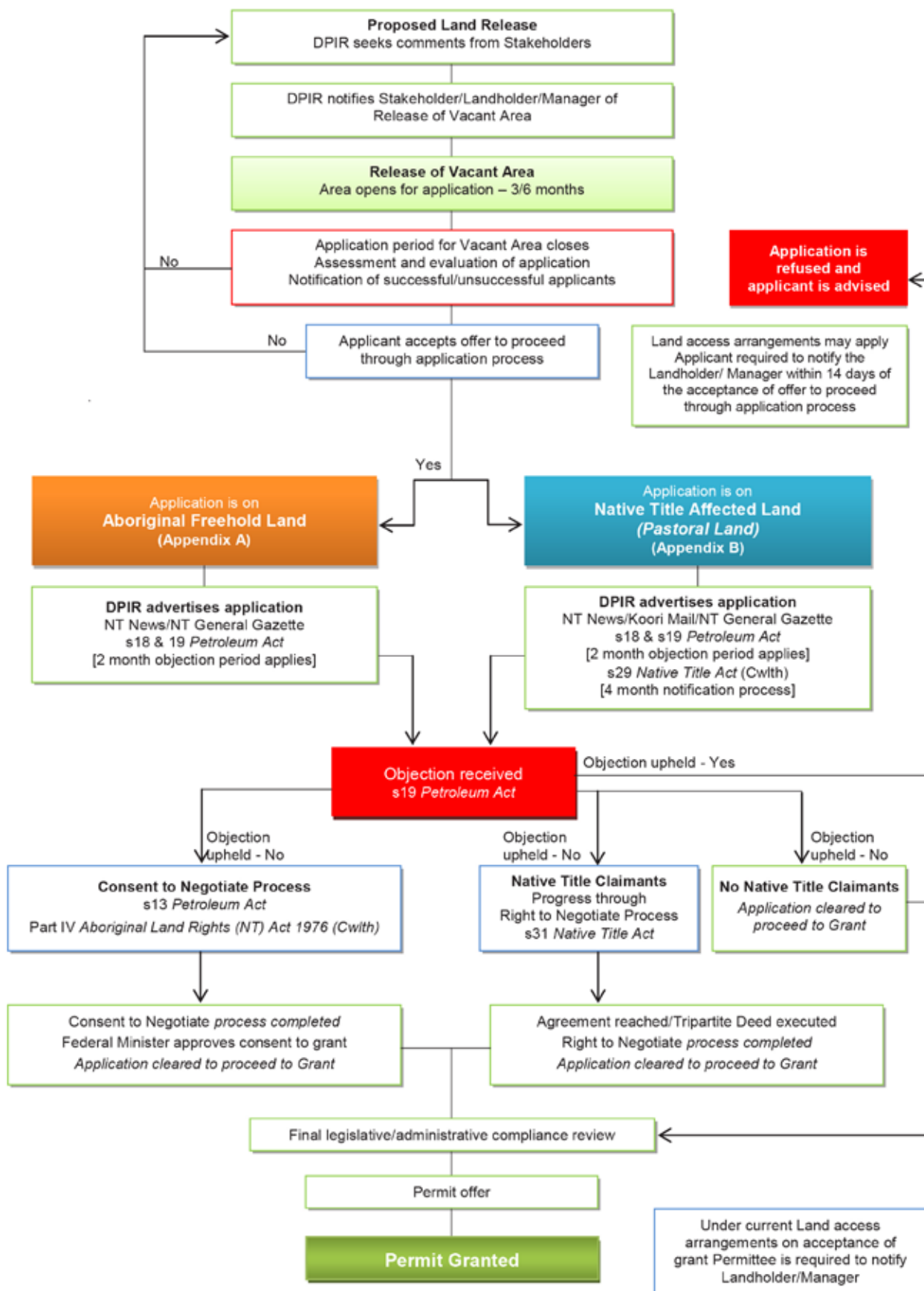
121 Petroleum Act, s 20(2).

122 Petroleum Act, s 20.

123 Petroleum Act, s 57AB.

124 Petroleum Act, s 57AD.

Figure 14.9: Flowchart of the exploration permit process. Source: DPIR.¹²⁵



125 DPIR submission 226, p 129.

The Petroleum Act does not provide for an external merits review process, third party or otherwise, to a person or organisation that is aggrieved by a decision to grant an exploration permit.

Similarly, there is no process contained in the Petroleum Act to seek the judicial review of a decision to grant or refuse an exploration permit. A dissatisfied applicant seeking judicial review must do so at common law (see the discussion below at Section 14.9). In other words, the current statutory regime limits access to justice to those seeking to challenge the decision of the Minister to grant an exploration permit (see the discussion below in Section 14.9).

Once the permit is granted, gas companies must comply with all conditions on the Permit and the Petroleum Act, including that they must:

- pay annual fees and royalties;
- conduct all operations in accordance with "good oilfield practice" and the approved technical works programme; and
- cause as little disturbance as practicable to the environment and comply with any directions given by the Minister.¹²⁶

14.7.1.1 Objections to applications

As described above, a person who has an estate or interest in the land the subject of an exploration application, or in land contiguous with that land, may lodge an objection to the granting of the permit, which the gas company can respond to, and which the Minister must take into account when making a decision to grant or to refuse to grant the title.¹²⁷

However, other landholders in the region, communities, experts, and interest groups (such as environmental groups) do not have the ability to object or provide material for the Minister's consideration in making a decision on the application. This limits the Minister's access to information, which can lead to uninformed and inferior decision-making. Allowing access to, and consideration of, a greater range of views and information facilitates better decision-making, including in relation to any conditions to be placed on the title. It also facilitates transparency and accountability and encourages greater faith in the decision-making process. In short, it assists in establishing an SLO. This occurs in NSW, where public comment in relation to applications for coal and petroleum exploration titles (including CSG) is permitted.¹²⁸

For the purposes of transparency and accountability, all objections should be made public.

Recommendation 14.9

That any person may lodge an objection to the proposed grant of an exploration permit.

That the Minister must, in determining whether to grant or refuse the application, take into account the objections received, and that all objections received by the Minister be published.

14.7.1.2 Principles of ESD to be applied

Many submissions to the Panel argued that, given the apparent scientific uncertainty associated with the nature, extent and management of the environmental risks associated with hydraulic fracturing, the regulatory framework should apply the principles of ESD, and in particular, the precautionary principle, to prevent any onshore shale gas activity.¹²⁹ The United Nations defines the precautionary principle as:

"Where there are threats of serious or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost-effective measures to prevent environmental degradation."¹³⁰

126 Petroleum Act, s 58.

127 Petroleum Act, ss 18-20.

128 NSW Public Comment Policy.

129 EDO submission 213, p 10; S Bury submission 189, p 2; M Haswell submission 183, pp 14, 17; PHAA submission 107, p 4; H Bender submission 144, pp 54-55. For example, the EDO submitted that there was enough uncertainty surrounding the environmental impacts of hydraulic fracturing to justify the application of the precautionary principle: "the overwhelming impression that [the EDO] has gleaned from the material is that there is a great deal of uncertainty with respect to the impacts of [hydraulic fracturing]". EDO submission 213, p 10.

130 1992 Rio Declaration, Principle 15.

It is a common misconception that if there is scientific uncertainty about the environmental risks, a particular project or industry should not go ahead. Rather, in order for the precautionary principle to be engaged, two pre-conditions must exist:

- first, that there is a threat of serious or irreversible environmental damage. This threat can be direct or indirect, and threats may be interrelated. Determining whether the threatened damage is serious or irreversible involves considering a number of factors, such as the spatial scale of the threat, the magnitude of possible impacts, the perceived value of the threatened environment and the complexity and connectivity of the possible impacts. However, not every claim of harm will satisfy this criterion, the threat must be adequately substantiated by scientific evidence; and
- second, that there is uncertainty as to the nature and scope of the threat of environmental damage. This uncertainty must likewise be based in scientific method.

The decision-maker applies the precautionary principle by proceeding on the basis that the threat of serious or irreversible damage is not uncertain, but is a reality, and makes a decision taking that 'reality' into account. In this way, preventative measures are undertaken until the reality and the seriousness of the threats become known.

In *Telstra Corporation Ltd v Hornsby Shire Council*, Preston J of the Land and Environment Court gave a full explanation of the ambit of the principle and conditions precedent to its application.¹³¹ The scope of the principle, and its application can be modified by Parliament.

The principles of ESD are defined in the Petroleum Environment Regulations as follows:

*" a) decision-making processes should effectively integrate both long-term and short-term economic, environmental, social and equitable considerations; b) if there are threats of serious or irreversible environmental damage, lack of full scientific certainty should not be used as a reason for postponing measures to prevent environmental degradation; c) the principle of inter-generational equity - that the present generation should ensure that the health, diversity and productivity of the environment is maintained or enhanced for the benefit of future generations; d) the conservation of biological diversity and ecological integrity should be a fundamental consideration in decision-making; and e) improved valuation, pricing and incentive mechanisms should be promoted."*¹³²

One of the objects of the Petroleum Environment Regulations is *"to ensure that regulated activities are carried out in a manner consistent with the principles of ecologically sustainable development"*¹³³ and that the Minister is required to take into account the principles of ESD in making decisions in relation to approval of EMPs. This is insufficient in the Panel's opinion. The precautionary principle, and other principles of ESD, should be integrated into the Petroleum Act and taken into account and applied by decision-makers for all decisions made under that Act.

The EDO and other stakeholders submitted that the current framework does not effectively apply the precautionary principle because:

*"While somewhat beneficial, for the precautionary principle to actually achieve what it is intended to, it must be 'operationalized' in some way. One of the criticisms levelled at the precautionary principle is that it has simply become part of legislative decision-making process, a tick a box, as opposed to a rule that produces a particular outcome. The [Petroleum Environment] Regulations are an example of legislation that makes the precautionary principle one of a number of boxes that must be ticked during decision making. In the case of the Regulations, the Minister must tick the precautionary principle box (by taking into account principles of ESD) before approving an Environmental Plan under r 9(2) of the Regulations. The Regulations fail to meaningfully operationalize the principle."*¹³⁴

One way in which the principles of ESD, including the precautionary principle, can be 'operationalised' within the regulatory framework is by requiring the decision-maker to take the principles into account and to apply them when making decisions under the Petroleum Act and

131 *Telstra Corporation Ltd v Hornsby Shire Council* (2006) 67 NSWLR 256; [2006] NSWLEC 133 at [125]-[186].

132 Petroleum Environment Regulations, cl 4.

133 Petroleum Environment Regulations, cl 2(a).

134 EDO submission 213, p 12; S Bury submission 189, p 2; M Haswell submission 183, p 14.

the Petroleum Environment Regulations. This is particularly important in respect of decisions such as whether or not to grant or refuse an exploration permit, retention licence, or production licence.

Recommendation 14.10

That the Petroleum Act be amended to require the Minister to take into account and apply the principles of ESD.

14.7.1.3 Consideration of a 'fit and proper person' test

A gas company must submit, as part of its application for an exploration permit, evidence of its technical and financial capacity to carry out the proposed works program and to comply with the Petroleum Act. The Minister is required to consider this information as part of his or her consideration of any application.¹³⁵ However, there is no requirement to include information about the gas company's history of regulatory compliance or history of environmental management. This history is relevant to the likelihood of the gas company complying with the Petroleum Act and the works program.

The EDO submitted that these matters should be taken into account by the Minister by the application of a 'fit and proper person' test. It notes that:

*"in its oral submission to the Inquiry, APPEA's Matt Doman, noted, 'there are many companies that don't have any oil or gas expertise or experience that hold petroleum exploration licences'" and that "given the heavy reliance placed on operators to do the right thing in the NT, particularly with an objective based set of regulations, this is a major concern."*¹³⁶

Taking into account whether a gas company is a fit and proper person is not novel in the petroleum industry. In NSW, for example, the relevant Minister may take into account whether a gas operator is a fit and proper person to hold a licence when making a decision in relation to the grant of a petroleum title (including whether or not to grant, transfer, cancel, or restrict operations under a petroleum title).¹³⁷ In determining whether the company or person is a fit and proper person, the Minister may take a number of matters into account, including:

- whether the person, or in the case of a body corporate, a director of the body corporate or of a related body corporate, has compliance or criminal conduct issues;
- the person's, or in the case of a body corporate a director of the body corporate or of a related body corporate, record of compliance with relevant legislation;
- whether, in the opinion of the Minister, the person or director is not of good repute or not of good character; or
- whether the person or director has demonstrated to the Minister the financial capacity to comply with any obligations under the petroleum title.¹³⁸

The EPBC Act provides that in making a decision whether to grant an approval to a person or company, the Minister may have regard to whether the applicant is a "suitable person" having regard to:

(a) the person's history in relation to environmental matters; and

(b) if the person is a body corporate—the history of its executive officers in relation to environmental matters; and

(c) if the person is a body corporate that is a subsidiary of another body or company (the parent body)—the history in relation to environmental matters of the parent body and its executive officers."¹³⁹

¹³⁵ Petroleum Act, s 20(2)(a).

¹³⁶ EDO submission 213, p 37.

¹³⁷ Petroleum (Onshore) Act (NSW), s 24A.

¹³⁸ Petroleum (Onshore) Act (NSW), s 24A(2).

¹³⁹ EPBC Act, s 136(4).

There are also a number of Commonwealth and State schemes that require decision-makers to take into account whether applicants for licences for specialised activities are fit and proper persons to hold the relevant licence.¹⁴⁰ In Victoria, the *Mineral Resources (Sustainable Development) Act 1990* (Vic) requires that, prior to granting an exploration permit with respect to mineral resources, the Minister must be satisfied that the applicant is a fit and proper person to hold an exploration licence.¹⁴¹ This includes, but is not limited to, taking into account whether the applicant or an associate of the applicant has breached that Act in the past, or has been convicted of an offence related to fraud or dishonesty.¹⁴²

The Panel therefore considers it a reasonable measure to require that the Minister determine whether a gas company is a fit and proper person to conduct onshore shale gas activities in the NT.

It should be noted that the matters going towards whether a person or entity is a fit and proper person should not be limited to compliance with legislation related to petroleum, but also include, for instance, compliance with work health and safety or taxation regimes, within Australia or overseas.

Recommendation 14.11

That the Minister must not grant an exploration permit unless satisfied that the gas company is a fit and proper person, taking into account, among other things, the company's environmental history and history of compliance with the Petroleum Act and any other relevant petroleum legislation.

That the Minister's reasons for determining whether or not the gas company is a fit and proper person be published.

14.7.2 Financial assurances

14.7.2.1 Bonds and securities

Financial assurance programs ensure that adequate resources are available to remediate a site in the event that a gas company fails to meet its legal obligations. The purpose of a financial assurance program is that the costs of rehabilitation are not passed on to the Government, and therefore, taxpayers.¹⁴³

A bond or a security is an amount of money that a gas company lodges with the Government to guarantee that certain obligations (usually, in this context, in relation to rehabilitation or remediation) are met. In the event that these obligations are not met, the Government uses the money for these purposes. In the NT gas companies are currently required to provide two securities. The first is a security in the amount of \$10,000 to secure the gas company's compliance with the Act and conditions on the exploration permit under s 79 of the Petroleum Act.¹⁴⁴ However, it is not clear which provisions of the Act or conditions of the exploration permit the \$10,000 is intended to secure.

The second is an "environmental rehabilitation security", that DPIR requires to be lodged "prior to the approval of any regulated petroleum activity" (there is no statutory requirement for this though).¹⁴⁵ As to the method used to calculate the security, DPIR told the Panel that it requires gas companies to fill in a spreadsheet "with detailed questions and calculations to determine actual clean-up cost."¹⁴⁶ The gas company's calculation is subsequently verified, or altered, by DPIR officers, the bond is paid, and the activity proceeds.¹⁴⁷ The amount of the environmental rehabilitation security is not currently publicly disclosed, (although it should be noted that the Government has recently changed its policy with respect to mining securities - not petroleum securities - and these are now publicly disclosed).¹⁴⁸

140 For example, *Ozone Protection and Synthetic Greenhouse Gas Management Act* (Cth), s 16; *Mining Act 1992* (NSW), s 380A; *Protection of the Environment Operations Act 1997* (NSW), s 83.

141 *Mineral Resources (Sustainable Development) Act 1990* (Vic), s 15(6)(a).

142 *Mineral Resources (Sustainable Development) Act 1990* (Vic), s 16(1).

143 STRONGER Guidelines, p 33.

144 DPIR submission 226, p 24 ; Department of Primary Industry and Resources, submission 295 (DPIR submission 295), p 1.

145 DPIR submission 295, p 1; DPIR submission 226, p 30.

146 DPIR submission 295, p 2.

147 DPIR submission 295, p 2.

148 DPIR submission 295, p 2.

Rehabilitation securities for extractive industries have been an issue in a number of Australian jurisdictions, many proving to be inadequate to meet the actual cost of rehabilitation many years later. A recent review of Queensland's financial assurance framework for resource exploration and extraction estimated that it cost Queensland \$73 million over a five-year period due to that State having underestimated the need for rehabilitation.¹⁴⁹ The review cites an example of an insolvent company where the security held was \$3.6 million whereas the estimated rehabilitation cost was \$80 million.¹⁵⁰

In NSW, the Auditor-General undertook a performance audit of mining rehabilitation security deposits required by the Department of Planning and Environment to assess whether that Department had maintained adequate security deposits to cover the liabilities associated with mine closures, including rehabilitation. The 2017 *NSW Auditor-General's Report to Parliament: Mining Rehabilitation Security Deposits* concluded that the securities held were "unlikely to cover the full cost of rehabilitation on each mine site."¹⁵¹ The rehabilitation cost calculation tool the Department had used had a number of deficiencies, including that several activities required to properly effect closure were not included and others had been underestimated, that the costs and allowances in the tool had not been updated since 2013, and that the Department could not provide the basis for the rates and allowances in the tool.

The importance of an appropriate and transparent rehabilitation security or bond was raised many times in submissions and during community consultations.

The Panel therefore recommends that the Government develop a transparent financial assurance framework for the onshore shale gas industry. The framework must be developed in consultation with the community and key stakeholders.¹⁵² The framework must clearly identify the types of onshore shale gas activities that require a financial assurance and clearly set out how each security is calculated.¹⁵³ The quantum of all securities lodged under the Petroleum Act, including the methodology used to calculate the security and the purpose of the security, must be publicly disclosed.¹⁵⁴

Recommendation 14.12

That Government develop a financial assurance framework for the onshore shale gas industry. The framework must:

- ***be transparent and developed in consultation with the community and key stakeholders;***
- ***clarify the activities that require a bond or security to be in place and describe how the amount of the bond or security is calculated; and***
- ***require the public disclosure of all financial assurances and the calculation methodology.***

14.7.2.2 Abandoned well fund levy

The Panel heard many concerns around the long-term management and safety of onshore shale gas wells, particularly in circumstances where the gas company has gone into liquidation or where the rehabilitation security is not sufficient to cover the costs of rehabilitation.¹⁵⁵ In these circumstances, it is the Government that bears the financial cost associated with remediating any decommissioned wells. The Government must ensure that there is adequate funding available so that it can undertake any assessment, plugging, closure or other remedy required.¹⁵⁶ The NLC submitted that any framework regulating an onshore shale gas industry must consider:

"the potential for future environmental impacts caused by abandoned wells and associated infrastructure, where responsibility for them ultimately rests, and how the costs associated with their maintenance will be managed."¹⁵⁷

149 Queensland Financial Assurance Review, p 1.

150 Queensland Financial Assurance Review, p 1.

151 NSW Auditor General 2017, p 3.

152 STRONGER Guidelines, p 67.

153 STRONGER Guidelines, p 34.

154 Vowles, media release, 12 September 2017; DPIR Mining securities.

155 Ms Charmaine Roth, submission 457 (**C Roth submission 457**), pp 7, 10; North Star Pastoral, submission 447 (**North Star submission 447**), p 7; Lock the Gate submission 437, pp 11, 13; Dr Errol Lawson, submission 369 (**E Lawson submission 369**), p 7; United Voice Northern Territory Branch, submission 314 (**United Voice submission 314**), pp 4, 6;

156 STRONGER Guidelines, p 64.

157 NLC submission 214, p 41.

Ms Charmaine Roth observed that,

*"the costs of continuous monitoring of air and groundwater around each and every abandoned well, along with the ongoing repairs and any possible future cleanup, should not be financed from the public purse. Companies that are set to make profits from extensive numbers of wells which have an estimated approximate production life of twenty years' maximum, should not expect the taxpayer to be financing their perpetual care."*¹⁵⁸

The Panel agrees with this position.

The issue is recognised in other jurisdictions where petroleum activities occur, for example, in Texas, USA and Alberta, Canada. Regulators in these jurisdictions impose a levy on operators, which is placed in a fund that pays for the remediation of, and other costs associated with, abandoned sites. For instance, Texas has a program in place to plug wells and clean up abandoned oilfield sites using funds collected from operators as part of their permit applications, statutory fees and bond fees.¹⁵⁹ The regulator publishes quarterly reports on the expenditure and details of the sites that it has remediated and makes these reports available to the public.¹⁶⁰ Similarly, Alberta has an abandoned well fund, the purpose of which is to pay for:

- suspension costs, abandonment costs and related reclamation costs in respect of orphan wells, facilities, facility sites and well sites;
- costs incurred in pursuing reimbursement for the above costs from the person responsible for paying them; and
- any other costs directly related to the operations of the AER in respect of the fund.¹⁶¹

The fund is funded by a levy prescribed by the AER, which is payable annually.¹⁶² The levy is \$15 million CAD for the industry, with each licensee or approval holder paying an amount proportionate to their deemed liabilities as a percentage of the total deemed liability of the industry.¹⁶³ Similarly, in New Zealand operators pay a levy into a fund that can be used to remediate leaks from abandoned wells.¹⁶⁴

Although no fund exists in Australia in relation to the onshore shale gas industry, it does with respect to other extractive industries. In 2013 the NT introduced an annual levy on mining securities to be used to address the rehabilitation of legacy mines. The levy is 1% of the total calculated rehabilitation cost of each operation authorised under the *Mining Management Act 2001* (NT). The cost to business is offset by a 10% discount on the security payable under that Act. WA has a *Mining Rehabilitation Fund*, established in 2012,¹⁶⁵ towards which tenement holders under the *Mining Act 1978* (WA) are required to make annual contributions based on the level and type of disturbance and the amount of rehabilitation required for each tenement.

These funds are important where a jurisdiction has a legacy of abandoned sites with no known owner.¹⁶⁶ The 2014 Hawke Report noted as follows:

*"the possibility that wells may leak and require significant remedial action decades after they are decommissioned presents a significant challenge for government policy and regulation. Even with open-ended liability of operators for abandoned wells, it may be difficult to enforce remediation decades after a well is decommissioned (analogous with the burden that government has often adopted in the remediation of legacy mine sites, in the NT and elsewhere)... This issue may potentially be addressed through some form of common liability or rehabilitation fund, one model for which is the WA Mining Rehabilitation Fund."*¹⁶⁷

158 C Roth submission 457, p 10.

159 Texas Railroad Commission 2016.

160 Reports on site remediation are available at: <http://www.rrc.state.tx.us/oil-gas/environmental-cleanup-programs/oil-gas-regulation-and-cleanup-fund/>.

161 *Oil and Gas Conservation Act* (Alberta), s 70.

162 *Oil and Gas Conservation Act* (Alberta), ss 73-74.

163 AER 2016.

164 Government of Saskatchewan 2017.

165 Under the *Mining Rehabilitation Fund Act 2012* (WA).

166 DPIR submission 424, p 4.

167 2014 Hawke Report, p 132.

As DPIR's predecessor submitted to the 2016 Australian Senate Select Committee on Unconventional Gas Mining, there is a need for the creation of a shale gas well abandonment fund in the NT:

"In many cases, the exploration leases will change hands and so there is some uncertainty about financial responsibility in the unlikely event that one of these "decommissioned" wells were to lose integrity leading to an environmental incident. DME is currently in the very early stages of investigating the possible introduction of an 'Abandoned Wells Legacy Fund'. This fund would build over time and be held by the NT Government. A possible model is one where operators contribute to the Fund in exchange for some reduction of the Environment Rehabilitation Bond. If adopted, the initiative will need to be legislated."¹⁶⁸

The Panel strongly agrees that such a fund should be established and that contributions by gas companies should be mandatory. This levy should not be offset by a reduction in the environmental rehabilitation bond because the two contributions serve different purposes.

Recommendation 14.13

That the government impose a non-refundable levy for the long-term monitoring, management and remediation of abandoned onshore shale gas wells in the NT.

14.7.3 Environmental and operational approvals

The grant of an exploration permit does not, by itself, grant a gas company the right to undertake activities such as drilling or hydraulically fracturing a petroleum well.¹⁶⁹ Other approvals are required, including approvals under the Petroleum Act, environmental approvals under the Petroleum Environment Regulations, and approvals under the Schedule.

DPIR submitted that an overarching 'Petroleum Project Approval' is required before any activity can commence in respect of a granted exploration,¹⁷⁰ but the Panel could not find any legislative basis for this assertion. The concept of an overarching project approval appears in the *Well Drilling, Work-over or Stimulation Application Assessment Process*¹⁷¹ and *Well Drilling, Work-over or Stimulation Activities Applications Guidelines*, but the contents of these documents are not enforceable. Rather, depending on the type of activity proposed, various plans and other materials must be submitted, each of which must be separately approved before an activity can proceed. There is no single overarching statutory project approval.

The process for obtaining environmental and operational approvals is shown in **Figure 14.10**.

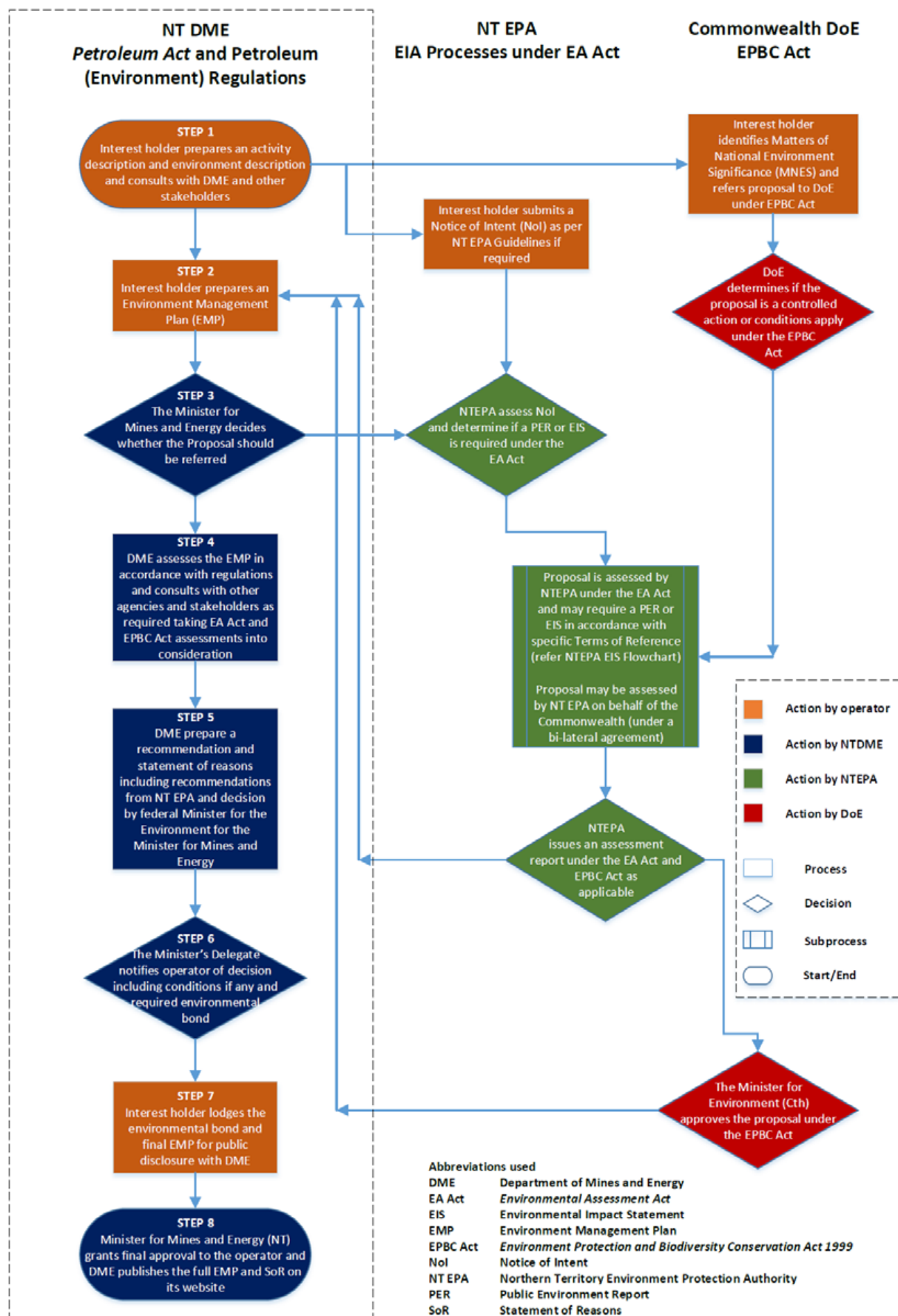
¹⁶⁸ NT DME 2016, pp 8-9.

¹⁶⁹ DPIR submission 226, p 28.

¹⁷⁰ DPIR submission 226, p 28.

¹⁷¹ DPIR submission 226, p 187.

Figure 14.10: The process for obtaining EMP approval and operational approvals for exploration. Source: DPIR



14.7.3.1 Environmental approvals

The Petroleum Environment Regulations establish a framework whereby gas companies are required to proactively avoid environmental risks by putting mitigation measures in place.

With very few exceptions, any activity that will have an adverse environmental impact must be approved by the Minister for Resources. This is the case regardless of how significant, or not, the potential environmental impact of that activity may be (as noted in Section 14.4.2, only activities that will have a “significant” environmental impact are assessed under the EAA). If an activity is undertaken without an approval in place, it will constitute a breach of the Petroleum Environment Regulations and penalties will apply.¹⁷² The only activities that do not require an approval under the Regulations are:

- taking water samples;
- taking rock samples without the use of heavy machinery;
- walking or driving on the permit area to do either of the above activities; and
- airborne surveys.¹⁷³

The Petroleum Environment Regulations expressly provide that drilling, hydraulic fracturing, and the release of any contaminant or waste material must be approved by the Minister before they can take place.¹⁷⁴

If an activity will have an environmental impact and does not fall into one of the exceptions above then an approved EMP must be in place before the activity can commence. The process for getting the approved EMP in place is as follows. First, a gas company must prepare a draft EMP. The draft EMP must contain certain information, including an identification of all of the environmental risks associated with the activity and the ways by which the gas company will reduce those risks to “acceptable” levels.¹⁷⁵

Second, the gas company must consult with all “stakeholders” (see also Section 14.6.1.2). A “stakeholder” is defined in the Petroleum Environment Regulations as any person whose rights or activities may be directly affected by the environmental impacts of the proposed activity or an agent or representative of such a person.¹⁷⁶ The gas company must give information to stakeholders about the activity and the possible risks associated with the activity.¹⁷⁷ The views of all stakeholders, and the gas company’s response to those views, must be included in the draft EMP that is submitted to the Minister for Resources for assessment.¹⁷⁸ Stakeholders are not able to comment on the draft EMP once it has been submitted to the Minister and stakeholders will not see the final EMP until it has approved by the Minister and published online.

The Energy Division in DPIR assesses the draft EMP. DPIR uses an online explanatory guide entitled *Petroleum (Environment) Regulations - An Explanatory Guide 6 July 2016*,¹⁷⁹ an internal guideline, and an internal checklist to assess the draft EMP.¹⁸⁰ None of the guidelines or checklists are legally enforceable, which means that a gas company’s non-compliance with these documents is not lawful grounds for the Minister to refuse to approve a draft EMP. The Minister can only refuse to approve an EMP if the approval criteria set out in the Petroleum Environment Regulations are not met.

If the Minister is satisfied that the approval criteria have been met, then the Minister must approve the EMP.¹⁸¹ The Minister must be satisfied that the implementation of the EMP will reduce all environmental risks and impacts associated with the activity to an “acceptable” level as well as a level that is ALARP. This requirement mirrors petroleum environmental laws in Western Australia¹⁸² and the Commonwealth in relation to offshore waters.¹⁸³

The Minister for Resources determines what an “acceptable” level of risk is. In making that determination, the Minister must consider two matters. First, the Minister must consider the

172 Petroleum Environment Regulations, cl 30.

173 Petroleum Environment Regulations, cl 5.

174 Petroleum Environment Regulations, cl 5.

175 Petroleum Environment Regulations, cl 9 and Sch 1.

176 Petroleum Environment Regulations, cl 7(3).

177 Petroleum Environment Regulations, cl 7(2).

178 Petroleum Environment Regulations, Sch 1, Pt 3.

179 Petroleum Environment Regulations Guide.

180 DPIR submission 226, pp 195-220.

181 Petroleum Environment Regulations, cl 9.

182 *Petroleum and Geothermal Energy Resources (Environment) Regulations 2012* (WA), cl 11(1)(b)-(c).

183 *Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009* (Cth), cl 11(1)(b)-(c).

principles of ESD,¹⁸⁴ including the precautionary principle. Second, the Minister must consider any recommendations from the EPA but only if the EPA has assessed the EMP under the EAA. If no assessment is required under the EAA, then the Minister for Resources is not required to consider the EPA's recommendations concerning the draft EMP. To reiterate, activity will only be formally assessed under the EAA if it will have a "significant" environmental impact, and to date, no exploration petroleum activities have been deemed "significant", and therefore, formally assessed by the EPA under the EAA.

The Minister for Resources can place enforceable conditions on environmental approvals, and those conditions must be complied with notwithstanding anything to the contrary in the EMP.¹⁸⁵ The ability to place enforceable environmental conditions on an environmental approval was considered by Dr Hawke to be an effective way to operationalise the principles ESD.¹⁸⁶ It is also an effective way to ensure that certain minimum standards or requirements are met. For example, it is possible for the Minister to require that a gas company comply with specific codes of practice.

But the requirements of the Petroleum Environment Regulations can be readily circumvented by gas companies. An example of this was Origin's proposal to hydraulically fracture the Amungee-NW-1h well. Origin's draft EMP for that activity was not assessed or approved under the Petroleum Environment Regulations, even though they were in force at the time. There is no statement of reasons for the Minister's decision available online. The Petroleum Act gives the Minister power to give directions on any matter that is dealt with in a regulation.¹⁸⁷ This means that the Minister can lawfully approve an EMP without regard to the Petroleum Environment Regulations.

Origin's draft EMP was assessed by the EPA, which determined that the environmental impacts and risks of the proposed activity were not significant.¹⁸⁸ Nonetheless, a decision to approve a draft EMP by way of a Ministerial direction has the capacity to erode community trust in the assessment and approval process.¹⁸⁹

The Panel's view is that greater transparency must be afforded to the process outlined above. The broader community does not have an opportunity to provide input into draft EMPs. The first time that the public sees an EMP (except those persons that must be consulted because they are "stakeholders" directly affected by the proposed activity)¹⁹⁰ is after the EMP has been approved by the Minister for Resources.¹⁹¹ There is also no opportunity for "stakeholders" to see the version of the draft EMP that a gas company submits to the Minister. Stakeholders also do not know if or how their comments and feedback have been incorporated into the plan. The public and stakeholders only see the approved EMP after the Minister has assessed and approved it.

To increase transparency and accountability, the Panel considers that the community must be given an opportunity to comment on draft EMPs for any onshore shale gas activity. The consultation must be taken into account by the Minister in assessing and approving the EMP.

Recommendation 14.14

That all draft EMPs for hydraulic fracturing must be published and available for public comment prior to Ministerial approval.

That all comments made on draft EMPs be published.

That the Minister must take into account comments received during the public consultation period when assessing a draft EMP.

Once an EMP is approved, it is published together with the Minister's statement of reasons for approving the EMP.¹⁹² The Petroleum Environment Regulations do not specify where or how the approved EMP and the statement of reasons are published. To date DPIR has published the approved plans on the Department's website. The Minister's statement of reasons must explain

184 Petroleum Environment Regulations, cl 9(2).

185 Petroleum Environment Regulations, cl 11(2)(a)(i).

186 2015 Hawke Report, pp xi and 8.

187 Petroleum Act, s 71.

188 Northern Territory Environment Protection Authority, submission 480 (EPA submission 480).

189 EDO submission 456, p 8.

190 Petroleum Environment Regulations, cl 7(3).

191 Petroleum Environment Regulations, cl 24.

192 Petroleum Environment Regulations, cl 24.

how the principles of ESD have been taken into account and how the Minister took into account the EPA's recommendations (if any).¹⁹³ The Minister must also publish all reports provided to the Minister on environmental matters relevant to the EMP.¹⁹⁴ This includes all baseline and monitoring data.¹⁹⁵

While this provides a considerable level of transparency, it can be improved. For example, the Petroleum Environment Regulations require gas companies to give notice to DPIR if a "reportable incident" occurs.¹⁹⁶ A "reportable incident" is an incident arising from an approved activity that causes material or serious environmental harm ("material" and "serious environmental harm" is means harm that is not trivial or negligible). It is not clear whether reports about reportable incidents are required to be publicly disclosed. The Panel's view is that all incident reports must be made publicly available to ensure that the community and other stakeholders "can be assured that there [are] no long term or widespread environmental impacts and so that similar incidents do not occur in the future."¹⁹⁷

Recommendation 14.15

That all notices and reports of environmental incidents, including reports about reportable incidents under the Petroleum Environment Regulations, must be published.

14.7.3.2 Operational approvals

Depending on the type of petroleum activity being proposed, different individual plans must be submitted, assessed, and approved by the Minister for Resources before the activity can commence. If a gas company wants to drill a petroleum well, for example, the company must submit each of the following plans to the Minister and the Minister must assess and approve each plan before that activity can commence:

- an EMP (see Section 14.7.3.1);
- a work program;
- an emergency response plan;
- a spill contingency plan; and
- a system integrity manual.

The requirement for plans listed above (other than the EMP) to be submitted, assessed and approved, is set out in the Schedule.

As stated above, the Schedule is not legislation and does not have force. It is effectively a series of standing directions.¹⁹⁸ When the Minister for Resources issues a permit to a gas company (see Section 14.7.1), the Minister also gives the gas company a direction under the Petroleum Act that the company must comply with the terms of the Schedule. If a gas company does not comply with a provision of the Schedule, the Minister can impose a standard penalty,¹⁹⁹ cancel the permit,²⁰⁰ and if necessary, the Minister can "do all or any of the things required by the [Schedule] to be done".²⁰¹

The Schedule purports to prescribe matters that are usually described as 'operational' and that are usually found in primary and secondary legislation.²⁰² For example, the Schedule regulates seismic surveys and well activities, including drilling programs and hydraulic fracturing. DPIR describes the Schedule as a document that, "includes detailed requirements for the management of seismic survey, drilling, completing and testing of wells including hydraulic fracturing. It also sets out requirements for the reporting of incidents, daily reporting requirements and data collection and transfer".²⁰³

193 Petroleum Environment Regulations, cl 12(3).

194 Petroleum Environment Regulations, cl 25.

195 Petroleum Environment Regulations, cl 25.

196 Petroleum Environment Regulations, cl 33(1); DPIR submission 226, pp 245-249

197 NLC submission 214, p 11.

198 Petroleum Act, s 71.

199 Petroleum Act, s 71(3).

200 Petroleum Act, s 74(1)(c).

201 Petroleum Act, s 72(1).

202 2012 Hunter Report, p 30.

203 DPIR submission 226, p 11.

In other Australian jurisdictions, these activities are regulated by legislation.²⁰⁴ See, for example, WA's *Petroleum and Geothermal Energy Resources (Resource and Management Administration) Regulations 2015* and the Commonwealth's *Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011* (which regulate seismic surveys and well activities in onshore WA and offshore respectively).

The Schedule requires specific petroleum activities to be approved prior to commencement. Activities that require approval include hydraulic fracturing,²⁰⁵ drilling²⁰⁶ and seismic surveys.²⁰⁷ The requirements of the Schedule for drilling and hydraulic fracturing are set out in Chapter 5. There are other petroleum activities that do not require a Ministerial approval but which must conform to the requirements of the Schedule. For example, the abandonment of a well does not require an approval from the Minister, but the Schedule requires that a cement plug be placed in the well in zones 100 metres above and 50 metres below any petroleum or water.²⁰⁸ It is not clear to the Panel why these requirements are in place and whether or not they reflect leading practice standards.

The use of the Schedule to regulate drilling activities and hydraulic fracturing is problematic. The Schedule has not been drafted in accordance with legislative drafting principles. It uses industry jargon, which is not always defined and which creates issues of enforceability. The Schedule is not always clear about the information that must be submitted to the Minister for the purposes of obtaining an approval, the timeframe within which the Minister must make a decision, or the matters the Minister must consider when making a decision (for example, approved spill contingency plans must be complied with, but there is no process set out for what must be included in a plan or how the plan is approved). The Schedule also duplicates provisions in work health and safety legislation and other legislation.²⁰⁹ The Schedule purports to provide powers to inspectors, however, this cannot be effected by Ministerial direction, which is how the Schedule is enforced. The Schedule offers the community no certainty that industry will comply with leading practice standards when it undertakes petroleum activities. And DPIR relies on guidelines, which are unenforceable, to fill in the gaps where the Schedule is deficient.

DPIR noted the limitations of the Schedule in its submission to the Panel, namely, that "*the Schedule, which is rule-based, is intensive on regulators and proponents and lacks the flexibility to regulate the technologically complex and evolving petroleum industry.*"²¹⁰

DPIR intends to replace the Schedule with resource management and administration regulations of the kind in WA and for Commonwealth offshore waters,²¹¹ however, this has not yet occurred. The Schedule must be repealed and replaced with enforceable and objective-based resource management and administration regulations as soon as possible. The regulations must be supported by enforceable codes of conduct that clarify exactly what is expected of the industry.²¹²

Recommendation 14.16

That the Schedule be repealed and replaced with legislation to regulate seismic surveys, drilling, hydraulic fracturing, and well abandonment prior to the grant of any production licence for the purpose of any onshore shale gas development.

14.7.4 Minimum standards and codes of practice

The NT is moving away from prescriptive regulation towards "*risk-based*" and "*outcome-focused governance*".²¹³ The latter is generally regarded as a more effective and efficient method of regulation that encourages innovation, flexibility and leading practice.²¹⁴ However, the corollary to the flexibility afforded by risk-based, outcome-focussed regulation is a lack of clarity and

204 See, for example, Pt 2 of the *Petroleum and Geothermal Energy Resources (Resource and Management Administration) Regulations 2015* (WA), which regulates seismic surveys and Pt 3 manages well activities; Pt 6 of the *Petroleum and Geothermal Energy Regulations 2013* (SA) regulates "*operational issues*", including geophysical surveys (Div 1) and drilling (Div 2).

205 Schedule, cl 342(1).

206 Schedule, cl 301(1).

207 Schedule, cl 503(1).

208 Schedule, cl 329(1).

209 See, for example, cls 201(4) and 501.

210 DPIR submission, p 38.

211 DPIR submission 226, p 12; DPIR submission 492, p 6.

212 2012 Hunter Report, pp 6, 31.

213 DPIR submission 226, p 38.

214 2016 Hunter Report, p 4.

certainty about how a particular activity should be regulated. For example, as discussed in Section 14.7.3.1, the Petroleum Environment Regulations require a gas company to demonstrate that it will reduce environmental risks and impacts to levels that are “acceptable” and ALARP, but the meaning of these terms is equivocal. Similar concerns exist in relation to with the term “good oilfield practice”, which appears in the Petroleum Act. Gas companies must, “conduct all operations in relation to the exploration permit...with reasonable diligence, in particular in accordance with good oilfield practice; and the approved technical works programme.”²¹⁵

The term “good oilfield practice” has been criticised in the NT for being “broad, vague and, given the vast variation in oilfield practices around the world lacks any type of certainty and would be difficult to enforce.”²¹⁶ The nebulousness of the term was found to have contributed to the regulatory failure under investigation in the Montara Commission of Inquiry:

“the current regulatory regime has effectively eliminated all levels of prescription in relation to well integrity, defaulting to an undefined standard of ‘good oilfield practice’. This has left regulators with an ambiguous standard to rely on when assessing applications submitted by operators. The Inquiry considers that this ambiguity is likely to have contributed to very basic requirements of well integrity being overlooked by both PTTEPAA and the NT DoR. This suggests that the pendulum may have swung too far away from prescriptive standards.”²¹⁷

In that Inquiry, it was recommended that the requirement of “good oilfield practice” be supplemented by the inclusion of minimum compliance standards.²¹⁸ The EDO supports the proposition that a level of prescription should form part of the regulatory framework to ensure that all stakeholders understand exactly what is required. The EDO submitted that in the NT, a combination of both objective and prescriptive regulation is appropriate. It stated that prescriptive standards:

- create certainty and a clear standard of behaviour that must be met;
- are easier to apply consistently; and
- are easier to enforce.²¹⁹

Without some level of prescription, it is difficult to know how the Minister will interpret terms like “acceptable”, “as low as reasonably practicable” and “good oilfield practice”. This is particularly important where an industry is new, like any onshore shale gas industry in the NT. As the EDO noted:

“having prescriptive requirements alongside objective requirements actually helps to provide clarity of expectations for operators. But, more importantly, it provides for greater ease of use by regulators in the Northern Territory. For example, compulsory design specifications for well integrity will allow all operators, regardless of their sophistication, to know exactly what is required of them. By contrast, objective based requirements provide a far less certain level of direction and are far more complicated to assess and enforce.”²²⁰

The success of an objective-based regulatory framework relies on a level of sophistication and diligence in an operator that is not always present. The Australian Expert Panel on Environmental Law (APEEL) in a recent review of environmental laws in Australia opined that a risk-based, outcomes-focussed approach could provide a sufficiently rigorous regulatory regime provided that it is “rigorous, efficient, transparent and well managed.” The APEEL was nevertheless “sceptical about the likelihood of these conditions being met in practice”²²¹ concluding that:

“there is a serious danger that risk-based regulation can become a process of negotiated regulatory outcomes in which the outcomes specified may be compromised or arbitrary and their accomplishment is neither monitored nor guaranteed.”²²²

215 Petroleum Act, s 58(b).

216 EDO submission 213, p 8.

217 Report of the Montara Commission of Inquiry, p 32.

218 Report of the Montara Commission of Inquiry, p 151.

219 EDO submission 213, p 16.

220 EDO submission 213, p 16.

221 APEEL Technical Paper 1, p 41.

222 APEEL Technical Paper 1, p 41.

Codes of practice are used in many jurisdictions to provide regulatory clarity. For example, in NSW the relevant Minister may impose conditions on petroleum titles that require the title holder to comply with any Codes of Practice or standards.²²³ There are a number of codes and standards that apply to the unconventional gas industry in that State. In relation to well casings, the *Code of Practice for Coal Seam Gas Well Integrity*²²⁴ provides the following requirement, directed towards the objective of a well casing withstanding stress:

*"Casing, casing connections, wellheads, and valves used in a CSG well must be designed to withstand the loads and pressures that may act on them throughout the entire well life cycle. This includes casing running and cementing, any treatment pressures, production pressures, any potential corrosive conditions, and other factors pertinent to local experience and operational conditions."*²²⁵

The following issues were raised in submissions as matters that should be prescriptively regulated in the NT:

- baseline testing and monitoring by an independent third party required prior to the proposed activity;²²⁶
- the design and construction of wells in a very specific way to ensure long-term well integrity;²²⁷
- methane emissions not exceeding a certain limits;²²⁸
- the prohibition of the use of BTEX chemicals;²²⁹ and
- the disclosure of all chemicals used in hydraulic fracturing.²³⁰

The Panel has made recommendations elsewhere on these matters in this Report and notes that the development of appropriate codes of practice will be an appropriate way of enforcing these requirements. Industry appears generally supportive of implementing a mix of prescriptive and minimum standards. For example, Santos stated that it:

*"would be supportive of legislative or regulatory amendment to enable best practice well construction and decommissioning. This may include the Code of Practice for Constructing and Abandoning Petroleum and Associated Bores in Queensland or Guidance and Specifications provided by American Petroleum Institute."*²³¹

Recommendation 14.17

That the Government develop and implement enforceable codes of practice with minimum, prescriptive, standards and requirements to give clarity to the regulatory framework.

223 Petroleum Act, Sch 1B, cl 6(2)(c).

224 Available at <http://www.resourcesandenergy.nsw.gov.au/_data/assets/pdf_file/0006/516174/Code-of-Practice-for-Coal-Seam-Gas-Well-Integrity.PDF>.

225 NSW Well Integrity Code, 4.2.2(a).

226 EDO submission 213, p 18; H Bender submission 144, p 3; Lock the Gate submission 171, pp 68, 72; ECNT submission 188, p 2; S Bury submission 189, p 3; C Roth submission 191, p 25; AFANT submission 190, p 8; Ms Helen Bender (H Bender submission 144, p 3) proposed 5-10 years minimum; Dr Scott Wilson suggested baseline studies should be conducted "over several seasons to account for natural weather, climatic and lifecycle fluctuations/perturbations" (EDO submission 213, p 19); and Ms Charmaine Roth (C Roth submission 191, p 25) proposed that seven years of baseline monitoring should be undertaken.

227 For example, the NLC proposed that petroleum wells should be constructed with multiple (that is, a minimum of five) layers of casing cemented in place: NLC submission 214, p 42.

228 Lock the Gate submission, p 73.

229 H Bender submission 144, p 59. The Panel notes that cl 342(3) of the Schedule prohibits the addition of BTEX compounds to hydraulic fracturing fluids.

230 EDO submission 213, p 28; M Haswell submission 183, p 14; Frack Free Darwin, submission 141 (FFD submission 141), p 11; Ms Juliet Saltmarsh, submission 165 (J Saltmarsh submission 165), p 2; Lock the Gate submission 171, p 71; H Bender submission 144, p 59.

231 Santos submission 168, p 104.

14.8 Production

14.8.1 Application for and granting of a production licence

The holder of an exploration permit or a retention licence may apply for a production licence in relation to the whole or part of his or her exploration permit or licence area.²³² Applications for production licences must include (among other things):

- a technical works program specifying the proposals for exploration, appraisal and production of petroleum within the proposed licence area;
- evidence of the technical and financial capacity of the gas company to carry out the technical works program and its ability to comply with the Petroleum Act;
- measures to protect the environment, including measures to be undertaken by the gas company for the rehabilitation of the licence area or other affected areas;
- the prescribed application fee; and
- any other information in support of the application as the gas company thinks fit.²³³

Unlike applications for exploration permits, where the Minister has the discretion to grant or to refuse to grant the permit, when a production licence is applied for and the gas company has complied with the exploration permit conditions, any directions given to the holder by the Minister, its obligations under the Petroleum Act, and has discovered a commercially exploitable amount of shale gas within the exploration permit area the Minister must grant the production licence, subject to any conditions the Minister sees fit.²³⁴

However, the Minister does have discretion in circumstances where:

- a production licence is applied for;
- the gas company has not complied with the exploration permit or retention licence conditions under which the exploration permit or retention licence was granted, or a direction given by the Minister; and
- the Minister is otherwise satisfied that circumstances exist that justify the granting of the production licence.

Production licences are also subject to various conditions, including that:

- the production licensee must use the licence area continuously and exclusively for the purposes for which it is granted;
- the production licensee must not produce gas obtained from the licence area until the Minister authorises the commencement of production operations;
- the production licensee must pay royalties under the Petroleum Act on petroleum produced;
- the production licensee must maintain an approved insurance policy for well redrilling and well recompletion expenses and for damages arising out of damage to property or the environment, including by pollution, seepage or contamination; and
- any such conditions as the Minister thinks fit and specifies in the licence document.²³⁵

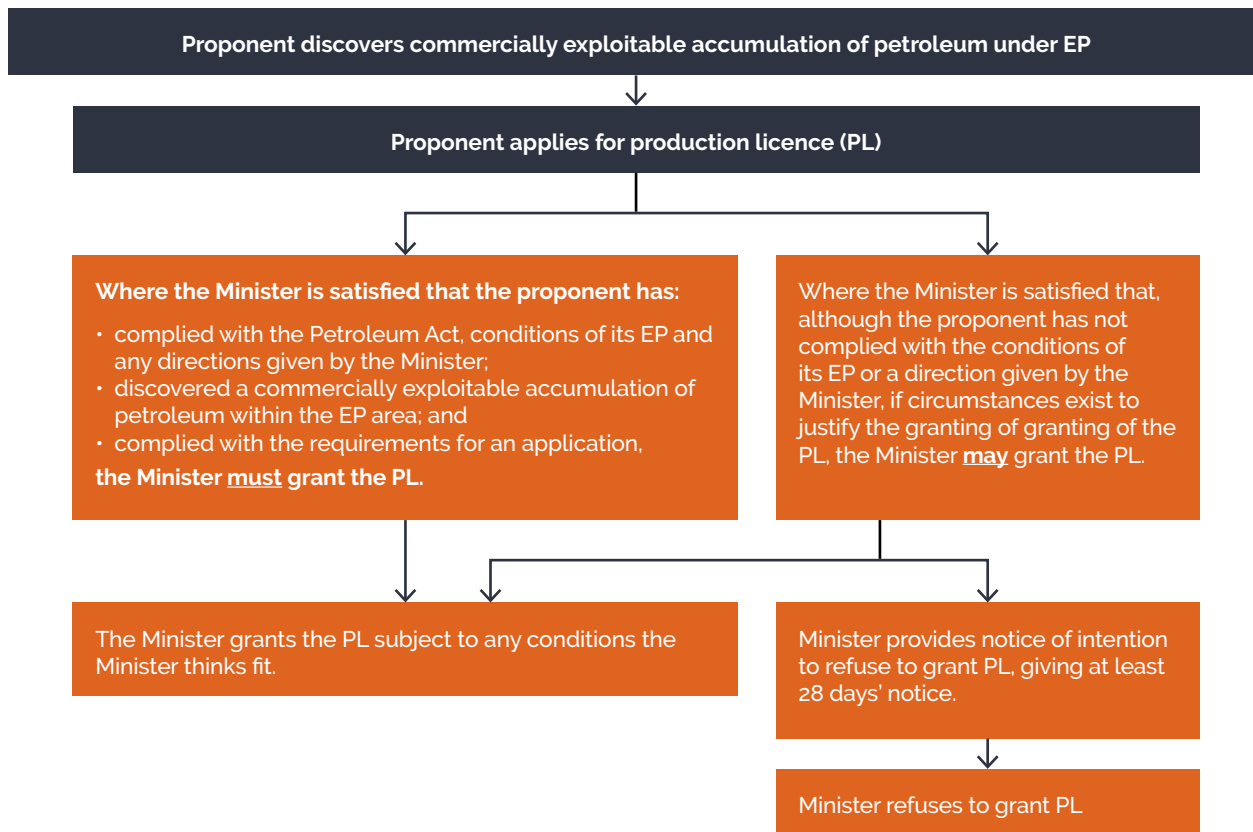
²³² Petroleum Act, s 44.

²³³ Petroleum Act, s 45.

²³⁴ Petroleum Act, ss 47, 54.

²³⁵ Petroleum Act, s 54.

Figure 14.11: Process of obtaining a production licence under the Petroleum Act



Many of the reforms proposed above with respect to exploration have direct application to the production phase of any onshore shale gas industry.

For example, it may be the case that between the granting of the exploration permit and the consideration of an application for a production licence, an event happens or information is obtained that calls into question the gas company's status as a fit and proper person (discussed at Section 14.7.1.3 above) to hold a production licence. The Panel considers that the fitness and propriety of a gas company is an equally relevant consideration at the production stage as it is at the exploration stage and something that the Minister must be satisfied of prior to any grant of a production licence.

Recommendation 14.18

That the Minister must be satisfied that a gas company is a fit and proper person to hold a production licence prior to the licence being granted.

14.8.2 Cumulative impacts and area or regional-based assessment

The current regulatory model in the NT typically occurs on a well-by-well, well-pad-by-well-pad, or project-by-project basis, and looks at individual actions at individual sites. This approach impedes consideration of the cumulative and regional effects of multiple drilling, production and transport activities on the environment, especially with respect to water and land use. As the discussion earlier in this Report notes (see Chapters 5 and 8), development of any onshore shale gas industry will involve considerable activity to build the necessary infrastructure, drill wells, extract the resources, process it and transport it to market. The cumulative and regional impact of these activities, especially with respect to their impact on water, land and air, demands an appropriate regulatory response. This is one of the international principles formulated by the International Energy Agency in its report *Golden Rules for a Golden Age of Gas*.²³⁶

Play-based, or regional or area-based assessments have the capacity to examine the cumulative impacts of development across a region or area. It allows for the assessment of broad scale environmental impacts that would not necessarily be encompassed in the scope of an individual project assessment.

236 IEA 2012, p 47, cited in Senate Select Committee on Unconventional Gas Mining, p 41.

In the context of any development of shale gas reserves in the NT, the desirability of regional or area-based assessment is particularly strong because, relative to conventional gas, there is a greater scale of development, use of water, and infrastructure required to extract and produce shale gas. Accordingly, the only way to adequately manage the cumulative effects of any onshore shale gas development is at the regional, and not the local, scale.²³⁷ Various jurisdictions employ regional, area or play-based assessment. In Canada, both Alberta and British Columbia (considered to have leading unconventional gas governance), have either developed, or have trialled, 'play-based' or 'area-based' assessment for unconventional oil and gas resource development.

In Alberta, under the AER, area-based regulation for unconventional gas plays underwent a pilot in 2016. Area-based regulation in Alberta is targeted at both the subsurface petroleum play and the surface impacts of any potential development of the play. It is premised upon three main components: integrated area assessment of both the subsurface and the surface of an area or play; collaborative engagement, which seeks to enhance local participation; and area practices and requirements, where the first and second components are brought together to establish practices and requirements for how energy development is to be undertaken in the defined area. Combined, the objective is orderly and responsible development that includes an understanding of any development on a landscape scale to better identify and mitigate potential risks to public safety, the environment, and the resource. The aim is to reduce cumulative effects, encourage oil and gas company collaboration, develop play-specific requirements, enhance public participation and disclosure, and develop single application and decision-making process.

An area-based regulatory approach was tested in a pilot in northwest Alberta in 2016. The location was an area with a considerable amount of ongoing energy development and where stakeholders in the area had expressed concerns about water use. A study into the pilot revealed mixed results, principally because applications received were for three- to five-year developments, which was much shorter than the pilot intended, and therefore, many of the envisaged longer-term benefits of the pilot did not materialise. Further shortcomings included insufficient understanding of the detail of the pilot, insufficient collaboration among the oil and gas companies and insufficient reduction in cumulative impacts. The most notable achievement was the development of an integrated single application and single decision-making approval process. The pilot resulted in 23 recommendations that the AER is working to assess and implement.

In British Columbia, the BC Oil and Gas Commission (**BCOGC**) engages in area-based analysis in order to manage the environmental and cultural impacts of oil and gas development in the north-east part of that province. Area-based analysis (**ABA**) is a framework for managing the impacts of oil and gas development:

*"It is a different and more effective way of characterizing landscape of unconventional gas basins to inform decisions on oil and gas applications. The Commission uses ABA to address the long term effects of oil and gas activity in its decision-making. Various decisions involving roads, water, seismic activity, well and facility locations and pipeline corridors cause cumulative effects to both environmental and social values. Considering effects on only a project – or sector- specific basis can allow unintended impacts to accumulate over time. ... This approach allows the Commission to manage industry activity comprehensively to protect ecological, social and cultural heritage values. The actions that will be assessed are the combined footprint impact of industrial development on the selected values...broad impacts can be considered when looking at specific application of activities, rather than just the localized effects of one permit."*²³⁸

In applying an ABA approach to unconventional gas activities, the BCOGC considers if a proposed petroleum activity has impacts upon area-based values such as groundwater, air quality, water quality and high priority wildlife. The goal is to avoid disturbance to these values, or if disturbance is necessary, to minimise its impact.

Regional planning as a measure to regulate risk management and address cumulative impacts was also recognised by Nova Scotia in the *Report of the Nova Scotia Independent Panel on*

²³⁷ Council of Canadian Academies 2014, section 9.5.

²³⁸ BC Oil and Gas Commission 2017b.

Hydraulic Fracturing,²³⁹ although the report observed that “it is important to note that regional planning is not a substitute for specific decisions about specific proposals, and that community participation in regional planning does not oust public involvement at other decision-making stages.”²⁴⁰ The Panel endorses this view.

The concept, while somewhat novel in Australia, is not wholly without precedent. For example, and albeit restricted to groundwater, in Queensland, under the *Water Act 2000* (Qld), a cumulative management area (**CMA**) can be declared in an area that contains two or more resource tenures (including gas, petroleum and mining) where there may be cumulative impacts on groundwater resulting from water extraction by the tenure holders. Declaring a CMA enables assessment of future impacts using a regional modelling approach and the development of management responses, such as monitoring programs. The rights of bore owners within a CMA are not affected by a declaration. Once declared, however, the management of groundwater is coordinated by OGIA, an independent statutory body, which produces an Underground Water Impact Report that includes a prediction of impacts on water levels, a water monitoring program and an assignment of responsibilities to individual resource tenure holders to undertake water management activities in the area. A CMA has been declared for the Surat Basin after consideration of the location of the petroleum and gas (including unconventional and conventional gas) operations, the geology of the area, the potential for interconnectivity between aquifers in the area and the cumulative impacts of water extraction by petroleum tenure holders.

At the Commonwealth level, strategic assessments can occur under Pt 10 of the EPBC Act to deal with cumulative impacts on MNES or nationally protected matters, such as a water resource in relation to CSG developments or large coal mining developments. Strategic assessments permit a much broader range of actions to be considered and address impacts at the landscape level. A strategic assessment is a collaborative assessment process between the Commonwealth Government and appropriate resource companies, and State and Territory Governments and agencies, and Aboriginal Land Councils. Examples of strategic assessments include offshore petroleum activities in the NT and SA coastal waters.

ACOLA has stated that, “the concept of risk-based and play-based regulation proposed by Alberta could be applicable to the Australian regulatory framework for shale gas and warrants further consideration”.²⁴¹

The benefits of strategic, area or regional-based assessment and regulation include:²⁴²

- improved public acceptance through proactive industry planning and consultation with the community;
- collaborative planning between industry partners and with and between regulatory agencies;
- collaboration on use and siting of new and existing infrastructure, including roads and pipelines, to minimise land disturbance;
- improved regulatory efficiency by avoiding duplications in regulatory process;
- improved economic gains due to infrastructure and regulatory efficiencies;
- better data collection;
- better information disclosure, and therefore, better transparency and accountability;
- efficiencies in compliance and enforcement;
- improved longer-term regulatory certainty; and
- encouragement of technical innovation and adoption of best practice and the use of the best available technology to mitigate impacts.

Disadvantages include:

- more planning and cost expenditure at an early stage;
- the need for greater stakeholder participation and collaboration; and
- the need for a significant reform of the existing regulatory regime.

239 Wheeler et al. 2014, pp 272-273.

240 Wheeler et al. 2014, p 273.

241 ACOLA Report, pp 27, 172; EDO submission 213.

242 Council of Canadian Academies 2014, p 206; ACOLA Report, p 172.

Notwithstanding these challenges, the Panel nevertheless considers that area-based assessment and regulation of any onshore shale gas development in the NT is required to identify and manage the cumulative impacts of any shale gas industry.

In Chapter 15, the Panel recommends that a SREBA be undertaken prior to the grant of any production licence for the purposes of any onshore shale gas development. In addition to this requirement, the regulatory framework must require the Minister to take the results of the SREBA into account when deciding whether or not an activity should proceed.

Recommendation 14.19

That, as part of the environmental assessment and approval process, the Minister be required to consider the cumulative impacts of any proposed onshore shale gas activity.

Recommendation 14.20

That the Government consider developing and implementing a regional or area-based assessment in the regulation of any onshore shale gas industry in the NT.

14.9 Challenging decisions

To improve decision-making and to maintain accountability and integrity in any onshore shale gas industry, review and appeal processes must exist to enable those directly and indirectly affected by a decision to challenge that decision (for example, the granting of an exploration permit).

14.9.1 Standing

In order to challenge a decision, a person or entity must have the 'standing' to do so. A person or entity with standing is usually taken to mean a person or entity whose 'interests' have been adversely affected by a decision. Generally, under the common law, interests are taken to mean financial or proprietary.²⁴³ Mere intellectual or emotional concern is not sufficient,²⁴⁴ however a cultural interest may suffice.²⁴⁵

A gas company will therefore have standing to seek judicial review of an adverse decision in relation to their own application (for example, a decision to refuse an application, approval or licence). A landholder on whose land unconventional gas activities are proposed will also have standing. The status of third parties such as environmental groups, nearby landholders, or community groups, is less clear under common law. However, standing can also be provided by legislation. The broader the standing provisions, the more accessible review processes are.

Many environmental statutes have 'third party standing', which means that a much larger class of people, as set out in the legislation, can bring an action challenging a decision. For example, the EPBC Act provides "*extended standing*" to:

- an Australian citizen or resident; or
- an organisation incorporated or otherwise established in Australia, with its objects or purposes including protection or conservation of, or research into, the environment;

if, at any time in the two years immediately before the decision the individual or organisation has engaged in a series of activities in Australia or an external Territory for protection or conservation of, or research into, the environment.²⁴⁶

'Open standing' is a type of standing provided by legislation that permits anyone to bring an action in relation to a decision irrespective of whether or not he or she is directly or indirectly affected by the decision. Open standing (or at the very least, broad categories of standing) is central to the proper administration of justice. The greater the access to justice by the public, the more accountable, transparent and improved decision-making is. Access to justice is an aspect of the rule of law and is, on any view, a necessary component of an SLO.²⁴⁷

Costs sanctions against the unsuccessful party usually prevent vexatious claims being brought in

²⁴³ See *Australian Conservation Foundation v Commonwealth* (1980) 146 CLR 493.

²⁴⁴ See *Australian Conservation Foundation v Commonwealth* (1980) 146 CLR 493.

²⁴⁵ See *Onus v Alcoa of Australia Ltd* (1981) 149 CLR 27.

²⁴⁶ EPBC Act, s 487.

²⁴⁷ Pepper 2017.

jurisdictions that have open or extended standing, and there is no evidence to suggest that more cases are brought in legal systems that entertain broader standing provisions than in those that have more restrictive standing provisions.²⁴⁸

Recommendation 14.21

That the Petroleum Act and Petroleum Environment Regulations be amended to allow open standing to challenge administrative decisions made under these enactments.

14.9.2 Types of review

There are generally two types of review that allow a person or entity to challenge an administrative decision: judicial review and merits review. In any mature and robust regulatory system, both forms of review will exist.

14.9.2.1 Judicial review

Broadly speaking, judicial review proceedings are those where the court determines whether the decision made by the original decision-maker was lawfully made. Judicial review is not concerned with examining whether the decision made was the preferable decision. It is concerned with the lawfulness of the process by which a decision was made.²⁴⁹

The Petroleum Act makes no provision for judicial review for decisions made under it,²⁵⁰ and unlike other Australian jurisdictions, the NT does not have a statutory judicial review framework. This means that any rights of judicial review in relation to decisions made under the Petroleum Act or Petroleum Environment Regulations are based in common law.

However, judicial review serves a purpose that is broader than the individual decision or matter. It (and other forms of independent review) *“safeguards the practice of decisions being made in accordance with the rule of law, contributes to quality in decision-making, ensures decision-makers are accountable in an open forum, develops environmental jurisprudence, and highlights problems and issues to be the subject of reform.”*²⁵¹

The Panel therefore repeats **Recommendation 14.21** with respect to standing.

14.9.2.2 Merits review

Merits review allows a person or entity to challenge the merits of, or reasons for, a decision. This type of proceeding is often made to an administrative tribunal or other type of review panel where the merits reviewer becomes the decision-maker (for example, NTCAT).

A form of merits review is provided for under the Petroleum Act to gas companies that are dissatisfied with a decision not to grant an exploration permit, production licence or retention licence, or to grant any of those approvals subject to conditions.²⁵² However, the review is conducted internally by a panel appointed by the Minister, which then provides a recommendation to the Minister, which the Minister may elect to accept or not.²⁵³

The Petroleum Environment Regulations allow the proponent to apply to NTCAT for merits review of the following decisions:

- the approval of an EMP subject to conditions;
- the refusal to approve an EMP;
- the revision of an EMP; and
- the revocation of an approval of an EMP.²⁵⁴

However, the current regulatory framework does not provide for merits review of decisions for any third parties.

248 Pepper 2017.

249 See, for example, in relation to the Carmichael Coal Mine and Rail Project, *Australian Conservation Foundation Incorporated v Minister for the Environment* [2016] FCA 104 at [4].

250 The Panel notes s 57M in Pt IIA of the Petroleum Act, which contains a provision that provides for judicial review of some petroleum activities affecting native title rights and interests however it is not yet operational.

251 APEEL Technical Paper 8, p 20.

252 Petroleum Act, s 57AB.

253 Petroleum Act, ss 57AC-57AE.

254 Petroleum Environment Regulations, cl 29, Sch 2.

The Panel considers that merits review should be available to third parties to challenge decisions made in relation to any onshore shale gas development.

Merits review fosters better decision-making. The Commonwealth Administrative Review Council (**ARC**) considers that *"the central purpose of the system of merits review is improving agencies' decision-making generally by correcting errors and modelling good administrative practice"*²⁵⁵ and that *"merits review ensures that the openness and accountability of decisions made by government are enhanced"*.²⁵⁶ Merits review facilitates transparency by providing a forum where all the facts and issues relevant to a particular decision can be tested. This transparency results in better decision-making because a decision-maker who knows that his or her decision may be subject to a public review on the merits will take particular care to ensure that it is defensible. Improved decision-making and transparency means that the public and other stakeholders will have more faith in the decision-maker and the decisions made. This is crucial for any regulator of any onshore shale gas in the NT and will encourage the establishment of an SLO.

Many submissions argued in favour of the inclusion of merits review, particularly 'third party' merits review, in legislation governing any onshore unconventional shale gas industry.²⁵⁷ The EDO submitted that such rights should be included in all legislation that has as one of its objectives the protection of the environment.²⁵⁸

DENR has acknowledged the importance of access to justice, and has committed to including avenues for review of decisions in respect of environmental assessment and approvals, including to *"limited third parties"*, such as members of environmental or industry groups, Land Councils and local government bodies, or people who have made a genuine submission during the assessment and approval process.²⁵⁹

The ARC considers that, as a matter of principle, an administrative decision that will, or is likely to, affect the interests of a person should, in the absence of good reason to the contrary, be subject to merits review, and that a broad approach should be taken in identifying decisions as being suitable for merits review.²⁶⁰

Recommendation 14.22

That merits review be available in relation to decisions under the Petroleum Act and Petroleum Environment Regulations including, but not limited to, decisions in relation to the granting of exploration permits and approval of EMPs.

That the following third parties, at a minimum, have standing to seek merits review:

- ***proponents (that is, gas companies) who are seeking a permit, approval, application, licence or permission to engage in onshore shale gas activity;***
- ***persons who are directly or indirectly affected by the decision;***
- ***members of an organised environmental, community or industry group;***
- ***Aboriginal Land Councils;***
- ***local government bodies; and***
- ***persons who have made a genuine and valid objection during any assessment or approval process.***

That an independent body, such as NTCAT, be given jurisdiction to hear merits review proceedings in relation to any onshore shale gas industry.

14.9.3 Costs

A significant barrier to challenging administrative decisions, particularly for third party litigants, is the cost. This includes not only the costs of solicitors, barristers, and experts, but also the prospect of paying the costs of the other party (usually a government agency or a corporation) if they are unsuccessful.

255 Administrative Review Council 2007, p 11.

256 Administrative Review Council 1999, para 1.5.

257 For example, North Star submission 447, pp 4-5; Lock the Gate submission 437, p 11; EDO submission 213, p 15.

258 EDO submission 213, p 15.

259 DENR Discussion Paper, pp 6, 20.

260 Administrative Review Council 1999, paras 2.1, 2.4.

The general rule in litigation is that 'costs follow the event', which means that the losing party must pay the winning party's legal costs. This is the case in the NT Supreme Court, although the Court does have discretion to depart from that principle.

In some jurisdictions, environmental litigation that has been genuinely brought 'in the public interest' and where there is no disentitling conduct, does not attract a costs sanction in the event of a loss. That is to say, even if the party bringing the action loses, each party will bear their own costs. For example, the Land and Environment Court of NSW can decide, if it is satisfied the proceedings have been brought in the public interest:

- not to make an order for the payment of costs against an unsuccessful applicant;
- not to make an order requiring the applicant to provide security for the respondent's costs; or
- not to make an order requiring the applicant to give any undertakings as to damages.²⁶¹

However, this discretion is not lightly exercised. In order for the Court to exercise its discretion, three things must be addressed. First, that the litigation is properly characterised as having been brought in the public interest. Second, there must be 'something more' than the mere characterisation. And third, there must be consideration of whether there are any countervailing circumstances that would prevent the proceedings being characterised as having been brought in the public interest.²⁶²

Another measure to mitigate against the inhibiting effect of an adverse costs order is protective costs orders, where a party may seek to have the amount of costs that it may be liable for capped at a fixed amount. An applicant to the Federal Court of Australia can apply for a protective costs order, which caps the amount the losing party must pay to the successful party for the costs of the matter.²⁶³ This has recently been utilised in public interest environmental litigation in the NT in relation to the construction of the controversial Port Melville on the Tiwi Islands.²⁶⁴

The Panel notes in this context that NTCAT is a 'no costs' jurisdiction, meaning that the default rule is that parties pay their own costs.²⁶⁵

Recommendation 14.23

Where litigation is brought genuinely in the public interest, that costs rules be amended to allow NT courts to not make an order for the payment of costs against an unsuccessful public interest litigant.

14.10 Compliance and enforcement

There is little utility in adopting even the best regulatory framework if it is not complied with.²⁶⁶ The Panel heard from both the community and other stakeholders that they have little confidence in the regulator's capacity or willingness to enforce compliance with the present regulatory framework. This lack of faith stems, in large part, from previous experience with extractive industries in the NT where it is perceived that inadequate action on the part of the regulator has occurred. A frequently cited example of poor regulation of extractive industries by the Government is the ongoing and unaddressed pollution from the McArthur River Mine.²⁶⁷

Many submissions raised the findings of the Montara Inquiry. That Inquiry found that the relationship between the regulator and the proponent in that matter "*had become far too comfortable*" and that a factor leading to the poor standards was the "*minimalist approach to regulatory oversight*" by the regulator.²⁶⁸

DPIR has taken a number of measures to address the criticisms made by the Montara Inquiry, which are relevantly discussed below.

²⁶¹ *Land and Environment Court Rules 2007* (NSW), r 4.2.

²⁶² See *Caroona Coal Action Group Inc v Coal Mines Australia Pty Ltd* (2010) 173 LGERA 280.

²⁶³ *Federal Court Rules 2011* (Cth), r 40.51.

²⁶⁴ *The Environment Centre Northern Territory Incorporated v Minister for the Environment (Commonwealth)* NTD3/2016, Order dated 13 April 2016; ABC News 2016.

²⁶⁵ *Northern Territory Civil and Administrative Tribunal Act 2014* (NT), s 131.

²⁶⁶ Productivity Commission 2013, p 103.

²⁶⁷ Raised, for example, at community consultations in Borroloola.

²⁶⁸ Mr Roger Heapy, submission 448 (**R Heapy submission 448**), Att 2; Lock the Gate submission 171, p 62; Report of the Montara Commission of Inquiry, p 16.

14.10.1 Compliance and monitoring

Monitoring of compliance is an important part of any regulatory scheme. It allows for the gathering of information and promotes a culture of compliance.

Inspections should be undertaken frequently and randomly. However, in a jurisdiction as large and sparsely populated as the NT, inspections can be highly resource and time intensive.

It is for this reason that regulatory fees must be appropriately set to accommodate for these factors (see the discussion above at Section 14.4.5).

14.10.1.1 The need for a detailed and transparent compliance policy

Under the Petroleum Act, Petroleum Environment Regulations and Schedule, gas companies must self-report in relation to a range of incidents. For example, as is noted above at Section 14.7.3.1, the Petroleum Environment Regulations require gas companies to notify the Minister of the occurrence of a 'reportable incident' and provide a comprehensive report of the incident.²⁶⁹

The Schedule also requires the gas company to report a number of matters to the regulator, including:

- death or serious injury;²⁷⁰
- serious damage other than environmental harm;²⁷¹
- a potentially hazardous event;²⁷²
- damage resulting in loss of structural integrity;²⁷³
- emergencies;²⁷⁴ and
- failure to achieve casing cementing requirements.²⁷⁵

As raised in the report of the Montara Inquiry, a regulator cannot rely on self-regulation (including reporting) by industry, it *"needs to actively probe and inquire; it should not be passive; the regulator needs to ask questions of the owner/operator; it should keep owner/operators up to the mark to ensure that the requirements of the [management plan] are in fact met; and the regulator needs to also make sure that the [management plan] itself is adequate - reflecting good oilfield practice- in the first place."*

DPIR noted that *"during the life of the project, compliance measures in place include mandatory self-reporting, inspections and audits"*²⁷⁶ and provided the Panel with a number of checklists to be used by inspectors in conducting site inspections. However, it is not clear how often these inspections occur, what auditing activities take place, or whether there is an overarching strategy informing compliance monitoring activities. This is imperative for appropriate risk management, particularly in relation to an objective-based regulatory framework.

The importance of a sophisticated compliance monitoring program has been recognised by the Australian National Audit Office (ANAO), which published the *Administering Regulation: Achieving the right balance* guide in 2014, which provides guidance to regulators on how to efficiently and effectively administer regulation. The goal is to maintain a balance between community protection while not imposing unnecessary costs on business or the broader community.

It notes that *"a systematic, risk-based program of compliance review activities provides a regulator with a cost-effective approach to monitoring compliance, enables available resources to be targeted to higher priority regulatory risks and to respond proactively to changing and emerging risks."*²⁷⁷

What is essential is the development and implementation of a compliance monitoring and enforcement strategy.²⁷⁸

The Panel notes that the *"Compliance and Enforcement Policy"* referred to by DPIR, while a good overview of general compliance and enforcement principles, does not set out how these principles will be followed, nor does it articulate specific activities to be undertaken with regard

269 Petroleum Environment Regulations, cls 33-35.

270 Schedule, cl 284.

271 Schedule, cl 286.

272 Schedule, cl 287.

273 Schedule, cl 288.

274 Schedule, cl 290.

275 Schedule, cl 307.

276 DPIR submission 226, p 33.

277 ANAO 2014, p 41.

278 ANAO 2014, pp 41-52.

to the regulator's powers under the Petroleum Act. By way of contrast, the SA regulator has a lengthy and detailed compliance and enforcement policy, setting out expectations on gas companies, enforcement tools available to the regulator, and enforcement policies for classes of non-compliance. The policy provides transparency and certainty for both industry and the broader community.

Recommendation 14.24

That the Government develop and implement a robust and transparent compliance monitoring strategy, having regard to the principles set out in the ANAO Administering Regulation: Achieving the right balance guide, and the policy in SA.

14.10.1.2 Whistleblowers

Valuable information in relation to compliance can also be brought to the attention of regulators through industry associates, locals on the ground, and whistleblowers.

Some submissions alleged a culture of deliberate non-reporting of compliance incidents by Origin in relation to its Queensland CSG facilities.²⁷⁹

Whistleblowing is not without risk for those who expose wrongdoing,²⁸⁰ and protections must exist or the capacity to allow the whistleblower to remain anonymous must be provided for.

Recommendation 14.25

That the Government enact whistleblower protections.

That a hotline be established to make anonymous reports about any onshore shale gas industry non-compliance and that such reports be investigated.

14.10.1.3 Tiered approach

SA has adopted a targeted approach to inspections and other monitoring activities. This is achieved by a two-tier approach classifying various regulated unconventional gas activities as either 'high level official surveillance' or 'low level official surveillance'. In SA it is a mandatory condition of petroleum titles to divide regulated activities to be carried out under the licence into activities requiring high level official surveillance and those requiring low level official surveillance. All activities are initially classified as requiring high level official surveillance, unless the licensee satisfies the Minister that, in view of the licensee's demonstrated competence to comply with statutory requirements and the conditions of its licence, the activities should be classified as requiring low level official surveillance.²⁸¹ The SA Department of Premier and Cabinet (the agency with the responsibility for regulating the onshore unconventional gas industry in that State) has characterised the main difference between high and low surveillance activities as *"the extent of regulatory scrutiny given by the regulator in the activity assessment and approval process and the surveillance level required whilst monitoring the activities as they are undertaken by the licensees"*²⁸² and that:

*"operators who achieve low-level official surveillance classification have extensive experience operating in the relevant region and have demonstrated their capability to continually perform in a manner which achieves the requirements of the relevant approved SEO and other regulatory requirements."*²⁸³

The Minister's prior written approval is required for activities requiring high level official surveillance.²⁸⁴ The Minister may, by written notice to a licensee, change the classification of activities under the relevant licence conditions.²⁸⁵

279 For example, Lock the Gate submission 171, p 70; Mr Joseph Costelloe, submission 85.

280 Ferguson 2017.

281 *Petroleum and Geothermal Energy Act 2000 (SA)*, s 74(2); *Petroleum and Geothermal Energy Regulations 2013 (SA)*, cl 16-17.

282 SA 2016 Compliance Report, p 18.

283 SA 2016 Compliance Report, p 19.

284 *Petroleum and Geothermal Energy Act 2000 (SA)*, s 74(3); the *Petroleum and Geothermal Energy Regulations 2013 (SA)*, cl 18-20.

285 *Petroleum and Geothermal Energy Act 2000 (SA)*, s 74(4); the *Petroleum and Geothermal Energy Regulations 2013 (SA)*, cl 21.

Significantly, if regulated activities are classified as requiring a low level of surveillance, the annual licence fee is reduced and the administrative burden is reduced.²⁸⁶ This acts as a powerful incentive on gas companies to comply with the regulatory framework. It also has the advantage of efficiently allocating regulatory resources towards the more problematic and less compliant gas companies. In a jurisdiction as large and remote as the NT, such a model is attractive.

Recommendation 14.26

That the Government consider developing and implementing a tiered regulatory model such as the one in SA, whereby gas companies with a demonstrated record of good governance and compliance require a lower level of monitoring, with a corresponding reduction in regulatory fees.

14.10.2 Enforcement

Without enforcement, conditions placed on titles and approvals are ineffective.²⁸⁷ Many submissions expressed concern about the ability or willingness of the regulator to take enforcement action in relation to non-compliance by petroleum and other extractive industry companies. The EDO noted that the NT has an: “*appalling environmental assessment regime, poor track record of cowboy operators and ad hoc and lax enforcement of environmental laws.*”²⁸⁸

Obligations imposed on gas companies must be clear and enforceable to encourage compliance. As discussed above, especially in respect of the Schedule, this is not necessarily the case in the NT. Furthermore, a robust regulatory framework should provide a range of enforcement powers and mechanisms to enable the regulator to take action that is proportionate to the risk posed by any non-compliance.²⁸⁹

The Panel is of the view that the range of enforcement measures available to the regulator under the Petroleum Act and Petroleum Environment Regulations is inadequate. Collectively, they provide for offences and infringement notices but not much more.

A modern regulatory system should provide a range of tools (sanctions) to the regulator to encourage flexibility in responding to instances of non-compliance. In NSW, for example, remediation directions are provided for. The Minister may require a person who is, or has been, the holder of a petroleum title to take steps necessary to give effect to any condition on the title relating to protection or rehabilitation of the environment.²⁹⁰ Failure to comply with such a direction is punishable by a maximum penalty of \$220,000 for an individual or \$1,100,000 for a body corporate. If the person does not comply, the Minister may cause the rehabilitation (or protection) of the environment to be carried out. Any expenses incurred in doing so are a debt payable by the gas company to the State.²⁹¹

In 2014 the Commonwealth enacted the *Regulatory Powers (Standard Provisions) Act 2014* (Cth) (**RP Act**), which contains a framework of standard regulatory powers to be adopted by Commonwealth regulators. NOPSEMA has implemented the framework. The RP Act provides for civil penalties,²⁹² infringement notices,²⁹³ enforceable undertakings,²⁹⁴ and injunctions.²⁹⁵ The availability of these responses means that a regulator, such as NOPSEMA, is able to take punitive action where, for example, the transgression does not support the expense and burden of evidence of criminal proceedings.

In order to provide the regulator with sufficient flexibility required to efficiently regulate any onshore shale gas industry, the Panel is of the view that the compliance and enforcement powers in the Petroleum Act and Petroleum Environment Regulations should be enhanced to afford a greater range of sanctions at its disposal.

²⁸⁶ *Petroleum and Geothermal Energy Act 2000* (SA), s 74(5).

²⁸⁷ Productivity Commission 2013, p 103.

²⁸⁸ EDO submission 213, p 5.

²⁸⁹ ANAO 2014, p 51.

²⁹⁰ *Petroleum (Onshore) Act 1991* (NSW), s 77.

²⁹¹ *Petroleum (Onshore) Act 1991* (NSW), s 78.

²⁹² *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 4.

²⁹³ *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 5.

²⁹⁴ *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 6.

²⁹⁵ *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 7.

Recommendation 14.27

That the Government enact a broader range of powers to sanction, including but not limited to:

- *remediation orders;*
- *enforceable undertakings;*
- *injunctions; and*
- *civil penalties.*

14.10.2.1 Civil enforcement

The Australian Law Reform Commission has observed that:

*"Political, bureaucratic and financial constraints mean the Attorney-General and other government plaintiffs cannot adequately represent the public interest in all matters. There is an important role to be played by private plaintiffs in the maintenance of the rule of law through the review of government decisions and the enforcement of statutory rights and obligations."*²⁹⁶

In some jurisdictions, such as NSW, members of the public can apply to a court to remedy or restrain breaches of environmental legislation in order to enforce environmental protections.²⁹⁷ These actions are called 'civil enforcement' proceedings.

The *Protection of the Environment Operations Act 1997* (NSW) provides that any person may bring proceedings in the Land and Environment Court of NSW for an order to:

- remedy or restrain a breach of that Act or its regulations,²⁹⁸ or
- restrain a breach of any other Act if the breach is causing or is likely to cause harm to the environment.²⁹⁹

The EPBC Act provides that the relevant Minister or an "*interested person*"³⁰⁰ may apply to the Federal Court of Australia for an injunction in relation to conduct amounting to a breach of that Act or its regulations.³⁰¹ The Court may, if it considers it appropriate to do so, make an order requiring the person engaging in the conduct amounting to a breach to carry out an act to remedy or stop the breach (including repairing or mitigating damage to the environment).³⁰²

Concern that these proceedings will 'open the floodgates' to unmeritorious actions are unfounded, costs being a significant barrier.

The existence of civil enforcement provisions provides legitimacy in any regulatory regime by empowering members of the community to take effective action in the event of potential or actual breach of environmental legislation. This assists in establishing an SLO.

Recommendation 14.28

That the Government allow civil enforcement proceedings to be instituted to enforce potential or actual non-compliance with the legislation governing any onshore shale gas industry.

14.10.2.2 Reversal of the onus of proof

A common concern of participants at consultations was the unreasonable burden of proving environmental harm believed to be caused by a gas company's activities.³⁰³ This is because the onus of proof generally falls on the complainant. Discharging this onus is expensive, usually requiring expert evidence. Pennsylvania has dealt with this issue by implementing a rebuttable presumption that a well operator is responsible for the pollution of a water supply that is within 1000 feet of the oil or gas well, where the pollution occurred within six months after the completion or drilling or alteration of the well.³⁰⁴ Reversing this presumption can be done by proving:

296 ALRC 1996, para 4.15.

297 Preston 2011, p 72.

298 *Protection of the Environment Operations Act 1997* (NSW), s 252.

299 *Protection of the Environment Operations Act 1997* (NSW), s 253.

300 An "*interested person*" is defined in s 475 of the EPBC Act.

301 EPBC Act, s 475.

302 EPBC Act, s 475.

303 See, for example, North Star submission 453, p 5; Lock the Gate submission 437, p 10.

304 *Oil and Gas Act 2012*, s 208 (58 Pa Cons Stat Sec. 601.208); *Unconventional Gas Regulations 2016*, cl 51 (25 Pa. Code §78a.51).

- the pollution existed prior to the drilling or alteration activity as determined by a pre-drilling or pre-alteration survey;
- the landowner or water purveyor refused to allow the operator access to conduct a pre-drilling or pre-alteration survey;
- the water supply is not within 1,000 feet of the well;
- the pollution occurred more than six months after completion of drilling or alteration activities; or
- the pollution occurred as the result of some cause other than the drilling or alteration activity.³⁰⁵

In order to use these defences, the gas company must retain the services of an independent certified laboratory to conduct the pre-drilling or pre-alteration survey of water supplies. A copy of the results of must relevantly be submitted to the regulator and the landowner.³⁰⁶

A similar legislative provision exists in Illinois. It requires an operator who has conducted high volume hydraulic fracturing operations within 1,500 feet of a polluted or diminished water source to:

"affirmatively prove by clear and convincing evidence any of the following: the water source is not within 1,500 ft of the well site; the pollution or diminution occurred prior to high volume horizontal hydraulic fracturing operations or more than 30 months after the completion of the high volume horizontal hydraulic fracturing operations; or the pollution or diminution occurred as the result of an identifiable cause other than the high volume horizontal hydraulic fracturing operations."³⁰⁷

One important advantage of reversing the onus of proof, or enacting a rebuttable presumption of harm, is that it acts as a powerful incentive for gas companies to obtain adequate baseline studies prior to commencing any exploration or production activity on the land.

Reversing the onus of proof was supported by many submissions to the Panel.³⁰⁸ For example, the EDO noted that, *"oil and gas industry representatives have expressed a high level of confidence in their processes and ability to manage the potential impacts of their industry on water resources. Given that, the EDO expects that Industry would support our recommendation for legislation to include a rebuttable presumption that gas operators are liable for water pollution."³⁰⁹*

Recommendation 14.29

That the Government consider enacting provisions that reverse the onus of proof or create rebuttable presumptions for pollution and environmental harm offences for all regulated onshore shale gas activities.

14.10.2.3 Criminal penalties should be increased

Where sanctions consist of other pecuniary penalties, the penalty must be sufficiently high to deter non-compliance, rather than the cost of doing business.³¹⁰ This is an aspect of the principles of ESD and the polluter-pays principle. The *Guide to Framing Commonwealth Offences* notes that:³¹¹

"A maximum penalty should aim to provide an effective deterrent to the commission of the offence, and should reflect the seriousness of the offence within the relevant legislative scheme. A higher maximum penalty will be justified where there are strong incentives to commit the offence, or where the consequences of the commission of the offence are particularly dangerous or damaging."

305 *Oil and Gas Act 2012*, s 208 (58 Pa Cons Stat Sec. 601.208).

306 *Oil and Gas Act 2012*, s 208 (58 Pa Cons Stat Sec. 601.208); Unconventional Gas Regulations 2016, cl 52 (25 Pa. Code §78a.52).

307 *Illinois Hydraulic Fracturing Regulatory Act*, s 1-85.

308 North Star submission 447, p 5; Lock the Gate submission 437, p 10; EDO submission 213.

309 EDO submission 213, p 24.

310 See, for example, Judicial Commission of NSW 2014: *Guide to Framing Commonwealth Offences*, p 37.

311 *Guide to Framing Commonwealth Offences*, p 38.

The penalties provided for in the Petroleum Act and Petroleum Environment Regulations are, in the Panel's opinion, too low, having regard to both the potential consequences of non-compliance and the commercial incentives for non-compliance.

The most serious environmental offence in the Petroleum Act carries a maximum penalty of \$592,900 or five years imprisonment for an individual, or \$2,962,960 for a body corporate.³¹² These are inadequate because, first, the offence requires knowledge by the offender that serious or material environmental harm might result.³¹³ Second, in the context of any shale gas development, the maximum penalty arguably is not likely to be a real deterrent. For example, Santos notes that in the two years from 2013 to 2014, its expenditure on exploration and development in SA was \$779 million.³¹⁴

By way of comparison, the maximum penalty for an equivalent offence under the *Protection of the Environment Operations Act 1997* (NSW) is \$5,000,000 for a body corporate, or \$1,000,000 and/or seven years imprisonment for an individual.³¹⁵

Most penalties for offences under the Petroleum Act and Petroleum Environment Regulations are significantly smaller than the maximum penalty above. For example, the maximum penalty for non-compliance with the Petroleum Act is \$15,400 for an individual and \$77,000 for a body corporate.³¹⁶ In NSW, the maximum penalty for non-compliance with a condition of a petroleum title is \$220,000 for an individual and \$1,100,000 for a body corporate.³¹⁷ In SA, the penalty for breach of a licence condition is \$120,000.³¹⁸

Under the Petroleum Environment Regulations non-compliance with an EMP carries a maximum penalty of \$30,800. By way of contrast, in Queensland non-compliance with an environmental authority in relation to activities under a petroleum title carries a maximum penalty of \$567,675.³¹⁹

Recommendation 14.30

That penalties for environmental harm under the Petroleum Act and Petroleum Environment Regulations be reviewed and increased in line with leading practice.

14.11 Water approvals

As explained in Chapter 7, hydraulic fracturing is a water intensive activity. The amount of water that is used in hydraulic fracturing must be regulated to ensure that there is sufficient water left for other users and the environment, particularly in areas where the water resource or the recharge rate is low. In Chapter 7, the Panel recommended that the Water Act be amended to require gas companies to obtain and pay for water extraction licences under that Act. This will ensure that Government can accurately model and manage the basin-wide impacts of any shale gas industry on water resources.

The Panel notes that the Government has committed to applying the Water Act to petroleum activities, and the Panel agrees that this should be done (see **Recommendation 7.1**).³²⁰ It is important to note that the Water Act deals with activities other than water extraction. For example, the Water Act requires a person to have an approval to interfere with waterways, construction dams, recharge an aquifer, pollute and to drill a bore. While the Panel supports the need for water extraction to be regulated by a single regulator, care must be taken to ensure that the application of the Water Act to petroleum activities will not duplicate assessments and approvals that are required under other legislation, including petroleum and environment legislation.

14.12 Towards a new regulatory model

14.12.1 The need for a new regulatory model

Petroleum projects have a tendency to be large and complex. From the community's perspective it is essential that, at the very least, if such projects are permitted, they must satisfy reasonable

312 Petroleum Act, s 117AAC.

313 Intentionally releasing contaminant or waste material.

314 Santos submission 168, p 119.

315 *Protection of the Environment Operations Act 1997* (NSW), s 119.

316 Petroleum Act, s 106.

317 *Petroleum (Onshore) Act 1991* (NSW), s 125E.

318 *Petroleum and Geothermal Energy Act 2000* (SA), s 77.

319 *Environmental Protection Act 1994* (Qld), ss 430 and 437.

320 DENR submission 230, p 7; see also NT Parliament 2016, p 145.

requirements aimed at protecting the environment, protecting human health and safety, and ensuring fairness with respect to land access. But it is also important to achieve these objectives without imposing unnecessary regulatory burden and costs and allowing any industry to operate efficiently.

Principles of good governance include clarity of purpose and function, well designed rules that are efficient and effective, accountability and transparency, trust and independence, consistent and fair processes and practices, appropriate institutional frameworks, appropriate resourcing of regulatory bodies and appropriately skilled regulatory bodies.³²¹ The Chief Scientist and Engineer of NSW described the key characteristics for an effective single regulator as including:³²²

- independence;
- scientific and engineering competence and expertise across a range of relevant disciplines such as water and geology;
- access to comprehensive and up-to-date data, including the capacity to draw upon information and advice from other government agencies;
- transparency in all processes; and
- full funding from industry levies.

However, as the detailed discussion above concerning the current regulatory regime governing any onshore shale gas industry in the NT demonstrates, it is very complex, giving rise to an opacity in decision-making processes, creating unnecessary regulatory burdens, engendering deep distrust in the community and generally being perceived as being inadequate to achieve the reasonable requirements referred to above.

14.12.1.1 Independence

The effectiveness of any regulatory framework is premised on an independent, competent and well-resourced regulator to enforce compliance with the regime.³²³ The need for an independent regulator was raised in many submissions.³²⁴ The Panel noted the widely and strongly held view in the community that DPIR is not independent from industry. Some submissions noted that there was a strong risk of regulatory capture.³²⁵ The CLC recommended that there be "*external independent scrutiny over DME regulation...to allay concern over a perceived lack of independence*".³²⁶

The Panel's main concern with the current regulatory framework is that the Minister for Resources and DPIR have responsibility for both the promotion and the regulation of industry. On one hand, the Petroleum Act sets up a framework for the promotion of exploration and production activities and the collection of royalties,³²⁷ and on the other hand, the Act seeks to ensure that petroleum development occurs in a way that reduces the risk "*so far as is reasonable and practicable, of harm to the environment during activities associated with exploration of or production of petroleum*".³²⁸ It is not difficult to comprehend how perceptions of regulatory capture arise in a jurisdiction where the promotional and regulatory functions are consolidated into a single decision-maker.

Therefore, to ensure that environmental decisions are being made independently from the promotion of any onshore shale gas industry, the Panel proposes that the regulation of the industry be the responsibility of an entity that does not also have responsibility for promoting the industry.³²⁹

Recommendation 14.31

That in order to ensure independence and accountability, there must be a clear separation between the agency with responsibility for regulating any onshore shale gas industry and the agency responsible for promoting that industry.

³²¹ Finkel et al. 2017, pp 342-343; Productivity Commission 2013, Ch 4; Productivity Commission 2009, Chs 3-4 and 9-10, in particular.

³²² NSW Report, section 6.2.4, p 45.

³²³ J McDonald submission 182, p 6; M Haswell submission 183, p 18; H Bender submission 144.

³²⁴ For example, NTCA submission 32, p 9; Regional Development Australia, submission 110 (RDA submission 110), p 1; CLC submission 47, Appendix B of Attachment, p 1; J Saltmarsh submission, p 2.

³²⁵ S Bury submission 189, p 4; NARMCO submission 186, p 10.

³²⁶ CLC submission 47, Appendix B of Attachment, p 1.

³²⁷ Petroleum Act, ss 3(2)(d), 84(1); DPIR and DENR submission 492, Attachment A, p 25.

³²⁸ Petroleum Act, s 3(2)(f).

³²⁹ EDO submission 213, p 6.

14.12.1.2 Transparency and accountability

Transparent decision-making by an accountable regulator is the cornerstone of a trusted and efficient regulatory regime.³³⁰ If the community has visibility of and, where appropriate, is able to participate in the decision-making process that leads to the development of any onshore shale gas industry, it is more likely that the community will support the decisions that are made and that the industry will earn an SLO.

The Petroleum Environment Regulations were an important first step in improving the transparency and accountability of the decision-maker. As discussed in Section 14.7.3.1, the regulations require the Minister for Resources to consider the views of stakeholders when deciding whether or not to approve or refuse an EMP. They also make the Minister accountable to the community by requiring the Minister to publish reasons why the EMP was approved and how the principles of ESD, or any recommendations from the EPA, were taken into account. The regulations require all approved EMPs to be made publicly available. The Panel has made recommendations about how those regulations can be further strengthened to increase transparency, including that draft EMPs for hydraulic fracturing be made available for public input prior to approval. This is consistent with the approach being adopted by the Commonwealth in respect of offshore waters.

But the Panel has identified areas of the regulatory framework where there is minimal transparency and accountability. For example, many of the matters assessed and approved under the Schedule are not approved in accordance with any clear criteria. There is no opportunity for community input. No statements of reasons are required. The approved plans are kept confidential. In short, the community cannot be confident that plans assessed and approved under the Schedule are consistent with leading practice.

14.12.1.3 Resourcing

If the Government lifts the moratorium and determines to strengthen the regulatory regime in the manner recommended in this Report, more resources will be needed to design, implement and enforce the new regulatory framework (see the discussion above in Section 14.4.5). Inadequate resourcing and concomitant lack of expertise due to an inability to attract and retain qualified personnel in regulatory agencies can lead to inefficiencies and inadequate regulatory decisions.³³¹

As some of the submissions noted, there are difficulties associated with regulating an industry whose activities occur in remote locations. Dr Liz Moore observed that *"the extreme remoteness of many sites and the dispersed nature of unconventional fracking"* will create a real risk that that regulatory framework *"would not be adhered to at all times"*.³³² The EDO also noted that, *"the Northern Territory is... a difficult place to run compliance operations. Much of the Northern Territory is effectively cut off during the wet season and, even during the dry the vast scale of the Territory make it impossible to keep close checks on operators"*.³³³

14.12.2 Options for reform of the regulator

In his report in 2015, Dr Allan Hawke AC proposed three options for reform:

- retain the current system with incremental changes;
- create a single environmental approval with the Minister for the Environment as the decision-maker; and
- a sectoral 'one-stop-shop' model of various project approvals under separate legislation brought together under a primary sectoral approval through a lead agency or department.³³⁴

In considering Dr Hawke AC's suggestions, the Panel has developed two options for how the regulatory framework can be structured to protect the environment, increase community confidence in the regulatory system, and to ensure that decisions about the environmental impacts of any onshore shale gas development are made independently.

330 See generally, Productivity Commission 2009.

331 Productivity Commission 2009, p 279.

332 Dr Liz Moore, submission 179 (L Moore submission 197), p 2; see also J McDonald submission 182, p 6.

333 EDO submission 213, p 36.

334 2015 Hawke Report, Ch 3.

In both Option 1 and 2, it is proposed that the executive (that is, a Minister) remains the accountable decision-maker. This approach is consistent with Australia's Westminster system. It is an important accountability mechanism. In short, if the public does not approve of Ministerial decisions with respect to any onshore shale gas industry, its disapproval may be exercised at an electoral level. Having said this, it must be acknowledged that research indicates that regulatory frameworks that separate the regulator from the executive arm of government do not necessarily guarantee better decisions.³³⁵ It is also important to note that the independence of Ministerial decisions can be strengthened by requiring Ministers to consider and respond in a transparent way to the advice of statutorily independent entities whenever they exercise their statutory powers. Both Option 1 and 2 adopt this principle.

In developing Options 1 and, in particular, Option 2, the Panel has examined the 'lead agency approach' adopted in the NT, SA and WA. Under a lead agency approach, approval of most, if not all, aspects of an application to carry out onshore unconventional petroleum activities rest with one designated agency. The agency coordinates all necessary approvals and information regarding those approvals. It maintains control of the application and assessment process of those approvals and consults with other relevant agencies, rather than formally referring an application to a separate agency for assessment. The lead agency approach is advantageous insofar as it is able to efficiently mobilise resources, streamline approval processes, and minimise delay. However, this approach can be deficient in that it is readily amenable to regulatory capture by industry and may be perceived as lacking in independence and being infected with a pro-development bias at the expense of decision-making in the public interest,³³⁶ particularly where the lead agency is the same agency that releases land for petroleum activities. Although these issues may be mitigated by clearly defining legislative responsibilities and having transparent regulatory processes that promote accountability, and while SA appears to have avoided these criticisms, given the sustained community anxiety expressed to the Panel about the deficiencies of the current governance framework in the NT, especially with respect to DPIR, it is unlikely that the adoption of a model where the regulator performs both a promotional role and a governance and enforcement role is appropriate in the NT context.

Both Option 1 and 2 assume the adoption by the Government of each of the recommendations made in this Chapter, including that:

- decision-making about water extraction remains with the Water Controller (see Section 14.11);
- area-based regulation is used for the assessment of all necessary onshore shale gas approvals (see Section 14.8.2);
- there is mandatory consultation between the relevant government agencies, including AAPA, and the Weeds, Land Resources and Water divisions of DENR;
- all plans, reports, comments and decisions must be published; and
- the regulator must be appropriately funded by industry by the establishment and implementation of a full cost recovery system (see Section 14.4.5).

14.12.2.1 Option 1

The first option takes into account and aligns closely with the Government's *"existing environmental reform process"*³³⁷ (described below) and proposes that all petroleum activities must have a separate environmental approval under uniform environmental legislation that is administered by an entity other than DPIR. Option 1 proposes that DPIR will continue to administer the Petroleum Act, which would cover all non-environmental matters associated with development of any onshore shale gas industry, including title administration, assessment and approval of technical work programs, collection and management of information, and resource management (royalties will continue to be administered by the Department of Treasury and Finance). This option ensures a clear demarcation between decisions about the promotion of the industry and development of the shale gas resource on the one hand, and decisions about protection of the environment on the other. Option 1 is also consistent with Dr Hunter's view that environmental management should be the responsibility of an entity other than the person responsible for resource management.³³⁸

335 Coglianese 2015, pp 42, 100-101.

336 NZ Report 2014, p 67.

337 Item 5 of the Inquiry's Terms of Reference.

338 2012 Hunter Report, p 35.

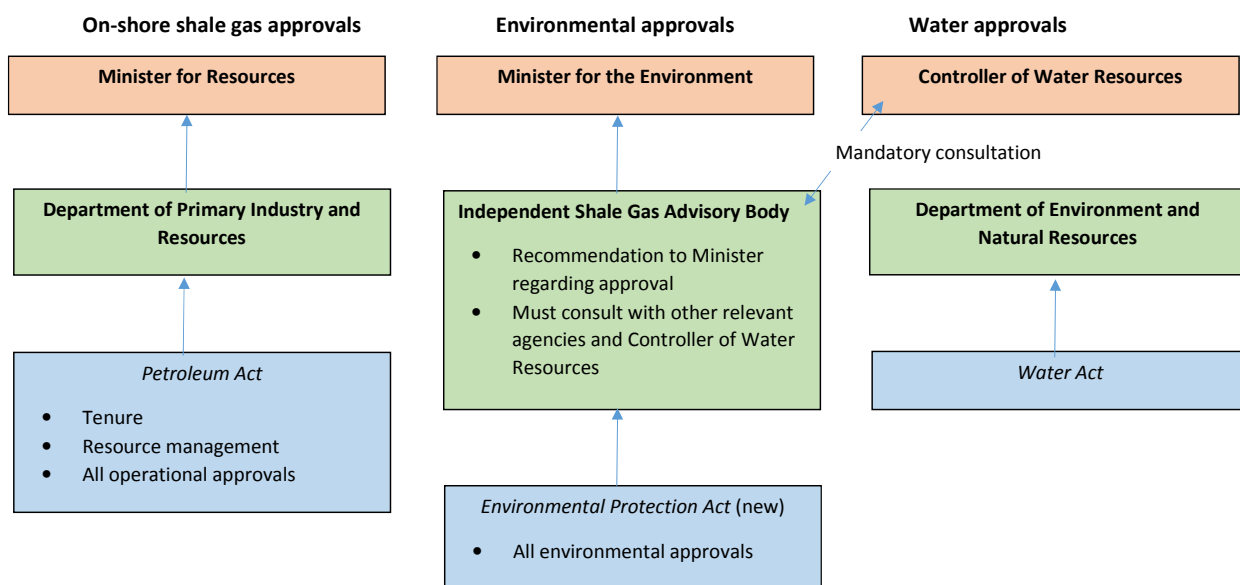
"resource management and environmental management/regulation functions should be separate to reduce conflict of interest. Worldwide experience, recently with the Montara and Macondo blowouts, has demonstrated that resource management and environmental management functions should be separated."³³⁹

The Government has proposed significant reforms to the current environmental regulatory framework. The proposed reforms align with Dr Hawke's second model in his 2015 Report. The reforms consist of the development of new environmental protection legislation (referred to in this Section as the **'Environmental Protection Act'**), which will replace the EAA and the Waste Management Act. The new Environmental Protection Act will require that all activities that have an environmental impact, including any onshore unconventional shale gas activities, will require a separate environmental approval under that Act in addition to any other approvals that may be required under other legislation including, for example, the Petroleum Act.³⁴⁰ The Minister with statutory responsibility for the new Environmental Protection Act will be the Minister for the Environment, who will be supported by a stronger, better resourced and independent EPA.³⁴¹

It is proposed that the development of the legislation will occur in two stages. Stage 1 involves the reform of the current EAA and introduction of the requirement of an environmental approval issued by the Minister for Environment. As discussed above, there is currently no requirement for the Minister to give a separate approval for matters that require assessment under the EAA.

Stage 2 involves merging the provisions of the Waste Management Act and the environmental assessment and approval provisions in petroleum and mining legislation (including the Petroleum Environment Regulations) into the new Environment Protection Act. The merging of the Waste Management Act into the new Environment Protection Act will remove the current demarcation between the regulation of activities that occur on and off petroleum permits. This reform will mean that only one set of environmental laws will apply to a project, which contrasts with the current system whereby various acts and regulators have jurisdiction over environmental matters.³⁴² The proposed legislative reforms will also mean that only one environmental assessment is undertaken, which will increase efficiency (currently, an environmental assessment is technically required under the Petroleum Environment Regulations and, if the activity will have a "significant" environmental impact, the EAA).

Figure 14.12: Option 1 - A separate environmental approval



339 2012 Hunter Report, p 35.

340 Territory Labor 2016, p 12; DENR Discussion Paper, p 5.

341 Territory Labor 2016, p 12; DENR Discussion Paper, p 5.

342 2012 Hunter Report, p 34.

The principle elements of Option 1 are as follows:

- a single, overarching Environmental Protection Act is introduced in accordance with the Government's current environmental reform agenda whereby the Minister for the Environment provides a separate and independent approval for all petroleum activities that have an environmental impact. The Act will require that Minister to decide whether or not petroleum activities (including any onshore shale gas activities) can occur or not, on environmental grounds only. The Minister must apply the principles of ESD, including the precautionary principle, when the Minister makes a decision, and the Minister must be satisfied that the environmental risks and impacts associated with the petroleum activity have been reduced to levels that are acceptable. Consistent with the current regulatory framework for petroleum activities, all environmental plans, approvals and reasons for all approvals must be published;
- the Environmental Protection Act will require the Minister for the Environment to take into account the advice of a wholly independent unconventional gas advisory body when making a decision about whether or not an activity can proceed. The advisory body must consult widely with other experts in the Government, including AAPA, and the Weeds, Land Resources and Water divisions in DENR, when providing advice to the Minister. The independent advisory body can be the independent EPA, provided that the EPA is strengthened to include expertise in managing the environmental impacts associated with the development any onshore shale gas industry;³⁴³ and
- the Minister for Resources, supported by DPIR, will retain responsibility for the Petroleum Act and all subordinate legislation under that Act. The Petroleum Act will be amended to remove all environmental matters, which will be transferred to the Environmental Protection Act. The Petroleum Environment Regulations will be repealed. The Petroleum Act will continue to regulate the calculation and collection of royalties (which can remain the responsibility of the Treasurer), the land release process, titles administration, data collection and resource management under new resource management and administration regulations consistent with Recommendation 14.16 above.

Under Option 1, two approvals will be required before a petroleum activity can proceed: one from the Minister for Resources under the Petroleum Act; and one from the Minister for the Environment under the Environmental Protection Act. While the requirement for two approvals for one activity may appear inefficient, it ensures that decisions about the environment are made completely independently from other issues that the current regulator has to balance, including the promotion of exploration for petroleum resources and issues relating to resource management. The requirement for a separate environmental approval for petroleum activities exists in other jurisdictions. For example, in Queensland a gas company can only undertake activities if it has an environmental authority under separate environmental legislation (the *Environmental Protection Act 1994* (Qld)). This requirement is in addition to a permit given under the *Petroleum and Gas (Production and Safety) Act 2004* (Qld). To increase efficiency, activities are assessed depending on the perceived level of risk, with lower impact activities being approved subject to standard conditions providing certain specified criteria are met.³⁴⁴ If the criteria are not met then an assessment is required.³⁴⁵

343 Witt et al. 2017, p 26 consider that "an independent agency, in this case the EPA, would be best suited to administer and regulate strategic assessment of shale gas development in the NT."

344 *Environment Protection Act 1994* (Qld), s 122.

345 *Environment Protection Act 1994* (Qld), s 124.

14.12.2.2 Option 2

Option 2 involves the creation of a single 'one-stop-shop' bespoke regulator (the '**Unconventional Shale Gas Regulator**', or '**USGR**'), which is responsible for all assessments and approvals for any onshore shale gas industry, except those with respect to land release, promotion of the resource, and water.

This Option is not novel. As was quoted by DPIR in its submission to the Panel:

"Safety and pollution prevention programs are more effective if a single agency is responsible and accountable for the regulation of operations. Unfortunately, legislative bodies do not always comprehend the safety and environmental risks associated with fragmented or compartmentalized regulatory regimes. These risks include regulatory gaps, overlap, confusion, inconsistencies, and conflicting standards. Also, a sufficient number of competent regulatory personnel may not be available to staff multiple agencies. Ideally, one agency would be responsible for all regulatory aspects of drilling and production operations. Safety and pollution prevention are inextricably linked and both should be regulated by this agency."³⁴⁶

The model has support overseas in Canada in the provinces of Alberta (the AER) and BC (BC Oil and Gas Commission). It has been mooted in the UK by the Royal Society and Royal Academy of Engineers,³⁴⁷ and the Task Force on Shale Gas.³⁴⁸

It was the preferred model of the NSW Chief Scientist and Engineer in her Independent Review of Coal Seam Gas Activities in NSW.³⁴⁹ As Prof Mary O'Kane observed:³⁵⁰

"the Review believes that there are significant advantages to having a single regulator in a whole-of-resource context. These include efficiencies, knowledge sharing... Well-constructed, a single regulator would have the capacity to draw on expertise both from within and outside Government... Having a single regulator means that all issues associated with environmental risks, health risks, water risks and pollution risks would be managed by one regulatory agency."

The duplication of regulators is a recognised source of regulatory burden.³⁵¹ It can lead to unnecessary compliance costs, inconsistent regulation and inconsistent reporting requirements.³⁵² As the EPA noted in its submission to the Panel, *"multiple environmental regulators cause community confusion"*.³⁵³

Option 2 draws from regulatory models seen in leading practice jurisdictions, such as the AER in Alberta, and proposes the establishment of a new bespoke regulator, the NT Unconventional Shale Gas Regulator ('**USGR**'), to regulate all aspects of the onshore shale gas industry, including environmental matters, resource management matters, and operational matters. The USGR will not, however, have responsibility for promotional matters or decisions about which land is released for shale gas exploration. These matters will remain the responsibility of the Minister for Resources and DPIR. The UGR will be established under new bespoke onshore shale gas legislation, the 'Unconventional Shale Gas Act' ('**USG Act**'), which will be the responsibility of the Minister for Environment.

³⁴⁶ Elmer P Danenberger, *submission to Montara Inquiry*, quoted in DPIR submission 226, p 37.

³⁴⁷ Royal Society Report, p 55.

³⁴⁸ Task Force on Shale Gas 2015, pp 15-16.

³⁴⁹ NSW Report, section 6.2.4.

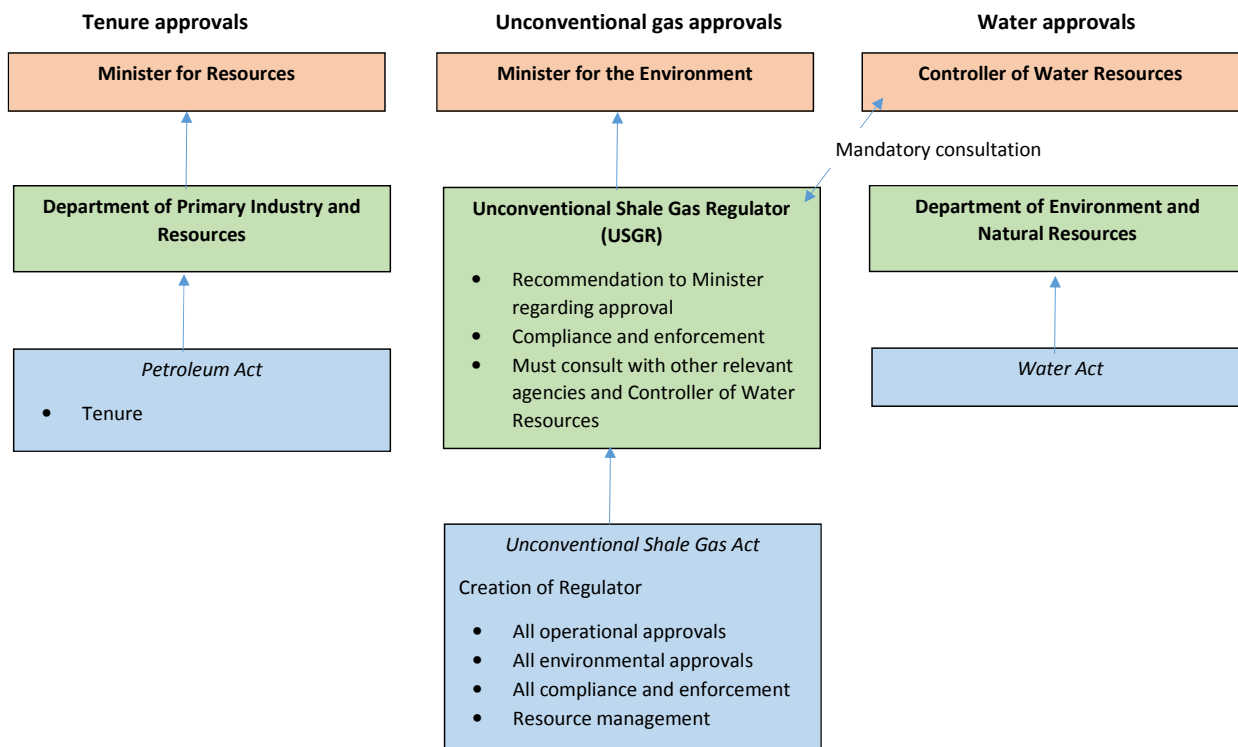
³⁵⁰ NSW Report, section 6.2.4, p 45.

³⁵¹ Productivity Commission 2013, pp 84-85.

³⁵² Productivity Commission 2013, p 85.

³⁵³ NT EPA submission 417, p 11.

Figure 14.13: Option 2 – Establishment of a new Unconventional Shale Gas Regulator (USGR)



The principal elements of Option 2 are as follows:

- the repeal and replacement of all existing legislation that would otherwise regulate an onshore shale gas industry in the NT with the USG Act;
- the power to assess and recommend the granting of, or refusal to grant, all approvals (both in respect of exploration and production), except water approvals (for the reasons given above in Section 14.11), for all onshore shale gas activities in the NT;
- the power to grant all approvals in respect of all onshore shale gas activities (except those with respect to water and the release of land for petroleum activities) is reposed in the Minister for the Environment. The power must be exercised having regard to the recommendation of USGR to grant or refuse the approval. All decisions made by the Minister contrary to the recommendation of USGR must be accompanied by published written reasons;
- USGR to be responsible for all compliance and enforcement, including complaints, dispute resolution (at first instance) concerning land access to non-Indigenous land (in relation to Indigenous land see the discussion in Chapter 11), and the imposition of sanctions, both civil and criminal;
- responsibility for engagement between industry and the community;
- responsibility for public education;
- USGR to have a regional presence with offices in locations as geographically proximate as reasonably practicable to the onshore shale gas activities; and
- the creation of a USGR website to serve as a 'one-stop-shop' information portal for all onshore shale gas activities in the NT.

The Panel recognises that the regulatory changes necessitated by Option 2 cannot be undertaken quickly. For this reason, the Panel recommends that the promulgation of USG Act and the creation of USGR occur prior to the production phase of any onshore shale gas development in the NT. In due course, however, USGR would be expected to have responsibility for all aspects of the industry, including exploration and production.

Recommendation 14.32

That the Government develop and implement the reforms described in Option 1 and/or Option 2 above prior to any production licences being issued for any onshore shale gas activities in the NT.

14.13 Conclusion

The design and implementation of a robust regulatory framework is a fundamental precursor to, and aspect of, the development of any onshore shale gas industry in the NT.

The Panel has described the necessary reforms to make the regulatory regime for any onshore shale gas industry in the NT sufficiently 'robust'. The key observations and recommendations are as follows. First, the Government must ensure a clear separation between the entity that is responsible for promoting the industry and the entity that is responsible for regulating the industry. While those responsibilities reside in the one agency, there will exist the perception that decisions have not been made independently and that the entity has been subject to regulatory capture. This in turn will further erode community confidence and trust.

Second, the Schedule must be repealed and replaced with enforceable, objective-based legislation. That legislation must be supported by transparent, enforceable, prescriptive codes of practice.

Third, the regulator must be completely transparent about how and why decisions about the onshore gas industry are made. EMPs, and all other approvals and reports, must be publicly available and the reasons why the Minister has made a particular decision (including which land should be released for exploration and which gas company should get a permit) should be published to demonstrate to the community that the Minister has balanced all competing interests fairly and in accordance with the legislation. Only when the decision-making process is transparent, the regulator is independent, and when the regulator and the industry are accountable, will any onshore gas industry be able to earn an SLO in the NT.