SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

INTERIM REPORT

JULY 2017

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The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory
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Front cover image: Central Australia Northern Territory. William Robinson. Source: Alamy Stock Photo.

The Hon Michael Gunner MLA
Chief Minister
Parliament House
Darwin, NT 0801

Dear Chief Minister

RE: RELEASE OF THE INQUIRY'S INTERIM REPORT

On 3 December 2016 your government announced the final Terms of Reference for the Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory (**the Inquiry**). Under the *Inquiries Act 1945* (NT) I was appointed Chair of the Inquiry. Ten scientists were also appointed to the Inquiry Panel.

I now have the pleasure of submitting the Inquiry's Interim Report to you. The Interim Report will also be released publicly for comment.

The Interim Report details the work undertaken by the Inquiry to date with respect to assessing the risks and benefits associated with any potential onshore unconventional shale gas development in the Territory. The Report provides detail on the principal issues identified by the Inquiry and the Inquiry's preliminary analysis of those issues. It also describes the future work of the Inquiry.

The Report draws upon an extensive consultation program, which has provided the Inquiry with evidence and commentary from relevant stakeholders and the public. So far, 37 organisations and individuals have presented directly to the Inquiry Panel at hearings held in Alice Springs, Tennant Creek, Katherine and Darwin. Community forums have afforded further important discussion at 17 regional centres and remote communities. In addition, over 290 written submissions have been received and considered by the Inquiry.

In presenting this Interim Report, I wish to thank and acknowledge the assistance of many people, including those members of the public who took the time to participate in the Inquiry's consultation process.

Yours sincerely

THE HON JUSTICE RACHEL PEPPER
Chair
13 July 2017

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Executive summary

"When I see a map of country I see land, sea and family. When they see a map of country, they see mining fantasies. When I see the seabed, I see sacred sites. When they see the seabed, they see dollar signs. When I see a map of exploration permit 266, I see them trying to reduce my country into three digits…People ask me for my story, but my story is your story".[1]

There is a scene in the 2010 movie *Gasland*, by documentary maker Mr Josh Fox, where a kitchen faucet is set alight. The intended inference is that the water has become so polluted by methane as a consequence of nearby hydraulic fracturing for gas that it is flammable. While it makes for dramatic viewing, the accuracy of that scene, and of many of the claims made in that movie, remain a matter of considerable controversy.[2]

But irrespective of its contestable content, the film nevertheless sharply captures the very real and genuine concerns that many in the community have about hydraulic fracturing, or 'fracking', for gas.

The movie was a cinematic response to one of the largest and most extensive domestic gas development campaigns in the United States of America (**US**). The convergence, more than 30 years ago, of the combined techniques of directional drilling and hydraulic fracturing of suitable geological strata exhibiting shale gas potential led to the 'shale gale' of the US gas revolution. This revolution turned the US from an energy importer into an energy exporter. It transformed the energy market in North America and significantly affected world trade in gas and oil. But in some instances, this transformation took place in jurisdictions that were poorly regulated, resulting in significant environmental damage. As a consequence, for many, the term 'fracking', whether for shale or coal seam gas (**CSG**), became synonymous with contaminated or depleted water, land degradation, air pollution and chronic health problems.

It is no doubt because of these issues, and the public anxiety accompanying them, that fracking has been legislatively prohibited in Victoria and is the subject of a moratorium in Tasmania and New South Wales (**NSW**). Overseas it has been banned in countries such as France, Germany and Scotland, in two provinces in Canada (New Brunswick and Nova Scotia), and in several states in the US (Vermont, New York and Maryland, for example). It is without doubt because of these concerns that this Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory (**Inquiry**) was established.

The anxiety, if not hostility, surrounding fracking was on display during the first round of community consultations held by the Inquiry. Overwhelmingly, the message received from the people who attended these meetings was that fracking was not safe, was not trusted, and was not wanted in the Northern Territory (**NT**). *"We want no government humbug here"*, was the response from one member of the public in Maningrida.

Having said this, it should be recognised that these are not universally held views. Many groups and individuals have expressed the opinion to the Inquiry that properly regulated, and adequately safeguarded, the onshore extraction of shale gas by hydraulic fracturing could be beneficial to the Territory, creating employment opportunities and raising much needed revenue.

The ultimate task of this Inquiry is not to recommend to the Government that it retain or lift the moratorium presently in place - that is a matter for the Government. Rather, the work of the Inquiry is to, based on the most current and best available relevant scientific data and literature, assess the environmental, social, cultural and economic risks associated with hydraulic fracturing for shale gas in the Northern Territory. In doing so, the Inquiry must sort fact from fiction and weigh up claim and counter-claim in making its assessments and in formulating its recommendations. As one community forum participant in Yuendumu stated, *"we've been told a lot of things from both sides. There's a lot of misinformation. We just want you to give us the truth".*

This Interim Report seeks to set out in detail the work undertaken by the Inquiry to date in assessing the risks associated with any potential onshore unconventional shale gas development in the Northern Territory. It also describes the future work of the Inquiry required to be undertaken prior to the release of its Final Report by the end of the year. Finally, it explains the method by which the Inquiry proposes to gather, and then assess, the evidence relevant to the issues for determination that it has identified and discussed with the public. Where appropriate, the Interim Report makes some preliminary assessments about the likelihood of some of those risks eventuating.

The principal themes emerging at this stage of the Inquiry, as summarised in this Report, are as follows:

- **shale gas development and management in Australia and the Northern Territory:** the geological setting of shale gas resources is well understood. But within Australia, shale gas development is still in its infancy. Australia is believed to have substantial prospective shale gas resources, with the Northern Territory estimated to have more than a third of the total resources in rocks at depths of between 1,500 to 4,000 metres below the surface. Almost 70% of this is thought to occur in the Beetaloo Sub-basin of the McArthur Basin, which is considered to be the main target for any future development in the Northern Territory. While there is considerable uncertainty about the likely scale

1 Ms Alice Eather, *My Story is Your Story*, 24 November 2014 <https://www.youtube.com/watch?v=l4q4uR29K84>. Permission given to reproduce extracts from the poem by Ms Helen Williams.

2 See, for example, *FrackNation*, which was made in 2012 as a direct rebuttal to *Gasland*. *Gasland Part II*, the sequel to *Gasland*, was subsequently released in 2013.

and rate of development of a shale gas industry in the Northern Territory, it is likely that only one or two shale gas resources could feasibly be developed within the next 5-10 years. While shale gas extraction always requires hydraulic fracturing, it does not need to first remove the large quantities of existing groundwater to unlock gas that CSG does. Extraction techniques that have evolved over the past three decades in the US and the United Kingdom (**UK**), in particular, are likely to be transferrable to the Northern Territory, as is accumulated expertise around the management of site infrastructure, well integrity, well decommissioning, water supplies, wastewater and solid waste, and potential seismicity. These issues have been addressed overseas by implementing strict regulatory controls and technological improvements to reduce the risk of detrimental impacts from shale gas development;

- **water:** effective water management will be crucial to the development of any unconventional onshore shale gas industry in the Northern Territory. This involves two critical aspects: first, sustainable water use from surface and groundwater resources; and second, maintaining acceptable quality of groundwaters (aquifers) and surface waters (for example, rivers, streams and wetlands). The Inquiry has reviewed and summarised the available information relating to Northern Territory water resources, the production and composition of wastewaters produced by the hydraulic fracturing process, and the management, treatment and possible reuse of these wastewaters. The Beetaloo Sub-basin is used as a case study for a preliminary analysis of water resources and water use because it is the most prospective area in the Northern Territory for shale gas development, and, importantly, it is the region where the best information is available. Where appropriate, for some of the water related issues identified, the Panel has expressed a preliminary view of the likelihood of, and the consequences if, that issue occurred. In most cases, however, the Panel's interim opinion is that more information is required before the risks and any possible mitigation options can be fully assessed;
- **land:** the Northern Territory is internationally renowned for its vast and often spectacular landscapes, many of which have outstanding wilderness values and represent an iconic part of outback Australia. The Northern Territory also has exceptional terrestrial biodiversity values, featuring a wide range of habitats and high levels of species diversity and endemism. The Panel has identified seven land-related risks of shale gas development that it assesses as requiring mitigation if shale gas development were to proceed. These are landscape amenity – detraction from iconic wilderness values; inappropriate planning of regional development due to inadequate knowledge of biodiversity assets; the spread of weeds; changed fire regimes; habitat loss and fragmentation; inappropriate location of infrastructure within a development area; and flora and fauna poisoning and soil contamination from chemical spills;
- **greenhouse gas emissions:** the life cycle of shale gas, from extraction through to use, will result in the emission of greenhouse gases (**GHG**) such as methane and carbon dioxide. Concern has been raised that these emissions may exacerbate the impacts of climate change. Based on the Panel's critical review of some of the relevant literature, the Panel's preliminary assessments include that while methane emissions dominate the upstream GHG emissions from shale gas, they are amenable to reduction; that the life cycle GHG emissions are dominated by carbon dioxide emissions from the combustion of natural gas for use, such as in heating and power generation; that depending on the use of gas, the life cycle GHG emissions can potentially represent a meaningful reduction, or possibly an addition, to Australia's GHG inventory; and that provided methane emission rates are lower than 3.3%, natural gas combined cycle power plants are expected to have a lower climate impact than coal power plants. Further work is required, including conducting a risk assessment of the hazards that may prevent lower levels of emissions from being achieved;
- **public health:** the potential impacts of shale gas development in the Northern Territory on public health have been considered in two broad categories. The first relates to adverse health effects in people, defined as the induction or exacerbation of specific diseases, or induced dysfunction of critical organs and physiological systems. These adverse health effects could result from exposures to chemicals associated with hydraulic fracturing activities, either associated with the contamination of aquifers and consequent ingestion by humans or livestock through drinking water, or associated with airborne emissions of volatile compounds from wellheads. The chemicals under consideration include those formulated in hydraulic fracturing fluids, or those of geological origin brought to the surface with flowback water. The Panel has concluded that these chemically-related risks will require site-specific formal health risk assessment, including an analysis of the pathways by which people and communities could be exposed. The second relates to possible negative effects on wellbeing. These could be related to accident trauma associated with increased road traffic, or changes in the social structure of communities, including stress relating to a 'boom and bust' economic climate and the transient nature of workforce development (fly in, fly out (**FIFO**) work practices);
- **Aboriginal people and their culture:** Aboriginal people make up most of the resident populations in the areas of the shale gas basins in the Northern Territory. Aboriginal people are linked with their land (including water bodies) by their ancient traditions and contemporary use of their land in accordance with those traditions. As a community, Aboriginal people must be able to maintain their cultural traditions relating to that land in order that their ownership rights continue to be recognised, from one generation to the next. Aboriginal communities are therefore particularly vulnerable to degradation of the landscape and the natural systems it supports. The Panel has been made aware of risks to human and community health on vulnerable people in remote areas. It is the Panel's assessment that Aboriginal people have not yet been given enough information about the potential risks and benefits of hydraulic fracturing. It is imperative that accurate information is provided to the Aboriginal groups likely to be directly affected by hydraulic fracturing well in advance of any decision being made;
- **social impacts:** recent developments in the Australian onshore unconventional gas industry have created some adverse social consequences and have heightened concerns in some part of the community. The result has been a loss of trust by the broader public in the onshore unconventional gas industry. Because the footprint of a developed unconventional onshore shale

gas industry in the Northern Territory is unknown, and because no two communities are the same and will respond to the risks and benefits associated with any such development in differing ways, the Inquiry has commissioned Coffey Services Australia Pty Ltd (**Coffey**) to develop and implement a social impact assessment framework for a potential onshore unconventional shale gas industry in the Northern Territory if the Government were to lift the moratorium (see the scope of works at Appendix 10). Coffey will then apply this framework to the communities in and around the Beetaloo Sub-basin, where it is known that there are economically viable shale gas deposits, with the aim of understanding what the likely social impacts of the development of an onshore unconventional shale gas industry might be, and whether, and to what extent, these impacts can be acceptably mitigated;

- **economic impacts:** the potential economic benefits that may flow from the development of an unconventional onshore shale gas industry in the Northern Territory, in terms of jobs and additional revenue, must be considered against the potential adverse consequences of any such development. Among other things, there are concerns around the equitable distribution of royalties, the long term sustainability of any jobs and growth created by the industry (the 'boom and bust' cycle of development), and the impact of the industry on existing industries such as tourism, agriculture, horticulture and pastoralism. During the consultations the public wanted to know what, if any, would be the real and enduring financial benefits to everyday Territorians of this industry were it to proceed. To answer these questions the Inquiry has engaged economic consultants ACIL Allen Consulting Pty Ltd (**ACIL Allen**) to provide realistic modelling on the matters set out in the scope of works appended (Appendix 9) to this Report; and
- **regulatory reform:** the design and implementation of a robust regulatory framework is the principal way in which the Northern Territory Government (**Government**) can ensure that the development of any onshore unconventional shale gas industry is consistent with the principles of ecologically sustainable development (**ESD**) and is in conformity with community expectations. Submissions to the Panel have indicated that the current system of governance for onshore unconventional gas development is deficient and needs to be strengthened to ensure that these goals are met. Operationalising the precautionary principle; identifying and enshrining 'no go zones' and reserved blocks; prescribing minimum standards; strengthening rehabilitation bond requirements; improving the structure, powers and resourcing of the regulator; and ensuring greater access to justice, are just some of the ways by which this can occur. In addition, the development of an unconventional shale gas industry in the Northern Territory has the potential to cause tension between those with rights and interests in the surface of the land, such as pastoralists and traditional owners (**TOs**), and those with rights to enter, explore for and extract gas from underneath the same land, that is, gas companies and operators. The Panel heard that the land access regime needs to be improved, particularly with regard to pastoral leases.

The ultimate task of this Inquiry is not to recommend to the Government that it retain or lift the moratorium presently in place - that is a matter for the Government. Rather, the work of the Inquiry is to, based on the most current and best available relevant scientific data and literature, assess the environmental, social, cultural and economic risks associated with hydraulic fracturing for shale gas in the Northern Territory.

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PURPOSE OF THE INQUIRY

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Chapter 1 Purpose of the Inquiry

1.1 Establishment of the Inquiry

As stated in the *Background and Issues Paper* (**Issues Paper**) released on 20 February 2017, on 14 September 2016, the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional shale reservoirs in the Northern Territory. The Chief Minister also announced that he would appoint an independent scientific panel (**Panel**) to inquire into the impacts and risks associated with hydraulic fracturing.

On 3 December 2016, the Northern Territory Government announced that it had established the Inquiry under the *Inquiries Act 1945* (NT).

The Inquiry is Chaired by Justice Rachel Pepper, a judge of the Land and Environment Court of New South Wales.

The Panel comprises 10 eminent scientists across a range of disciplines. A list of the names and biographies of the Chair and the other Panel members can be found on the Inquiry's website at frackinginquiry.nt.gov.au.

The Government has stated publicly that the moratorium will stay in place for the duration of the Inquiry.

1.2 The Terms of Reference

The Government published draft Terms of Reference on 14 September 2016. After public consultation these were amended, and on 3 December 2016 the Government announced the final Terms of Reference for the Inquiry. The Terms of Reference are set out at Attachment A in the Issues Paper and are available on the Inquiry's website.

1.3 The purpose of the Inquiry

The purpose of this Inquiry is found in the Terms of Reference. While limited to onshore unconventional shale gas only, the Terms of Reference are nevertheless broad in their scope. They require the Panel to assess and determine:

- the nature and extent of the risks associated with hydraulic fracturing of onshore unconventional shale reservoirs and its associated activities on the environmental (aquatic, terrestrial and atmospheric), social, cultural and economic conditions of the Northern Territory;
- whether these risks can be mitigated to an acceptable level;
- if they can, by what methodology or methodologies can these risks be mitigated; and
- whether the existing regulatory framework is sufficient to implement these methodologies, and if not, what changes need to be made.

As was discussed in the Issues Paper,[3] this is not the first inquiry the Northern Territory has held into hydraulic fracturing (see also Chapter 14). This Inquiry differs from its predecessors, however, by reason of its scope (it is wider) and its mandated intention to consult widely with Territorians.

1.4 The identified risks of fracking in the Northern Territory

The potential risks associated with fracking for onshore shale gas in the Northern Territory were identified in the Issues Paper as 'issues', which were categorised into nine themes for ease of reference. The Panel is aware that some or all of these risks may have a cumulative effect that will need to be separately assessed.

The date for comment on the Issues Paper formally closed on 30 April 2017, however, submissions have continued to be accepted after this date.

A total of 293 submissions have been received by the Inquiry. This is in addition to the information obtained at the hearings and community forums, and the feedback contained in the 'Have Your Say' forms.

The risks set out in detail in the Issues Paper were extensively discussed at hearings and consultations in urban centres and communities across the Northern Territory. As a result of these discussions, additional issues were identified which have been taken into account by the Panel. A revised list of issues compiled pursuant to this process is attached at Appendix 1. The new risks raised by the public during the course of the first round of consultations are identified in italics.

As indicated above, the Panel is now in the process of determining whether or not those risks are material, and if they are, assessing whether they can they be mitigated to an acceptable level by appropriate safeguards.

The Panel will release a draft Final Report with draft final recommendations towards the end of the year and will publish its Final Report and recommendations by the end of 2017, following a final round of consultation.

To reiterate, it will be a matter for the Government, not the Inquiry, upon receipt of the Final Report, to determine whether or not the moratorium should be lifted. The Terms of Reference do not permit such a recommendation to be made by the Inquiry.

1.5 Purpose of this Interim Report

In addition to setting out the work of the Inquiry so far, this Interim Report seeks to provide an initial discussion of the principal issues identified in the revised list of issues, based on the presently available information and data and the Panel's analysis to date of that material.

To the extent that knowledge gaps exist, these have been identified and the measures taken to remedy these data deficiencies explained. Similarly, to the extent that further research is required to be undertaken by the Panel, this is detailed.

The Inquiry will use the Interim Report as the basis for further public consultation and submissions commencing at the end of July 2017.

3 Issues Paper, p 10.

WORK OF THE INQUIRY TO DATE

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2.1 Panel meetings

Since the Inquiry was constituted on 3 December 2016, the Panel has formally met on five occasions, four times in person and once by way of telephone:

Date	Location
8 December 2016	Sydney, NSW
8-9 February 2017	Sydney, NSW
11 March 2017	Darwin, Northern Territory
5 May 2017	by telephone
2 June 2017	Melbourne, Vic

2.2 Interstate visits

The Panel has undertaken one interstate visit to South Australia (**SA**) (on 31 January 2017) to consult with officers of the Energy Resources Division of the South Australian Department of State Development concerning the regulatory framework governing conventional and unconventional onshore gas development in that State. Consultation also occurred with the Nuclear Fuel Cycle Royal Commission Consultation and Response Agency, to discuss models of community engagement.

On 1 and 2 February 2017 the Panel travelled to Moomba in SA to conduct a two day site visit of Santos Ltd's (**Santos**) operations in the Cooper Basin.

The purpose of the visit was to observe drilling and hydraulic fracturing activities associated with deep gas (shale and tight gas) extraction, rather than CSG extraction.

The type of gas extraction witnessed at Santos' operation in the Cooper Basin was tight gas, not shale gas, however, the infrastructure, processes and supporting operations are relevantly comparable to those of a typical shale gas operation.

The field trip was an important activity to undertake during the early stages of the Inquiry in order to better understand the size and scale of the hydraulic fracturing process for deep gas extraction and its impact on the local environment.

During the two day visit, the Inquiry witnessed the hydraulic fracturing of a fracture stage at the Allunga 2 and 3 well pads, as well as the equipment and processes associated with the hydraulic fracturing. At the site the Panel observed a demonstration of the composition and mixing of hydraulic fracturing fluid used at that location. The Panel also visited a producing gas well at the adjacent Allunga 1 well pad.

At the Caraka 2 well site, the Panel witnessed the drilling of a well for the purpose of hydraulic fracturing, and the associated infrastructure and equipment. The Panel had a tour of the drilling rig floor and the storage area used for surface and production casing.

While onsite board and lodgings (one night) and ground transportation were provided by Santos, the remaining costs associated with the trip were paid for by the Inquiry.

2.3 Stakeholder meetings

Between 20 and 24 February 2017, the Chair (Justice Rachel Pepper) and the Deputy Chair (Prof Barry Hart AM) met with stakeholders at various locations in the Territory to discuss the work of the Inquiry and to seek their input into the first round of community consultations. A list of the stakeholders the Chair and the Deputy Chair met may be found at Appendix 2.

2.4 Departmental briefings

Various Government departments have briefed the Panel on subjects relevant to the work of the Inquiry. The purpose of these briefings was to provide background information only. The briefings were not submissions to the Inquiry. A description of the departmental briefings is set out at Appendix 3.

2.5 Consultation

The Inquiry was given a mandate to consult widely with Territorians about their views on the development of an onshore unconventional shale gas industry in the Northern Territory.

The first round of consultation following the release of the Issues Paper consisted of hearings and community information and engagement sessions, or community forums.

A summary of the discussions that occurred during the first round of consultations is contained in Chapter 4.

Inquiry Chair Justice Pepper (front left) with Panel members during community consultation visits March 2017.

2.5.1 Hearings

The hearings were open to anyone who had registered in advance. Generally those persons or entities appearing at the hearings consisted of environmental groups and petroleum industry representatives. A full list of those who attended the hearings may be found at Appendix 4.

The hearings were recorded and live-streamed on the Inquiry's website to facilitate access for those who could not otherwise attend in person. The live-stream was viewed by more than a thousand people, including those in Canada, US, Ireland, UK, Hungary, Spain and Switzerland. The video recordings are available to be viewed on the Inquiry's Submission Library website page at frackinginquiry.nt.gov.au/submission-library.

The video recordings and transcripts of each hearing, as well as any documentation provided by the presenters (which have been tabled as submissions to the Inquiry) are available to view on the Inquiry's Submission Library website page listed under the name of the organisation or person who presented at frackinginquiry.nt.gov.au/submission-library.

The hearings were open to the public and the media. The media were allowed to separately record the hearings.

2.5.2 Community forums

The first round of consultation also included community information and engagement sessions or forums. These forums were designed to encourage active discussion and participation by those who attended. They were open to the public. Prior registration was not a prerequisite to attendance.

Media were allowed to attend but were not permitted to audio record the forums, in order to facilitate open discussion.

The community forums commenced with a brief presentation from either Emeritus Prof Peter Flood or Dr Ross Smith, to explain the process by which unconventional shale gas is extracted. The attendees then broke into smaller roundtable groups, each with an allocated Panel member, to discuss the issues raised by the presentation, identified in the Issues Paper, and any other concerns or comments that the community wanted to raise. At the conclusion of the group discussions, each Panel member presented a summary of their group discussion to the entire forum.

The roundtable format was designed to encourage broad participation from the community by enabling a greater number of people to speak in a smaller, facilitated setting. The roundtable format was very well received by attendees in all communities.

2.6 Presentations by the Chair

The Chair was invited to present a summary of the work of the Inquiry to the following organisations

Date	Organisation	Event
30 March 2017	Aboriginal Areas Protection Authority, Alice Springs	Board meeting
31 March 2017	Northern Territory Cattlemen's Association	Annual General Meeting and Industry Conference, Darwin
2 April 2017	Amateur Fishermen's Association of the Northern Territory	Annual General Meeting, Darwin
11 May 2017	Central Land Council	Full Council Meeting, Tennant Creek
31 May 2017	Northern Land Council	Full Council Meeting, Katherine

2.7 Community updates

In order to keep Territorians regularly informed of the work of the Inquiry, the Inquiry has released 12 community updates. A list of these is appended to this Report at Appendix 6.

2.8 Media engagements

As a matter of transparency, it is important that the media has access to the Inquiry. In this regard, the Chair has participated in 26 media engagements. These have included television and radio interviews (both live and pre-recorded), articles, and letters to newspapers. A list of the Chair's media engagements to date is located at Appendix 5.

Inquiry Chair Justice Rachel Pepper conducting an interview with Indigenous broadcaster Esau Marshall at PAW Media radio studio in Yuendumu March 2017.

EVIDENCE AND RISK ASSESSMENT METHODOLOGY

3

3.1 Evidence relied upon

A comprehensive bibliography of the literature that the Panel has considered so far and a complete list of the submissions provided to the Inquiry to date is located at Appendices 14 and 7, respectively.

Unless indicated otherwise, all written submissions, letters and emails received by the Inquiry have been, and will continue to be, in the interests of fairness and transparency, published on the Inquiry's website. For legitimately confidential submissions (where good reason has been provided in writing), a brief description of the submission (without disclosing its confidential content) will be provided on the website, together with the reason for maintaining confidentiality.

The oral submissions and feedback from the community during the Inquiry's initial round of consultations, together with the views expressed in the 'Have Your Say' forms (181 forms were received), has been taken into account by the Panel. This information is important having regard to the issues identified in the Issues Paper, particularly those concerning the unique social, cultural and economic conditions of the Northern Territory, and in light of the Terms of Reference governing the work of the Inquiry. The attitudes and opinions of the public towards hydraulic fracturing in the Northern Territory are directly relevant to determining whether or not any onshore unconventional shale gas industry holds a social licence to operate, and if absent, how it can be obtained.

A summary of the principal matters raised and discussed during the community consultations is located at Chapter 4 and is reflected in the revised list of issues at Appendix 1.

In addition to their own expertise, the Panel has also drawn upon domestic and international literature analysing the documented risks associated with fracking.

In Australia, the Panel is examining, among other material, the 2012 and 2016 Hunter reports and the 2014 and 2015 Hawke reports (as referred to in the Issues Paper).[4] Also being considered is the Final Report of the Australian Council of Learned Academies (**ACOLA**), *Engineering Energy: Unconventional Gas Production* published in May 2013 (**ACOLA Report**)[5] and the reports of various reviews into unconventional gas in Tasmania, NSW, SA, Western Australia (**WA**), Victoria and Queensland.[6] Overseas, studies into fracking in the UK, US, Canada and even South Africa are also being considered.[7] In particular, the findings from the authoritative United States Environmental Protection Agency's report, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States* (**US EPA Report**),[8] are being taken into account.

It may be assumed that all material received by the Panel has been read and considered, even if no express reference is made to a particular submission in either the Interim or the Final Reports.

3.2 Methodology and assessment of risk

3.2.1 Methodology

In many instances, hydraulic fracturing is discussed and described, especially in the media, as a uniform and immutable practice, irrespective of its geographical, geological, historical, or regulatory setting. This is partly due to a paucity of readily accessible and comprehensible information or published data regarding the extent, location, methodology and technology of fracking. It has contributed to claim and counter-claim, leading to confusion and misinformation presented on both sides of the debate, concerning the potential risks and benefits of the extraction of unconventional gas.

Having regard to the most current and relevant scientific literature (and not, as is too often the case, out of date studies from other jurisdictions), the Panel must identify, collect, analyse, and distil the available scientific evidence concerning the list of issues set out at Appendix 1. The Panel will then assess those risks in terms of the likelihood of that risk occurring and the consequences if that risk were to eventuate. The combination of the level of likelihood and the level of consequence will give a resultant level of risk. For example, the likelihood of a well blowout may be very low (see Chapter 5), but if this were to cause significant environmental damage then the resultant level of risk would be high.

Finally, the Panel will determine the mitigation measures that are currently available to reduce the levels of risk identified to an acceptable level. If no safeguard or mitigation measure can be implemented to reduce the level of risk to an acceptable level, then the Inquiry will say so explicitly by way of express findings. If, however, the risk level can be acceptably reduced, then it will be the task of this Inquiry to formulate, with as much precision as possible, given the expertise of the Panel and the timeframe within which this Inquiry must report, a relevant recommendation as to how the identified risk can be mitigated to an acceptable level.

3.2.2 Assessment of risk

To assist in the assessment of the issues associated with onshore shale gas development, the Panel has adopted a risk assessment framework that combines the likelihood of an impact occurring and the consequences of that impact, to assess the resultant risk level. The level of assessed risk is then used to determine if any additional mitigation will be required to reduce the risk level to a low (acceptable) level should the development proceed.

The Panel's risk assessment framework, detailed in Appendix 13, is based on the Government's risk assessment framework for resource development.[9] The original 6x6 level risk matrix has been condensed to three levels each for 'Likelihood', 'Consequence', and 'Risk': namely, 'Low',

4 Issues Paper, p 11.

5 Available at http://acola.org.au/wp/reports-library/.

6 See, for example, the *Review of Hydraulic Fracturing in Tasmania Final Report; the Final Report of the Independent Review of Coal Seam Gas Activities in NSW; the Inquiry Into Unconventional Gas (Fracking) Final Report; the Roadmap for Unconventional Gas Projects in South Australia; Implications for Western Australia of Hydraulic Fracturing for Unconventional Gas (**WA Report**); the Inquiry into Onshore Unconventional Gas in Victoria Final Report; the Coal Seam Gas Review Final Report; and the Review of the Socioeconomic impacts of coal seam gas in Queensland.* The list is not exhaustive. For full citations generally, see Appendix 14 – References.

7 See, for example, *Shale gas extraction in the UK: a review of hydraulic fracturing (**Royal Society Report**); Environmental Impacts of Shale Gas Extraction in Canada; Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States (US EPA Report); and Shale Gas Development in the Central Karoo: a Scientific Assessment of the Opportunities and Risks.* The list is not exhaustive.

8 Available at https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=33299.

9 Petroleum Environment Regulations Guide, pp 26-29.

'Medium' and 'High'. Each Chapter has adapted the definition of the 'Consequence' to be relevant to the context of that Chapter, while still being generally consistent with the descriptions given in Appendix 13.

For the purposes of this Report, an assessment of risk will only be undertaken when there is sufficient information, and if undertaken, the assessment of the current level of risk will assume application of the current regulatory regime and the enforcement of that regime.

3.3 Knowledge gaps

3.3.1 Commissioned work

Where required information to undertake the assessment is missing, the Inquiry has, and will continue to, request its provision from the appropriate government body, industry entity or community stakeholder (see Appendix 8).

Where knowledge gaps have been identified that require more detailed and in-depth analysis that is beyond the capability of the Panel having regard to the timeline for the completion of the Inquiry, additional research has been commissioned.

With respect to the impact of any potential onshore unconventional gas industry in the Northern Territory on climate change, Prof Sandra Kentish, Head of the School of Chemical and Biomedical Engineering at the University of Melbourne, was commissioned to quantify the methane emissions from unconventional onshore shale gas operations, focussing principally on the likelihood of methane emissions from these operations and to determine whether those risks can be managed in a cost-effective manner. Prof Kentish's contributions are incorporated into Chapter 9.

In addition, Emeritus Prof Peter Flood, University of Sydney, School of Geosciences, was engaged to describe what onshore unconventional shale gas is and the mechanisms by which it is extracted. In particular, he has detailed how the wells are drilled, how hydraulic fracturing occurs, how the gas is extracted, and what occurs when wells are abandoned (see Chapters 5 and 6).

Two substantive pieces of work were put out to public tender:

- an economic assessment, to determine actual and potential direct and indirect economic benefits and risks associated with the development of the onshore unconventional shale gas industry in the Northern Territory, as well as the effect that an ongoing moratorium will have on the Northern Territory economy. The scope of services is located at Appendix 9. The tender period ran from 13 April to 4 May 2017. Six tenders were received. The successful tender was awarded to ACIL Allen on 24 May 2017. The final report by ACIL Allen must be delivered by 1 September 2017, before the Inquiry is due to release its Final Report. The final ACIL Allen report will be published on the Inquiry's website. Further details may be found in Chapter 13; and
- the development of a social impact assessment framework and the implementation of that framework to the people, or groups of people, that would most likely be affected by any onshore unconventional shale gas industry, namely, the Beetaloo Sub-basin.

  The Beetaloo Sub-basin was selected because that area is known to contain significant deposits of shale gas and an unconventional shale well that was drilled and hydraulically fractured by Origin prior to the moratorium (the Amungee NW1H well) indicates that there is a high likelihood that the Beetaloo sub-basin will be productive.[10] The scope of services is attached at Appendix 10. The tender period ran from 3 to 17 May 2017. The tender was awarded to Coffey on 28 June 2017. A final assessment must be delivered to the Panel by 15 September 2017. Again, the final assessment will be published on the Inquiry's website. For more information see Chapter 12.

3.3.2 Adequacy of baseline studies

During the first round of consultations it was constantly stated, by both stakeholders and individual members of the public, that there existed a paucity of baseline studies in respect of the unique environmental conditions of the Territory. Initial research by the Panel indicates that there is considerable truth to this observation.

Where, during the course of this Inquiry, it becomes apparent that further study and research is required prior to any exploration for, or development of, any onshore unconventional shale gas industry proceeding, the Panel will not hesitate to make such a recommendation.

10 Issues Paper, pp 10-11; Chapter 5 below.

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SUMMARY OF DISCUSSIONS AT COMMUNITY FORUMS AND THE REVISED LIST OF ISSUES

4

Chapter 4 Summary of discussions at community forums and the revised list of issues

4.1 Community forums

The Issues Paper identified the issues that the Panel considered to be the main risks, or issues, arising from the development of an onshore unconventional shale gas industry in the Northern Territory. The Panel sought feedback from Territorians about those issues, and about any other concerns the community had about the hydraulic fracturing of onshore shale gas reservoirs, at a series of community information engagement sessions (community forums) (for a description of the community forum process see Chapter 2).

These forums took place in the following urban centres and regional communities:

Date	Location
6 March 2017	Alice Springs
7 March 2017	Tennant Creek
8 March 2017	Katherine
9 March 2017	Darwin
9 March 2017	Humpty Doo
20 March 2017	Gapuwiyak
20 March 2017	Nhulunbuy
21 March 2017	Ngukurr
21 March 2017	Borroloola
22 March 2017	Daly Waters
23 March 2017	Mataranka
24 March 2017	Timber Creek
27 March 2017	Wadeye
29 March 2017	Hermannsburg
29 May 2017	Yuendumu
30 May 2017	Maningrida
4 July 2017	Elliott

The Panel met with, and listened to, the views of more than 1,000 Territorians during this process.

4.2 Key issues raised

Most of the issues listed in the Issues Paper were raised by the public during the course of the community forums. Some issues were, however, identified as key concerns by those present. These are summarised below in the order of their importance to the community.

Maningrida community consultation March 2017: Inquiry Panellist Dr Ross Smith (left) and Inquiry Chair Justice Rachel Pepper (second from left) illustrating hydraulic fracturing processes with Maningrida community members

4.2.1 Water

The primary and most consistently raised issue across all community forums was the potential impact of any onshore unconventional shale gas industry on water resources (surface water and groundwater) in the Northern Territory, both in respect of human use and dependent ecosystems:

- it was repeatedly stressed that much of the Northern Territory relies on groundwater for its water supplies, including for 'domestic' and commercial use. Therefore, any adverse impact on potable water was universally seen as unacceptable;
- potential causes of water contamination were constantly raised. These included aquifer contamination due to well failure caused by pipe or cement corrosion or seismic activity, spillage of fracking fluid, spillage of wastewater, and wastewater storage ponds overflowing given the extreme rainfall events common in the Northern Territory;
- the significant amount of water required for hydraulic fracturing and where this water would be sourced from was repeatedly mentioned. In this context, it was routinely suggested that water usage should be monitored and that a water licensing regime should be implemented to ensure adequate water quantity and quality for multiple uses; and
- many participants considered that there was insufficient baseline data to properly assess the long term impacts on water of horizontal drilling and hydraulic fracturing for onshore shale gas.

4.2.2 Regulatory reform

The adequacy of the regulatory framework governing any onshore unconventional shale gas industry in the Northern Territory was another key concern for participants at the community forums. The complaints consisted of:

- an absence of faith in the current Territory regulatory framework to adequately, or in some instances, at all, protect the environment from the risks inherent in any onshore unconventional shale gas industry;
- distrust in the Government to make decisions in the best interests of the community;
- a perception that Government and the petroleum industry were too closely aligned and that the petroleum industry had the ability to distort executive decision-making;
- a demand for higher penalties for environmental damage, for the public reporting of incidents, for the imposition of adequate rehabilitation bonds, for the independent baseline testing of water and air quality, and for any onshore unconventional shale gas development to be subject to the *Water Act 1992* (NT) (**Water Act**); and
- a need for laws to be enforced by a well resourced regulator that was wholly independent from Government and the petroleum industry. Suggestions for resourcing the regulator included a levy on the gas industry. Ongoing legacy mine issues were frequently cited as an example of the inadequacy of the regulator to prevent, penalise, or remediate environmental damage caused by the petroleum activity.

4.2.3 Land

The concerns expressed during the community forums in relation to land were:

- a loss of landscape amenity values - there was a widespread and deeply-held concern within Northern Territory communities that shale gas development would lead to the industrialisation of what are currently iconic outback landscapes. The concern was not just about amenity values for residents, but also about the impact on the Northern Territory tourism industry due to the loss of an outback wilderness experience, a primary visitor drawcard;
- a loss of habitat for wildlife - there was substantial community concern that the vegetation clearing required for shale gas development would have a significant impact on biodiversity. A related and frequently expressed concern was the very limited knowledge of the Northern Territory's biodiversity assets, particularly for invertebrates;
- the spread of weeds - weeds can have significant impacts on both the conservation and production values of landscapes, and there was concern from multiple sectors that shale gas development would lead to the spread of weeds, including into areas where they were currently not present;
- the contamination of land - the deleterious impact of land contamination on ecosystems and livestock due to spillages was often raised; and
- the impediment of stock movement caused by a network of roads, pipelines, fences and well pads was a matter of concern.

4.2.4 Air

The contribution of any onshore unconventional shale gas industry to climate change was a major issue for a significant number of participants. It was noted that shale gas is a fossil fuel and that its extraction, production and use, cause greenhouse gas emissions (carbon dioxide and methane) that contribute towards climate change.

The list of community concerns based on comments raised during the community forums is as follows:

- in respect of methane emissions, that:
  - Australia has limited or no measurements of methane levels at gas production sites; and
  - the Australian Government estimates for methane emissions are much lower than those reported in the literature;
- in respect of GHG emissions and downstream use, that:
  - there is an absence of baseline data and that the ongoing monitoring of GHG emissions is difficult;
  - life cycle GHG emissions for both upstream and downstream stages must be evaluated; and
  - at elevated methane emissions, life cycle GHG emissions for gas can be similar to GHG emissions for coal;
- in respect of emission monitoring, that:
  - there is a need for baseline measurements;
  - there is a need for independent monitoring of emissions; and
  - there are good examples of GHG regulations (for example, North Dakota and Colorado in the US) which should be examined; and
- in respect of climate change, that:
  - it is necessary to consider GHG emissions for Australia; and
  - it is necessary to consider implications of these GHG emissions for additional gas production and use.

Finally, whether shale gas was a 'cleaner' source of energy was questioned. Numerous participants stated that the Northern Territory should be focussing on developing renewable energy resources and not extracting additional fossil fuels.

4.2.5 Aboriginal people and their culture

The potential impact of any onshore unconventional shale gas development on Aboriginal people and their culture was raised by traditional Aboriginal owners, members of the Aboriginal community, and by many non-Aboriginal people. Most were worried that any development would irreversibly disturb and damage country for future generations:

- there was a significant amount of concern about the detrimental effect that any onshore shale gas industry would have on songlines, sacred sites, and cultural landscapes. The Panel heard that the process of horizontal drilling was particularly troubling because sacred sites extend beneath the surface of the earth and the process of horizontal drilling in multiple directions underneath a sacred site could irrevocably damage that site. As one participant said, *"we need to protect the roots of the totem also"*;

- there was a widespread view among Aboriginal and non-Aboriginal people that most petroleum industries did not make a genuine effort to engage appropriately with, or to properly inform, traditional Aboriginal owners of the actual impact of that activity prior to seeking consent to it; and
- there was concern that traditional land use by Aboriginal persons (camping, hunting, fishing and the collections of 'bush tucker') would be restricted.

4.2.6 Social impacts

The most frequently raised potential adverse social impacts that an onshore shale gas industry might have on local communities were that:

- a rapid increase in population associated with the development of any industry could lead to increased pressure on health services, schools, infrastructure and accommodation;
- the development of the industry could result in conflict within the community between those who were in favour of the industry and those who were opposed to it, and moreover, between those that stood to gain from the industry and those that would miss out;
- an influx of FIFO workers could have a negative effect on the social fabric of the community, especially in circumstances where FIFO workers were employed in preference to locals; and
- a 'cash splash' could result in increased alcohol and drug abuse, and therefore, increased crime.

4.2.7 Public health

The eight key issues raised in community forums relating to public health impacts associated with unconventional gas extraction (**UGE**) can be summarised as:

- the contamination of water used for domestic consumption and stock watering by chemicals used in hydraulic fracturing fluids (**HFF**), or in 'flowback' and 'produced water' (see Chapter 5) that is recovered from wells after hydraulic fracturing has occurred and during the extraction phase of the gas deposits;
- the release of fugitive emissions, including volatile organic compounds and airborne dusts from UGE activities, that could have an impact on respiratory and related health effects;
- the air contamination caused by dust generated by increased land clearing, earthworks, and traffic, particularly if that dust has been contaminated by chemical spillage or wastewater;
- the potential additional impacts on climate change resulting from fugitive methane emissions and from the more generalised use of shale gas as a source of energy generation and other industrial activities;
- an increased risk of spills of chemicals along transport routes as a result of the greatly increased number of transport movements;
- an increased risk of road trauma associated with the construction of wellheads, the transport of chemicals and other materials to well sites, and the construction activities associated with pipeline development;
- the impacts on mental health and wellbeing associated with changes in the social structure of communities, including the stress relating to a 'boom and bust' economic climate and the transient nature of workforce development (FIFO work practices); and
- the impacts on mental health and wellbeing caused by the industrialisation of the landscape that would diminish the amenity of the land.

4.2.8 Land access

Access to land for the purposes of exploration and extraction of shale gas was a significant issue, particularly for Aboriginal people and pastoralists. The concerns raised included that:

- pastoral lessees and Native Title holders did not have a right to refuse access to their property for petroleum activities which was a matter of considerable anxiety;
- while it was noted that traditional Aboriginal owners of land subject to the *Aboriginal Land Rights (Northern Territory) Act 1976* (Cth) (**Land Rights Act**) have the ability to refuse access to their land at the exploration stage, there was no cognate right of veto at the production stage;
- there was a power imbalance between traditional Aboriginal owners and landholders, on the one hand, and the petroleum industry, on the other, particularly when it came to negotiating land access arrangements; and
- there should be restrictions on access to areas of particular environmental, cultural, or agricultural significance ('no go zones').

4.2.9 Economic impacts

The principal matters that were discussed during the community forums concerning the economic impacts of any onshore shale gas development were that:

- there was a significant amount of scepticism expressed about the true value of any economic benefit created by the development, especially in terms of employment, public revenue generation, and royalties;
- there was a strong belief that those who bore the risks of the development would not receive the benefits. In this regard, many members of the public expressed a desire for a 'Royalties for Regions' scheme, and/or the implementation a Territory gas reservation policy;
- many participants considered that investing in onshore unconventional shale gas, rather than in renewable energy, would result in an opportunity cost to the community and to the Government, and that the Government should not be *"investing in a declining industry"*;
- the industry might have an adverse impact on other industries such as tourism, pastoralism, horticulture, and agriculture, especially on the clean and green image of the Northern Territory;
- the rehabilitation and remediation costs of any air, land and water pollution and degradation would fall on the public, particularly if the relevant gas operator had gone into liquidation; and
- the public did not believe that the development of any onshore shale gas industry in the Northern Territory would alleviate the purported 'gas crisis' facing some parts of Australia. It was considered that Australia presently had sufficient gas reserves, but that these had been improperly managed.

4.3 Revised list of issues

As a result of the feedback received during the community consultation process, the list of issues contained in the Issues Paper was revised to take into account the additional risks raised by the public but not included in that document. The revised list of issues can be found at Appendix 1. All new issues are indicated in italics.

SHALE GAS DEVELOPMENT AND MANAGEMENT

5.1 Differences between conventional and unconventional gas

5.1.1 Occurrence of conventional and unconventional gas

The terms 'conventional' and 'unconventional' gas are often misunderstood and have taken on different meanings in the literature relating to the gas industry. For the purpose of this Inquiry, 'unconventional' gas is found in relatively impermeable source rocks, where the gas has been trapped where it was formed. This is different from 'conventional' gas, which has migrated from its original source rocks into more porous, permeable rocks and has then been trapped under a seal of impermeable rocks. Unconventional gas includes CSG (found in coal seams), shale gas (found in shale rocks), and tight gas (found in sandstone). Irrespective of whether it is conventional or unconventional, natural gas is composed mainly of methane – up to 98% – with varying amounts of other trace gases such as ethane, propane, butane and other hydrocarbons. From a consumer's perspective, unconventional gas is practically identical to conventional sources of natural gas.

While the strict distinction between CSG, shale gas and conventional gas is determined by the rocks in which the gas occurs, a significant additional difference in Australia is that while most sources of conventional gas are located offshore, unconventional gas sources occur onshore and in proximity to other pre-existing land uses, including towns, prime agricultural land, and traditional land.

5.1.2 Extraction of conventional and unconventional gas

Conventional gas can typically be developed with a limited number of wells due to the accumulation of the hydrocarbons in a confined area with well connected pore spaces within the rock that enable effective drainage from strategically placed wells. The gas will flow to the surface under its own pressure driven by a water table (or aquifer) underneath a pressurised gas cap.

By contrast, the source rocks that hold unconventional gas have much lower porosity (that is, the void spaces between the grains that make up the rock are very small) and much lower permeability (that is, the interconnectedness of the pore spaces to allow the gas to move through the rock is very low). In order to extract unconventional gas, it is necessary to increase the level of porosity and permeability. This is termed 'artificial stimulation' and generally involves hydraulic fracturing.

There are differences in the extraction techniques for the different forms of unconventional gas:

- **coal seams:** are typically found relatively close to the sur face (usually no more than 1,000 metres deep). The extraction of coal seam gas does not always require hydraulic fracturing (currently around 8% of wells in Queensland), but does require the removal of water from the coal to unlock the gas (dewatering). Large amounts of salty water (brine) are produced (known as 'produced water') and must be treated and disposed of;
- **shale gas source rocks:** occur deeper at between 1,500 to 4,000 metres deep. Extraction of gas from shale always needs hydraulic fracturing, but does not need to remove large quantities of existing groundwater to unlock gas. Only a portion of the water that is used in the hydraulic fracturing process is returned to the surface. This returned water (known as 'flowback water') can be reused for subsequent hydraulic fracturing operations, or must be treated and disposed of; and
- **tight gas source rocks:** usually occur at similar depths to shale gas source rocks. These rocks have such low permeability that hydraulic fracturing is always necessary to allow the trapped gas to be liberated at economic rates. Like shale gas, the returned water (flowback water) can be reused for subsequent hydraulic fracturing operations, or treated and disposed of.

Consistent with the Terms of Reference, the Inquiry is only concerned with onshore shale gas, and not tight gas or CSG.

5.2 Shale gas development

5.2.1 History

Hydraulic fracturing was developed more than 100 years ago, but its combination with horizontal drilling in the 1990s began a shale gas revolution in the US that has since transformed the energy market in North America and significantly affected world trade in gas and oil. The shale gas industry has since developed in countries such as Canada, Europe and the UK, and other countries such as China, Russia, and Argentina are evaluating its potential. The current world ranking among countries of recoverable shale gas resource is: China, Argentina, Algeria, US, Canada, Mexico, Australia, South Africa, Russia and Brazil, although recent Northern Territory discoveries in the Beetaloo Sub-basin are likely to increase Australia's global ranking of gas resources from seventh to sixth (see Chapter 6).

Although shale gas resources have been known to exist in Australia for many years, shale gas development is still in its infancy. In 2012, Santos' Moomba-191 well in the Cooper Basin in SA became the first commercially producing unconventional gas (tight gas) well in Australia, and followed almost 10 years of exploration for unconventional gas in that Basin. None of the Northern Territory's considerable shale gas resources are under commercial production (Chapter 6).

5.2.2 Stages of exploration and development

The commercial production of shale gas is the culmination of a process spanning several years of concept development, exploration, drilling, hydraulic fracturing, testing and economic analysis.[11] The different stages of shale gas development and their constituent activities can be summarised as follows:

- **stage 1:** identification of the gas resource - negotiating and securing land access agreements, securing seismic survey and drilling permits, and undertaking initial geological, geophysical and geochemical surveys;

11 See, for example, www.csur.com/sites/default/files/shale_gas_English_Web.pdf.

- **stage 2:** early evaluation drilling - seismic mapping of the extent of gas-bearing formation and other geological features such as faults, initial vertical drilling to evaluate shale gas resource properties, and collection of core samples;
- **stage 3:** pilot project drilling - drilling of initial horizontal wells to determine reservoir properties and to help optimise operational techniques, and initial production testing;
- **stage 4:** pilot production testing drilling - drilling of multiple horizontal wells from a single pad, full optimisation of operational techniques including drilling and multi-stage hydraulic fracturing, pilot production testing, and planning of pipeline corridors for field development;
- **stage 5:** commercial development - following a commercial decision to proceed, and government approvals for construction of gas plants, pipelines and other infrastructure, the drilling and fracturing of a network of production wells; and
- **final stage:** decommissioning - removal of the wellhead, plugging of the steel casing with cement and steel, and removal of all production equipment, production waste, pipelines and other infrastructure, and the rehabilitation of all cleared areas.

5.3 Site and well management considerations

5.3.1 Site infrastructure

During drilling and hydraulic fracturing there is a concentration of heavy equipment on site, along with large stockpiles of drilling supplies and hydraulic fracturing materials. This can involve thousands of truck movements per well site over some months, with directional drilling occurring over several months, and hydraulic fracturing usually taking less than one month.[12] After the completion of drilling and hydraulic fracturing, all heavy equipment is removed and permanent surface infrastructure constructed, including a cement well pad, a wellhead, gas pipeline, and fencing to keep livestock and other animals away from the well. In most cases, the final footprint of the wells and surface facilities is much smaller than the original drilling footprint.

5.3.2 Well integrity

There is considerable evidence to indicate that well integrity is an issue for the shale gas industry, however, the performance of well integrity in modern wells is much improved when compared to earlier wells and legacy wells.

Reports from some shale gas fields of the US (for example, the Marcellus Basin in Pennsylvania) indicate a sixfold higher incidence of cement and/or casing issues for shale gas wells compared with conventional gas wells: 6.2% compared with 1.0% for oil wells.[13] However, according to the Australian Petroleum Production and Exploration Association (**APPEA**), the average fracture rate of casing or cement in the US is as low as 0.1% to 0.3%. For wells constructed to modern standards this rate has been reported to be only 0.004% compared with 0.2% for older wells,[14] and is most commonly attributed to slow leakage of methane around the external casing, which, once identified, can be remediated by additional cementing and pressure testing. Faulty well integrity and not hydraulic fracturing is considered to be the primary cause of the aquifer contamination that has occurred in Pennsylvania and Texas in their respective shale gas basins.[15] The improvements of the past few decades in well design and well testing are considered to have substantially reduced well integrity risks for contemporary installations.[16]

The Queensland Gasfields Commission has reported on well integrity where the statutory notification rate regarding failure or suspect downhole cement was 0.3%. Following remediation the likelihood, and therefore, risk of a subsequent breach of well integrity has been reported as being very low to near zero.[17] The Western Australia Department of Mines and Petroleum (**WA DMP**) analysed over 1,000 non-decommissioned wells and found that 9% had production tubing failures and 3% had production casing failure.[18] However, importantly, in all cases, the near surface aquifers surrounding the wells remained protected by the surface ground conductor casings, where no failures were shown to have occurred.

To date in SA there have been no reported impacts on aquifers, noting that while the conventional oil and gas industry is mature in that State, the unconventional gas industry is still at a very early stage in its development following Santos' first successful tight gas well drilled in 2012.

The WA Legislative Council's Standing Committee on Environment and Public Affairs assessed the likelihood of vertical fractures from the hydraulic fracturing process intersecting near-surface groundwater aquifers as negligible, and the risk of water contamination as a result of upward migration of methane during hydraulic fracturing as highly unlikely.[19] The report recommended baseline monitoring of groundwater water quality to measure the concentration of methane prior to hydraulic fracturing occurring to determine the pre-existing 'natural' concentrations of methane in order to ensure that any subsequent rises in methane that are detected provide unambiguous evidence for impact from the gas extraction operation, and to provide the benchmark for any remediation that may be required.

There has been one instance of a well blowout in the Northern Territory. This occurred for a vertical fracturing operation being conducted in September 2012 on Petrofrontier's Baldwin-1 well.[20]

12 ACOLA Report.
13 Ingraffea et al. 2014; Jackson 2014.
14 Australian Petroleum Production and Exploration Association, submission 215 (**APPEA submission**).
15 Darrah et al. 2014.
16 Jackson 2014.
17 Queensland Gasfields Commission 2016.
18 APPEA submission.
19 WA Report.
20 Department of Primary Industry and Resources, submission 226 (**DPIR submission**).

5.3.3 Decommissioning

Following the production lifetime of a well (typically 20 to 50 years), the wellhead is removed and the steel casing is plugged with cement and steel. In addition to closure of wells, decommissioning involves the removal of all production equipment, production waste, pipelines and other infrastructure, and the rehabilitation of all cleared areas.

At the well site, the wellhead is removed, the steel casing is filled with cement at various intervals, including the perforated zone, the middle of the well bore and within about 30 m of the surface. Also, fluid with an appropriate density is placed between the cement plugs in order to maintain adequate pressure in the voids between the plugs.

Pangaea Resources Pty Ltd's (**Pangaea**) submission to the Inquiry presents a detailed explanation of the measures implemented by it to prevent fluid/gas flow and to minimise the possibility of freshwater aquifer contamination or surface water contamination after the decommissioning of wells:

- steel bridge plugs are inserted in the wellbore at various levels. Together with the cement plugs they provide a long term barrier and create segmented pressure cells should the steel casing ever corrode or be broken by fluids in the local geological setting or tectonic stresses or even earthquakes;
- after the well bore is plugged, the fluids remaining in the reservoir are no longer capable of flowing to the surface because the lowest pressures within the pathway are into-not out of- the reservoir; and
- cement plugs are placed inside the steel casing adjacent to zones bearing hydrocarbons or water bearing zones, ensuring that the cement external to the casing and the casing itself are not compromised by corrosive fluids or tectonic stresses over long periods of time.[21]

Should fluids gain access into the casing, the presence of several layers of cement plugs should mitigate the risk of and movement into a place where environmental harm would result.

5.4 Water use

Shale gas extraction requires the use of large quantities of water, which may be obtained from local surface or groundwater sources, or is transported to the site from outside the region, and is typically stored in large, above ground ponds.[22]

There has been a substantial amount of data published over the past 10 years regarding the volumes of water used for drilling and hydraulic fracturing.[23] Considerable care needs to be taken in interpreting this information because of the rapid changes in technology that have occurred over this period, and the differences in water use and well density between vertical and horizontal wells. In particular, the increasing use of multi-well assemblies in association with much longer horizontal well sections is profoundly changing the water use profile of the industry.

In the US, the most recent long horizontal wells require 30-40 fracturing stages, with a current overall industry average of 16 stages per horizontal well. This requires a proportional increase in water use per well: for example, a 3 km horizontal well will require three times as much water as a 1 km horizontal well. Typical water volumes used are around 1-2 ML for well drilling, and approximately 1-2 ML for each hydraulic fracturing stage.[24]

5.5 Wastewater production and composition

Three main sources of wastewater are produced during the shale gas extraction process:

- **water:** in drilling mud used to drill the initial well bore;
- **flowback water:** water that is returned to the surface in the first few weeks to months after hydraulic fracturing has occurred; and
- **produced water:** water from the shale layer produced over the lifetime of the well.

5.5.1 Wastewater production

Depending on the nature of the hydrocarbon-containing shale formation, 20-50% of the volume of the initially injected water is returned to the surface as flowback water. Thus, for a typical 20 ML total volume of water used to hydraulically fracture a horizontal well, some 4-10 ML could come back to the surface as flowback water.[25] Based on US experience, the discharge of flowback water typically lasts for 4-6 weeks, during which time the discharge rate decreases from about 550 L/min to about 4 L/min.[26] Once above ground, the flowback water is either stored in temporary storage tanks or ponds or is conveyed by a pipeline to a wastewater treatment plant.

The initial period of flowback water collection (up to two months) is followed by a production period of 20 to 40 years, during which time a typically much smaller amount of produced water returns to the surface along with the gas produced.[27] Although the rate of flow is very much less than in the initial flowback stage, in aggregate, the volume of produced water can be quite substantial. Based on US experience, the ratio of volume of flowback to produced water is very dependent on the formation.[28] This produced water also needs to be collected and conveyed to a central storage or treatment facility for the life of the well.

5.5.2 Composition of hydraulic fracturing fluid

The United States Environmental Protection Agency (**US EPA**) found that approximately 1,100 different chemicals had been used in hydraulic fracturing in the period between 2005 and 2013. Hydraulic fracturing technology has evolved rapidly over the past decade, and much greater attention is now being paid to the potential for contamination of below ground and surface environments, with a much smaller fraction of these chemicals now being routinely used in modern hydraulic fracturing practice. For example, a detailed analysis (based on 34,675 disclosures and 676,376 ingredient reports contained in the United States FracFocus database) of the chemical usage data in the United States between January 2011 and February 2013 showed that only 5% (35) of the total identified number of chemicals was used in most of the fracturing operations over that period.[29]

However, technology providers did not disclose the actual identity of a total of 381 chemicals, and claimed those chemicals, or chemical mixtures, as confidential business information (**CBI**). The use of CBI reduces the completeness

21 Pangaea Resources Pty Ltd, submission 220 (Pangaea submission).
22 Hoffman et al. 2014.
23 ACOLA Report; US EPA Report
24 ACOLA Report; US EPA Report; APPEA submission.
25 ACOLA Report; US EPA Report.
26 Ziemkiewicz and He 2015.
27 Kondash and Vengosh 2015.
28 Kondash and Vengosh 2015; Kondash et al. 2017.
29 US EPA Report.

of the data sets and the level of confidence that can be placed in any assessment of the toxicity of chemical used in hydraulic fracturing. The issue of CBI is contentious and is anecdotally one of the reasons the industry is moving towards the use of non-proprietary chemicals that can be openly disclosed in databases like Fracfocus.[30]

The Panel notes that public disclosure of *"specific information regarding chemicals"* used in hydraulic fracturing is required in the Northern Territory,[31] a condition that has been accepted by the shale gas companies. For example, the chemicals used for the 8 unconventional wells[32] that have been hydraulically fractured in the Northern Territory are available on the Department of Primary Industry and Resources (**DPIR**) website.[33] The chemicals used for the Origin Energy Ltd (**Origin**) Amungee NW-H1 production test well were disclosed by Origin to the Northern Territory Government and to the Panel.[34] This is likely to be indicative of contemporary practice for multistage horizontal hydraulic fracturing.

The 40 chemicals listed by Origin in its environment management plan (**EMP**) for the Amungee NW-IH well are a consistent subset of the much larger list compiled by the US EPA.[35]

5.5.3 Composition of flowback and produced water

The initial composition of the flowback water that is produced soon after hydraulic fracturing ceases and pressure is relieved is likely to closely resemble depleted fracturing fluid. However, with time, the decreasing daily volumes of fluid produced will contain more and more of the mobile (soluble) geogenic components present in the fractured rock.[36]

Typically, the flowback water produced after the initial flush is quite saline (>50,000 mg/L TDS), especially if the target formation is of marine origin. Flowback water contains residuals of the chemicals used in the hydraulic fracturing process plus geogenic chemicals that originate from the shale formation itself.[37] These geogenic chemicals include salts, metals and metalloids, organic hydrocarbons, and naturally occurring radioactive material (**NORM**), depending on the geochemistry of the deposit. The actual concentrations of these various components depend both on the geochemical nature of the target formation and on the hydraulic fracturing process used.

Produced water is typically very saline (50,000-200,000 mg/L TDS) with higher concentrations of geogenic chemicals than in flowback water but with very little of the chemical signature of the fracturing fluid that was used.[38]

In the US, approximately 600 discrete chemicals have been detected in flowback and produced waters, and of this number, only 77 were components of the hydraulic fracturing fluids used.[39] This suggests that many of the hydraulic fracturing chemicals are either retained in place or else are degraded or transformed into other chemical compounds (or perhaps not specifically measured). There is increasing evidence that such transformation reactions do occur between components of the hydraulic fracturing mixture, and by reaction of hydraulic fracturing components with geogenic compounds.[40]

A variety of volatile and semi-volatile organic compounds, including BTEX (benzene, ethylbenzene, toluene and xylenes), have been detected in flowback and produced water from shale reservoirs.[41] In particular, average total BTEX levels in shale flowback water have been found to be one to two orders of magnitude higher than in water produced from CSG extraction. This is an important finding because it indicates that caution needs to be exercised in extrapolating risk assessments made on CSG produced waters to what might be the case with flowback water from deep shales. There are, however, wide variations in the concentrations of organic compounds being measured across different shale plays,[42] which could result from lateral variations in the extent of organic maturation across the formation, combined with differences in the compositions of the hydraulic fracturing fluids being used.

The Panel is cautious in using US data, which is quite variable across individual shale basins, to gain an understanding of the likely composition of flowback waters that will be produced in the Northern Territory. Only over the past five years have more extensive (and intensive) measurements been made in the US of the concentrations of organic compounds present in flowback and produced water. Knowledge of flowback water compositions is therefore provided by a few studies on a relatively limited number of samples wherein the full range of inorganic and organic constituents have been determined. This has limited the capacity for meaningful risk assessments of flowback waters to be undertaken, compared with the known chemicals present in the hydraulic fracturing formulations. This situation is also complicated by the fact that the concentrations of these organic compounds are very site specific, depending both on the shale formation being targeted and on the formulation of the hydraulic fracturing fluid(s) being used.

There is very limited data on the composition of flowback water produced by shale gas extraction in Australia, and this makes the need for empirical data from test wells all the more important. However, the overseas studies do suggest that flowback and produced water can contain a much greater number of potentially environmentally sensitive chemicals than are present in the original hydraulic fracturing fluid composition, and that the majority of these additional compounds originate from the minerals and organic compounds present in the shale formation. However, this does not mean that because a chemical is detected in flowback or produced water it will be harmful to human health or the environment.

The Panel notes that while the shale gas industry in the US is now, for the most part, required to publicly disclose the composition of hydraulic fracturing fluids in databases such as Fracfocus, similar disclosure has not been required for the composition of flowback waters.

30 www.FracFocus.org.

31 *Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (NT), cl 342(4).

32 DPIR submission, page 47.

33 At https://dpir.nt.gov.au/mining-and-energy/public-environmental-reports/chemical-disclosure-reports.

34 Origin Energy Ltd, submission 153 (**Origin submission**).

35 US EPA Report.

36 Ziemkiewicz and He 2015.

37 Hayes and Severin 2012; Arthur and Cole 2014; Ziemkiewicz and He 2015; US EPA Report; Butkovskyi et al. 2017; Stringfellow et al. 2017.

38 Kondash et al. 2017.

39 US EPA Report.

40 Kahrilas et al. 2016; Tasker et al. 2016; Hoelzer et al. 2016.

41 US EPA Report; Butkovskyi et al. 2017.

42 Maguire-Boyle and Baron 2014.

This causes difficulties with the assessment of the status of water management practices in the industry, a situation that has been noted in recent publications on water sourcing, treatment and disposal practices in the shale gas industry in the US and Canada.[43]

A similar situation currently exists in the Northern Territory, where disclosure of the composition of flowback water is not mandated. This contrasts with the UK, where the UK Onshore Shale Gas Well Guidelines require that a range of information (including volumes and composition) about flowback fluids should be available for disclosure by the operator.[44]

5.6 Management and reuse of flowback and produced water

5.6.1 Storage

Flowback water is typically stored initially in open, lined surface ponds that may be constructed on the land surface or excavated below ground level. In the US there has recently been a move towards storing flowback water in special purpose, above ground tanks. The same ponds or tanks that are used to store the water used to initially formulate the fracking fluid can also be used to store flowback water, depending on quality of the water, and extent of reuse.

The Panel notes that since 1-2 ML of water is required for each stage of fracking, and at least 20 stages of fracking are likely based on developing industry practice, this means that at least 40 ML of storage will be needed per well for a fully developed production scenario. Obviously, this volume will not be cumulative for a multi-well pad configuration, depending on the extent of reuse possible, and noting that the wells would be fractured sequentially rather than concurrently.

An example of the type of storage used and storage volumes required was provided by Origin in its EMP for the Amungee NW-1H 11 frack stage test well.[45] An aerial photograph of the site showing the layout of the ponds and other site infrastructure was provided in Origin's submission to the Panel.[46]

5.6.2 Re-use

Re-use refers to the practice of using treated or untreated flowback and produced water as a proportion of the water used to make new batches of hydraulic fracturing fluid. Re-use of wastewater can reduce, but not eliminate, the amount of fresh water needed for hydraulic fracturing since the volume of flowback water from a single well is generally small compared to the total volume needed to fracture a well.

The extent of re-use of flowback or produced water depends on its quality, as certain contaminants can interfere with hydraulic fracturing performance. For example, the presence of calcium and sulfate ions can cause scaling in the well, and the presence of suspended solids can decrease the effectiveness of biocide, which together with scaling can cause plugging of fracture networks and wells. 'Slickwater' fracturing systems, containing polyacrylamide polymer as a friction reducer, are generally considered best suited for re-use because most of this polymer remains in the shale. However, slickwater treatments usually require substantially more water than gel-based systems.

Based on the chemical composition of the hydraulic fracturing wastewater and the desired effluent water quality, a series of treatment technologies are necessary. The development of cost-effective treatment systems for the complex mixture of inorganic and organic compounds contained in flowback waters is currently a rapidly evolving field.[47]

Salinity is generally not an issue for the treatment of shale gas wastewaters, since high concentrations of ions such as sodium and chloride can be tolerated in re-use water. Indeed, seawater has been successfully used to prepare hydraulic fracturing fluid for offshore operations. However, high salinity flowback water can also be supersaturated with salts like gypsum, barite or calcite that could severely compromise the efficiency of subsequent fracturing operations by causing precipitates to form and block up the newly created fracture network. In particular, when calcium and barium levels are high, scale inhibitors must be used or salt content reduced before the water can be re-used.[48]

Flowback water also contains a diverse range of organic compounds, some of which may be difficult to treat.[49] However, many of these organic compounds are biodegradable and could be treated in purpose built biological treatment plants.[50] The effective removal of these organic compounds would be of most concern if flowback water is to be treated and disposed of offsite, rather than being reused for hydraulic fracturing.

Removal of suspended solids, using a process such as electrocoagulation, is much less costly than the removal of dissolved salts using energy intensive processes such as reverse osmosis or thermal brine concentration.[51] This may be the only treatment required if there are low concentrations of potentially problematic ions (for example, calcium and sulfate) in the flowback water.

However, conventional oilfield water treatment technologies (such as reverse osmosis) may not always be effective in unconventional gas projects due to specific constituents in flowback and produced water, such as residual polymers (from hydraulic fracturing chemicals), which have the potential to severely interfere with membrane-based treatment.

5.6.3 Reinjection

Historically, in the US there has been a generally low percentage re-use of flowback water,[52] and >95% of all wastewater from oil and gas extraction has historically been disposed of through reinjection into disposal wells located in conventional petroleum reservoirs.[53] However, aquifer re-injection is being increasingly restricted because of concerns with potential for groundwater contamination and induced seismicity.

43 For example, Alessi et al. 2017.
44 UK Onshore Oil and Gas 2016, section 9.3.
45 Origin 2016, p 21.
46 Origin submission, p 81.
47 US EPA Report, Appendix F.
48 Maguire-Boyle and Barron 2014.
49 Butkovskyi et al. 2017.
50 Kekacs et al. 2015; Lester et al. 2015.
51 Butkovskyi et al. 2017; Costa et al. 2017.
52 US EPA Report.
53 Rodriguez and Soeder 2017.

There are no known potential sites for re-injection of flowback water into conventional hydrocarbon formations in the Northern Territory outside the Amadeus Basin.[54]

5.6.4 Wastewater management incidents

The 2016 assessment by the US EPA collated data from thousands of wells that had been drilled and fractured over the past decade.[55] It concluded that there was no evidence of widespread impact on shallow aquifers, and no demonstrated cases of contamination of drinking water resources from hydraulic fracturing at depth. However, it did identify cases of drinking water contaminations from spills of fracturing fluids or flowback water, and contamination of aquifers as a result of failure of well integrity during and after hydraulic fracturing.

There is potential for accidental releases, leaks and spills of hydraulic fracturing chemicals and fluids, and flowback water that could lead to contamination of nearby surface water and seepage through the soil profile into shallow aquifers.[56] This is discussed in greater detail in Chapter 7.

Most spills are related to the storing of water and materials in tanks and pits, and in moving wastewaters in pipelines between equipment.[57] Not surprisingly, the incidence of spills has been found to be greatest within the first three years of well life when 75-94% of spills occurred. This is the period when wells are drilled, hydraulically fractured, and have their largest water production volumes.[58] However, while there have been more than one million fracture stimulations (fracturing) treatments in North America and more than 1,300 in South Australia's Cooper Basin, there has been no reported evidence of fracturing fluid moving from the fractures to near surface aquifers.[59]

There have been instances of contamination of surface waterways by discharges of incompletely treated flowback waters. This occurred in Pennsylvania in the US during the early development of the Marcellus gas field.[60] This is a separate issue from surface spills and occurred as a result of inappropriate use of municipal wastewater treatment plants to treat flowback water, a function for which they were never designed, followed by discharge of the partially treated water into rivers. This practice has now been banned by US federal regulation.

Hydraulic fracturing has been taking place in the Northern Territory since 1967, but mainly as a process to enhance hydrocarbon production from conventional reservoirs in vertical wells. Only since 2011 has very limited hydraulic fracturing of unconventional formations been undertaken. The DPIR reports that to date these operations have had little impact on water resources, but no specific details were provided in the DPIR submission.[61] There has been no independent assessment and reporting of environmental performance by the gas industry in the Northern Territory. In any event, the gas industry in the Territory is in its infancy (in size) and the performance data available is unlikely to be representative of a contemporary full-scale industry.

5.7 Solid waste management

The solids produced by drilling represent a substantial waste stream associated with the production of shale gas. When a well is drilled, drilling fluids (including drilling muds) are used to maintain circulation of the drill bit and to transport drill cuttings back to the surface. Drill cuttings produced by exploration activities are typically disposed of in drill mud pits, which are backfilled to the ground surface when drilling is completed. Before this is done excess liquids are typically evaporated, and the drilling muds are able to be reused in the drilling of new wells.

In the US, the disposal of the large amounts of drill cuttings produced by a full-scale industry is the cause of some concern, given the nature of this material and its potential to leach organic and inorganic components into the near surface environment.[62]

The magnitude of the issue is exemplified by considering the situation for an 8 well pad, drilled to 3,000 m depth, with 3,000 m long horizontal sections for each well, and with a 10 cm diameter well bore. This well configuration would produce around 190 m^3 of shale horizon material from the horizontal wells and approximately the same amount of material from the vertical sections depending on depth, not allowing for drilling cuttings from the larger diameter conductor and upper casings. Thus, approximately 870 tonnes[63] (dry weight) of shale and other material would be extracted per multi-well pad. While this is a very small amount of material compared with that produced by a typical coal or metal mine, when aggregated over hundreds of wells it would comprise a substantial amount of material requiring appropriate management.

A strategic management issue for any potential shale gas industry in the Northern Territory will be the question of whether this solid waste should be contained in a purpose-built and engineered centralised facility, or contained and managed on a per well pad basis as is currently the case for the exploration regime.

5.8 Seismicity and subsidence

5.8.1 Seismicity induced by hydraulic fracturing

There is potential for induced seismicity to result from the uncontrolled propagation of fractures produced during the hydraulic fracturing that can extend for up to several hundred metres in varying directions in the adjacent geological strata.

There is now considerable evidence[64] that low magnitude earthquakes recorded in the US and the UK may occur during hydraulic fracturing and certainly larger scale (Richter scale magnitude greater than 2.0) earthquakes have occurred during the reinjection of wastewater.[65] There is always the possibility that any introduced water could lubricate existing geological faults and therefore the location of deep injection wells should be controlled by knowledge of the local geology and the avoidance of highly faulted areas.

54 DPIR submission.
55 US EPA Report.
56 US EPA Report; Maloney et al. 2017.
57 Patterson et al. 2017.
58 Patterson et al. 2017.
59 Cooke 2012; US EPA Report.
60 Mauter et al. 2014; Mauter and Palmer 2014.
61 DPIR submission.
62 Phan et al. 2015.
63 Assuming a density of 2.3 t/m^3.
64 For example, de Pater and Baisch, 2011; Royal Society Report.
65 ACOLA Report; US EPA Report.

Induced seismicity associated with shale gas hydraulic fracturing has been reported in both the UK and the US.[66] The US experience is that the seismicity levels vary for individual shale gas basins, which reflects a combination of the depth of the producing layers (shallower layers experience lower induced seismicity levels before shutdown of the hydraulic fracturing process occurs) and local geology (degree of faulting in the area of interest).[67]

Based upon the US and UK experience, the extent of fracturing can be monitored using sophisticated technologies, with the fracturing distance controlled by varying the pressure used in the hydraulic fracturing process.[68] The Panel has been told that implementation of the trigger levels used in the Traffic Light Monitoring System,[69] which inform the operators as to the induced seismicity occurring during hydraulic fracturing by monitoring seismic activity in real time, can reduce the likelihood of induced seismic events (earthquakes). Hydraulic fracturing will be stopped if minor earth tremors of magnitude 0.5 on the Richter scale occur. This technique can be used to reduce the likelihood of earthquakes during the hydraulic fracturing operations.

Overseas findings to date suggest that hydraulic fracturing stimulation of earthquakes of sufficient scale (Richter scale magnitude 2.0 or greater) as to be felt locally and to cause slight damage to buildings are extremely rare.[70]

In its submission, DPIR states that there is no evidence to suggest that the hydraulic fracturing process can produce measurable earthquakes in non-faulted geological areas.[71] The statement must, however, be qualified by the comment that Australia does not yet have any seismic risk data covering shale gas operations.

Seismic activity caused by the reinjection of wastewater into the ground is discussed below in Chapter 7.

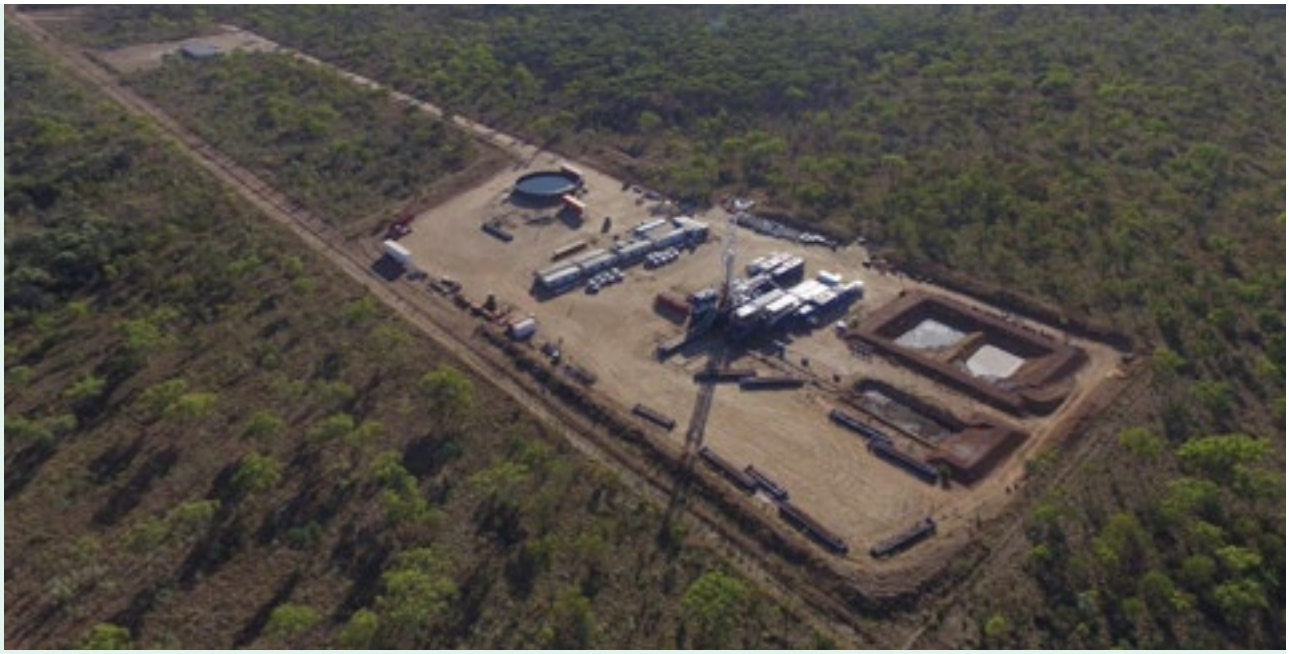
5.8.2 Subsidence

The development of sinkholes as a result of the hydraulic fracturing process has been noted as a concern of the community. Also of community concern was the presence of cavities in karstic terrains (known to occur in the Beetaloo Sub-basin) that could possibly result in problems with the placement and anchoring of the conductor casing and upper sections of any wellbore.

The Panel has not located any scientific information to date about the potential for the development of sinkholes or diminished well integrity as the result of drilling in karstic terrain. However, the Panel notes that sinkholes normally occur at shallow depths (tens of metres) in either limestone or evaporite (salt) rock that has been subject to long term solution by groundwater.

Further, the Panel considers that sinkholes are unlikely to occur as a result of hydraulic fracturing because of the large vertical distance between the hydraulic fracturing zone and the surface (several thousand metres), a distance over which the intervening rocks should compensate for any cavities produced by hydraulic fracturing. In this context, the Panel notes that very little incompressible material is actually removed during the drilling and fracturing process, so there are very few cavities that could contribute to subsidence. This contrasts with CSG operations where a substantial proportion of the original void volume is removed as produced water, and there is a real possibly of subsidence given the closer proximity to the surface.

The Panel acknowledges, however, the potential for complications associated with drilling in karstic terrain, and the importance of having experienced and licenced drillers conducting drilling operations in such areas.



Amungee NW-1H wellsite in EP98 during drilling operations (30-60 days). Source: Origin.

66 Clarke et al. 2014; Warpinski et al. 2012, respectively.
67 Warpinski et al. 2012.
68 Royal Society Report.
69 UK Government 2017; Wong et al. 2015.
70 SHIP 2017.
71 DPIR submission.

SHALE GAS IN AUSTRALIA AND THE NORTHERN TERRITORY

6

6.1 Australian unconventional gas supplies and total energy use

While the development of CSG reserves has been underway for almost two decades in Queensland, the shale gas industries are still largely in the exploration phases. Australia is considered to, however, have substantial resources of onshore unconventional gas including CSG, shale gas and tight gas.

Geoscience Australia has assessed Australia's potential for unconventional gas (**Table 6.1** and **Figure 6.1**), including CSG, tight gas and shale gas. Its report indicates a 'contingent resource' of shale gas (that is, considered to be potentially recoverable but not yet mature enough for commercial development due to technological or business hurdles) of 12,252 petajoules (**PJ**) and a 'prospective resource' (that is, estimated as of a given date to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which has not yet been drilled) of 681,273 PJ. By comparison, conventional gas is estimated to have a commercially recoverable reserve (a reserve that is commercially recoverable and has been justified for development) of 77,253 PJ, a contingent resource of 108,982 PJ, and a prospective resource of 235,913 PJ.[72]

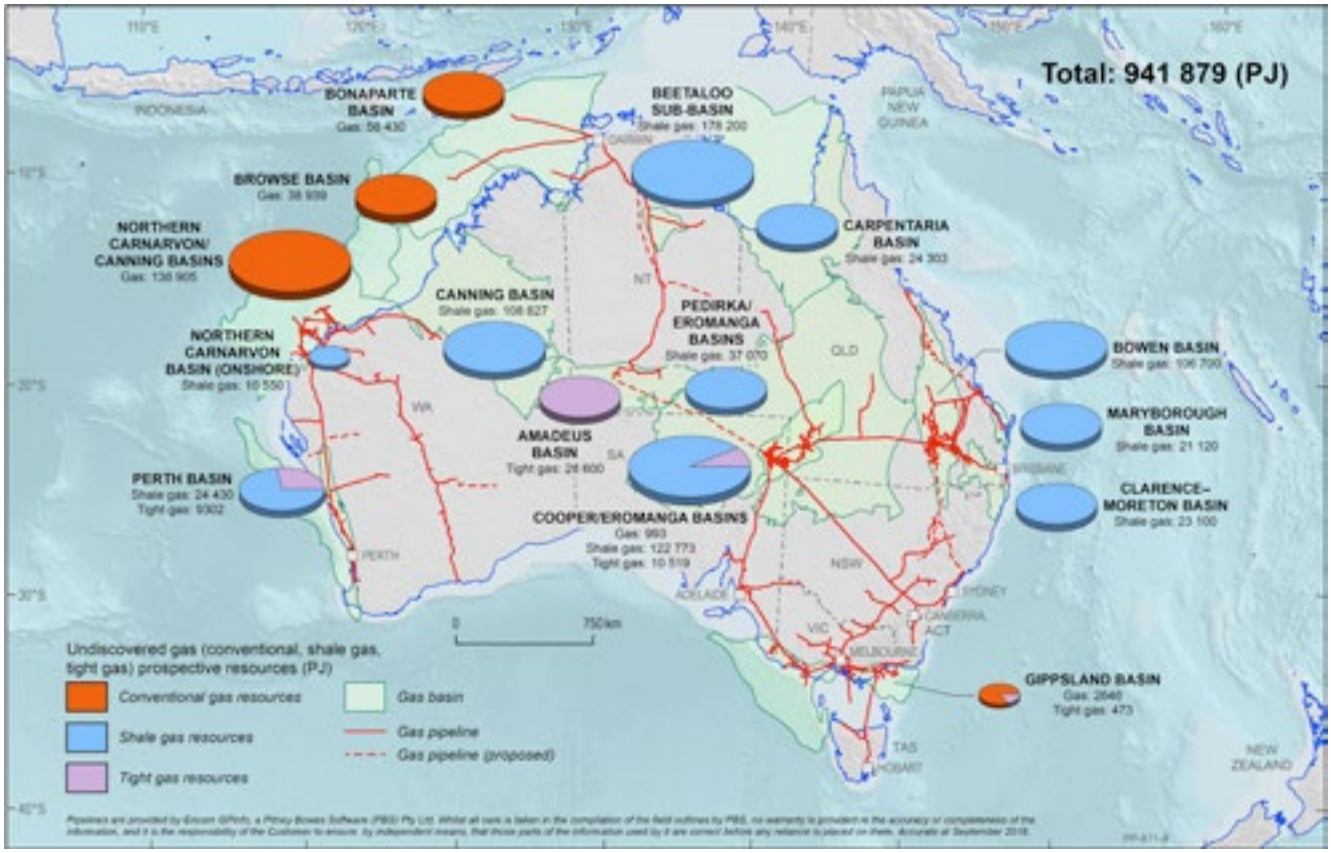
Table 6.1: Total Australian gas resources.[73]

Resource category	Conventional gas		Coal seam gas		Tight gas		Shale gas		Total gas	
	PJ	Tcf	PJ	Tcf	PJ	Tcf	PJ	Tcf	PJ	Tcf
Reserves (resources which are commercially recoverable and have been justified for development)	77,253	70	45,949	43	39	0	0	0	**123,241**	**114**
Contingent resources (resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles)	108,982	99	33,634	32	1,709	2	12,252	11	**156,578**	**143**
Prospective resources (estimated, as of a given date, to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled)	235,913	214	6,890	7	48,894	44	681,273	619	**972,969**	**885**

72 Australian Energy Resource Assessment.

73 Australian Energy Resource Assessment.

Figure 6.1: Summary of Australia's prospective gas resources.[74]



Other reports provide slightly different resource estimates, however, they are of a similar order of magnitude. The Council of Australian Governments Energy Council (**COAG Energy Council**) reports a best estimate prospective resource of 702,000 PJ,[75] and ACOLA provides an aggregated resource of 1,100,000 PJ from 16 basins across Australia.[76]

According to the Office of the Chief Economist's Australian Energy Statistics, Australia's total annual energy consumption from all sources in 2014-2015 was 4,075 PJ, and the Northern Territory's annual consumption over the same period was 85 PJ.[77]

These estimates reflect the state of knowledge several years ago and are due to be updated later in 2017.

74 Geoscience Australia Submission 2017.
75 COAG Energy Council 2015.
76 ACOLA Report.
77 Australian Energy Statistics 2016.

6.2 Exploration for and development of unconventional gas in Australia

In the early 2010s, the Cooper Basin was widely considered to be the most attractive prospect for unconventional gas development in Australia due to the presence of already existing infrastructure that could be leveraged to incorporate unconventional gas sources into the network. It is the basin where the most exploration and development activities have taken place to date. Production facilities and an extensive pipeline network are already in place, supplying gas to SA, NSW, Queensland and Victoria.[78]

However, recent exploration activities and the announced discovery by Origin in 2016 confirming a commercial shale gas resource in the relatively unexplored Beetaloo Sub-basin of the McArthur Basin in the Northern Territory is significant for Australian (and the Northern Territory) shale gas exploration.

The Senate Select Committee on Unconventional Gas Mining Interim Report, Chaired by Senator Glenn Lazarus in 2016 (**Lazarus Report**) provides a comprehensive account of Australia's unconventional gas reservoirs and where exploration and development activity is currently underway.[79] This indicates that:

- unconventional gas production, specifically CSG production, is currently operational in Queensland (since 1996) and NSW (since 2001);
- there is currently no commercial production of shale gas in Australia; and
- exploration is currently underway in Queensland, SA, WA and the Northern Territory, all of which have shale gas prospects.

Since the publication of the Lazarus Report, there has been a moratorium on hydraulic fracturing in the Northern Territory and NSW, and a legislative ban in Victoria.

6.3 Shale gas potential of the Northern Territory

According to Geoscience Australia,[80] total shale gas resources in the Northern Territory are estimated to be 257,276 PJ. Importantly, almost 70% of this (178,200 PJ) is estimated to occur in the Beetaloo Sub-basin of the McArthur Basin. This resource is larger than any one of the North West Shelf conventional gas resources, the Cooper/Eromanga basins, or the Canning Basin shale gas resources. It suggests that the Beetaloo Sub-basin is a world class resource comparable to several of the US shale gas basins.[81]

Geologically, the Northern Territory is underlain by thick sedimentary rock sequences deposited in a number of geological basins. The understanding of these subsurface sequences has been largely developed indirectly through inspection of rocks where they outcrop, geophysical surveys of the subsurface, and interpretation of other indirect indications of the nature of the subsurface such as groundwater chemistry. Direct evidence of the nature of the subsurface geology has been gained where drilling has been undertaken. However, by Australian and global standards, the Northern Territory's petroleum-bearing basins are relatively underexplored and, as a result, the level of geological knowledge of the basins is incomplete and highly variable.

Current understanding of the potential shale gas bearing geological basins is shown in **Figure 6.2**, and is discussed below. The basins that are currently considered to have prospective rocks with the necessary prerequisites for shale gas occurrence, and that have had some confirmation of this interpretation through exploration drilling, are the Amadeus Basin and Beetaloo Sub-basin.

A number of other potential basins are present that have not been extensively or successfully tested to date. These are also considered to have the potential to bear shale gas, and are discussed below. While the broader Northern Territory is still relatively unexplored, current geological knowledge suggests that shale gas is unlikely to occur outside the areas referred to here.

6.3.1 Amadeus Basin

The Amadeus Basin, south of Alice Springs, has had the highest levels of exploration in the Northern Territory and more than 30 years of continuous oil and gas production sourced from conventional reservoirs. The Basin is a large (170,000 km^2) basin up to 14 km in thickness, which contains numerous petroleum systems and the only producing conventional petroleum fields in the onshore Territory (Mereenie oil and gas and Palm Valley and Dingo gas fields), with an additional field (Surprise oil) that is currently not in production. Its thick sedimentary succession is prospective for petroleum at numerous stratigraphic levels, although most exploration and production in the Basin to date has focussed on conventional petroleum systems. While this basin has rocks such as the Horn Valley Siltstone that are prospective for unconventional gas, exploration and development in the region are considered likely to continue to focus on conventional plays.

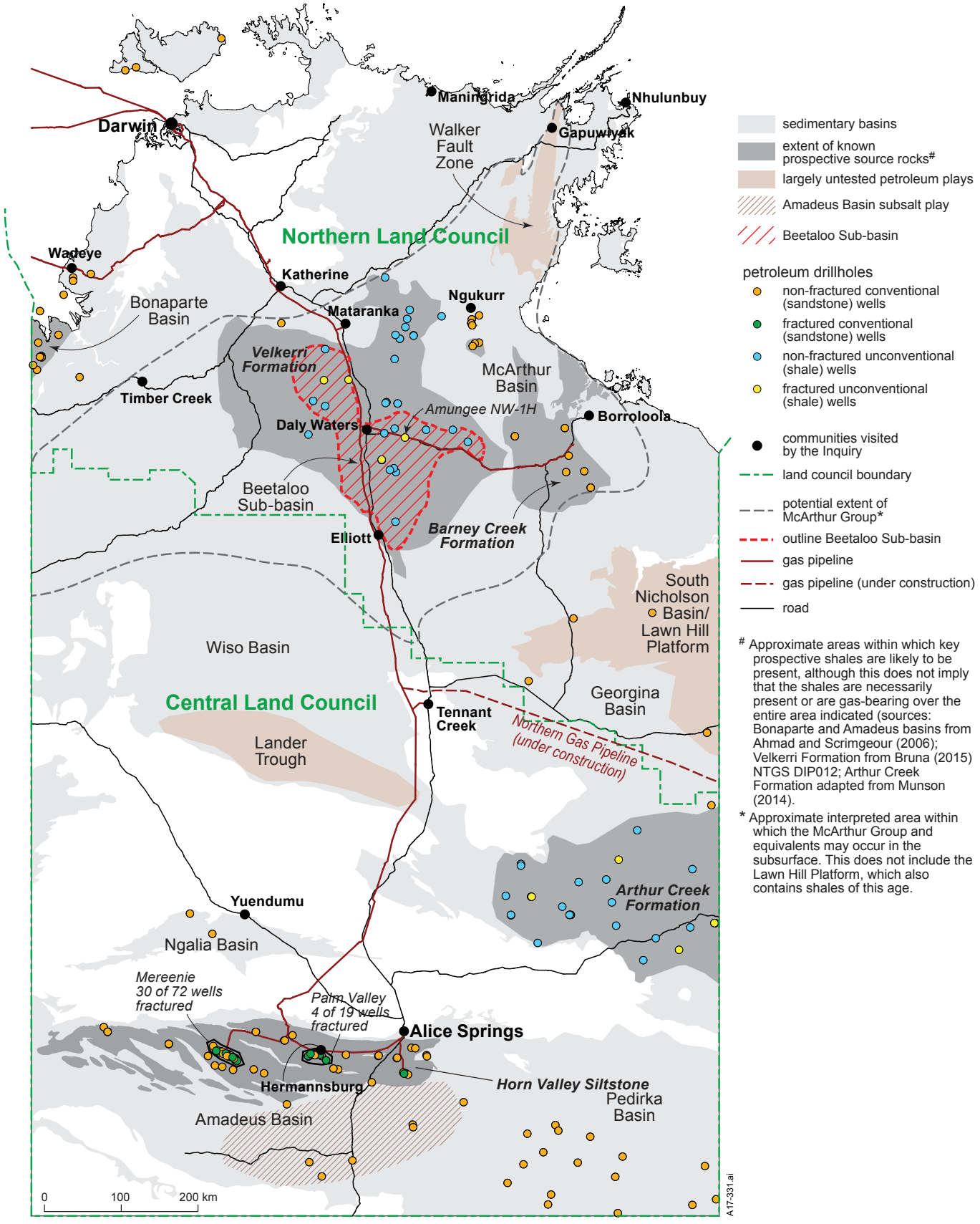
6.3.2 McArthur Basin

The McArthur Basin underlies much of the north-eastern Territory, and contains a succession of sedimentary and minor volcanic rocks that are up to 15 km deep. Petroleum systems in the McArthur Basin include demonstrated conventional and unconventional petroleum systems in the McArthur Group, and a less well understood petroleum system in the underlying Tawallah Group. The Batten Fault Zone within the McArthur Basin, west of Borroloola, has attracted serious attention as a potential gas province since 2010. The most important potential source rock and shale gas play within this part of the broader McArthur Basin is the Barney Creek Formation. Overall, however, while the shales of the McArthur Group are considered to be prospective, they are regarded as a higher exploration risk than the Beetaloo Sub-basin due to the variability of their thickness and organic content.

78 Lane et al. 2015.
79 Australian Senate Select Committee on Unconventional Gas Mining 2016.
80 Australian Energy Resource Assessment.
81 Scrimgeour 2016.

Figure 6.2: Petroleum wells in the Northern Territory showing extent of known prospective source rocks. Source: DPIR.

The grey areas show the extent of known prospective shale gas source rocks, that is, rocks that are considered to have the necessary prerequisites for shale gas occurrence and commercial development. The taupe areas are those that are considered to have the potential prerequisites for shale gas to occur but that have not been tested through drilling.



Approximate areas within which key prospective shales are likely to be present, although this does not imply that the shales are necessarily present or are gas-bearing over the entire area indicated (sources: Bonaparte and Amadeus basins from Ahmad and Scrimgeour (2006); Velkerri Formation from Bruna (2015) NTGS DIP012; Arthur Creek Formation adapted from Munson (2014).

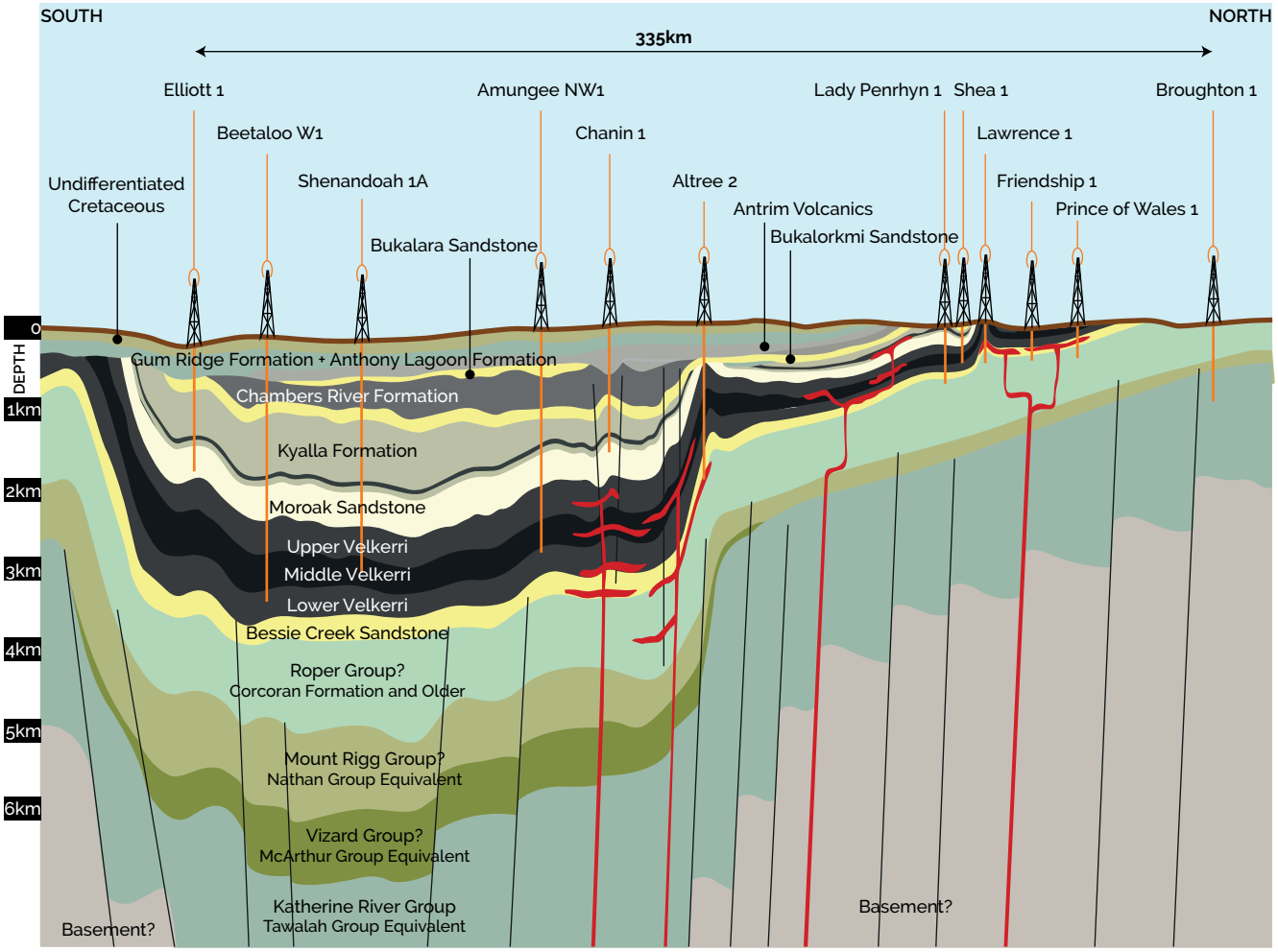
* Approximate interpreted area within which the McArthur Group and equivalents may occur in the subsurface. This does not include the Lawn Hill Platform, which also contains shales of this age.

6.3.3 Beetaloo Sub-basin of the McArthur Basin

Exploration over the past five years in the Beetaloo Sub-basin of the McArthur Basin (south-east of Katherine) has demonstrated the existence of a substantial shale gas resource. The Beetaloo Sub-basin occurs over an area of approximately 30,000 km^2 in the Sturt Plateau region between Mataranka and Elliott, and is comprised of the McArthur Basin's youngest rock unit, the Roper Group, which contains the Territory's most explored shale gas play. The Beetaloo Sub-basin does not outcrop at the surface, but has been defined by seismic profiles, drilling and geophysical data (**Figure 6.3**). The Roper Group consists of a thick sequence of quartz sandstones, siltstones and mudstones, deposited in a variety of shallow-marine, nearshore to shelf environments.[82] The Roper Group sediments are essentially continuous and flat-lying, and range from thicknesses of 1,500 m over most areas to greater than 3,000 m. The Roper Group includes the prospective shales of the gas saturated, quartz-rich Velkerri and Kyalla formations, which have a well demonstrated and potentially productive shale gas resource.

A more detailed description of the geology of the Beetaloo Sub-basin is provided by Fulton and Knapton, GHD, Scrimgeour, Close et al and in the submissions from Origin[83] and Santos.[84]

Figure 6.3: Schematic cross-section across the Beetaloo Sub-basin, showing exploration wells drilled to date[85]



A detailed geological cross section schematic showing the construction and orientation of Origin's Amungee NW-1H well, its relationship to the CLA, and the location of the horizontal section in the Velkerri shale formation, is shown in Figure 6.4. This figure which was provided in Origin's submission to the Inquiry provides a primary reference point for subsequent discussion in Chapter 7 of the potential for sub-surface impacts on water quality.

82 Munson 2016 and references therein; Scrimgeour 2016.
83 Origin submission.
84 Santos submission 168.
85 Close et al 2017.

6.3.4 Bonaparte Basin

The Bonaparte Basin is a large, predominantly offshore, sedimentary basin, extending from onshore coastal areas along the Northern Territory/WA border northward into the Timor Sea. The offshore portion of the Basin is a well established oil and gas province, with proven resources and a number of currently producing fields (for example the Blacktip gas field). The onshore basin in the Territory contains the Weaber gas field. Oil and gas shows have also been recorded from a number of onshore wells, and multiple conventional petroleum systems have been defined in onshore areas. There is also considered to be significant unconventional petroleum potential including tight gas plays in sandstone and limestone reservoirs. However, there has been no on-ground exploration since 2014.

6.3.5 Georgina Basin

The Georgina Basin is comprised of the sedimentary Kiana Group, basalts of the Kalkarindji Province and the marine sedimentary succession of the Barkly Group. The latter includes a thick limestone sequence that forms the Cambrian Limestone Aquifer (**CLA**), a regionally significant water supply aquifer. The Georgina Basin is capped by Cretaceous mudstone and sandstone and recent alluvial and laterite deposits. The southern part of the Georgina Basin is considered to be among the most prospective onshore areas in the Territory for oil and gas potential and to have world class shale source rocks, but the Basin is underexplored. Estimates of potential resources are considered to be poorly constrained, and after unsuccessful well testing in 2014, there have been no active explorations. There is, however, still considered to be potential for both conventional and unconventional discoveries.

6.3.6 Pedirka Basin

The Pedirka Basin occurs in the south-eastern corner of the Territory in the Simpson Desert and also extends over areas of adjoining Queensland and SA. This largely subsurface basin overlies the Amadeus and Warburton basins, and is overlain by the Eromanga Basin. It contains a diverse succession of fluvioglacial, fluvial, lacustrine and coal swamp, and continental red bed deposits up to 1.5 km thick. It has an area of about 100,000 km^2, and much of the basin reaches depths of greater than 400 m, and maximum depths are in excess of 3,000 m at its deepest points in the east. No commercial petroleum has been discovered in the Pedirka Basin, and only non-commercial conventional hydrocarbon accumulations have been found to date in basal sandstones of the overlying Eromanga Basin.

6.3.7 Other basins with possible shale gas potential

Other basins in the Territory have possible shale gas potential but limited geological information.

The level of geological knowledge in the Wiso Basin is low, as the basin is poorly exposed and there have been no petroleum or deep stratigraphic wells drilled anywhere in it. As a result, the Wiso Basin is effectively unexplored for petroleum, although minor hydrocarbon shows have been noted in two of several drill holes. The most prospective area is considered to be the main depocentre of the basin, the Lander Trough in the south of the Basin, with a modelled depth of 2,000-3,000m down to a maximum of 4,500 m.

There is also limited geological information about the South Nicholson Basin and Lawn Hill Platform in the east of the Northern Territory. These contain interpreted stratigraphic correlatives of the McArthur Basin, and are considered to have potential for both conventional and unconventional hydrocarbons. Their correlations with basins with known petroleum systems, plus the lack of exploration to date, suggests that these basins could be important frontier exploration targets in the future.

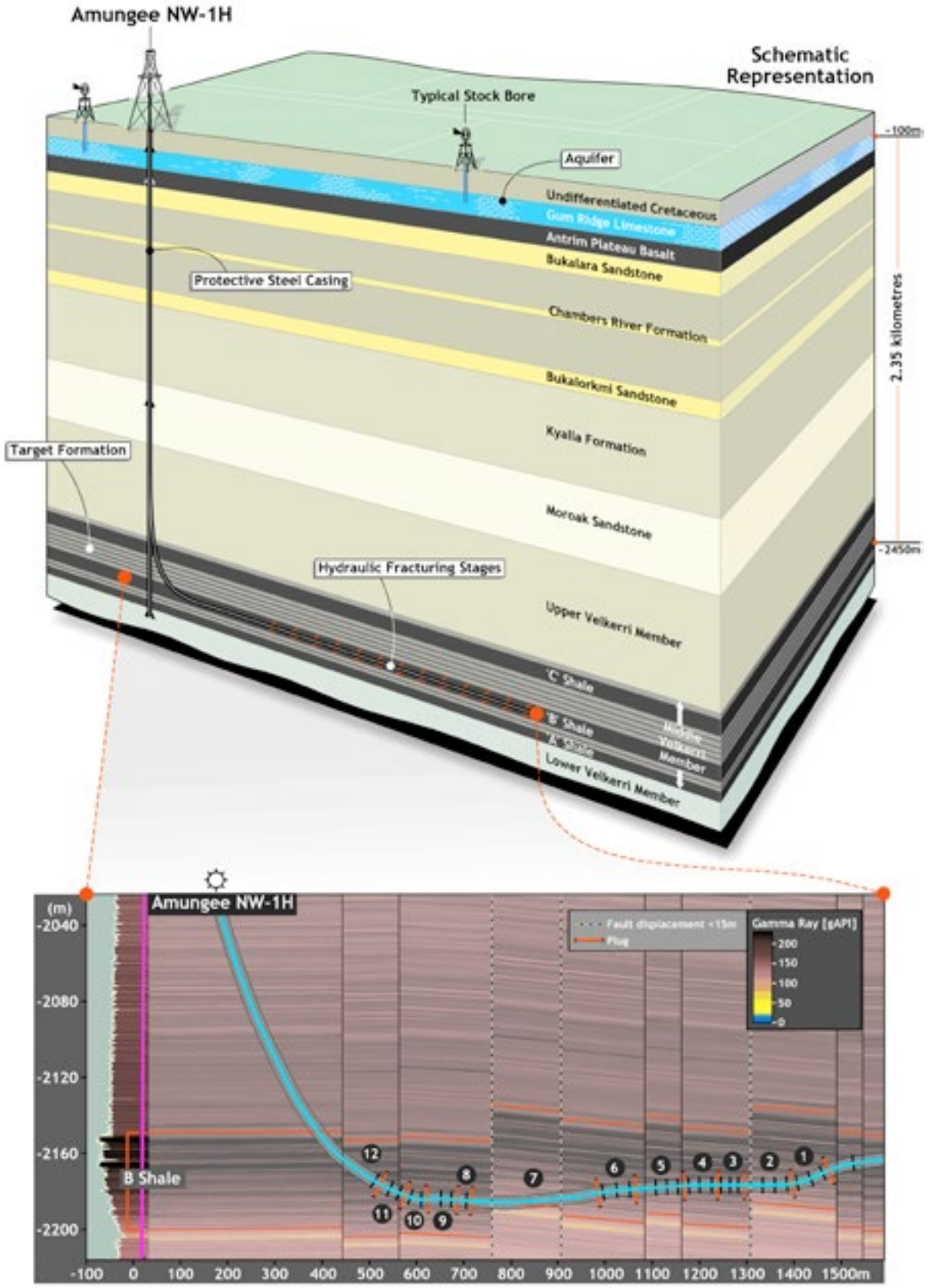
6.4 Likely areas of shale gas development in the Northern Territory

Figure 6.5 shows the current extent of granted petroleum titles in the Northern Territory as well as areas with shale gas potential, indicating that there is current exploration attention focussed on all of the shale gas bearing basins, with the exception of the northern part of the Georgina Basin. In recent years, exploration has focussed predominantly on the Beetaloo Sub-basin, which has received around 50% of the total $505 million of exploration investment since 2010.

Figure 6.6 shows the interest holders for each of the granted petroleum exploration permits as well as the locations of hydraulically fractured unconventional wells. These have been focussed on the Beetaloo Sub-basin and the Georgina Basin. Not all have indicated the presence of shale gas, particularly in the Georgina Basin, which has subsequently seen the relinquishment of exploration tenure by several companies. By contrast, in the Beetaloo Sub-basin hydraulic fracturing results indicated a potentially productive shale gas resource.

Noting the long lead time from exploration to development of shale gas resources, these figures suggest that the most likely area for shale gas development in the foreseeable future (5-10 years) would be the Beetaloo Sub-basin.

Figure 6.4: The Amungee NW1H well lateral section was landed and drilled through the 'B Shale' of the middle Velkerri approximately 2.3 km below the Cambrian Limestone Aquifer. Source: Origin.[86]



86 Origin submission, p 31.

Figure 6.5: Granted petroleum titles and prospective shale gas areas. Source: DPIR.

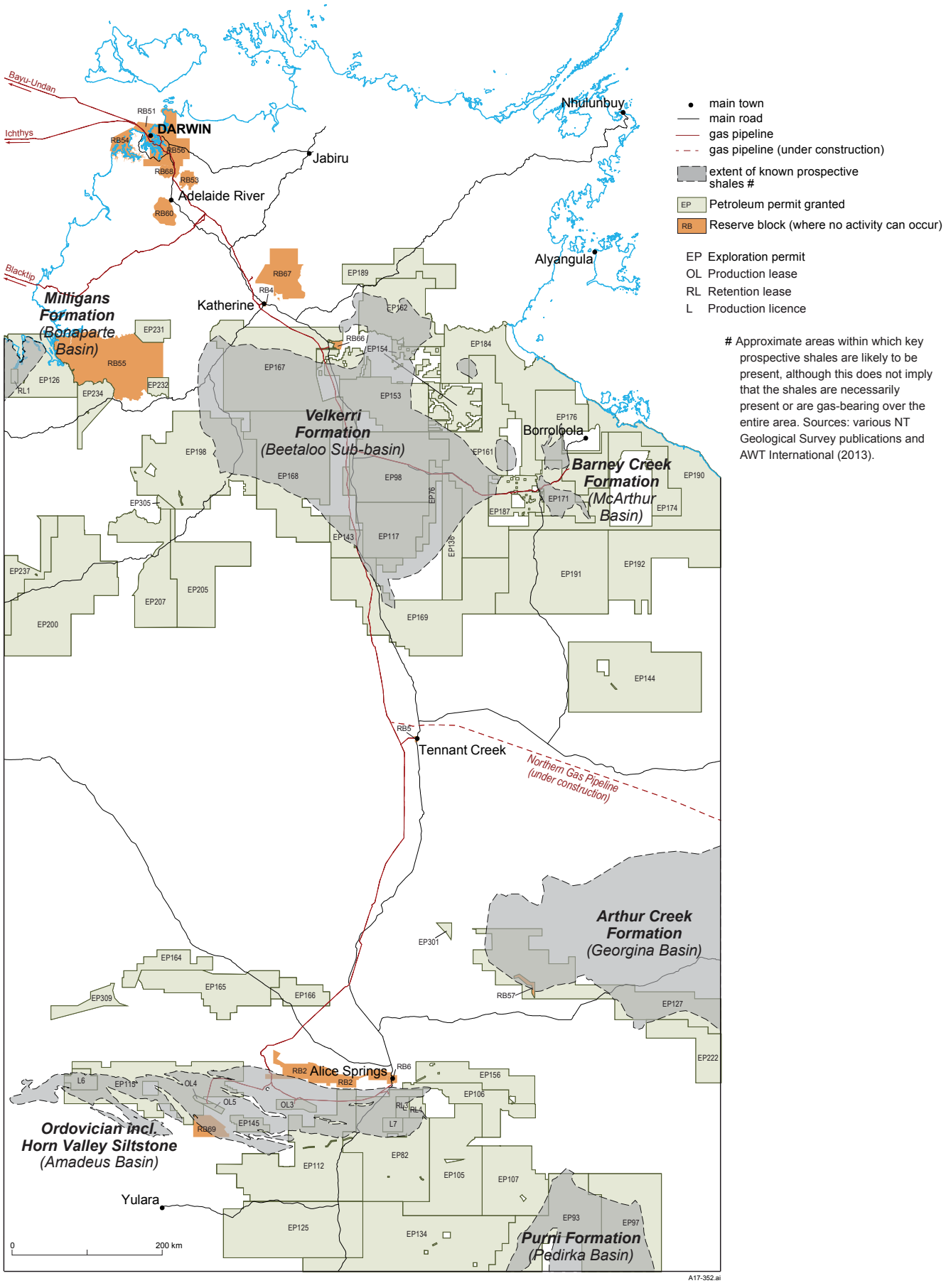


Figure 6.6: Interest holders for granted tenements and hydraulically fractured unconventional petroleum wells in the Northern Territory. Source: DPIR.

Hydraulically Fractured Wells for Shale Resources (2007 to current)

1. Wyworrie-1
Pangaea Resources Pty Ltd

2. Birdum Creek-1
Pangaea Resources Pty Ltd

3. Amungee NW1H
Origin Energy Resources Limited

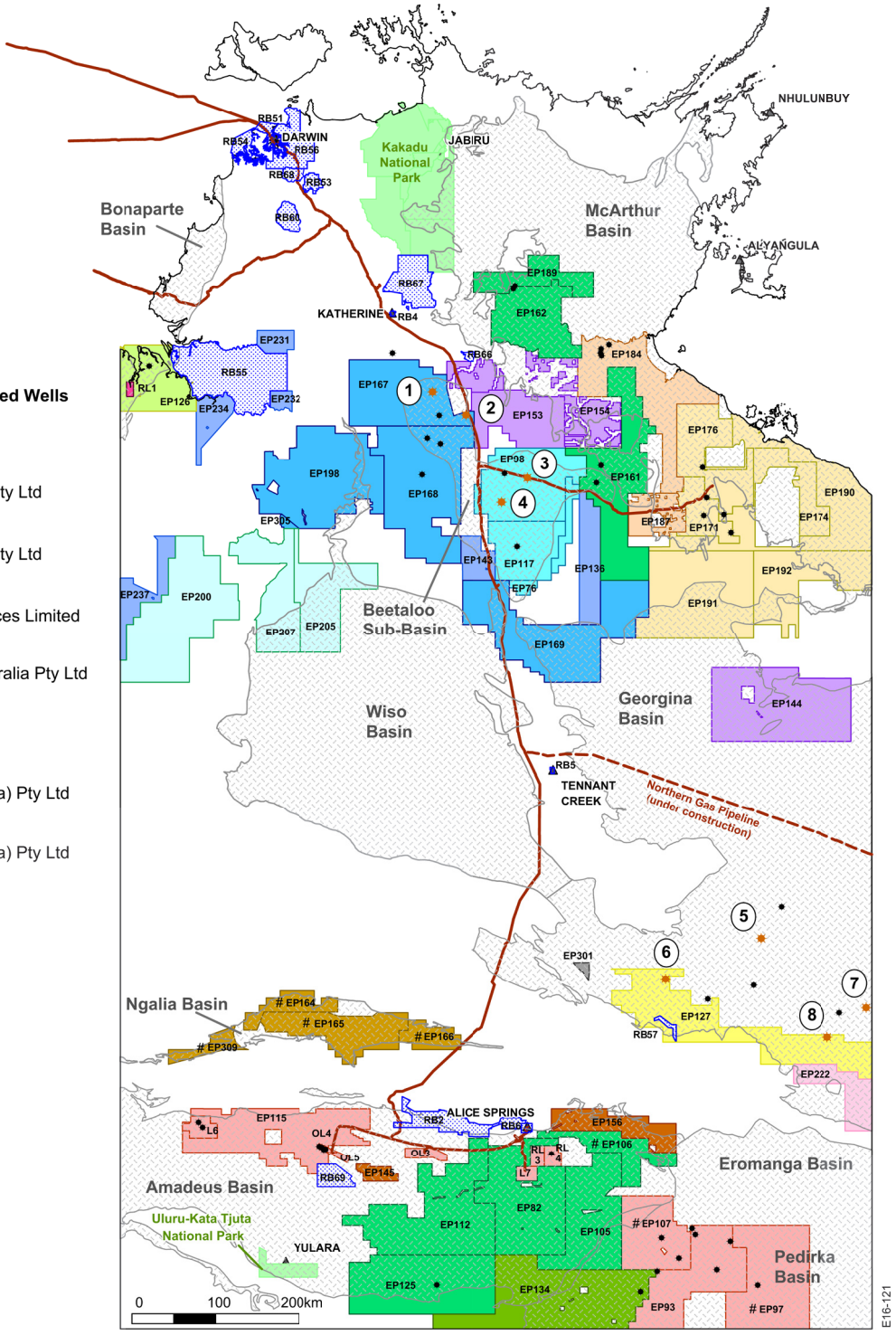
4. Shenandoah-1A
Falcon Oil & Gas Australia Pty Ltd

5. OzDelta-1
Statoil Australia

6. MacIntyre 2H
PetroFrontier (Australia) Pty Ltd

7. Owen 3H
PetroFrontier (Australia) Pty Ltd

8. OzBeta-1
Statoil Australia



Advent Energy Ltd
Armour Energy Limited
Baraka Energy and Resources Limited
Beach Petroleum (NT) Pty Ltd
Blue Energy Limited
Central Petroleum Limited
Imperial Oil & Gas Pty Limited
Minerals Australia Pty Ltd
Mosman Oil and Gas Ltd
Origin Energy Resources Limited
Paltar Petroleum Limited
Pangaea (NT) Pty Ltd
Santos QNT Pty Ltd
Tamboran Resources Limited
Tri-Star Energy Company
Wiso Oil Pty Ltd
Tom Oates
Petroleum Reserved Block
Gas pipeline
Gas pipeline (under construction)
Prospective Petroleum Basin
World Heritage Site
Petroleum Well 2007 to Current
HF Petroleum Well for Shale Resources 2007 to Current
Locality
Application for Surrender Pending

6.5 Possible development scenarios in the Northern Territory

On request from the Panel, three petroleum companies with major activities in the Beetaloo Sub-basin (Origin, Santos and Pangaea) have provided possible future development scenarios. These are summarised in **Table 6.2**. For this Interim Report, the Panel has used this information to provide some idea of the possible development scenarios for an onshore shale gas industry in the Beetaloo Sub-basin, noting that these scenarios are presently uncertain.

6.5.1 Scale of development

The scale of development is difficult to establish at the current time. The estimates provided by three petroleum companies suggest that the combined developments over the next 25 years could result in between 1,000 and 1,200 wells associated with around 150 pads.[87] However, the Energy Division of DPIR predicts some 15,506 shale gas wells could be developed in the greater McArthur Basin, with possibly around 6,250 wells in the Beetaloo Sub-basin.[88] This estimate is more than one order of magnitude (10 times) larger than the industry projection.

In Origin's submission two possible scenarios are described for its tenements, namely, small scale or large scale:

- a smaller scale development would require 50-100 wells drilled from 6-12 pads using existing regional infrastructure to access the Amadeus Gas Pipeline. This development would occur over a 20-40 year timeframe and deliver 50-100 TJ/day (0.05-0.1 PJ); or
- a large scale development would require new pipeline infrastructure to carry adequate volumes of gas at 400-500 TJ/day to serve the Darwin and/or east coast markets. This development would require between 400-500 wells drilled on 50-65 pads over a 20-40 year period. Additional gas gathering systems, gas plant, and pipelines would be required. The entire development area would cover approximately 500 km^2, with a directly affected surface area of less than 10 km^2 (or 2%) cumulatively. During peak production the development could have up to 57 well pads active with each pad comprising eight wells. The hydraulic fracking of these 456 wells is estimated to be staggered over 24 years.[89]

Depending on pipeline capacity, Origin's proposed scale of development could be replicated by other tenement holders throughout the Beetaloo Sub-basin, or other potential shale gas basins. Preliminary estimates, based on the area that are gas plays as a percentage of the total sedimentary basin area, are that less than 30% of the Sub-basin will be the required development area.

6.5.2 Rate of development

ACOLA suggests that to simultaneously develop the potential Australian shale gas resources some 300 drilling rigs could be operational at any one time with full development extending over several decades.[90] However, in Australia the availability of drilling rigs and hydraulic fracturing crews is very limited and this would slow production. It is therefore likely that only one or two shale gas resources will be able to be developed in the Northern Territory in the foreseeable future.

ACOLA also estimated that one drilling rig could produce between 11 and 18 wells per year.[91] Allowing for wet season interruptions, this figure would be optimistic for the Northern Territory. Nevertheless, if the shale gas fields are to be developed in stages over several decades, the number of drilling rigs required will depend on the rate of development, so that 10 rigs operating for a decade could complete the task. ACOLA explained the infrastructure needs for a 50 PJ production target.[92] However, the proposed development by the three companies with leases in the Beetaloo Sub-basin is many times (almost 10 times) that scale of development (see **Table 6.2** for details).

Whether the proposed developments would proceed in parallel or sequentially will have a significant impact on the infrastructure, plant, equipment and workforce requirements.

6.5.3 Infrastructure needs

Establishment of a full scale shale gas industry in the Northern Territory will require the drilling of thousands of wells, the construction of thousands of kilometres of roads and access tracks, the clearing of vegetation from well pads, accommodation facilities, production facilities, and pipelines for transporting the gas. This level of construction will have flow-on impacts to regional populations, towns and Darwin itself. There will be demands for heavy vehicles, plant and equipment, drilling rigs, hydraulic fracturing units and temporary accommodation, as with any major construction.

At this stage, information provided to the Panel regarding the infrastructure needs of the possible development scenario in the Beetaloo Sub-basin suggests that 200 drilling pads and more than 1,000 wells could be required. Access to the well sites would require several hundred roads in the first instance, and the installation of connecting pipelines to treatment/production facilities.

There would also be a significant surface infrastructure requirement to develop the shale gas resources both in the initial drilling and hydraulic fracturing stages, and in the development of gas pipelines feeding the gas to processing plants and then feeding the cleaned natural gas to the gas distribution pipeline network for ultimate consumption. Pipeline infrastructure in the Northern Territory is currently inadequate to handle the new discoveries in the McArthur Basin, of which the Beetaloo Sub-basin is a part. Accordingly, trucking and rail may be the most practicable initial options to transport the gas.[93]

The actual infrastructure requirements will require careful scrutiny. Experience in the US has shown that well production and field production can decline over time, requiring additional wells to be commissioned to meet demand.

Hughes has discussed the disparity of the estimates reported from the US shale gas plays used in projecting future production of shale gas plays in the US Energy Information *Administration Drilling Deeper Report* and the real situation. They are:

- **rate of well production decline:** shale gas plays have high well production decline rates, typically in the range of 75-85% in the first three years;
- **rate of field production decline:** shale gas plays have high field production declines, typically in the range of 30-45% per year, which must be replaced with more drilling to maintain production levels;

87 Assuming eight horizontal wells per pad.
88 DPIR submission, Addendum 1.
89 Origin submission, p 36.
90 ACOLA Report, p 75.
91 ACOLA Report.
92 ACOLA Report.
93 ACOLA Report, p 80.

- **average well quality:** all shale gas plays invariably have 'core' areas or 'sweet spots' where individual well production is highest and hence the economics are best. Sweet spots are targeted and drilled off early in a play's life cycle, leaving lesser quality rock to be drilled as the play matures (requiring higher gas prices to be economic); therefore, the number of wells required to offset field decline inevitably increases with time. Although technological innovations including longer horizontal laterals, more fracturing stages, more effective additives, and higher volume treatments, have increased well productivity in the early stages of the development of all plays, they have provided diminishing returns over time and cannot compensate for poor quality reservoir rock. The generally low gas prices in the past several years has led gas producers to focus on sweet spots, disproportionately depleting high-productivity drilling locations compared to the overall number of potential drilling locations in each play;
- **number of potential wells:** plays are limited in area and therefore have a finite number of locations that can be drilled. Once the locations run out, production goes into terminal decline; and
- **rate of drilling:** the rate o rate of drilling, which is determined by the level of capital investment.[94]

6.5.4 Preliminary assessment

From the above discussion, it is apparent that there is considerable uncertainty about the likely scale and rate of development of a shale gas industry in the Northern Territory. Having said this, the most likely region for development in the foreseeable future is the Beetaloo Sub-basin of the McArthur Basin.

However, the scale and rate of this development depends on external economic considerations (including international gas and other commodity prices), practical constraints to the rate of development, and the production success of drilling (which can only be inferred from the limited number of exploration wells in existence). These factors suggest that (leaving aside, for present purposes, any regulatory amendments: see, for example, Chapter 14) even if the moratorium on hydraulic fracturing were to be lifted by the Government immediately, full scale development in the Beetaloo Sub-basin would take at least 5-10 years to achieve.

Table 6.2: Probable shale gas developments over the next 10 years (should the moratorium be lifted)

Potential	Company	Where[1]	EPs	Number wells (Pads[2])	Land area	Water use[3]	Gas production (TJ)
High	Origin[94]	Beetaloo Sub-basin, around Amungee, near Daly Waters	98, 117, 76	Large scale: 400-500 (approx. 50-60) Small scale: approx. 50-100 (approx. 10)	500 km^2 (20 km x 25 km)	Large approx. 1,200 ML/y for 25 years = 30,000 ML (or 30 GL)[4]	Large: 400-500 TJ/d over 20-40y Small: 50-100 TJ/d over 20-40y
	Santos[95]	McArthur Basin, Beetaloo Sub-basin	161, 162, 189	300-350 (approx. 10-80)	Approx. 400 km^2	Approx. 200-400 ML/y for 30 years = 6,000-12,000 ML (or 11 GL)	Initial: <35-100 TJ/d Full development: 400 TJ/d
	Pangaea[96]	Beetaloo Sub-basin, west of Stuart Hwy	167, 168	Approx. 300 (approx. 40)	Approx. 400 km^2	600-900 ML/y for 7 years = 4,200-6,300 ML (or 4-6 GL)	Not stated but est 200-300 TJ/d from Origin figures

1. See **Figure 6.5.**
2. Assumes 8-10 horizontal wells per pad.
3. Assumes no recycling.
4. Peak total water usage, including recycled flowback fluid, for drilling and stimulation is forecast at 2,600 ML approximately 7 to 10 years into a large scale.

94 Hughes 2016.
95 Origin submission.
96 Santos submission.
97 Pangaea submission.

WATER

7

7.1 Introduction

Water-related risks were the central concern raised in the formal submissions and in the community consultations. The experience of shale gas development overseas (particularly in the US) provides some basis for this concern, noting, however, that the technological, geological, biophysical and regulatory characteristics of shale gas in those jurisdictions are not necessarily analogous to any onshore unconventional shale gas development in the Northern Territory.

Concerns around the impacts of CSG development in Queensland were also reflected in public anxiety expressed about onshore shale gas development in the Territory. But in this context it is important to recognise that the process of CSG extraction is very different to that of shale gas extraction because of the large volume of produced water extracted during CSG operations (Chapter 5).

Effective water management will be crucial to the development of any onshore unconventional shale gas industry in the Northern Territory. This involves two critical aspects: first, sustainable water use from surface and groundwater resources; and second, maintaining acceptable quality of groundwaters (aquifers) and surface waters (for example, rivers, streams, and wetlands).

In this Chapter, the Panel has reviewed the relevant scientific literature and submissions made to the Inquiry in order to provide, where sufficient information is available, a preliminary assessment of the water-related risks associated with hydraulic fracturing of onshore shale gas reservoirs. For the purposes of the Interim Report the Panel has, however, focussed its attention on the Beetaloo Sub-basin because there is sufficient data with respect to that area to make a meaningful assessment of the identified water-related risks.

7.2 Water in the Northern Territory

The Northern Territory climate ranges from tropical and, subject to monsoonal influence in the north, to arid or semi-arid in the southern and central regions. The rainfall ranges from around approximately 2,000 mm/y in the north to 150 mm/y in the Simpson Desert (see **Table 7.1**).

The summer monsoon totally dominates rainfall from north of about Tennant Creek (500 mm/y), where there is virtually no winter rain. Water dynamics in the north are dominated by the summer monsoon, when aquifers are recharged, floodplains are inundated, and billabongs and waterholes are refreshed.

The monsoon has an influence further south, but there are also increasing amounts of winter rain such that rainfall becomes essentially a-seasonal.

In total, up to 90% of the approximately two million gigalitres (**GL**) that falls across the Northern Territory during the wet season evaporates, and of the remaining 10%, less than 2% enters groundwater.

Table 7.1: Long-term average rainfall and evaporation levels[98]

Location	Rainfall (mm/y)	Evaporation (mm/y)
Darwin	1723 (1941-2017)*	2545 (1941-2017)*
Katherine	980 (1873-2017)*	No data
Daly Waters	677 (1939-2017)*	2449 (1939-2017)*
Alice Springs	284 (1941-2017)*	3142 (1941-2017)*

* period of record

7.2.1. Surface water resources

The surface hydrology of the northern, central, and southern regions of the Northern Territory are very distinct from each other, reflecting the contrasting patterns of rainfall seasonality, in addition to quantity.

The northern region has extensive river and wetland systems, whereas surface water is largely absent from the southern region. There are only two perennial river systems in the Northern Territory, the Daly and the Roper, and flow in these are maintained during the dry season by discharging groundwater systems.[99] There is community concern that excessive groundwater extraction from this aquifer by a possible shale gas industry could reduce or even halt these dry-season flows.

Stream flow is seasonal (summer) in the central region, and is to a large extent a-seasonal (and often not occurring for years) in the southern region.

7.2.2 Groundwater resources

The Northern Territory's groundwater systems vary from the Top End to the semi-arid central and southern arid regions. In the Top End, the monsoonal climate ensures that most aquifers are recharged every year in the wet season, resulting in groundwater of very low salinity. In the southern two thirds of the Territory (south of Larrimah), known as the semi-arid and arid zones, groundwater receives minimal annual recharge apart from during extreme rainfall events, and surface water resources are virtually non-existent. Where surface waters do occur, such as waterholes, they are sustained by groundwater flows. Groundwater quality decreases with reduced recharge rates, and in the arid zone is commonly brackish to saline, with high concentrations of ions such as fluoride and nitrate.

These contrasting groundwater regimes vary in their likely sensitivity to shale gas and other developments. As a general rule, groundwater systems in the Top End are relatively more resilient to extraction and other impacts because they have more rapid through-flow rates, meaning they are replenished more rapidly. By contrast, impacts on arid zone groundwater systems are likely to be much more enduring, because these systems are recharged far more slowly, if at all. However, to understand each individual groundwater system and predict the likely impacts of any development on it, it is critical to

98 Greg Browning, BOM Darwin. Personal communication. May 2017.

99 Bruwer and Tickell 2015; Department of Environment and Natural Resources, submission 230 (**DENR submission**), Addendum 2.

have a baseline understanding of the characteristics and behaviour under pre-development conditions for each regional groundwater system.

Groundwater accounts for 90% of all of the Northern Territory water supplies, a much higher proportion than any other Australian jurisdiction. The Northern Territory has a number of large groundwater basins, including the Daly, Georgina and Wiso Basins in the central region, the Amadeus Basin to the south and west of Alice Springs, and the Great Artesian Basin in the southeast corner.

These basins have large storage capacities. However, only the Daly Basin is seasonally recharged by monsoonal rainfall. For the other (more arid) basins, recharge is episodic and dependent on infrequent large rainfall events.[100] Of particular relevance to this Inquiry given the development focus to date, the Water Resources Division of the Northern Territory Department of Environment and Natural Resources (**DENR**) has collated the available information and reports for the Daly, Wiso and Georgina Basins, which overlie the Beetaloo Sub-basin and surrounds, to a depth of 400 m.

7.2.3 Aquatic ecosystems and biodiversity

Rivers, wetlands and other water-dependent ecosystems are a dominant feature of the northern (higher rainfall) region of the Northern Territory, and are also critical ecosystems in many parts of the central and southern regions. Far northern Australia has one of the world's highest concentrations of free-flowing rivers, and along with their associated wetlands are of international significance because of their ecological intactness and high biodiversity values.[1001]

There is a limited understanding of the environmental flows required to maintain most of Australia's tropical rivers in good ecological health.[102] A notable exception is the Daly River, where extensive hydrological research has been undertaken to underpin sustainable agricultural development.[103] Under current Government policy, water extraction for consumptive purposes cannot exceed 20% of either annual river flows or recharge of aquifers in the northern region, and cannot exceed 5% of annual river flows in the central and southern regions.[104]

The Panel is unaware of any studies of stygofauna (groundwater dependent fauna) within aquifers associated with potential shale gas developments in the Northern Territory, but the importance of stygofauna assemblages in the two adjacent states suggests that the Northern Territory is also likely to support important stygofauna assemblages. However, the importance and need for protection of stygofauna is increasingly being recognised. In WA they are recognised as being of global significance due to high levels of endemism and substantial diversity,[105] and are known to occur in aquifers in limestone, sandstone and alluvium in the Kimberley.[106] Recent guidelines have been released for their assessment being released in Queensland.[107]

7.2.4 Water use and management

The Northern Territory supports a diverse range of industries that are reliant on water resources, especially in the agricultural, horticulture, pastoral and tourism (including recreational fishing) sectors. The two perennially flowing rivers, the Daly and the Roper, are particularly important tourist and recreational fishing destinations, and are fed from the Daly, Georgina and Wiso Basins.[108] The pastoral and horticultural industries are heavily dependent on groundwater.

Many high yielding aquifers within the Northern Territory are close to full allocation against the contingent allocations prescribed in the Northern Territory Water Allocation Planning Framework.[109] Groundwater and surface water resources in a number of specific areas such as Alice Springs, Darwin Rural, Douglas Daly, Katherine and Mataranka are recognised as being under pressure from resource development.[110]

The arrangements for the management of water resources in the Northern Territory, both surface and groundwater, are documented in the submission from DENR.[111]

The *Water Act 1992* (NT) (**Water Act**) is the primary legislation that provides for the investigation, allocation, use, control, protection, management and administration of water resources. DENR manages the day-to-day operational aspects of that Act, including conducting water resource investigations, monitoring compliance, preparing water allocation plans and administrating licenses and permits. However, activities on mining and petroleum tenements are currently exempt from the provisions of that Act, which means that petroleum companies do not require water extraction licences under the Water Act.

7.3 Likely water requirements of an onshore shale gas industry in the Northern Territory

In its submission, DPIR has identified four major basins in the semi-arid and arid regions of the Northern Territory where shale gas development may occur.[112] It is likely that groundwater will be the main water resource available for development of these possible gas developments given the scarcity of surface water resources in these regions.

Because onshore shale gas production in Australia is still in its infancy, the average volume of water needed to hydraulically fracture Australian shales is not as well known as the average volume required for CSG extraction.[113] The actual volume required for the hydraulic fracturing process in any given basin depends on local geological conditions (such as depth to shale layers, porosity, and existing fractures in the shale), the number and length of the horizontal wells, and the number of fracture stimulations along each horizontal well. It can vary both within and between geological basins. However, current estimates indicate that typically 1-2 ML is required for each of the well drilling and hydraulic fracturing stages of a fracture stimulation program.[114] The water requirements for Origin's

100 DENR submission.
101 Lukacs and Finlayson 2008.
102 Warfe et al. 2011; King et al. 2015.
103 Erskine et al. 2003.
104 Water Allocation Planning Framework.
105 WA EPA 2016.
106 WA EPA 2007.
107 DSITI 2015.
108 DENR submission.
109 DENR submission.
110 DENR submission.
111 DENR submission.
112 DPIR submission.
113 ACOLA Report.
114 ACOLA Report; US EPA Report; APPEA submission.

2016 production testing of the Amungee NW-1H well were approximately 11 ML of water used for the full 11-stage fracture stimulation program, ranging from 0.7-1.4 ML per stage.

It is increasingly common practice for gas companies to recycle as much of the flowback fluid from the hydraulic fracturing operations as possible. This can make up to 30-50% of the water requirements for the operation.[115] However, the extent to which this flowback water can be reused for hydraulic fracturing depends on its content of salts and residual chemicals, and there is no certainty at present of the amount of recycling that could be achieved for an Northern Territory shale gas industry.

7.3.1 Beetaloo Sub-basin case study

As noted in Chapter 6, the most prospective and best studied area in the Northern Territory is the Beetaloo Sub-basin (**Figure 6.2**) and, as explained above, it is for this reason the Panel has used that sub-basin as a case study to make a preliminary assessment of water-related risks (needs and possible contamination), and to highlight information gaps. The Panel intends to broaden this assessment to other shale gas basins in the Northern Territory in its Final Report, assuming adequate data exists to do so.

The three petroleum companies currently with petroleum activity in this Beetaloo Sub-basin - Origin, Santos and Pangaea – have provided the Panel with various possible shale gas development scenarios. Their estimates suggest a combined development over the next 25 years that could result in between 1,000 and 1,200 wells associated with around 150 well pads.[116] However, DPIR envisages a much larger shale gas industry, possibly around 6,250 wells, for the Beetaloo Sub-basin.[117]

The Beetaloo Sub-basin is a sub-surface basin, within the broader McArthur Basin, with no surface expression or local outcropping of the rocks. The Sub-basin has a thickness of greater than 3,000 m below the overlying basins and the Sturt Plain (**Figure 6.3**). It covers a relatively flat landscape (115-319 m AHD) and has an area of approximately 27,000 km^2.

The Sub-basin's climate ranges from a dry tropical savannah climate in the north to a warm desert climate towards the south. The average rainfall ranges from around 665 mm in the north to 518 mm in the south (**see Table 7.1**).[118] This rainfall is closely linked to the northern Australian monsoonal system, and falls largely between December and March each year.

The groundwaters of the Beetaloo Sub-basin are the most extensively studied in the Northern Territory.[119] The principal groundwater resource in the Beetaloo Sub-basin is the Cambrian Limestone Aquifer, which occurs across three basins: the Daly, the Wiso and the Georgina (**see Figure 7.1**).

Over most of the Beetaloo Sub-basin, the Gum Ridge Formation, and its equivalents in the Wiso Basin, is the main aquifer system.[120] The Gum Ridge aquifer is located at 35-220 m (average 105 m) below the surface (**Figures 7.2 and 7.3**). In the southern half of the Beetaloo Sub-basin, the Gum Ridge Aquifer occurs at depth below the Anthony Lagoon Beds.

To the north in the Daly Basin, the hydro-stratigraphically equivalent Tindall Limestone Aquifer forms the main aquifer system.

The regional groundwater flow of the aquifers in the Beetaloo Sub-basin is generally northwards as shown in **Figure 7.1**. GHD reports that the flow is greater in the north (that is to say, steeper hydraulic gradient), and that the lower hydraulic gradient in the south is due to the more limited recharge due to lower rainfall and the overlying Mullaman Beds.[121]

An estimated 800 registered water bores in the Beetaloo Sub-basin[122] extract around 6,000 ML/y of groundwater, with most of this used to water stock.[123] The Cambrian Limestone Aquifer also provides domestic water for several towns including Elliott, Newcastle Waters, Daly Waters and Larrimah. Just north of the Beetaloo Sub-basin, the towns of Mataranka and Katherine also access water from the same aquifer system. Katherine is the largest user at 8,000 ML/y, although not all of this comes from the Tindall Limestone Aquifer.[124]

The detailed recharge of the Cambrian Limestone Aquifer is poorly known,[125] although it is considered that recharge only occurs in the wet season when rainfall intensity and duration are sufficient to overcome evapotranspiration. Infiltration through sinkholes and preferential recharge through soil cavities are thought to be the dominant recharge mechanisms. One estimate of the recharge rate, derived from the dry season flow in the Roper River (assumed to be entirely groundwater fed), was around 100,000-130,000 ML/y.[126] Bruwer and Tickell estimated a higher recharge rate for the region between Mataranka and Daly Waters of around 330,000 ML/y over the past 30 years.[127] The recharge rate in the southern region of Beetaloo Sub-basin would be expected to be considerably less that this because of the lower rainfall.

Origin and Santos have engaged the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) to undertake regional and local scale studies to improve understanding of recharge mechanisms and total aquifer storage and sustainable yield in the region.[128] These studies are not scheduled for completion until around September 2018.

The groundwater quality within the Beetaloo Sub-basin is quite high.[129] In the Gum Ridge Formation, salinity electrical conductivity (**EC**) averages around 1,400 uS/cm, and is dominantly Ca-Mg-HCO_3 rich, as is expected from an aquifer in a limestone and dolomite system.

Temporary waterbodies (for example, waterholes and billabongs) exist in the Beetaloo Sub-basin and other semi-arid regions, generally for short periods of time after substantial rains. They are sources of water and food for birds and other terrestrial biota, including livestock. The low abundance of temporary waters in semi-arid landscapes makes these water bodies more important for the resident fauna. Perennial aquatic refuges within networks of temporary waters can be particularly important for maintenance of biodiversity as many taxa, including all but one of Australia's freshwater fishes, are unable to survive drying out.

115 Origin submission; Santos submission.
116 Assuming 8 horizontal wells per pad.
117 DPIR submission, Addendum 1.
118 Fulton and Knapton 2015.
119 Fulton and Knapton 2015; Bruwer and Tickell 2015; GHD 2016; DENR submission; Santos submission.
120 Fulton and Knapton 2015; Bruwer and Tickell 2015; GHD 2016.
121 GHD 2016.
122 Origin submission, p 46.
123 Fulton and Knapton 2015.
124 DENR submission, Addendum 2.
125 Fulton and Knapton 2015, p 37.
126 Jolly et al. 2004.
127 Bruwer and Tickell 2015.
128 Origin submission, p 51.
129 Fulton and Knapton 2015, p 38.

Figure 7.1: Cambrian Limestone Aquifer overlying the three main Basins (Daly, Wiso, Georgina) and the Beetaloo Sub-basin. Source: DENR.

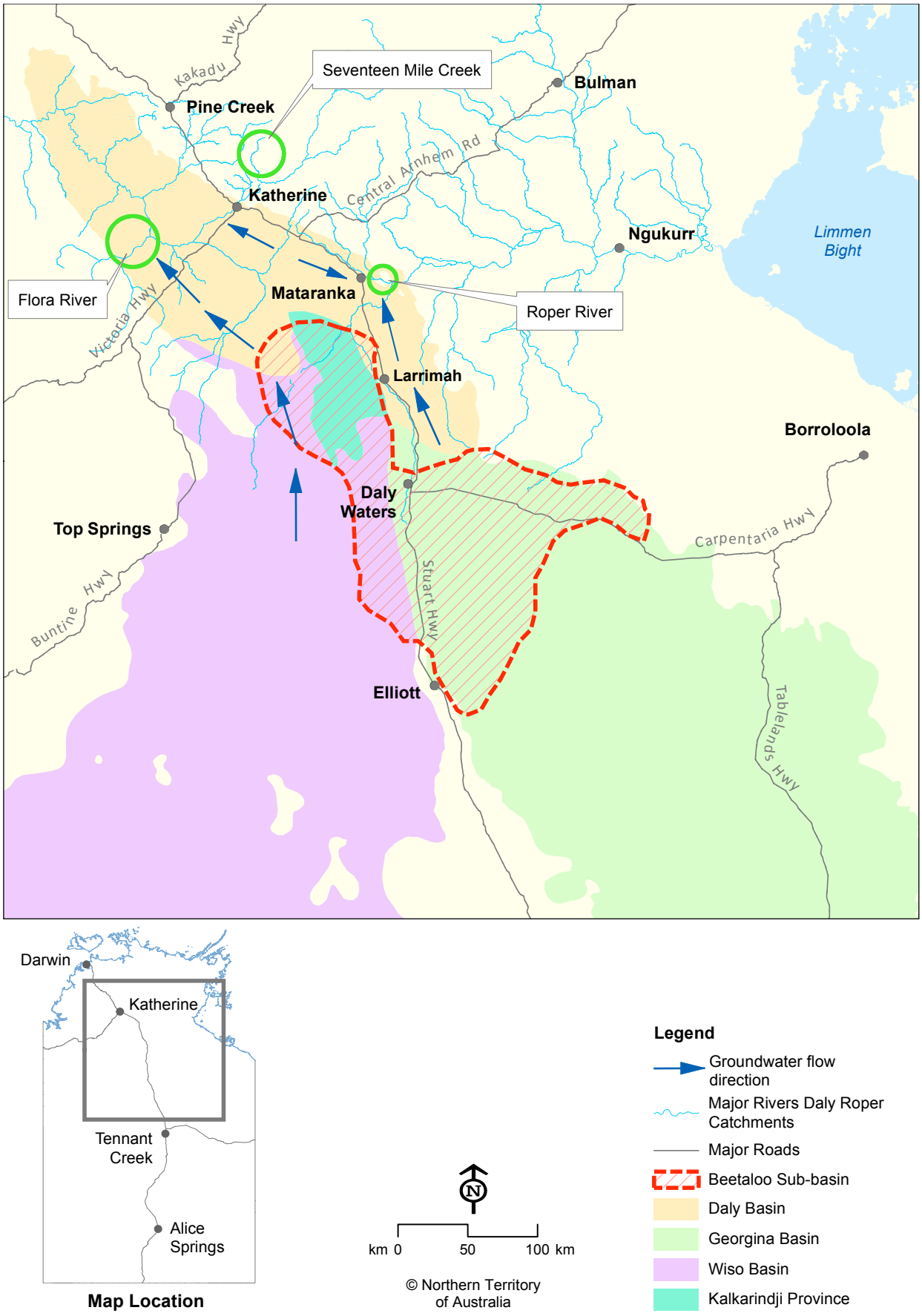
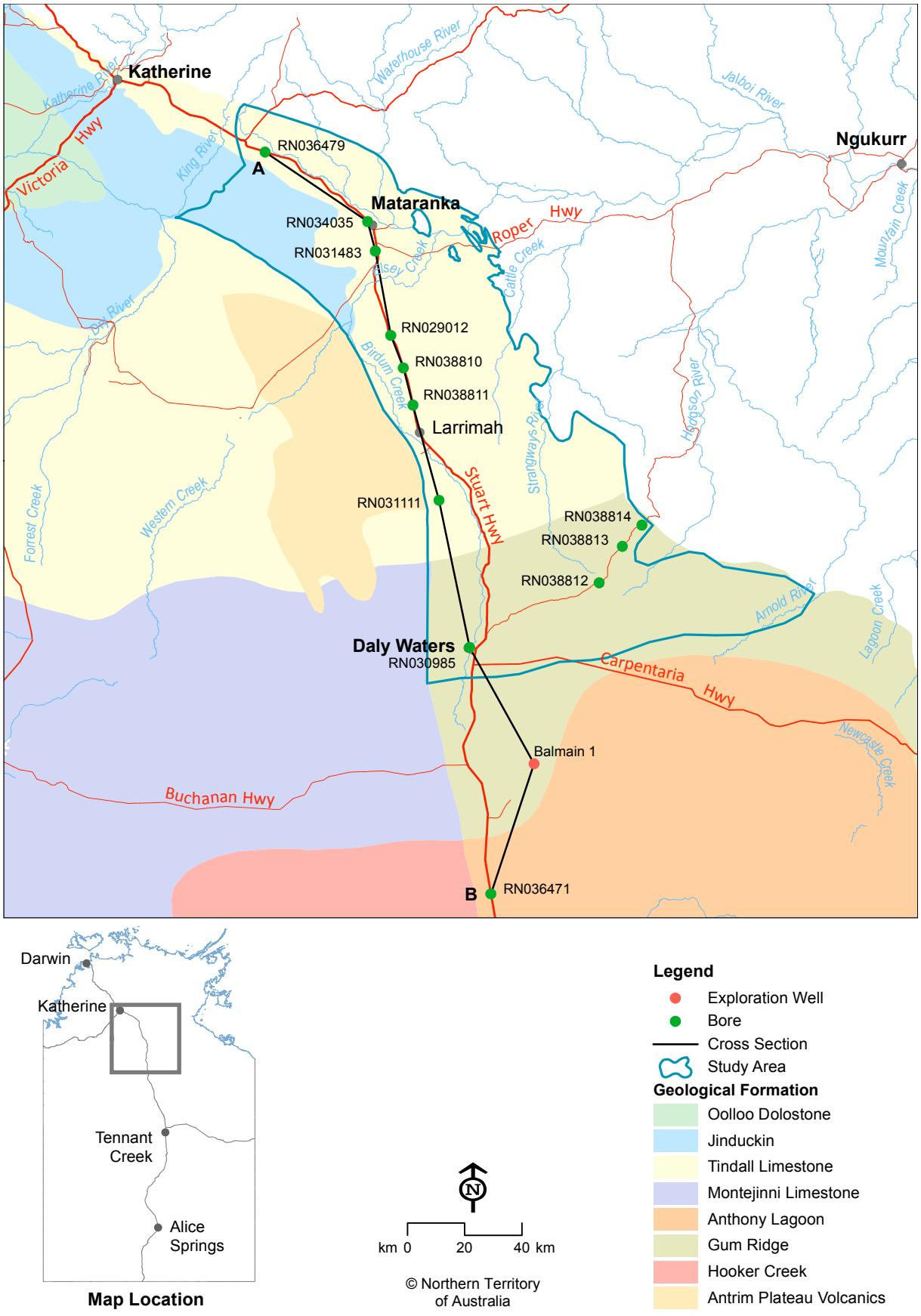
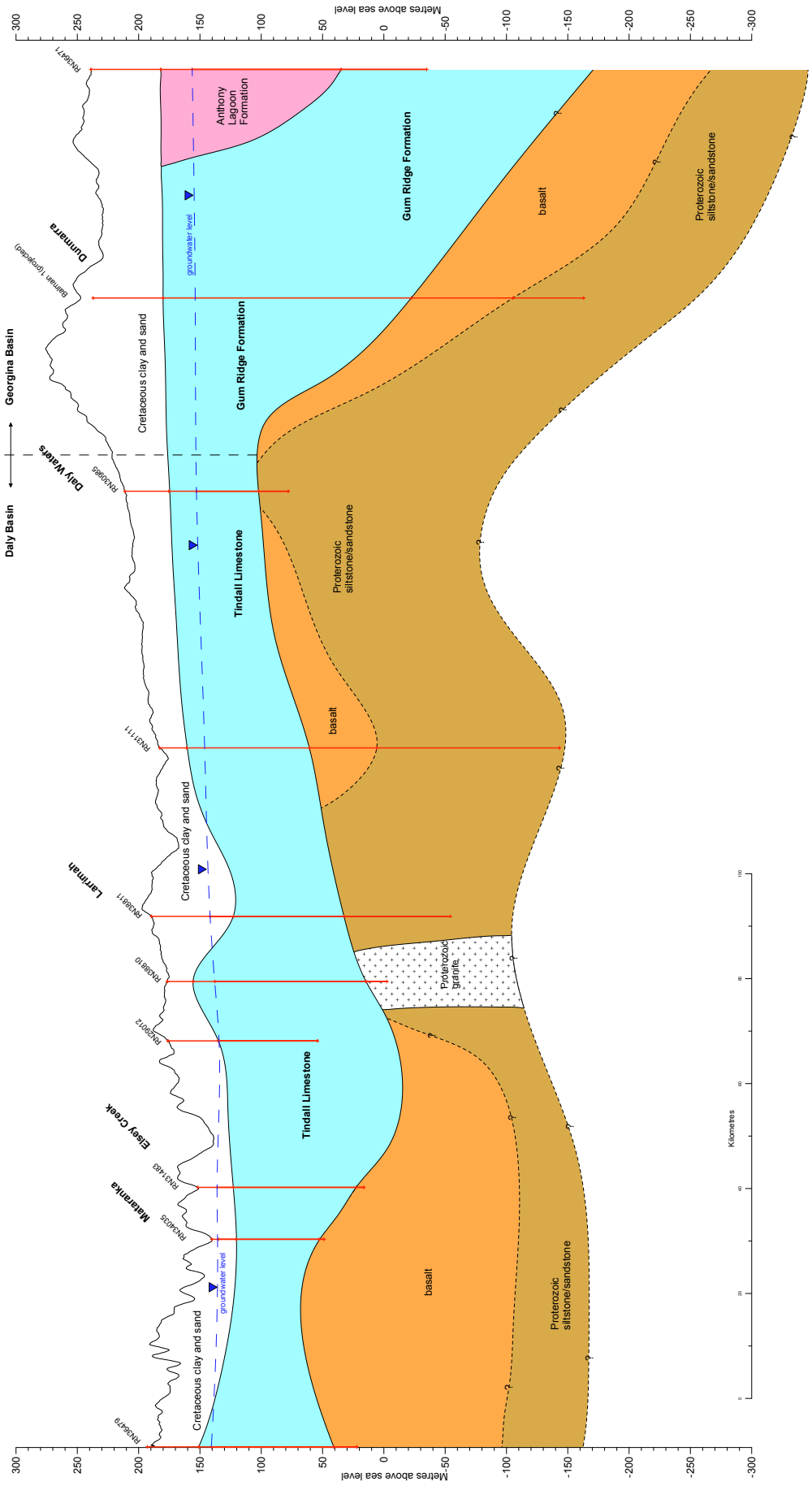


Figure 7.2: Geographical map showing location of cross section. Source Tickell 2015.



Figure

Figure 7.3: Schematic geological cross section A-B, north to south - refer Figure 7.2. Source: Tickell 2015.



Surface discharge of aquifers can be important in sustaining groundwater dependent ecosystems, for example, perennial streams, waterholes, springs or seeps. There is evidence that the Cambrian Limestone Aquifer is very important for the Roper River system, sustaining Elsey National Park, Mataranka thermal pools, Red Lily Lagoon, and the riparian vegetation along the Roper River beyond the Beetaloo Sub-basin.[130]

It has been suggested that groundwater-dependent surface ecosystems are unlikely to occur in the Beetaloo Sub-basin because the groundwater in this region is typically greater than 30 m deep and is not connected to the surface.[131] However, a contrary view expressed to the Panel was that there has been very little attempt to locate groundwater-dependent ecosystems in this region and that it is possible that some could be present, including stygofauna in the deeper aquifers.

In all potential shale gas areas, there is very little information about the nature of deeper groundwater systems, just as there is limited understanding of the deeper geological systems in these basins. The relatively impermeable nature of gas bearing shales, and their distance beneath potable aquifers suggests very limited and extremely slow (likely to be in the order of thousands of years) interchange between shale rocks and overlying aquifers under existing conditions. In the absence of actual data derived from drilling and groundwater testing, understanding the nature of this relationship and predicting whether and how this interchange would be altered as a result of hydraulic fracturing or other shale gas related development can only be done through probabilistic mathematical modelling of hypothetical scenarios.

7.4 Preliminary assessment

The Panel has developed a framework for systematically assessing the potential risk to the environment from shale gas hydraulic fracturing. The descriptors the Panel will use to define what is meant by the 'Low', 'Medium' and 'High' consequence for each of the major water-related risks are provided in Appendix 13 (and see the explanation given in Chapter 3).

Where sufficient evidence is available, the Panel has endeavoured to express a preliminary view of the risks associated with the various water-related issues. In most cases, however, the Panel requires additional information on the likelihood of various water-related impacts occurring before it can make a proper assessment of the level of risk.

7.4.1 Water supply

The major concern regarding the potential impact of shale gas developments in the Beetaloo Sub-basin is the possible excessive use of groundwater, with adverse effects on groundwater levels both locally and regionally. It is unlikely that there are adequate surface water resources in this region, or other prospective regions, to sustain the water use requirements of an onshore shale gas industry.

Regarding possible effects on groundwater resources, the Panel has sought information on the potential water use by an onshore shale gas development in the Beetaloo Sub-Basin consisting of 1,000 to 1,200 hydraulically fractured wells. This information will be used to assess the regional effects on the sustainable yield of the aquifer of greatest concern that is likely to be used (Cambrian Limestone Aquifer) and the local effects associated with individual water supply bore fields.

The Panel has also sought information on the potential for the petroleum companies to use less high quality groundwater by reuse of some of the treated or untreated wastewater (flowback or produced water), or to use more saline groundwater from deeper aquifers. Both these options are feasible, but whether they can be adopted will depend upon detailed site investigations, consideration of possible environmental impacts, regulatory governance, and cost.

7.4.1.1 Possible adverse effects on water supplies due to the water extraction required for drilling and hydraulic fracturing

Surface water

Because of the lack of any permanent surface water resources (rivers, streams, lakes and waterholes) in the Beetaloo Sub-basin, the risk to surface water supply in the basin is relatively low. There may be surface waters in this region for short periods during the wet season (temporary waterbodies). Although the major companies with petroleum exploration permits in this area have committed in their submissions to not use surface water resources in the Beetaloo Sub-basin for hydraulic fracturing, regulatory reforms will still be necessary to ensure risks to surface water resources are avoided.

There is, however, a risk that unconventional gas development will affect surface water resources in areas outside the Beetaloo Sub-basin because surface water resources could be available in those areas during the wet season. The use of such surface water resources by an onshore shale gas industry would need to be considered along with other consumptive users within the sustainable limits of the resource in order to demonstrate that extraction of this water during the wet season would not compromise the values of the resource.

The Panel's preliminary assessment is that the risk to surface water flows is likely to be low for semi-arid (Beetaloo Sub-basin) and arid areas of the Northern Territory, especially because these water resources are unlikely to be available, at least in the Beetaloo Sub-basin. However, the risk for any shale gas developments in areas in the northern parts (wet/dry monsoonal tropics) of the Northern Territory will need to be assessed on a case-by-case basis, and consideration may need to be given, depending on the results, as to whether these areas should be considered 'no go zones' or 'restricted activity zones' (see Chapter 14).

Groundwater

As noted earlier, groundwaters are likely to be the only economically viable water source for hydraulic fracturing in semi-arid and arid areas (the Beetaloo Sub-basin). Industry experience, from company, government and third party reviews, is reasonably consistent on the volumes of water needed for well drilling and hydraulic fracturing, although the actual volumes can change depending upon the particular conditions at a site. There appears to be a consensus on figures of around 1-2 ML for well drilling and 1-2 ML for each hydraulic fracturing stage, or around 10-20 ML for a 10-stage fracturing. For example, Origin suggests it will require 50-60 ML for drilling and stimulation per well.[132]

The US EPA reported that the median volume of water required to fracture a horizontal gas well in the US in 2014 was 19 ML, noting that the average number of fracturing stages at this time was about 14.[133] The actual volume used in a particular location will depend upon the length of the horizontal well and the number of fracturing stages.

130 Bruwer and Tickell 2015.

131 DENR submission, Addendum 1.

132 Origin submission.

133 US EPA Report

Accordingly, a development scenario comprising 1,000 to 1,200 wells, associated with 150 multi-well pads over 25 years in the Beetaloo Sub-basin, would require an average of 2,500 ML/y (up to 5,000 ML/y at peak demand) of water, or a total of 20,000-60,000 ML from the aquifer system over the 25 years. For example, Origin provided indicative water requirements for a 450 shale well operation over 25 years, which would require an average of around 1,200 ML/y reaching a maximum of around 2,500 ML/y between years 5 and 9 (see **Figure 7.4**).[134]

DPIR has also provided to the Panel some estimates of the potential water use by a shale gas industry in the Northern Territory.[135] For a development scenario that produces 50 Tcf (53,250 PJ) of gas over 40 years, it estimates this would require around 6,250 wells (or about 420 well pads), with each well producing eight PJ of gas. Such a development would require 125,000 ML of water over the 40 years (or around 3,000 ML/y), assuming each well requires 25 ML of water and there is a 20% recycle rate.

The Panel has received a number of submissions suggesting that the above water use volumes represent a very small percentage of the sustainable yield from the CLA in the Beetaloo Sub-basin.[136] However, there appears to be little consensus on the actual sustainable yield in this region.

For the northern section of the Beetaloo Sub-basin (Mataranka to Daly Waters) the Panel is aware of three estimates for the sustainable yield (recharge rate) that range from 100,000 ML/y[137] to 130,000 ML/y[138] to 330,000 ML/y.[139]

From a regional perspective, the use of up to 5,000 ML/y from the groundwater system is a relatively small proportion (<5%) of the suggested recharge rate of 100,000 to 330,000 ML/y.[140] The Panel has no estimate for the recharge rate of the CLA in the southern part of the Beetaloo Sub-basin (around Elliott), but expects it to be considerably less than the above figures because of the lower rainfall in this region. The Panel intends to seek further information from the DENR on recharge rates in the southern part of the Sub-basin.

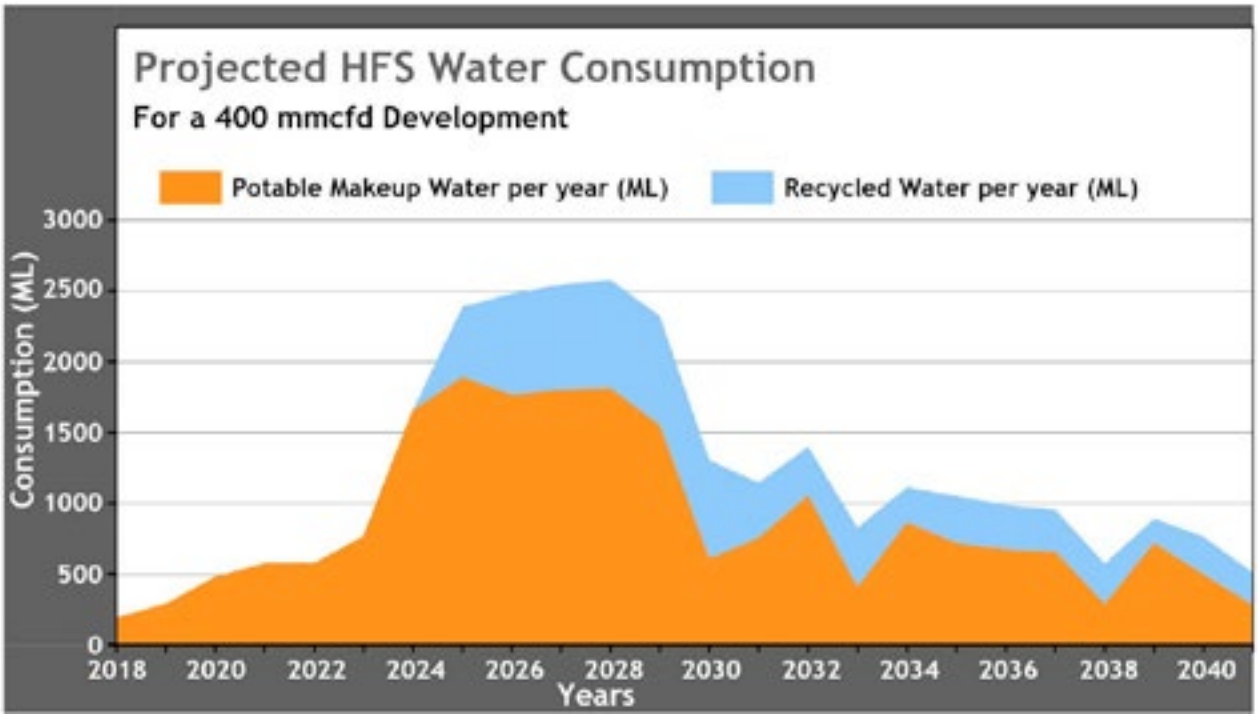
Similar sustainable yield assessments will need to be made for other prospective basins in the Northern Territory prior to any decision regarding the development of an onshore shale gas industry, noting that the groundwater knowledge base is much better developed for the Beetaloo Sub-basin than elsewhere in the Territory.

At the local scale, aquifer drawdown could be significant depending upon how the groundwater is extracted, particularly the rate of pumping and the spatial extent of the bore field. Origin has provided drawdown information for the bores used to provide water for the Amungee NW-1H well that was hydraulically fractured in late 2016.[144] However, the regional implications of this for groundwater users are not clear.

The Panel will seek further evidence on the possible local effects on groundwater aquifers in the vicinity of any potential onshore shale gas operations.

In other regions, understanding the significance of potential impacts of groundwater extraction upon local groundwater levels would require consideration on a case-by-case basis. In all situations, a baseline understanding of current groundwater characteristics and computer modelling of likely responses to changes from groundwater extraction is critical to informing the likely significance of any impacts.

Figure 7.4: Indicative water requirements for 450 well shale gas operation over 25 years. Note this assumes 30% recycling of flowback water. Source: Origin.[142]



134 Origin submission.

135 DPIR submission, Addendum.

136 For example, Origin submission; Santos submission; Pangaea submission; APPEA submission; and DPIR submission.

137 Fulton and Knapton 2015.

138 GHD 2016, Appendix A.

139 Bruwer and Tickell 2015.

140 DENR submission, Addendum 1.

141 Origin submission, p 87.

142 Origin submission, p 86.

7.4.1.2 Possible adverse effects on the quality or flow characteristics of surface waters due to the discharge of flowback and produced water

Surface water resources only exist in the Beetaloo Sub-Basin for short periods of time during the wet season and there are no permanent streams or surface waterbodies in the Beetaloo Sub-basin (with perhaps the exception of Lake Woods and Longreach Billabong, near Elliott, in very wet years).

None of the shale gas companies have indicated that they would seek to discharge wastewaters (treated or not) to either drainage lines or surface waters when these are present. On this question, DPIR has stated to the Panel that:

> *"Current practice requires that wastewater from hydraulic fracturing activities is fully contained on site. The fluids may be held in double HDPE lined evaporation ponds. Evaporation may be aided with sprinklers or other devices to accelerate evaporation rates. Concentrated waste fluids must be collected and transported to a licenced waste treatment facility in accordance with the Waste Management and Pollution Control Act. Certificates of acceptance of waste fluids by the treatment facility must be provided to the Department."*[143]

The Panel will request further information from DPIR at to the content of this 'current practice', including whether the details are documented in an industry guideline, how it is put in place for a particular development, and how it is enforced.

The potential for occurrence of high intensity and extended rainfall events during the northern wet season means that during this time there is a higher likelihood of spills of chemicals and overtopping of flowback water storages. During the wet season there is a much higher probability of any spills being able to be transported overland to ecologically important temporary or permanent waterbodies. These waterbodies are also more likely to be affected during the wet season by sediment-laden runoff coming from unsealed road and pipeline corridors.

For these reasons, the Panel's preliminary view is that the annual work program of any onshore shale gas operation should be scheduled to minimise the amount of hydraulic fracturing during the wet season.

Both Origin and Santos propose to minimise the risk of containment overtopping by designing to 1 in 100 year rainfall events.[144] However, past experience with extreme weather events in the Northern Territory has shown that design should be based on the maximum probable precipitation event coupled with an appropriate maximum operating level. The deliberate discharge of untreated wastewater from hydraulic fracturing operations to either drainage lines or surface waters in the Northern Territory should be prohibited.

The other possible source of spills is from broken pipelines carrying contaminated flowback or produced water for recycling or to a central treatment plant. The US EPA noted that pipeline spills can be very large, with the largest documented spill occurring in North Dakota, where approximately 11 ML of wastewater spilled from a broken pipeline and affected surface water and groundwater.[145]

Further information on the containment and possible treatment of wastewaters is required and will be sought by the Panel. In the interim, however, it is the Panel's view that the deliberate discharge of untreated wastewater from hydraulic fracturing operations to either drainage lines or surface waters in the Northern Territory should not take place.

7.4.1.3 Possible adverse effects to surface or groundwater due to possible seismic activity caused by hydraulic fracturing or reinjection of wastewater

As discussed in Chapter 5, there appears to be limited evidence for substantial induced seismic activity due to the hydraulic fracturing process.[146] Davies et al found from a survey of hundreds of thousands of fracturing operations that the likelihood of induced seismicity felt on the surface by hydraulic fracturing was very small.[147]

This is not the case, however, with reinjection of fracturing wastewaters where positive links have been made between deep well reinjection and felt seismic activity.[148] Most recently, the US Geological Survey (**USGS**) has indicated that reinjection of wastewater into existing conventional reservoir wells is the primary cause of the recent increase in low intensity earthquakes in certain areas of the central United States.[149]

The Panel's preliminary assessment is that the practice of reinjecting wastewater into aquifers should not occur.

7.4.2 Water quality

There are five main potential pathways by which hydraulic fractured shale gas operations may contaminate groundwaters or surface waters (see **Figure 7.5**):

- leakage of either hydraulic fracturing fluid, flowback or produced water from operating wells;
- spills during transport of chemicals or wastewater from either road transports or pipelines;
- surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water at the well site or other handling facility;
- re-injection of untreated wastewater to deep aquifers; and
- direct discharge of treated or untreated wastewaters to surface waters or drainage lines.

As explained in Chapter 5, the likelihood of leakage of contaminated water from the hydraulic fracturing process or from post fractured operating wells will be dependent upon the integrity of wells. That is, the likelihood of operating wells failing.

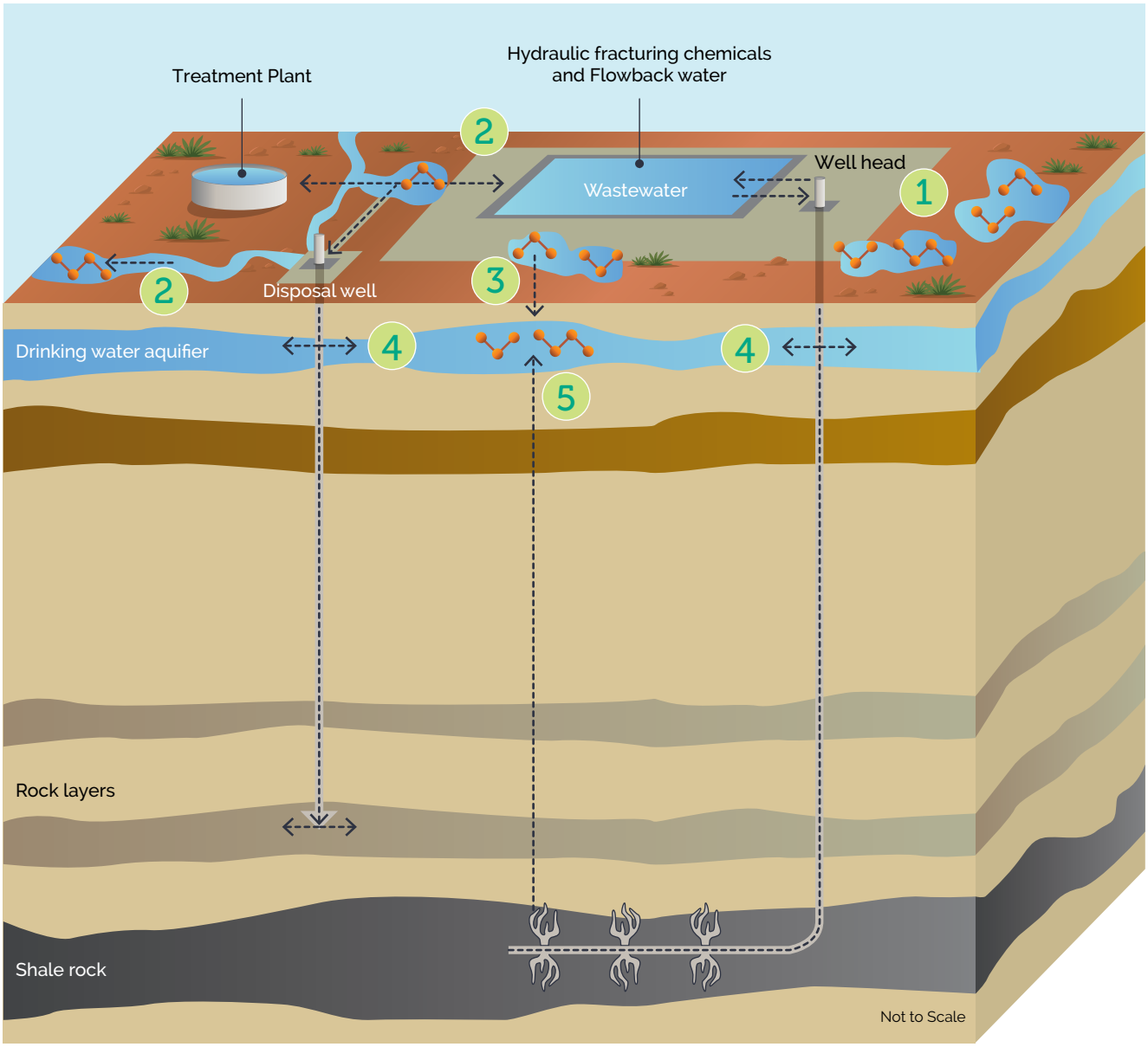
The Panel has sought information from the major petroleum companies on the likely composition of hydraulic fracturing fluids and flowback and produced waters. Petroleum companies in the Northern Territory are required to disclose to DPIR, and to the general public, specific information regarding the chemicals used in the hydraulic fracturing process.[150] However, the identity and concentrations of geogenics (chemicals extracted from the shale as a result of the hydraulic fracturing process) do not require disclosure. At this stage, the Panel has no Australian information on the actual composition of flowback or produced water from shale gas operations.

143 DPIR submission, Addendum.
144 Origin submission; Santos submission.
145 US EPA Report.
146 Costa et al. 2017.
147 Davies et al. 2013.
148 ACOLA Report; US EPA Report; Costa et al. 2017; USGS 2017.
149 USGS 2017.
150 *Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (NT), cl 342(4).

Additionally, the Panel has reviewed the available evidence on the management and treatment of these shale gas wastewaters. The requirement for wastewater treatment is not unique to this industry, and has many aspects in common with other extractive industries. However, the composition of flowback water may provide specific technical, operational and cost challenges for achieving treatment targets.

Re-use of the treated wastewater (flowback or produced water) for the hydraulic fracturing process is feasible, and is being actively considered by some of the gas companies. Recent examples of where flowback water has been effectively treated and reused are provided by Schlumberger Australia Pty Ltd (**Schlumberger**)[151] Origin and Santos suggest they could reuse treated flowback water to supplement 30% and 50% respectively of the water needed for hydraulic fracturing.[152] DPIR suggests that higher re-use rates than these may be achievable and in support of this cited the experience in the US Marcellus field (which has similarities to the Beetaloo Sub-basin), where recycle rates of 85% have been achieved.[153] However, outside of the Marcellus region, re-use rates are lower: typical estimates are 0% for the Bakken field, and 5% for the Barnett and Haynesville fields.[154]

Figure 7.5: Modes of potential environmental exposure



(1) surface spills resulting in contamination of soil; (2) surface spill runoff into surface water (3) surface soills leaching into shallow aquifier;
(4) contamination of shallow groundwater via borehole leakage, fault lines, and abandoned wells; (5) contamination of shallow groundwater via induced fractures.

151 Schlumberger Australia Pty Ltd, submission 231 (**Schlumberger submission**).

152 Origin submission; Santos submission, respectively.

153 DPIR submission, Addendum.

154 US EPA Report.

7.4.2.1 Surface water

Possible contamination due to on-site spills of wastewater, including as a result of extreme weather events

As explained in Chapter 5, flowback water is typically very saline and contains concentrations of heavy metals and organic compounds (geogenic chemicals) extracted from the shale formation, and also residuals of chemicals that are used in the hydraulic fracturing process.

Under normal conditions in the Beetaloo Sub-basin, the main risk from spills of wastewaters will be to groundwater aquifers, and not surface waters. However, as stated earlier, it is possible under extreme weather events (floods) there could be substantial surface water on the landscape, which could be at risk from spills of wastewater. The risk of spills to surface waters may be higher in the case of any onshore shale gas development in the northern part of the Beetaloo Sub-basin, because it is more influenced by monsoons.

The environmental risks and impacts associated with on-site spills are currently regulated by DPIR under the *Petroleum Act 1984* (NT) (**Petroleum Act**), the *Petroleum (Environment) Regulations 2016* (NT) (**Petroleum Environment Regulations**) and the *Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (NT) (**Petroleum Schedule**). Where there is a risk of a spill associated with an activity, an approved environment plan must be in place before the activity can be undertaken. In addition, the Petroleum Schedule requires that operators must have an approved 'spill contingency plan' in place. The requirement for a spill contingency plan appears to duplicate the requirement for there to be an approved environment plan in place.

DPIR does not have jurisdiction over a spill if it occurs outside the petroleum permit area. As DPIR notes in its submission, when spillage or waste leaves the permit area, the *Waste Management and Pollution Control Act 1998* (NT) (**Waste Management Act**), which is administered by the EPA, has jurisdiction. The EPA also administers the Water Act, which does not apply inside petroleum permits. Outside petroleum permits, however, the Water Act applies, and any polluting act will require a waste discharge licence under that Act.

The regulation of petroleum activities by various Government agencies and different pieces of legislation for on-site and off-site impacts has the capacity to diminish the transparency, accountability and efficacy of the regulatory framework governing any onshore hydraulic fracturing for shale gas.

Possible contamination due to spills during transportation of chemicals and wastewater

Assuming that all fracking chemicals and fluid additives will be transported by road or rail to the various shale gas sites, the *Australian Code for the Transport of Dangerous Goods by Road and Rail* will apply.

This Code is given legal effect in the Northern Territory by the Transport of *Dangerous Goods by Road and Rail (National Uniform Legislation) Act 2010* (NT), administered by Northern Territory Worksafe. The Panel will confirm which chemicals and fluid additives, if any, are dangerous goods for the purposes of the Act and the Code and will consider the adequacy of the administration and enforcement of the Act and Code by Northern Territory Worksafe.

The Panel will also confirm the role, if any, that DPIR has in the management of chemicals and waste being transported off site.

Current industry practice in the transportation of chemicals requires that both primary and secondary containment measures are in place.[155] Primary containment ensures that additives are stored and transported in properly designed materials (for example, high density polyethylene thermos plastic material) and protected by a steel cage to maintain the structural integrity of the container. Secondary containment measures are also put in place to mitigate the risk of a spill in the event the primary containment fails, by preventing or mitigating any uncontrolled release of chemicals to ground and possibly to waterways. For example, by constructing bunded working areas designed to contain maximum probable precipitation events and engineered above ground ponds with sufficient freeboard or closed tanks. It is also possible that wastewater may be transported by pipeline to a centralised water treatment plant.

7.4.2.2 Groundwater

Possible contamination of groundwater aquifers due to surface spills of chemicals, flowback water or produced water

The likelihood of wastewater spills and resultant contamination is ever present in all resource extraction operations. As many submissions have pointed out to the Panel, there are numerous examples in Australia and overseas of poor wastewater management practices that have resulted in environmental impact.

Without adequate management there is potential for accidental leaks and spills due to pond or pipeline failure. Potential incidents include:

- spillage, overflow or water ingress or leaching from cuttings/mud pits;
- spillage of fracking fluids or component chemicals during preparation or use;
- spillage of flowback or produced fluids during transfer to storage;
- loss of containment of stored flowback or produced fluids;
- spillage of flowback or produced fluids during transfer from storage to tankers for transport; and
- spillage of flowback or produced fluids during transport to wastewater treatment works.[156]

While the available evidence suggests that spills of chemicals and/or wastewater do occur, the likelihood of occurrence can be reduced with well engineered wastewater containment facilities and existing management strategies.

It has been suggested that the likelihood of contaminants in a spill rapidly reaching a surface aquifer prior to any clean up action is low because:

- the depth of the groundwater aquifers (50-200 m below surface in the Beetaloo Sub-basin);
- the installation of appropriate containment facilities; and
- the interaction with the soil zone that will reduce the concentrations of many of the contaminants.[157]

155 Origin submission.

156 Santos submission, p 99.

157 McLaughlin et al. 2016.

There is considerable evidence for the attenuation of contaminants transported through soils.[158]

However, the Panel has no specific information regarding the potential for toxic contaminants in flowback and produced water to be 'removed' in passing through the soil profile in the Beetaloo Sub-basin, and will seek specific information on this aspect.

The US EPA noted that the consequences of toxic chemicals entering an aquifer are likely to be more severe than spills into surface waters because of the slow movement of the water in an aquifer, which significantly reduces the potential for these chemicals to be diluted.[159] The Panel notes, however, that reaction with aquifer materials may attenuate or reduce the concentrations of some contaminants, depending on the nature of the aquifer material and the nature of the chemicals.

The US EPA notes two other reasons why aquifer contamination can be problematic. The first is that groundwater contamination can only be detected if monitoring bores are installed in the area where contamination is most likely. The second is that groundwater can be difficult and expensive to remediate.

Possible contamination of aquifers due to the reinjection of treated or untreated wastewater into other aquifers

Reinjection of wastewater is common practice by shale gas companies overseas, and particularly in the US. The US EPA found that in 2012 around 93% of the flowback and produced water from the oil and gas industry in that country was injected into Class II wells associated with extraction of oil and gas from conventional reservoirs. It also reported that this practice had been associated with seismic activity in several states.[160]

For this reason, the onshore shale gas industry in the US is now focussed more on reusing these wastewaters for well drilling and hydraulic fracturing. For example, in the Marcellus shale basin approximately 90% of the flowback and produced water (around 3.2 ML per well) is reused for hydraulic fracturing, with this recycle component making up around 14% of the 16-18 ML per well currently used for fracturing.[161]

There has been limited test work on reinjecting CSG produced water in Queensland. It is not known if this practice is employed elsewhere in Australia. However, the Panel is also aware that managed aquifer recharge (**MAR**) is practised in many areas of Australia and overseas. MAR involves the injection of water of compatible chemistry into aquifers, which requires both an aquifer with suitable permeability and structural integrity to receive injected waters, and for the waters to have a suitable chemical composition so there are no adverse chemical reactions with aquifer materials leading to either clogging of the injection bore or aquifer, or liberation of other chemicals in the aquifer material.[162]

In its submission to the Panel, Origin noted that is has not considered or planned for reinjection of flowback fluid, and would not consider this option *"except where the water is treated to the same standard as the aquifer water and regulatory approval is provided".* [163]

There is insufficient information concerning any potential reinjection of wastewaters in the Beetaloo Sub-basin (or elsewhere) to make any assessment of the contamination risk associated with this practice. The information required to support a risk assessment of this practice would include the quality and volume of the wastewater to be reinjected, the composition of water in the target aquifer, the potential to influence other connected aquifers, and the long term changes in water quality in the target aquifer.

Therefore, until further information is obtained to determine whether or not the risks associated with this practice can be managed to acceptable levels, the practice of disposal of wastewaters by reinjection of untreated wastewaters (for example, brines) into aquifers should generally not be permitted.

Possible contamination of aquifers due to induced connectivity between hydraulically fractured shale rock formations and overlying aquifers

Claims were made in submissions and during community consultations, that surface aquifers could be contaminated as a result of the hydraulic fracturing process by reason of hydraulic fracturing fluids travelling through the rock strata from the fractured shale area vertically to overlying aquifers containing high quality water.

Conversely, it has been stated that the likelihood of this occurring is low given the large distance (1,000 to 2,000 m) between the shale layer and the high quality aquifer, and the very low permeability of the intervening strata.[164]

In deep shales with horizontal wells the hydraulic fractures occur vertically from the well, and at least in the Marcellus shale basin, the median fracture length has been reported at 140 m.[165] The longest recorded fracture has been approximately 600 m.

However, as Lock the Gate Alliance Northern Territory (**Lock the Gate**) have noted, if there is a fault between the fractured region and the aquifer, this may provide a preferred pathway between the shale layer and the aquifer for fluid flow during the hydraulic fracturing operation.[166] Contaminants that could be transported include hydraulic fracturing fluids, hydrocarbons (including methane gas), and naturally occurring brines.[167]

According to the petroleum companies, the location of faults is taken into consideration during the design and construction of each well. Gas companies actively avoid faults because their occurrence can seriously compromise the effectiveness of the hydraulic fracturing operation, as well as being a potential environmental risk. This was the case for the Amungee NW-1H well where a section of the horizontal bore was not fractured precisely because of the inferred existence of a small fault system.[168]

It is not possible to predict the likelihood of aquifer contamination as the result of groundwater flow through faults, or whether this is likely to be exacerbated by hydraulic fracturing, without predictive computer modelling of the local hydrogeological characteristics. The Panel will therefore seek further clarification on the likelihood of existing faults to provide potential inter-connecting pathways between shale layers and overlying aquifers in the Northern Territory, and the adequacy of the existing regulations to ensure that relevant seismic information is available during the well design stage.

158 Pichtel 2016.
159 US EPA Report.
160 US EPA Report.
161 US EPA Report.
162 This is discussed in some detail in NRMMC 2009.
163 Origin submission, p 84.
164 APPEA submission; Origin submission; Santos submission.
165 US EPA Report.
166 Lock the Gate Alliance, submission 171 (**Lock the Gate submission**), p 10.
167 US EPA Report.
168 Origin submission

Possible contamination due to changed groundwater pressures as the result of groundwater extraction for hydraulic fracturing

If the water required for hydraulic fracturing is sourced from local groundwater there will be a resultant decrease in groundwater pressure in that particular aquifer, which may result in underlying or overlying groundwater bodies flowing into that aquifer and possibly changing water quality. This has been perceived as a potential issue of concern in some CSG operations.[169]

The evidence available to the Panel suggests that if the make-up water for hydraulic fracturing fluid is sourced from groundwater, there is potential for changes to groundwater pressures sufficient to impact groundwater flow pathways, and potentially water quality. However, it is not possible to determine whether these impacts on groundwater flow pathways will result in changes in groundwater quality without considering the local hydrogeology and applying predictive computer modeling.

The Panel is aware that the volumes of water involved are likely to be significantly less than those involved in CSG operations, which need to extract a substantial volume of groundwater before gas can be developed. Onshore shale gas operations require only the volume of water required for hydraulic fracturing, and if significant recycling of flowback water is possible (see the discussion above), the volume of groundwater required can be reduced.

If local groundwater is used as the water source for hydraulic fracturing, there is a risk that the water quality and quantity in the aquifer could be adversely impacted, but this risk can only be quantified with site specific hydraulic modeling.

In the absence of further information, it is the Panel's preliminary view is that hydraulic fracturing ought not be permitted unless site specific hydraulic modelling of the local groundwater system is included in any environment plan and it can be demonstrated that there is no adverse impact on groundwater quality and quantity.

Possible contamination due to leaky wells as a result of poor design, construction or operation

It is possible for fluid (liquid or gas) to move into an aquifer through defects or deficiencies in the production well casing and/or the cement.[170] However, as discussed in Chapter 5, the likelihood of this occurring is low assuming wells are constructed to current best or leading practice standards.

The greatest potential for contamination of aquifers from leaky wells is where the well goes through the aquifer.[171] As explained in Chapter 5, it is now standard practice for a well to be lined with multiple layers of piping (casing), with a specialised cement layer between each of the pipes and also between the outer pipe and the rock strata.[172] These multiple casing strings are designed to isolate rock or aquifer zones and prevent migration of fluids between the well and an aquifer or between the rock zones.

The design, construction and operation of onshore shale gas wells in Australia and the US is much better developed technically than in previous decades.[173] As noted in Chapter 5, recent analysis of the frequency of well failures has shown that the incidence has markedly declined with modern methods of design and construction being implemented.

The technologies involve deep horizontal drilling and multiple-stage hydraulic fracturing, together with associated real-time sensing to monitor and guide the drilling and fracturing process.[174]

Possible contamination due to leaky or degraded wells when the operations are completed and the well is abandoned

There is little experience with the abandonment of hydraulic fractured onshore shale gas wells in Australia. However, there is some experience with decommissioning of wells in the US and elsewhere (see Chapter 5).

Various submissions to the Panel, and reports in the literature, have questioned the long-term integrity of the cement plug and the well piping from corrosion. The submissions to the Panel from the major petroleum companies (for example, Origin and Santos), APPEA and DPIR did not comment on how the long-term integrity of abandoned wells is assured.

The Panel will obtain further information from industry and DPIR on how abandoned wells will be secured, how they will be monitored, what remediation may be needed if these wells degrade, who will be responsible for this remediation, and who will pay for any remediation.

7.4.3 Aquatic ecosystems and biodiversity

Some of the major features of aquatic ecosystems in the Northern Territory have been summarised earlier in this Chapter. It has been noted that most of the permanent surface water bodies in the Northern Territory are found in the northern, high-rainfall regions. Although there are no permanent surface water bodies in the Beetaloo Sub-basin, temporary waterbodies do occur. However, the Panel currently has little specific information about the aquatic ecosystems sustained by those temporary waterbodies.

7.4.3.1 Water quantity

Water extraction can have potentially serious impacts on rivers, wetlands and other water-dependent ecosystems, including on aquatic wildlife.[175] Rivers, in particular, can be ecologically degraded by excessive water extraction.[176] For example, excessive water extraction can potentially cause perennial rivers to become intermittent,[177] and can have major ecosystem impacts on intermittently flowing rivers by decreasing the period of hydrological disconnection between deep-pool refugia during the wet season, or increasing the risk of poor water quality during the dry-wet transition phase. On the other hand, discharges from an industry source could extend the duration of flow altering the ecosystem development over the wetting-drying cycle. High-turbidity flows from surfaces exposed by land clearance, during the wet–dry transition phase could greatly alter ecosystem structure and functioning during that critical stage.[1778]

The two permanently flowing rivers in the Northern Territory (the Daly and Roper Rivers) have their dry-season flows maintained by groundwater systems connected to the CLA overlying the Beetaloo Sub-basin.[179] There is community concern that excessive groundwater extraction from this aquifer by a possible shale gas industry could reduce or even stop these dry-season flows.

169 IESC 2014.

170 US EPA Report.

171 ACOLA Report; US EPA Report.

172 As discussed in Chapter 5 above.

173 ACOLA Report; Origin submission; Santos submission; US EPA Report.

174 APPEA submission; Origin submission; Santos submission; ACOLA Report; US EPA Report.

175 Bunn and Arlington 2002; Burton et al. 2014; King et al. 2015; Smith et al. 2012.

176 Burton et al. 2014.

177 Warfe et al. 2011; King et al. 2015.

178 King et al. 2015.

179 Bruwer and Tickell 2015; DENR submission, Addendum 2.

Additionally, the northern region of the Northern Territory has many groundwater-dependent ecosystems,[180] and these might also be affected by groundwater extraction.

In the semi-arid and arid region of the Beetaloo Sub-basin there are very few, if any, groundwater-dependent surface ecosystems, since the groundwater is typically greater than 30 m deep and is not connected to the surface.[181]

7.4.3.2 Water quality

The effective management of wastewaters (flowback and produced water) is a particularly important issue for aquatic ecosystems and biodiversity. As discussed earlier, contamination of aquatic systems can occur during either the wet or dry season through discharges of contaminated wastewaters, accidental spills of contaminated wastewaters, or accidents during the transport of chemicals or wastewater.[182] Spills that occur during the dry season, if not remediated, can result in contaminated water being flushed into temporary waterbodies during the wet season. Increased erosion and transport of sediments into waterways due to the construction of roads and pipelines can also impact aquatic systems.[183]

There has been limited study of the susceptibility of temporary water ecosystems to changes in water quality. Ramsay et al and Botwe et al have described potential effects from agricultural, urban land-uses and mining on temporary waters in Queensland and SA, respectively.[184] There are calls for regulatory agencies across Australia to give greater focus on the protection and management of these systems, similar to that afforded to perennial waters.[185]

7.5 Knowledge gaps and next steps

The Panel has documented a number of knowledge gaps that will need to be addressed before a credible and robust assessment of the water-related risks of possible onshore shale gas development in the Beetaloo Sub-basin and other areas in the Northern Territory can be made.

In particular, the Panel requires further information on:

- the CLA groundwater resource in the Beetaloo Sub-basin (recharge rates and variations thereof from the north to the south, extent of possible local drawdown due to extraction of water for hydraulic fracturing);
- the likely volumes and composition of flowback and produced water from the hydraulic fracturing operations, and the collection, storage and treatment of this wastewater;
- the location, prevalence and ecology of temporary waterbodies and groundwater dependent ecosystems;
- the likely volumes of flowback and produced water that will be reused;
- what 'leading practice' consists of in the design, construction and operation of hydraulically fractured wells; and
- the likelihood that accidental on-site surface spill of chemicals or wastewater could reach the groundwater aquifer, and if they do, what their outcome would be.

The next steps to be undertaken by the Panel will be to:

- consider additional scientific evidence and community feedback on the assessments documented in this Interim Report;
- develop recommendations for mitigation measures that would be required for each key risk if onshore unconventional shale gas development were to proceed in the Northern Territory;
- consider what regulatory controls should be imposed to minimise the possibility of faulty wells; and
- consider the need for a bioregional assessment of the Beetaloo Sub-basin to obtain further information on the aquatic ecosystems and biodiversity.

180 BOM 2017.
181 DENR submission, Addendum 1.
182 Burton et al. 2014.
183 Entrekin et al. 2011.
184 Ramsay et al. 2012; Botwe et al. 2015.
185 Acuna et al. 2014.

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LAND

8

8.1 Introduction

The Northern Territory is internationally renowned for its vast and often spectacular landscapes, many of which have outstanding wilderness values and represent an iconic part of outback Australia. These unspoiled landscapes are integral to the cultural heritage of Territorians. This is especially the case for Aboriginal people, who retain the deep cultural and spiritual connection to land that has been fundamental to traditional society for millennia (issues relating to Aboriginal cultural values are addressed in Chapter 11). However, this is also the case more broadly; for the pastoral sector that depends on native pastures sustained by healthy ecosystems, and for people in remote communities who are attracted to the 'frontier' lifestyle. It is also why most non-residents choose to visit, making it fundamental to the tourism industry, a mainstay of the Northern Territory economy.

The Northern Territory has some of Australia's premier conservation reserves, including Kakadu, Uluru-Kata Tjuta, Nitmiluk and Litchfield National Parks. Most of these are located outside shale basins (see **Figure 8.1**). In addition to the network of national parks and other protected areas, there are 67 sites in the Northern Territory that are formally recognised as being of high significance for biodiversity conservation.[186] These sites can be highly localised (for example, the Mataranka thermal pools), but most cover substantial areas, such as the Tiwi Islands, South-West Tanami Desert, and Greater MacDonnell Ranges. The majority of these sites also lie outside shale basins (none occur in the Beetaloo Sub-basin), except in the southern region, and especially the Amadeus basin.[187]

The Northern Territory has exceptional terrestrial biodiversity values, featuring a wide range of habitats and high levels of species diversity and endemism.[188] For example, more than 900 species of ants are known from the Top End (north of Katherine), most of which occur nowhere else.[189] This is about the same number as occurring in the whole of the US. Almost all the Northern Territory is covered by natural vegetation due to the very limited agricultural development. There is extensive pastoralism, but this is based almost entirely on native pastures. Much of the Northern Territory's biodiversity is therefore intact.[190] A major exception is the small-mammal fauna, which has suffered severe depredations by feral animals, especially foxes and cats. Many of the small-mammal species from arid regions are now long extinct,[191] and species from the northern, higher rainfall zone have undergone recent population crashes, likely due to predation by cats, exacerbated by removal of shelter due to fire and high levels of grazing.[192] In total, the Northern Territory has 90 plant species recognised as *"threatened"* under Commonwealth or Territory legislation,[193] and 126 terrestrial animal species, comprising 48 mammals, 31 birds, 12 reptiles, 1 frog and 34 invertebrates (30 land snails, 3 butterflies and a moth).[194]

The Northern Territory has a very strong latitudinal gradient in mean annual rainfall, from 2,000 mm on the Tiwi Islands off the northern coast, to about 150 mm in the far south. Rainfall is a dominant driver of the distribution of plants and animals, and also has a major effect on ecosystem function. In particular, the summer monsoon dominates the rainfall of the northern and central regions (from about Tennant Creek north), producing extensive herbaceous growth during the summer, which dries out and burns during the winter dry season. This distinguishes the tropical savannah landscapes to the north from the desert ecosystems to the south. In the southern (arid) region, herbaceous production and subsequently fire are driven by decadal-scale periods of unusually high rainfall. The desert/savannah transition at about 500 mm/y is the Northern Territory's primary biogeographic boundary in terms of the composition of plant and animal species. The next most important boundary is between the semi-arid savannahs of the central region, and the high-rainfall savannahs of the northern region, at about Katherine.[195]

Due to its vast size and remoteness, most of the Northern Territory has never been systematically surveyed for plants and animals. Consequently, the distributions of most species are known only in general terms at best, and there is very limited knowledge of geographic patterns of diversity and endemism. Information is particularly scant for terrestrial invertebrates, which represent the great majority of the Northern Territory's faunal species and play critical roles in the functioning of ecosystems. DENR has provided the Inquiry with summary information on terrestrial biodiversity in the Beetaloo and Southern Georgina Sub-basins. The Beetaloo Sub-basin has been moderately well sampled for plants (1,341 known species), but only sporadically sampled for vertebrates (437 known native species), with sampling concentrated around main roads. The vertebrate fauna includes 17 threatened species. There have been virtually no systematic invertebrate surveys in the region. The flora and fauna of the Southern Georgina Sub-basin is even less well known, but includes at least 825 native plant and 293 native vertebrate species, a total of ten of which are listed as *"threatened"*.

186 Figure 8.1; Northern Territory Government, List of sites of conservation significance.

187 See Figure 8.1.

188 Woinarski et al. 2007a.

189 Andersen et al. 2016.

190 Woinarski et al. 2007a.

191 Woinarski et al. 2007b.

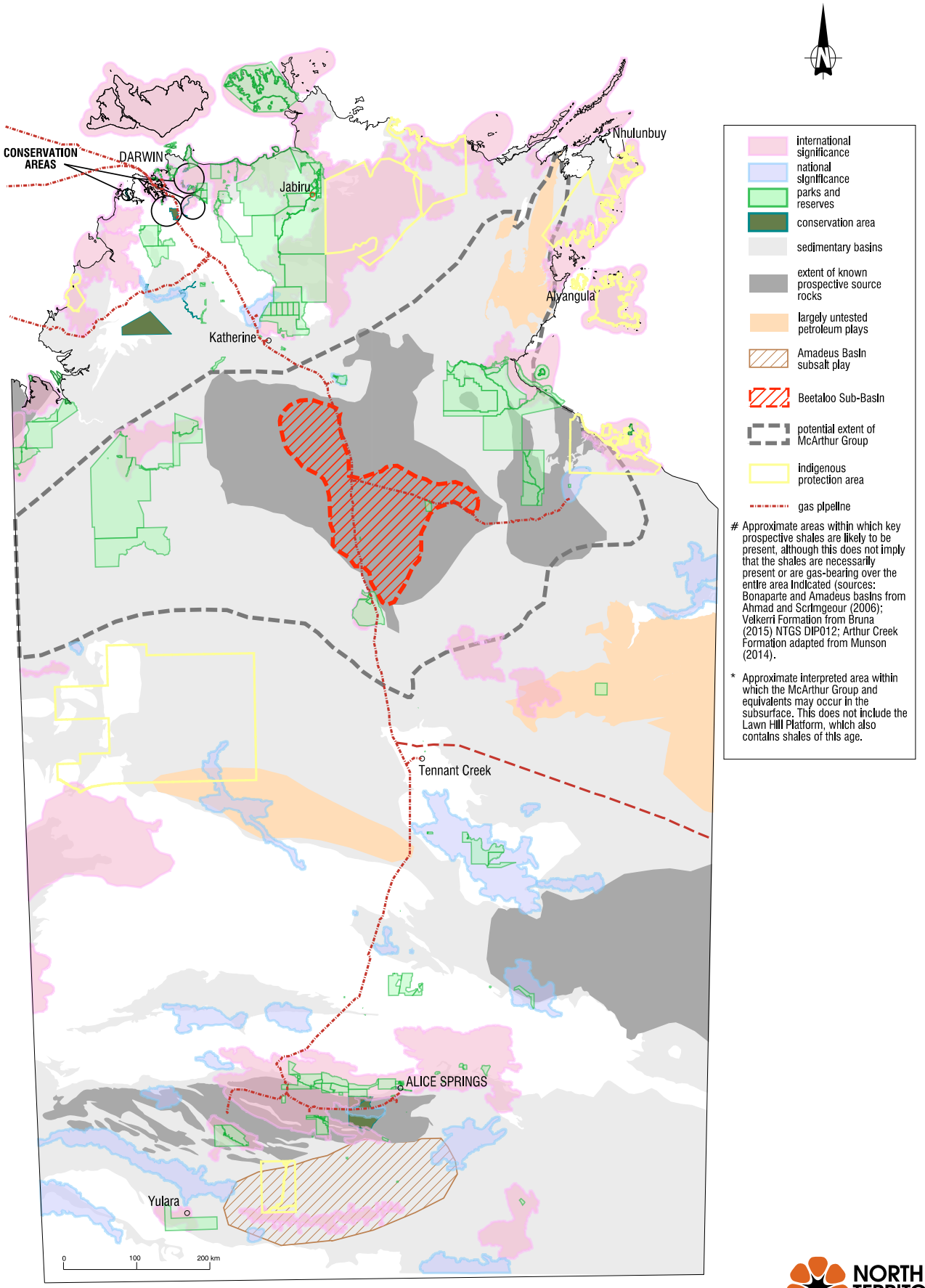
192 Woinarski et al. 2011; Andersen et al. 2017.

193 NT Government, List of threatened plants.

194 NT Government, List of threatened animals.

195 Andersen et al. 2015.

Figure 8.1. Locations of conservation reserves and sites of conservation significance in relation to shale basins in the Northern Territory. Source: DIPL.



8.2 Key issues raised

Large scale onshore shale gas development could potentially have a major impact on the amenity values of landscapes. This has often been the experience with developments overseas, especially for CSG, where surface infrastructure can be a highly visible and sometimes dominant feature of the landscape due to the close spacing of well pads.

There is extensive scientific literature on the impacts of shale gas and other onshore oil and gas development on terrestrial biodiversity and ecosystem health, and this has been the subject of several recent reviews in the scientific literature.[196] The main impacts that have been identified are:

- **vegetation clearing:** shale gas development involves substantial land clearing for the establishment of well pads, access roads, pipelines and other infrastructure. For example, land clearing for shale gas development in the central Appalachians, US, has resulted in a 4.5% loss in forest cover.[197] However, recent advances in technology involving multiple wells per pad and horizontal drilling would substantially reduce the surface footprint of new shale gas developments;
- **habitat loss and fragmentation:** vegetation clearing for shale gas infrastructure not only represents direct habitat loss, but also results in the fragmentation of habitat not directly affected.[198] A key consequence of fragmentation is the proliferation of habitat edges, with edge effects on the abiotic environment (including microclimate, light and wind) occurring up to 500 m or more from cleared areas in forest.[199] For onshore gas development, it has been estimated that loss of core habitat through edge effects is at least twice that lost directly through vegetation clearing.[200] The 4.5% loss in forest cover in the central Appalachians due to shale gas development has been assessed as translating to 12.4% loss in core forest once edge effects are considered, and this has had a detectable impact on local bird communities.[201] Habitat loss and fragmentation can be a particularly important issue when development areas cover a substantial portion of the distributions of legislatively-listed threatened species.[202]
- **spread of weeds:** weed invasion is a major driver of terrestrial biodiversity decline globally, and the risk of the spread of weeds is inherent in any regional development. This risk is especially an issue for shale gas development because it involves such extensive linear infrastructure in the form of pipelines and roads, which are primary sites of weed dispersal and establishment, and act as corridors for the spread of weeds into new regions;[203]
- **roads and pipelines as ecological barriers and corridors:** pipelines and roads can disrupt important ecological processes, especially those involving the flow of water (and the sediment and nutrients in it) across landscapes.[204] This can relate to water flow along drainage and creek-lines, or to the smaller scale run-off/run-on dynamics that are especially important in flat, semi-arid landscapes.[205] Pipelines and roads can also disrupt the spread of fire, which is a dominant agent of natural disturbance throughout the world[206] and a key driver of global vegetation dynamics.[207] Pipelines and roads can also disrupt the movement of fauna,[208] and can act as corridors to facilitate movement and hunting by predators (with cascading effects on their prey),[209] as well as the spread of exotic animals;[210]

196 Kiviat 2013; Brittingham et al. 2014; Souther et al. 2014.
197 Farwell et al. 2016.
198 Racicot et al. 2014.
199 Zipperer 1993; Harper et al. 2005.
200 Slonecker et al. 2012.
201 Farwell et al. 2016.
202 Gillen and Kiviat 2012.
203 Forman and Alexander 1998; Trombulak and Frissell 2000; Mortensen et al. 2009.
204 Brittingham et al. 2014.
205 Ludwig et al. 1996.
206 Bowman et al. 2009.
207 Bond et al. 2005.
208 Machtans 2006.
209 Howell et al. 2007; Latham et al. 2011.
210 Brown et al. 2006.

Outback near Alice Springs, Northern Territory, Australia. Genevieve Vallee. Source: Alamy Stock Photo.

- **chemical spills:** spillages of toxic substances often occur during shale gas development, involving chemicals used during hydraulic fracturing, and wastewaters additionally containing potentially harmful substances from the rock formation (see Chapters 5 and 7). Spills can occur during transportation to and from a drilling site, storage on site, mixing of fluids and chemicals on site, management of flowback water, or wastewater disposal. Chemical spills can poison local wildlife, and contaminate soils. Many of the chemical additives of fracking fluids rapidly biodegrade, but there can be significant longer-term issues with soil contamination;[211]
- **drinking of wastewater by wildlife:** shale gas development requires at least short-term local storage of substantial volumes of wastewater of variable quality. The poisoning of wildlife by toxic waterbodies can be a significant management issue for the mining industry.[212] In shale gas development, water storage is typically in above-ground holding ponds where it is accessible only to flying animals, and the lack of vegetation and other aquatic life make them generally unattractive to fauna other than for drinking. Any drinking of wastewater would most likely be by birds or bats in arid regions where natural sources of water are very limited. Moreover, birds actively avoid drinking hypersaline water,[213] noting that the salinity of shale flowback water is typically at least as high as seawater. Further, shale gas wastewater is unlikely to contain acutely toxic substances that are at all comparable to the cyanide used in gold mining that can cause mass poisoning of wildlife;[214]
- **noise and light:** shale gas development involves relatively short-term (up to several weeks) increases in noise during site clearing, well drilling, and construction of roads, pipelines and other infrastructure. Pipeline compressor stations are a long-term source of increased noise. Chronic noise can influence wildlife in many ways,[215] with animals relying on vocal communication, such as birds, being especially affected.[216] Some shale gas infrastructure is brightly lit at night, and such artificial light can affect wildlife through direct mortality, and through changes in foraging behaviour and success;[217]
- **increased human activity:** the development of shale gas infrastructure requires substantial levels of human activity. For example, it has been estimated that the development of each horizontal well requires more than 3,300 one-way truck trips.[218] Increased traffic can have negative effects on wildlife through road kills and changes in animal behaviour. And new roads will increase public access to, and therefore disturbance of, surrounding areas.[219] The latter is especially pertinent for the Northern Territory's remote and 'wild' landscapes, many areas of which are currently inaccessible to most people.

The Inquiry has comprehensively reviewed the relevant scientific literature to identify the issues relating to land-based impacts of shale gas development. Based on this review, along with community concerns expressed during public hearings and community forums, and information provided by stakeholders in formal submissions, the Inquiry has determined the key risks to land-based values and assets of shale gas development in the Northern Territory, as outlined below.

8.3 Preliminary assessment

The risk-assessment framework used in this Interim Report is described in Appendix 13. This Chapter uses the following descriptors to define low, moderate and high consequences of impacts to amenity, biodiversity and ecosystem health:

- low: minor short-term damage to an area of limited significance but not affecting ecosystem functions;
- medium: moderate effect on biological and physical environment with significant short-term effect on ecosystem functions. This equates to *"material environmental harm"* under the Petroleum Environment Regulations;[220] and

211 Pichtel 2016; McLaughlin et al. 2016.
212 Minerals Council of Australia 1996.
213 Smith et al. 2008.
214 Ryan and Shanks 1996; Donato et al. 2007.
215 Francis and Barber 2013.
216 Bayne et al. 2008; Francis et al. 2011
217 Rich and Longcoren 2006; Stone et al. 2009; Perkin et al. 2011.
218 Bureau of Oil and Gas Regulation 2011.
219 Trombulak and Frissell 2000.
220 Petroleum Environment Regulations, s 117AAB.

- high: significant environmental impact on ecosystems or species, widespread medium and long-term impact. This equates to *"serious environmental harm"* under the Petroleum Environment Regulations.[221]

The Panel has identified seven land-related risks of shale gas development, four of which have been assessed as potentially high and three as potentially medium, and all requiring mitigation if development were to proceed. It is the Panel's view that other impacts on wildlife, such as those relating to noise, light, increased human activity, roads and pipelines as barriers and corridors for faunal movement, and the drinking of wastewater (see above), represent low risks without a need for mitigation.

8.3.1 Landscape amenity

The amenity impact of onshore shale gas development is particularly relevant to the Northern Territory because of the largely undeveloped nature of its landscapes. This was a major issue raised during community consultations. As stated above, there are widespread and deeply-held concerns within Northern Territory communities that shale gas development would lead to the industrialisation of what are perceived to be iconic outback landscapes. Impacts on landscape amenity values are directly related to the density and visibility of well pads and associated infrastructure. In well forested (higher rainfall) country, well pads and associated infrastructure would not be visible from the ground beyond 100 m or so, whereas in open (low rainfall) country they would be visible from several hundred metres. However, even in well forested country, the access roads and pipelines associated with well pads separated by substantially longer distances could be a conspicuous part of the landscape from high vantage points (lookouts or in aircraft), and could significantly detract from amenity values when driving through a development area even if the well pads themselves were not visible.

The Panel's preliminary assessment is that the consequences of amenity impact would be high if shale gas development significantly detracted from iconic wilderness values. In the absence of additional mitigation measures, the likelihood of such an impact is assessed as medium. Industry policy is to avoid National Parks and other conservation reserves, but such exclusion is not currently enshrined in legislation. Moreover, many other Northern Territory landscapes (including sites of conservation significance: see below) also have extremely high amenity value. There are current Northern Territory guidelines that define high value 'no go' zones,[222] but these are not prescriptive (they are defined as *"Areas of high ecological value - as determined through the Northern Territory's robust environmental assessment process"*), and are guidelines only. Industry forecasts are for low well pad densities (each serving an area of at least 10 km^2), but this is not certain given that the shale gas industry is at such an early stage of development in the Northern Territory. Amenity impacts can be mitigated through, first, clearly defined and legislatively enshrined 'no go' zones with defined minimum offset distances around such areas, and second, the specification of a minimum acceptable well pad spacing/density.

8.3.2 Inappropriate planning of regional development due to inadequate knowledge of biodiversity assets

Development will inevitably have significant impacts on biodiversity if it occurs in locations of especially high conservation value. A well developed understanding of biodiversity assets within prospective regions for shale gas development is therefore required to minimise risks to biodiversity by identifying specific areas where development should not occur. Such an understanding requires, first, region-wide information on spatial patterns of biodiversity, including the identification of areas of special significance such as biodiversity hotspots or centres of endemism; and second, particular information on the distribution of threatened species. In neither case is the information currently adequate for effective regional-scale planning that minimises risks to biodiversity in prospective regions for shale gas development in the Northern Territory.

The Panel is considering making a recommendation that shale gas development should be excluded from all current conservation reserves and sites of conservation significance. However, the locations of these have historically not been proclaimed on the basis of systematic evaluations of regional biodiversity assets, and therefore it cannot be assumed that they are representative of broader regional biodiversity values. Environment management plans for testing and development of shale gas permit areas include biodiversity assessment,[223] but the usefulness of such assessments is severely limited by a lack of region-wide information on spatial patterns of biodiversity, in most cases including no information on key invertebrates.

The Panel's preliminary assessment of the consequences of biodiversity impacts due to inadequate knowledge of biodiversity assets is high because these impacts would be significant, widespread and long term. The likelihood of such impacts without additional mitigation is assessed as high, given that knowledge about the distribution of biodiversity assets within prospective shale basins is so limited. Adverse impacts of inappropriate planning of regional development due to inadequate knowledge of biodiversity assets can only be mitigated by implementing the findings from strategic basin-wide assessment of biodiversity values conducted prior to development. Strategic assessment is widely recognised as the most appropriate basis for limiting the impacts on biodiversity of regional development, and is formally recognised as such under *the Environment Protection and Biodiversity Conservation Act 1999* (Cth) (**EPBC Act**), including for *"large-scale industrial development and associated infrastructure"*.[224] Such assessment provides a clear planning framework for development that gives certainty to both industry and communities, and achieves better environmental outcomes by addressing cumulative impacts.

221 Petroleum Environment Regulations, s 117AAB.

222 DPIR submission, Attachment H.

223 For example, Origin 2016.

224 Australian Government 2011.

8.3.3 Spread of weeds

The Territory has 139 declared weed species,[225] many of which are highly invasive, have substantial impacts on conservation and agricultural production values, and are priorities for prevention of spread, control and eradication. Due to the largely undeveloped nature of most of the Northern Territory, shale gas development has the potential to spread weeds into regions where they do not currently occur, or exacerbate spread and density where establishment has already occurred. Some of the most problematic weeds were originally introduced as pasture grasses that are readily spread by human activity, can rapidly invade, dominate and transform native ecosystems, and are extremely difficult to control at the landscape scale. One of the worst of these is gamba grass (*Andropogon gayanaus*) which was originally introduced from Africa as pasture for cattle, and has invaded extensive areas of non-pastoral land in the Top End. It is an extremely tall (up to 4 m) grass with exceptional herbaceous biomass, and this fuels fires of unprecedented intensity that cause major declines in tree cover.[226] These fires also represent a significant threat to people's lives and property.[227] Buffel grass (*Cenchrus ciliaris*), an undeclared perennial grass used for pasture improvement and soil stabilisation, can increase fuel loads and fire hazard in more arid regions.[228]

Weed management is dealt with under several pieces of Northern Territory legislation and appears to fall within the jurisdiction of two government agencies. There is no express statutory requirement for a weed management plan under the Petroleum Act or supporting regulations. The Petroleum Environment Regulations, however, which are administered by DPIR, require that an environment plan be approved prior to the commencement of any regulated activity, such as a seismic survey. Where the spread of weeds is a risk associated with the activity, the environment plan must therefore include a strategy to ensure the risk of weeds spreading is reduced to acceptable levels. DPIR's guidelines, which are not enshrined in legislation, require that a weed management plan must be part of an application to drill or hydraulically fracture.[229] It is not clear whether the Weed Management Branch in DENR reviews or approves all environment plans and weed management plans that are submitted to the DPIR under petroleum legislation. There is also some uncertainty around whether or not the Weed Management Branch is involved in the monitoring of such plans.

The *Weeds Management Act 2011* (NT) (**Weeds Act**), which is administered by DENR, places obligations on the *"owner and occupier"* of land to take reasonable measures to prevent land being infested by weeds.[230] The Panel will seek clarification on whether or not a permit holder under the Petroleum Act is an *"occupier"* for the purposes of the Weeds Act and whether or not the penalties for an infringement of that Act are appropriate. If a permit holder is an *"occupier"*, he or she must comply with any statutory weed management plan that is in place. There are ten statutory weed management plans dealing with the management of various weed species. The Weeds Act also prohibits *"any person"* from bringing declared weeds into the Northern Territory, spreading or propagating declared weeds.[231]

The Panel's preliminary assessment of the consequences of weed spread is high because weed invasion in the Northern Territory has a history of significant and widespread impact on ecosystems. The likelihood of significant weed spread is also assessed as high because it historically occurs with extensive regional development, particularly associated with access corridors. In the Beetaloo Sub-basin, for example, proposed exploration and development could pass through areas affected by declared weeds such as bellyache bush, grader grass, parkinsonia, noogoora burr, rubber bush and gamba grass. The Panel acknowledges that the shale gas industry has procedures in place to minimise the risk of spreading weeds.[232] However, the risk of weed spread can subsequently be exacerbated by other users of newly created corridors. Increased public accessibility may be unavoidable, but industry would be in a position to take responsibility for the management of resultant weed infestations.

The Panel's view is that there is a need for increased clarity around the regulation, compliance and enforcement of comprehensive weed management plans for all areas affected by or adjoining exploration and development areas. Such plans should have the following key elements:

- **baseline assessment:** a comprehensive assessment of the occurrence of weeds in the development and surrounding areas would be required, allowing for the identification of infestations that could potentially be spread by development activity, and for the determination of future management requirements and arrangements;
- **prevention of weed spread:** a dedicated program should schedule necessary control works prior to weed seed set and afford the designation, use and management of wash/blow down areas. All vehicles, machinery and equipment with the potential to be carrying seeds would need to be subject to appropriate weed hygiene (for example, wash-down) before entering a development area, and, within a development region, when moving from a weed-infested area. All contractors should be able to identify and respond appropriately to the presence of a declared weed; and
- **weed monitoring and management:** a robust, field-based weed monitoring program would need to be established, and any new or high risk infestations managed according to agreed property or regional plans. It is the Panel's view that the shale gas industry should play a leading role in such management, and responsibility should not just fall to the land owner.

8.3.4 Changed fire regimes

Fire is a key ecological process in the tropical savannah landscapes of northern Australia (covering both the northern and central regions, including the Beetaloo Sub-basin), most of which are burnt every two to five years.[233] The savannah biota has an evolutionary history in association with frequent fire, and is adapted to the open habitat conditions created by it, such that long-term fire exclusion and subsequent canopy closure leads to substantial biodiversity loss.[234] Conversely, the savannah landscapes also include vegetation types such as obligate-seeding shrublands that require lower fire

225 See Northern Territory Government, Declared weeds.
226 Rossiter et al. 2003.
227 Setterfield et al. 2013.
228 Franks 2002; Smyth et al. 2009.
229 DPIR submission, p 193.
230 Weeds Act, s 9(1).
231 Weeds Act, s 9(4).
232 Origin submission; Santos submission; Pangaea submission.
232 Origin submission; Santos submission; Pangaea submission.
233 Andersen et al. 2003.
234 Andersen et al. 2012.

frequencies,[235] as well as isolated patches of fire-sensitive vegetation that requires complete protection from fire, such as monsoon forests,[236] Callitris pine,[237] and Lancewood.[238] Savannah fires are also important for Australia's carbon accounts, because they release substantial emissions of greenhouse gases. The use of prescribed fire to reduce fire extent and intensity, and therefore greenhouse gas emissions, is emerging as a significant economic activity across northern Australia, especially for remote Aboriginal communities.[239] Fire is less prevalent in arid regions of the Northern Territory, but is still ecologically important.

Onshore shale gas development could potentially affect the frequency, timing and areal extent of fire. This may be through increased ignitions because of increased human activity (acting to increase fire frequency), or through roads and pipelines acting as barriers to the spread of fire (acting to decrease fire frequency and areal extent).

The Panel's preliminary assessment is that the consequences of significantly altered fire regimes is high given the key importance of fire as a driver of vegetation dynamics and greenhouse gas emissions, especially in higher-rainfall regions.[240] The likelihood of significantly changed fire regimes due to shale gas development is assessed overall as medium. The likelihood of significance in relation to biodiversity impacts is relatively low because the savannah biota generally has a high degree of resilience to moderate variation in fire regimes. However, the likelihood of increased greenhouse gas emissions due to increased fire frequency and extent is relatively high because increased human activity (including the public) is highly likely to result in increased ignitions.

Should onshore unconventional shale gas development proceed, the Panel's view is that regional baselines for fire regimes should be established for the decade prior to commencement, based on remotely sensed information that is readily available on the North Australian Fire Information website. There would then be annual fire mapping for monitoring any subsequent change. If significant change were detected then this would require ongoing mitigation, such as through strategic early-season burning or active fire control. Should the industry proceed, the Panel recommends consideration be given by industry to establishing fire management partnerships with regional landholders, possibly as Commonwealth approved projects for earning carbon credits from reduced greenhouse gas emissions.

8.3.5 Habitat loss and fragmentation

Given that the shale basins in the Northern Territory are almost entirely covered by native vegetation, development would involve substantial clearing. In **Table 8.1**, the total area cleared within a development area is estimated for a range of well pad densities, based on assumptions of initial well pad size and lengths, and widths and lengths of access roads and pipelines. The percentage of total areas cleared in development areas when well pads are spaced by 1 km, 3 km and 5 km are estimated at 13.1%, 2.6% and 1.3% respectively. The Panel will seek further advice on initial well pad areas, and the likely lengths and widths of pipeline easements and access roads (noting that the Origin submission forecasts clearing widths of 10 m and 20-40 m for roads and pipelines respectively).

Based on submissions from Origin, Santos and Pangaea, industry forecasts are for well pad densities of one per 10-20 km^2 (equating to an average spacing between well pads of 3.2-4.4 km),[241] which would require vegetation clearing from approximately 1.5-2.5% of the development area, based on the figures in **Table 8.1**. In its submission to the Inquiry, Origin estimates that the total disturbance area (including pipelines and access roads) associated with each well pad in its development area in the Beetaloo Sub-basin would be 14 ha, equating to 1.4% of the total area over the life of development given a well pad density of one per 10 km^2.[242] With a forecast well pad density of approximately one per 19.4 km^2, Santos estimates a surface footprint of 0.03-0.05% of the total development area during the development phase, reducing to 0.01-0.02% during production following rehabilitation.[243] This is two orders of magnitude lower than that estimated in **Table 8.1** and by Origin, and seems unrealistically low.

In addition to the direct effects on the biota of cleared areas, such clearing would have especially pervasive edge and other fragmentation effects on uncleared vegetation because much of the clearing is linear (for pipelines and access roads).

235 Russell-Smith et al. 1998.
236 Russell-Smith and Bowman 1991.
237 Bowman and Panton 1993.
238 Woinarski and Fisher 1995.
239 Russell-Smith et al. 2009; Russell-Smith et al. 2013; Richards et al. 2012.
240 Andersen et al. 2005.
241 Origin submission; Santos submission; Pangaea submission.
242 Origin submission.
243 Santos submission.

Table 8.1. Estimated areas of vegetation clearing required for different densities of well pads (one well pad per 1, 9 and 25 km²) over a development area of 2,500 km². Industry forecasts are for each well pad to service an area of 10-20 km².

Area serviced per well pad (km²)	1	9	25
No. well pads	2,500	256	100
Well pad clearing, at 10 ha/pad (km²)	250	25	10
Total length of roads (km)	2,700	1,536	900
Road clearing, at 20 m width (km²)	54	30.72	18
Total length of pipelines (km)	2,295	816	495
Pipeline clearing, at 10 m width (km²)	22.95	8.16	4.95
Total clearing (km²)	326.95	63.88	32.95
Total clearing (% total area)	13.1	2.6	1.3

The Panel's interim assessment is that the consequences of habitat loss and fragmentation for biodiversity and ecological function due to shale gas development at the regional scale is medium, and the likelihood of significant impacts is also medium. Impacts of habitat loss and fragmentation can be mitigated through three complementary measures:

- **minimisation of vegetation clearing:** through specification of maximum well pad densities (for example, one well pad per 10 km²);
- **rehabilitation:** once in operation, well pads require a much smaller ongoing area (the Panel will seek further advice on the likely area), and the remaining cleared area would need to be rehabilitated. All pipeline routes would need to be rehabilitated following completion of development. Access roads may represent ongoing community assets, and their fates would need to be determined through community consultation. The aim of rehabilitation should be to ensure that previously cleared areas develop vegetation structure comparable with surrounding areas, and become integrated with the surrounding landscape in terms of ecosystem function (do not act as barriers to water and energy flow, or to faunal movements); and
- **offsetting:** given the substantial area of vegetation clearing, there would be inevitable impacts on biota. Such impacts could be offset by the provision of compensatory biodiversity benefits, such as the funding of local Aboriginal Ranger programs for the management of fire, weeds and feral animals that is not directly related to shale gas development.

8.3.6 Inappropriate location of infrastructure within a development area

Broad areas that might be considered as generally suitable for shale gas development are still likely to contain local sites of important habitat (for example patches of monsoon forest), particularly sensitive ecosystems (for example, wetlands, creeks and riparian zones), or culturally important places. The disturbance of these places would have unnecessary ecological impacts when there are alternative options for locating infrastructure, as is typically the case for shale gas development, where there is a high degree of flexibility for infrastructure location. Development should be planned to avoid locally sensitive sites of especially high biodiversity or cultural value, and this is industry practice, which includes pre-development surveys for identifying locally sensitive sites.[244]

The Panel's interim assessment of the consequences of inappropriate location of infrastructure within a development area is medium and the likelihood is also medium. Although the Panel acknowledges that industry practice is to avoid locally sensitive sites, where these are known, this conduct is not enshrined in regulation.

8.3.7 Chemical spills

There are risks of wildlife poisoning and soil contamination from chemical spills associated with onshore shale gas development,[245] as is the case for resource development more generally. In a recent high-profile case, approximately 10,000 L of untreated saline water leaked from a water treatment facility as part of coal seam gas operations in the Pilliga State Forest, NSW, causing soil contamination by sodium and other salts that led to reduced vegetation health.[246]

The Panel's preliminary assessment is that the consequences of wildlife poisoning by chemical spills due to shale gas development would be low, because soil contamination would be highly localised, and any wildlife mortality would be limited and would not compromise regional biodiversity values. The likelihood of *significant* wildlife poisoning and/or soil contamination from chemical spills is assessed as medium. The Panel acknowledges industry practice in limiting the likelihood of chemical spills, but history shows that spills do happen and have ecological consequences. The risks of chemical spills are considered in more detail in Chapter 7.

244 See, for example, Origin submission; Santos submission.

245 Pichtel 2016.

246 See *Connell v Santos New South Wales Pty Ltd (2014) 199* LGERA 84.

8.4 Knowledge gaps and next steps

There are two primary knowledge gaps relevant to land-based risks of onshore unconventional shale gas development. The first relates to the current very limited understanding of the distribution of an economically viable shale gas resource, meaning that there is very high uncertainty over the location and scale of potential development. The second relates to information on the distribution of biodiversity assets across prospective regions. Current information on species distributions and patterns of diversity and endemism are inadequate for making robust assessments of risks to biodiversity at the regional scale, including the identification of any areas outside formal conservation reserves and sites of conservation significance that are of sufficient conservation value to merit consideration for exclusion from development. Knowledge of the distributions of plant and vertebrate species, including threatened species, is sparse. There is little or no information available for invertebrates, which make a dominant contribution to biodiversity. Such information requires extensive field surveying, which is beyond the scope of this Inquiry.

The Panel's next steps are to:

- consider scientific and community feedback on the key risks, their assessments and potential mitigation options as outlined in the Interim Report;
- seek further advice on issues such as weed management in the Northern Territory, and extent of vegetation clearing required for roads and pipelines;
- consider the need for a bioregional assessment of the Beetaloo Sub-basin to obtain further information on the terrestrial ecosystem and biodiversity; and
- refine recommendations for appropriate mitigation measures for each key risk that would be required for onshore unconventional shale gas development to proceed.

GREENHOUSE GAS EMISSIONS

9.1 Introduction

The life cycle[247] of shale gas, from extraction through to use, will result in the emission of GHGs such as methane (**CH_4**) and carbon dioxide (**CO_2**). Concern has been raised that these emissions may add to the risk of climate change. Based on the issues raised in the hearings and in the community consultations, this Chapter provides the Panel's review of some of the relevant literature on emissions from shale gas operations and use, and the Panel's preliminary assessments of the issues.

GHG emissions are known to be the major contributors to climate change. In 2015, Australia signed the agreement negotiated at the United Nations Framework Convention on Climate Change (**UNFCCC**) Paris Climate Conference (**COP21**). The Agreement has a goal of *"holding the increase in the global average temperature to well below 2°C and above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C".*

As part of the Paris 2015 Agreement, the Australian Government has committed to reduce greenhouse gas emissions to 26-28% below 2005 levels by 2030. This will be a difficult task. The Australian emissions are projected to be 592 Mt CO_{2e}[248] in 2030, which will require a reduction of 990-1055 Mt CO_{2e} in cumulative emissions between 2021 and 2030. The largest contributor to Australia's greenhouse gas footprint is stationary energy which includes fossil fuel combustion for electricity generation, petroleum refining, gas production and solid fuel manufacture.

Natural gas is primarily composed of methane, but also contains ethane, propane and heavier hydrocarbons, carbon dioxide and small amounts of nitrogen, hydrogen sulphide and trace amounts of water. Natural gas is also a source of fugitive emissions, which is the intentional and unintentional release of greenhouse gases during the production, processing, transport, storage, transmission and distribution of fossil fuels. Energy is also required for the production, processing and movement of natural gas and the use of this energy results in the liberation of various gases (including GHG) and particulates, including carbon dioxide

9.2 Key issues raised

In response to the issues identified in the Issues Paper and the concerns raised in the community consultations, this Chapter will consider the GHG emissions that are:

- attributable to both methane and carbon dioxide; and
- applicable to the two key stages associated with the extraction and use of natural gas: first, the upstream stage; and second, the combined upstream and downstream stage of natural gas which is commonly referred to as the full 'life cycle'. The upstream stage comprises natural gas production, processing, transmission and delivery. The downstream stage represents the energy conversion phase of natural gas for commercial/ industrial or domestic purposes.

There is controversy as to the climate impact of methane relative to carbon dioxide. The Intergovernmental Panel on Climate Change (**IPCC**) adopts a concept of the Global Warming Potential (**GWP**) to convert the warming potential of gases to an equivalent warming potential of carbon dioxide. The United Nations Framework Convention on Climate Change requires a value of 25 to be used for this parameter, based on the Fourth Assessment Report from the IPCC. However, the IPCC Fifth Assessment Report indicates that over a short period such as 20 years, the GWP of methane is much higher, between 84 and 87.[249] It is usually more common to use a 100 year time frame, and in this case, this Report indicates that the GWP is between 28 and 36.

Here, the term grams of CO_2 equivalent (**g CO_{2e}**) is used to refer to the total global warming effect of GHG in terms of an equivalent quantity of CO_2. Thus if 1 gram of methane is emitted and a GWP of 36 is used for a 100-year timeframe, this is calculated as 36 g CO_{2e}.

The Panel has reviewed the scientific literature on the levels of methane and GHG emissions from shale gas operations and this has been used to make preliminary observations on possible levels of emissions. Using this information, the Panel has made a preliminary assessment of the issues related to a number of hazards that may prevent lower levels of methane emission performance from being achieved. In addition, knowledge gaps are identified and further work is outlined.

This Chapter draws upon data and literature from the US, given the very large shale gas industry within that country, and reference is made to Australian data where relevant. It should be noted that there are differences between the emissions from conventional and CSG wells, which are prevalent in Australia, and shale gas wells.

9.3 Methane emissions

The major contributor to upstream greenhouse gas emissions from shale gas, and most of the uncertainty, arise from fugitive emissions of methane.[250]

Reviews of the literature[251] have reported methane emissions that vary by several orders of magnitude. A recent report from the Melbourne Energy Institute (**MEI**) similarly quotes emissions from 0.22% to 17% of total methane production.[252] Extreme values are bounded at the low end by component-level measurements at the exact point of emission ('bottom up' techniques), and on the high end by continental measurements after atmospheric mixing ('top down' techniques). Both approaches are subject to error. In particular, it is difficult, if not almost impossible, to distinguish the many sources of emissions when considering the results from 'top-down' investigations. It is important to also consider the timeframe of each study. In the US prior to 2012, the mixture of water and gas generated during well completions was often released directly to the environment (venting) which resulted in very large methane emissions. However, new standards (referred to as New Source Performance Standards, or **NSPS**) introduced by the US EPA

247 The life cycle of gas comprises two stages: the upstream stage that includes natural gas production, processing, transmission and delivery, and the downstream stage that represents the energy conversion phase of natural gas for commercial/ industrial or domestic purposes.

248 Mt CO_{2e} = million tonne of CO2 equivalents

249 Fleurbaey, Kartha et al. 2014.

250 Skone et al. 2016.

251 For example, Brandt, Heath et al. 2014.

252 Lafleur, Forcey et al. 2016.

require reduced emission well completions for all new wells starting in 2015.[253] As these standards have penetrated the industry, emission levels have fallen. Reductions have also occurred due to reduced compressor station emissions, increased use of plastic piping, which has lower emissions than other pipe materials, and upgrades at metering and regulating stations.[254] The US EPA inventories of methane emissions from US natural gas production show a reduction from 2.27% in 1990 to 1.25% of the dry production volume in 2015 when using a consistent methodology. Using the estimate by Brandt, Heath et al that measured emissions are typically 1.5 times higher than in this inventory,[255] would suggest a reduction from 3.4% in 1990 to 1.9% in 2015.

In the introduction to a major recent study, Littlefield et al note that new data sources are necessary to reconcile the differences between bottom-up methods and other quantification approaches.[256] A synthesis of new methane emission data from a recent series of ground-based field measurements[257] was integrated with other data to estimate that 1.7% of the methane is emitted (with a 95% confidence interval (**CI**) from 1.3% to 2.2%) between extraction and delivery, across the US natural gas supply chain, including both conventional and unconventional gas wells.[258] As part of the study, the authors note that using data from basin-wide measurements, the total site-level emissions are higher than the sum of component emissions at production sites. The difference between the observed site-level emissions and the sum of known component emissions is referred to as 'unassigned' emissions. These emissions are not from a specific emission source, but comprise a small number of production sites with atypically high emission rates, production equipment that requires maintenance, intermittent wellhead maintenance events or any combination thereof. The authors quantify these unassigned emissions as 0.3% (with a 90% CI of 0.1 to 0.5%) for gas produced for the Barnett Shale region in the US. The inclusion of unassigned emissions makes the bottom-up compilation of emission sources more complete, but is a source of uncertainty that points to opportunities for further research. Overall, this most recent study concludes that 19% of all methane emissions fall into this 'unassigned' or 'super-emitter' category. The skewness of the original data supports the existence of a small share of emission sources that represent a large share of total emissions, and the analysis translates this variability to a national supply chain average. Gathering systems, pneumatic controllers, and unassigned emissions are the top three contributors to these emissions. Gathering facilities, a key connection between production and processing, are a significant emission source that has been omitted or undercounted in many studies to date.

Australia reports its emissions through the National Greenhouse Gas Inventory[259] using a structure that is consistent with the IPCC Guidelines.[260] As in the US, the fugitive emissions reported from the oil and gas industry within Australia, have declined as a percentage of production since 1990. In the financial year 2014-15, the published data for Australia suggests an overall methane emission rate of 0.5%, if all the methane emissions are associated with natural gas production. As noted in the recent MEI report,[261] this level of emissions is clearly an underestimate – it is lower than all values presented by the US EPA and by all scientific studies outlined above.

Furthermore, there are discrepancies between the emissions factors used by the Australian National Greenhouse and Energy Reporting System and the Australian National Greenhouse Gas Inventory, and the current US EPA dataset. These discrepancies need to be reviewed by the Commonwealth to reflect current research and overseas datasets.

9.4 Upstream GHG emissions

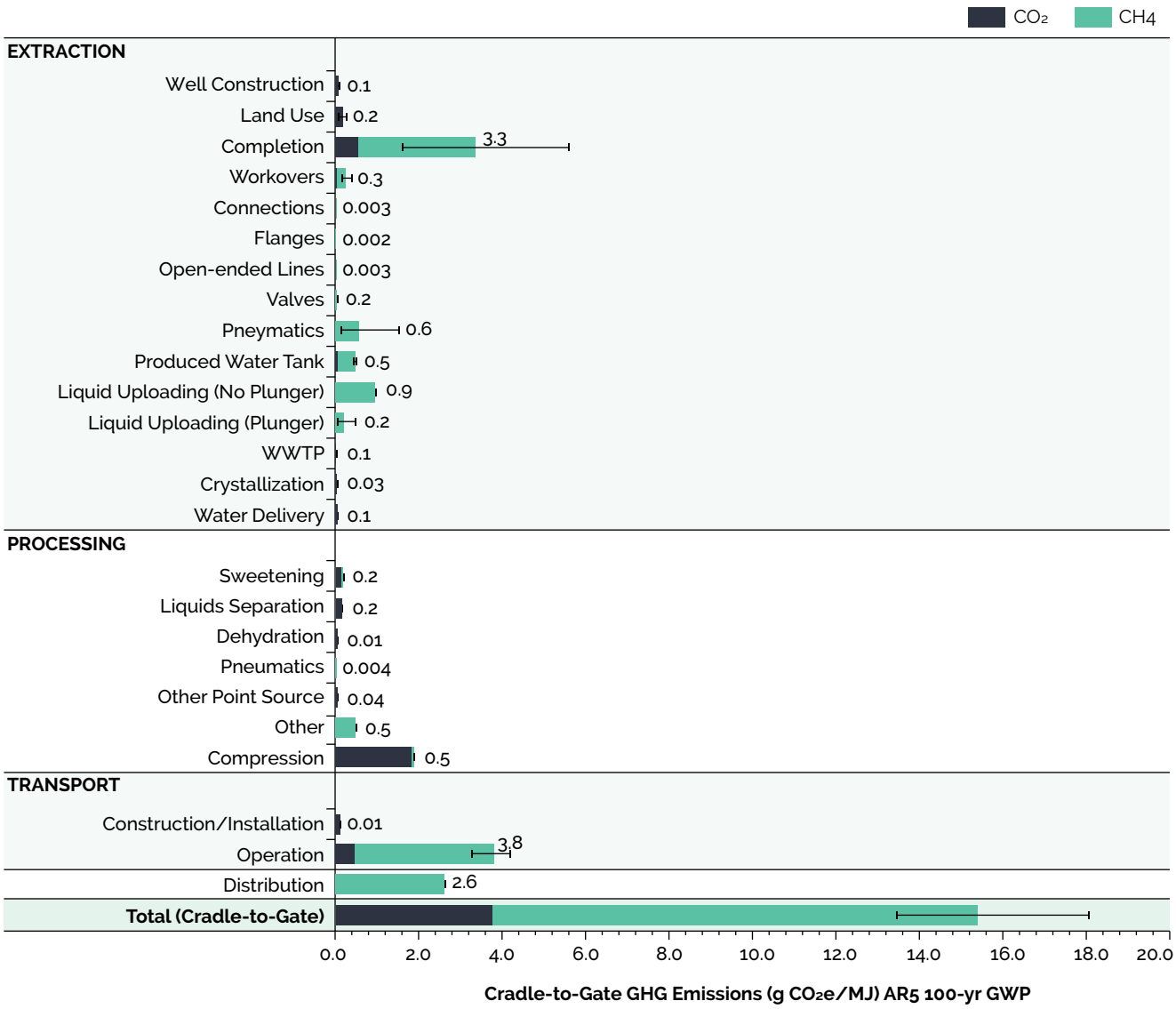
The USA National Energy Technology Laboratory (**NETL**) has compiled the data from many studies into a comprehensive model that covers both upstream and downstream stages of natural gas production and both methane emissions and carbon dioxide emissions from energy use.[262] This model suggests that for a typical shale gas field in the US, the key contributors to GHG emissions are fugitive emissions from transport and distribution systems (26%), episodic emissions from well completion (21%), and fuel combusted by processing compressors (12%). The results show that episodic or occasional activities in shale gas production such as well completions, workovers and liquids unloading can be significant contributors to total GHG emissions.[263]

In the case of a representative shale gas field (the Appalachian field), and using historical data before the introduction of reduced emissions completion regulations, the total upstream emissions are 15.5 g CO_{2e}/MJ (the 90% confidence interval is 13.7 - 18.1 g CO_{2e}/MJ): see **Figure 9.1**. Of these emissions, the release of methane accounts for 11.9 g CO_{2e}/MJ, which is equivalent to a methane emission rate of 1.8% of the natural gas production and represents 77% of the total emissions.

The NETL also conducted an evaluation of the next evolution of shale gas wells in the Appalachian field. In this case, the parameters were adjusted to reflect potential emission reduction technologies (for example, liquids unloading via 100% use of plunger lifts compared with 55% previously), as well as the NSPS regulations introduced in 2015 to mandate reduced emissions completions (**REC**) (100% compared with 43 to 51% previously), and higher well estimated ultimate recoveries (**EURs**). In this instance, the hypothetical well scenario has GHG emissions that are 23% lower than historical practices (12 g CO_{2e}/MJ). The methane emission is equivalent to a methane emission rate of 1.25% on a mass basis.[264] All emission reductions occur at the extraction/ production stage and are associated with methane reductions.

253 US EPA 2012.
254 Lamb, Edburg et al. 2015.
255 Brandt, Heath et al. 2014.
256 Littlefield et al. 2017.
257 Zavala-Araiza, Lyon et al. 2015.
258 Littlefield et al. 2017.
259 Department of the Environment and Energy 2016.
260 IPCC Guidelines.
261 Lafleur, Forcey et al. 2016.
262 Skone et al. 2016; Littlefield et al. 2017.
263 Skone et al. 2016.
264 Skone et al. 2016.

Figure 9.1. Upstream Cradle-to-gate GHG Emissions for gas from an Appalachian shale gas field based on a methane GWP = 36. Source: Skone et al.[265]



Variability between natural gas sources can lead to substantial differences in emissions. Conditions which can lead to increased emissions are shale gas wells that have a low average expected ultimate recovery and do not capture or flare the gas emitted during well completions. Under these circumstances the average upstream emission rate can be significantly higher (for example, 72% higher).

9.5 Life cycle emissions

9.5.1 Electricity production

The life cycle emissions of shale gas require the combination of the downstream emissions with the upstream emissions in terms of CO_{2e}. Downstream emissions refer to final use of the natural gas such as heating or electricity production and in the case of electricity generation, it includes the operation of power plants and the transmission and distribution of electricity to the consumer.

Skone et al estimated that the life cycle emission for natural gas combined-cycle (**NGCC**) turbines is 497 kg CO_{2e}/MWh for 100-year GWP (and 592 kg CO_{2e}/MWh for 20-year GWP).[266] Fleet baseload, fleet load-following and fleet peaking gas-fired plants have greater emissions.

Some important trends are evident from these results:

- the total life cycle GHG emissions are dominated by CO_2 from power generation; and
- in the case of NGCC, the downstream power generation represents 78% of total life cycle GHG emissions and the upstream emissions accounts for 20 to 22% of life cycle GHG emissions.

265 Skone et al. 2016.

266 Skone et al. 2016.

9.5.2 Comparison with coal

Questions have been raised as to how GHG emissions from the life cycle of shale gas production and use compares with that of conventionally produced natural gas or other fuel sources such as coal. Natural gas–fired power has lower GHG emissions per unit of electricity than coal-fired power because of the relatively low carbon-to-energy intensity of natural gas, and the relatively high efficiency of natural gas power plants. However, upstream CH_4 emissions can reduce the life cycle GHG advantage of natural gas–fired power plants.

Recent literature has sometimes come to different conclusions, largely due to differing assumptions, comparison baselines, and system boundaries. Heath et al have employed a process of harmonisation to normalise a wide range of results to a common set of units while ensuring consistent system boundaries and sets of major activities throughout the production and use of shale gas.[267] Ten harmonised estimates of life cycle GHG emissions from the use of shale gas for electricity generation are compared with 215 harmonised estimates for conventional gas and coal power generation, all from the peer reviewed literature.[268] Even with the greater consistency after harmonisation, variability in results remained because of intrinsic differences between the study conditions; hence, the validity of comparing individual results from different authors is highly questionable. However, the authors found the central tendency of GHG life cycle emissions from shale gas-generated electricity, from NGCC plants, to be less than half those from coal and roughly equivalent to those from conventional natural gas. The median estimates for the life cycle emissions of shale and conventional gas after harmonisation are nearly identical: 465 kg CO_{2e}/MWh for shale and 461 kg CO_{2e}/MWh for conventional. The median estimate for the life cycle emissions of coal-fired electricity generation after harmonisation was 980 kg CO_{2e}/MWh; this covers four coal combustion technologies and thermal efficiencies representative of modern plants.

Littlefield et al determined that for electricity generation, the upstream methane emission rate would have to be greater than 4.4% of natural gas production for NGCC to be worse than super critical, pulverised coal power generation for a 20 year GWP; or 10.0% for a 100-year GWP.[269] An alternative procedure is to use the Technology Warming Potential (**TWP**) that is independent of GWP timeframes. Using the TWP approach, found that as long as CH_4 emission rates are lower than 3.3%, NGCC power plants have a lower climate impact (in terms of cumulative radiative forcing) than super critical, pulverised coal power at all points in a time series.[270]

9.6 Monitoring

It is essential to undertake baseline monitoring of methane levels in the soil and atmosphere before drilling commences. Other emission sources (these can include wetlands, landfills, sewage treatment facilities and livestock such as cattle and sheep) can mean that 'top down' measurements of fugitive emissions can substantially over estimate the emissions generated from gas extraction unless a baseline is established. As described in a recent MEI report, a study has observed from space a hot spot of methane emissions in the Four Corners region of the US, but the authors were unable to determine whether this arises from oil, CSG, or coal mining activities, due to a lack of baseline data.[271] Baseline measurements should begin 12 months before production commences to capture potential seasonal variations and then repeated over the production life of the field.

Natural methane seepage can lead to elevated methane concentrations in the ambient air and in the soil.[272] These natural methane seeps can also result in the bubbling of methane on the surface of dams and waterways, and oil films on the water surface.[273] As an example, the NSW Division of Resources and Energy sampled water bores throughout NSW between 1994 and 2004 (before CSG activities commenced). Of the 300 bores sampled, 90% emitted methane. The methane concentrations varied from 3 to 600,000 ppm (0.0003 to 60% methane).[274] Indeed, the detection of such seeps is often used to identify potential drill sites for gas.[275] These background methane levels mean that images such as those shown in the film *Gasland*, where the water from a tap is ignited, need to be treated with caution before conclusions are drawn that the gas is from unconventional gas sources. The question must be asked as to whether the same image could have been recorded even prior to gas extraction operations. Similarly, it is well documented that the bubbling of methane from the Condamine River in Queensland has increased threefold since ongoing measurement began in early 2015, although it is now declining. However, there is no conclusive evidence that this increase is related to CSG activities. It may relate to the migratory emissions described by the MEI,[276] but it could also relate to changes in river water flows or natural changes in groundwater flows.[277]

It is noted that Santos is in the planning phase of a baseline methane monitoring assessment in the Beetaloo Sub-basin. It is anticipated that this will be performed by CSIRO scientists.[278]

9.7 Quantity of life cycle GHG emissions and methane emissions

Estimates are given here for the quantity of life cycle GHG emissions and methane emissions, on an annual basis, for a potential shale gas field. They are then compared first with national GHG emissions and second with other energy conversion technologies, such as the use of coal for electricity generation.

These estimates are based on possible production estimates provided by Origin and Santos, and some speculation from Pangaea where a potential shale gas field is assumed to produce either 800-1,100 TJ/day for a large development and 100-220 TJ/day for a small development.[279] In addition, DPIR provided a best estimate development scenario that equates to 3,400 TJ/day (1,250 PJ/year).[280] Based on these three development scenarios, the life cycle GHG emissions, which combine upstream GHG emissions with the downstream GHG emissions from the combustion of

267 Heath et al. 2014.
268 Whitaker et al. 2012; O'Donoughue et al. 2014.
269 Littlefield et al. 2016.
270 Littlefield et al. 2016.
271 Lafleur, Forcey et al. 2016.
272 Saddler and Gotham 2013.
273 Saddler and Gotham 2013.
274 NSW Bore Water Data Package.
275 Saddler and Gotham 2013.
276 Lafleur, Forcey et al. 2016.
277 CSIRO 2016.
278 Santos submission, p 110.
279 Origin submission; Santos submission; Pangaea submission.
280 Department of Primary Industry and Resources, submission 281 (**DPIR submission 281**).

natural gas for end use application, are estimated and shown in **Table 9.1**. The downstream emissions from combustion of natural gas was assumed to be 57 g CO_{2e}/MJ and the upstream emissions were 15.5 CO_{2e}/MJ (100-year GWP) or 32.0 CO_{2e}/MJ (20-year GWP). DPIR assumes that with their best estimate production, 1,000 PJ/year is used for liquid natural gas (**LNG**) (the assumed upstream emissions are 22.7 CO_{2e}/MJ (100-year GWP) and 250 PJ/year is used for domestic gas consumption (life cycle emissions are assumed to be 72.5 CO_{2e}/MJ, for 100-year GWP). The data in **Table 9.1** represents gross additional quantity of GHG emissions for given levels of new gas production. However, they do not take account of the particular use for gas and whether gas is replacing other fossil fuels.

Table 9.1: Gross quantity of life cycle GHG emissions and comparison to the total GHG footprint for Australia

Total gas production	Life cycle GHG emissions per year	Proportion of Australia's emissions for 2015-6
TJ/day	MT CO_{2e}/ year	%
Based on a 100 year GWP (36)		
1,000	26.5	5.0
200	5.3	1.0
3,400	40.8	7.6
Based on a 20 year GWP (87)		
1,000	32.5	6.1
200	6.5	1.2
3,400	50.7	9.5

The gross quantity life cycle GHG emissions from a shale gas field can average 5% of Australia's GHG emissions in the case of 100-year GWP, or 6% of Australia's GHG emissions for a 20-year GWP, for a gas production of 1000 TJ/day. The gross quantity life cycle GHG emissions from a shale gas field can average 7.6% of Australia's GHG emissions in the case of 100-year GWP, or 9.5% of Australia's GHG emissions for a 20-year GWP, for a gas production of 3,400 TJ/ day when 80% of the gas is used for LNG export and 20% is used for domestic consumption.

Gas may be used to replace a renewable energy source, or to assist with grid stability where there are high levels of renewables, or to replace coal (in the latter case a valid comparison would compare the emissions from coal and gas generated electricity). Alternatively, the gas may be exported in which case, the downstream emissions would contribute to world emissions, and the upstream emissions would contribute to Australia's GHG inventory. When gas is exported, there are additional upstream emissions associated with the conversion of gas to LNG.[281]

Quoting recent research conducted in the US and Europe, APPEA notes that renewables and fastreacting gasfired power general technologies appear highly complementary and should be jointly installed to meet the goals of reduced emissions and stable supply.[282] However, concern has been raised about developing an over reliance on gas and renewables as an energy mix. For example, the Climate Council has observed that using existing gas-fired generators and supply infrastructure prudentially to complement wind and solar power, while scaling up a range of renewable energy technologies, energy storage, and energy efficiency measures, could deliver a limited benefit, provided the end goal is phasing out the use of all fossil fuels as quickly as possible.[283]

Where natural gas displaces coal from electricity production in Australia, then the net unit CO_{2e} savings are in the order of 515 kg CO_{2e}/MWh of electricity for 100-year GWP; this saving is based on the harmonised life cycle emission results presented previously by Heath.[284] If it is assumed that all of this additional production of natural gas is used to displace coal from electricity production in Australia and the efficiency of conversion of natural gas to electricity is 51% (a modern NGCC plant), then the development of these fields could result in a meaningful reduction in Australia's GHG footprint. For example, if there is a reduction in Australia's GHG emissions of 1% in the case of 200 TJ/day production and 5%

in the case of 1000 TJ/day production. If a 20 year GWP is adopted, the reduction in GHG emissions are some 70% of the reductions achieved for a 100-year GWP.

9.8 Preliminary assessment

While carbon dioxide emissions dominate the life cycle GHG emissions (because downstream combustion of natural gas generates high amounts of carbon dioxide), methane emissions dominate the upstream GHG emissions. Furthermore, the quantity of methane emissions is more uncertain and they are more amenable to reduction. Accordingly, the focus of the proposed risk assessment is on methane emissions. A framework for an interim risk assessment is given in **Table 9.2** for a number of hazards that may prevent lower levels of methane emission performance from being achieved. These levels of methane have been discussed previously.

At this stage, the Panel has insufficient information to make an informed assessment of risk. This risk assessment will be used to identify areas where mitigation of risks is required and to assess strategies to mitigate those risks.

281 Hardisty, Clark et al. 2012.

282 APPEA submission.

283 Stock, Steffen et al. 2017.

284 Heath et al. 2014.

Table 9.2: Interim risk assessment framework for hazards that may prevent lower levels of methane emission performance from being achieved

Hazard	Comments	Likelihood	Consequences	Risk
Regulations are not implemented at either State or Federal level.	Regulations are required for reduced emissions completions, compressor emissions and pneumatic controllers			
Regulations are not fully complied with	This may have the effect of allowing increased emissions			
Monitoring of regulatory compliance is not undertaken or is inadequate	Monitoring by a regulatory authority may not occur because of lack of resources.			
Monitoring of both baseline emissions and emissions during production is not undertaken	Monitoring emissions is one means for assuring compliance and also to possibly detect "super emitters"			
Low production performance means emission performance is not achieved	Wells that have low ultimate gas recovery can give rise to higher emission rates. Such wells may also be uneconomical			
Failure of plant or equipment occurs during the lifetime of the well	Consequences can range from a minor to a catastrophic release of gas for a relatively short period over the life of a well			

Based on the information presented previously, the Panel's interim assessments regarding the possible greenhouse emission rates, the likely contribution of greenhouse gases to the national inventory from a potential shale gas industry in the Northern Territory and related matters, are provided below.

9.8.1 Methane emissions

Methane emissions dominate the upstream GHG emissions from shale gas. Furthermore, the quantum of methane emissions is uncertain and they are amenable to reduction. One-time or periodic events (well completions, workovers, and liquids unloading), as part of the upstream phase of the natural gas cycle, are methane emission sources that, although occasional, represent significant contributions to the total emissions from the supply chain.

Some reports suggest a range of methane leakage rates from 0.22% to 17%, based on 'bottom up' and 'top-down studies'. Most top-down studies suffer from the inability to distinguish between multiple sources of emissions and the lack of baseline studies. Studies have attempted to rationalise the differences between these 'bottom up' and top down' studies, by reference to the existence of 'super emitters', where a small number of sites or facilities can account for a large proportion of emissions due to malfunctioning equipment or to short-term well venting for liquids unloading.

The regulatory and practice regime that applied in the US shale gas industry prior to 2012 clearly led to significant methane emissions levels as indicated in a range of these studies. However, if the recent deployment of modern emission reduction technologies and practices in the US were replicated in Australia, then the expected methane emission levels could be around 2%. These regulations need to at least replicate the NSPS regulations introduced in the US in 2012, which mandate reduced emission completions and reduce leakage rates for compressors, pneumatic controllers, and storage tanks.

9.8.2 Upstream greenhouse gas emission rates

A typical value for the upstream GHG emissions for a modern US shale gas field is 15.5 g CO_{2e}/MJ (with a range between 13.7 and 18.1) of lifetime natural gas production. Included in this rate is an upstream methane emission rate of 11.9 g CO_{2e}/MJ, or 1.8 % representing 77% of the total upstream emissions.

The application of further emission reduction technologies (including reduced emissions completions) can result in the upstream GHG emissions being 23% lower than historical practices for shale gas wells, namely, 12.0 g CO_{2e}/MJ. The methane emission rate is reduced to 1.3% and represents 68% of total upstream GHG emissions.

9.8.3 Life cycle greenhouse gas emissions

The life cycle GHG emissions are dominated by carbon dioxide emissions from the combustion of natural gas for use, such as in heating or power generation. In the case of NGCC plants for electricity generation, the downstream power generation represents 78 % of total life cycle GHG emissions and the upstream emissions accounts for 22 % of life cycle GHG emissions. The upstream methane emissions represent some 17 % of the life cycle GHG emissions.

For a shale gas field with a production of 1000 TJ/day, the quantity of life cycle GHG emissions can average 5% of Australia's GHG emissions in the case of a 100-year GWP or can average 6% in the case of a 20-year GWP. While these values are the gross quantity of GHG emissions, they do not take account of the particular use for gas and whether gas is replacing other fossil fuels. Emissions that are released during the exploration (appraisal) stage can be significant and add to these values, and they need to be minimised.

The central tendency (median) estimate for the life cycle GHG emissions from shale gas-generated electricity is less than half those from coal and roughly equivalent to those from conventional gas-generated electricity. For a gas field producing 1000 TJ/day of gas and where all of this additional natural gas displaces coal from electricity production in Australia, the net GHG savings are some 26 Mt CO_{2e}/ year or a saving of 5% of Australia's GHG emission inventory.

Provided methane emission rates are lower than 3.3%, NGCC power plants are expected to have a lower climate impact than super critical, pulverised coal power.

9.8.4 Risk assessment

Given the importance of methane emissions and that the quantity of emissions is uncertain but that they are amenable to reduction, an assessment will be conducted for a number of hazards that may prevent lower levels of methane emission from being achieved. While a risk assessment framework has been developed, the Panel has insufficient information to make an informed assessment of risk at this stage. The risk assessment will be used to identify areas where mitigation of risks is required and to assess possible strategies to mitigate those risks.

9.8.5 Greenhouse gas reporting

Inconsistencies were identified for Australia's National Greenhouse Gas Inventory System and the National Greenhouse and Energy Reporting system, and the current US EPA dataset. These discrepancies need to be reviewed to ensure Australian data reflects current research and overseas datasets.

9.8.6 Monitoring

It is essential to undertake baseline monitoring of methane levels in the soil and atmosphere before drilling commences. Other emission sources can mean that measurements of fugitive emissions can substantially overestimate the emissions generated from gas extraction unless a baseline is established. Baseline measurements should begin 12 months before production to capture potential seasonal variations. Monitoring of emissions should continue over the production life of the field, partly with the purpose of identifying any abnormal emissions.

9.9 Knowledge gaps and next steps

The Panel requires further knowledge on:

- **methane emissions:** for example, while the synthesis of the new data by Littlefield improves the understanding of methane emissions, it also reveals significant gaps in the knowledge.[285] Most of these knowledge gaps could be resolved through geographically diverse emission measurement campaigns that focus on emissions and activities at a level of detail that allows disaggregation of existing emission categories and reduces reliance on extrapolation and augmentation. In particular, production site and top-down measurements in multiple production regions would allow more understanding about unassigned emissions;
- **methane emissions and monitoring:** including details of proposed monitoring in the Beetaloo Sub-basin;
- **abandoned wells:** Information is needed on the emission rates from these wells; and.
- **risk assessment:** there is insufficient information to make an informed risk assessment at this stage.

Strategies will be identified to mitigate those risks that may prevent lower levels of GHG emissions from being achieved. The focus will be on the identification of cost-effective risk mitigation strategies.

The Panel will also consider any implications arising from the recently published *Independent Review into the Future Security of the National Electricity Market* by the Australian Government Chief Scientist, Dr Alan Finkel.

285 Littlefield et al. 2017.

PUBLIC HEALTH

10

10.1 Introduction

In common with all of the other potential risk areas associated with shale gas extraction, there has been a rapidly increasing coverage over the past five years of public health aspects in the peer-reviewed literature.[286] There have been entire special issues of journals that have addressed the topic[287] as well as review papers.[288] Most of these reviews analyse data from US operations, however, similar issues have been canvassed for unconventional gas extraction activities in the UK.[289] The public health issues raised in reports from WA Health in relation to unconventional gas exploration in WA[290] have been critiqued in a 2017 review by Professor Melissa Haswell from the Queensland University of Technology.[291]

Submissions to the Inquiry, previous reports prepared for various government authorities, and recently published articles, suggest that more than 700 papers on the specific topic of the impact of the unconventional gas industry on public health have been published in recent years. The Panel does not claim to have examined all these papers, rather, a selection has been taken into consideration in order to address the key issues identified by the Panel (Appendix 1) and in submissions to the Inquiry, as possibly impacting on public health.

Public health impacts fall into two broad categories:

- adverse health effects, including the induction or exacerbation of specific diseases, or induced dysfunction of critical organs and physiological systems; and
- negative effects on wellbeing, including altered mental health.

The issue addressed in this Interim Report is whether any of these public health impacts can be attributed to specific causal factors in the environment resulting from activities associated with hydraulic fracturing to recover shale gas from deep shale deposits in the Northern Territory.

Public health impacts are generally measured in terms of adverse health changes in large exposed groups or populations. This is because it is usually too difficult to attribute a causal relationship between exposure to an environmental factor and adverse health effects in an individual, or in a small group such as an individual family or small community. An important conventional tool for assessing public health impacts from environmental sources or activities is to conduct a formal Human Health Risk Assessment (**HHRA**). The methodologies for conducting an HHRA are well set out in many references, with the 2012 enHealth (the national Environmental Health Standing Committee) guidance taking precedence in the Australian context.

In the case of somatic human health risks associated with chemical exposures, two important elements must be present. These are:

- first, knowledge of the intrinsic toxicity (toxicological profile) of chemical(s). That is, what health effects might occur if the exposures are high enough in either the amounts of chemical in the exposure media, or associated with a sufficiently long period of exposure. This knowledge is generally gained from a number of sources. Important among these sources are epidemiological studies of human populations where different patterns of adverse health effects can be categorised according to some degree of measured exposure. Other types of studies compare disease incidence in groups that can be identified as having been exposed to a chemical, compared to those not exposed. Another source of human data, although generally more subjective and less reliable, is the accumulated experience of usage patterns where extensive human exposures have occurred. Because of the intrinsic difficulties of interpreting epidemiological data, the main source of quantitative data for HHRA purposes is conventionally drawn from experimental studies in animals, where the exposures can be controlled in relation to both dose and duration. The data from these studies may be used to demonstrate a level of exposure where the risk of adverse health effects is negligible, or unlikely, after incorporation of conservative 'safety factors' that address the inherent uncertainty of extrapolating from effects seen in animals to those likely to occur in humans. In this context, it should be noted that the 'hazard potential' for individual chemicals, as opposed to an estimate of risk (or likelihood) is usually only able to be demonstrated in studies where the exposures are orders of magnitude higher than those expected to result from exposure to environmental sources. Risk estimates derived from a conventional HHRA are therefore based on an extrapolation of these dose-response relationships to a level of exposure associated with the environmental scenario under investigation; and
- second, knowledge and quantitation of all the pathways by which humans could conceivably be exposed through transfer from environmental media (for example, ingestion of contaminated drinking water or food; breathing in airborne gases, vapours or dusts; or direct skin contact with soil or other contaminated media). In this context it is conventional to construct a Conceptual Site Model (**CSM**) detailing all such pathways from a contaminated site to individuals or collectives of humans around that source (termed 'receptors' in the terminology of HHRA), along with an assessment of how likely those exposure pathways are to be 'complete' – that is, exposure has actually occurred, as opposed to a theoretical possibility. An example of a CSM applicable to hydraulic fracturing is that used by the WA Department of Health in its formal HHRA (see **Figure 10.1**).

In the context of this Inquiry, these are the two key factors that would be needed to facilitate a formal quantitative HHRA. The chemicals of concern (**CoC**) are likely to be those

286 Costa et al 2017.
287 Bamberger and Oswald 2013; Stern et al, 2014; Barcelo 2016.
288 For example, Carpenter 2016; Finkel 2015; Hays 2016; Meng 2017.
289 Prpich et al 2016; Watterson and Dinan 2016; Saunders et al 2016.
290 WA Department of Health 2015.
291 Haswell 2017.

added to the hydraulic fracturing fluid (**HFF**), the composition of which can be quite variable and where, until recently, relatively few of the chemicals have been specifically identified (see Chapter 6). Additional CoC would be those extracted from the shale deposits and brought back to the surface in flowback and produced water (see Chapter 6). The potential pathways that could cause exposure to members of the general community are discussed below.

Other CoC could be airborne chemicals, such as volatile organic carbon (**VOC**) gases and vapours, diesel fumes associated with transport and drilling equipment, and airborne dusts generated by land-clearing and other activities.

The exposure pathways that could result in broad community exposures are likely to be quite different to those by which onsite workers (occupational exposures) might occur. The magnitude of such exposures, and the consequent health risks, are likely to be higher for workers who are directly handling these chemicals, or are exposed to greater 'doses' as a result of their proximity to the construction, drilling and gas extraction activities. The terms of reference of this Inquiry focus on the potential impacts of hydraulic fracturing activity on the general community of the Northern Territory, and the Issues Paper noted that managing the risks associated with on-site occupational exposures are considered to be industry responsibilities, and out of scope for this Inquiry. The Panel notes that the WA Health HHRA described below also excluded on-site workers.

10.2 Key issues raised

The Issues Paper identified a number of potential risks to public health from any onshore shale gas development (Appendix 1).

The main change to issues relating to public health has been to recognise that concerns about BTEX in flowback water have been mainly raised in the US in relation to shale gas, and from extraction activities relating to CSG. This data may not be relevant to the shale deposits that are the subject of this Inquiry, although the Panel acknowledges that specific data on BTEX potential concentrations from flowback water from hydraulic fracturing activities in the Northern Territory is quite limited. This point is discussed in more detail in Chapter 6.

The issue of water security of aquifers essential in the Northern Territory for drinking water and for support of the horticultural, agricultural and pastoral activities was consistently raised as the primary area of concern. Protection of ground and surface waters from contamination associated with hydraulic fracturing and gas extraction activities was considered to be essential. The impact of unknown interactions and interlinkages between aquifers was also raised several times. The impression consistently conveyed in public consultations and submissions was that any contamination of an aquifer would be unacceptable. There was also scepticism that flowback and produced water could be effectively treated or transported safely to other locations.

A balancing view is that aquifer contamination would only be likely to become a real issue to public health or horticultural, agriculture and pastoral activities if the amount of contamination is high enough result in adverse health effects to people or animals consuming the water. This point is further addressed below.

There was a common concern that the injection of large quantities of 'unknown' chemicals into the ground would be an inevitable outcome of 'fracking' with an associated potential for contamination of groundwater. This anxiety was not assuaged by information indicating that many of the chemicals would be recovered with flowback water and this water could then be treated to remove the chemical residues, including the chemicals leached from the shale (for example, BTEX, metals and minerals, and NORM).

Industry submissions emphasised the technological developments that have occurred in the 'fracking' industry, and pointed out that disclosure of chemicals used in HFF is now more common, including in Queensland and the Northern Territory, where it is a mandatory requirement. In the Northern Territory, the proposed composition of the fracking fluid must be provided in the EMP and submitted to DPIR for assessment and approval before the activity can take place.

A consistent theme in many public submissions and opinions was that it was crucial that adequate baseline data on public and environmental health be collated ahead of any development, so that future impacts of the industry could be reliably assessed. This point has also been raised in some published papers.[292] This was also seen to be an important element for informing claims for any compensation for environmental damage by the holders of land on which the activity takes place.

10.3 Preliminary assessment

The Panel has comprehensively reviewed the relevant scientific literature to identify the issues relating to possible impacts of onshore shale gas development on human health, and these have been summarised in this Chapter. Based on this review, along with community concerns expressed during public hearings and community forums and information provided by stakeholders in formal submissions, the Panel has evaluated the possible public health risks associated with shale gas development in the Northern Territory, and has expressed some preliminary views as set out below.

A link between unconventional gas extraction activities and a number of adverse health effects were alleged in several submissions to the Inquiry, as well as being addressed in some published papers. The nature of the evidence, and its relevance to onshore shale gas development in the Northern Territory, is crucial. In some cases, the Panel notes that the allegations are related to health effects associated with CSG extraction in Queensland.[293] The relevance of these findings to the prediction of risks associated with hydraulic fracturing of onshore shale gas deposits is questionable, due to the differences between the two processes, as described in Chapter 5.

292 For example, Schmidt 2011; Korfmacher and Elam 2014; Steinzor et al. 2013.

293 For example, Ms Katherine Marchment, submission 259 (**K Marchment submission**).

In other cases, particularly in peer-reviewed published papers, the linkages were based on surveys and reviews of health effects relating to UGE from shale gas fields in the US, particularly around Pennsylvania, Texas and Colorado. Werner et al have commented that the strength of the epidemiological evidence of health impacts associated with UGE remains tenuous, with many studies of health outcomes lacking methodological rigour.[294] However, they also point out that while the evidence is somewhat weak and is focussed more on acute health effects, rather than chronic ones, it is not possible to entirely rule out a relationship between hydraulic fracturing and adverse health impacts.

There is strong evidence that proximity to UGE activities is a crucial factor,[295] with a survey of health effects showing that residents living beyond 0.8 km of wells had a lower incidence of a range of health effects than closer residents (see below for more detail).[296] This is not surprising since airborne, dust-borne and water-borne contamination would be expected to undergo dilution as it spreads away from the site of release, resulting in a lower potential for human exposure. However, the relevance of these findings to UGE in the Northern Territory is questionable. The Panel notes that most of the proposed areas for shale gas development in the Northern Territory are in relatively remote areas distant from habitation and established communities, while most of the UGE activities assessed in the US are in relatively close proximity to established residential communities. In this context, it should be noted that in the US the national average offset distance of a shale gas extraction well from other land use activities is only 94 m.[297] The current Northern Territory guidelines for permitting of such activities excludes close proximity to residential areas and a range of defined land uses.[298]

This point is reinforced in a review by Watterson and Dinan of the UK experience with unconventional gas extraction. They stated that, *"globally accurate estimates of the human populations exposed to UGE chemicals, by-products, and contaminants do not yet exist."*[299]

The Panel has identified four main potential risks to public health of shale gas development in the Northern Territory that could represent a need for further assessment, mitigation or management by appropriate regulation if development were to proceed. These are discussed below.

10.3.1 Impacts associated with contamination of aquifers

The four most likely pathways by which aquifers could be contaminated by chemicals used in HFF or in the 'produced water' that flows back after hydraulic fracturing has occurred are:

- direct contamination of contiguous aquifers through fractures induced in the shale deposits;
- direct leakage from single or multiple steel- and concrete-encased wells at a particular site, where the drill casings pass through an aquifer;
- overflow, or escape from containment ponds where the flowback water is stored; and
- spillage from HFF mixing sites, during transport of chemicals to sites or during transfer of wastewater for treatment.

The potential for such leakages to occur are discussed in Chapters 5 and 7. The opinion consistently expressed in industry submissions is that such risks are manageable, and that contamination of aquifers from the process of hydraulic fracturing is improbable because of the spatial separation between the deep shale deposits and the beneficial use aquifers that are typically much closer to the surface.

By contrast, an analysis of incidents of surface water contamination associated with recorded spills and well failures in the US suggest a higher level of risk, and a greater need for effective risk management.[300]

Knowledge of the toxicological profile of many of the chemicals used in HFF is incomplete (see Chapter 6 and further comment above). There are also apparent misconceptions about the relevance of analyses based on the early use of HFF in the US. A quote from a report to the WA Government summarises this point.

> *"There is much misinformation in the public domain regarding the types of chemicals that are routinely used in Australia for hydraulic fracturing. The Committee distinguishes between the chemicals used overseas (specifically, in the USA) and those which are used in Western Australia."*[301]

The Panel notes that where adequate toxicological information is available, HFF chemicals appear to have low toxicity.[302] At the concentrations used in HFF ingestion would be unlikely to represent an acute health risk, although direct exposure to some of the chemicals in pure form prior to formulation would represent a much greater health risk. In the case of the low concentrations that are present in fracking fluids or in flowback water, there would need to be continuous exposure over a much longer period to constitute a chronic health risk. The Panel is still investigating the potential for contamination of drinking water aquifers if leakage of wastewater was to occur as a result of leakage from the well itself or from a spill. Further information is being sought on the likelihood that contaminated wastewater would make it through the soil profile, what dilution and dispersion would occur within the aquifer. With this information, the Panel will be in a position to assess the potential adverse health effects that could occur in people or animals ingesting water extracted some distance from that source.

Some of the CoC reported in flowback and produced water (see Chapter 5) may be more of a health concern than those initially added to the HFF. In particular, BTEX,[303] other volatile organic compounds (**VOCs**) and NORM extracted from hydrocarbon deposits in the shale can reach concentrations that would exceed health-based water quality guideline values. However, once again, a risk-mitigating factor is that the dilution effect should probably substantially reduce these concentrations in an aquifer that was contaminated by such water to a level that would not be of concern for exposure through ingestion.

294 Werner et al. 2015.
295 Meng and Ashby, 2014; Meng 2015; Meng 2017.
296 McKenzie et al. 2012.
297 Rogers et al. 2015.
298 DPIR submission, Appendix 7.
299 Watterson and Dinan 2016.
300 Mrdjen and Lee 2016.
301 WA Report.
302 Stringfellow et al 2017
303 Gross et al 2013.

The importance of site-specific factors in evaluating risks to groundwater resources is well documented in the recent US EPA report on potential impacts of hydraulic fracturing activities:

> *"Evaluating potential hazards from chemicals in the hydraulic fracturing water cycle is most useful at local and/or regional scales because chemical use for hydraulic fracturing can vary from well to well and because the characteristics of produced water are influenced by the geochemistry of hydraulically fractured rock formations. Additionally, site-specific characteristics (e.g., the local landscape, and soil and subsurface permeability) can affect whether and how chemicals enter drinking water resources, which influences how long people may be exposed to specific chemicals and at what concentrations."*[304]

The Panel's initial assessment is that any evaluation of human health risks associated with contamination of drinking water resources can only be meaningful if it is done on a site-specific basis. This requirement for a site-specific HHRA, identifying the sources, exposure pathways and location of human 'receptors' (as outlined above) is a crucial element of any health impact assessment (**HIA**) and this has been acknowledged in the submission by Origin.[305]

The issue of aquifer contamination in the Northern Territory may be informed by a report on the potential for groundwater contamination prepared by the WA Department of Health in 2015.[306] In common with the Northern Territory, WA relies on a significant proportion of its drinking water by extraction from groundwater aquifers. That report took the form of a formal HHRA that examined the potential pathways by which groundwater could become contaminated with chemicals used, or generated, in hydraulic fracturing processes. The HHRA followed the process outlined in enHealth guidance.[307]

The CSM utilised in the WA HHRA is shown in **Figure 10.1.** It is a comprehensive analysis of all the pathways noted in the introduction to this Chapter.

The WA HHRA was hampered by the lack of local measured/reported data on the concentrations of the chemicals identified in HFF and produced water so it primarily used data sourced from US operations to estimate likely exposures. It further noted that elevated levels of some chemicals found in drinking water around some sites in the US may not necessarily be attributable to hydraulic fracturing, due to their natural (or background) presence in some regions. The WA Health HHRA did not identify any specific human receptors or their proximity to drilling sites, although it did acknowledge that distance and travel time from the wellhead to the drinking water source are key parameters influencing such an assessment. The approach taken in the risk characterisation component of the HHRA simply compared the concentrations of chemicals reported in US, flowback water with relevant health-based guideline values (for example, Australian Drinking Water Guideline values – of which there were very few for the chemicals in hydraulic fracturing fluids) or other available benchmarks. This would represent a 'worst-case' analysis since actual exposures through drinking would not be to such high concentrations due to the dilution effects occurring over the distance between source of the chemicals and where the water was extracted for drinking.

The overall conclusions of the WA Health HHRA were that:

> *"The HRA has found that, under the right conditions, hydraulic fracturing of shale gas reserves in WA can be successfully undertaken without compromising drinking water sources."*

- *Firstly, in WA, shale and tight gas reserves have been identified at depths of between two and four kilometres below ground level which are a considerable distance below potable ground water sources.*
- *Secondly, the risks to drinking water sources associated with hydraulic fracturing can be well managed through agreed industry and engineering standards, best practice regulation, appropriate site selection (including consideration of Public Drinking Water Source Areas) and monitoring of the drinking water source."*[308]

10.3.2 Impacts associated with fugitive emissions and airborne chemicals

A number of published papers have addressed the potential public health impacts of volatile organic compounds and other airborne chemicals in dusts that may travel off-site. The strength of the US evidence on health effects is quite mixed. A table from a recent review of health studies around Colorado illustrates this point.[309]

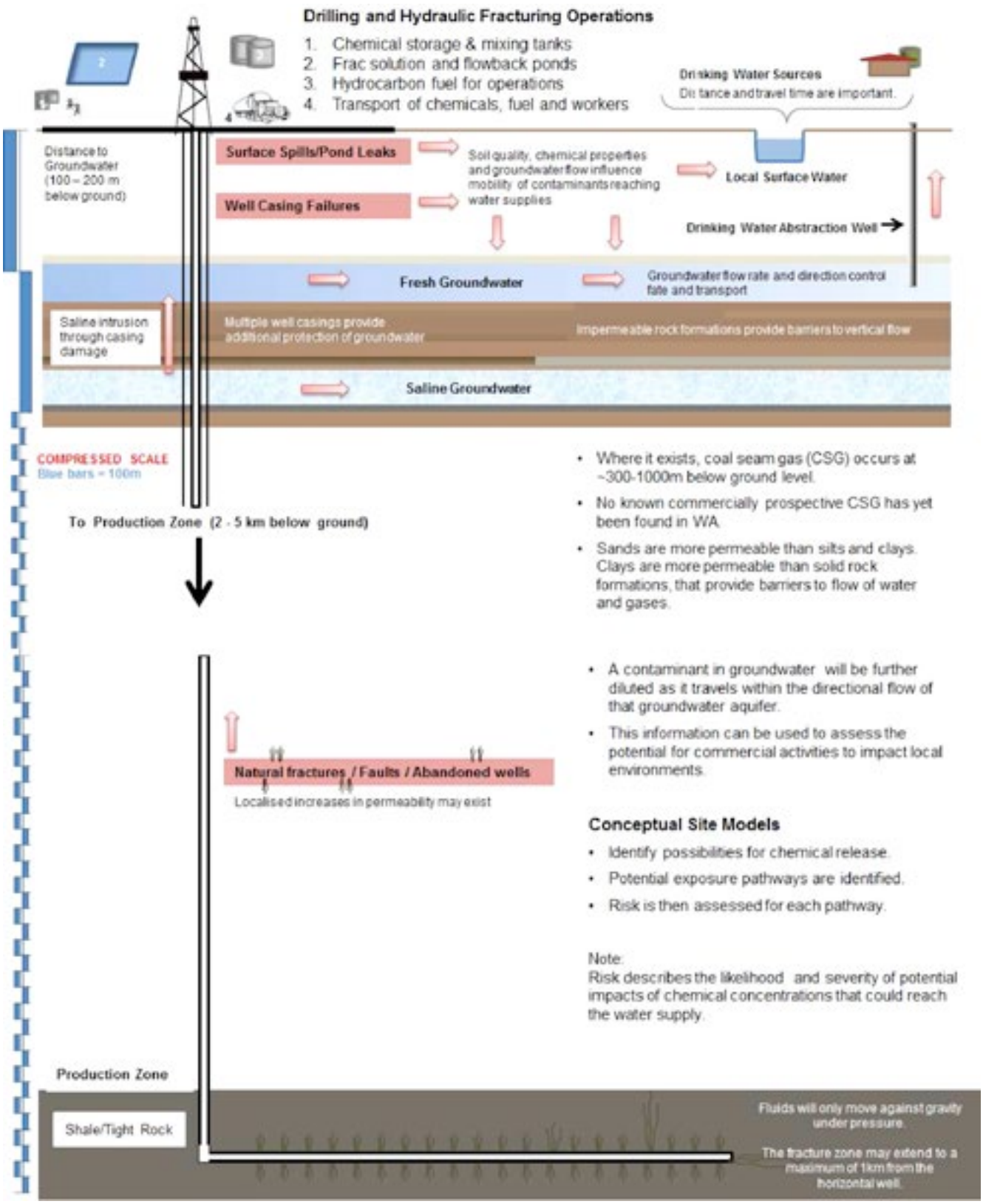
An attempt to analyse all the adverse health effects listed in the McMullin et al table is beyond the scope of this Interim Report, rather the Report will comment on the findings more generally.

It is common for health impacts of UGE activities to be assessed by self-reporting questionnaires. For example, a questionnaire based study of residents around UGE sites in Pennsylvania showed an apparent association of UGE with nasal and sinus symptoms, headache and symptoms of fatigue, While the overall response rate was low (33%) and only 23-25% reported symptoms, the calculated odds ratios achieved statistical significance for some of the outcomes. These OR (95% CI) of 1.49 (0.78, 2.83) for chronic rhinosinusitis (**CRS**) plus migraine; 1.95 (1.18, 3.21) CRS plus fatigue; 1.84 (1.08, 3.14) for all three outcomes suggested an association, presumably related to airborne VOCs.[310] Consistent with the hypothesis that distance is a significant factor, the spatial distribution showed higher rates of response in areas contiguous with UGE activity.

McKenzie et al carried out a conventional HHRA for both cancer and non-cancer effects around UNGE sites in Garfield County, Colorado. The risks were primarily driven by airborne VOCs released mainly during well creation activities (trimethylbenzenes, xylenes and aliphatic hydrocarbons - none of which are part of the fracking fluids used, and are presumably derived from flowback water). The calculated Hazard Indices (**HI**) (where a value >1 represents a likelihood that the combined exposures exceed conservative health-based guideline values thought to be protective of population health) were 1 for residents living <0.8 km and 0.4 for residents living >0.8 km. The estimated cumulative lifetime cancer risks were 10 in a million and 6 in a million respectively, for distance from source, driven primarily by exposure to benzene.[311]

304 US EPA Report.
305 Origin submission.
306 WA Department of Health 2015.
307 enHealth 2012.
308 WA Department of Health 2015.
309 McMullin et al. 2017.
310 Tustin et al. 2017.
311 McKenzie et al. 2012.

Figure 10.1: Conceptual Site Model. Potential pathways for hydraulic fracturing chemicals to impact drinking water supplies. Source: WA Department of Health.[312]



312 WA Department of Health 2015, Figure 8.

Figure 10.2: Summary of overall strength of evidence for epidemiological studies by health effect. Source: McMullin et al.[313]

Health Effects Categories	Number of studies*	Health Effects	Evidence
Birth outcomes	4	Preterm birth	Mixed
		Low APGAR	Mixed
		Small for gestational age	Mixed
		Birth weight (LBW & mean)	Mixed
Birth Defects	1	Congenital heart defects9	Insufficient
		Oral Clefts9	Insufficient
		Neural tube defects9	Insufficient
Respiratory (eye, nose and throat (ENT) and lung)	6	Multiple, self-reported symptoms	Mixed
		Hospitalizations	Failing to show an association
		Asthma exacerbations	Limited
Neurological (migraines, dizziness)	5	Hospitalizations	Mixed
		Multiple, self-reported	Insufficient
		Migraine/severe headache	Mixed
Cancer	4	Overall childhood cancer incidence19	Insufficient
		Childhood Hematological (Blood) Cancers	Mixed
		Childhood CNS tumors	Insufficient
		Hospitalizations	Mixed
Skin (irritation, rashes)	2	Multiple, self-reported	Limited
Psychological (depression, sleep disturbances	4	Multiple, self-reported	Failing to show an association
		Hospitalizations	Insufficient
Cardiovascular (heart)	2	Hospitalizations	Insufficient
		Multiple, self-reported	Insufficient
Gastrointestinal (nausea, stomach pain)	3	Hospitalizations	Insufficient
		Multiple, self-reported	Failing to show an association
Musculoskeletal (joint pain, muscle aches)	2	Hospitalizations	Insufficient
		Multiple, self-reported	Mixed
Blood/Immune	2	Hospitalizations	Mixed

* A total of 12 studies were included with some studies evaluating multiple health effects

These findings were confirmed to some extent in a different type of study. Bunch et al collected air monitoring data for VOCs at seven fixed sites around Dallas-Fort Worth, analysing these airborne VOCs in comparison with health-based guideline values.[314] The nearby Barnett Shale deposits comprise one of the largest active onshore gas fields in North America, with an estimated 15,870 producing wells across 500 sq miles. The seven monitoring sites were clustered around the heaviest density of producing wells. None of the measured VOCs exceeded acute health-based guideline values, and none of the annual averages entered into probabilistic and deterministic HHRA programs suggested that the UGE activities would represent a chronic health risk.

By contrast, Brown et al used measured airborne VOC and particulates ($PM_{2.5}$) around a Washington County, Pennsylvania UGE field to model possible human exposure at a specific residence surrounded by three UGE facilities (1, 2 and 3 km distant) over different stages of activity and different timeframes. The modelled residence was based on data showing a typical distribution of residences around the field (214 homes with 1-77 well pads 2-5 km away; 85 homes with 1-17 well pads 1-2 km away; and 31 homes with 1-7 well pads within 1 km). Modelled peak exposures occurred 83 times over 14 months of simulated emissions, with drilling, flaring and finishing and gas production stages producing higher intensity exposures compared to the hydraulic fracturing stage. Exposures were episodic, with peaks occurring at different times of the day, the highest tending to be at night when air mixing is likely to be least. The conclusion from this study was that human exposures leading to adverse health effects are possible in the scenario described, although the authors made no attempt to compare the estimated peaks and average exposures to health-based guidelines values.[315]

Bamberger and Oswald, in a longitudinal study of the health impacts in humans, companion animals, and food-producing animals around US UGE sites (21 human cases

313 McMullin et al 2017, Table 2.

314 Bunch et al. 2014.

315 Brown et al. 2015.

across 5 states), noted that the reported effects in humans (mainly neurological, respiratory, vascular, dermatologic and gastrointestinal) and animals were variable over the 25 months from first to second interviews. In humans, there was an overall decline in symptoms that had been attributed to the drilling operations (50% of cases), while those attributable to wastewater management (33% of cases) were unchanged. The reduction in reported symptoms was strongest where exposure to drilling operations was reduced, either by reduced operational activity, or by families moving away.[316]

It is reiterated that the exposure scenarios described in the above examples are unlikely to be representative of UGE activities in the Northern Territory, because of the much closer proximity of habitation to the gas fields in the US.

10.3.3 Impacts associated with increased road traffic

The Panel notes that this risk has been addressed in some of the submissions and it has been raised anecdotally by some people during consultations. In particular, it has been noted in some industry submissions that driver training and promotion of safe work practices is a priority for the industry in addressing this potential risk.[317]

The issues are canvassed more broadly in a review by Adgate et al[318] and are also cited in the submission from the Public Health Association of Australia.[319] However, the Adgate et al review cites evidence drawn from studies in the US, where the proximity of communities to UGE sites may not be so relevant to the situation in the Northern Territory. In particular, the Adgate et al review notes that an increased incidence of road accidents is primarily associated with increased truck traffic in residential districts.[320]

The Panel has been unable to draw any conclusions about this specific risk at this time, in the absence of evidence that defines the magnitude of this risk or supports a formal evaluation.

10.3.4 Impacts on social cohesiveness, mental health and wellbeing

The Panel notes that this risk has been addressed in some of the submissions and it has been raised anecdotally by some people during consultations, but it has been unable to find any firm evidence that supports an evaluation of the magnitude of this risk. Some aspects of this risk are likely to be addressed in the social impacts study that the Inquiry has commissioned (see Chapter 12).

The Panel notes that, in a recent review of health impacts of UGE, the limited number of available studies on psychological impacts only allowed the evidence to be graded as either insufficient or failing to show an association (see **Figure 10.2** above).[321] Psychosocial and socioeconomic impacts, both positive and negative, have also been reviewed by Adgate et al,[322] but again, the relevance of these largely US based studies to UGE developments in the Northern Territory is questionable.

The Panel also notes that some of the submissions from industry suggested more positive effects on wellbeing, associated with improved employment opportunities and improved social benefits and facilities associated with UGE developments. Work of CSIRO, in collaboration with the Gas Industry Social and Environmental Research Alliance (**GISERA**) has included a report on community responses to the social and environmental impacts of coal seam gas development in the Western Downs region of Queensland.[323]

10.4 Knowledge gaps and next steps

Some reviews have acknowledged that the risks associated with UGE are still unresolved. The review by Werner et al summarises the gaps in knowledge and points out why epidemiological studies have so far been unable to answer some of the key questions relating to health impacts.[324] The following quote from a Canadian review also makes this point, although since it was published in 2014, some of the issues have since become clearer:

> *"But the literature on the risks of hydraulic fracturing, while voluminous, is not clear. The most authoritative studies by governmental academies and agencies suggest that more information needs to be gathered, but at present the risks are judged to be modest and manageable with existing technologies."*[325]

Other reviews focussing on airborne emissions from UGE fields (VOCs, dusts and methane) have reached similar conclusions about the need for enhanced air monitoring to inform risk management and to better understand the potential for air pollution at different stages of the UGE cycle.[326]

Knowledge gaps that will need to be addressed to better inform the risk assessments to public health include:

- detailed knowledge of the chemicals proposed to be used specifically in formulating fracking fluids for operations in the Northern Territory;
- further details of the chemical composition of flowback and produced water specific to the geological features of the Northern Territory sites proposed for shale gas development, along with the proposed methods of treatment and/or disposal of this water; and
- further information on proposed sites for wellhead development, so that the proximity of human 'receptors' in residential communities can be factored into the CSMs needed to inform a detailed HHRA for these specific sites.

This last matter is crucial given the consistent conclusion of this Interim Report that only HHRA determinations that are site-specific will provide meaningful information on the public health risks.

It is also expected that public health issues will become better informed by the release of the following two reports:

- the NICNAS (National Industrial Chemicals Notification and Assessment Scheme) report that forms part of the National Risk Assessment project of the Commonwealth that is expected to outline suitable HHRA methodologies; and
- a formal HHRA of UGE sites across Queensland, commissioned by Origin and cited in its submission to the Inquiry.[327]

316 Bamberger and Oswald 2015.
317 For example, the APPEA submission.
318 Adgate et al. 2014.
319 Public Health Association of Australia, submission 107 (**PHAA submission**).
320 Adgate et al. 2014.
321 Adgate et al. 2014.
322 Walton et al. 2014 cited in the APPEA submission.
323 McMullin et al. 2017.
324 Werner et al. 2015.
326 Moore et al. 2014.
327 Origin submission.

ABORIGINAL PEOPLE AND THEIR CULTURE

11

11.1 Introduction

11.1.1 Cultural traditions link Aboriginal people to their land

In the Northern Territory it has long been recognised that places of spiritual or religious significance to Aboriginal people need to be protected *"to avoid the harm to the Aboriginal people identified with such places that would arise if they are damaged".*[328] This is particularly important because places of spiritual or religious significance under Aboriginal tradition connect Aboriginal people to their country, and maintenance of the traditions relating to such places is the continuing basis for recognition of land ownership and associated cultural traditions. To ensure that their ownership rights continue to be recognised, Aboriginal people must be able to maintain their cultural traditions relating to that land from one generation to the next.

The Issues Paper acknowledged that Aboriginal people comprise most of the resident populations in the shale gas basins of the Northern Territory. These populations are also one of the most disadvantaged in Australia. Notwithstanding this, Aboriginal people have proprietary interests (under communal freehold title and/or Native Title) over almost all areas proposed for hydraulic fracturing. The Panel understands that under both the Land Rights Act, the *Native Title Act 1993* (Cth) (**NTA**), and at common law these proprietary interests are underpinned by traditional practices that connect Aboriginal landowning groups with their country.

As outlined in Chapter 14, most land in the Northern Territory is either Aboriginal freehold, leasehold, or other tenure that exist concurrently with underlying native title. There are well established laws and systems for recognising and protecting Aboriginal traditional interests in their land and culturally significant sites on the land.

11.1.2 Traditional ownership and sites of cultural significance

The owners of Aboriginal inalienable freehold land and native title holders are often referred to as 'traditional owners'. This is because they have been recognised as belonging to the group that, in common, are affiliated with the land through their traditional beliefs and practices relating to that land. Traditional owners have interests in land through the two land tenure systems that apply across 98% of the Northern Territory: the native title system, comprising common law native title rights established by the High Court in the Mabo case,[329] and the provisions of the NTA, and the system of inalienable freehold title established under the Land Rights Act. Both are systems of communal title and both are relatively new from the perspective of Australian land administration. Chapter 14 of this Report outlines the practical application of these two systems in relation to land access for the purposes of the hydraulic fracturing of onshore unconventional shale reservoirs and its associated activities.

In addition to creating and establishing the system for managing Aboriginal land held under inalienable freehold title, the Land Rights Act also protects culturally significant places ('sacred sites') on all forms of land tenure. The Act defines a sacred site as a *"site that is sacred or otherwise of significance according to Aboriginal tradition"* and prohibits unapproved entry to it.[330] Complementary Northern Territory legislation prohibits any works on, or in the vicinity of a sacred site unless it is carried out in accordance with the wishes of its Aboriginal custodians.

11.1.3 Responsibility for protecting culturally significant sites

The Aboriginal Areas Protection Authority (**AAPA**) has responsibility for ensuring sacred sites are protected. The central purpose of AAPA is to:

- consult with the Aboriginal custodians of sacred sites *"on or in the vicinity of land where use or works is proposed"* to ensure that sacred sites are protected;
- determine the nature of the constraints (if any) on particular land use proposals; and
- issue approvals for works or use of land on or in the vicinity of a sacred site, in accordance with the wishes of Aboriginal custodians, that grant indemnity against the operations of the offence provisions of the relevant legislation.

This process is designed to ensure that while land that falls within the definition of 'sacred site' may be identified, mapped and officially recognised, the implications of the existence of a sacred site on a particular land-use proposal (such as hydraulic fracturing of onshore unconventional shale reservoirs) will be determined on a case-by-case basis following consultation with the relevant Aboriginal people.

Four Land Councils have statutory responsibilities for representing the interests in land held by the traditional Aboriginal owners and native titleholders within their respective jurisdictions. The Northern Land Council and Central Land Council represent traditional owners of the land in all the known onshore shale gas basins.

11.2 Key issues raised

The Issues Paper released by the Inquiry in February 2017 lists six possible risks that the hydraulic fracturing of onshore unconventional shale reservoirs and its associated activities may have on Aboriginal people and their culture (see Appendix 1).

The concerns raised about the effects of hydraulic fracturing on Aboriginal people and their culture, in formal submissions and discursive consultations, fall into five interrelated critical issues discussed below.

11.2.1 Aboriginal people not informed enough to understand risks or benefits

It was put to the Panel that Aboriginal people have not yet been given enough information about the potential risks and benefits of hydraulic fracturing. Such a lack of knowledge would reduce the possibility of an informed decision about whether or how the industry could be accommodated in a way that did not pose a risk to the cultural landscape, in particular, how to protect culturally significant features of the land and more generally, community cohesion in Aboriginal communities and the nature and extent of potential economic benefits.

328 Woodward 1974.

329 *Mabo v Queensland (No 2)* (1992) 175 CLR 1; [1992] HCA 23.

330 Land Rights Act, s 3.

The Panel was told that it was important that Aboriginal people be made aware of the processes involved in hydraulic fracturing. This includes the technical processes involved beneath the surface and the risks this poses for aquifers, but also the wider implications of onshore shale gas development for landscape health and greenhouse gas emissions. Information being provided to Aboriginal groups *"tends to be industry or anti-fracking centric and subject to bias and misinformation".*[331]

The Panel was told that some Aboriginal people in remote communities had been given *"misinformation"* and *"unsubstantiated propaganda"*[332] designed to frighten them about the oil and gas industry. It was suggested that further engagement with remote Aboriginal communities is required to address this situation.

As a corollary to this, the Panel also received submissions that Aboriginal land ownership and cultural interests are very well protected by legislation, and that the statutory bodies charged with administering this legislation are required by law to ensure that any decisions made by Aboriginal people in relation to their land or their culturally significant sites were informed by an understanding of the consequences of such a decision.

11.2.2 Potential adverse impact on the health of Indigenous communities

Concern was expressed in several submissions about the human and community health impacts of the fracking industry on vulnerable people in remote areas.[333] This concern was based in part on potential risks from chemicals used and waste products generated by the industry – but also the more general negative effect on wellbeing arising from loss of control, due to alienation from the technology and the influx of transient FIFO workers associated with the industry.[334] This, it was argued, could reduce the capability of Aboriginal communities to sustain cultural transmission across generations and that the traditional values that sustain community cohesion could be weakened. The AAPA submission summarised these effects:

> *"Loss, grief, anger and betrayal are common themes of Aboriginal responses to sacred site damage. These can compound into social tensions at the local level in terms of blame and the relative responsibilities and accountabilities that different categories of kin may hold in relation to a sacred site. At the emotional level site damage is generative of emotional distress and grief and is often associated with physical illness and death."*[335]

This issue is central to the concerns outlined below with respect to the potential disruption of traditional cultural practices.

The potential risks from chemicals used and waste products generated by the industry are discussed above at Chapters 5, 7 and 10. Potential negative effects on wellbeing arising from loss of control and alienation arising from the *'industrialisation of the landscape'* and the influx of transient FIFO workers will be assessed in the social impact assessment outlined in Chapter 12.

11.2.3 Potential disruption of traditional cultural practices

Concerns have been expressed in a number of submissions and at all the community consultations that there is a risk to Aboriginal traditional cultural practices because of both direct damage to sacred sites and what has been described as *"fragmentation of the cultural landscape".* Other submissions have drawn the Panel's attention to the potential for the industry to damage the places of spiritual or religious significance under Aboriginal tradition (in addition to formally recognised sacred sites) that connect Aboriginal people to their country, including the potential for damage to culturally significant features underground. AAPA told the Panel that:

> *"there is no doubt that Aboriginal beliefs about the sanctity of land encompass beliefs, knowledge and sanctions that do extend to the subterranean. Many narrative accounts depict ancestral heroes travelling underground, or being embedded in the earth at locations typically referred to as sacred sites."*[336]

The Panel was told that Aboriginal traditional land uses are at risk of being disrupted by the industrialisation of the landscape - the network of roads, pipelines and well pads - and FIFO workers who have no connection to the country and who are unlikely to be able to develop the long-term relationships with the community that is required to build understanding of Aboriginal cultural values of the landscape. The potential for disruption to traditional cultural practices resulting from hydraulic fracturing and its associated activities was summarised for the Panel:

> *"site damage may also entail significant social impacts. Unexpected death, illness or bad luck may be attributed to an incident of damage or changed circumstance of a sacred site. Blame and ensuing sanctions for breach of responsibility for a sacred site resulting in its damage, whether directly attributable to a custodian or not, can cause social rupture. Such rupture can rebound through local social relationships as blame and retribution is exacted, and extends to disruption of regional social and ceremonial relationships."*[337]

The Panel received submissions that the framework for the protection of culturally significant places in the Northern Territory *"is limited in its capacity to manage and mitigate subsurface impacts that may be associated with the practice of hydraulic fracturing"*[338] and further, that the responsible agency, the AAPA *"has limited capacity to assess, analyse, and interpret subsurface impacts and how these might affect sacred sites, particularly those that might have water as a feature of the sacred site".*[339]

331 Central Land Council, submission 47 (**CLC submission**).

332 Mr Jim Sullivan, Cave Creek Station, submission 73 (**J Sullivan submission**).

333 Mr Tom Measham, Commonwealth Scientific and Industrial Research Organisation, submission 77 (**T Measham submission**).

334 Doctors for the Environment, submission 96 (**Doctors for the Environment submission**); PHAA submission.

335 Aboriginal Areas Protection Authority, submission 234 (**AAPA submission**).

336 AAPA submission.

337 AAPA submission.

338 AAPA submission.

339 AAPA submission.

11.2.4 Potential benefit for local Aboriginal communities

The Panel also received submissions outlining the potential economic benefits for Aboriginal communities through training agreements and contracts mandating Indigenous employment and other benefits.[340] The potential economic benefit of any onshore unconventional shale gas industry, and how enduring value may be captured in remote communities is referred to in Chapter 13.

11.2.5 Potential to degrade aquatic and terrestrial ecosystems central to Aboriginal traditional cultural practices

There was general agreement in submissions to the Panel, including those from peak bodies representing Aboriginal interests, that Aboriginal people have a special relationship with their traditional country. This relationship is one where Aboriginal people are linked with their land (including waterbodies) by their ancient traditions and contemporary use of their land in accordance with those traditions.

It was put to the Panel that this special relationship makes Aboriginal people, and therefore, Aboriginal communities, particularly vulnerable to degradation of the landscape and the natural systems it supports. Particular concern was expressed about the potential risks to surface and groundwater sources:

> *"Water … is of the utmost importance both in terms of resource use and its associated cultural values. There are numerous instances of water being a key feature of sacred sites."*[341]
>
> *"Our water is part of our native title through our cultural and ceremonial practices that are part of the birds, animals, plants and us."*[342]

For instance, if fracking caused the water table to be lowered permanently and a spring, sacred under Aboriginal tradition, dried up, not only would there be no more water and the sacred site permanently destroyed, but there would be significant other social costs.[343] The Panel notes that the policy and legislative framework for water allocation in the Northern Territory recognises a special benefit provided by certain water sources for *"the condition of places that provide physical and spiritual fulfilment to Indigenous people"*, referred to as *"cultural flows"*.[344] The potential exists for this to be better integrated with the legislation and processes for protecting sacred sites.[345]

The risks to aquatic and terrestrial ecosystems systems posed by hydraulic fracturing are discussed in Chapters 7 and 8 of this Report.

11.3 Preliminary assessment

11.3.1 Aboriginal people not informed enough to understand risks or benefits

The Panel notes the Northern Land Council's submission that *"the rights of Aboriginal people are well protected because companies access to land subject to* [Aboriginal interests] *is prescribed by law. This creates negligible risk that a project would be able to proceed without the knowledge of, or without prior consultation with, Aboriginal people"*.[346] The Panel notes that the Land Councils are required under the Land Rights Act to ensure that before any activity on Aboriginal land is permitted, informed consent must be obtained. The Panel understands that land councils devote significant resources to informing traditional owners about the nature of proposed works and potential risks and benefits they entail. The Panel notes that both the Land Councils and AAPA must operate in a social and political context where both the identity of traditional owners, and the cultural significance of the landscape may be contested. As a consequence, the statutory duty *"to consult Aboriginal people and ensure informed decision making in the group setting is a challenging space to work in"*.[347]

The Panel also heard evidence from Aboriginal field workers from Seed (an affiliate of the Australian Youth Climate Coalition), who had travelled to Aboriginal communities in the Barkly Region to explain the nature and purpose of the hydraulic fracturing industry. They put to the Panel that Aboriginal people from these communities, where hydraulic fracturing is most likely to initially proceed first, if the Government lifts the moratorium, have inadequate knowledge of what is entailed. They found that the Aboriginal people they spoke to had no knowledge of the techniques of horizontal drilling and fracturing of deep shale beds, and when these facts were put before Aboriginal people in the region they expressed great concern.[348]

Putting to one side the question of whether this is an accurate reflection of the state of knowledge and the views held among Aboriginal groups in the Barkly Region, current knowledge by the Aboriginal community is inadequate, and as a consequence, this points to an emerging social risk with Aboriginal people becoming enmeshed in conflict between pro and anti-fracking groups.

The Panel has received submissions complaining about the dissemination of incorrect information, for the specific purpose of intimidating Aboriginal people about the prospect of hydraulic fracturing. Even more socially corrosive could be a situation where Aboriginal custodians make an informed decision based on sound information and in accordance with their traditional belief systems, only to find that this decision was then challenged by external interests. The Panel's attention was drawn to issues around the nomination of Muckaty Station on Warlmanpa land, as a potential site for storage of radioactive waste. In 2010, traditional owners commenced proceedings in the Federal Court of Australia alleging that the Northern Land Council had failed to take appropriate steps to ensure the traditional owners understood the nature and purpose of the nomination and had failed to obtain proper consent before nominating the site. The Northern Land Council withdrew the nomination in 2014 and the Federal Court proceedings were accordingly withdrawn.[349]

The Panel notes that it is imperative that accurate information is provided to the Aboriginal groups likely to be directly affected by hydraulic fracturing as soon as practicable, and that the peak bodies with responsibility for carrying out this work give the highest priority to ensuring this occurs well in advance of requirements for decision-making.

340 DPIR presentation; Ms Theresa Cummings, submission 249 (**T Cummings submission**).

341 AAPA submission.

342 Northern Land Council, submission 214 (NLC submission).

343 Watts 2008.

344 Tindall Aquifer Water Allocation Plan.

345 AAPA submission.

346 NLC submission; AAPA submission.

347 CLC submission.

348 Seed Indigenous Youth Climate Network, submission 267 (Seed submission).

349 See, for example, Bennett 2014.

11.3.2 Potential disruption of traditional cultural practices

The Panel notes that there are well established laws and systems for recognising and protecting Aboriginal traditional interests in their land and culturally significant sites on the land.

Further, it has been the practice of the companies involved in the exploration and development of shale gas reserves in the Northern Territory to apply to AAPA for an Authority Certificate, certifying that consultations have been carried out with the appropriate Aboriginal custodians and that the proposed works will not damage or interfere with any Aboriginal sacred sites[350] To date, all applications to AAPA have been for vertical drilling and associated drill pads and work areas, and have not specified the process of horizontal drilling, nor any of the other processes that must be carried out to extract gas from the onshore shale reservoirs.

The Panel is aware from the literature that there have been cases in the Northern Territory where traditional owners have rejected mining proposals because of their traditional beliefs about what lies beneath the ground.[351] The Panel notes a publication on land management issues published by the Central Land Council in the mid-1990s with a section entitled *"Dreamings go underneath"*, which documents the fact that Aboriginal people in the study area consider that the rocks and mineralisation beneath the ground is an integral part of the observable features of sacred sites on the surface:

> *"Many respondents raised the issue that they were concerned for Dreaming trails under the ground, not just those sites above ground, and complained about the emphasis placed on the latter in discussions over mining. People said that they could not understand why whitefellas did not see the danger to the 'Dreaming underneath.'"*[352]

That report goes on to quote an Aboriginal person at as stating that:

> *"Those whitefellas all the time worried for rock and tree but they got more in the ground. The Dreaming goes underneath, that's where the life is. Where it all came, it came out from that site, but it went down there now still. We people got to look after that one or we're all dead."*[353]

The Central Land Council records that these views were expressed by Aboriginal people interviewed at Yuendumu, Lajamanu and Tennant Creek, where it is stated that the earthquake is attributed to underground mining activities. The Panel heard similar stories about the Tennant Creek earthquake during in the course its initial round of community consultations. At the meeting between the Chair and the Board of the AAPA, several board members expressed views similar to those recorded by the Central Land Council.

From these discussions, the Panel's preliminary assessment is that if the risk of disruption of traditional practices is realised, the consequences (social costs) are likely to be high. For example, the loss of the amenity value of the site for the education of future generations could result in a feeling of powerlessness and failure being engendered in the traditional custodians of the site. The potential for this arises because of the direct personal responsibility Aboriginal people have for looking after their country. An inability to protect the site, which may include underground features,[354] is likely to invoke a feeling loss of control. Custodians of the site are also likely to feel that they will be held accountable, by neighbouring groups sharing the same traditions, for failing to protect an important site that may have been part of a Dreaming track spanning thousands of kilometres and linking many Aboriginal groups.

The Panel also notes that there is no basis under existing site protection legislation in the Northern Territory for Aboriginal custodians to prevent work on an underground rock formation, even if this is based on Aboriginal traditional beliefs, as long as the works do not affect any feature of the surface landscape. The definition of a sacred site, while broad, appears to preclude this. The panel has sought the views of Land Councils and the AAPA on this issue.

It is the Panel's view that the laws protecting Aboriginal cultural heritage should be better integrated with legislation protecting the environment and regulating the petroleum and gas industries. The Panel accepts the recommendation by AAPA *"that the regulatory framework for the approval of hydraulic fracturing and the processes of the NTAboriginal Sacred Sites Act be aligned to ensure the adequate protection of sacred sites"*[355] and further, that *"the Environmental Assessment Act and the Petroleum Act contain provision to ensure that an Authority Certificate has been issued to a proponent proposing to utilise hydraulic fracturing as a technique prior to any approvals being granted under those statutes."*[356]

11.3.3 Potential to degrade aquatic and terrestrial ecosystems central to Aboriginal traditional cultural practices

It is the Panel's assessment that there may need to be a higher threshold test applied for the protection of natural ecosystems that have a strong cultural significance in addition to their ecological significance.

This principle has been applied to water allocation through the recognition of a special benefit provided by certain water sources for *"the condition of places that provide physical and spiritual fulfilment to Indigenous people"*, referred to as *"cultural flows."*[357] In practice, this could be achieved by applying the principles applied to areas of high conservation significance under the *National Water Quality Management Strategy* and, in addition, applying water and sediment quality guideline values that are specifically protective of particular species of cultural significance. It was put to the Panel that *"cultural needs* [for water] *of remote communities and homelands are the highest priority and placed before the needs of competing industries".*[358]

The Panel notes that the current separate regulatory frameworks and departmental accountabilities for management of water quantity (flow allocation) and quality make it difficult to achieve this policy objective.

350 Origin submission; Pangaea submission.
351 Scambury and Lewis 2016; Stewart 1991.
352 Rose 1995; CLC submission, p 141.
353 Rose 1995; CLC submission, p 141.
354 AAPA submission.
355 AAPA submission.
356 AAPA submission.
357 Tindall Water Allocation Plan.
358 NLC submission.

11.4 Knowledge gaps and next steps

The Panel is seeking further information in three main areas relating to Aboriginal people and their culture:

- the cultural significance (if any) of sub-surface features such as aquifers and rock formations;
- the adequacy and effectiveness of measures to protect culturally significant sites (other than formally-recognised sacred sites), particularly those with features under the ground and any gaps in the current approach to protecting culturally significant sites that warrants attention by the Panel; and
- the location and characteristics of any temporary surface waterbodies (for example, waterholes) or groundwater dependent ecosystems that may occur in the arid and semi-arid regions containing the likely shale gas reservoirs, that may be culturally significant to Aboriginal people.

In addition, the Panel has requested these issues to be specifically addressed by the organisations responsible for the protection of culturally significant areas.

The Inquiry is aware that the Land Councils and the AAPA have 40 years' experience working with the mining industry protecting the traditional cultural interests of traditional Aboriginal owners and native titleholders and places of cultural significance to Aboriginal custodians. This includes specific experience with the unconventional gas industry. The Inquiry notes also that the Northern Land Council has called for the Inquiry to explicitly address the direct and indirect impact of hydraulic fracturing on Aboriginal culture and society. The knowledge gained by these statutory bodies in the course of their work will be invaluable to the Panel's task of considering risks to cultural conditions in the Northern Territory.

The Land Councils and the AAPA have been invited to prepare written submissions outlining their experience and understanding of risks arising from damage to or interference with culturally significant sites. In particular:

- the cultural significance (if any) of sub-surface features such as aquifers and rock formations;
- the cultural values relating to traditionally significant sites including their amenity value;
- the nature and extent of the impacts and risks that hydraulic fracturing and the associated activities could have on cultural values in the Northern Territory, including culturally significant sites;
- whether or not any additional work is required in order to understand the nature and extent of those risks;
- the approach taken to mitigate the impacts and risks identified above;
- the adequacy and effectiveness of these measures and any gaps in the current approach to protecting culturally significant sites that warrants attention by the Inquiry;
- risks to maintenance of traditions that underpin recognition of ownership rights under both the Land Rights Act and the NTA; and
- the approach taken by the Land Councils to mitigate the impacts and risks identified above in conditions placed on mining operations on Aboriginal land.

The Panel will obtain further submissions on the issues identified in this Interim Report and from the specific studies now being prepared, including the submission from AAPA and social impact assessment (see Chapter 12).

SOCIAL IMPACTS

12

12.1 Introduction

At a recent petroleum industry conference, Mr Peter Coleman, the CEO and managing director of Woodside Petroleum, said that the nation's oil and gas industry had *"lost the trust of the public"*. He warned that as a consequence, the industry's *"social licence to operate is at risk"*.[359]

Based on the peer reviewed literature, media coverage and the number of inquiries (such as this one) that have been carried over the past several years, there is no doubt that recent developments in the onshore unconventional gas industry have created widespread concern. Australia is no different, but the way that individual Australian jurisdictions have responded has varied widely.

Social impacts can be described as any change that arises from new developments and infrastructure projects that positively or negatively influence the preferences, wellbeing, behaviour or perception of individuals, groups, social categories and society in general.[360]

While the Northern Territory's focus is on unconventional shale gas, the impacts are likely to be similar to those relating to CSG. Therefore, an analogy may be drawn from the early social science research in Queensland (and overseas) to help inform considerations of social impacts more generally. However, no two communities are the same, and clearly the Northern Territory has a unique set of communities that span urban, regional and remote areas. It is therefore important to identify the social impacts across the different regions at different scales.[361] Regardless, it is often as a result of a range of cumulative impacts that an industry, government or project will lose their social licence to operate (**SLO**).

12.2 Social licence to operate

Absent from the Issues Paper was the risk that the gas industry did not have, and may not obtain and maintain, a social licence to operate. The absence of a social licence to operate may be a risk to the Government, the community and industry for at least the following reasons:

- **the Government:** because it owns the petroleum resource and relies on statutory royalties under the Petroleum Act to deliver government programs. The Government, however, also represents Territorians, who voted to implement a moratorium on hydraulic fracturing at the last election. The moratorium will directly impact upon the Government's ability to receive statutory royalties;
- **the community:** because it may be disempowered and fractured in the event that development proceeds without a social licence; and
- **industry:** because there are financial costs associated with no social licence, including delays in agreement making, uncertainty, moratoriums on certain activities, and the potential exercise of statutory veto rights.

The origins of SLO trace back to the mining sector around the mid-1990s, where it emerged in response to a number of highly publicised conflicts with communities over failures of chemical spills and tailing dams.[362] Although it has no agreed formal definition, it has come to be known as *"the ongoing acceptance or approval of an operation by those local community stakeholders who are affected by it and who can affect its profitability"*.[363] Due to the intangible nature of an SLO many suggest that it is often easier to know when a project does not hold a social licence to operate than when it does.[364] A failure to have an SLO can often lead to political intervention and sometimes project failure.[365]

Trust is a critical element of an SLO. While trust takes time to be established, it can easily be eroded if it is not well managed. Trust is built through open and transparent communication between all parties. There is a recognition that to gain trust, congnisance of the cultural differences and the requirements of different stakeholder interests involved or intersecting with the project in some way must exist.[366] Each stakeholder will require specific communication methods that easily accommodate that particular stakeholder's needs. As part of building trust, the context in which a project is operating, including any legacy issues, has been shown to strongly influence how new projects are accepted.[367] If historical evidence suggests that poor regulatory conditions have prevailed, or there is a track record of industry failures to uphold explicit commitments to stakeholders and the environment, it will result in low trust in both the government and the associated industry. Subsequently, it limits the ability of those project operators, and often the associated government, to gain an SLO.[368]

12.3 Key issues raised

The Issues Paper listed 13 possible impacts, including cumulative impacts, from the associated activities of hydraulic fracturing of onshore unconventional shale reservoirs on communities across the Northern Territory (see Appendix 1).

The recent consultations confirmed that the risks referred to in the Issues Paper represented the main community concerns. There was, however, a diversity of views expressed with respect to each issue. Below is a summary of the principal social impact themes arising from the community forums and the written and oral submissions lodged with the Inquiry to date.

12.3.1 'Boom and bust' nature of the industry

A consistent theme that emerged was the changing nature of an unconventional onshore shale project over the duration of its lifetime. There was concern that any project would generate large activity early in its life, but that once established, this would rapidly decline. It was felt that this would have far-reaching adverse social impacts both on the sustainability of local businesses over the longer term, as well as the availability of the services to support the increased numbers of people living and working in a particular community.

359 Robins 2017.
360 Geurs, Boon, and Van Wee 2009; Vanclay 2003.
361 Esteves, Franks, and Vanclay 2012.
362 Thomson, Boutilier and Darling 2011.
363 Moffat and Zhang 2014.
364 Parsons, Lacey and Moffat 2014.
365 Prno and Slocombe 2012.
366 Serje 2017.
367 Bradbury et al. 2009.
368 Gallois, Ashworth et al. 2016.

Included, was the impact on local infrastructure, where it was felt that those in the Northern Territory will bear the risks and potential damage of the industry, whereas non-Territorians would receive the major benefits. In addition to a fear of increased cost of living prices, a major concern was the impact on roads. That is to say, increased traffic would lead to a subsequent rise in the road toll and road surfaces would deteriorate, particularly in the wet season.

Other direct impacts were around housing availability - the price of housing increasing dramatically during any boom and potential for local businesses to collapse once the bubble was burst.

Similarly, a lack of literacy/numeracy skills for many across the Territory was observed as constraining local employment opportunities.

12.3.2 Impact of 'fly in fly out' workers

The negative impacts of an associated FIFO workforce was universally raised. Concerns included a lack of employment opportunities for locals; the ability of communities to accommodate an increased workforce and the subsequent impacts on housing affordability; whether there would be enough public health services to support the FIFO workers and still meet the local community needs; and the changing nature of existing communities - a fear was expressed that additional FIFO workers might create conflict and a social divide between themselves and locals. It was also acknowledged that there was likely to be an increase in alcohol consumption from an influx of FIFO workers, with all of its negative social effects. References were also made in relation to the skills required to participate in the industry. That is to say, all of the specialised jobs would go to FIFO workers, while the locals would only likely be afforded semi-skilled or unskilled jobs, if at all.

As one submission stated, *"the extensive use of FIFO's, use of external supply chains, use of overseas fabricators, disinterest in local community well-being and development, and the degradation of local assets, particularly roads have not endeared mining companies to many local communities. There is an expectation that local communities should receive local tangible benefits which outweigh the risks and adverse impacts on their assets, lifestyles and local environment."* [369]

12.3.3 Loss of amenity

In both its verbal and written submissions, the Amateur Fishermen's Association of the Northern Territory (**AFANT**) identified the potential impacts on people's mental health and wellbeing that may result from a loss of amenity and connection to the pristine environments of the Northern Territory:

> *"The specific concern we have relates to the concept that the enjoyment of the pristine, remote ecosystems of the Northern Territory, and the sustainable access to its abundant natural resources, is often a significant factor in Territorians balancing choices about where they are willing to live and work.*
>
> *Disruption to this balance, through the alteration of access to, and the condition of environments they value, may have the potential to leave individuals and communities with sense of loss and alienation. Depending on the scale and importance of the loss, affected residents may even decide to re-evaluate their choices."* [370]

The stress levels of local people were also alluded to. Several participants acknowledged the polarising nature of the industry can cause conflict, particularly if the benefits are unevenly distributed. And much has been written about the strong sense of place attachment that can emerge in individuals, and this appears to be especially true for those living in the Northern Territory (see Chapter 8).[371]

12.3.4 Intergenerational equity issues

Intergenerational equity was a priority for many of those attending the consultations, both Aboriginal and non-Aboriginal. Many stressed that allowing further petroleum extraction was contrary to urgently needed climate change mitigation. Many did not believe that the petroleum industry cared about the interests of future generations.

These issues were highlighted in the submissions of the Arid Lands Environment Centre, who observed that:

> *"Intra- and inter-generational equity, public participation, precautionary principle and the polluter pays approach should be embedded in the process of identifying and assessing the scientific material on the risk of hydraulic fracturing. The decisions taken now in this panel will impact communities for many generations to come and their rights to a healthy environment and sustainable development are just as important as the needs of current generations."* [372]

12.3.5 Perceived absence of a social licence to operate

The perceived absence of an SLO was referred to regularly during the community consultations. Reasons for the lack of an SLO varied, but consistent with the literature, common concerns focussed on legacy mining issues that had not been resolved and the inability of the government to manage these appropriately. This has led to a distrust in both the Government, Aboriginal land councils, and the broader oil and gas industry, to manage any risks appropriately and to protect the environment in the long term for all Territorians.

APPEA provided a number of useful case studies of many of the social impacts vexing the public. However, as the APPEA submission also went on to illustrate, these issues can, and have been, proactively managed by oil and gas companies, resulting in positive outcomes for communities and individuals. It cites a number of peer-reviewed reports and literature, both by CSIRO and the University

369 Coomalie Community Government Council, submission 15 (**Coomalie Council submission**).

370 Amateur Fishermen's Association of the Northern Territory, submission 190 (**AFANT submission**).

371 Ms Yolande Doecke, submission 25 (**Y Doecke submission**).

372 Arid Lands Environment Centre Inc, submission 88 (**ALEC submission**).

of Queensland, which suggest that these issues can be managed if companies work together with communities and government to address concerns as and when they are raised.[373]

The Northern Territory Cattlemen's Association (**NTCA**) also made reference to the importance of collaboration between the industry and landholders to ensure coexistence. In addition to fair compensation, it stressed the need for respectful relationships that did not prioritise one side over the other. Its submission concluded by stating that the:

> *"NTCA is of the view, that empowering landholders and tenement holders the ability to agree on fair and equitable terms for access to the land and compensation for the Authorised Activities (given the impacts that will occur as a result of the resource tenement holders' activities) preserves dual rights granted by the Northern Territory, enabling contented coexistence."*[374]

12.4 Knowledge gaps and next steps

In the Issues Paper it was recognised that an exhaustive assessment of the social impacts of the whole of the unconventional onshore shale gas industry across the whole of the Northern Territory was not feasible because:

- the footprint of a fully developed unconventional onshore shale gas industry in the Northern Territory is currently unknown. Further exploration is required to understand the nature and extent of the resources and the infrastructure and workforce required to develop it; and
- no two communities in the Northern Territory are the same. Each community has its own unique community profile and will respond to the risks and benefits associated with development in a different way.

Given the time constraints of the Inquiry's completion, the Inquiry has commissioned an independent study from Coffey to inform its social impact deliberations. The scope of services (at Appendix 10) requires the creation and implementation of a social impact assessment framework for the development of onshore unconventional shale gas in the Northern Territory. The framework will be applied to the Beetaloo Sub-basin to assess the people, or groups of people, that will most likely be affected by such a development. Coffey has also been requested to review the current literature surrounding an SLO as that concept is applied to an onshore unconventional shale gas industry in the Northern Territory. A final report will be submitted to the Panel by 15 September 2017, for its consideration prior to the release of its Final Report.

373 APPEA submission.

374 Northern Territory Cattlemen's Association, submission 217 (**NTCA submission**).

ECONOMIC IMPACTS

13

13.1 Introduction

The Northern Territory Budget 2017-18 estimates the Territory's population at approximately 245,000, which equates to 1% of Australia's population. The structure of the Territory's economy substantially deviates from that of the national economy, reflecting its abundant natural resources, a large public sector, a defence presence, and a small private sector that is significantly influenced by major projects.[375]

Over the past decade the Territory economy has benefited from multiple major projects. Gross state product (**GSP**) has grown from $15 billion in 2004-05, to $22 billion in 2014-15. However, economic growth is forecast to moderate as the Territory transitions from investment led growth to predominantly export driven growth. The relatively modest rate of growth in the short term reflects a return to more historical levels of private investment compared to the record due to major projects.[376]

APPEA argued that resource development brings the potential for a substantial and stabilising public benefit. It further asserted that new industries are now needed to support the Northern Territory economy as the Ichthys LNG project transitions from construction to production.[377] Multiple submissions lodged by the oil and gas sector described the potential for substantial benefit to the Territory's economy of development of an onshore shale gas industry based on the geological extent of prospective source rocks. Falcon Oil and Gas Australia, which holds a 30% interest in exploration permits EP76, EP98 and EP117 (located in the Beetaloo Sub-basin) submitted that, *"economic benefits cannot be quantified due to the infancy of the discovery and the need for further appraisal. However, should the project advance it would contribute to economic prosperity for decades to come through direct jobs on a range of skill levels and indirect jobs through the 'multiplier effect' when a new industry is created."*[378]

There is, however, considerable community concern that the exploitation of unconventional onshore shale gas could have significant negative economic consequences, including rapid increases in the cost of living for Territorians not involved in the industry, exacerbation of existing issues of inequality and disadvantage, and reductions in the financial viability and sustainability of existing businesses.[379]

13.2 Key issues raised

The Issues Paper lists seven possible economic risks, including cumulative impacts, that may be associated with hydraulic fracturing of onshore unconventional shale reservoirs and its associated activities in the Northern Territory (see Appendix 1).

The Panel understands that the economic risks identified in the Issues Paper are appropriate. The Panel has received a variety of views on how the development of onshore unconventional shale gas might benefit, or adversely impact upon, the Territory's economy. The following discussion provides additional detail around known risks and other emergent themes.

13.2.1 Distribution of potential economic benefits

Origin describes an extractive business's role as that of a developer, to *"facilitate the transformation of a natural asset, which is a publicly owned good, into social or economic benefit for shareholders, governments and host communities."*[380] However, multiple submissions indicate that there is still significant public concern regarding how the revenue generated from potential future gas sales will be managed and divided.

The NTCA stated that, *"equilibrium must be imbued, so that both landholders and tenement holders' rights and interests in the land are balanced, ensuring dichotomous entitlements and rights to economic benefits are fairly and adequately accommodated"*.[381] The NTCA noted that, *"advantages which flow from the access and use of the land to obtain resources (minerals/petroleum) beneath the surface of the soil are for the benefit of the resource tenement (profit) and the Northern Territory (licence fees and royalties), however is to the detriment of the landholder, who under the current Northern Territory regime, is only entitled to compensation where damage or loss arises after the Authorised Activities"*.[382] The NTCA proposes that a tenement holder should not be entitled access to private leasehold land without first:

> *"Obtaining written consent of the landholder by way of a conduct and compensation agreement (valid for no more than one (1) year), including provision for compensation payable by the tenement holder to the landholder as a result of the disruption / disturbance / granting of the right to enter the land for the purpose of undertaking necessary investigative or more intrusive activities."*[383]

375 NT Budget Economy Book, p 3.
376 NT Budget Economy Book, p 5.
377 APPEA submission.
378 Falcon Oil and Gas Australia Pty Ltd, submission 79 (**Falcon submission**), pp 2-3.
379 ALEC submission.
380 Origin submission, p 157.
381 NTCA submission, p 1.
382 NTCA submission, p 5.
383 NTCA submission, pp 2, 5.

13.2.1.1 Government revenue

Approximately 70% of the Government's annual income comes from the Commonwealth, with the remaining 30% from a Territory owned revenue source. Changes to goods and services tax funding allocation and national economic volatility have the potential for a greater impact on Northern Territory economic sustainability. Growing the Northern Territory economy will reduce this risk and reliance on the Commonwealth.

While multiple submissions support unconventional shale gas development as a means to gaining greater independence from the Commonwealth, and to strengthen the Northern Territory economy, the Australia Institute nevertheless noted that, *"mining and gas royalties are a not a major source of funding for Australian state and territory governments"*.[384] It describes declining payments received under the Petroleum Resource Rent Tax and the lack of payment of company tax by large gas companies as limitations to Government revenue, and goes on to say that, *"balanced against the modest increases in revenue, costs that accrue to the state through infrastructure provision and other forms of subsidy need to be considered"*.[385]

13.2.1.2 Employment (direct economic contribution)

In its recent report, Deloitte Access Economics (**Deloitte**) presented two scenarios (success and aspirational) for potential onshore gas development in the Northern Territory. Associated predictions for employment were estimated to be between 4,200 and 6,300 full time equivalent jobs above the base case by 2040.[386]

The petroleum industry has expressed an intention to deliberately invest in providing local training, jobs and business support, particularly in remote and regional areas.[387] Origin stated that its *"approach to living local and buying local will ensure economic benefits accrue in our areas of greatest activity and impact"*.[388] Pangaea also advocated an approach that supports a long term focus towards community integration. Examples of 'local content' provided in its submission included employing pastoralists in seismic separation; TOs in civil access and construction works; engaging local civil earthworks contractors; waste disposal companies; and camp and accommodation companies.[389] Multiple submissions received from a variety of Territory based businesses agreed on the need for 'local content' with respect to employment.[390]

The Northern Land Council advised that many Aboriginal communities are remote and are largely dependent on welfare. Its submission described how a *"mature and well-designed onshore oil and gas industry"* offers the potential to address a number of economic pressures through potential income streams including business development, training and direct employment.[391]

However, a range of submissions questioned the long term employment benefits to rural and remote communities in the event that unconventional shale gas supplies are developed. Models reliant on a largely FIFO workforce were widely criticised by the community during consultation sessions for lack of contribution at community or regional scales. The Australia Institute expanded upon concerns, predicting that Territorians will have to compete with the thousands of experienced workers no longer employed in the Queensland CSG sector as a result of industry decline since 2015.[392]

13.2.1.3 Purchase of local goods and services (indirect economic contribution)

Origin stated that production royalties would substantially increase and diversify the Northern Territory revenue base without affecting critical existing industries, such as cattle export and tourism. Its submission stated that employees of local extractive businesses and their contractors buy locally, and they pay for local services including education, health services, transportation, accommodation, food and entertainment.[393] Having said this, the Panel notes concerns raised during the initial round of community consultations described concerns that the presence of the oil and gas industry in the community could cause the price of food, goods, and services to increase. Localised inflation was also raised as an issue by the Northern Land Council.[394]

13.2.1.4 Infrastructure development and induced economic effects

Origin references advantages provided by improved civic infrastructure and increased cash flow through local communities that will result from investment in unconventional shale gas extraction. Its view was supported by local submissions. Mr Mark Sullivan described required infrastructure, and the potential for development through the support of the oil and gas sector, for example, bitumen roads, bridges, regional power generation and distribution, communications, health centres and education facilities.[395] Conversely, the NTCA raised the point that in under-developed regions where there is limited infrastructure, substantial capital costs may deter valuable private investment.[396]

The Northern Land Council advised that community infrastructure and development benefits that can be negotiated as part of a production agreement may assist in fostering community development and help to ease the economic pressures currently faced in remote and welfare dependent Aboriginal communities.[397]

384 The Australia Institute, submission 158 (A**ustralia Institute submission**), p 7.

385 Australia Institute submission, p 7.

386 2015 Deloitte Report, p 5.

387 Falcon submission, p 3.

388 Origin submission, p 147.

389 Pangaea submission, p 5.

390 Mr Bill Sullivan, Sully Pty Ltd, submission 160, pp 1, 2 (**B Sullivan submission**); Mr Mark Sullivan, Flying Fox Station, MS Consulting, submission 166 (M Sullivan submission), pp 4, 8; Mr David Armstrong, Terrabos Consulting, submission 180 (**D Armstrong submission**), p 4.

391 NLC submission, p 33.

392 Australia Institute submission, p 13.

393 Origin submission, p 147.

394 NLC submission, p 34.

395 M Sullivan submission, p 10.

396 NTCA submission.

397 NLC submission, p 33.

13.2.1.5 Royalties

The Northern Territory Petroleum Royalty Overview provided by the Department of Treasury and Finance stated that:

> *"royalties are payments made to the Northern Territory Government as the owner of the petroleum, in consideration of a right granted to extract and remove petroleum and are calculated at the rate of 10 per cent of gross value at the wellhead on petroleum production. The Territory's royalty regime encourages present and future exploration and development of petroleum resources. At the same time it compensates the Northern Territory community for allowing the private extraction of the Northern Territory's non-renewable resources."* [398]

During community meetings held by the Panel questions were raised as to how royalties would flow through to local communities that would be bearing the risks of any onshore shale gas industry. Many members of the public said that a 'Royalties for Regions' program should be considered. The NTCA argued that:

> *"a policy similar to the Western Australia Royalties for Regions program, to ensure economic benefits generated as a result of the unconventional gas industry are invested into the communities affected by the shale gas projects. Benefits should be in the form of investment in infrastructure and long term capital assets."*[399]

13.2.2 Property values

Multiple submissions referenced the negative influence of unconventional gas developments on, and in close proximity to, residential and agricultural properties.[400] Examples of the presence of unconventional gas wells in Queensland leading to reduced property values and subsequent refusals by banks to accept those properties as security for finance or bridging loans were given.[401]

Lock the Gate cited a 2011 submission by Rabobank Australia and New Zealand to the Australian Senate Inquiry into Management of the Murray-Darling Basin to the effect that *"until such time as the comprehensive, detailed investigations into CSG exploration, mining and production activities are carried out, Rabobank is not able to opine as to whether the agriculture and energy industries can coexist."*[402]

But the notion of declining property values was refuted in a number of submissions on the basis that of infrastructure improvements could benefit remote cattle stations.[403] For example, Mr Rohan Sullivan of Birdum Creek Station advised of *"understandable anger"* in relation to the current moratorium because it had stalled Pangaea's 2016 infrastructure program worth $100M, including the commencement of the Western Creek Road upgrade in the Sturt Plateau. According to Mr Sullivan, other positive investments made by Pangaea included the installation of monitoring equipment in bores; the identification and mapping of a deeper aquifer that was previously only poorly understood; and LIDAR assessment of the area to assist with developing road infrastructure that will also assist with on-station dam development.[404]

Increases in housing values driven by 'boom' periods may have both positive and negative outcomes. CSIRO stated that increased housing values may be seen as a positive outcome for the owner of a house, but a negative outcome for someone seeking to purchase a house. Local tenants may not benefit from the direct income increases and may instead suffer from increased rents, poverty, and outmigration, especially in lower income households.[405]

APPEA stated that resolving housing pressure is clearly a matter of balance when a temporary workforce is involved. Communities will be keen to maximise the benefits that can accrue from resident workers rather than nonresident (or FIFO) workers. This shift will increase pressure on the existing stock of housing and will require new residences to be built. But once the workforce peaks and employment opportunities are reduced, excess housing supply can also cause problems.[406] APPEA advised that the industry needs to work closely with regulators, local government and the local community to collaboratively address housing needs.[407]

13.2.3 Impact on other industries

13.2.3.1 Reduced revenue and competition for resources

The Arid Lands Environment Centre (**ALEC**) stated that, *"shale gas will compete for access to resources within the dominant agricultural, pastoral and tourist industries of the Northern Territory"*. It specifically cited land and water access constraints that were required for continued livelihood.[408]

The NTCA submitted that, *"many of the areas targeted by tenement holders are rich agricultural areas with valuable water resources. Ideally, neither right to land should supersede the other"*.[409] They acknowledged that the considerable gas reserves located within the Northern Territory provided significant economic enticement to Governments, present and future, however, they noted that, *"fossil fuel reserves are finite, while livestock production and agriculture generally will operate in perpetuity"*.[410]

Consolidated Pastoral Company Pty Ltd (**CPC**) advised that, *"any adverse impacts on access to groundwater or the quality of groundwater would have a significant impact on the CPC and the Territory pastoral industry. Further any changes in land use on pastoral leases that limit the carrying capacity of the lease would have an adverse impact on the viability of the enterprise"*.[411]

398 NT Petroleum Royalty Overview, p 1.

399 NTCA submission, p 7.

400 Mr Daniel Tapp, submission 11 (**D Tapp submissio**n), p 2; Mr Rod Dunbar, Lexcray Pty Ltd, submission 75 (**R Dunbar submission**), p 8.

401 Lock the Gate submission, p 60.

402 Lock the Gate submission, p 58.

403 B Sullivan submission, p 5.

404 Mr Rohan Sullivan, Birdum Creek Station, submission 18 (**R Sullivan submission**), p

405 T Measham submission, p 8.

406 APPEA submission, p 78.

407 APPEA submission, p 75.

408 ALEC submission, p 13.

409 NTCA submission, p 1.

410 Northern Territory Cattlemen's Association submission 32 (**NTCA submission 32**), p 2.

411 Consolidated Pastoral Company Pty Ltd, submission 218 (**CPC submission**), p 12.

Lock the Gate listed the deleterious impacts of unconventional gas development known to affect agricultural land as *"intensification, fragmentation, disruption to agricultural operation and alienation of agricultural land, large water demand, vegetation clearing and the production of polluting waste."*[412] In relation to CSG development, Lock the Gate observed the potential for further economic losses from disruption of agricultural operations, spills and leaks of wastewater, or the spread of weeds.[413]

Tourism is a large economic driver of the Northern Territory economy. Concern was regularly raised that, *"our long established reputation as a unique tourism destination centred round our extraordinary natural landscapes and rich aboriginal culture"* may be affected by the onshore unconventional oil and gas industry.[414] The tourism industry in Central Australia is described as being highly vulnerable to onshore unconventional shale gas development because of the perception that it has *"pristine, wild and natural landscapes"*.[415] AFANT reiterated the economic and social value of the recreational fishing industry to the Territory, *"given the reliance of the Northern Territory's world class recreational fisheries upon intact water resources/ healthy ecosystems, and the significant, well established and sustainable social and economic benefits of the recreational fishing sector, it is clear that unconventional gas development presents risks that must be taken seriously"*.[416]

13.2.3.2 Regional employment

A review of the socioeconomic impacts of coal seam gas in Queensland by the Office of the Chief Economist stated that *"there is evidence that some of the employment in the CSG sector has been drawn from other industries, as the growth in employment in CSG has been associated with a reduction in agricultural employment. However, the latter decline could also be attributed to drought, increased mechanisation, and a trend toward consolidation of farm ownership"*.[417] The review hypothesised that negative shifts from the agricultural sector could be a result of direct migration into mining jobs or due to high labour costs encouraging a move toward less labour-intensive agriculture. The review described the limited availability and increasing cost of rural labour experienced by farming communities as a result of competition between CSG companies, especially at peak times such as planting and harvest.[418]

13.2.3.3 Environmental remediation

Multiple submissions raised the potential for groundwater and surface water pollution, land pollution, and air pollution, through various contamination pathways. The costs associated with either remediation, or potentially irreversible environmental damage, were a matter of concern for the community, particularly where those costs were perceived to be likely to be borne by the Government or local authorities (that is to say, the public), and not the gas operator responsible for the pollution and harm. This potential cost had to be considered when determining whether any onshore unconventional share gas industry will result in a net economic benefit.[419]

13.2.4 Energy security

Multiple submissions described how the Northern Territory's entry into a potentially volatile global gas market could have implications on local electricity prices.[420] According to the Australia Institute, *"potential connections to the chaos of the Eastern Australian market, or expansion of export facilities in Darwin"* is *"the biggest threat to security of gas supply in the."*[421]

Multiple submissions referenced the 2016 report *Pipe Dream, A Financial Analysis of the Northern Gas Pipeline* published by the Institute of Energy Economics and Financial Analysis. This report concluded that the *"construction of the North East Gas Interconnector (NEGI) is being proposed at a time in which global liquefied natural gas (LNG) markets are in a glut. The NEGI deal—if it were built—would occur under a monopoly arrangement whose economic benefits, if there are any, would be limited to foreign owners"*. In response, Deloitte argued that the experience of the US suggests that shale and tight energy sources will play a vital role in meeting future demand.

The NTCA has requested that the Inquiry investigate the merits of a gas reservation policy on behalf of all Territorians to ensure that Northern Territory residents have access to clean and affordable gas in the foreseeable future.[422] But other submissions argued that, *"fracking will inhibit investment and growth in the renewables sector"*.[423]

13.3 Knowledge gaps and next steps

In the absence of any economic expertise on the Panel, the Inquiry has engaged ACIL Allen to undertake a realistic economic impact assessment of any potential onshore unconventional shale gas industry being developed in the Northern Territory.

The economic assessment to be undertaken by ACIL Allen is a broad study focussing on the actual and potential direct and indirect economic benefits, impacts, and risks of hydraulic fracturing for onshore shale gas development in the Northern Territory under the current regulatory regime (see the scope of work at Appendix 9). ACIL Allen must consider the following scenarios in making the assessment:

- **scenario 1 (or the baseline scenario):** the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place;
- **scenario 2:** the development of the onshore unconventional shale gas industry in the Northern Territory takes place; and
- **scenario 3:** the development of unconventional shale gas reservoirs takes place in the Beetaloo Sub-basin only.

The Inquiry must approve all assumptions made by ACIL Allen. The Inquiry will have continual oversight of ACIL Allen's work. ACIL Allen will also be required to liaise with a wide range of stakeholders in the Northern Territory to consider the impacts of onshore unconventional shale gas development on other industries, such as, tourism,

412 Lock the Gate submission, p 6.
413 Lock the Gate submission, p 64.
414 Top Didj Cultural Experience, submission 269 (Top Didj submission), p 1.
415 ALEC submission, p 14.
416 AFANT submission, p 9.
417 Lock the Gate submission, p 50
418 Lock the Gate submission, p 50.
419 R Dunbar submission, p 4.
420 Australia Institute submission, p 3.
421 Australia Institute submission, p 6
422 NTCA submission 32, p 2.
423 ALEC submission, p 14.

agriculture, horticulture, and pastoralism. ACIL Allen has been specifically directed to consult with Lock the Gate and the Australia Institute, as Inquiry stakeholders. The final ACIL Allen economic assessment report will be published in full upon its completion by 1 September 2017.

REGULATORY REFORM

14

14.1 Introduction

The regulation of the onshore petroleum industry and, in particular, hydraulic fracturing, has been a controversial matter in the Northern Territory since at least 2010. In order to address the community's concerns about the development of the industry, each of the last three Northern Territory governments has commissioned at least one inquiry or investigation into the onshore petroleum industry.

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

There is, however, a real risk that the current regulatory framework in the Northern Territory may not achieve these objectives.

14.2 Overview of previous inquiries into hydraulic fracturing

In 2011 the former Labor government commissioned Dr Tina Hunter, an expert in petroleum law, to report on the capacity of the Northern Territory's legal framework to regulate the development of the onshore petroleum industry in the Northern Territory (**2012 Hunter Report**).[424] A key recommendation from the 2012 Hunter Report was that government should prioritise the development and implementation of regulations under the Petroleum Act for the protection of the environment (Recommendation 16).

In March 2014 the former Country Liberal Party (**CLP**) government under Chief Minister Adam Giles commissioned Dr Allan Hawke AC to conduct an inquiry into the potential impacts of hydraulic fracturing in the Northern Territory (**2014 Hawke Report**).[425]

The 2014 Hawke Report's major recommendation was that, *"consistent with other Australian and International reviews, is that the environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory system"*.[426]

Another relevant recommendation was that the Northern Territory Government conduct a review of the environmental assessment and approval process in the Territory. The CLP government therefore reengaged Dr Hawke to conduct this inquiry. Dr Hawke's second report (**2015 Hawke Report**) was released in May 2015.[427]

Following the 2012 Hunter Report and the 2014 and 2015 Hawke Reports, new Petroleum Environment Regulations were promulgated in July 2016.

In early 2016 the CLP Government commissioned Dr Tina Hunter to conduct an independent assessment of the Petroleum Environment Regulations (**2016 Hunter Report**) to ensure that they complied with the principles of best practice regulation. Dr Hunter described the new environment regulations as *"a quantum leap from the Northern Territory regulations of old"* and that *"the fundamentals of the Regulations are sound"*.[428]

14.3 The current regulatory regime governing petroleum activities in the Northern Territory

The primary piece of legislation that regulates the onshore unconventional gas industry in the Northern Territory is the Petroleum Act. That Act is supported by the Petroleum Environment Regulations, the Petroleum Regulations, and the Petroleum Schedule. The legislation is administered by DPIR.

14.3.1 Petroleum Act

The object of the Petroleum Act is to, among other things, create a framework for *"the reduction of risks, so far as is reasonable and practicable, of harm to the environment, during activities associated with exploration for or production of petroleum."*[429]

The Petroleum Act is the primary legislation that regulates the onshore petroleum industry. The Act itself does not set out a process for the management of environmental risks and impacts associated with onshore petroleum activities. Matters relating to environmental management are dealt with in the Petroleum Environment Regulations.

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 condition 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: s 74).

The Environmental Defenders Office (NT) (**EDO**) argues that there are deficiencies with the Petroleum Act in its current form:[430]

- the term *"good oilfield practice"*, an expression of uncertain content, continues to be used in it;
- the Petroleum Schedule is imposed on gas operators by way of direction only and is uncertain and lacking in transparency;
- baseline testing of groundwater, surface water, soil, sediment and air quality is not mandated to be obtained prior to the commencement of shale gas activities (unless imposed by direction under the Act, but see the criticism immediately above);
- the Act fails to include a 'fit and proper person' test or a requirement that an operator's environmental history be considered prior to any approval being given to carry out activities;
- the Act does not include third party merits review rights, nor does it provide any open standing provisions for judicial review;
- compensation for landholders is currently inadequate and there are no provisions requiring the negotiation of 'make good' agreements; and

424 2012 Hunter Report.
425 2014 Hawke Report.
426 2014 Hawke Report.
427 2015 Hawke Report.
428 2016 Hunter Report, p 4.
429 Petroleum Act, s 3(2)(f).
430 Environment Defenders Office (NT), submission 213 (**EDO submission**), pp 9, 18.

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

14.3.2 Petroleum Schedule

The Petroleum Schedule operates alongside the Petroleum Environment Regulations and the Petroleum Act to regulate certain petroleum activities, such as the design and construction of petroleum wells.

The Petroleum Schedule, by itself, is not enforceable.[431] It is given legal effect by the Minister for Resources, who issues each interest holder with a direction under s 71 of the Petroleum Act, which requires the interest holder to comply with the terms of the Schedule.[432]

The Petroleum Schedule includes provisions relating to operational matters relating to onshore petroleum activities, such as seismic surveys used in exploration, drilling and well integrity. The Schedule was amended in July 2016 to remove all references to environmental management because these matters are now dealt with in the Petroleum Environment Regulations.

The Petroleum Schedule has been described as an ineffective regulatory tool, particularly by Dr Hunter.[433] In its current form, it is highly prescriptive, which means that it focusses more on the interest holder engaging in certain activities and less on setting and achieving environmental outcomes for that activity. Prescriptive regulation does not necessarily promote best practice and does not facilitate the development of new and effective ways to mitigate environmental risks. As DPIR stated in its submission to the Inquiry, *"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."*[434] Further, the Schedule is not subject to any type of regulatory assessment, which must occur in connection with primary and secondary legislation. While this type of regulation gives the Government significant flexibility (the Petroleum Schedule can be amended immediately), it lacks transparency and oversight.

Both the 2012 and the 2016 Hunter Reports recommended the phasing out of the Petroleum Schedule,[435] and DPIR has publicly committed to phasing out the Schedule and replacing it with exploration and production regulations.[436]

14.3.3 Petroleum Environment Regulations

The absence of a clear process for the management of environmental risks and impacts associated with the onshore petroleum industry in the Petroleum Act and the Schedule was considered, as per Dr Hunter's reports, a significant weakness in the regulatory framework. Accordingly, in early 2016 the Petroleum Act was amended and, as stated above, the Petroleum Environment Regulations were introduced shortly thereafter.[437] The objective of the 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."*[438]

The Petroleum Environment Regulations implement many of the recommendations from the reports listed in the first part of this paper but in particular the 2015 Hawke Report. The Regulations:

- 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 environment plans and the Minister's statement of reasons for approving a plan;
- require stakeholder engagement as a precursor to the submission of an environment plan;
- require the Minister to consider any recommendations made from the Northern Territory Environment Protection Authority (**EPA**) when making a decision about a plan; and
- operationalise the *"as low as reasonably practicable"* test (**ALARP**) in the decision-making process.[439]

Guidelines on the operation and application of the Petroleum Environment Regulations have been drafted,[440] however, they have no enforceable legal effect.

Under the Petroleum Environment Regulations the decision-maker must determine what an *"acceptable"* level of risk is by reference to the principles of ESD and any recommendations from the EPA. There remains, however, uncertainty about what level of risk the Minister can, or should, consider to be an *"acceptable"* level of risk.

In this context it should be noted that the Inquiry's terms of reference require the Inquiry to determine *"the level of environmental impact and risk that would be considered acceptable in the Northern Territory context"*.

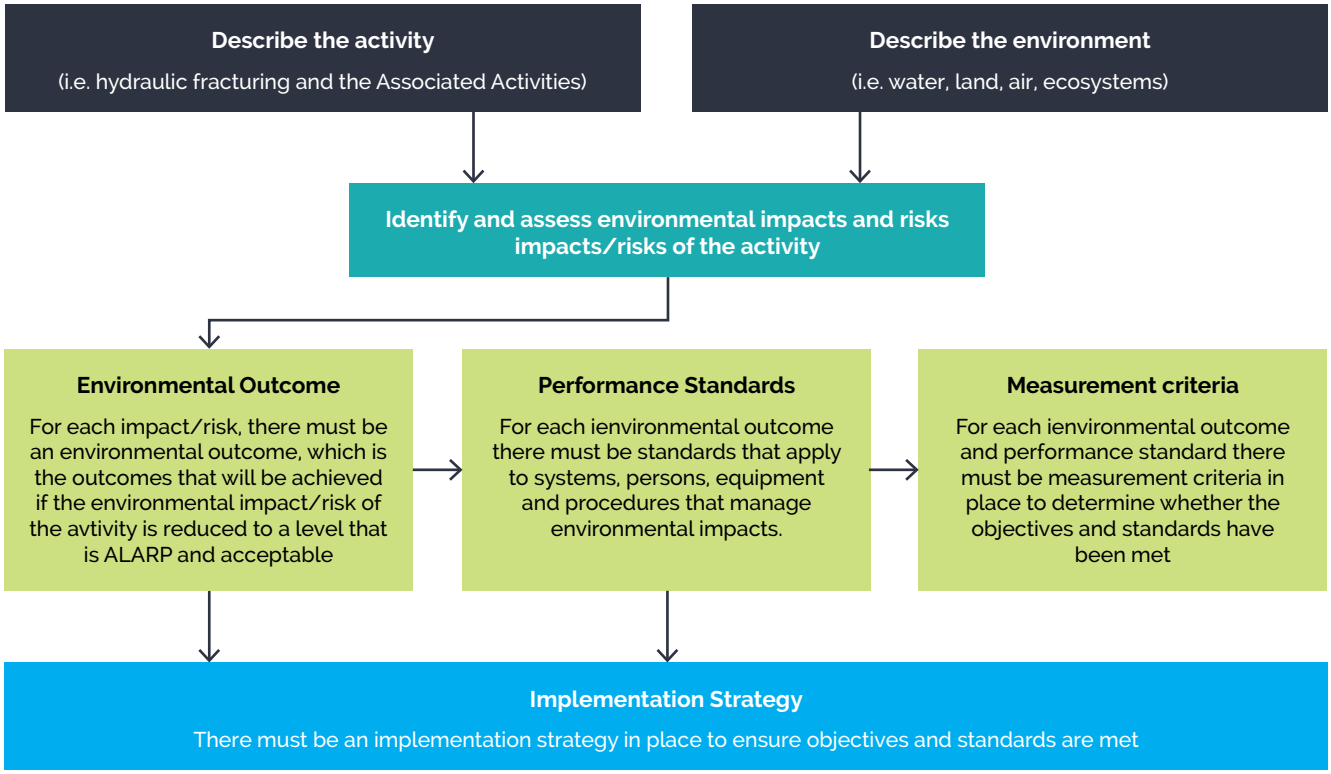
The Petroleum Environment Regulations apply to any petroleum activity that has an environmental impact. This includes hydraulic fracturing because "hydraulic fracturing"

431 2016 Hunter Report, p 15.
432 Petroleum Act, s 71.
433 2016 Hunter Report, p 15.
434 DPIR submission, p 38.
435 2016 Hunter Report p 15; 2012 Hunter Report.
436 DPIR submission, p 38.
437 DPIR submission, p 38.
438 DPIR submission, p 38.
439 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: see http://www.hse.gov.uk/risk/theory/alarpglance.htm.
440 Petroleum Environment Regulations Guide.

is listed as a "regulated activity."[441] It is an offence to conduct hydraulic fracturing without an approved environment plan.[442] 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 environment plan will reduce all environmental impacts and risks associated with the activity to levels that are both ALARP and acceptable. The Minister must publish reasons for his or her decision.

The contents and linkages of an environment plan are depicted below:

Figure 14.1: Environment plan linkages.



It has been submitted to the Panel that the terms *"ALARP"* and *"acceptable"* should be defined in the Petroleum Environment Regulations, however, the meaning of an "acceptable" level of risk will vary depending on the nature of the activity being proposed and the receiving environment. Nevertheless, the level of risk that is deemed to be *"acceptable"* must always be a level that is consistent with the principles of ESD, which includes the precautionary principle.[443]

14.4 Key issues raised

The community expressed an acute lack of confidence in the current regulatory framework during the hearings, community forums and in the submissions received.[444]

14.4.1 Operationalising the precautionary principle

Many submissions argued that, given the apparent scientific uncertainty associated with the nature, extent and management of environmental risks associated with hydraulic fracturing, the precautionary principle should be operationalised within the regulatory framework.[445]

The precautionary principle requires that, where there is scientific uncertainty, decisions should be made to avoid serious or irreversible environmental harm. 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."*[446]

441 Petroleum Environment Regulations, cl 5.

442 Petroleum Environment Regulations, cl 30.

443 Petroleum Environment Regulations, cl 9(2).

444 Prof Melissa Haswell, submission 183 (**M Haswell submission**), p 14; EDO submission, p 36; NTCA submission, p 8; NLC submission, p 39; Mr Justin Tutty, submission 152 (**J Tutty submission**), p 2; Lock the Gate submission, p 68; Environment Centre Northern Territory, submission 188 (ECNT submission), p 3; AFANT submission, p 7; Ms Charmaine Roth, submission 191 (**C Roth submission**), pp 15-16; Coomalie Council submission 15; Central Desert Regional Council, submission 76 (**CDRC submission**), p 1. A small number of submissions considered that onshore unconventional gas industry was being well regulated, see Origin submission, pp 160, 163; M Sullivan submission, p 5; Mr Stuart Jones, Petroleum Exploration Society of Australia, submission 170 (**S Jones submission**).

445 EDO submission, p 10; Ms Sharyn Bury, submission 189 (**S Bury submission**), p 2; M Haswell submission, pp 14, 17; PHAA submission, p 4; Ms Helen Bender, submission144 (**H Bender submission**), 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]."

446 1992 Rio Declaration, Principle 15.

In *Telstra Corporation Ltd v Hornsby Shire Council*, Preston J of the Land and Environment Court of New South Wales, gave a full explanation of the ambit of the principle and conditions precedent to its application.[447] The scope of the principle and its application can, of course, be modified by Parliament.

Notwithstanding the statement that, *"activities are carried out in a manner consistent with the principles of ecologically sustainable development"* contained in the Petroleum Environment Regulations,[448] the Petroleum Act does not, of itself, expressly mention or operationalise the principles of ESD or the precautionary principle.

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."*[449]

The Petroleum Environment Regulations attempt to operationalise the principles of ESD, including the precautionary principle, in the following way:

- an environment plan must demonstrate that all environmental risks are reduced to levels that are *"acceptable"*;[450]
- the Minister decides what the level of *"acceptable"* risk is, and he or she must make that decision by taking the principles of ESD, as enshrined in the Regulations, into account;[451] and
- if the Minister is satisfied that the environmental plan will reduce impacts to "acceptable" levels or levels that are ALARP (whichever is lower) then the plan must be approved.[452]

The EDO and other stakeholders submitted that the current framework does not effectively operationalise the precautionary principle because:[453]

> *"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 [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."*

The EDO recommended that the Minister be required to apply the principles of ESD, rather than *"merely take them into account"*.[454] The Panel will consider this recommendation in its future work.

14.4.2 Identifying and implementing 'no go zones'

The Inquiry's Terms of Reference require the Panel to identify priority areas for 'no go zones'. A 'no go zone' is an area over which exploration or production for unconventional gas cannot occur at any time. In other words, it is an area over which a petroleum exploration permit cannot be granted.

Many stakeholders saw the implementation of 'no go zones' as an effective way to operationalise the precautionary principle.[455] That is, where there is uncertainty or insufficient data available on the environmental impact of petroleum activities in a certain area, the activities should not be permitted in that area.

National parks and reserves are currently not 'no go zones', which means these parks and reserves can be the subject of an application for an exploration permit unless it is also a 'reserved block'.[456] The EDO noted that petroleum exploration has occurred within at least one Territory Park, namely, Limmen National Park.[457]

The Panel heard that the following areas should be 'no go zones', including, in some cases, areas with clearly identified buffer zones:

- agricultural land;
- all significant groundwater and surface water resources, including flood zones and groundwater recharging zones;
- sacred sites;
- cultural landscape and tourism icons;
- towns and residential areas;
- national parks and reserves;
- other ecologically important areas or areas of high conservation value; and
- areas where there are significant data gaps in relation to the Northern Territory's geology, groundwater and fauna.[458]

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

448 Petroleum Environment Regulations, cl 2(a).

449 Petroleum Environment Regulations, cl 4.

450 Petroleum Environment Regulations, cl 9(1)(c).

451 Petroleum Environment Regulations, cl 9(2).

452 Petroleum Environment Regulations, cl 11.

453 EDO submission, p 12; S Bury submission, p 2; M Haswell submission, p 14.

454 EDO submission, p 14.

455 EDO submission, p 21.

456 See s 15 of the Petroleum Act, which provides the matters the Minister must consider before granting an interest on a park or reserve.

457 EDO submission, p 20.

458 EDO submission, pp 6, 20, Attachment D; Lock the Gate submission, p 73; S Bury submission, p 4; ECNT submission, p 3.

There are two types of zones that the Panel will consider in its future work:

- **'no go zones':** which are areas over which exploration or production for unconventional gas cannot occur at any time, that is, an area over which a petroleum exploration permit cannot be granted (see, for example, the recent decision concerning Watarrka National Park) ; and
- **'restricted activity zones':** which are areas where certain activities are restricted even though a petroleum exploration permit has been granted.

There appear to be three ways to create 'no go zones' under the current regulatory framework. These are discussed immediately below.

14.4.2.1 Exploration veto on Aboriginal land

The exercise of the exploration veto under the Land Rights Act, described below in this Chapter, is one way to operationalise a 'no go zone'. Traditional Aboriginal owners can veto the grant of all, or part, of a petroleum exploration permit application on Aboriginal land for any reason. The areas that are vetoed do not become subject to a petroleum exploration permit for at least a five year period, which means they become 'no go zones'. Granted Exploration Permit 154 shows the areas that have been vetoed by traditional owners. Those areas are not granted as part of the permit area.

After five years the original applicant can reapply to have the permit granted and traditional Aboriginal owners are able to either veto the area again or agree to the grant of the permit.[459] As examined below, the Land Rights Act gives traditional Aboriginal owners significant power to control petroleum exploration activity on Aboriginal land.

Native title holders under the NTA and pastoralists do not have the right to veto a petroleum exploration permit, so 'no go zones' are not carved out of the granted permit area on those forms of tenure.

14.4.2.2 Land release process

Before a petroleum exploration permit application goes through the Land Rights Act and NTA processes (described below), the Government must determine whether or not land should:

- be released for exploration at all (land release process); and
- if so, which gas company is best placed to do the work.

'No go zones' can be created through the land release process.

The Government introduced the new land release process for petroleum exploration on 1 January 2014. Prior to this process, applications for a petroleum exploration permit were awarded on a 'first in first served' basis. However, this process, combined with a growing interest in the Northern Territory's unconventional gas reservoirs, resulted in *"permit applications being submitted over 85% of the Northern Territory. In some cases applications were lodged over areas with high conservation values or [areas with] little to no prospectivity for oil or gas."*[460]

The new land release process that was introduced in 2014 allows the government to strategically release land for petroleum exploration.[461] The government only releases land in accordance with the land release policy which is set out in a fact sheet entitled *Where Oil and Gas Activities Can Occur*.[462] The fact sheet provides that *"future land release for oil and gas activities will not be approved in residential areas, rural residential areas or areas of other land use or classification where oil and gas activities do not meet government land use objectives."*[463]

Land that is not released becomes a 'no go zone' because it will not be subject to an application for a petroleum exploration permit. It remains a 'no go zone' until the Government decides to release it.

Unfortunately, by the time the new land access regime was introduced, much of the Northern Territory was already covered by petroleum applications pursuant to the prior 'first in first served' regime, as **Figure 14.3** demonstrates:

Some of the applications cover areas that appear to be of the kind that are clearly intended to be 'no go zones' according to DPIR, including areas of high ecological and cultural value. As the Central Land Council noted, DPIR's reforms *"came too late for the initial rush"*.[464]

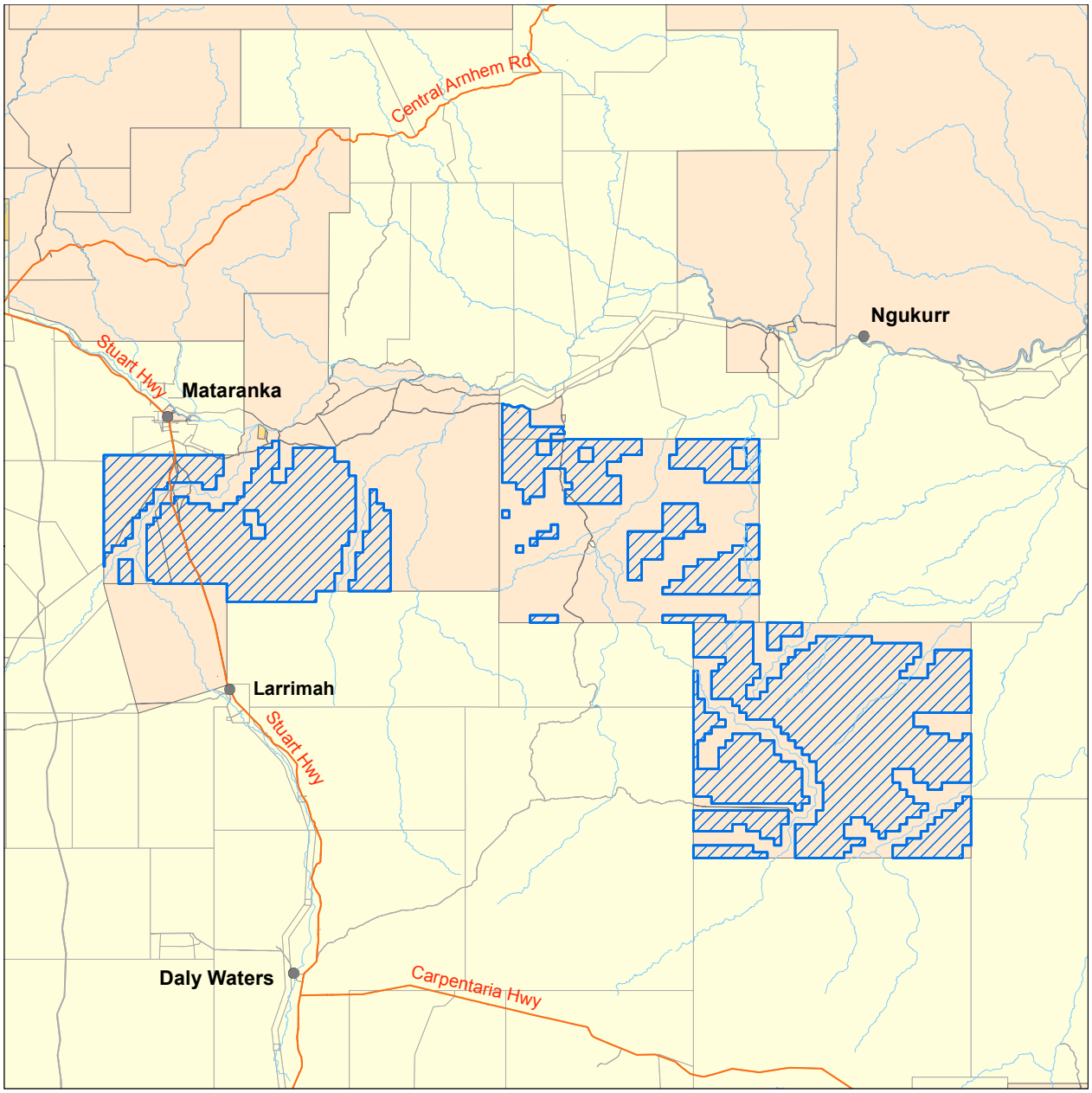
The applications that were made prior to the 2014 reforms are, according to DPIR, at various stages of the negotiation process set out under the Land Rights Act or NTA. DPIR's view on these applications is, however, that *"natural justice must be provided so as to allow the negotiation process to be completed and to avoid risk of litigation and loss of opportunity for Traditional Owners (TOs) to reach an agreement with an applicant."* [465]

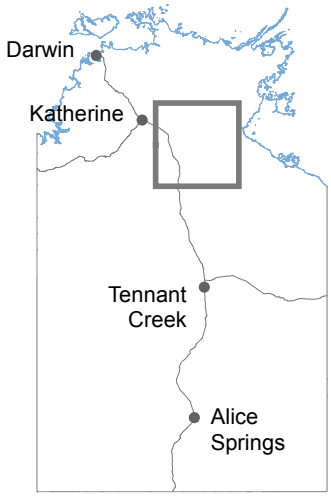
Notwithstanding this statement, DPIR has submitted that the land release policy will also apply to the assessment of applications that are currently on foot.[466] DPIR submitted that it will *"not approve existing applications, nor release for competitive bidding any areas assessed as exhibiting one or more of the* [criteria set out in the guidelines]."[467]

The Panel is concerned that there are granted permits and applications over areas that are clearly intended to be, or should in fact be, 'no go zones'. The Panel is also concerned that uncertainty exists over the areas that are intended to be 'no go zones'. The terms *"residential area", "areas of intensive agriculture"* and *"areas of high ecological value"*, are not clearly defined and are not depicted on a map so the community is uncertain about areas that will, and will not, be released for exploration. Further, the Panel is concerned that the policy has no legislative force. The Minister is not statutorily required to consider the assessment criteria as part of either the land release process or the grant process.[468]

459 Land Rights Act, s 48.
460 DPIR submission, p 13.
461 DPIR submission, p 13.
462 A copy of the policy is provided at DPIR submission, p 335.
463 DPIR submission, p 336.
464 CLC submission, p 7 of Attachment.
465 DPIR submission, p 13.
466 DPIR submission, p 337.
467 DPIR submission, p 14.
468 Petroleum Act, s 20.

Figure 14.2 Granted Exploration Permit No. 154 showing areas that have been vetoed by traditional Aboriginal owners under the Land Rights Act





Map Location

km 0 20 40 km

© Northern Territory of Australia

Legend

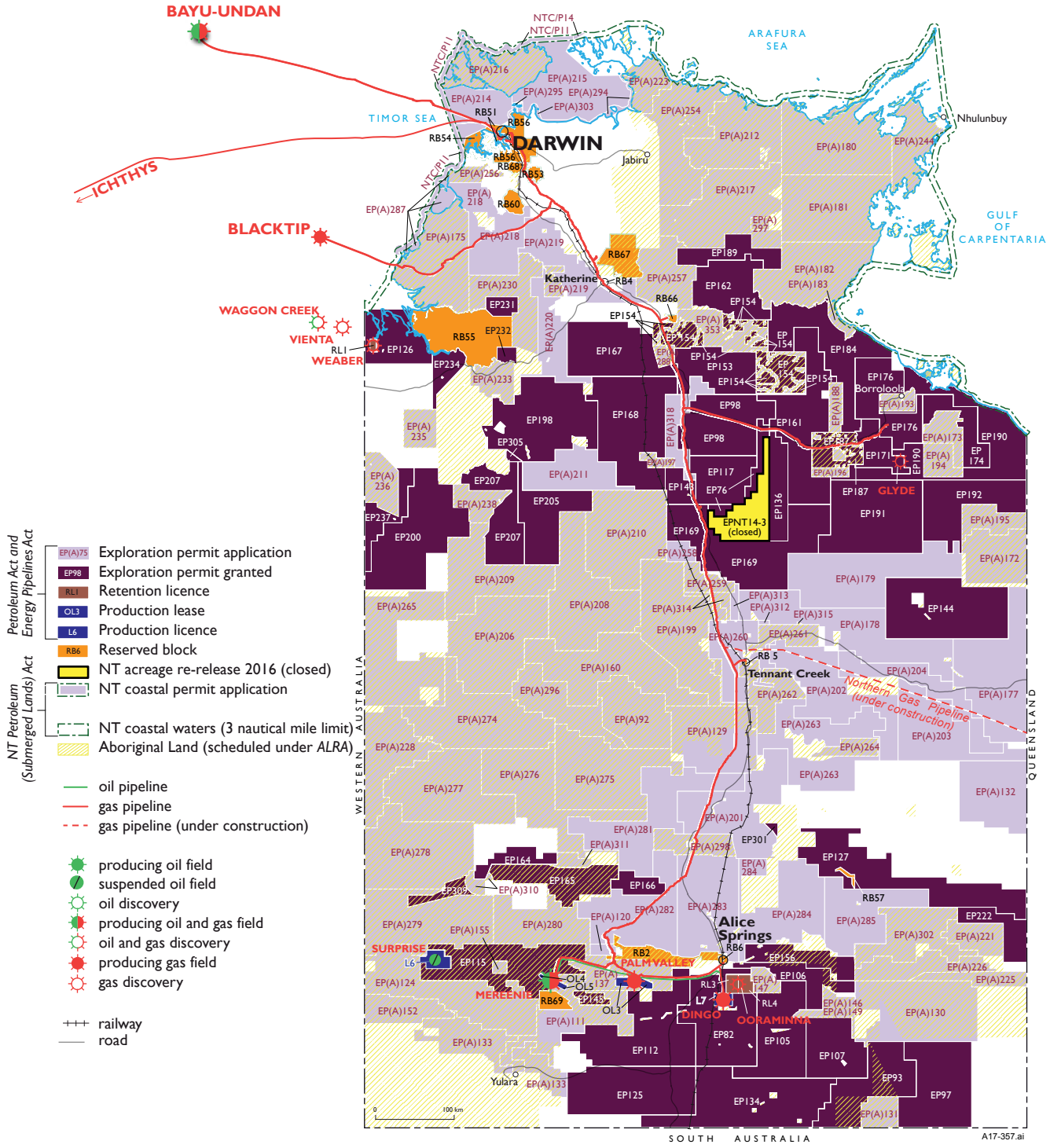
- Major Rivers
- Major Roads
- Granted Exploration Permit 154
- Cadastre

Aboriginal Land

- Scheduled under ALRA
- NT enhanced Freehold

NORTHERN TERRITORY GOVERNMENT

Figure 14.3: Onshore petroleum titles and developments. Source: Northern Territory Government.



NORTHERN TERRITORY GOVERNMENT

14.4.2.3 Reserved blocks

The Petroleum Act allows the Minister to declare that a specific area will not be the subject of a petroleum exploration permit.[469] These areas are called *"reserved blocks"* and are clearly depicted on a map provided by DPIR (**Figure 14.4**). Reserved blocks have been declared over Nitmiluk National Park and Watarrka National Park.[470] Reserved blocks are the clearest and most certain way in which to operationalise 'no go zones' under the current regulatory framework.

The Panel will give further consideration to areas that should be 'no go zones' and 'restricted activity zones', including the most effective and efficient way to implement the zones in the regulatory framework.

14.4.3 Rehabilitation bonds

As noted by Origin, rehabilitation bonds are *"designed to provide the Northern Territory Government with a mechanism to undertake rehabilitation where [an interest] holder has failed to fulfil their rehabilitation obligations."*[471]

Many submissions expressed concern about the long term integrity of wells and where liability for rehabilitation would lie in the event of environmental damage.[472] The Northern Land Council noted that the regulatory framework 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."*[473]

The Petroleum Act requires the interest holder to lodge a security *"for the amount and from the person the Minister thinks fit… to secure the applicant's compliance with* [the] *Act"*.[474]

DPIR's submission states that the amount of the security required for "compliance with the Act" under s 79 is $10,000.[475]

DPIR submitted that it also requires an *"Environmental Rehabilitation Security"* as a *"mandatory step in the project approval"* process.[476] The amount of the Environmental Rehabilitation Security is calculated by the interest holder using an assessment template on DPIR's website. DPIR determines whether or not the amount is acceptable.[477] The requirement for an Environmental Rehabilitation Security to be in place and the criteria used to assess its acceptability does not appear to be statutory.

Industry noted some issues with the calculation of the security. For example:

> *"For petroleum activities the [assessment] template is blank with no defined units or costs of measure (as opposed to mining where the rates are defined) which has the potential to lead to inconsistent development of rates between industry and the government. Other jurisdictions within Australia have developed industry specific calculators for environmental rehabilitation with Queensland being one example."*[478]

DPIR describes how the Environmental Rehabilitation Security is returned to the interest holder/operator:

"At the conclusion of a project, the operator must demonstrate that rehabilitation of the site has been carried out in accordance with its Environmental Rehabilitation Strategy in order to become eligible to receive the Environmental Rehabilitation Security Bond."[479]

Some submissions noted the need for a more transparent process in the assessment and determination of environmental rehabilitation bonds.[480] There does not appear to be a statutory requirement for the amount of the Environmental Rehabilitation Security to be made publicly available. DPIR does not currently publicly disclose the amount.

469 Petroleum Act, s 9.

470 DPIR submission, p 14.

471 Origin submission, p 164.

472 ECNT submission, p 2; NLC submission; Regional Development Australia; submission 110 (**RDA submission**), p 2; Lock the Gate submission, p 73; S Bury submission, p 5; Ms Pauline Cass, submission 192 (**P Cass submission**), p 27; R Dunbar submission, pp 3-4; CDRC submission, p 1.

473 NLC submission, p 41.

474 Petroleum Act, s 79.

475 DPIR submission, p 24.

476 DPIR submission, p 34.

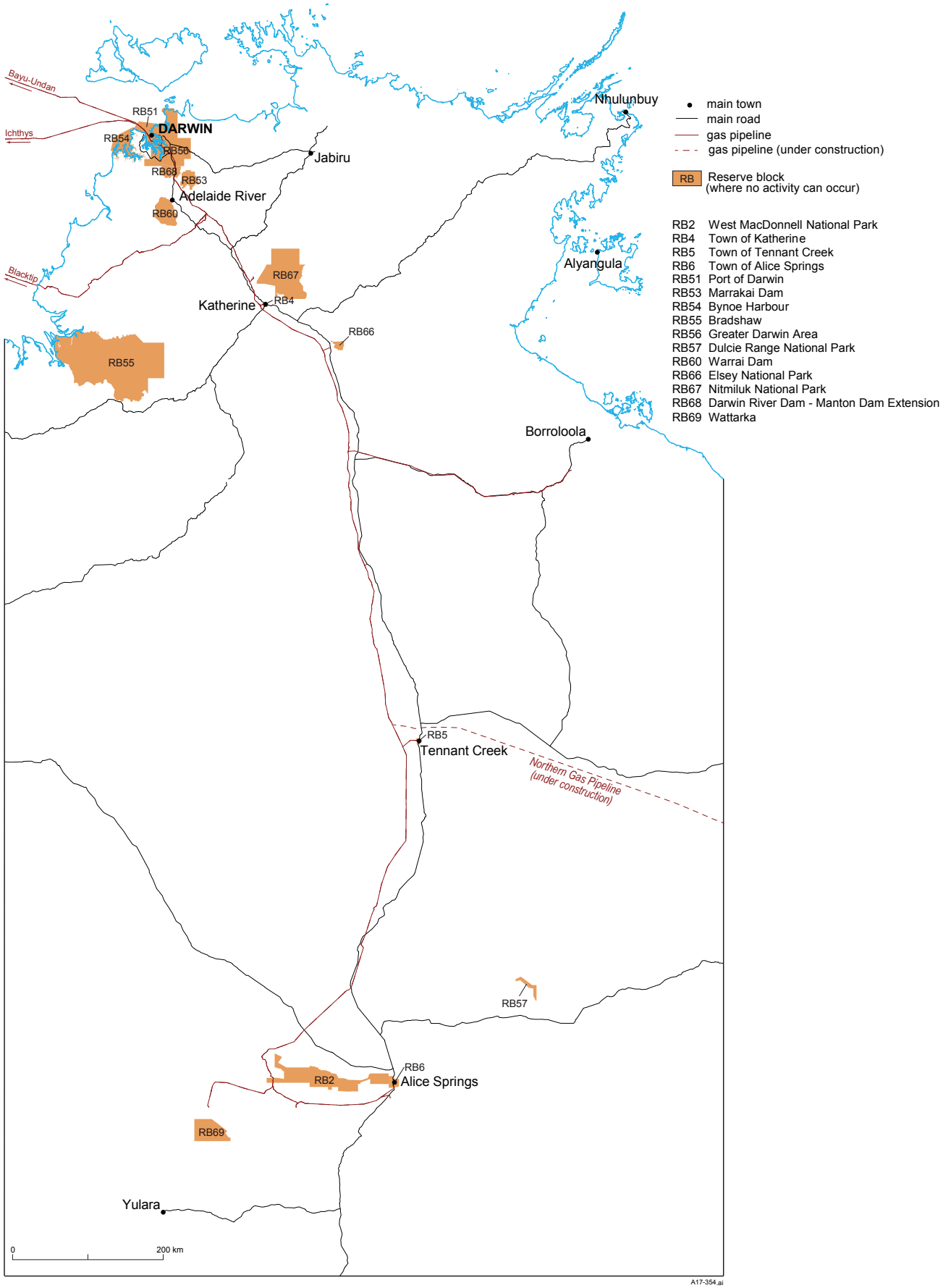
477 DPIR submission, p 29.

478 Origin submission, p 164.

479 DPIR submission, p 34.

480 NLC submission, pp 39-40; NTCA submission, p 9.

Figure 14.4: Petroleum reserved blocks. Source: Northern Territory Government.



14.4.4 Minimum standards

The Northern Territory has commenced the process of moving away from prescriptive based regulation towards 'risk-based' and 'outcome-focussed' governance.[481] While this is generally regarded as a more effective and efficient method of regulation because it encourages innovation, flexibility and best practice, various submissions questioned whether or not it was preferable that certain risks be managed through prescription to ensure that minimum environmental standards are attained.[482] The EDO submitted that prescriptive regulation was better because it:

- created certainty and a clear standard of behaviour that must be met;
- was easier to apply consistently; and
- was easier to enforce.[483]

And that *"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."*[484]

Various submissions raised the following issues as matters that should be prescriptively regulated:

- baseline testing and monitoring must be statutorily required in advance of the proposed activity by an independent entity;[485]
- petroleum wells must be designed and constructed in a very specific way to ensure long term well integrity;[486]
- methane emissions must not exceed a certain figure;[487]
- BTEX must be prohibited;[488] and
- statutory disclosure of all chemicals used in hydraulic fracturing.[489]

These prescriptive requirements would be minimum requirements that would operate alongside the requirement to take all measures to reduce risks to levels that are ALARP and acceptable.

Industry appeared generally supportive of implementing some prescriptive and minimum standards within any regulatory framework. 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."*[490]

14.4.5 Regulator

The effectiveness of the regulatory framework is meaningless without a wholly independent, competent and well resourced regulator to enforce compliance with the regime.[491]

The Panel noted the community's lack of confidence in the current regulator for the reasons outlined below.[492]

14.4.5.1 Independence

The need for an independent regulator was raised in many submissions.[493] The Panel noted the widely held view in the community that the DPIR is not independent from the industry. Some submissions noted that there was evidence of regulatory capture, which is where the regulator becomes inappropriately aligned with the industry that it regulates and is therefore reluctant to regulate it.[494] The Central Land Council recommended that there be *"external independent scrutiny over DME regulation"*[495], which is *"essential to allay concern over a perceived lack of independence"*. Various submissions also raised Dr Tina Hunter's recommendation that wells should be inspected by an independent certified third party inspector.[496]

14.4.5.2 Resourcing

Various stakeholders had the impression that DPIR was *"under resourced and under staffed"*, which jeopardised the ability of the agency to perform its statutory duties.[497] The EDO expressed *"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."*[498]

The Panel will give further consideration to the resourcing requirements of the regulator, including ways to increase its effectiveness and efficiency.[499]

14.4.5.3 Remoteness

As some submissions noted, there are difficulties associated with regulating an industry that occurs in remote areas. Dr Liz Moore observed that, *"the extreme remoteness of many*

481 DPIR submission, p 38.

482 EDO submission, p 16.

483 EDO submission, p 16.

484 EDO submission, p 16.

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

486 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, p 42).

487 Lock the Gate submission, p 73.

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

489 EDO submission, p 28; M Haswell submission, p 14; Frack Free Darwin, submission 141 (**Frack Free Darwin submission**), p 11; Ms Juliet Saltmarsh, submission 165 (**J Saltmarsh submission**), p 2; Lock the Gate submission, p 71; H Bender submission, p 59.

490 Santos submission, p 104.

491 Ms Jean McDonald, submission 182 (**J McDonald submission**), p 6; M Haswell submission, p 18; H Bender submission.

492 Mr Phil Cross, submission 27 (**P Cross submission**); EDO submission, p 36; J McDonald submission; CDRC submission, p 2; The Planning Action Network, submission 51 (**PAN submission**), p 4.

493 For example, NTCA submission 32, p 9; RDA submission, p 1; CLC submission, p 1 of Appendix B of Attachment; J Saltmarsh submission, p 2.

494 S Bury submission 189, p 4; Northern Australian Rural Management Consultants Pty Ltd, submission 186 (**NARMCO submission**), p 10.

495 CLC submission, p 1 of Appendix B of Attachment.

496 J Tutty submission, p 2; the Panel also notes cl 103 of the Petroleum Schedule, which requires "validation and or verification by an independent validator" of the "construction, alteration or reconstruction of drilling and production equipment, wells, safety systems and emergency facilities" if requested by the Minister.

497 Lock the Gate submission, p 69; Climate Action Darwin, submission 175 (**Climate Action Darwin submission**), p 14; NARMCO submission, p 9.

498 EDO submission, p 36; see also NLC submission, p 39; P Cross submission.

499 Consideration will be given to the South Australia model whereby operators are classified as either low or high risk, based on past behaviour. This has the dual effect of allowing compliance teams to triage their operations and also rewards companies that continually do the right thing. See EDO submission, p 36.

sites and the dispersed nature of unconventional fracking". And that, *"therefore, even if a strict regulatory framework was imposed, there is a real risk that it would not be adhered to at all times"*.[500]

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 curing the wet season and, even during the dry the vast scale of the Territory make it impossible to keep close checks on operators"*.[501]

The Northern Australian Rural Management Consultants Pty Ltd (**NARMCO**) suggested basing a compliance team in Katherine to *"ensure the regulators will be closer to the industry activity thus improving their capacity to be well informed, be more up to date and be able to respond quicker to any issues. A Katherine based team will be able to create wide spread local networks to gain formal and informal information, particularly with workers and contractors in the industry who can report any concerns, including informally. Typically, Darwin based regulators do not get the opportunity to socialise across the Katherine region and are not well networked."*[502]

14.4.5.4 Legacy issues

Many submissions pointed to various examples of purported failures by DPIR to regulate the resources industry,[503] including:

- overflows at tailing ponds at Ranger uranium mine;[504]
- legacy mines, such as Mt Todd Gold Mine,[505] Rum Jungle and McArthur River Mine; and
- the uncontrolled release of petroleum from the Montara wellhead.

Various submissions quoted the criticisms made about the regulator and the regulatory framework in the Report of the *Montara Commission of Inquiry* undertaken by Commissioner David Borthwick AO PSM (**Montara Inquiry**).[506] DPIR noted that it has made a series of administrative and structural reforms following the Montara Inquiry, including the recruitment of petroleum engineers to address the gap in technical expertise, improvement of assessment and approval process and implementation of a well operation activity approval co-assessment system with the WA Designated Authority.[507] There has also been a complete review and overhaul of DPIR's internal assessment and compliance monitoring procedures.

14.4.6 Access to justice

To improve decision-making and to maintain accountability and integrity in any developed onshore unconventional 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, granting an exploration permit, drilling for or extracting shale gas).

Other mechanisms must also exist that enhance access to justice by those persons or entities who are aggrieved by decisions made by the Government.

14.4.6.1 Types of review

There are generally two types of processes that allow a person affected by a decision to challenge it:

1. **judicial review:** which allows a person or entity to challenge the lawfulness of the process used to make the decision. This type of proceeding is commenced in a court. The usual remedy is that the decision is set aside and remitted to the decision-maker to be remade. Generally no new evidence may be called; and
2. **merits review:** which 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 in effect becomes the decision-maker (for example, the Northern Territory Civil and Administrative Tribunal (**NTCAT**)). Fresh evidence may be relied upon and the factual basis for the decision may be fully examined.

In any mature and robust regulatory system, both forms of review will co-exist.

14.4.6.2 Standing

A person must have legal standing to bring a challenge. The broader the standing provisions, the more accessible review processes are. Many environmental enactments have third party standing, which means that a much larger class of people can bring an action challenging a decision.

There are different views as to who should have the right to seek judicial or merits review and the types of review that should exist.

A question arises as to whether there should be open standing to bring challenges to a decision. Open standing permits anyone to bring such an action irrespective of whether or not he or she is affected by the decision.[508] Costs sanctions against the losing party usually prevent vexatious claims being brought in jurisdictions that have open standing and there is no evidence to suggest that more cases are brought in legal systems that entertain open standing that those that have more restrictive standing provisions.

In the absence of open standing, at a minimum the following third parties should have rights of review:

- proponents – those who are seeking a permit, approval, application, licence or permission to engage in onshore shale gas activity;
- a person who is directly or indirectly affected by the decision;
- members of an organised environmental, community or industry group;
- Aboriginal land councils;
- local government bodies; and
- a person who has made a genuine and valid objection submission during any assessment or approval process.

500 Dr Liz Moore, submission 179 (**L Moore submission**), p 2; see also J McDonald submission, p 6.

501 EDO submission, p 36.

502 NARMCO submission, p 10.

503 C Roth submission, p 16; Climate Action Darwin submission, p 13; J McDonald submission, p 4.

504 J McDonald submission, p 6.

505 PAN submission, p 4; J McDonald submission, p 5; Climate Action Darwin submission, p 14.

506 The Report made some damning statements about the Northern Territory regulatory framework, including that: (a) the Northern Territory did not take adequate steps to ensure that the company complied with good oilfield practice; (b) the regulatory regime was inadequate and little more than a 'tick and flick' exercise; (c) there was evidence of regulatory bias or regulatory capture; and (d) the resources and expertise in the department were inadequate. See also, Lock the Gate submission, pp 70-71; Climate Action Darwin submission, p 14.

507 DPIR submission, p 42.

508 See, for example, the *Environmental Planning and Assessment Act* 1979 (NSW).

The EDO has strongly argued for the inclusion of third party merits review rights in any legislation that has as one of its objectives the protection of the environment.[509] It has contended that such rights would be a powerful vehicle by which the precautionary principle could be operationalised.[510]

14.4.6.3 Onus of proof

A person seeking to challenge a decision, or prosecute or enforce non-compliance with a law, generally bears the onus of proof of demonstrating that the decision is somehow defective, or that the law has not been complied with. The cost and complexity of doing so can often present as a real barrier to justice.

Accordingly, it is possible to either reverse the onus of proof or, if appropriate, to impose strict liability. An example of the former is to shift the burden of proving that there is a threat of serious or irreversible environmental damage, a precondition necessary to engage the precautionary principle, from the person seeking to challenge the decision to the decision-maker to prove that there is no such threat. An example of the latter is a provision that makes a gas operator automatically liable for any pollution that occurs as a consequence of its activities.

Given the confidence expressed by the gas industry in relation to its ability to manage any environmental risks occasioned by an onshore unconventional shale gas industry,[511] the EDO submitted that any reversal of the onus or proof or imposition of strict liability for environmental harm, should arguably be supported by that industry.[512]

14.4.6.4 Costs

Usually 'costs follow the event', which means the losing party must pay the winning party's legal costs. The threat of an adverse costs order is a significant barrier to justice.

In some jurisdictions (see, for example, NSW), 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.

Other measures include 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, or the creation of 'no costs' jurisdictions within which to litigate.

The Panel will consider in detail the appropriateness and efficacy of these, and other, costs mechanisms, in its future work.

14.4.7 Assessing cumulative risks

Various stakeholders submitted that the regulatory framework does not adequately assess or manage the cumulative risks and impacts associated with the development of any onshore unconventional shale gas industry.[513]

Under the current regulatory framework, every activity that has an environmental impact, such as hydraulic fracturing, must have an approved environment plan in place before the activity commences.[514] An environment plan must include *"as far as practicable – any cumulative effects of [the] impacts and risks when considered both together and in conjunction with other events that may occur in or near the location of the activity"*.[515]

If the Minister is not satisfied that the environment plan will reduce all environmental risks, including cumulative risks, to levels that are ALARP and acceptable, he or she must not approve the plan.[516]

The EDO submitted that the current regulatory requirement is too narrow because *"confining the requirement for consideration of cumulative impacts to other "events" that may occur "in or near the location of the activity" unnecessarily narrows the scope of the requirement on proponents to consider and outline the potential cumulative impacts of their activity and, consequently, reduces the information that must be considered by the Minister in relation to cumulative impacts."*[517]

The EDO recommended that the regulatory framework include a specific requirement to consider cumulative impacts at a 'landscape scale' with a particular focus on the cumulative impacts of water use, habitat fragmentation and gaseous emissions.[518] Both the Central and Northern Land Council's submissions supported the use of bioregional assessments.[519]

The Northern Land Council submitted that robust regulation *"is best informed through bioregional assessments of prospective gas production areas that consider cumulative impacts, not only across multiple well placements, those of other, nearby industrial, pastoral and agricultural developments. Such an assessment should be spatial and temporal in nature, incorporate bioregions and should be included as part of a wider Strategic Environmental Assessment for the Northern Territory."*[520]

The EDO's submission also raised the possibility of implementing 'play based regulation' to allow for the effective management of cumulative impacts across an entire petroleum play. Play based regulation has been trialled in Alberta, and consists of *"a single, integrated application that allows energy companies to submit one application for all activities under an energy development project, instead of submitting separate applications for each activity"*.[521]

509 EDO submission, p 15.
510 EDO submission, p 15.
511 APPEA submission.
512 EDO submission, p 24.
513 NLC submission, p 41; see also CLC submission, p 8; EDO submission pp 6, 39.
514 Petroleum Environment Regulations, cl 30.
515 Petroleum Environment Regulations, cl (2)(b), Sch 1.
516 Petroleum Environment Regulations, cl 11(2)(b).
517 EDO submission, p 39.
518 EDO submission, pp 39- 40.
519 CLC submission, p 8 of Attachment.
520 NLC submission, pp 40-41; see also CLC submission.
521 EDO submission, pp 41-42 referring to the Alberta Energy Regional Pilot Project, available at https://www.aer.ca/about-aer/spotlight-on/pbr-pilot-project.

14.4.8 Other considerations

Other legislation may be relevant in this context. For example (this list is not exhaustive):

- the Northern Territory's environmental assessment legislation, which is administered by the EPA, will apply if a proposed activity is deemed to have a significant environmental impact, however, the EPA is currently of the view that the environmental impacts associated with hydraulic fracturing do not rise to this level;
- the Commonwealth's environmental assessment legislation, the EPBC Act, will apply if a proposed activity will have a significant impact on a matter of national environmental significance; and
- the Water Act and the Waste Management Act do not apply to petroleum activities. Those statutes exempt mining and petroleum activities, including hydraulic fracturing, from the need to obtain an approval under those Acts. An approval to conduct hydraulic fracturing is still, however, required under the petroleum regulatory framework in accordance with the discussion above. In November 2015 the former CLP government committed to removing the exemption from the Water Act but to date this has not occurred.

Amendment to some or all of this legislation may be appropriate to strengthen the regulatory regime applicable to any onshore unconventional shale gas industry if the Government were to lift the moratorium.

In addition, the Panel should also consider the following matters:

- the current Northern Territory statutory regime does not made adequate provision for the potential for legacy or orphaned wells, which may later have an impact on the environment and human health. The imposition of an appropriate legacy levy on any onshore unconventional shale gas industry to fund the future monitoring and maintenance of abandoned wells will be considered by the Panel;[522]
- the need for greater transparency and clarity around the calculation of the rehabilitation bond under the Petroleum Act;
- the costs and benefits of expanding the coal seam gas water trigger in the EPBC Act to cover unconventional shale gas development, which is presently excluded;[523]
- the need to ensure that all regulatory processes are clearly enshrined in legislation. For example, the Central Land Council referred to the informal arrangement between DPIR and the EPA with regard to environment plans and noted that *"the environmental assessment and monitoring of petroleum activities is not a transparent process although there appears to be accepted interdepartmental administrative procedures in relation to the Environmental Assessment Act and the Water Act. There are benefits around incorporating these protections into legislation for purposes of clarity, consistency and transparency"*;[524]
- the need to ensure that all agencies involved in the regulation of the onshore shale gas industry (including the legislation they administer) work cooperatively and collaboratively to ensure that duplication is avoided and regulatory lacunae are closed;
- the need to ensure that the regulatory framework is not overly complex. NARMCO submitted that, *"over-regulation often creates entry barriers and unaffordable cost impost on small business and limits their capacity to be engaged in the industry"*;[525]
- the introduction of a 'fit and proper person' test to ensure that at all times the holder of a permit is financially viable and has no record of non-compliance with any environmental or company laws.[526] The Central Land Council also submitted that proponents should be screened and approved as suitable and capable to commence exploration by the regulator;[527]
- increasing the role of the Federal Government, whereby the Federal Government will *"monitor the capacity of [DPIR] and provide additional support to maintain a high level of regulation"*;[528]
- mechanisms to ensure that liability for environmental damage statutorily rests with industry, including the implementation of a rebuttable presumption that the gas company is responsible for any environmental harm;[529]
- application of the provisions of the Water Act to petroleum activities, which is widely supported;[530] and
- introduction of a cost recovery mechanism (fee for services) or levy on operators to ensure adequate resourcing of an independent regulator.

14.5 Land access

Development of the unconventional gas industry in Australia has, in many instances, caused tension between those with rights and interests in the surface land, such as pastoralists and traditional owners, and those with rights to enter, explore for and extract gas from underneath the same land, that is, gas companies.

The following types of land in the Northern Territory are relevant to the issue of land access for the purposes of carrying out petroleum activities, including exploration for and extraction of shale gas:

- Aboriginal land under the Land Rights Act;
- land where native title rights and interests have not been extinguished; 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 at **Figure 14.5**. Some forms of land tenure 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 Northern Territory.

522 NLC submission, p 42.

523 NLC submission.

524 CLC submission, p 8 of Attachment.

525 NARMCO submission, p 10.

526 Lock the Gate submission, p 74.

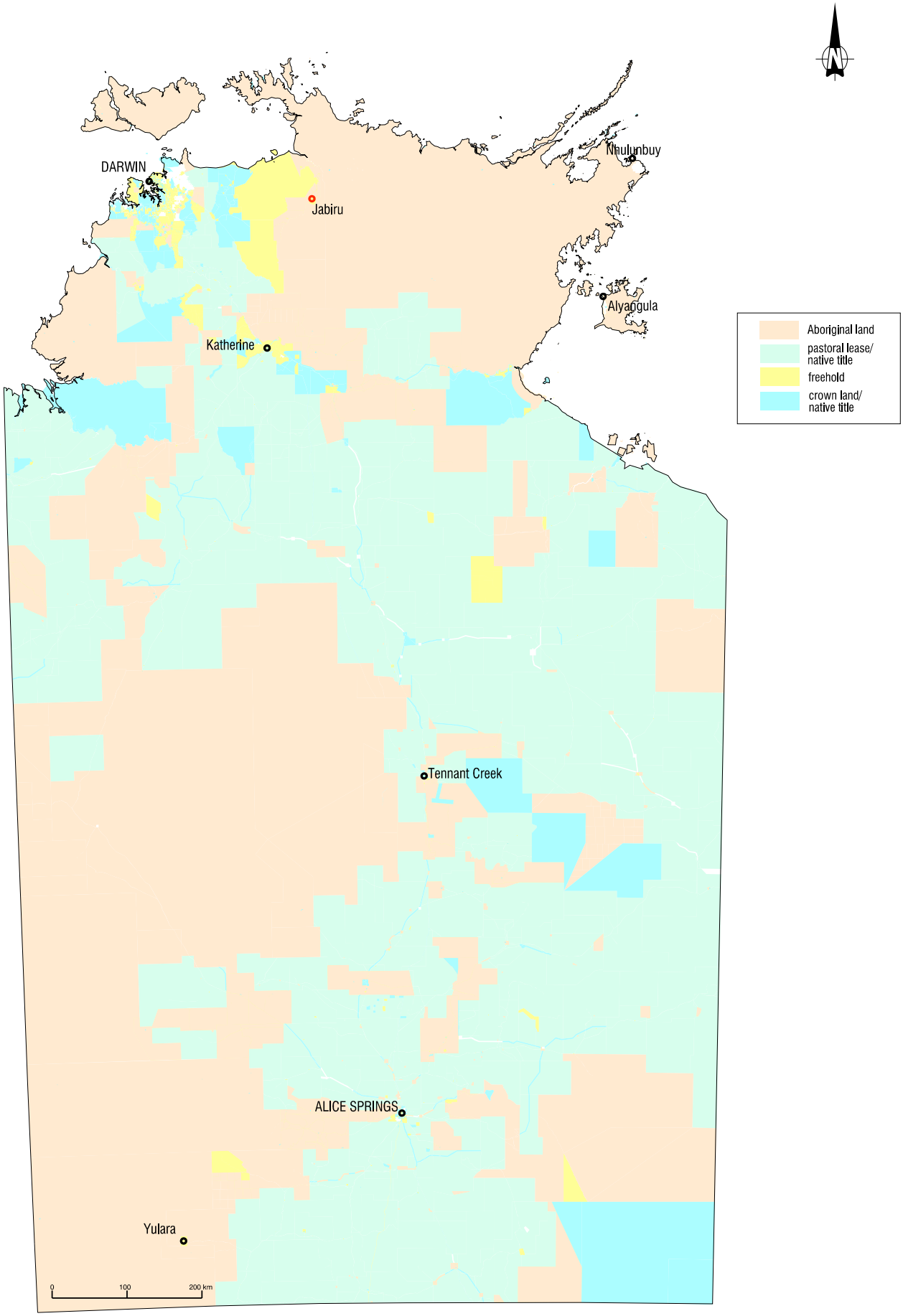
527 CLC submission.

528 CLC submission, p 1 of Appendix B of Attachment; see also NLC submission, p 39, which recommended *"a harmonised "dual systems approach" where control is devolved to individual States (or Territories), but the Commonwealth retains a degree of coordination and oversight, to create a minimum level of standards and consistency across Australia."*

529 EDO submission, pp 36-37; J McDonald submission; Lock the Gate submission, p 78; ECNT submission; C Roth submission; M Haswell submission, p 15; H Bender submission; S Bury submission.

530 S Bury submission, p 2; CLC submission, p 7; EDO submission, p 22; Origin submission, p 163.

Figure 14.5: Land tenure in the Northern Territory. Source: Northern Territory Government.



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The table below shows the key features of the main types of land tenure in the Northern Territory, including the presence, or not, of the interest holder's right to veto access by petroleum companies to the relevant land.

Table 14.1: Land tenure in the Northern Territory.

	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 *Pastoral Land Act 1992* (NT)	Native Title rights and interests are defined in s 224 of the *Native Title Act 1993* (NT).	Inalienable statutory freehold established under the Land Rights Act.	*Law of Property Act 2000* (NT)	*Crown Lands Act 1931* (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?	*Petroleum Act 1984 (NT); Petroleum (Environment) Regulations 2016* (NT); Land Access Guidelines	*Native Title Act 1993 (NT); Petroleum Act 1984* (NT); *Petroleum (Environment) Regulations 2016* (NT)	*Aboriginal Land Rights Act (Northern Territory) 1976* (Cth)	*Petroleum Act 1984* (NT); *Petroleum (Environment) Regulations 2016* (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

14.5.1 Aboriginal land

Aboriginal land is a communally held and inalienable form of title established under the Land Rights Act. Given that approximately half of the Northern Territory land mass and approximately 70% of the coastline is Aboriginal land, the processes whereby gas companies access Aboriginal land is an important consideration for the Inquiry. The Land Rights Act is Commonwealth legislation that only applies in the Northern Territory.

14.5.1.1 Accessing Aboriginal land to explore for unconventional shale gas

Part IV of the Land Rights Act contains provisions outlining consultation and consent procedures that must be complied with before the Northern Territory Government can grant a petroleum exploration permit on Aboriginal land. The statutory process is set out below:

- a gas company applies to the Northern Territory Minister for Resources and the Minister consents to the gas company entering into negotiations with the relevant Aboriginal Land Council;
- the gas company submits a *"comprehensive"* written application to the Land Council;[531]

531 Land Rights Act, s 41(6); CLC submission, p 10.

- the Land Council and the gas company negotiate an agreement as to the terms and conditions to which the grant of the exploration permit will be subject;
- the Land Council identifies, and convenes meetings with, the relevant *"traditional Aboriginal owners"* and the *"Aboriginal community"*;
- within 22 months of receiving the application the Land Council must either refuse to consent (provided the Land Council has consulted with the *"traditional Aboriginal owners") or consent (provided the Land Council has consulted with the relevant "traditional Aboriginal owners"* and ascertained their consent) to the grant of the permit. The Land Council must also consult with the *"Aboriginal community"* and give the community a chance to express their concerns to the Land Council. The consent of the *"Aboriginal community"* is not required; and
- the relevant federal Minister must also consent to the grant of the exploration licence.

14.5.1.2 Key issues raised

The Land Rights Act represents the high-water mark of how domestic law can operationalise Indigenous peoples' international law right to free, prior and informed consent (**FPIC**).[532] The principle of FPIC requires that:

- indigenous peoples are not coerced, pressured or intimidated in their choices of development;
- their consent is sought and freely given prior to the authorisation and start of development activities.
- they have full information about the proposed development activities; and
- their choice to give or withhold consent over developments affecting them is respected and upheld.[533]

Should traditional Aboriginal owners have the right to veto a project at the production phase?

Traditional Aboriginal owners can veto all, or part, of an application for a petroleum exploration permit for any reason, including to protect sacred sites or hunting grounds, or because they are uncertain about the environmental impact of a particular activity on that area.

Traditional Aboriginal owners do not, however, have the right to veto the grant of a petroleum production licence on Aboriginal land.[534] Instead of giving traditional owners a veto right at the production phase, the Land Rights Act sets out an arbitration process in the event the parties cannot reach agreement on how a production project should be developed. There can be no doubt that the absence of the right to veto at the production phase places traditional Aboriginal owners in a difficult position at the exploration phase, which is the only point at which they can exercise their veto right, because the information that is available with respect to production at the exploration phase will be very limited.[535]

The EDO submitted that giving traditional owners the right to veto the grant of a production licence on Aboriginal land was particularly important in the context of unconventional gas development because of large *"landscape scale impacts"* of the industry that cannot be foreseen at the exploration stage.[536] The Northern Land Council and the EDO proposed that, given the Land Rights Act is Commonwealth legislation, the Government should amend the Petroleum Act to give traditional owners the right to veto the grant of a production licence.[537]

What are the challenges involved in consulting under the Land Rights Act?

As described above, the Land Councils have a statutory duty to consult with and obtain the consent of traditional Aboriginal owners. In the context of a petroleum exploration permit, the consultation process can be an *"enormous and complex"* task for Land Councils.

The Central Land Council noted that applications for petroleum exploration permits can cover areas of up to 16,000 km^2. Applications of this size can cover multiple land trusts and many Aboriginal language groups, meaning that the Land Councils may need to consult and obtain the consent of up to 20 different estate groups.[538] This can be time consuming and resource intensive.

The Land Councils also explained some of the challenges associated with consulting on petroleum exploration programs: *"Presenting complex scientific information about hydraulic fracturing to lay audiences is challenging, more so when the first language is not English, and developing understanding requires a process of information exchange that takes time."* [539]

Both the Northern and Central Land Councils submitted that, notwithstanding the challenges associated with fulfilling their statutory functions under the Land Rights Act, they were experienced and were accomplished in this area and had entered into various exploration agreements where traditional Aboriginal owners had given their consent to petroleum activities occurring on Aboriginal land.[540]

The Central Land Council has adopted strategies to ensure contemporary and accurate information is provided to traditional Aboriginal owners and Aboriginal communities, including:

- the development of expertise on unconventional gas;
- site visits, panel sessions and presentations to Land Council members;[541] and
- community information sessions.[542]

Land Council processes were generally well regarded by industry, with Origin submitting that, *"the four statutory land councils in the Northern Territory are amongst the most competent, experienced and better resourced anywhere, and the Northern Territory government is highly attuned to working collaboratively with Aboriginal custodians and their representatives."*

532 CLC submission, p 2 of Attachment; Origin submission, p 135; EDO submission, p 31; D Armstrong submission, p 6.

533 UN Commission on Human Rights 2005.

534 When the Land Rights Act was introduced in 1976 there was a right to veto at both the exploration and production phases of development, however the production stage veto was removed in 1987 following successful lobbying by the Northern Territory Government and the mining industry that the production veto was failing to facilitate exploration activity on Aboriginal land.

535 See also EDO submission, pp 30-31; CLC Agreements Guide.

536 EDO submission, p 31; Lock the Gate submission, p 73.

537 EDO submission, p 31; NLC submission, p 43; S Bury submission, p 4.

538 CLC submission, p 4 of Attachment.

539 CLC submission, p 8.

540 CLC submission, p 4 of Attachment; NLC submission, p 5.

541 The Central Land Council described a panel session that includes participants from APPEA, the Northern Territory Government, the gas industry and the EDO to discuss hydraulic fracturing: see CLC submission, p 9.

542 CLC submission, p 8.

Some stakeholders criticised the way in which the Land Councils execute their statutory functions. For example, Lock the Gate submitted that the Land Councils' consultation materials do not accurately describe the impacts associated with unconventional shale gas development. The EDO recommended that the Land Councils' consultation materials be statutorily required to include, as a minimum:

- sources of water under a production licence;
- maximum amount of water required for production;
- visual aids detailing the impact of an onshore shale gas field under production; and
- discussion of cumulative impacts, habitat fragmentation, and edge impacts.[543]

Do traditional Aboriginal owners have access to independent advice?

The Panel also heard from stakeholders that were concerned about the Land Councils' independence because *"they are mostly funded by mining royalties. The NLC is bullying the* [traditional owners] *into fracking on their land."*[544]

The relationship between the Land Councils' funding and mining/petroleum royalties is a feature of the Land Rights Act. The Act sets up an account to, among other things, fund the Land Councils. The account is called the Aboriginal Benefits Account (**ABA**). The Act requires the Commonwealth to credit the ABA with amounts equal to the amount of any royalties received by the Commonwealth (as the owner of uranium in the Northern Territory) or the Government (the owner of non-uranium minerals and petroleum in the Northern Territory) for projects on Aboriginal land. Payments made by the Commonwealth into the ABA are generally known as *"Statutory Equivalents"*. An amount determined by the Federal Minister is disbursed from the ABA to the various Land Councils to cover their administration and running costs.

It was submitted to the Panel that Land Councils provide reliable and independent advice to traditional owners. The Central Land Council described its statutory responsibilities as follows:

- it identifies the traditional Aboriginal owners of relevant land;
- it acts as adviser to the traditional Aboriginal owners;
- it ascertains traditional Aboriginal owner decisions; and
- it administers any resulting negotiated contracts.[545]

The Panel heard that gas companies have no control over the consultation process:

> *"Resource companies have no control over the consultation process; they are directed as to when and where a meeting will be held. Land councils set the agenda, identify who the correct Traditional Owners are, and provide relevant information to the TO's. During the course of the meeting resource companies are invited by TO's to present their information and answer questions, and the presentation is monitored by [land council] staff."*[546]

Does township leasing impact the right of traditional Aboriginal owners to say "no" to a petroleum exploration permit?

The Land Rights Act includes a mechanism whereby an Aboriginal land trust, which owns the freehold interest in Aboriginal land, can grant a township lease to the Executive Director of Township Leasing. There are many communities across the Northern Territory with township leases in place. During consultations the Panel heard from various Aboriginal people who were concerned that township leases would impact the right of traditional Aboriginal owners to say "no" to the grant of a petroleum exploration permit on Aboriginal land. The presence, or not, of a township lease, which is done under s 19A of the Land Rights Act, will have no impact on the statutory rights set out under Part IV of the Land Rights Act, which is the part of the Land Rights Act that gives traditional Aboriginal owners the right to say "no" to the grant of petroleum exploration permits.

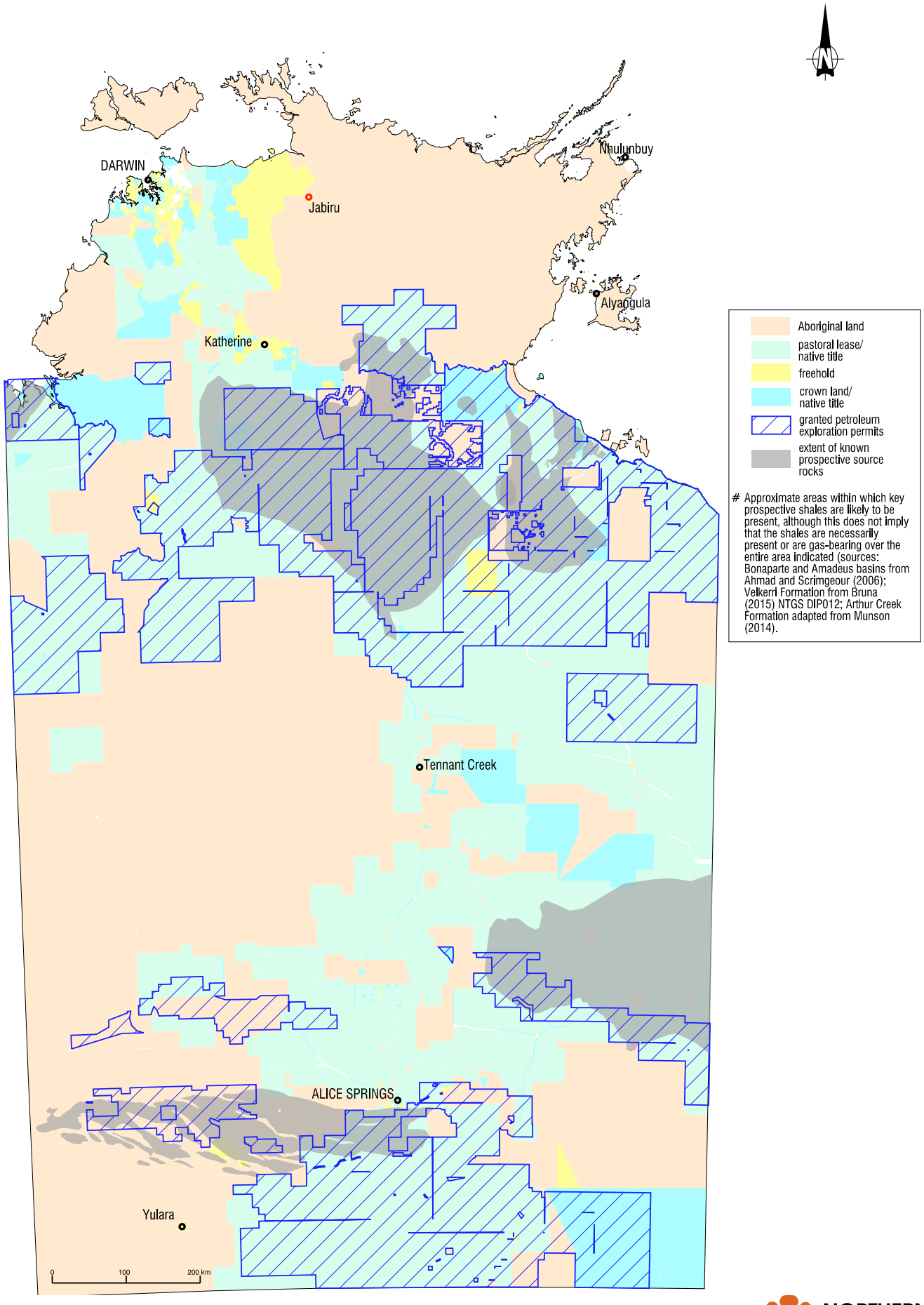
14.5.2 Native title

Figure 14.6 shows that most granted petroleum exploration permits and areas that are prospective for unconventional shale gas are on Native Title land and Pastoral Leases.

In *The Wik Peoples v The State of Queensland & Ors; The Thayorre People v The State of Queensland* (1996) 187 CLR 1; [1996] HCA 40, the High Court of Australia held that native title could coexist with Pastoral Leases. Where a petroleum exploration permit application is made over land subject to both native title and pastoral interests, both land access regimes, described below, will apply.

543 EDO submission, p 31; Lock the Gate submission, pp 64-65.
544 D Tapp submission, pp 3-4.
545 CLC submission, p6, p 4 of Attachment.
546 D Armstrong submission, p 5.

Figure 14.6: Pastoral leases and granted exploration permits. Source: Northern Territory Government



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14.5.2.1 Description of native title

The existence of native title in Australia was recognised by the High Court in *Mabo v Queensland* (No 2) (1992) 175 CLR 1; [1992] HCA 23. That case overthrew the longstanding and deeply repugnant legal fiction that Australia was *terra nullius*, or empty, at the time of colonisation in 1788. The Commonwealth responded to the *Mabo* decision by enacting the NTA in the following year.

The term *"native title"* is defined in the NTA as the communal, group, or individual rights and interests of Aboriginal peoples or Torres Strait Islanders in relation to land or waters that are possessed under traditional law and custom.[547] Native title rights and interests are sometimes described as a 'bundle "of rights', including the right to hunt, fish and gather.

14.5.2.2 Accessing Native Title land to explore for unconventional shale gas

Native title holders do not have a statutory right to veto either:

- the grant of an exploration permit by the Government; "or
- entry by the gas company on the permit once the title has been granted, although the Northern Land Council described a process set out in a private agreement (see below) whereby the Land Council must *"clear"* activities before they take place on Native Title land.[548]

The grant of a petroleum exploration permit by the Northern Territory Government under the Petroleum Act is a *"future act"* for the purposes of the NTA. That is, the grant of the permit is an act that affects native title.[549] Where a *"future act"* is proposed, the *"future act"* provisions of the NTA, described below, must be complied with for the act to be valid. The process is outlined below.

If the Government proposes to grant a petroleum exploration permit to a gas company, the government must give notice to any native title parties in the application area.[550] Once notice has been given, the Government, native title party, and the gas company have six months to *"negotiate in good faith with a view to obtaining the agreement of each of the native title parties to the doing of the act"*.[551] The NTA does not prescribe what must go into the agreement. If an agreement cannot be reached in that period any party can make an application to the National Native Title Tribunal for the matter to be arbitrated.[552]

In the Northern Territory, the parties referred to above, as well as the relevant Land Council, enter into a *"tripartite"* agreement whereby the native title party consents to the Government granting the permit to the gas company. Separate to the tripartite agreement is an *"ancillary"* agreement between the native title party, the Land Council, and the gas company with provisions about land access, sacred site protection, remuneration and other matters.[553] The *"ancillary"* agreements are confidential. The Panel has not sighted these agreements and is unaware of any contractual land access arrangements between native title holders and gas companies.

14.5.2.3 Key issues raised

Agreement-making between Aboriginal people and the gas industry is commonplace in Australia. Since the introduction of the NTA in 1993, land councils, Aboriginal people, governments and industry have developed structures and processes to accommodate the requirements of the NTA. As noted by Origin, *"agreement making with land connected Aboriginal Peoples is now common place in Australia… Through several decades of experience in the Northern Territory and Australia, agreement making processes have evolved and agreements now form a critical part of the thinking, planning, operation and closure activities of many extractive projects and operational assets."*[554]

Are Native Title holders adequately informed and consulted?

While there is no statutory right to veto the grant of an exploration permit, the Panel heard that the future act provisions of the NTA ensure that native title holders are informed and consulted about activities that are occurring on Native Title land.[555] The Northern Land Council submitted that there is a *"negligible risk that a project would be able to proceed without the knowledge of, or without prior consultation with, Aboriginal people"*.[556]

The Panel heard that native title holders are consulted at least two times in connection with a petroleum exploration permit on Native Title land:

> *"The NLC uses a two-part process during its NTA negotiations. At the first meeting the company describes its proposals to the Native Title Parties, who then instruct the NLC whether or not to negotiate an agreement with the company. If the Native Title Parties instruct the NLC that they are not willing to negotiate an agreement, the company then has the right to seek an arbitrated outcome. If the Native Title Parties instruct the NLC to negotiate an agreement, the finalised agreement is taken to a second meeting to ratify its terms and conditions."*[557]

But to the Panel's knowledge, there has been no application made to the National Native Title Tribunal for a determination regarding the grant of a petroleum exploration permit on Native Title land in the Northern Territory.

Do native title holders have access to good information?

Access to current, comprehensive and accurate information is an essential part of good faith agreement-making. As described in the section on Aboriginal land above, an applicant for a petroleum exploration permit on Aboriginal land must provide land councils with a *"comprehensive proposal"* of the exploration activities that are proposed to be undertaken if the permit is granted to assist them in negotiating an exploration agreement.[558] This requirement is not in the NTA. The Central Land Council submitted that the absence of this requirement in the NTA undermines the ability of native title holders to provide informed consent to the grant of a petroleum exploration permit, which would be consistent with principles of FPIC.

547 NTA, s 233.
548 NLC submission, p 37.
549 NTA, s 233.
550 NTA, s 29.
551 NTA, s 31.
552 NTA, s 35.
553 DPIR submission, p 23.
554 Origin submission, p 134.
555 NLC submission, p 35.
556 NLC submission, p 35.
557 NLC submission, p 35.
558 Land Rights Act, s 41(6); CLC submission, p 10.

14.5.3 Pastoral Leases

Gas companies require access to Pastoral Leases to exercise their statutory right to explore for and extract petroleum on the permit area.[559]

14.5.3.1 Description of Pastoral Leases

Pastoral Leases are issued by the Crown under the *Pastoral Land Act 1992* (NT) (**PLA**). The holder of the lease (**pastoralist**) must use the lease area for pastoral purposes.[560] 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 (that is, the owner of the title), do not have the right to exclusive possession of the Pastoral Lease area. A pastoralist must pay rent to the landowner in exchange for the rights given under the Pastoral Lease.[561] Pastoralists, like native title holders, Aboriginal land trusts, and owners of fee simple interests, do not own subsurface minerals or petroleum.[562]

14.5.3.2 Accessing Pastoral Leases to explore for unconventional shale gas

The Northern Territory does not currently give pastoralists the right of veto to petroleum companies accessing Pastoral Leases to conduct petroleum operations. 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**).

Access under the Petroleum Act

There is no statutory requirement for the petroleum company to enter into an access and/or compensation agreement with a pastoralist. Once a petroleum exploration permit is granted, a petroleum company has the exclusive right to enter and remain on the permit area to explore for petroleum.[563] The Petroleum Act does, however, require the gas company to compensate a pastoralist for any deprivation of use or enjoyment of the land or damage caused by the company.[564] If agreement as to the amount of compensation cannot be agreed then either party can refer the matter to NTCAT.[565] The Act requires the gas company to give notice to the owner or occupier of the relevant land before commencing exploration.[566]

Access under the Land Access Guidelines

The Department of Mines and Energy, as it was formerly known, 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 the Department, the NTCA and APPEA.[567] 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 current land access regime.[568]

The Land Access Guidelines require the pastoralist and the gas company to reach an agreement prior to the commencement of an exploration program. The 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 experienced industry representatives.[569] 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"*.[570] It is not clear what judicial remedies are available to the parties.

Access under the Petroleum Environment Regulations

As described above, the former Government introduced the Petroleum Environment Regulations (under the Petroleum Act) in 2016. The Petroleum Environment Regulations do not require that an access and/or compensation agreement is negotiated between a gas company and a pastoralist. 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.[571] The Petroleum Environment Regulations require a gas company to consult with stakeholders about their proposed activity and give such stakeholders a chance to respond to the information prior to submitting an environment plan to the government.[572] Under the Petroleum Environment Regulations, *"stakeholders"* are people that may be affected by the regulated activity and include pastoralists. The environment plan that is submitted for approval must include details about any stakeholder engagement that was, and will be, undertaken.[573] Stakeholders do not have the right to veto a gas company undertaking a regulated activity.

14.5.3.3 Key issues raised

Does the current regime facilitate agreement-making and a cooperative relationship between pastoralists and gas companies?

It was submitted that, in general, the current land access regime facilitates agreement making and a cooperative relationship between pastoralists and gas companies.[574]

559 Petroleum Act, s 29(1).

560 PLA, s 38(1)(d). There is a regime in the Act that allows pastoralists to use their leases for non-pastoral purposes.

561 PLA, s 55.

562 PLA, s 38(1)(b); Petroleum Act, s 6; regarding Aboriginal 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, p 2; DPIR submission, p 15; R Dunbar submission, p 1.

563 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)).

564 Petroleum Act, ss 81, 82.

565 Petroleum Act, s 81(3).

566 Petroleum Act, s 81(2).

567 DPIR submission, p 15. The Land Access Guidelines are included at p 180ff of DPIR's submission.

568 See also EDO submission, p 9; R Dunbar submission, p 3.

569 DPIR submission, p 184.

570 DPIR submission, p 184.

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

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

573 Petroleum Environment Regulations, Schedule 1, cl 9.

574 Pangaea submission; D Armstrong submission; Santos Ltd, submission 58 (**Santos submission 58**); Santos submission; Origin submission; Energy Networks Australia, submission 101 (**ENA submission**); Roper Resources, submission 181 (**Roper Resources submission**); Oilfield Connect, submission 174 (**Oilfield Connect submission**); B Sullivan submission; M Sullivan submission; APPEA submission; R Sullivan submission, pp 1-2.

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."*[575]

Various gas companies cited the number of access agreements they have entered into as evidence that the current access regime works. APPEA noted that, *"over 50 pastoralists have land access agreements in place and are working collaboratively with our industry."*[576] Origin, however, acknowledged that not all relationships with pastoralists have been harmonious, but it observed that the reasons for the 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."*[577]

Some pastoralists also submitted that the current access regime was working effectively.[578] Central to the success of the negotiation process was adequate time to negotiate, independent and affordable legal advice, and clarity on the legal requirements of the agreement-making process.

Is there is a power imbalance between pastoralists and gas companies?

There an undeniably strong relationship between pastoralists and 'their' land. The Panel heard that some pastoralists have been involved in the pastoral industry for many generations, raising families and building successful businesses in very remote parts of Australia.[579] It is clear that many pastoralists feel a deep personal sense of belonging and control over their Pastoral Lease even though they do not hold the freehold interest in the land or any rights to the sub-surface petroleum resources.

Various submissions noted that the current land access regime gives more negotiating power to gas companies than to pastoralists.[580] One stakeholder noted that the *"power imbalance"* is a 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."*[581]

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.[582] 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 for all legal costs associated with agreement-making to be paid for by the gas companies.[583] The Panel notes that this is already being undertaken by various gas companies.[584]

Should pastoralists have a right to veto access by gas companies?

Various stakeholders told the Panel that pastoralists should have the right to veto access by gas companies to their Pastoral Lease.[585] This is the official position of the NTCA.

Those in support of a statutory veto right for pastoralists thought that it would fix the apparent power imbalance between gas companies and pastoralists described above.[586] Various submissions referred to the access agreement for CSG operations entered into between Santos, AGL, NSW Farmers, Cotton Australia and the NSW Irrigators Council dated 28 March 2014, as the high water mark of land access arrangements in Australia. The gas companies that are party to that agreement have agreed that farmers have the right to say 'yes' or 'no' to the conduct of CSG operations on their land.[587] The agreement is not enshrined in statute.

The Panel was also asked to consider a number of arguments why pastoralists should not have the right to veto access by various gas companies.[588] Those arguments may be summarised as follows:

- granting a right to veto to access by gas companies would be the same as giving pastoralists de facto ownership over gas reservoirs, which they do not own.[589] 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 foreign investors the power to *"stop Territorians benefiting from [their] resources"*;[590]
- a right of veto might mean that pastoralists could negotiate substantial payments in exchange for their consent, possibly in the form of a royalty based on the value of the petroleum. Payments of this kind might reduce the amount of revenue that would go to the Government under any statutory royalty regime;[591]
- the payments (or other benefits) that are received by the pastoralist 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?"*,[592]

575 Origin submission, p 156.

576 APPEA submission, p 5; Origin submission, p 156; Santos submission 58, p 7; Pangaea submission, p 81. See also D Armstrong submission, p 7.

577 Origin submission, p 157.

578 B Sullivan, submission, p 7; R Sullivan submission, pp 1-2.

579 R Dunbar submission, p 4.

580 NTCA submission, p 1.

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

582 S Bury submission, p 4.

583 Armour Energy Ltd, submission 23 (**Armour submission**), 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, p 74.

584 Origin submission, p 156; Santos submission, p 115.

585 See North Star Pastoral submission; Lock the Gate submission; S Bury submission, p 4; NTCA submission, p 2, and submission 32, p 7; R Dunbar submission, p 2; Mr Clinton Dennison, submission 5 (**C Dennison submission**), p 2.

586 NTCA submission, p 1.

587 EDO submission, p 27; North Star Pastoral submission, p 5; CPC submission, p 7. The agreement is available at http://www.nswfarmers.org.au/__data/assets/pdf_file/0008/35567/Agreed-Principles-of-Land-Access-280314.pdf.

588 Mr Paul Brant, submission 71 (**P Brant submission**); Origin submission, p 154; D Armstrong submission; B Sullivan submission; M Sullivan submission; R Sullivan submission; Oilfield Connect submission; Roper Resources submission Santos submission 58; ENA submission.

589 APPEA submission, 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, p 155.

590 D Armstrong submission, p 8.

591 APPEA submission, p 94.

592 Oilfield Connect submission p 46; see also APPEA submission, p 94.

- a statutory veto right for pastoralists might impact the amount of rent that pastoralists are required to pay under the PLA, which is calculated on the unimproved value of the land.[593]
- a right to veto access could impact on the rate of economic development in the Northern Territory 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"*;[594]
- a right of veto over access might place pastoralists under potential *"unfair and distressing"* pressure from environmental activists.[595] One stakeholder noted the *"substantial pressure placed on Aboriginal people from activists as they have the right of veto, with scare tactics and misinformation"*;[596]
- the traditional Aboriginal owners' right to veto the grant of a petroleum exploration permit (described above) did not justify giving pastoralists a similar statutory right. The policy reasons behind the exploration veto in the Land Rights Act are historical, complex, and grounded in international law. 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;[597] and
- in any event, a statutory veto right might be 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 a statutory requirement for all legal fees to be paid by the gas companies.[598]

Should pastoralists be compensated?

Notwithstanding the arguments above, many submissions echoed the sentiment expressed by the Commonwealth Minister for Resources and Northern Australia, 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."*[599]

While not necessarily supportive of a pastoralist's right to veto access, 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. Further 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 being they are a beef and gas producer. They would therefore be more inclined to support the oil and gas industry and be proactive in assisting its development"*.[600]

14.6 Knowledge gaps and next steps

The development of a robust regulatory framework for the development of the unconventional onshore gas industry will be the most important task for the Government should it lift the moratorium. It is paramount for all stakeholders. As Origin noted:

> *"Appropriate regulation is paramount to all stakeholders, including industry proponents, as without such regulation the actual or perceived risks of development may be considered to outweigh the benefits, and in such an environment moratoriums on activity can become total bans, as seen in Victoria recently."*[601]

Moving forward the Panel will, among other things, specifically consider:

- the most effective and efficient way to operationalise the principles of ESD, including the precautionary principle, within the regulatory framework;
- mechanisms to ensure that minimum standards for environmental protection are guaranteed in the regulatory framework, such as the requirement to undertake baseline studies prior to hydraulic fracturing;
- how to operationalise and regulate 'restricted activity zones';
- the role of bioregional assessments in ensuring that the cumulative risks associated with the development of the onshore unconventional gas industry are effectively identified and managed, including the most effective way to operationalise this requirement within the regulatory framework;
- options to engender trust in an independent regulator, including ensuring that it is adequately resourced to effectively and efficiently implement the requirements of the regulatory framework; and
- mechanisms allowing for greater access to justice to operationalise the principles of ESD and enhance environmental protection.

The Panel will also examine the governance systems regulating domestic onshore unconventional gas activities in Queensland, NSW, WA and SA. Overseas, the regulatory regimes of Alberta, Colorado, Texas, the UK, North Dakota and Pennsylvania, among others, will be considered.

The Panel notes that both the NTA and the Land Rights Act are Commonwealth legislation and any amendments to those statutes must be undertaken by the Commonwealth. As noted above, Pt IV of the Land Rights Act sets out an administrative regime to facilitate access by petroleum companies to Aboriginal land. The Panel understands that the Aboriginal Land Commissioner, the Hon Justice Mansfield AM, has undertaken a review of Pt IV of the Land Rights Act. His Honour's report, which made 22 recommendations, was handed down in March 2013. The Inquiry has written to the Federal Minister for Indigenous Affairs seeking information on the process being undertaken, if any, to determine which of Mansfield J's recommendations

593 M Sullivan submission, p 5; see also B Sullivan submission, p 6; D Armstrong submission, p 8.

594 Oilfield Connect submission, p 45; Roper Resources submission, p 2.

595 Origin submission, p 165.

596 D Armstrong submission, p 9.

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

598 D Armstrong submission, p 8.

599 Canavan, media release, 9 May 2017.

600 D Armstrong submission.

601 Origin submission, p 160.

will be implemented by the Commonwealth, which recommendations are supported, and why, and whether any other amendments to Pt IV of the Land Rights Act are being considered.

The Panel's preliminary view is that the land access regime must be reformed to address the perceived unfairness of the current land access framework. Any access regime must balance both the rights of the pastoralists and the fact that unconventional gas is a resource that is owned by the Crown (the public). Potential reforms might include the development of a clear land access code - enshrined in legislation, and not merely guidelines - as well as the development of an improved negotiating process for land access and compensation agreements. These agreements might mandate:

- an express requirement that gas companies pay all legal costs associated with the negotiation of a land access and compensation agreement;
- the development of a standard form land access agreement, some of the terms of which cannot be amended; and
- the creation of an independent body to facilitate communication between the industry and landholders.

FUTURE WORK OF THE INQUIRY

15

The following additional activities are planned between now and the release of the draft Final Report.

15.1 Future interstate visits

A site visit to Queensland to visit CSG operations in that State (Chinchilla, Roma and Darling Downs), and to consult with the Queensland Gas Commission, is planned for shortly after the release of the Interim Report.

In addition, the Panel intends to travel to Canberra (ACT) for briefings on climate change, energy security and the Australian Government Bioregional Assessment Program.

15.2 Visit to pastoral leases

The Panel intends to visit several pastoral leases, including those in and around the Beetaloo Sub-basin.

15.3 Consultation with Alberta Energy Regulator

The Chair, the Deputy Chair, and other relevant Panel members will consult by telephone with the Alberta Energy Regulator. The purpose of this conference is to ascertain the regulatory framework within which the onshore unconventional gas industry operates within that Province, and to determine if there are measures from that jurisdiction which can be appropriately adapted and applied in the Northern Territory.

15.4 Next steps

As indicated in the Issues Paper,[602] pursuant to the release of this Report, a second round of public hearings and community consultations will take place. Community consultations will be held between 22 August and 1 September 2017. The public hearing schedule is outlined below:

Date	Location
31 July - 2 August 2017	Darwin
3 - 4 August 2017	Alice Springs
8 - 9 August 2017	Katherine
10 August 2017	Tennant Creek

It is anticipated that a draft Final Report will be published towards the end of the year, and that the Final Report will be handed down by the end of 2017.

15.5 Further information

Further information about the Inquiry, including upcoming community visits, is available on the Inquiry's website www.frackinginquiry.nt.gov.au.

The Inquiry's contact information is as follows:

Hydraulic Fracturing Inquiry
GPO Box 4396
Darwin, Northern Territory 0801, Australia
Phone: (+61) 08 8999 6573
Email: fracking.inquiry@nt.gov.au

The website includes:

- latest news and updates about the Inquiry;
- information about hydraulic fracturing;
- links to other hydraulic fracturing inquiries in Australia;
- the "Have your say" page with information about how to make a submission to the Inquiry;
- the submission library;
- community updates, which are also sent directly to those registered on the Inquiry's website;
- a registration option to receive email updates about the Inquiry directly; and
- the Inquiry's contact information.

602 At p 26.

APPENDICES

Appendix 1 Revised list of issues

1.1 Water

Water quality

Groundwater

- There may be a risk of groundwater contamination as a result of:
  - induced connectivity between hydraulically fractured shale formations and overlying or underlying aquifers;
  - surface spills of chemicals, flowback water or produced water into near-surface groundwater;
  - leaky wells as a result of poor design, construction, operation or abandonment practices or as a result of well degradation over the life of the well;
  - re-injection of flowback water, produced water or treatment brines into a groundwater aquifer;
  - induced connectivity between different groundwater systems as a result of seismic activity caused by hydraulic fracturing or reinjection of water ; and/or
  - *changed groundwater pressure regimes from hydraulic fracturing activities.*

Surface water

- There may be a risk of impacts on surface water quality as a result of the following types of incidents:
  - on-site spills, including as a result of extreme weather events such as cyclones and floods;
  - spills that occur during transportation of chemicals to or from the site during the development and production phases;
  - spills of flowback water, produced water or brines produced by water treatment; and/or
  - *inputs of sediment from erosion of road and pipeline corridors.*

Water supply and distribution (quantity)

- There may be a risk of adverse environmental impacts (including those listed in this table) as a result of reduced water supply due to the large amounts of water being extracted for use in hydraulic fracturing.
- There may be a risk of changes to the timing and/or quantity of surface water flows because of the discharge of produced water, which may be significant particularly in arid to semi-arid landscapes.
- There may be a risk to surface water and groundwater flow processes as the result of possible seismic activity caused by hydraulic fracturing or reinjection of water.
- *There may be a risk of surface disturbance affecting surface flow paths and altering infiltration.*

Aquatic ecosystems and biodiversity

- There may be a risk of adverse impacts on aquatic ecosystems and biodiversity, including groundwater dependent ecosystems. This may result from changes in the quality and/or quantity of surface and/or groundwater available to them.

Amenity values

- There may be adverse impacts on general amenity values such as in national parks, rangelands and recreational fishing areas. This may result from changes in the quality and/or quantity of water available.

Public health

- There may be adverse impacts on human and livestock health due to changes to water quality, supply and distribution as a result of hydraulic fracturing and the associated activities.

Aboriginal people and their culture

- Natural water bodies are central to traditional land use and many sites of significance to Aboriginal people relate to water. A reduction in either water quantity or quality may impair the traditional use and/or value of the sites.

Economic

- Changes to water quality, supply and distribution may have an adverse impact on industries that may co-exist with the onshore unconventional gas industry, such as agriculture, pastoralism, fishing and tourism.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.2 Land

Terrestrial ecosystems and biodiversity

- There may be a risk that hydraulic fracturing and the associated activities will have an adverse impact on terrestrial ecosystems and biodiversity in the Northern Territory. Specifically, there may be a risk of:
  - biodiversity loss on a local and regional scale as a result of areas being cleared for roads, pipelines and drill pads or as a result of spills;
  - biodiversity loss and reduced ecosystem function due to habitat loss and fragmentation;
  - adverse impacts on terrestrial ecosystems, including fauna and flora, as a result of changes to water quality and availability;
  - biodiversity loss and ecosystem function due to the spread of weeds;
  - impacts on biodiversity and greenhouse gas emissions due to changed fire regimes;
  - adverse impacts on fauna as a result of increased noise and light from gas operations;
  - *loss of biodiversity due to inadequate knowledge of biodiversity assets leading to inappropriate planning of regional development;*
  - *disruption of surface water flows at the landscape scale by road and pipeline infrastructure;*
  - *loss of locally important or sensitive sites due to inappropriate location of infrastructure within a development area; and/or*
  - *increased human activity, roads and pipelines acting as barriers and corridors for faunal movement and the drinking of wastewater.*

Soil health

- There may be a risk that the chemicals used in the drilling and hydraulic fracturing process will have an adverse impact on soil health, including as a result of spills of flowback water.
- There may be a risk that there will be compaction of soils underneath production pads or along pipelines.

Aboriginal people and their culture

- The landscape, terrestrial ecosystems, plants and animals are central to traditional cultural values. Adverse impacts to these things may have an adverse impact on Aboriginal cultural values.

Seismic activity

- There may be a risk of seismic activity caused either by the hydraulic fracturing process or the reinjection of wastewater into the ground.

Subsidence

- *There may be a risk that the drilling and hydraulic fracturing process causes land subsidence.*

Economic

- An adverse impact on terrestrial ecosystems may be a risk to industries that co-exist with the onshore unconventional gas industry, such as agriculture, pastoralism, fishing and tourism.

Amenity values

- The Panel recognises that the Northern Territory has iconic wilderness values as a core part of the Australian outback. There may be a risk that the development of the unconventional gas industry will have an adverse impact on the outback experience (for example, tourism) through infrastructure development (for example, the construction of pipelines and processing plants), and increased traffic, noise and light (from flaring).
- *There may be a risk of solastalgia.*

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.3 Air

Public health

- The possible health risks associated with the release of gases from the hydraulic fracturing process are discussed below in '1.4 Public health'.

Climate change

- There may be a risk that greenhouse gases, including hydrocarbons (methane and ethane) and carbon dioxide, will be released during hydraulic fracturing and the associated activities. Emissions may be from sources such as wellheads, pipelines, compression stations and final use. The potential contribution of hydraulic fracturing and the associated activities to the burden of greenhouse gas emissions will be assessed by the Panel.

Amenity values

- There may be a risk that there will be adverse impacts on amenity values such as in national parks and rangelands due to gaseous emissions and flaring.

Air contamination

- *There may be a risk that soil contaminated by spills of fracking fluids or wastewater becomes airborne as dust causing harm to the environment and to human health.*

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.4 Public health

Drilling and fracking chemicals

- There may be a risk that chemicals used during the drilling and hydraulic fracturing process are harmful to humans and livestock. Further, there may be a risk that those chemicals come into contact with humans or livestock via groundwater or atmospheric pathways. While the concentrations of potentially harmful chemicals in the water are low, the actual amount of chemicals can be significant and may pose a threat to the water supply if not properly managed.

Hydrocarbons and BTEX

- There may be a risk that hydrocarbons associated with the extracted gas come into contact with humans or livestock via groundwater or atmospheric pathways. This may include aromatic hydrocarbons such as BTEX, which have featured prominently in some risk assessments relating to flowback water from petroleum and unconventional gas extraction activities in the US. The addition of BTEX in drilling and fracking fluids is prohibited in the Northern Territory.

Radioactive substances

- There may be a risk that naturally occurring radioactive materials from underground come into contact with humans or livestock as a result of the drilling or hydraulic fracturing process.

Mental health and wellbeing

- There may be a risk that the mental health and wellbeing of persons could be affected by an unconventional gas project. These factors could include increased costs of living associated with changing property values, access to social services, business failures, increased traffic, effects on the natural environment and concerns about the amenity of the local area, *including solastalgia.*

Diesel fumes

- There may be a risk of emissions from plant and equipment, such as diesel fumes from drilling equipment and pumps and from off-site increases in road traffic.

Physical safety

- There may be a risk that physical safety may be compromised by factors associated with hydraulic fracturing including road transport accidents.

Aboriginal health

- *There may be risk that as a consequence of the possible impacts described above, the physical and mental health of Aboriginal persons and communities, as a group that is especially vulnerable and disadvantaged, is particularly affected (that is, the 'gap' is increased and not decreased).*

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.5 Aboriginal people and their culture

Land ownership

- There may be a risk that hydraulic fracturing or the associated activities will disrupt traditional practices that connect Aboriginal landowning groups with their country and underpin recognition of their ownership of that land.
- *There may be a risk that there is inadequate or inappropriate consultation with Aboriginal landholders in obtaining access to their lands and/or permission to carrying out any onshore unconventional shale gas development.*

Benefits

- There may be a risk that the development of the industry will occur without short and long term benefits flowing to local Aboriginal communities.

Culture, values and traditions

- There may be a risk that the above and/or below ground disturbance associated with drilling and hydraulic fracturing of onshore shale gas formations will have an adverse impact on Aboriginal culture, values and the traditions that connect landowning groups with their country and sustain community cohesion.
- *There may be a risk that access to and the use of traditional lands will be denied or restricted by the presence of any onshore unconventional shale gas development.*
- *There may be a risk that sacred sites and cultural landscapes are degraded and damaged both above and below the ground.*

Community wellbeing

- The development of the onshore unconventional shale gas industry may have an adverse impact on the wellbeing of Aboriginal communities
- *There may be a risk of solastalgia caused by any onshore unconventional shale gas development.*
- *There may be a risk that any onshore unconventional shale gas industry causes community division in respect of those who may benefit from any industry and those who will not.*

Aquatic and terrestrial ecosystems

- The development of the unconventional gas industry may have an adverse impact on aquatic and terrestrial ecosystems important to Aboriginal culture.

Aboriginal health

- There is a risk of an exacerbated adverse impact on Aboriginal health, taking into account the particular vulnerabilities and disadvantage of that population.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.6 Social impacts

Housing and rents

- There may be impacts on local housing, which may decrease or increase rents and house prices as a result of an increased population.

Insurance

- There may be a risk that there will be an increase in insurance costs and liabilities of landowners, occupiers, and traditional owners.

Health services

- There may be impacts on the local health system (hospitals, health services and so on) as a result of an increased population, including that there may be increased health services in remote communities as a result of industry's presence.

Education

- There may be an impact on the local education system as a result of an increased population.

Infrastructure

- There may be an impact on infrastructure, such as roads, as a result of increased traffic.

Livelihoods

- There may be an impact on livelihoods.

Long term benefits

- There may be a risk that the development of the industry will occur without short and long term benefits flowing to the local community.

Community cohesion

- *There may be an adverse impact on community cohesion and resilience. That is, there may be a risk of social division being created between those who benefit from the development of any onshore unconventional shale gas industry and those who do not.*

Crime

- There may be an increase in crime.

Employment

- They may be an impact on local employment and skill levels.
- *There may be negative impact caused by an influx of FIFO employees.*

Business

- There may be an impact on local business opportunities.

Amenity

- There may be a risk that the amenity of people will be adversely impacted by hydraulic fracturing and its associated activities.

Social licence to operate

- *There may be a risk that no social licence to operate an onshore unconventional shale gas industry exists.*

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.7 Economic impacts

Distribution

- There may be a risk that any economic benefits will not be shared by the regions that are directly affected by the industry, and/or will not be shared equitably between the gas companies, the government, and the community.

Property values

- There may be a risk that there will be a decrease or increase in existing property values.

Other industries

- There may be a risk that there will be an adverse impact on other businesses, such as tourism, fishing, agricultural and pastoral businesses.

Energy security

- There may be an impact on the energy security of the Territory.

Employment

- *There may be an impact on employment in the Territory.*

Net impacts

- There may be a risk that any economic benefits will not outweigh economic detriments.
- *There may be an opportunity cost of investing in an onshore unconventional shale gas industry rather than in renewable energy.*
- *There may be a risk of residents leaving a particular region because of the presence of an onshore unconventional shale gas industry.*

Management

- There may be a risk that, if not properly managed, any economic benefits will result in 'boom and bust' economic activity.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.8 Land access

Consultation

- There may be a risk that gas companies do not consult adequately with land owners, occupiers, or traditional owners, in gaining access to the land for exploration and extraction purposes.

Consent

- There may be a risk that gas companies enter the land without, where required, obtaining the consent of the landowner, occupier, or traditional owners, causing conflict.

Conditions

- There may be a risk that gas companies and landowners, occupiers, and traditional owners, do not negotiate mutually beneficial conditions associated with any agreement permitting access.

Compensation

- There may be a risk that compensation paid for access and/or disturbance to land will not be adequate.
- There may be a risk that if there is an incident in the exploration, extraction or production of any gas, the land may not be properly remediated or the land owners, occupiers, or traditional owners may not be adequately compensated.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

1.9 Regulatory framework

Failure to protect the environment

- There may be a risk the regulatory framework does not adequately protect the environment (water, land, and air) from risks associated with hydraulic fracturing and its associated activities.
- *There may be a risk that the regulatory framework does not ensure adequate, or any, remediation and/or rehabilitation of any environmental damage caused by hydraulic fracturing and its associated activities.*
- *There may be a risk that the cost of any remediation and/or rehabilitation of environmental damage caused by hydraulic fracturing and its associated activities is not passed on, either in whole or in part, to the entity that caused the harm, but is passed on to the public.*

Land access

- There may be a risk the regulatory framework does not appropriately balance the rights of landowners, occupiers, and traditional owners, with those of gas companies.

Public health

- There may be a risk the regulatory framework does not adequately mitigate public health risks associated with the onshore unconventional shale gas industry.

Aboriginal culture and communities

- There may be a risk the regulatory framework does not adequately protect Aboriginal culture, values, traditions and communities from risks associated with the unconventional shale gas industry.

Social impacts

- There may be a risk the regulatory framework does not adequately mitigate the social risks associated with the onshore unconventional shale gas industry.

Economic impacts

- There may be a risk the regulatory framework does not ensure that any economic benefits are appropriately distributed between the gas companies, the government and the local community.

Compliance and enforcement

- There may be a risk of inadequate monitoring or enforcement of compliance with the regulatory framework. This may arise from, for example, inadequate resourcing of the regulatory agency, inadequate expertise, or inadequate training.
- There may be a risk that sanctions provided for in the regulatory framework are inadequate or are not utilised by the regulator.
- There may be a risk that the cost of complying with the regulatory framework is too high for industry and the industry becomes uneconomic.

Access to justice

- *There may be a risk that access to justice by the public is denied or restricted by the regulatory framework.*

Complexity

- There may be a risk that the regulatory framework developed is too complex.
- *There may be a risk that given its complexity, any regulatory framework that developed is rushed and is inadequate.*
- *There may be a risk that there is inadequate information about the long term risks associated with hydraulic fracturing and its associated activities to develop a suitably robust regulatory framework.*

Regulatory capture

- There may be a risk of 'regulatory capture' whereby the regulatory body becomes inappropriately aligned with industry and becomes reluctant to regulate against the interest of any onshore unconventional shale gas industry.
- *There may be a risk of the perception of regulatory capture which may have a tendency to undermine confidence in both the regulatory body and the Government.*

Political risks

- *There may be a risk that the Government is perceived to be subject to undue influence by the gas industry thereby leading to a loss of public confidence in the Government and the democratic process.*
- *There may be a risk that, given the short term nature of the political cycle, the long term consequences of any onshore unconventional shale gas industry cannot be appropriately regulated.*

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

Appendix 2 Stakeholder meetings

Location/Date	Stakeholder organisation	Representatives
DARWIN		
20 February 2017	Department of the Chief Minister	Ms Jodie Ryan, Chief Executive Officer Ms Rachel Bacon, Deputy Chief Executive Officer
	Frack Free Alliance, Darwin	Ms Belinda Quinlivian Mr Chris Naden
	Lock the Gate Alliance (NT)	Ms Naomi Hogan, Northern Territory Coordinator
	Environmental Defenders Office (NT) Inc	Mr David Morris, Principal Lawyer and Executive Officer
	Environment Centre (Northern Territory)	Mr Drew English, Chair Ms Shar Molloy, Director
	Frack Free Alliance, Darwin Rural	Ms Pauline Cass
	Chamber of Commerce Northern Territory	Mr Brian O'Gallagher, Acting Chief Executive Officer Mr Greg Ireland
	Australian Petroleum Production and Extraction Association	Mr Matthew Doman, Director South Australia/Northern Territory
	Origin Energy Limited	Dr David Close, Chief Geologist and Unconventional Exploration Manager Ms Stephanie Stonier, Corporate Affairs Manager (Northern Australia)
	Central Petroleum Limited	Mr Richard Cottee, Managing Director and Chief Executive Officer
	Pangaea Resources Northern Territory Pty Ltd	Mr Todd Hoffman, Geoscientist
	Santos Ltd	Mr Bill Ovenden, Vice President Exploration and Subsurface Mr Tom Baddeley, Manager Government and Community Relations Mr Che Cockatoo-Collins, Aboriginal Employment Adviser
KATHERINE		
21 February 2017	Department of the Chief Minister	Mr John de Koning, Regional Executive Director
	Amateur Fishermen's Association of the Northern Territory	Mr Warren de With, President
	Katherine Town Council	Mayor Fay Miller Deputy Mayor Toni Tapp-Coutts Mr Robert Jennings, Chief Executive Officer
	Victoria Daly Regional Council	Mayor Brian Pedwell
	Don't Frack Katherine	Ms Kerrie Mott Dr Errol Lawson
	Jawoyn Association Aboriginal Corporation	Mr John Berto, Chief Executive Officer
NHULUNBUY		
22 February 2017	Department of the Chief Minister	Mr Jim Rogers, Regional Executive Director
	East Arnhem Regional Economic Development Committee	Representatives from the following organisations: Gumatj Aboriginal Corporation; Miwatj Employment and Participation Ltd; Dhimurru Aboriginal Corp; Rio Tinto; East Arnhem Regional Council; Australian Department of Prime Minister and Cabinet
TENNANT CREEK		
22 February 2017	Tennant Creek Regional Economic Development Committee	Mr Greg Marlow, Chair Mr Steven Edgington Ms Josephine Bethel, Secretariat

Location/Date	Organisation	Witness
ALICE SPRINGS		
23 February 2017	Alice Springs Town Council	Mr Jimmy Cocking, Director
	Public Health Association Northern Territory; Doctors for the Environment	Dr Rosalie Schultz
	Alice Springs Town Council	Mayor Damien Ryan Councillor Jade Kudrenko Mr Rex Mooney, Chief Executive Officer
	Chamber of Commerce, Alice Springs/ Tennant Creek	Ms Kaye Eade, Chair Mr Martin Glass
	Central Desert Regional Council	Ms Cathryn Hutton, Chief Executive Officer
	Frack Free Northern Territory Alliance	Ms Lauren Mellor, Coordinator Ms Marli Banks
DARWIN		
24 February 2017	Northern Land Council	Mr Murray McLaughlin , Media and Policy Manager Ms Rhonda Yates, Manager, Minerals and Energy Branch Mr Michael O'Donnell, Principal Legal Officer
	Northern Territory Farmers Association	Mr Simon Smith, President Mr Tom Harris, Director
	Department of Primary Industry and Resources	Mr Alister Trier, Chief Executive Officer
	Department of Environment and Natural Resources	Ms Joanne Townsend, Chief Executive Officer
	Amateur Fishermen's Association of the Northern Territory	Mr David Ciaravolo, Executive Officer

Appendix 3 Departmental briefings

Date	Presenters	Description
8 December 2016	Mr Alister Trier, Chief Executive Officer, Northern Territory Government Department of Primary Industry and Resources and Mr Ian Scrimgeour, Northern Territory Geological Survey, Northern Territory Government Department of Primary Industry and Resources	Presentation on Northern Territory gas resources, basins and energy demand
8 February 2017	Mr Des Yin Foo, Water Assessment, Northern Territory Government Department of Environment and Natural Resources	Presentation on water, focussing on climate change and major aquifers in the Northern Territory
8 February 2017	Mr Anthony Swirepik, Director, Bioregional Assessments, Office of Water Sciences, Australian Government Department of Energy and Environment	Presentation on bioregional assessments
8 February 2017	Mr Bill Date, Chief Inspector, Petroleum and Gas Inspectorate, Queensland Department of Natural Resources and Mines and Mr Ian Heiner, A/Executive Director, CSG Compliance Unit, Queensland Department of Natural Resources and Mines	Presentation on the Queensland experience with unconventional gas, focussing on land access issues and the Gasfields Commission
9 February 2017	Mr Jop van Hattum, Senior Director, Petroleum Technology and Operations Northern Territory Government Department of Primary Industry and Resources	Presentation on technical overview of hydraulic fracturing for shale gas
9 February 2017	Ms Jodie Ryan, Chief Executive Officer, Northern Territory Government Department of the Chief Minister	Presentation on the economy of the Northern Territory
11 March 2017	Mr Jop van Hattum, Senior Director, Petroleum Technology and Operations, Northern Territory Government Department of Primary Industry and Resources	Presentation on the *Petroleum Act 1984* (NT) and the *Petroleum (Environment) Regulations 2016* (NT)

Appendix 4 Hearings

Location/Date	Stakeholder organisation	Representatives
ALICE SPRINGS		
6 March 2017	Alice Springs Town Council	Mayor Damien Ryan Deputy Mayor Jamie de Brenni Councillor Jade Kudrenko
	Arid Lands Environment Centre	Mr Jimmy Cocking, Director Mr Alex Read, Policy Officer
	Aloha Therapeutic Massage	Mr Jason Trevers
	Central Petroleum Limited	Mr Richard Cottee, Managing Director and Chief Executive Officer Mr Rolf Schulte, Alice Springs Area Manager Mr David Liddle, Public Relations and Communications
	Drill and Complete Pty Ltd	Mr Ash Chawla, Well Engineering and Project Management
	Central Land Council	Mr David Ross, Director Mr James Nugent, General Manager Legal Ms Julie Ann Stoll, Mining Manager
	Public Health Association NT; Doctors for the Environment; Central Australian Rural Practitioners Association	Dr Rosalie Schultz
	Central Australia Frack Free Alliance	Ms Marli Banks Mr Dalton Dupuy
TENNANT CREEK		
7 March 2017	Barkly Landcare and Conservation Association	Mr Anthony Cox, President Ms Anne Alison Ms Naomi Wilson Mr Michael Anderson
	Cattle Creek Station	Mr Rohan Sullivan
	Seed Indigenous Youth Climate Network	Ms Larissa Baldwin, National Co-Director Ms Vanessa Farrelly
KATHERINE		
8 March 2017		Ms June Tapp
	Big River Station	Mr Daniel Tapp
	Katherine Mining Services Association	Mr Geoff Crowhurst, Chair
	Top Didj Cultural Experience and Art Gallery	Ms Petrena Ariston
	Don't Frack Katherine	Dr Errol Lawson
		Ms Annette Raynor
		Ms Teresa Cummings
	Katherine Town Council	Mr Robert Jennings, Chief Executive Officer
DARWIN		
10 March 2017	OzEnvironmental Pty Ltd, representing North Star Pastoral	Mr Warwick Giblin
	Australian Petroleum Production and Exploration Association	Mr Matthew Doman, Director, South Australia/Northern Territory Mr Keld Knudsen, Policy Director, Exploration
	Origin Energy Limited	Mr Ross Evans, General Manager, Exploration and New Resources Dr David Close, Chief Geologist and Unconventional Exploration Manager Mr Alexander Cote, Senior Petroleum Engineer Ms Stephanie Stonier, Corporate Affairs Manager (Northern Australia)
	Lock the Gate Alliance (NT)	Ms Naomi Hogan
	Santos Ltd	Mr Bill Ovenden, Vice President Exploration and Subsurface Mr Che Cockatoo-Collins, Aboriginal Employment Adviser Mr Andrew Snars, Maranoa Regional Manager Mr Rohan Richardson, Manager Design and Construction Onshore

Location/Date	Stakeholder organisation	Representatives
DARWIN		
10 March 2017	Armour Energy Limited	Mr Luke Titus, Chief Geologist
	Amateur Fishermen's Association of the Northern Territory	Mr David Ciaravolo, Executive Officer
	Environmental Defender's Office (NT) Inc	Mr David Morris, Principal Lawyer and Executive Officer
	Environment Centre (Northern Territory)	Ms Shar Molloy Mr Drew English
	Frack Free Alliance, Darwin	Ms Belinda Quinlivian Mr Chris Naden Ms Melissa Burey
	Northern Territory Cattlemen's Association	Ms Tracey Hayes, Chief Executive Officer Mr Tom Stockwell, President
	Consolidated Pastoral Company	Mr Troy Setter
		Mr Justin Tutty
		Ms Katherine Marchment
		Ms Merrilee Baker
	Pangaea (NT) Pty Ltd	Mr Tim Radburn, Executive Director
	Halliburton	Ms Diana Grantham, Senior Technical Professional Production Enhancement Mr Ian Adams
	Climate Action Darwin	Ms Anna Boustead Ms Grusha Leeman

Appendix 5 Media engagements

Date	Activity	Media organisation
3 December 2016	Media event	ABC and Northern Territory News
7 February 2017	Interview	ABC Radio, Northern Territory Country Hour
14 February 2017	Interview	ABC Radio, Darwin
20 February 2017	Media event	ABC, Channel 9, Northern Territory News, Territory FM
21 February 2017	Interview	Territory FM
23 February 2017	Media event	ABC TV; ABC Radio, Northern Territory Country Hour; Alice Springs News; Centralian Advocate
28 February 2017	Interview	Territory Q Magazine
6 March 2017	Interview	ABC Radio, Alice Springs
9 March 2017	Written response	Katherine Times
	Written response	Alice Springs News
10 March 2017	Interview	ABC Radio, National AM
	Interview	ABC Radio, Darwin
20 March 2017	Interview	Yolngu Radio
21 March 2017	Written response	NT News
23 March 2017	Interview	ABC TV, Darwin
4 April 2017	Interview	ABC Radio, Darwin
	Interview	ABC Radio, Alice Springs
13 April 2017	Written response	NT News
3 May 2017	Written response	NT News
8 May 2017	Written response	Alice Springs News
25 May 2017	Written response	ABC Darwin
26 May 2017	Written response	Alice Springs News
	Written response	Centralian Advocate
29 May 2017	Interview	PAW Radio
30 May 2017	Written response	Alice Springs News
8 June 2017	Written response	ABC Darwin

Appendix 6 Community updates

Update	Date	Description
1	20 December 2016	The inaugural meeting of the Panel of 8 December 2016, the importance of community consultation and the proposed hearings and consultations.
2	6 February 2017	The visit of the Chair and Panel members to Moomba, SA, to witness hydraulic fracturing, well drilling and associated infrastructure.
3	13 February 2017	The second meeting of the Panel and the March hearings and community consultation schedule.
4	21 February 2017	The release of the Background and Issues Paper on 20 February 2017, stakeholder meetings and the hearings and community consultation sessions.
5	6 March 2017	The commencement of the first round of hearings and community meetings.
6	11 March 2017	The completion of the first round of hearings and community meetings in urban centres.
7	20 March 2017	The postponing of the community session in Maningrida.
8	27 March 2017	The conclusion of the first round of community consultations in regional and remote communities.
9	27 April 2017	A reminder that submissions of the Background and Issues Paper close on 30 April 2017 and discussion of hearings, community meetings and other forums in which the Inquiry has sought to hear the views of Territorians. Release of public tender for economic modelling.
10	5 May 2017	Release of public tender for a social impact assessment and management framework.
11	24 May 2017	Award of tender to undertake economic impact modelling to ACIL Allen.
12	28 June 2017	Award of tender for a social impact assessment and management framework to Coffey.

Appendix 7 Submissions

Current as at 16 June 2017.

1	Mr Barry Nicholson
2	Ms Katherine Marchment
3	Ms Monica O'Connor
4	Mr Terry Baldwin
5	Mr Clinton Dennison
6	Mr Mark Edward
7	Mr Lawrence Lyons, Environics
8	Central Australia Frack Free Alliance
9	Mr Robert Adams
10	Ms Harshini Bartlett
11	Mr Daniel Tapp, Big River Station
12	Mr Daniel Tapp, Big River Station
13	Mr Phil Walcott
14	Mr Denny Migl, Sigma Cubed Inc
15	Coomalie Community Government Council
16	Ms June Tapp
17	Mr Barry Nicholson
18	Mr Rohan Sullivan, Birdum Creek Station
19	Mr Blair McFarland
20	Mr Paul Brant
21	Dr Michael Blockey
22	North Star Pastoral, represented by OzEnvironmental Pty Ltd
23	Armour Energy Ltd
24	Mrs Helen Davison
25	Ms Yolande Doecke
26	North Star Pastoral, represented by OzEnvironmental Pty Ltd
27	Mr Phil Cross
28	North Star Pastoral, represented by OzEnvironmental Pty Ltd
29	Mr Gerry Wood MLA, Member for Nelson
30	Origin Energy Ltd
31	Withdrawn
32	Northern Territory Cattlemen's Association
33	Ms Pauline Cass
34	Ms Merrilee Baker
35	Mr Paul Brant
36	Mr David Jagger
37	Ms Eleanor Wilson
38	Mr Mark Sinclair
39	Mr George Kyreakou
40	Mr Daniel Leather
41	Mr Tony Hayward-Ryan
42	Ardent Group Pty Ltd
43	Mr Colin Mellon
44	Ms Amanda Doyle
45	Mr Thomas Lynch
46	Don't Frack Katherine
47	Central Land Council
48	Ms Helen Armstrong, Gilnockie Station
49	Ms Jenny Knight
50	Withdrawn
51	PLan: The Planning Action Network
52	Ms Kelly-Lee Hickey
53	Dr Geralyn McCarron
54	Mr Tony Hayward-Ryan
55	Withdrawn
56	Lock the Gate Alliance Northern Territory
57	Santos Ltd
58	Santos Ltd
59	Environment Centre Northern Territory
60	Pangaea Resources Pty Ltd
61	Halliburton Australia Pty Ltd
62	Climate Action Darwin
63	North Star Pastoral, represented by OzEnvironmental Pty Ltd
64	Central Petroleum Limited
65	Don't Frack Katherine
66	Withdrawn
67	Ms Annette Raynor
68	Top Didj Cultural Experience and Art Gallery
69	Mr Paul Brant
70	Mr Paul Brant
71	Mr Paul Brant
72	Mr Greg Reilly
73	Mr Jim Sullivan, Cave Creek Station
74	Mr Jason Trevers, Aloha Therapeutic Massage
75	Mr Rod Dunbar, Lexcray Pty Ltd
76	Central Desert Regional Council
77	Mr Tom Measham, Commonwealth Scientific and Industrial Research Organisation
78	Ms Jennifer McFarland
79	Falcon Oil and Gas Australia Pty Ltd
80	Ms Julia Siddall

81	Ms Barbara Molanus
82	Ms Gabby Watson-Scotty
83	Ms Jessica Graham
84	Ms Jasmine Sammut
85	Mr Joseph Costelloe
86	Mr Jim Green
87	Mr Andrew Andrejewskis
88	Arid Lands Environment Centre Inc
89	Mr Tim Forcey
90	Ms Harshini Bartlett
91	Ms Nicole Pietsch
92	Mr John Armstrong , Gilnockie Station
93	Central Australia Frack Free Alliance
94	Prof Madelon Finkel
95	Katherine Town Council
96	Doctors for the Environment Australia
97	Halliburton Australia Pty Ltd
98	Sweetpea Petroleum Pty Ltd
99	Central Petroleum Limited
100	Jemena Limited
101	Australian Pipelines and Gas Association and Energy Networks Australia
102	WL Tinapple
103	Mr Lindsay Owler, Argonaut Resources
104	Mr Bruce Beer, B.C. & M. Beer Pty Ltd
105	Dr Matthew Currell, School of Engineering, RMIT University
106	Ms Sue Slater
107	Public Health Association of Australia
108	Mr Warwick Smyth, Geoconsult
109	Dr Steve Mackie, Geosim Consulting Pty Ltd
110	Regional Development Australia Northern Territory
111	Mr Rob Ross, Qeye Labs Australia Pty Ltd
112	Mr Mick Curran
113	Mr Luke Marshall
114	The Norwood Resource Incorporated
115	Mr Alexander Belford
116	Prof John Kaldi, Australian School of Petroleum, The University of Adelaide
117	Dr Andrew Kulpecz
118	Mr Andrew Pedler, Matau Advisory Pty Ltd
119	Mr Ryan Taylor-Walshe
120	Mr Greg Carlsen
121	Mr David Warner
122	Dr David King
123	Dr Kris Waddington, Buru Energy Ltd
124	Mr Ralf Oppermann, OPPtimal Resource Solutions Pty Ltd
125	Mr John Wilson
126	Mr Richard Osbon
127	Mr Michael Micenko
128	Mr John Kopcheff
129	Mr Craig Gumley, Gumley Advisory Services
130	Mr John Heugh, PetroAfrique Oil and Gas Ltd
131	Mr Gregory Meldrum
132	Dr Steve Mackie, Petroleum Exploration Society of Australia
133	Mr Eric Streitberg, Buru Energy Ltd
134	Mr David Adderley
135	Blue Energy Limited
136	Mr Griffiths Weste
137	Mr James Groombridge
138	Mr Mark Fabian
139	Mr Darryl Roy Kingsley
140	Mr Anthony Kress
141	Frack Free Darwin
142	Institute for Energy Economics and Financial Analysis
143	Mr Robert Laws
144	Ms Helen Bender
145	Beyond Zero Emissions
146	Mr Chris Carty
147	Ms Liz Howells
148	Mr Miles Ponsonby
149	Mr Greg Kemp
150	Nation Energy (Australia) Pty Ltd
151	Mr Robert Pearson
152	Mr Justin Tutty
153	Origin Energy Ltd
154	D.R Johns
155	North Star Pastoral
156	Mr Chris Harwood
157	Paltar Petroleum Limited
158	The Australia Institute
159	Mr James Wright
160	Mr Bill Sullivan, Sully Pty Ltd

161	Mr Bevan Warris
162	Imperial Oil and Gas Pty Ltd
163	The Desert Fruit Company
164	Ms Sandy Watters
165	Ms Juliet Saltmarsh
166	Mr Mark Sullivan, Flying Fox Station, MS Contracting
167	Ms Andrea Broughton, Groundwater Solutions International
168	Santos Ltd
169	Mr John Geary
170	Mr Stuart Jones, Petroleum Exploration Society of Australia
171	Lock the Gate Alliance (NT)
172	Mr Alex Ross
173	Mr Simon Molyneux
174	Oilfield Connect Pty Ltd
175	Climate Action Darwin
176	Mr Alex Yeadon
177	1 Territory Party
178	Schlumberger Australia Pty Ltd
179	Dr Liz Moore
180	Mr David Armstrong, Terrabos Consulting
181	Roper Resources Pty Ltd
182	Ms Jean McDonald
183	Prof Melissa Haswell
184	Mrs Frederika Saltmarsh
185	Katherine Mining Services Association
186	Northern Australian Rural Management Consultants Pty Ltd
187	Ms Rachel Tumminello
188	Environment Centre Northern Territory
189	Ms Sharyn Bury
190	Amateur Fishermen's Association of the Northern Territory
191	Ms Charmaine Roth
192	Ms Pauline Cass
193	Ms Gypsy Cass
194	Mr Cameron Fink, Bridgeport Energy Ltd
195	Mr Rebel Cass
196	Mr Titan Cass
197	Mr Robert Bates
198	Mr Michael Harcla
199	Mr Steve Vidler
200	Ms Rose Matyr
201	Ms Emma Burkitt
202	Ms Megan Fleming
203	Ms Jeananne Baker
204	Mr Geoff Baker
205	Ms Bianca-Jade Stevanovic
206	Mr Michael Baker
207	Mr Brian Baker
208	Ms Renee Baker
209	Mr James Donley
210	Ms Mandy Hall
211	Dr Peter Dart, School of Agriculture and Food Sciences, The University of Queensland
212	Mr Lachlan Bestic
213	Environment Defenders Office (NT)
214	Northern Land Council
215	Australian Petroleum Production and Exploration Association
216	Dr Errol Lawson
217	Northern Territory Cattlemen's Association
218	Consolidated Pastoral Company Pty Ltd
219	Mr Justyn Wood, Wood Petroleum Exploration Pty Ltd
220	Pangaea Resources Pty Ltd
221	Halliburton Australia Pty Ltd
222	Oilfield Connect Pty Ltd
223	Ms Grusha Leeman
224	Department of Environment and Natural Resources
225	Ms Jill Emerson-Smith
226	Department of Primary Industry and Resources
227	Ms Yvonne Werner
228	Mr Bryce McLaren, Buru Energy Ltd
229	SG Interest I, Ltd
230	Department of Environment and Natural Resources
231	Schlumberger Australia Pty Ltd
232	Santos Ltd
233	Origin Energy Ltd
234	Aboriginal Areas Protection Authority
235	Alice Springs Town Council
236	Mr Jason Trevers, Aloha Therapeutic Massage
237	Amateur Fishermen's Association of the Northern Territory
238	Arid Lands Environment Centre Inc
239	Australian Petroleum Production and Exploration Association
240	Ms Merrilee Baker
241	Barkly Landcare
242	Mr Daniel Tapp, Big River Station
243	Mr Rohan Sullivan, Cave Creek Station and Birdum Creek Station
244	Central Australia Frack Free Alliance
245	Central Land Council
246	Central Petroleum Limited

247	Climate Action Darwin
248	Consolidated Pastoral Company
249	Ms Teresa Cummings
250	Don't Frack Katherine
251	Drill and Complete
252	Environment Centre Northern Territory
253	Environmental Defenders Office (NT)
254	Frack Free Darwin
255	Halliburton Australia Pty Ltd
256	Katherine Mining Services Association
257	Katherine Town Council
258	Lock the Gate Alliance Northern Territory
259	Ms Katherine Marchment
260	North Star Pastoral, represented by OzEnvironmental Pty Ltd
261	Northern Territory Cattlemen's Association
262	Origin Energy Ltd
263	Pangaea Resources Pty Ltd
264	Dr Rosalie Schultz
265	Ms Annette Raynor
266	Santos Ltd
267	Seed Indigenous Youth Climate Network
268	Ms June Tapp
269	Ms Petrena Ariston, Top Didj Cultural Experience
270	Mr Justin Tutty
271	Department of Environment and Natural Resources
272	Origin Energy Ltd
273	Origin Energy Ltd
274	Halliburton Australia Pty Ltd
275	Department of Environment and Natural Resources
276	Santos Ltd
277	Halliburton Australia Pty Ltd
278	Department of Environment and Natural Resources
279	Pangaea Resources Pty Ltd
280	Santos Ltd
281	Department of Primary Industry and Resources
282	Mr Mark Goldstein
*283	Origin Energy Ltd
284	Origin Energy Ltd
285	Coal and CSG Free Mirboo North – Margaret, Gayle
286	Lock the Gate Alliance (NT)
287	Groundswell Gloucester
288	1Earth Media
289	Department of Primary Industry and Resources
290	Tax Justice Network Australia
291	Mr Jason Trevers, Aloha Therapeutic Massage
292	Ms Barbara Molanus
293	Ms Deidre Olofsson

* Confidential submission (commercial-in-confidence as necessitated by ASX reporting obligations).

Appendix 8 Table of correspondence requesting further information

Current as at 16 June 2017.

Date	Recipient	Details
28 April 2017	Origin Energy	Request for data in relation to petroleum resources, water use and land access and disturbance
28 April 2017	Pangaea Resources Pty Ltd	Request for data in relation to petroleum resources, water use and land access and disturbance
28 April 2017	Santos Ltd	Request for data in relation to petroleum resources, water use and land access and disturbance
28 April 2017	Schlumberger Australia Pty Ltd	Request for data in relation to water use and chemical toxicity
28 April 2017	Department of Environment and Natural Resources	Request for data in relation to water resources and ecosystems
28 April 2017	Department of Tourism and Culture	Request for data in relation to tourism areas, cultural sites, recreational sites and National Parks
28 April 2017	Department of Primary Industry and Resources	Request for data in relation to petroleum resources and water use
28 April 2017	Halliburton Australia Pty Ltd	Request for data in relation to water use and chemical toxicity
22 May 2017	Department of Environment and Natural Resources	Request for data in relation to water resources
24 May 2017	Department of Environment and Natural Resources	Request for data in relation to water resources
26 May 2017	Origin Energy	Request for information in relation to fluid ecotoxicity
26 May 2017	Santos Ltd	Request for information in relation to fluid ecotoxicity

Appendix 9 Scope of services for economic impact modelling

Scope of Services

Background to the Inquiry

On 14 September 2016 the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory. At the same time, the Chief Minister announced that a *Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory* (the **Inquiry**) would be established and released draft Terms of Reference, which were open for public comment for four weeks.

On 3 December 2016 the Northern Territory Government announced the final Terms of Reference for the Inquiry and the composition of the panel that will be undertaking the Inquiry (the **Panel**).

The Inquiry was established under section 4 of the Inquiries Act 1945 (NT) and is comprised of a judicial chair, the Hon Justice Rachel Pepper, and ten highly regarded scientists with expertise in areas ranging from hydrogeology to social science.

The Inquiry's final Terms of Reference can be read in full on the Inquiry's website (www.frackinginquiry.nt.gov.au).

On 20 February 2017 the Inquiry released a Background and Issues Paper, also available on the Inquiry's website, which was followed by hearings and community meetings held in March 2017 in various town centres and remote communities across the Northern Territory. The Issues Paper includes a timeline for the Inquiry, which indicates that an interim report will be released in mid-2017, a draft final report will be released during the last quarter of the year, and a final report will be released in December 2017.

The Hydraulic Fracturing Taskforce (the **Taskforce**) has been established in the Department of the Chief Minister to support the Inquiry.

Terms of Reference for the Inquiry and the economic impact theme

The Panel has divided the work of the Inquiry into the following themes: water, land, air, social impacts, economic conditions, cultural conditions, human health, land access, and the regulatory framework. This request relates to the economic theme only, however, there are overlaps with the social impact and regulatory framework themes. A sub-group of Inquiry Panel members has been allocated responsibility for each theme.

The Terms of Reference for the Inquiry require the Panel to do the following in respect of each theme:

- determine and assess the impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the associated activities;
- determine whether additional work or research is required to make that determination;
- advise the level of impact or risk that is acceptable in the Northern Territory context;
- describe methods, standards or strategies that can be used to reduce the impact and risk to acceptable levels; and
- identify what government can do, including implementing any policy or regulatory changes, to ensure that the impacts and risks are reduced to the required levels.

The *Background and Issues Paper* includes a non-exhaustive list of the potential risks and benefits associated with the economic theme at page 22.

In accordance with the definitions in the Terms of Reference, a reference to an "unconventional reservoir" in this document is a reference to a reservoir where the rock formation is *shale*. There is currently no gas being produced from unconventional, or shale, reservoirs in the Northern Territory. The Amadeus Basin is currently producing gas from conventional reservoirs.

With regard to the third Term of Reference stated above, the level of impact or risk that is acceptable will ultimately be a matter for the decision maker under the relevant legislation (typically the Minister), however, at this stage the meaning of acceptability or acceptable levels of risk is a matter for the Panel, taking into account principles of ecological sustainable development, including the precautionary principle and intergenerational equity.

The Terms of Reference make it clear that the Panel must not only look at the impacts of hydraulic fracturing and the associated activities on economic conditions in the Northern Territory – the Panel must also consider the economic impacts of the onshore unconventional gas industry as a whole on the Northern Territory. This is made clear in the following extract from the Terms of Reference, which has been amended to include the relevant language only:

> *"When the inquiry makes a determination… about whether or not there has been an impact or risk on … economic conditions, the inquiry will … consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry."*

Steering Committee

A Steering Committee has been established to oversee the work. The Steering Committee is comprised of the Hon Justice Rachel Pepper, Dr Vaughan Beck and the Executive Director of the Hydraulic Fracturing Taskforce. The point of contact for all matters will be the Executive Director of the Hydraulic Fracturing Taskforce.

Probity Advisor

The Territory has appointed a Probity Advisor to oversee the Territory's processes in relation to the stages of this process. The Probity Advisor's role is to ensure that fairness and impartiality are observed throughout, and that the evaluation criteria stated in any related documentation are consistently applied to all submissions.

Scope of Work

The supplier must consider the following scenarios:

- **Scenario 1** or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place;
- **Scenario 2**, which involves the development of the onshore unconventional shale gas industry in the Northern Territory; and
- **Scenario 3,** which involves the development of unconventional shale gas reservoirs in the Beetaloo sub-basin only.

Benefits

The supplier must describe, in both quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with each of Scenarios 1, 2 and 3 on the Northern Territory economy under the current regulatory regime.[603]

The supplier must describe, in quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with Scenario 2 on the national economy under current regulatory, fiscal and economic settings.

For each of Scenarios 1, 2 and 3 the supplier must estimate the following:

- Gross State Product (**GSP**);
- State Final Demand (**SFD**);
- employment;
- business investment and output;
- CPI;
- population;
- wages; and
- the quantum of royalties that might be received by the Northern Territory Government under the *Petroleum Act 1984* (NT) (to avoid doubt this will include any royalties received in connection with both unconventional and conventional reservoirs).

The supplier must provide the Steering Committee with:

- in accordance with Part C, any assumptions made and an explanation of the methodology used to develop such assumptions, both of which must be approved by the Steering Committee prior to undertaking any economic modelling. The supplier must explain how reasonable and reliable the assumptions are, as well as how any potential bias has been managed, and
- a description of the similarities or differences between the assumptions made under item 7(a) above and the assumptions made in the report entitled Economic Impact of Shale and Tight Gas Development in the Northern Territory dated 14 July 2017 by Deloitte Access Economics.

The supplier must describe the options available to the Northern Territory Government, whether through policy or regulatory reforms or otherwise, to maximise and sustain the benefits captured by Territorians and others.[604] In this regard the supplier must:

- conduct a literature review to advise on leading practice methods for the sustainable development of onshore unconventional shale gas projects from an economic perspective, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and what lessons can be learned from these experiences in the Northern Territory context.

The supplier must describe the options available to the Northern Territory Government, including regulatory or policy reforms, for how revenue from the development of onshore unconventional shale industry can be retained both jointly and separately in the regions affected by the development and the Northern Territory, in each case, without impeding investment. Consideration must be given to:

- local procurement requirements, local training programs and other mechanisms to improve local capacity as well as any 'Royalty for Regions' or similar type programs, and
- case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and the lessons that can be learned for the Northern Territory context.

Risks

The supplier must describe, in qualitative terms, any actual and potential adverse impacts and risks associated with Scenario 1, Scenario 2, and Scenario 3 on the Northern Territory economy under the current regulatory regime.

The supplier must consider the impacts of development on other industries in the Northern Territory, including, but without limitation, the tourism, agricultural, horticultural and pastoral, industries.

The supplier must describe the options available to the Northern Territory Government, including policy or regulatory reforms, to mitigate and manage any actual and potential impacts and risks identified above. For example, the supplier must advise what the Northern Territory Government can do to mitigate any "boom and bust" economic cycle associated with the development of any unconventional shale gas industry.

The supplier must:

- conduct a literature review to advise on leading practice methods that could be used to manage and mitigate any risks identified, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful, and what lessons can be learned from these experiences in the Northern Territory context.

Assumptions

No production licences have been granted under the Petroleum Act for the purpose of producing unconventional shale gas in the Northern Territory. Further exploration work, including the drilling of appraisal wells, is required to fully understand the scope of the Northern Territory's shale gas reservoirs and whether or not they are commercially recoverable.

The most prospective area for shale gas development, should the moratorium be lifted by the Government, is the Beetaloo sub-basin (see Attachment A). Origin Energy announced a significant discovery of unconventional shale gas in the Beetaloo sub-basin in February 2017, which significantly increased prior estimates of the resource.

603 Indirect benefits might include the opening up of supply chains for local businesses, innovation spin offs, opportunities to develop or support supply and maintenance industries and any other flow-on opportunities the supplier identifies.

604 It is noted that onshore unconventional gas industry, local communities, local governments, Aboriginal stakeholders (including Aboriginal land councils and prescribed bodies corporate under the *Native Title Act 1993* (Cth)) have a significant role to play in the maximisation of economic benefits, however, the scope of the work is limited to actions that government can take.

In developing any assumptions required to undertake Part A and B, the supplier must consult with relevant stakeholders, including, but without limitation, the Departments of Treasury and Finance; Primary Industry and Resources; Trade, Business and Innovation; Chief Minister; Northern Territory Farmers; the Northern Territory Cattlemen's Association; petroleum operators and titleholders in the Beetaloo sub-basin, Aboriginal Land Councils, and the Australian Petroleum Production and Exploration Association.

The supplier must notify the Steering Committee prior to any consultation and members of the Steering Committee may attend the consultation.

Timelines and Reporting

The work must be in the form of a written report. The report must be written in plain English. All technical terms (including economic metrics such as Gross State Product, State Final Demand, and employment multipliers) must be explained.

At the end of each calendar month following the award of the tender the supplier must provide the Steering Committee with a written progress report and a verbal presentation within five working days of receipt of the report.

The supplier must provide the Steering Committee with a draft final report and a verbal presentation to the Steering Committee on or prior to 18 August 2017.

A final report must be provided to the Steering Committee by 1 September 2017 and the supplier must present the final report to the Panel on a date to be determined.

The Inquiry will publish the final report on the Inquiry's website on a date to be determined.

The supplier must keep all correspondence, reports and presentations to the Steering Committee confidential, except that the supplier may make the final report publicly available after it has been published on the Inquiry's website.

Appendix 10 Scope of services for social assessment modelling

Scope of Services

3.1 Background to the Inquiry

On 14 September 2016 the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory. At the same time, the Chief Minister announced that a *Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory* (the **Inquiry**) would be established and released draft Terms of Reference, which were open for public comment for four weeks.

On 3 December 2016 the Northern Territory Government announced the final Terms of Reference for the Inquiry and the composition of the panel that will be undertaking the Inquiry (the **Panel**).

The Inquiry was established under section 4 of the *Inquiries Act 1945* (NT) and is comprised of a judicial chair, the Hon Justice Rachel Pepper, and ten scientists with expertise in areas ranging from hydrogeology to social science.

The Inquiry's final Terms of Reference can be read in full on the Inquiry's website (www.frackinginquiry.nt.gov.au).

On 20 February 2017 the Inquiry released a Background and Issues Paper, also available on the Inquiry's website, which was followed by hearings and community meetings in March 2017 in various town centres and remote communities across the Northern Territory. The Issues Paper includes a timeline for the Inquiry, which indicates that an interim report will be released in mid-2017, a draft final report will be released during the last quarter of the year, and a final report will be released in December 2017.

The Hydraulic Fracturing Taskforce (the **Taskforce**) has been established in the Department of the Chief Minister to support the Panel.

3.2 Terms of Reference for the Inquiry and the social impact theme

The Panel has divided the work of the Inquiry into the following themes: water, land, air, social impacts, economic conditions, cultural conditions, human health, land access, and the regulatory framework. This request for tender relates to the social impacts theme only, however, there are overlaps with the economic, cultural and regulatory framework themes.

The Terms of Reference for the Inquiry require the Panel to do the following:

a) determine and assess the impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the associated activities;

b) determine whether additional work or research is required to make that determination;

c) for each risk that is identified, advise the level of impact or risk that is acceptable in the Northern Territory context;

d) describe methods, standards or strategies that can be used to reduce the impact and risk to acceptable levels; and

e) identify what government can do, including implementing any policy, regulatory or legislative changes, to ensure that the impacts and risks are reduced to the required levels.

The Background and Issues Paper includes a non-exhaustive list of the potential risks and benefits associated with the social impact theme at page 21.

The Terms of Reference make it clear that the Panel must not only look at the impacts of hydraulic fracturing and the associated activities on social conditions in the Northern Territory – the Panel must also consider the social impacts of the onshore unconventional gas industry as a whole on the Northern Territory. This is made clear in the following extract from the Terms of Reference, which has been amended to include the relevant language only:

> *"When the inquiry makes a determination… about whether or not there has been an impact or risk on … social conditions, the inquiry will … consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry. This may be undertaken through a social impact assessment or similar activity."*

In accordance with the definitions in the Terms of Reference, a reference to an "unconventional reservoir" in this document is a reference to a reservoir where the rock formation is shale. There is currently no gas being produced from shale reservoirs in the Northern Territory. The Amadeus Basin is currently producing gas from conventional reservoirs.

3.3 Steering Committee

A Steering Committee has been established to oversee the work of the supplier. The Steering Committee is comprised of the Hon Justice Rachel Pepper, Dr David Ritchie, Prof Peta Ashworth and the Executive Director of the Hydraulic Fracturing Taskforce. The point of contact for all matters will be the Executive Director of the Hydraulic Fracturing Taskforce.

3.4 Probity Advisor

The Territory has appointed a Probity Advisor to oversee the Territory's processes in relation to the stages of this process. The Probity Advisor's role is to ensure that fairness and impartiality are observed throughout, and that the evaluation criteria stated in any related documentation are consistently applied to all submissions.

605 A 'social impact' is defined as a change to any of the values or conditions set out at **Attachment A** and must include cumulative social impacts.

Part A – Social Impact Assessment

3.5 Development and implementation of a social impact assessment framework

The supplier must develop a leading practice framework for the identification, assessment and management of the social impacts associated with the development of onshore unconventional gas in the Northern Territory.[605] The framework:

a) must include a requirement for public participation;

b) may include components of both strategic and project-level social impact assessment; and

c) must operate in conjunction with the Northern Territory and Commonwealth environmental assessment frameworks in a way that minimises unnecessary duplication and inconsistency.

The supplier must explain why the proposed framework is leading practice and in doing so must refer to the literature and leading practice social impact assessment frameworks used in other jurisdictions, including overseas jurisdictions.

The supplier must describe the current policy and regulatory regime in the Northern Territory for the identification, assessment and management of social impacts associated with onshore unconventional gas development.

The supplier must identify the structural, policy, regulatory and legislative reforms that must be made to the current regime in the Northern Territory to implement the social impact assessment framework described above.

The supplier must describe how the framework will operate in conjunction with the Northern Territory and Commonwealth environmental assessment frameworks in a way that minimises unnecessary duplication and inconsistency.

3.6 Beetaloo Sub-basin

The supplier must identify the people or groups of people that are most likely to be impacted by the development of unconventional gas resources in and around the Beetaloo sub-basin, shown in Attachment B, which may include, without limitation, community members, pastoralists, Aboriginal organisations and local businesses (the Affected Communities).

The supplier must describe the methodology used to identify the Affected Communities.

The supplier must describe the Affected Communities (that is, describe the community profile or baseline conditions), which must include a description of the values listed at Attachment A and how such information was collected.

The supplier must describe the type of potential social impacts, issues, concerns, risks and benefits that may arise from the development of the unconventional gas industry in the Beetaloo sub-basin on the Affected Communities. In identifying the potential impacts the supplier must consider:

a) the list of social impacts, risks and benefits described in sections 7.5, 7.6, 7.7, and 7.8 of the *Background and Issues Paper*;

b) submissions made to the Panel in connection with the *Background and Issues Paper*;

c) social impacts, issues, benefits and risks typically associated with the development of onshore unconventional gas resources that have been identified in the literature and in other jurisdictions; and

d) issues that have been identified in other social impact assessments and related studies that have been completed in or around the Beetaloo sub-basin, including those listed at **Attachment C**.

For each potential impact identified, the supplier must, to the extent possible:

a) assess the potential impact (or risk) in terms of likelihood and consequence (high, medium, low);

b) identify a potential measurable indicator, which can be qualitative or quantitative, and develop a methodology for the collection of appropriate baseline data in the Affected Communities so that changes in social values or conditions as a result of any unconventional gas development can be measured over time;

c) collect such baseline data;

d) identify ways to avoid, mitigate and/or manage the risk over time (including the entity that should be responsible for the management and monitoring of such risk) and predict what the level of risk will be following mitigation; and

e) indicate whether or not the level of risk following mitigation would be deemed acceptable, and why.

For every potential social benefit that is identified, the supplier must recommend strategies to realise and maximise such benefit.

The supplier must identify any issues that must be addressed in subsequent project-based social impact assessments associated with the development of unconventional gas in the Beetaloo sub-basin.

The supplier must develop and implement a leading practice community consultation program to support its responses to section 3.6. The supplier must consult, without limitation and where practicable, the Aboriginal Areas Protection Authority; the Northern Land Council; the Departments of Primary Industry, Resources and Trade, Business and Innovation, and Tourism Northern Territory; local and regional councils; the Northern Territory Cattleman's Association; Northern Territory Farmers, and petroleum operators and titleholders in the Beetaloo sub-basin. The Steering Committee must approve the program prior to implementation.

Part B - Social Licence to Operate

3.7 The supplier must describe, with reference to the literature and examples from other jurisdictions:

a) the concept of a "social licence to operate" as it applies to the onshore unconventional gas industry in the Northern Territory;

b) the nature and extent of any potential risks to affected stakeholders, including the Northern Territory Government, petroleum titleholders and operators in the Northern Territory, the Northern Territory community, and the communities affected by development, where industry has not obtained and/or maintained a social licence to operate;

c) the measures that onshore unconventional gas industry and government can take to enable industry to earn and maintain a social licence to operate in the Northern Territory; and

d) how industry's social licence to operate can be measured in the Northern Territory, including a part of the Northern Territory.

3.8

The supplier must identify, to the extent practicable, the measures that the petroleum titleholders and operators in the Beetaloo sub-basin have taken in the past, and can take in the future, to earn and maintain a social licence to operate in the Affected Communities.

3.9 Timelines and Reporting

The work must be in the form of a written report.

The report must include a literature review that includes all references used in section 3.5 and 3.6.

At the end of each calendar month following the award of the tender the supplier must provide the Steering Committee with a written progress report and a verbal presentation within five working days of receipt of the report.

The supplier must provide the Steering Committee with a draft final report and a verbal presentation to the Steering Committee on or prior to 1 September 2017.

A final report must be provided to the Steering Committee by 15 September 2017 and the supplier must present the final report to the Panel on a date to be determined.

The Inquiry will publish the final report on the Inquiry's website on a date to be determined.

Attachment A

The *International Association for Impact Assessment* defines "social impacts" as changes to one or more of the following:[606]

a) people's way of life – that is, how they live, work, play and interact with one another on a day-to-day basis;

b) their culture – that is, their shared beliefs, customs, values and language or dialect;

c) their community – its cohesion, stability, character, services and facilities;

d) their political systems – the extent to which people are able to participate in decisions that affect their lives, the level of democratisation that is taking place, and the resources provided for this purpose;

e) their relationship with their environment – the quality of the air and water people use; the availability and quality of the food they eat; the level of hazard or risk, dust and noise they are exposed to; the adequacy of sanitation, their physical safety, and their access to and control over resources;

f) their health and wellbeing – health is a state of complete physical, mental, social and spiritual wellbeing and not merely the absence of disease or infirmity;

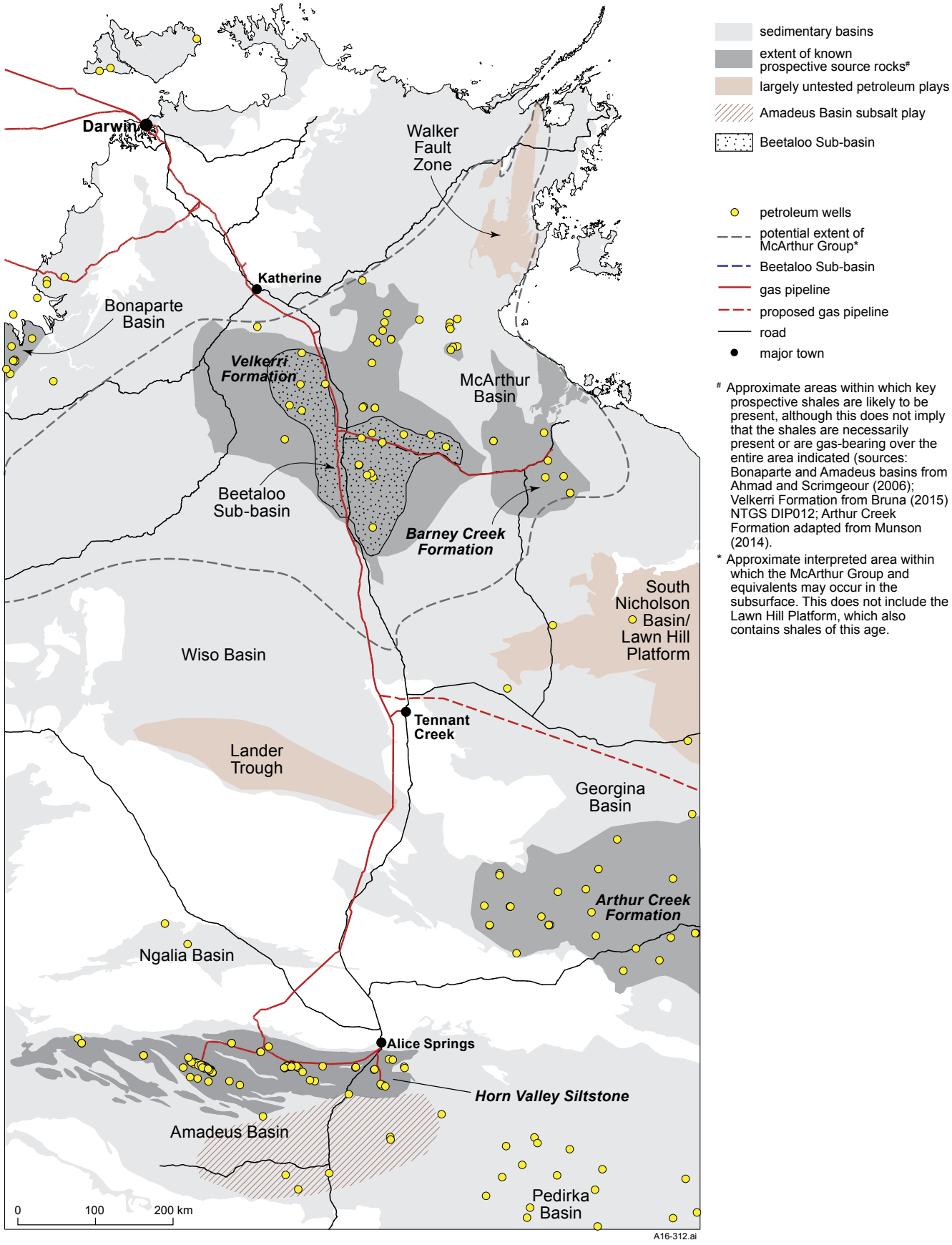
g) their personal and property rights – particularly whether people are economically affected, or experience personal disadvantage which may include a violation of their civil liberties; and

h) their fears and aspirations – their perceptions about their safety, their fears about the future of their community, and their aspirations for their future and the future of their children,

in each case, to the extent such impact would not otherwise be assessed as part of an environmental impact assessment under Northern Territory or Commonwealth legislation.

606 Adapted from Vanclay, F. 2003 International Principles for Social Impact Assessment. Impact Assessment and Project Appraisal 21(1), 5-11 (available at http://dx.doi.org/10.3152/147154603781766491 last accessed 21 April 2017).

Attachment B(1)

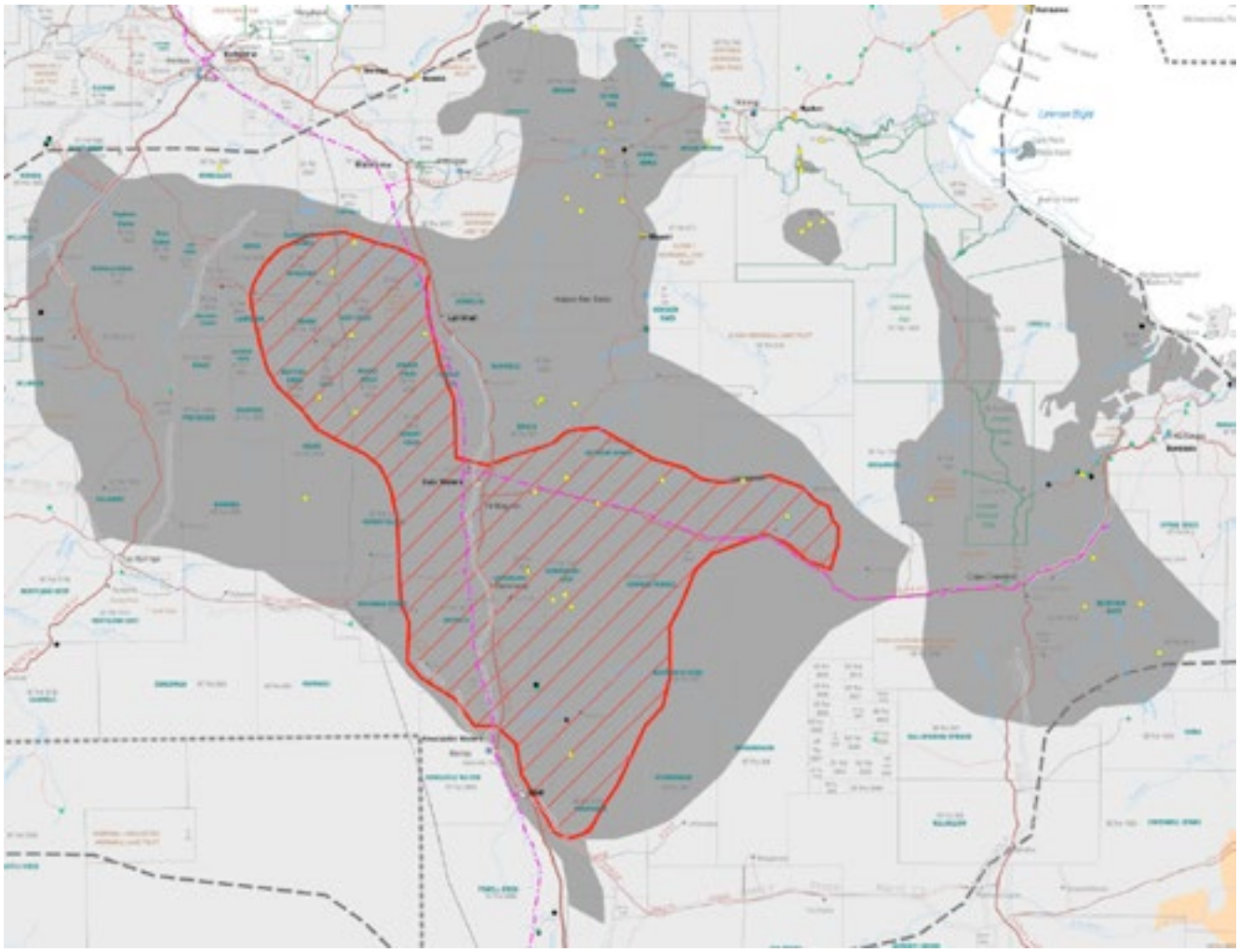


Approximate areas within which key prospective shales are likely to be present, although this does not imply that the shales are necessarily present or are gas-bearing over the entire area indicated (sources: Bonaparte and Amadeus basins from Ahmad and Scrimgeour (2006); Velkerri Formation from Bruna (2015) NTGS DIP012; Arthur Creek Formation adapted from Munson (2014).

* Approximate interpreted area within which the McArthur Group and equivalents may occur in the subsurface. This does not include the Lawn Hill Platform, which also contains shales of this age.

NORTHERN TERRITORY GOVERNMENT

Attachment B(2)



ATTACHMENT C

- The research monograph entitled Ngukurr at the Millenium:" A Baseline Profile for Social Impact Planning in South East Arnhem Land, by J. Taylor, J. Bern, and K.
- Social Impact Assessment undertaken by EcOz in connection with the Western Desert Resources Roper Bar Iron Ore Project.
- The Economic and Social Impact Assessment undertaken by EcOz in connection with the Sherwin Creek Iron Ore Project.
- The Social Impact Assessment Scoping Study and the Economic and Social Impact Assessment undertaken by Circle Advisory in connection with the Northern Gas Pipeline.

Appendix 11 Glossary

Term	Definition
AAPA	Aboriginal Areas Protection Authority
ACOLA	Australian Council of Learned Academies
ACOLA Report	P Cook, V Beck, D Brereton, R Clark, B Fisher, S Kentish, J Toomey and J Williams, *Engineering Energy: Unconventional Gas Production*, report for the Australian Council of Learned Academies, May 2013
AER	Australian Energy Regulator
ALARP	As low as reasonably practicable
APPEA	Australian Petroleum Production and Exploration Association
ATSE	Australian Academy of Technological Sciences and Engineering
Ba	Barium
BOM	Bureau of Meteorology
BTEX	Benzene, toluene, ethane, xylene
Ca	Calcium
CBI	Confidential business information
CH4	Methane
CLA	Cambrian Limestone Aquifer
CLC	Central Land Council
CLP	Country Liberal Party
CNG	Compressed natural gas
CO2	Carbon dioxide
CoC	Chemicals of concern
COP21	Conference of the Parties, United Nations Framework Convention on Climate Change, 21st sess
CSG	Coal Seam Gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSM	Conceptual Site Model
DENR	Department of Environment and Natural Resources (NT)
DIPL	Department of Infrastructure, Planning and Logistics
DPIR	Department of Primary Industry and Resources (NT)
EIA	Environmental Impact Assessment
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EMP	Environmental Management Plan
ENT	Ear, nose, and throat
EPA	Northern Territory Environment Protection Authority
EPBC Act	*Environment Protection and Biodiversity Conservation Act 1999* (Cth)
ESD	Ecologically Sustainable Development
Exploration Permit/ EP	Petroleum exploration permit under the *Petroleum Act 1984* (NT)
FIFO	Fly in fly out worker
Fracking	Fracturing of rock with a liquid under high pressure to create artificial openings and cracks in the rock to increase the rock's permeability. See also 'hydraulic fracturing'
Fugitive emissions	Intentional and unintentional release of greenhouse gases during the production, processing, transport, storage, transmission and distribution of fossil fuels
GA	Geoscience Australia
GAB	Great Artesian Basin

Term	Definition
GDE	Groundwater dependent ecosystem
UGE	Unconventional gas extraction
GISERA	Gas Industry Social & Environmental Research Alliance
Government	Northern Territory Government
GWP	Global Warming Potential
HDPE	High-density polyethylene
HF	Hydraulic fracturing
HFF	Hydraulic fracturing fluids
HFS	Hydraulic fracture stimulation. See 'hydraulic fracturing'
HHRA	Human health risk assessment
HI	Hazard index
HIA	Health impact assessment
Hydraulic fracturing	Fracturing of rock with a liquid under high pressure to create artificial openings and cracks in the rock to increase the rock's permeability. See also 'fracking'
IEA	International Energy Agency
Inquiry	Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory
IPCC	Intergovernmental Panel on Climate Change
Land Rights Act	*Aboriginal Land Rights (Northern Territory) Act 1976* (Cth)
LCA	Life cycle analysis. Analysis of emissions through the entire life of a unit of fuel
LNG	Liquefied natural gas
MEI	Melbourne Energy Institute
Native Title land	Land subject to a native title application or determination under the *Native Title Act 1993* (Cth)
NETL	US National Energy Technology Laboratory
NGCC	Natural gas, combined-cycle (turbine)
NICNAS	National Industrial Chemicals Notification and Assessment Scheme
NLC	Northern Land Council
NORM	Naturally occurring radioactive materials
NSPS	New Source Performance Standards
NSW	New South Wales
NTA	*Native Title Act 1993* (Cth)
OECD	Organisation for Economic Cooperation and Development
Panel	The independent scientific panel appointed by the Chief Minister to conduct the Inquiry
Paris Agreement	Decision of the Conference of the Parties, United Nations Framework Convention on Climate Change, *Adoption of the Paris Agreement*, 21st sess, UN Doc FCCC/CP/2015/L.9/Rev.1
Pastoral Lease	Pastoral leases granted under the *Pastoral Land Act 1992* (NT)
Pastoral Lessee	Holder of a pastoral lease under the *Pastoral Land Act 1992* (NT)
Petroleum Act	*Petroleum Act 1984* (NT)
Petroleum Environment Regulations	*Petroleum (Environment) Regulations 2016* (NT)
Petroleum Permittee	Holder of a petroleum exploration permit under the *Petroleum Act 1984* (NT)
Petroleum Schedule	*Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (NT)
SA	South Australia
SIMP	Social impact management plan
SIA	Social impact statement
SLO	Social licence to operate

Term	Definition
TOs	Traditional owners
UGE	Unconventional gas extraction
UIC	Underground injection control
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
UNE	Unconventional natural gas extraction
US	United States of America or United States
US EPA	United States Environmental Protection Agency
VOC	Volatile organic carbon
VOCs	Volatile organic compounds
WA	Western Australia
Water Act	*Water Act 1992* (NT)
Waste Management Act	*Waste Management and Pollution Control Act 1998* (NT)
Weeds Act	*Weeds Management Act 2001 (NT)*

Appendix 12 Units of measurement

Unit	Definition
AHD	Australian Height Datum
Bcm	Billion cubic metres
CI	Confidence interval
CO_{2e}	Carbon dioxide equivalent. A metric for the measurement of the global warming potential of a substance
EC	Electrical conductivity
EUR	Estimated Ultimate Recoveries
GL	Gigalitre
GL/y	Gigalitres per year
GWP	Global Warming Potential
ha	Hectare (10,000 m^2)
km	Kilometre
km^2	Kilometre squared
L	Litre
L/s	Litres per second
L/min	Litres per minute
m^3	Metres cubed
mg/L	Miligrams per litre
MJ	Megajoule (1 joule x 10^6)
ML	Megalitre (1 litre x 10^6)
ML/y	Megalitres per year
mm	Millimetre
mmcfd	Million cubic feet per day (energy industry)
mm/y	Millimetres per year
Mt CO_{2e}	Million tonnes of carbon dioxide equivalent
MWh	Megawatt-hour
OR	Odds ratio
PJ	Petajoules
PM	Particulate matter
t	Tonne (1,000 kg)
Tcf	Trillion cubic feet
TDS	Total Dissolved Solids
TJ	Terajoule (1 joule x 10^{12})
TJ/d	Terajoule (1 joule x 10^{12}) per day
TOC	Total Organic Content
TSS	Total Suspended Solids
uS/cm	Microsiemens

Appendix 13 Risk assessment matrix

As described in the Issues Paper, an environmental risk arises when there is an interaction between an activity, such as hydraulic fracturing, and the environment. The level of risk is determined by assessing the likelihood and the consequence of the risk. All risks associated with an activity fit somewhere inside a risk matrix.

For the purposes of assessing risk levels in the Interim Report, the Panel has identified whether the likelihood and consequence of an activity is either 'Low', 'Medium' or 'High'. Once this assessment is made the resultant risk will also be either 'Low', 'Medium' or 'High' in accordance with the risk matrix below.

Risk matrix

		Likelihood		
		(L) The likelihood of the impact occurring is < 1%	**(M) The likelihood of the impact occurring is between 1 – 10%**	**(H) The likelihood of the impact occurring is > 10%**
Consequence (see table below)	(H)	M	H	H
	(M)	L	M	H
	(L)	L	L	M

Descriptions of consequence levels

The consequence descriptors in the table below have been adapted from the Consequence Ratings Table 1 on p 29 of the Petroleum Environment Regulations Guide (referred to below as the 'DPIR table').

Key changes between the descriptors below and the DPIR table are:

- unlinking social and cultural impacts; and
- the removal of personnel safety

While each Chapter may have separate definitions of consequences that are relevant to their particular circumstances, these will generally be consistent with the descriptions given in the Table below.

For example, while the descriptions for 'L', 'M' and 'H' consequences for Natural Environment in the Table below are taken from the DPIR table, they are largely focussed on land and biodiversity impacts. Tailored consequence descriptions for water, land and GHG emissions will be provided in Chapters 7 (Water), 8 (Land) and 9 (Greenhouse gas emissions).

The financial descriptors are a measure of the costs that may be required to compensate or rehabilitate the consequence and are provided as an alternative to the qualitative descriptors. In many cases, they may not be applicable, given that many important values (for example, amenity, biodiversity, sacred sites, and so on) are unable to be valued in monetary terms.

Theme		L	M	H
		The consequence is less than or equal to the descriptions below. The descriptions below are adapted from the "moderate-2" column of the DPIR table. (Note: "Low" covers Minor-1 and Moderate-2 of the DPIR Table)	The consequence is greater than the impact described in (L) and less than the impacts described in (H). Examples of the consequences for a moderate impact are described below. The descriptions below are adapted from the "serious- 3" column of the DPIR table.	The consequence is greater than or equal to the descriptions below. The descriptions below are adapted from the "major-4" column of the DPIR table. (Note: "High" covers Major-4, Critical-5 and Catastrophic-6 of the DPIR Table)
Qualitative Descriptors	Natural Environment	Loss of containment within declared activity area with minor short term damage to an area of limited significance but not affecting ecosystem functions	Moderate effect on biological and physical environment with significant short term effect on ecosystem function	Significant environmental impact on ecosystems or species. Widespread medium and long-term impact.
	Public Health	Medical treatment for injury or condition by a health practitioner with only minor temporary impact, or prediction from a formal health risk assessment that chemical exposures would not exceed relevant health-based guideline values	Medical treatment for injury or condition by a specialist or health practitioner with impact lasting more than a week but less than 3 weeks, or prediction from a formal health risk assessment that chemical exposures could exceed relevant health-based guideline values, but by no more than ten-hundred fold (within conventional safety factors built into such values)	Serious but temporary injury or condition of members of the public with lasting effects over 3 weeks requiring specialist medical assistance, or prediction from a formal health risk assessment that chemical exposures could exceed a relevant health-based guideline value by more than one hundredfold.
	Aboriginal people and their culture	Minor medium term cultural impact which is repairable within two months.	Community, NGO attention and criticism, ongoing cultural issues, permanent but minor damages to items of cultural significance.	Significant and widespread cultural impacts, significant damage to items of cultural heritage.
	Social	Minor medium term social impact which is repairable within two months.	Community, NGO attention and criticism, ongoing social issues.	Significant and widespread social impacts.
Financial Descriptors		< $250,000	> $250,000 to < $1 million	> $1 million

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