SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

FINAL REPORT

APRIL 2018

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This is the *Final Report of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory*. There is also a Summary of the Final Report and a set of Appendices.

Each document has been published separately, but together they form the totality of the Final Report.

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

Dear Chief Minister

RE: RELEASE OF THE INQUIRY'S FINAL 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 together with a panel of eminent scientists across a diverse range of expertise (**the Panel**).

I am pleased to present to you the Inquiry's *Final Report*, which is the culmination of the Panel's comprehensive scientific research, extensive consultation with the community, and consideration of more than 1250 submissions.

The *Final Report* contains 135 recommendations to reduce the identified risks associated with any development of any onshore shale gas industry in the Northern Territory to acceptable levels.

The Inquiry would like to expresses its utmost gratitude to everyone who has contributed to it during the past 15 months. The level of engagement with the Inquiry by the public, by environmental groups, by the gas industry and by other stakeholders has been of a consistently high quality, and which is reflected in the Report and its recommendations.

The Inquiry would also like to thank the Government for the considerable respect that it has afforded the Inquiry's processes. At all times the Government has allowed the Inquiry to carry out its duties free from political interference or influence. The public can have every confidence that the Inquiry has been truly independent.

The Inquiry has had the great privilege of visiting many different communities and interacting with many people, groups and organisations during the course of its work. If it has learnt one thing, it is that the Northern Territory is immensely fortunate to have so many passionate and committed individuals who only have the Territory's very best interests and brightest future at heart.

Yours sincerely

THE HON JUSTICE RACHEL PEPPER
Chair
27 March 2018

Dr Alan Andersen
Prof Peta Ashworth
Dr Vaughan Beck AM
Prof Barry Hart AM
Dr David Jones
Prof Brian Priestly
Dr David Ritchie
Dr Ross Smith

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Final Report foreword

There are many people who must be thanked because without their advice, expertise, diligence and herculean effort, the completion of this Report, and therefore, this Inquiry, would not have been possible.

Ms Jane Coram was an invaluable member of the Panel until 20 December 2017, when she resigned to take up her appointment as CEO of the National Measurement Institute. Ms Coram has recently been appointed as the Land and Water Director of CSIRO.

The Taskforce established to assist the Inquiry, comprising of Mr James Pratt, Ms Amy Dennison, Ms Geraldine Lee and Ms Kate Walker, has been unparalleled and unwavering in their support. Each has done the work of many, always to the highest possible standard and always willingly. They are a credit to the Northern Territory.

Until 28 June 2017, Mr Richard McAllister provided further administrative assistance as part of the Taskforce.

The communications strategy was commendably carried out by Ms Claire Sprunt and Ms Jo Brosnan.

The Aboriginal Interpreter Service (**AIS**) organised interpreters to accompany the Panel to consultations in remote communities. The AIS also translated the key publications of the Inquiry into language, the recordings of which are available on the Inquiry's website.

The team at Dreamedia Creative Event Production was outstanding in providing the technical and transcription expertise necessary to conduct the highly successful public hearings.

Additional academic assistance was provided by Prof Sandra Kentish (University of Melbourne) in respect of Chapter 9 and Mr Angus Veitch and Ms Nicole Heesh (University of Queensland) for Chapter 12.

Research assistance was more than capably provided by Ms Rachael Chick and Ms Veronica Finn.

Proofreading of the *Interim Report, Draft Final Report* and *Final Report* was carefully carried out by Ms Jo Robertson of Communicate NT.

The graphic designers are to be commended for giving life to the text through their layout and design.

This and other reports of the Inquiry were printed by Zip Print, Image Offset and Colemans Printing, occasionally at short notice but always professionally and without compromise to the quality of the final product.

Webservices were ably provided by Brainium Labs.

Ms Kim Pitt, along with others, provided critical secretarial support.

Chambers were generously found for the Inquiry in Sydney by the Hon Chief Justice Tom Bathurst AC of the Supreme Court of New South Wales, Mr Chris D'Aeth, Executive Director and Principal Registrar of the Supreme Court of New South Wales (for whom no problem was too big to solve), and Ms Melinda Morgan, Registrar of the Industrial Relations Commission of NSW.

Because the Panel took its mandate to consult the community seriously, many hours were spent in small planes travelling between urban, rural and remote communities. In particular, Hardy Aviation, Chartair, Airnorth, Murin Air and Adagold Aviation delivered us safely and comfortably to each destination.

Initially, advice was sought on that most prosaic of matters, namely, how to run an inquiry. It was willingly and generously given by Professor Mary O'Kane, the former New South Wales Chief Scientist and Engineer, the Hon Justice Peter Garling of the Supreme Court of New South Wales and the Hon Justice Tim Moore of the Land and Environment Court of New South Wales. All of it proved to be invaluable.

To the long suffering partners of both the Panel and the Taskforce, who endured many absences and countless domestic disruptions, the debt is profound.

Finally, the Inquiry must express its deep gratitude to all those people who genuinely and sincerely participated in the Inquiry by way of written submissions, public presentations and community forum discussions. From the outset this Inquiry was always intended to be for the Territory, by the Territory. This is exactly what occurred. Territorians embraced the consultation process in full, and in doing so, greatly strengthened and improved the end result.

The enthusiasm and passion with which Territorians engaged with the Inquiry was inspiring. And while not everyone may agree with some, or even any, of the findings made in this Report, their effort is reflected in many of the recommendations made by the Panel. There can be no doubt that the *Final Report* is all the better for it.

THE HON JUSTICE RACHEL PEPPER

Chair of the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory

27 March 2018

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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 gas reservoirs in the Northern Territory (NT). 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 (**Government**) announced that it had established the Inquiry under the *Inquiries Act 1945* (NT).

The Inquiry is Chaired by the Hon. Justice Rachel Pepper, a judge of the Land and Environment Court of New South Wales (LEC) a superior court of record. Her Honour was formally appointed as Chair of the Inquiry on 30 January 2017.

The Panel is comprised of nine 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 www.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 in Appendix 1.

1.3 The purpose of the Inquiry

The purpose of this Inquiry is found in the Terms of Reference, the drafting of which the Inquiry had no input into. 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 gas reservoirs and its associated activities on the environmental (aquatic, terrestrial and atmospheric), social, cultural and economic conditions of the NT;
- 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.

The Terms of Reference, notwithstanding their breadth, nevertheless provide constraints on the scope of the Inquiry. Excluded from its scope is coal seam gas (CSG), sandstone (or 'tight') gas and shale oil. Critically, an examination of the place and future of renewable energy within the NT is outside the Terms of Reference as are the occupational health and safety implications of any onshore shale gas industry.

In the course of delivering on its Terms of Reference, the Inquiry was required to develop and implement a stakeholder engagement program, which included opportunities for the public to make oral and written submissions to and consult with the Panel.

1.4 Overview of previous inquiries into hydraulic fracturing in the NT

As was discussed in the Issues Paper[1], this is not the first inquiry that the NT has held into hydraulic fracturing. However, as indicated above, this Inquiry differs from its predecessors, by reason of its scope (it is wider) and its mandate to consult widely with Territorians.

In 2011, the former Labor Government commissioned Dr Tina Hunter, an expert in petroleum law, to report on the capacity of the NT's legal framework to regulate the development of the onshore petroleum industry in the NT (**2012 Hunter Report**).[2] A key recommendation from the 2012 Hunter Report was that the Government should prioritise the development and implementation of regulations under the *Petroleum Act 1984* (NT) (**Petroleum Act**) for the protection of the environment[3].

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 NT (**2014 Hawke Report**).[4]

The 2014 Hawke Report's major recommendation was that, *"consistent with other Australian and International reviews... the environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory system"*.[5]

Another relevant recommendation was that the 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.[6]

Following the 2012 Hunter Report and the 2014 and 2015 Hawke Reports, new *Petroleum (Environment) Regulations 2016* (NT) (**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 said that "the fundamentals of the Regulations are sound".*[7]

The principal difference between this Inquiry and the reviews described above is the broad scope of the Inquiry's Terms of Reference and its clear instruction to consult widely with all Territorians.

1 Issues Paper, p 10.
2 2012 Hunter Report.
3 2012 Hunter Report, recommendation 16.
4 2014 Hawke Report.
5 2014 Hawke Report.
6 2015 Hawke Report.
7 2016 Hunter Report, p 4.

1.5 The identified risks of hydraulic fracturing in the NT

The potential risks associated with hydraulic fracturing for onshore shale gas in the NT were identified in the Issues Paper as 'issues', which were categorised into nine themes for ease of reference.

A total of 1260 submissions have been received by the Inquiry (of which 582 are pro forma letters that do not materially differ in substance from each other). This is in addition to the information obtained at the hearings and community forums, and the feedback contained in more than 221 'Have Your Say' forms.

The risks set out in detail in the Issues Paper have been discussed during extensive consultations in urban centres and rural and remote communities across the NT. As a result of these discussions, additional issues were identified, which have been taken into account by the Panel. A final list of issues compiled pursuant to this process is attached at Appendix 2. The new risks raised by the public during the course of the consultations are identified in italics.

Based on the available evidence, the Panel has now assessed these risks and determined whether or not they are material, and where it has been found that they are, the extent to which, if any, they can be mitigated to an acceptable level by appropriate recommended safeguards (the Panel's methodology is set out in Chapter 4). The Panel has made a number of recommendations (see Chapter 16) to the Government to assist it in the effective establishment and maintenance of those safeguards.

Ultimately, it is a matter for the Government, not the Inquiry, upon receipt of this Report, to determine whether or not the current moratorium should be lifted. The Terms of Reference do not permit such a recommendation to be made by the Inquiry.

WORK OF THE INQUIRY TO DATE

2

2.1 Stakeholder engagement program

As stated in Chapter 1, the Inquiry was directed to consult widely with Territorians about their views on the development of any onshore unconventional shale gas industry in the NT.

The Inquiry implemented an extensive stakeholder engagement program that included opportunities for the public to make written submissions and consult directly and indirectly with the Inquiry. The issues raised during the course of this program that fell within the Terms of Reference have informed the work of the Panel.

The first round of consultation took place in March 2017, following the release of the Issues Paper. It consisted of public hearings and community information and engagement sessions, or 'community forums'.

Following the release of the *Interim Report* in July 2017 (**Interim Report**), a second round of consultation was undertaken during August 2017 in the same format as the first round. And following release of the *Draft Final Report* in December 2017 (**Draft Final Report**), a final round of consultation was undertaken in February 2018.

A summary of the discussions that occurred during the first, second and third rounds of consultations is contained in Chapter 3.

2.1.1 Public hearings

Two rounds of public hearings were conducted in 2017 and one round in 2018. The hearings were open to anyone who had registered in advance. The Inquiry held 151 public hearings in Alice Springs, Tennant Creek, Katherine and Darwin. Presenters included members of the public, environmental groups, the gas industry, pastoralists, Aboriginal land managers, Land Councils local governments, and other stakeholders. A full list of those who attended the hearings is found at Appendix 7.

The hearings were recorded and live-streamed on the Inquiry's website to facilitate access for those who could not otherwise attend in person. During March and August 2017 and February 2018, the live-stream was viewed by almost 2,000 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 www.frackinginquiry.nt.gov.au/submission-library

The video recordings and transcripts of each hearing, as well as any documentation provided by the presenters (the documents were tabled as a submission 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 www.frackinginquiry.nt.gov.au/submission-library

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

Public hearing held in Katherine. August 2017.

2.1.2 Community forums

Consultation during the Inquiry has also included community forums. These forums were designed to encourage active discussion and participation by those who attended. They were open for anyone. Prior registration was not a prerequisite to attendance. A full list of the community forums is contained in Appendix 8.

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

The first round of community forums commenced with a brief presentation from either Prof Peter Flood or Dr Ross Smith, explaining the process by which onshore 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, or 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 the group discussion to the entire forum.

The second and third round of community forums featured a presentation by the Panel of the Inquiry's work to date, the content of the Interim Report and the Draft Final Report and a description of future work of the Inquiry Group roundtable discussion occurred following the presentations.

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

An Inquiry community forum held in Elliott. July 2017.

2.1.3 Northern Territory visits and stakeholder consultations

Between 20 and 24 February 2017, the Chair 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 full list of stakeholder meetings is at Appendix 5.

On 4 July 2017, the Chair and Dr Alan Andersen travelled to Newcastle Waters to meet with the traditional owners of that area and then on to Elliott to meet with a number of community members. Representatives from the Northern Land Council (**NLC**) attended the meeting at Newcastle Waters. At both meetings, a range of issues were discussed, including the need to be properly and fully informed and consulted in respect of any potential onshore shale gas activities on Aboriginal and native title land (that is, the need to be told of both the benefits and the potential adverse consequences of the development); the need for the NLC to act in a wholly disinterested manner in conducting negotiations with gas companies on behalf of Aboriginal people, the concern of Aboriginal people of the capacity for environmental and cultural damage to occur as a result of any onshore shale gas industry (especially with respect to water, traditional cultural practices, bush tucker and sacred sites); and the need to ensure that the benefits of any onshore unconventional gas development flowed to the communities upon whose land the development would take place, in particular, the need to create and retain local employment opportunities.

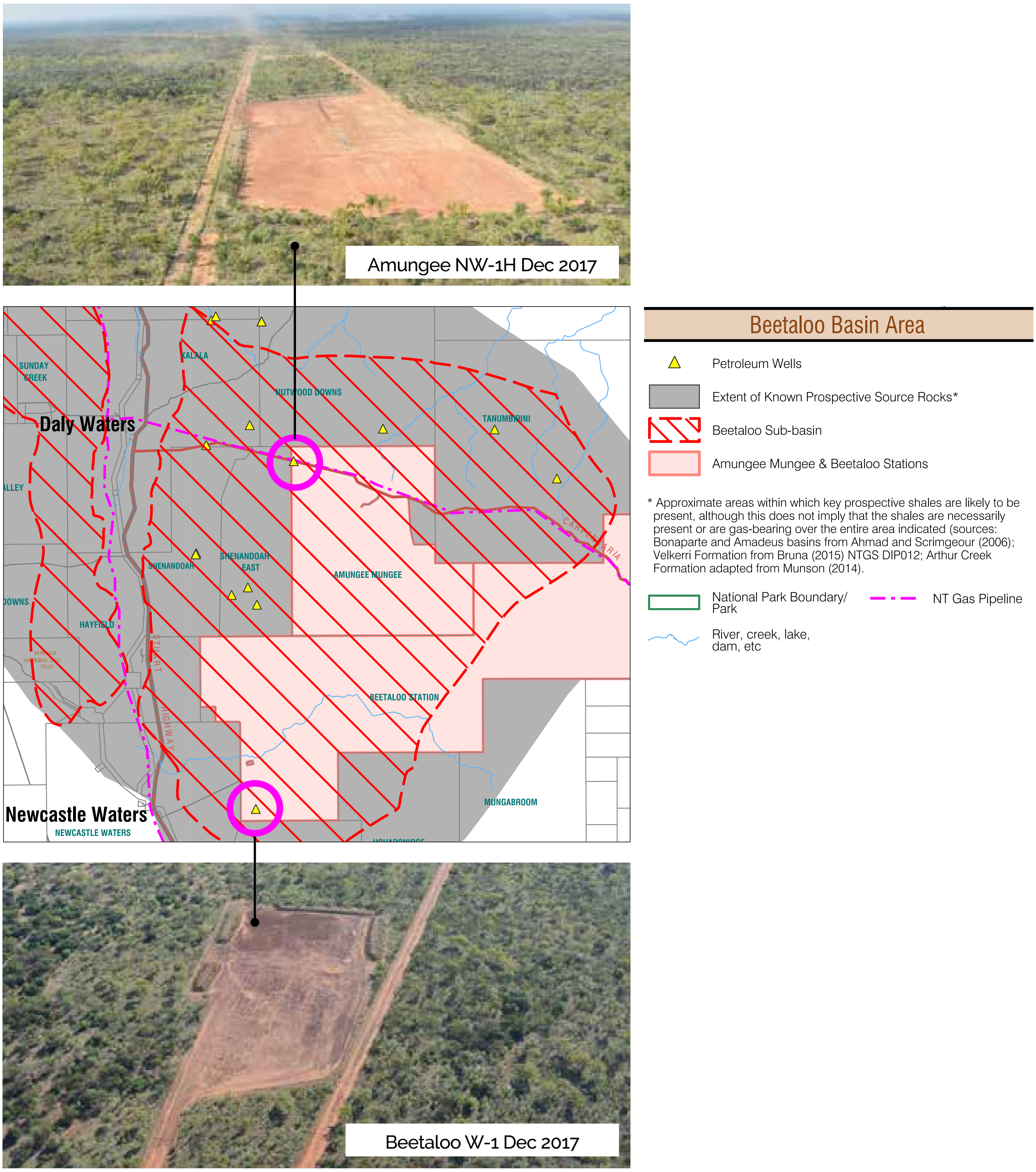
On 5 and 6 July 2017, the Chair, again accompanied by Dr Andersen, visited two NT pastoral stations,namely, Hayfield Station, operated by the Dyer family, and Maryfield Station, operated by North Star Pastoral Pty Ltd. The purpose of this visit was to understand, firsthand, the operation of a cattle station in order to assist in evaluating the potential impacts, both adverse (for example, disruption to business) and beneficial (improvements in infrastructure and the creation of an ongoing revenue stream) that any onshore shale gas development might have on that industry.

On 28 August 2017, the Panel visited a gas field operated by Central Petroleum Limited (**Central Petroleum**) in Palm Valley, Central Australia. The Palm Valley Gas Field is not currently producing gas. The Panel viewed gas well infrastructure, including pipelines and water retention ponds.

On 13 December 2017, the Panel travelled to the Beetaloo Sub-basin to speak with pastoral lessees regarding exploration, well construction and testing of shale gas wells on their properties. The Panel met Mrs Jane Armstrong on Beetaloo Station (7,078 km^2) and Mr Adrian Brown on Amungee Mungee Station (3,169 km^2). These stations fall within EP 98 and EP 117 respectively, both of which are administered by Origin Energy Limited (**Origin**). Beetaloo Station has had two wells constructed on it over the past 10 years: one by Sweetpea Petroleum Pty Ltd (prior to 2010); and one by Origin in 2015. The first well did not proceed to production and has since been abandoned. The second well has been drilled and tested but not hydraulically fractured. The single horizontal well which was drilled on Amungee Mungee Station is the most recently hydraulically fractured well in the NT and the first that has been horizontally drilled and production tested. The Panel inspected that well and the well pad.

Finally the Panel visited Central Petroleum's facilities at Mereenie gas field on 14 December 2017. The Mereenie gasfield covers an area of approximately 130km^2 in the Western Amadeus Basin, 250km west of Alice Springs. The fields are located on Luritja Aboriginal land and are contained within NT petroleum leases OL4 and OL5. Production commenced in 1984. The workforce constitutes approximately 40 people, of which 60% are based in Alice Springs and 12 are Aboriginal. Forty-five of the 65 predominantly vertical sandstone wells (tight gas) located on the gasfield have been hydraulically stimulated.

Figure 2.1 Extract from the Beetaloo Sub-basin showing stations visited by the Panel and respective well locations.



2.2 Departmental briefings

Various governmental departments, both within the NT and from other jurisdictions, have briefed the Panel on subjects relevant to the work of the Inquiry. The purpose of these briefings was to provide essential background information on a range of topics. A list of the briefings is set out at Appendix 6.

It should be noted, however, that apart from these briefings and the written submissions provided to the Inquiry, no Government department or agency has made a public appearance before the Panel. This has done little to enhance public confidence and trust in the Government.

2.3 Interstate visits and stakeholder meetings

On 31 January 2017, the Panel undertook an interstate visit to South Australia (**SA**) to consult with officers of the Energy Resources Division of the Department of State Development about the regulatory framework governing conventional and unconventional onshore gas development in that State. Consultation also took place 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's operation in the Cooper Basin was tight gas, not shale gas. However, the infrastructure, processes and supporting operations observed were relevantly comparable to those of a typical onshore 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 on-site 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.

Hydraulic fracturing operation in Moomba, South Australia.

On 18 and 19 July 2017, the Panel went to Canberra, ACT, to meet with a range of Commonwealth stakeholders, including the Department of the Environment and Energy. The environmental risks of the chemicals used during CSG extraction were discussed, together with the funding announcement in the 2017 federal budget for combined geological and bioregional resource assessments. Also discussed was Australia's current emissions reductions targets, whether or not a supply of natural gas to the east coast of Australia could assist in meeting these targets, and the role of the Northern Gas Pipeline.

Between 24 and 28 July 2017, the Inquiry travelled to Queensland to meet with stakeholders directly affected by CSG exploration and extraction, consult with government regulators and visit a CSG field operated by Santos.

During an evidence gathering tour of the Darling Downs and south west region of Queensland, the Panel met with landowners, local government and businesses in Dalby, Roma and Miles that were directly involved with or affected by CSG development. The Panel spoke with people who had been adversely affected by CSG development, especially landowners whose interactions with unconventional gas operators had been unfavourable, including Ms Helen Bender and Mr John Jenkyn. Some of the people the Panel spoke to complained of the deleterious health effects of living in close proximity to CSG development. With others, the detrimental social impacts of a rapid escalation in CSG activity were discussed (see Chapter 12).

But, the Panel also met with farmers who had enjoyed the beneficial use of processed produced CSG water for irrigation and cattle grazing, which had resulted in increased productivity and income. The Panel also visited the Miles State High School Trade Centre, which in partnership with Origin provides vocational education and employment pathways for its students. Similarly, the Panel heard from local business people and local government officials who gave examples of infrastructure improvements, such as new or improved roads, paid for by gas companies.

Inquiry Chair Justice Rachel Pepper and Prof Barry Hart AM with students from the Miles State High School Trade Centre.

While in Queensland, the Panel travelled to Brisbane to meet with a range of regulatory agencies and government departments. The Panel learnt about the resulting governance structures and industry standards that have evolved to meet public expectation and afford improved levels of social licence. Meetings were facilitated with various stakeholders such as AgForce, the Queensland Farmers' Federation, the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**), the Gas Industry Social and Environmental Research Alliance (**GISERA**), the University of Queensland's Centre for Coal Seam Gas (**CCSG**), the Department of Natural Resources and Mines, the Department of Environment and Heritage Protection, and the Office of Groundwater Impact Assessment (**OGIA**). The consistent theme of these talks and presentations was the need to ensure that an appropriately robust regulatory framework was in place before the development of any unconventional gas resource, a matter that many of the regulators conceded had not been attended to in Queensland prior to the large number of CSG activities occurring in that State, leading to many of the adverse social impacts experienced in that jurisdiction.

Further, the Panel toured a Santos operated CSG field in Roma where the Panel saw various multi-pad well sites and the disturbance footprint of those sites. The Panel also inspected a cattle grazing operation in co-existence with a CSG development. On the same visit, the Panel visited Santos's Roma gas processing hub and Unburri, the Roma field workers' camp.

On 7 September 2017, the Chair and Dr Vaughan Beck AM travelled to SA to further consult with the Department of State Development about the governance of unconventional gas in that State and the potential application of a similar regulatory regime the NT.

2.4 Overseas visits and consultations

The Panel consulted with the Alberta Energy Regulator (**AER**). The purpose of this engagement was to better ascertain the statutory framework within which the onshore unconventional gas industry operates in that Province, and moreover, to determine whether there are governance measures from that jurisdiction that can be appropriately adapted and applied in the NT. The consultation resulted in the AER making a formal submission.[1]

On 21 December 2017, while on leave, the Chair met with various representatives of the BC Oil and Gas Commission **(BCOGC)** in Victoria, Canada, to discuss various aspects of the regulation of onshore shale gas activities in that province, and the structure and functioning of the BCOGC.

The Chair has also consulted with Dr Ray Gosine, Chair of the Newfoundland & Labrador Hydraulic Fracturing Review Panel, where a range of topics were canvassed, including the timing of the implementation of the recommendations made as a consequence of that Review.[2]

2.5 Panel meetings

Since the Inquiry was constituted on 3 December 2016, the Panel has formally met on 12 occasions (see Appendix 4).

2.6 Presentations by the Panel

Members of the Panel have been invited to present a summary of the work of the Inquiry to date to the organisations listed in Appendix 9.

2.7 Community updates

In order to keep Territorians regularly informed of the work of the Inquiry, the Inquiry has released 31 community updates. A list and brief description of these updates is appended to this Report at Appendix 10.

2.8 Media engagements

As a matter of transparency, it was important that the media had access to the Inquiry. In this regard, the Chair has participated in 37 media engagements. These have included television and radio interviews (both live and pre-recorded), articles, and letters to various newspapers. A list of the Chair's media engagements is located at Appendix 11.

1 Alberta Energy Regulator submission 483.
2 Newfoundland & Labrador Report.

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

3

Chapter 3 Summary of discussions at community forums and the final list of issues

3.1 Community forums

Community information engagement sessions, or 'community forums', were an essential component of the Inquiry's extensive stakeholder engagement program insofar as they provided the opportunity for the public to discuss their concerns face to face with the Panel.

3.2 Key issues raised by the community

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 issues raised in the community forums fall into five broad areas of perceived risk:

- the potential impact of any onshore shale gas industry on water resources (surface water and groundwater) and the land;
- distrust in the Government to make decisions in the best interests of the community and antipathy towards the current regulatory framework;
- the potential negative impact of any onshore shale gas development on the health and wellbeing of local communities, particularly on Aboriginal people and their culture;
- the contribution of any onshore shale gas industry to climate change; and
- scepticism about the likelihood of any real economic benefits of any onshore shale gas industry flowing to local communities.

These issues are outlined below in the order of their importance to the community. The final list of issues can be found at Appendix 2.

Katherine community forum, March 2017.

3.2.1 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 NT, both in respect of human use (including for cultural purposes) and dependent ecosystems:

- it was repeatedly stressed that much of the NT 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 hydraulic fracturing fluid, spillage of wastewater, and wastewater storage ponds overflowing given the extreme rainfall events common in the NT;
- the significant volume 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;
- 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; and
- the importance of water with respect to a range of traditional cultural practices among Aboriginal communities was emphasised.

3.2.2 Regulatory reform

The adequacy of the regulatory framework governing any onshore unconventional shale gas industry in the NT 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 the 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 is wholly independent from the 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.

3.2.3 Land

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

- 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 NT's biodiversity assets, particularly for invertebrates;
- the spread of weeds and feral and exotic pests – weeds and feral and exotic pests 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 and feral and exotic pests, 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;
- the impediment of stock movement caused by a network of roads, pipelines, fences and well pads; and
- a loss of landscape amenity values – there was a widespread and deeply held concern within NT 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 NT tourism industry due to the loss of an outback wilderness experience, a primary visitor drawcard.

3.2.4 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 to 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 greenhouse gas emissions and downstream use, that:
  - there is an absence of baseline data and that the ongoing monitoring of greenhouse gas emissions is difficult;
  - life cycle greenhouse gas emissions for both upstream and downstream stages must be evaluated; and
  - at elevated methane emissions, life cycle greenhouse gas emissions for gas can be similar to greenhouse gas 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 greenhouse gas regulations that should be examined.
- in respect of global climate change, that:
  - it is necessary to consider Australian greenhouse gas emissions; and
  - it is necessary to consider implications of these greenhouse gas emissions for additional gas production and use.

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

3.2.5 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 owners, members of Aboriginal communities 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 there has not been a genuine effort to engage appropriately with or to properly inform, Indigenous landholders of the actual impact of petroleum activities prior to seeking consent for such activity on land over which they have rights; and
- there was concern that traditional land use by Aboriginal people (camping, hunting, fishing and the collection of bush tucker) would be restricted.

Attendees at the Maningrida community forum demonstrate their views, February 2018.

3.2.6 Social impacts

The most frequently raised potential adverse social impacts that any 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 who stood to gain from the industry and those who would miss out;
- an influx of fly-in, fly-out (**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.

3.2.7 Public health

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

- the contamination of water used for domestic consumption and stock watering by chemicals used in hydraulic fracturing fluids, 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 onshore shale gas extraction activities, which 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 well heads, 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 (that is, 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.

3.2.8 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, tourism, or agricultural significance ('no go zones').

3.2.9 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 therefore, that the Government should not be *"investing in a declining industry";*
- the petroleum 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 NT;
- 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 NT 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.

3.3 The majority of community forum participants were opposed to hydraulic fracturing

As stated above in Chapter 2, the final round of community forums was held in February 2018 and focussed on the findings and recommendations made in the Draft Final Report. Based on the outcomes from the Panel's risk assessment (detailed in Chapter 4), the Draft Final Report contained recommendations to the Government that, if implemented in their totality, the Panel believes will reduce the risks identified and assessed in the Draft Final Report to an acceptable level.

While some of the participants in the community forums expressed the view that many of the attendant risks of any onshore shale gas industry could be mitigated by genuine industry engagement with the community and an acceptance by the gas industry to pay for all necessary reform, this was a minority opinion. Rather, the constant refrain heard by the Panel from the majority of the participants before the Inquiry was that, in their opinion, the Government and the gas industry neither have the will nor the capacity to implement meaningful regulatory change in the NT.

In short, the view of most of the Territorians who engaged with the Panel at the community forums remains that as stated in the Inquiry's previous reports, namely, that *"overwhelmingly"* they were opposed to hydraulic fracturing and were opposed to the lifting of the moratorium.

EVIDENCE AND RISK ASSESSMENT METHODOLOGY

4

4.1 Introduction

In many instances, hydraulic fracturing is 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 lack of readily accessible and comprehensible information or published data regarding the extent, location, methodology and technology of hydraulic fracturing. The result has been claim and counter-claim, which has led to confusion and misinformation concerning the potential risks and impacts associated with hydraulic fracturing.

The Inquiry's scope of work is set out in its Terms of Reference (Appendix 1), and requires the Panel to first, identify the environmental, cultural, economic and social risks and impacts associated with hydraulic fracturing and onshore shale gas development, and second, to identify how those risks and impacts may be managed to a level that is 'acceptable' and consistent with the principles of ecologically sustainable development (**ESD**).

4.2 Principles of ESD

The principles of ESD (see **Table 4.1**) are at the core of the Panel's analysis. The Panel has used these principles to formulate environmental objectives as an initial part of its risk assessment process and to identify mechanisms that will ensure that those objectives are achieved.

Many submissions to the Panel and many attendees at the community forums argued that given the apparent scientific uncertainty associated with the nature, extent and management of the environmental risks associated with any onshore shale gas industry, the principles of ESD, and in particular, the precautionary principle, should be applied to prevent any onshore shale gas activity from proceeding whatsoever. This is a common misconception as to the operation of the principle, a matter discussed in greater detail in Chapter 14 at Section 14.7.1.2.

Table 4.1: Principles of ESD

The precautionary principle	Where there is a threat 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. Invoking the precautionary principle requires: • a threat, based on scientific evidence, of serious or irreversible damage; and • scientific uncertainty regarding that damage.
The principle of intergenerational equity	The present generation should ensure that the health, diversity and productivity of the environment is maintained or enhanced for the benefit of future generations.
The principle of the conservation of biological diversity and ecological integrity	Conservation of biological diversity and ecological integrity should be a fundamental consideration in decision-making.
Principles relating to improved valuation, pricing and incentive mechanisms	Relevant principles include: • that environmental factors should be included in the valuation of assets and services; • the polluter pays principle, namely, that those who generate pollution and waste should bear the cost of containment, avoidance or abatement; • that the users of goods and services should pay prices based on the full life cycle costs of providing goods and services, including the use of natural resources and assets, and the ultimate disposal of any wastes; and • that environmental goals, having been established, should be pursued in the most cost-effective way by establishing incentive structures, including market mechanisms, that enable those best placed to maximise benefits and/or minimise costs to develop their own solutions and responses to environmental problems.
The principle that decision-making should include long and short-term considerations and cumulative impacts	Decision-making processes should consider the potential for cumulative impacts and effectively integrate long-term and short-term economic, environmental, social and equitable considerations.

4.3 Evidence used by the Panel

A comprehensive bibliography of the scientific literature and reports that the Panel has considered, together with a complete list of the submissions (oral and written) provided to the Panel is located in the References.

Unless otherwise indicated, all submissions received by the Inquiry have been, in the interests of fairness and transparency, published on the Inquiry's website. Where a submission is legitimately confidential, the reason for maintaining confidentiality has been provided in Appendix 12. Where necessary, the Panel has sought additional information and clarification in respect of a number of submissions (see Appendix 13). The requests and answers have been published on the Inquiry's website. All material received by the Panel has been read and considered, even if no express reference has been made to a particular submission or report in the body of this Report.

The Panel examined, among other material, the 2012 and 2016 Hunter reports, the 2014 and 2015 Hawke reports[1], the Final Report of the Australian Council of Learned Academies (**ACOLA**) *Engineering Energy: Unconventional Gas Production* published in May 2013 (**ACOLA Report**) and the reports of various reviews into unconventional gas in Tasmania, NSW, SA, WA, Victoria and Queensland.[2] Overseas, studies into hydraulic fracturing in the UK, US, Canada, NZ and South Africa have also been considered.[3] In particular, the findings from the authoritative United States Environmental Protection Agency's report (**US EPA**), *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States* (**US EPA Report**), were taken into account.

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, have also been taken into account by the Panel. The attitudes and opinions of the public towards hydraulic fracturing in the NT are directly relevant to determining how the onshore shale gas industry can earn a social licence to operate (**SLO**). A summary of the principal matters raised and discussed during the community consultations is located in Chapter 3 and is reflected in the final list of issues at Appendix 2.

Specialist consultant work on the social and economic impacts of a potential shale gas industry in the NT was commissioned by the Inquiry (see Chapters 12 and 13 respectively). Further, CSIRO was engaged to provide independent external analysis of issues associated with shale gas well integrity (see Appendix 14). That report was used as evidence in, and otherwise informed, this Report.

1 Issues Paper, p 11.

2 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 (***NSW Report***); 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.

3 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**); *Shale Gas Development in the Central Karoo: a Scientific Assessment of the Opportunities and Risks. New Zealand Parliamentary Commissioner for the Environment* (**Scholes et al. 2014**); *Report of the Nova Scotia Independent Panel on Hydraulic Fracturing* (**Nova Scotia report**); Unconventional Opportunities and Challenges: Results of the Public Review of the Implications of Hydraulic Fracturing Operations in Western Newfoundland (**Newfoundland & Labrador Report**). This list is not exhaustive.

4.4 Overview of the risk assessment process

Having regard to the most relevant, current, and available scientific literature, the Panel identified, collected, analysed, and distilled the available evidence concerning the risks and impacts associated with any onshore shale gas industry (see the final list of issues at Appendix 2). These issues were grouped into the following broad categories, or themes, during the consultation process:

- water (quality and quantity);
- land;
- greenhouse gases;
- public health;
- Aboriginal people and their culture;
- social impacts;
- economic impacts; and
- regulatory reform (including land access).

The process that the Panel has followed to assess the issues or risks associated with each theme depended on the particular nature and context of that issue or risk. During the Panel's deliberations, and taking into account the published scientific data and the submissions received, it became apparent that the biophysical (water, land and air) and public health issues were best assessed by applying a standardised multi-step risk assessment process (see Section 4.5). The Panel has assessed these risks in terms of the likelihood of the impact occurring and the consequence(s) if the impact were to eventuate. This methodology (see below for details) has been applied in Chapters 7 to 10, covering water, land, air and public health, respectively. By contrast, Aboriginal people and their culture (Chapter 11), social impacts (Chapter 12), and economic impacts (Chapter 13) were not suited to this type of assessment. Accordingly, the methods used to assess the nature of those risks are described and dealt with separately in each of their respective Chapters.

Regulatory reform (Chapter 14) is considered by the Panel to be a mitigating factor rather than a risk requiring assessment. That is, if regulation is robust in content and is effectively implemented, it should reduce the risks posed by the development of any onshore shale gas industry to an acceptable level.

4.5 Methodology for assessing risks to biophysical and public health issues

The Panel has adopted a seven-stage process for the identification, assessment, and management of risks associated with the development of any onshore shale gas industry in the NT. The process is depicted in **Figure 4.1** and is described in detail below.

Figure 4.1: Risk assessment process.

STEP 1	STEP 2	STEP 3	STEP 4	STEP 5	STEP 6	STEP 7
Environmental Value (EV) What do we want to protect?	**Environmental Objective (EO)** What must be achieved to protect the EV to an acceptable level?	**Risk** What risk or threat does the shale gas industry pose to achieving the EO?	**Risk assessment** What is the consequence and likelihood of the risk or threat occurring?	**Mitigation measure** How can the risk be managed to achieve the EO?	**Residual risk assessment** If we implement the mitigation measure, what is the residual risk or threat?	**Recommendations** What can the Government do to achieve the EO?

4.5.1 Identifying environmental values

Environmental values (**EV**) represent those environmental, cultural, social and economic issues of particular concern to Territorians that are considered to be in need of protection from any adverse impacts by any onshore shale gas development. Examples of environmental values are iconic landscapes, water quality and quantity, greenhouse gases, public health, community cohesion, and the maintenance of cultural connection to country. These values have been articulated and identified through the community consultation process under the themes of water, land, greenhouse gas emissions, public health, Aboriginal people and their culture, social impacts, and economic impacts. These themes have subsequently comprised the major areas of assessment for the Panel. The objective of the community consultations was to canvas public opinion as widely as possible to identify, as comprehensively as possible, the range of risk factors that could affect these values.

As noted above, the methodology used to assess cultural, social, and economic risks are dealt with in Chapters 11, 12 and 13 respectively.

4.5.2 Identifying environmental objectives

For each environmental value, the Panel has determined one or more environmental objectives (**EO**) that must be achieved to ensure that the environmental value is protected to an acceptable extent. Where possible, the Panel has identified environmental objectives that are measurable, actionable and realistic. These objectives provide performance indicators against which the environmental outcomes can be assessed. The environmental objectives that have been developed and applied to each theme, or set of risks, have been clearly identified in each of the corresponding Chapters in this Report. For example, in the case of water quality, these environmental objectives are articulated quantitatively by water quality criteria for water use (human drinking, stock watering) and/or for the protection of the aquatic environment.

4.5.3 Identifying risks

Following an extensive period of public consultation and a review of the scientific literature, the Panel identified a number of issues associated with any onshore shale gas development that may threaten the achievement of environmental objectives, and therefore, have an adverse impact on a core environmental value (see Appendix 2).

4.5.4 Assessment of risk

An assessment of risk was only undertaken if there was sufficient information or evidence to do so. In making an assessment, the Panel has assumed the application of the current regulatory regime. In the event that a risk could not be assessed, or if there was a high degree of uncertainty in the magnitude of that risk, the precautionary principle (**Table 4.1**) has been applied where there was a possibility that the consequence of the risk resulted in an unacceptable impact on the environmental value to be protected. In other words, a mitigation measure, or measures, was required to be implemented to prevent a possible unacceptable impact from occurring unless it could be proven by the acquisition of additional information that the risk did not require the original prescribed level of mitigation.

Risk may be assessed by 'qualitative' or 'quantitative' methods, as described in the Australian and New Zealand standard for risk assessment[4] and associated materials.[5] In general, a 'qualitative' risk assessment is conducted, first, to identify priority risk factors that may need to be subjected to a semi-quantitative, or a full quantitative risk assessment, depending on the availability of sufficient input data (or quantitative computer models), to enable the risk to be evaluated at a requisite level of detail. Qualitative methods use descriptive terms and expert opinion to identify and record the consequences and likelihoods of events and resultant risk. 'Quantitative' methods identify likelihoods as frequencies or probabilities, and use quantitative measurements of consequences, such as the proportion of a population, or number of species, that would be affected in a specified way at a specified level of exposure.[6]

To assist in the assessment of the biophysical (water, land and air) and public health risks associated with any onshore shale gas development, the Panel adopted a qualitative risk assessment framework that combines the estimated likelihood of an impact occurring, and the consequence(s) of that impact, to assess the resultant risk level. The resultant risk level is then used to determine if any additional mitigation measure is required to reduce the risk level to a sufficiently low (or acceptable) level should the industry proceed. As noted above, the economic impacts and the risks to Aboriginal people and their culture have been assessed differently.

The Panel's risk assessment framework is based on the Government's risk assessment framework for resource developments.[7] The 6x6 risk matrix was condensed to three levels each for 'likelihood', 'consequence', and 'risk', namely, 'low - L', 'medium - M' and 'high - H' (**Table 4.2**). This was done because the amount of information available to the Panel meant that there was no advantage in using a more complex matrix for a qualitative risk assessment. The combinations of categories in the 6x6 matrix used to produce the 3x3 matrix applied by the Panel are contained in **Table 4.3**.

Table 4.2: Risk assessment matrix used by the Panel.

		Likelihood		
		L	M	H
Consequence (see **Table 4.4**)	H	M	H	H
	M	L	M	H
	L	L	L	M

4 AS/NZS2009.
5 AS/NZS2006.
6 A good practical introduction to the topic of risk assessment is provided in Appendix 1 of the Risk Assessment Handbook developed for use by the mining industry and published by the Australian Government as part of its *Leading Practice Sustainable Development Program for the Mining Industry* series of handbooks. Appendix 1 provides a very comprehensive overview of the application of different types of risk assessment approaches and their strengths and weaknesses: Australian Government 2016.
7 Petroleum Environment Regulations Guide, pp 26-29.

Table 4.3: Creation of condensed risk assessment matrix used by the Panel.

Element		Combination of categories [1]
Likelihood	L	Remote, Highly Unlikely, Unlikely
	M	Possible
	H	Likely, Almost Certain
Consequence	L	Minor, Moderate
	M	Serious
	H	Major, Critical, Catastrophic

1 From the Government's risk assessment framework for resource development.[8]

'Likelihood' was assigned on a quantitative or qualitative basis depending on the amount of information available. Where sufficient evidence was available from the published literature about likely probability (chance) of occurrence for a risk type (for example, a surface spill or leakage of gas from a well) in the onshore shale gas industry, the following assessments were made:

- 'L' - less than 1% probability of occurring;
- 'M' - between 1 and 10% probability of occurring; and
- 'H' - greater than 10% probability of occurring.

Where quantitative information was not available, the following qualitative thresholds were applied based on the professional judgement and experience of the Panel: 'L' - unlikely to occur, 'M' - a reasonable chance that this might occur and 'H' - a strong chance of occurring.

Each of the biophysical and public health Chapters in this Report (Chapters 7 to 10) has developed its own relevant definitions of 'consequence' for each theme (**Table 4.4**), which are generally consistent with the descriptions used in the Government's risk assessment framework for resource development.

The risk of the activity being assessed is obtained by combining the assigned 'likelihood' and 'consequence' categories in the matrix (**Table 4.2**) above to identify an overall 'L', 'M' or 'H' risk. For example, if the 'likelihood' is rated 'M' and the 'consequence' is rated 'M', the resultant risk is rated 'M'. Whereas if the 'likelihood' is rated 'L', and the 'consequence' is rated 'M', the resultant risk is rated 'L'. For example, even though the likelihood of a well blowout is very low (see Chapter 5), if this were to cause significant environmental damage, the 'consequence' would be rated 'H' and the resultant level of risk would be 'M'.

If the risk is assessed as being sufficiently low, and therefore, acceptable, generally no additional mitigation measures are needed. However, for some risks, even where the risk was identified as low, the Panel nominated measures that could further reduce the risk to a level that is as low as reasonably practicable (**ALARP**). The factors that scored 'M' or 'H' for risk require further mitigation to reduce, the risk to a level that is low and acceptable.

8 Petroleum Environment Regulations Guide, pp 26-29.

Table 4.4: Descriptions of the levels of consequence for the biophysical and public health themes.

Values	Low	Medium	High
Water • quantity • quality • aquatic ecosystems	Localised spill or leak from a primary containment that is confined within existing disturbed area; no impact on surface water or groundwater quality; short-term (one week) impact on water availability (quantity); no impact on aquatic ecosystems (surface or groundwater dependent).	Spill or leak that escapes physical containment of existing disturbed area and spreads to nearby land surface or waterway; minor contamination of groundwater that is insufficient to trigger public or environmental health concerns; no adverse impact on aquatic ecosystems; drawdown of water table so that water can no longer be accessed by existing installed bores for a short period of time (~ one month).	Major off-site release or spill with large footprint area, potentially also including surface waterways; contamination of groundwater requiring remediation; adverse impact on aquatic ecosystems; drawdown of water table so that water can no longer be accessed by existing installed bores and/or degradation of water quality so that water resource is no longer suitable for its original beneficial use.
Land • biodiversity • visual amenity • disturbance	Impacts of limited significance [1] confined to the existing approved disturbed area, without affecting the terrestrial biodiversity, ecosystem or amenity values of the broader region. 1 Assuming that the initially approved area did not contain high value biodiversity or significant habitat area for rare and endangered species.	Impacts extending beyond approved disturbed area, with detectable effects on the terrestrial biodiversity, ecosystem or amenity values of the broader region able to be restored by natural recovery processes.	Widespread impacts, with material effects on the terrestrial biodiversity, ecosystem or amenity values of the broader region, requiring active remedial intervention.
Air emissions • climate change • greenhouse gas emissions	Increase in greenhouse gas emissions in the gas field that are deemed moderate (that is, less than 0.1% of global emissions).	Increase in greenhouse gas emissions in the gas field that are deemed serious (that is, less than 0.5% of global emissions).	Increase in greenhouse gas emissions in the gas field that are deemed major (that is, greater than 0.5% of global emissions).
Public health • water • air	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 three weeks, or prediction from a formal health risk assessment that chemical exposures could exceed relevant health-based guideline values, but by no more than tenfold to one hundredfold (within conventional safety factors built into such values).	Serious but temporary injury or condition of members of the public, with lasting effects over three 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.

4.5.5 Potential additional mitigation measures

For risks that were initially assessed as unacceptable (namely, 'M' or 'H'), the Panel has identified measures that, if implemented, will potentially further reduce the 'likelihood' or 'consequence' of the risk so that the reassessed residual, or remaining, risk will meet the environmental objective and be acceptable. Such measures could include increased and/or more rigorous monitoring, improved compliance, more robust regulation, improved enforcement, or the implementation of world-leading practice guidelines.

The Panel did not use the 'as low as reasonably practicable' (or **ALARP**) test to determine what an acceptable level of risk is. The ALARP test is frequently used in assessing whether all reasonably practicable measures are, or will be, in place to control or mitigate a potential risk or impact. However, the ALARP test only requires that the level of residual risk associated with an activity be balanced against the mitigation measures needed to control that risk in terms of 'money, time or trouble'. The Panel's view is that other matters must also be considered when determining whether the extent of mitigation provided by ALARP is sufficient in order to be acceptable.

In determining what an acceptable level of risk is, the Panel considered the principles of ESD (including the precautionary principle), relevant international standards, and the unique social and cultural conditions that exist in the NT. As alluded to above, the application of the precautionary principle does not mean that any onshore shale gas development cannot proceed whatsoever in the absence of full scientific certainty. Rather, the application of the precautionary principle means that, assuming the worst, the maximum level of mitigation must be implemented until contrary evidence is obtained. Where the Panel has concluded that the residual risk is still 'medium' or 'high', notwithstanding the implementation of all potential mitigation measures, then the action has been assessed as 'unacceptable'.

Consideration of the principles of ESD may require that certain areas are declared 'no go zones', or that additional safeguards must be put in place before the remaining risk can be assessed as 'acceptable'. It should be noted the principles of ALARP and of acceptability are both addressed in the Petroleum Environment Regulations where it is stated that, "*when deciding whether to approve an EMP, the Minister must be reasonably satisfied that environmental impacts and environmental risks will be reduced to a level that is both ALARP and acceptable*".[9]

The Panel reassessed each risk assuming that the mitigation measures identified in Step 5 (see **Figure 4.1**) have been implemented. The Panel then considered whether the residual risk is likely to be sufficiently low, and therefore, acceptable. Each of the biophysical and human health chapters have developed their own definition of what is considered 'acceptable' based on the best available scientific information. These definitions have been fully documented in each of the corresponding chapters, with a summary compilation provided for convenience in **Table 4.5**. In general terms, 'acceptable' could be considered to equate to the 'low' category of risk documented in **Table 4.4**.

9 Petroleum Environment Regulations Guide, pp 7-8.

Table 4.5: Acceptability criteria for the biophysical and public health themes.

Theme	Criterion	Measures of Acceptability
Water quantity - groundwater	Extraction of groundwater does not does not result in sustained drawdown of the water table that would compromise supply of water for domestic or stock use, or adversely affect groundwater dependent ecosystems.	• Extraction (in total) does not exceed 20% of sustainable yield from an aquifer system. • Local sustained drawdown of potable or stockwater bores does not exceed 1m.
Water quantity - surface water	Extraction of water does not exceed 20% of flow at any time.	Low likelihood that water use will exceed 20% of flow at any time.
Water quality – groundwater	The current highest value use of the water will not be compromised.	• Australian drinking water quality criteria. • Australian livestock watering quality criteria.
Water quality – surface water	The current highest value use of the water will not be compromised.	• Australian drinking water quality criteria. • Australian livestock watering quality criteria. • Australian and New Zealand (ANZECC/ ARMCANZ) criteria for the protection of aquatic ecosystems.
Land-biodiversity and ecosystem health	• No regional-scale impact on terrestrial biodiversity values. • Maintenance of overall terrestrial ecosystem health, including the provision of ecosystem services, at the regional scale.	• Exclusion ('no go zones') of any shale gas development from areas where regional conservation values are very high. • No introduction or spread of any declared weeds. • No increase in fire frequency in production areas. • Minimal clearing of native vegetation and avoidance of critical habitats. • Roads and pipelines designed to minimise disruption to surface water flow.
Land-amenity	• Shale gas surface infrastructure should not become a highly visible feature of the landscape. • The volume of heavy-vehicle traffic should not have an unacceptable impact on landscape amenity and place identity.	• No impact on the physical appearance of the NT's most scenic and highly visited outback landscapes. • Minimal visibility of shale gas infrastructure from public roads in areas where development occurs.
Greenhouse gas emissions	• Minimise greenhouse gas emissions. • Minimise fugitive methane emissions.	• Offset life cycle greenhouse gas emissions in Australia from shale gas produced in the NT to ensure no net emissions. • Set a methane concentration limit that is equivalent to methane emissions that are 1.7% of dry production.
Public health-air and water	Based on site-specific Human Health Risk Assessments, communities will not be exposed to water-borne or airborne chemical emissions that exceed relevant health-based guideline values.	Exposure concentration less than Australian and international water and air quality guidelines for specific chemicals.
Public health-stress	No measurable impacts on mental health or other amenity-based criteria that are directly attributable to any onshore shale gas production operations.	Hospital admission data or other relevant health survey data show that health issues are not significantly different to pre-development baseline values.

The complete risk assessment matrixes developed by the Panel for assessing the biophysical and public health risks are provided for reference in Appendix 3. The contents of these matrixes show the successive steps of the process and the estimated residual risk if the required mitigation measures are implemented.

4.6 Recommendations

Based on the outcomes of the risk assessment, the Panel has made recommendations to the Government that, if implemented, the Panel believes will reduce the risks to an acceptable level. If the Panel finds that specific risks cannot be reduced to an acceptable level, this is stated. In a number of cases, the Panel has recommended that a strategic regional environmental and baseline assessment (**SREBA**) (see Chapter 15) must be undertaken to provide the additional scientific knowledge and baseline information required before a final risk assessment can be made.

4.6.1 Quantitative risk assessment

A qualitative risk assessment process has been used by the Panel to filter the range of risk factors identified during the consultation process. However, by their very nature, qualitative risk assessments cannot adequately address situations where the level of complexity is such that a numerical or quantitative assessment is needed. An example is the prediction of the consequence of a leak from a gas extraction well on groundwater quality at a stock watering bore located several kilometres away. A qualitative assessment (see, for example, Chapter 7) may be able to indicate the risk of a leak occurring, but in the absence of a groundwater computer model containing specific local information about rock type, aquifer water quality, groundwater movement, volume and composition of the leak, together with possible dilution and decomposition processes occurring, it is not possible to infer, with any level of certainty, what the future water quality will be at the watering bore and, therefore, what the consequence is (for example, of contaminant concentrations being above or below the National Health and Medical Research Council (**NHMRC**) Australian drinking water guidelines). This is where a quantitative risk assessment is required. The principles of quantitative risk assessment, as applied to estimating the public health impacts of chemical exposures, are outlined in Chapter 10 (Section 10.1).

A good example of a quantitative assessment is the National Chemicals Risk Assessment (**NCRA**) for chemicals used in the extraction of CSG commissioned in 2012 by the Australian Department of the Environment and Energy. The NCRA was prepared in collaboration with the National Industrial Chemicals Notification and Assessment Scheme (**NICNAS**) and CSIRO.[10] The NCRA was commissioned because of the increased scientific and community interest in better understanding the risks of chemical use by the CSG industry. It aims to develop an improved understanding of the occupational, public health and environmental risks associated with chemicals used in drilling and extraction of CSG in an Australian context. This is the only independent assessment that has been completed in Australia of the risks posed to the aquatic environment and human health by CSG drilling and by the chemicals used for the extraction of CSG (with analogous implications for many of the chemicals used for the extraction of shale gas).

The NCRA is a large and complex scientific undertaking. At the time it was commenced, no comparable assessment had been undertaken in Australia or overseas, and new models and methodologies had to be developed and tested for the deterministic (quantitative) risk assessment of CSG chemicals. The US EPA has subsequently undertaken its own assessment of the risk of shale gas extraction to drinking water resources, and there are many parallels between the two approaches.[11] It is noted, however, that the US EPA review is restricted to the assessment of potential impacts on drinking water from a human health perspective and does not extend to the broader aquatic environment, unlike the NCRA.

The NCRA considers the potential risks to the environment (surface and near surface water environments) of 113 chemicals identified as being used for CSG extraction in Australia from the period 2010 to 2012.[12] Risk factors addressed include the transport, storage and mixing of chemicals, and the storage and handling of water pumped out of CSG wells (flowback or produced water) that can contain residual amounts of the chemicals used. Although the extraction process for CSG differs from extraction of shale gas (as described in Chapter 5 and see also the Issues Paper), there are many similarities between the two types of gas extraction in the associated infrastructure and in the surface handling of chemicals and wastewater. The Panel notes that geogenic chemicals (that is, those extracted from the coal seam and contained in the produced water) are not included as part of the NCRA. Assessment of contamination of soil, or

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10 Australian Department of the Environment and Energy 2017 a-f.
11 US EPA Report.
12 Australian Department of the Environment and Energy 2017 a-f.

impacts on terrestrial plants or animals by leaks or spills of chemicals or wastewaters are also not part of the scope of the NCRA.

Rather, the focus of the NCRA is on the impacts of surface discharges (spills or leaks) on surface water and near-surface groundwater, extending to potential downgradient effects on surface water through overland flow or discharge of the shallow groundwater into surface waterways. The reason for this priority is that international studies have shown that the greatest risk to human health and the environment is from spills or releases of chemicals during surface activities, such as transport, handling, storage, and the mixing of chemicals. The potential effect of chemicals injected into deeper groundwater on near-surface aquifers was not part of the initial assessment; although, this aspect has subsequently been addressed by an extension of the work.[13]

The findings from the NCRA significantly strengthen the evidence base and increase the level of knowledge about the chemicals used in CSG extraction in Australia and, therefore, similarly inform the shale gas industry, which utilises many similar types of chemicals. This information improves the understanding of which chemicals can continue to be used safely, and which chemicals are likely to require extra monitoring, industry management, and regulatory consideration.

Further details of content and specific findings from the NCRA are presented and discussed in Chapters 7 (Water) and 10 (Public health), where it is used as evidence for the Panel's assessments of risk for these topics.

13 Mallants et al. 2017.

SHALE GAS EXTRACTION AND DEVELOPMENT

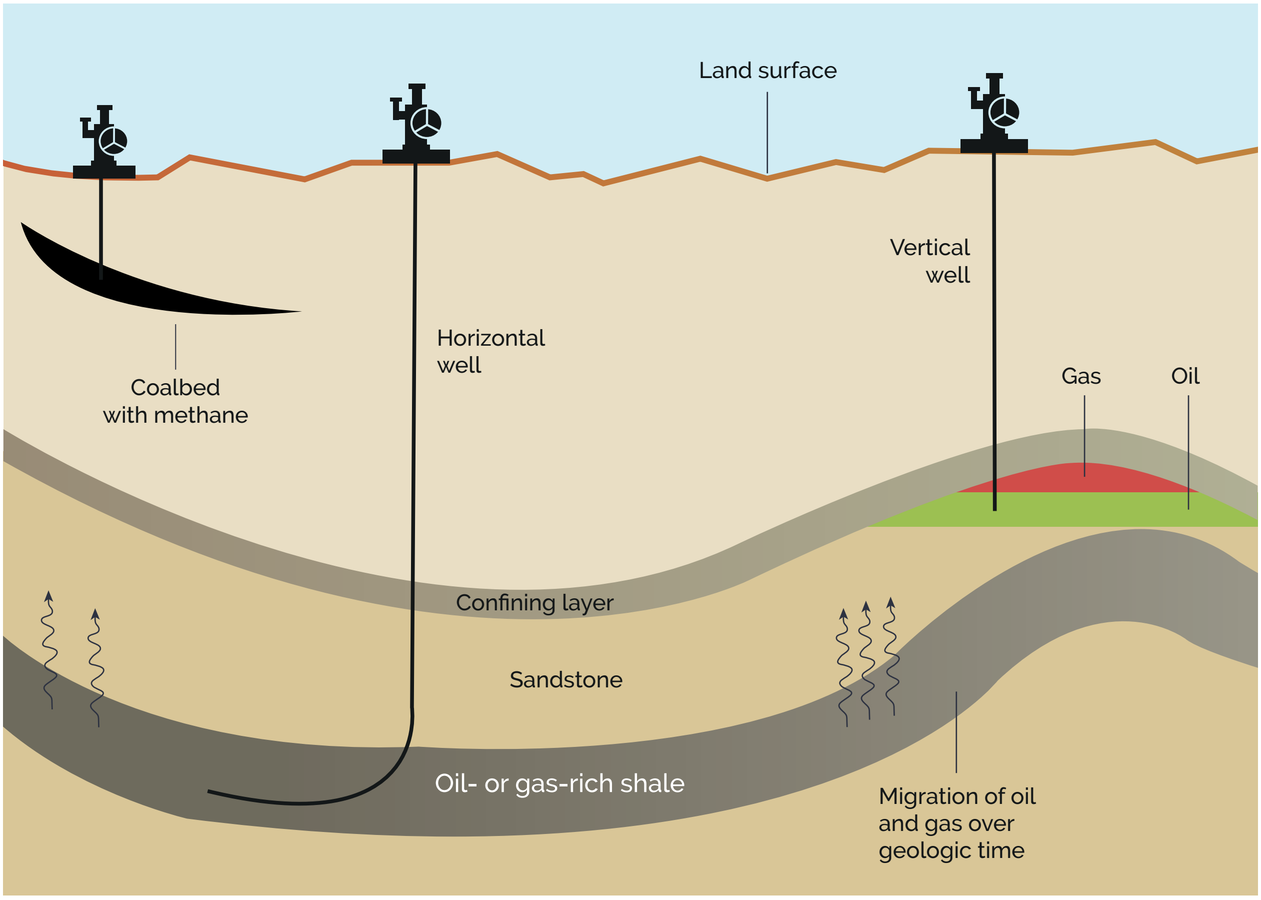
5

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 assumed different meanings in different material 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 (**Figure 5.1**). 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, which is found in coal seams, shale gas (found in shale rocks), and tight gas (found in sandstone). The Inquiry's Terms of Reference require the Panel to consider unconventional shale gas only.

Figure 5.1: Schematic showing different types of petroleum accumulations and development. Source: Modified from US Environmental Protection Agency.



Irrespective of where it occurs, natural gas is composed mainly of methane with varying amounts of carbon dioxide and trace gases such as ethane, propane, butane and other hydrocarbons. From a consumer's perspective, unconventional gas is effectively identical to conventional gas.

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 storing the gas that enable effective gas production from strategically placed wells. The gas will generally flow to the surface under its own pressure without the need for pumping, most likely driven by a water table (or aquifer) underneath a pressurised gas cap or an impermeable barrier.

By contrast, the shales 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 shale gas, it is necessary to increase the level of porosity and permeability. This is achieved by 'artificial stimulation', which is another term for hydraulic fracturing.[1]

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

- **coal seams:** are typically found relatively close to the surface (usually no more than 1,000 m deep). The extraction of CSG 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 water are produced (known as 'produced water'), which must often be treated to remove excess salt prior to disposal;
- **shale gas source rocks:** occur deeper at between 1,500 and 4,000 m underground. Extraction of shale always needs hydraulic fracturing, but does not need the removal of large quantities of groundwater to unlock the gas. Only a portion of the water that is used in the hydraulic fracturing process is returned to the surface. This returned water ('flowback water') can often be reused for subsequent hydraulic fracturing operations, or must be treated and disposed of; and
- **tight gas deposits:** 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. Like shale gas, the returned water (flowback water) can often be reused for subsequent hydraulic fracturing operations, or must be treated and disposed of.

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 NT 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, following almost 10 years of exploration for unconventional gas in that basin. None of the Northern Territory's considerable shale gas resources have yet been commercially developed (Chapter 6).

5.2.2 Stages of exploration and development

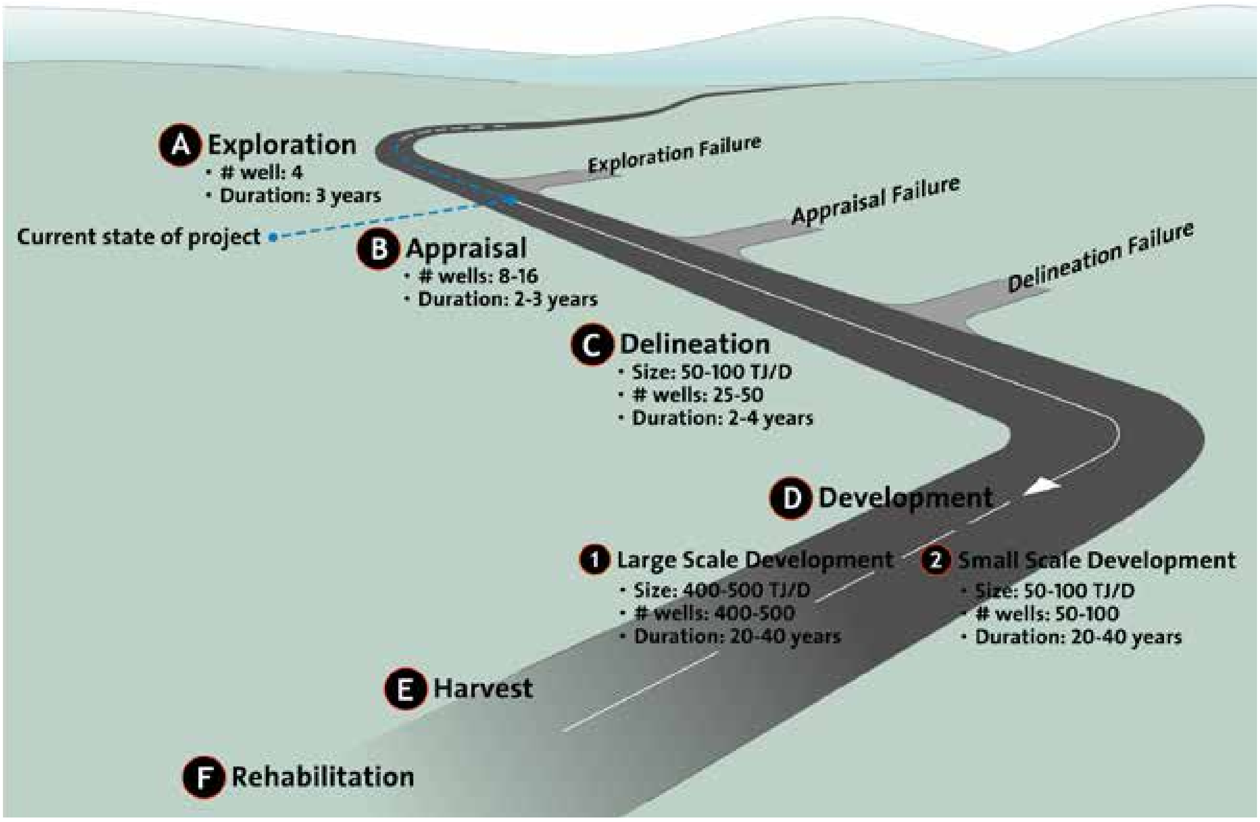
The commercial production of shale gas is the culmination of a process spanning several years, and includes exploration, drilling, hydraulic fracturing, testing and economic analysis (**Figure 5.2**).[2] The different stages of shale gas development are:

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

1 King 2012.
2 King 2012; Origin Energy Ltd, submission 153 (**Origin submission 153**), p 38.

- **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 small number of single pads, 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 production and for construction of gas plants, pipelines and other infrastructure, drilling and fracturing of a network of production wells. During drilling and hydraulic fracturing of the wells, there will be a concentration of heavy equipment on site, along with large stockpiles of drilling supplies and hydraulic fracturing chemicals. This can involve thousands of truck movements per well site over several months, with directional drilling occurring over several months, and hydraulic fracturing usually taking less than one month.[3] After the completion of drilling and hydraulic fracturing, all heavy equipment is removed and permanent surface infrastructure is constructed, including a cement well pad, a well head, gas pipeline, and fencing to keep livestock and other fauna away from the well. The final footprint of the wells and surface facilities is much smaller than the original drilling footprint (see Section 8.3);
- **stage 6:** decommissioning – the removal of the well head, plugging the steel casing with cement and covering the plugged well with soil to ground level. The removal of all production equipment, production waste, pipelines and other infrastructure and the rehabilitation of all cleared areas; and
- **stage 7:** abandonment (also referred to as' relinquishment', if a planned process) – as far as the operator is concerned, this occurs when a period of post-decommissioning monitoring (groundwater quality and fugitive methane) has shown no unacceptable leakage issues, and the state assumes responsibility for long-term stewardship of the well. At this time, the well is technically defined as an orphan, under the care of the state (see ***Recommendation 14.13*** for the establishment of an orphan well fund).

Figure 5.2: Schematic representation of a project phasing in gas developments, with specific estimates of activity for a notional development in the Beetaloo Sub-basin. Source: Origin.[4]



3 ACOLA Report.
4 Origin Submission 153, p 38.

5.3 Extraction of onshore shale gas

5.3.1 Overview

As stated above, shale gas reservoirs are typically located at depths of 1,500 to 4,000 m below the ground surface. Because of their very low permeability, shales need to be split (fractured) before the gas can flow into the well and up to the surface.

The drilling and hydraulic fracturing technologies used in extraction of onshore shale gas have evolved considerably from those used for the conventional petroleum resources over the past two decades.[5] Drilling for shale gas now typically involves the drilling of multiple wells from a single well pad with horizontal extensions ('laterals') increasing the exposure to the target shale formation.[6] In order to produce shale gas, multiple intervals, or sections for hydraulic fracturing, are placed along the horizontal section of the well. The most common hydraulic fracture designs for shale gas wells in the US use water-based hydraulic fracturing fluids, which are pumped into the well at a high pressure.[7] The adoption of these technologies has led to a rapid growth of shale gas and oil production in the US.[8]

The very nature of the extraction process, which involves drilling to great depths and the injection of chemical mixtures at high pressure into the well, is of paramount concern to the community. The maintenance of 'well integrity' throughout the operational life of a well and beyond is of crucial importance.

For this reason, the Panel commissioned CSIRO to produce a comprehensive review of this topic (the report is located at Appendix 14). The Panel has drawn heavily on CSIRO's report for producing the well integrity section of this Chapter. However, all conclusions and recommendations are those of the Panel.

5.3.2 Well life cycle

All wells follow a similar life cycle, with some variations in their design and operational aspects depending upon their purpose and the local geology. The well life cycle phases are described below.

5.3.2.1 Design phase

The design phase includes consideration of the overall well life cycle, including all future operations for the well, through to its eventual abandonment. A description of this type of approach to well design was provided by Origin in a submission to the Panel.[9] The design of the casing, cementing and completion are critical considerations for long-term well integrity, and for ensuring isolation between the shale formation and the surface, including isolation of any aquifers and problematic layers between the target shale and the surface, such as those containing gas, hydrocarbons and/or saline water. The well design is based on a detailed analysis of the following:[10]

- well design and specification of materials and equipment (such as casing and cement);
- data acquisition program, including well logging, sample collection and well testing;
- well-stimulation activities;
- well barriers to manage well integrity;
- operating procedures, including risk management and well integrity management; and
- plans for final abandonment.

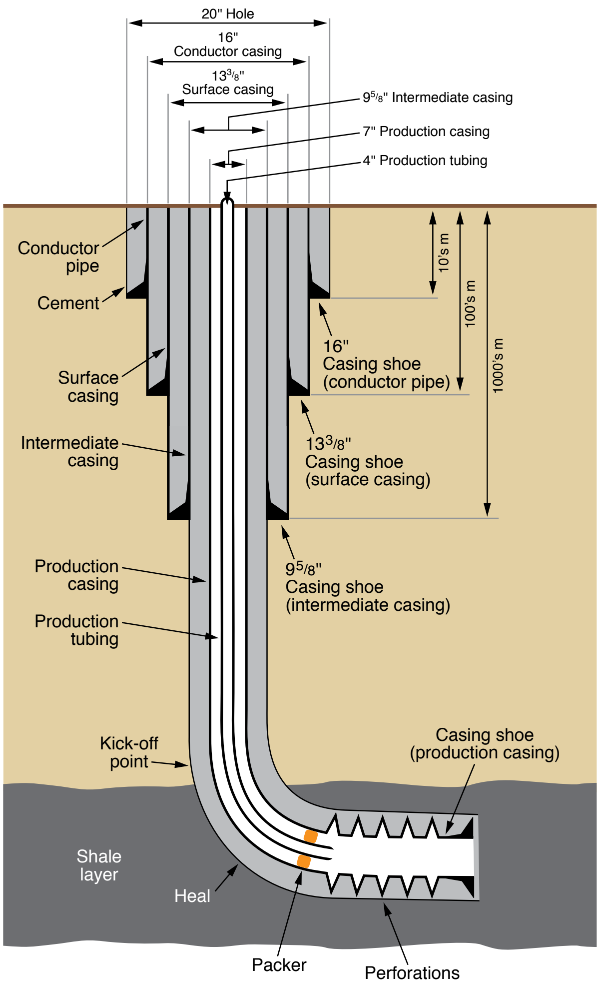
The 'casing' is the steel pipe that provides a pressure-tight conduit between the shale gas resource and the surface.[11] It is a highly engineered product that must cope with anticipated wellbore conditions, including the potentially very high pressures applied during hydraulic fracturing (see Section 5.3.2.3). International standards cover the manufacture, testing,

5 Golden and Wiseman 2015, pp 968-974.
6 ACOLA Report, pp 54-56.
7 Gallegos et al. 2015.
8 ACOLA Report.
9 Origin submission 153, pp 55-60.
10 ISO 2017.
11 Hossain and Al-Majed 2015, pp 433-501.

engineering specification, mechanical properties and performance of the casing.[12] The casing is designed to prevent the unintended flow of drilling and hydraulic fracturing fluids out of the well, to keep the well open through weak or broken rock layers, and to prevent formation fluids from entering the well and from moving between layers of rock through the well.

Well drilling occurs in stages, with each stage cased before further drilling using a smaller diameter drill bit. **Figure 5.3** shows the general layout of casing used in shale gas wells, demonstrating that the diameter of the well decreases with depth, as successive casings are placed inside the previous casing strings. The design of casing for a well needs to take into account the depths of layers of rock or aquifers that must be isolated from each other, the corrosive nature of fluids or gases (such as hydrogen sulfide or carbon dioxide) that may be encountered, the stresses that the casing will be subjected to, and the operational requirements of the well.

Figure 5.3: General layout of casing in a shale gas well. Not to scale (width is significantly exaggerated). Note that the casing sizes are specified in imperial and not metric units Source: CSIRO[13].

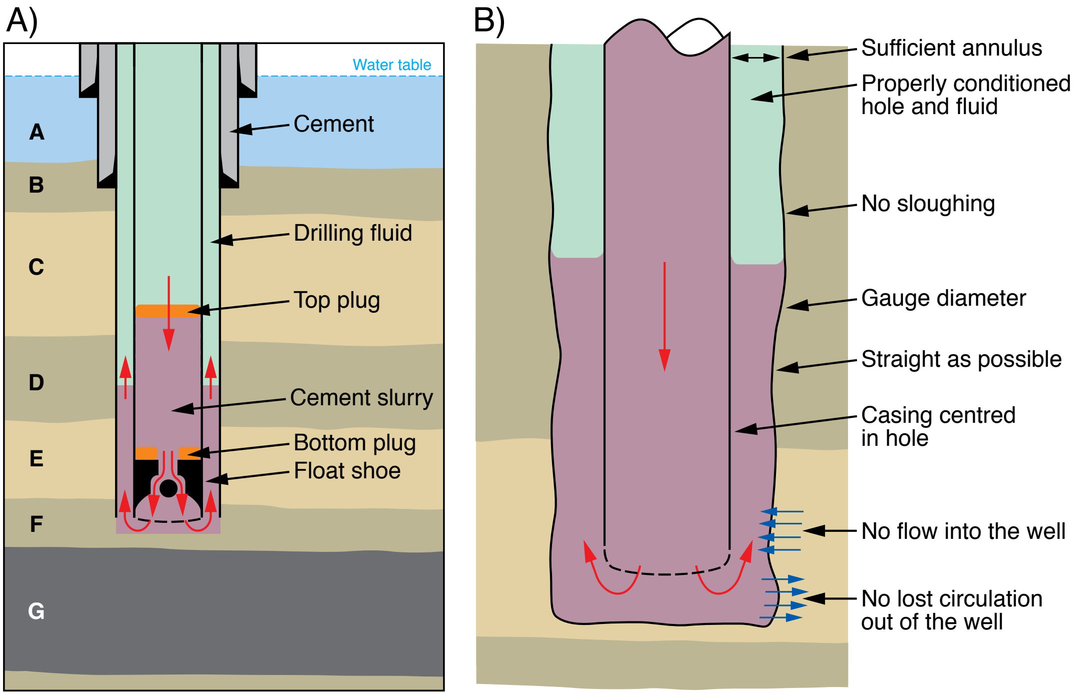


The casing is cemented to the well, and this is essential for two reasons. First, to provide strength to the well, and second, to provide a seal between the casing and the surrounding rock so that gas and fluids cannot flow from the shale formation (and other intersected formations) to the surface.[14] During the cementing process, a cement slurry is pumped down the centre of the well and flows up the annulus (the gap between the rock formation and the most recently placed casing) (**Figure 5.4**). Well cements are designed, tested and prepared using established procedures to meet relevant specifications and have negligible permeability to formation fluids when cured.[15] Well cements are very different to those used in normal construction. While most

12 ISO 2014.
13 CSIRO 2017, at Appendix 14 of this Report.
14 Taoutaou 2010.
15 ISO 2009; Lavrov and Torsæter 2016.

wells can be cemented with standard well cements, there are situations that can require a special cement blend to create the best seal in the well. Some of the well types that require a specialised blend of cement include moderate to high-pressure gas wells, horizontal wells, wells completed through salt zones, high temperature wells, and wells that are very deep (below 5000 m).[16]
The casing and cement work together as an integral system that is critical to well integrity. The stability and longevity of cements is covered in Section 5.4.2.4.

Figure 5.4: The process for cementing casing into a well. The cement is pumped down the centre of the well and returns up the outside of the well (A). The well requirements for an effective cementing are shown in (B). Not to scale. Source: Modified from Smith.[17]



The design of wells, the specification of materials and equipment used in their construction, and well operations are covered by a large number of standards. As at June 2016, the International Association of Oil and Gas Producers listed more than 150 primary standards related to well construction and well operations.[18] These standards are mandatory in some, but not all, jurisdictions. Most of them relate to quality control for operations and the provision of services and materials to the industry.

5.3.2.2 Construction phase

Well construction involves drilling, cementing, and hydraulic fracturing in accordance with the well design. Drilling fluids (drilling muds) are an essential component of drilling operations[19] because they provide cooling and lubrication to the drill bit and drill string and lift drill cuttings from the well.

Casing is installed and cemented in place in a number of stages, as shown in **Figure 5.3**. Initially, a large diameter surface casing is set sufficiently deep to protect surface aquifers and is fully cemented in the ground. Once a well is drilled to the depth where a casing string is required, a steel casing string is run into the borehole and cemented (**Figures 5.3 and 5.4**) The cement fills and seals the annulus between the casing strings, or between the casing string and the formation rock. This process is repeated until the well construction is complete. The term ‘sheath’ is used to describe this encasing layer of cement.

16 US National Petroleum Council 2011.
17 Smith 1990.
18 IOGP 2016.
19 Hossain and Al-Majed, pp 73-139.

At each stage the well is prepared (cleaned by the circulation of drilling fluid) then cement is pumped down the centre of the well so that it flows around and up the annulus between the casing and the surrounding rock. The well integrity provided by the cement is not only dependent on the cement slurry design but also on a number of other aspects of the well cementing process, such as the cleaning and preparation of the wellbore and the condition and centralisation of the casing in the wellbore.[20]

Importantly, during drilling and cementing, testing of the well's integrity is undertaken.[21] For example, pressurising the well to verify that it can hold the maximum pressures that it may be exposed to over its life, including the initial hydraulic fracturing operation. This is designed to test the integrity of both the well casing and cement.[22] Additionally, there are a number of downhole sensor and logging tools that can be used to measure the state of the casing and the integrity of the bond between the casing, cement and rock.[23] If the pressure testing indicates a problem, there are a number of procedures that can be undertaken by way of remediation (see Section 5.3.2.4).

The final activity in the construction phase is the 'completion' of the well; that is, preparing it for the production of gas.[24] Completion involves the installation of hardware in the well and on the surface to allow the safe and efficient production of gas from the well at a controlled rate.

5.3.2.3 Hydraulic fracturing

Hydraulic fracturing is a stimulation technique used to increase the production of oil and gas from unconventional reservoirs, such as shales, by the injection of a hydraulic fracturing fluid at high pressure into a cased wellbore (**Figure 5.5**). Hydraulic fracturing is usually conducted over a number of intervals along the production zone of the well (the horizontal or lateral section), called 'hydraulic fracture stages' (**Figure 5.6**).

Most hydraulic fracturing treatments in shale gas wells take place in the relatively long (up to several kilometres) horizontal or nearly horizontal section of the well (lateral). The number of fracture stages in a single well has increased over time in US unconventional gasfields. For example, in 2009, 10–12 fracturing stages would have been typical, with a spacing of around 200 m. In 2017, it is common for 40–100 fracture stages in a single lateral, with a spacing of around 15–30 m between segments that are being fractured.[25]

The hydraulic fracturing fluid is predominantly a mixture of water, proppant (commonly sand, or ceramics where formation pressures are high), and a small percentage of chemical additives (typically less than 1%).[26]

20 CSIRO 2017, p 12.
21 NORSOK D-010 Rev. 4.
22 For example, see Origin submission 153, pp 63-66.
23 Jeffrey et al. 2017, Section 3.5.
24 Hossain and Al-Majed 2015.
25 CSIRO 2017, p 15.
26 US EPA 2016a, pp 3-21.

Figure 5.5: Schematic diagram of shale gas extraction process showing hydraulic fracturing. Source: Modified from Total S.A.

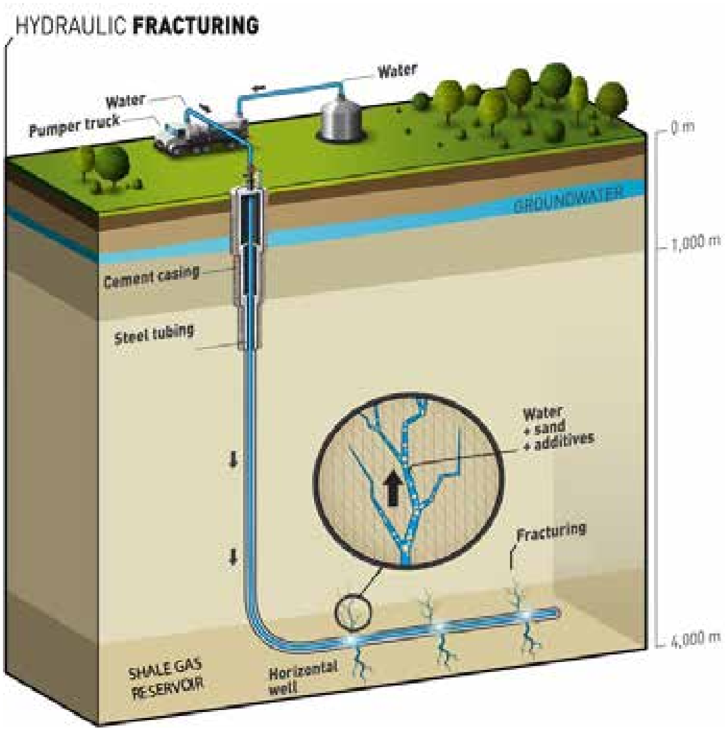
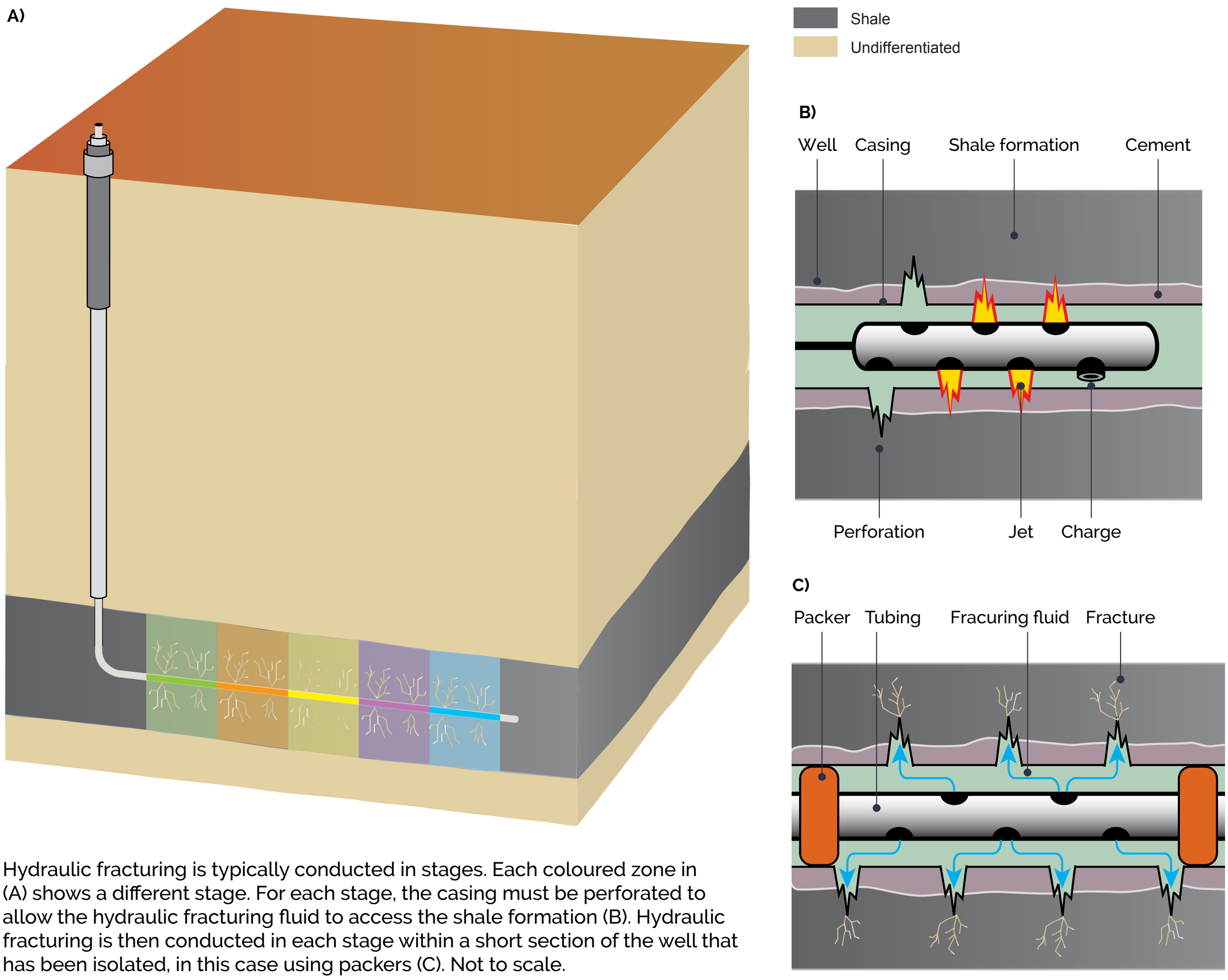


Figure 5.6: Hydraulic fracture stages. Source: CSIRO[27]



Hydraulic fracturing is typically conducted in stages. Each coloured zone in (A) shows a different stage. For each stage, the casing must be perforated to allow the hydraulic fracturing fluid to access the shale formation (B). Hydraulic fracturing is then conducted in each stage within a short section of the well that has been isolated, in this case using packers (C). Not to scale.

27 CSIRO 2017.

The most common approach to hydraulic fracturing in use today is called 'plug and perf' (short for 'perforation') by the gas industry (**Figure 5.6**). This involves initially perforating the zone within the lateral for each fracturing stage using shaped charges. The perforated stage is then isolated using mechanical plugs or other devices before the hydraulic fracturing fluid is injected into the isolated wellbore section. The stage nearest the end of the horizontal well (that is, the most distant segment from the vertical wellbore) is stimulated first by injecting the hydraulic fracturing fluid through the main production casing of the well.

As the hydraulic fracturing fluid is constrained within the isolated wellbore zone, the pressure builds up until it exceeds a threshold known as the 'breakdown pressure'. Once the hydraulic fracture fluid pressure exceeds the breakdown pressure, it fractures the rock. The direction in which the hydraulic fracture propagates depends on the orientation of in-situ stress in the rock, with growth mainly occurring in a direction perpendicular to the minimum principal stress.

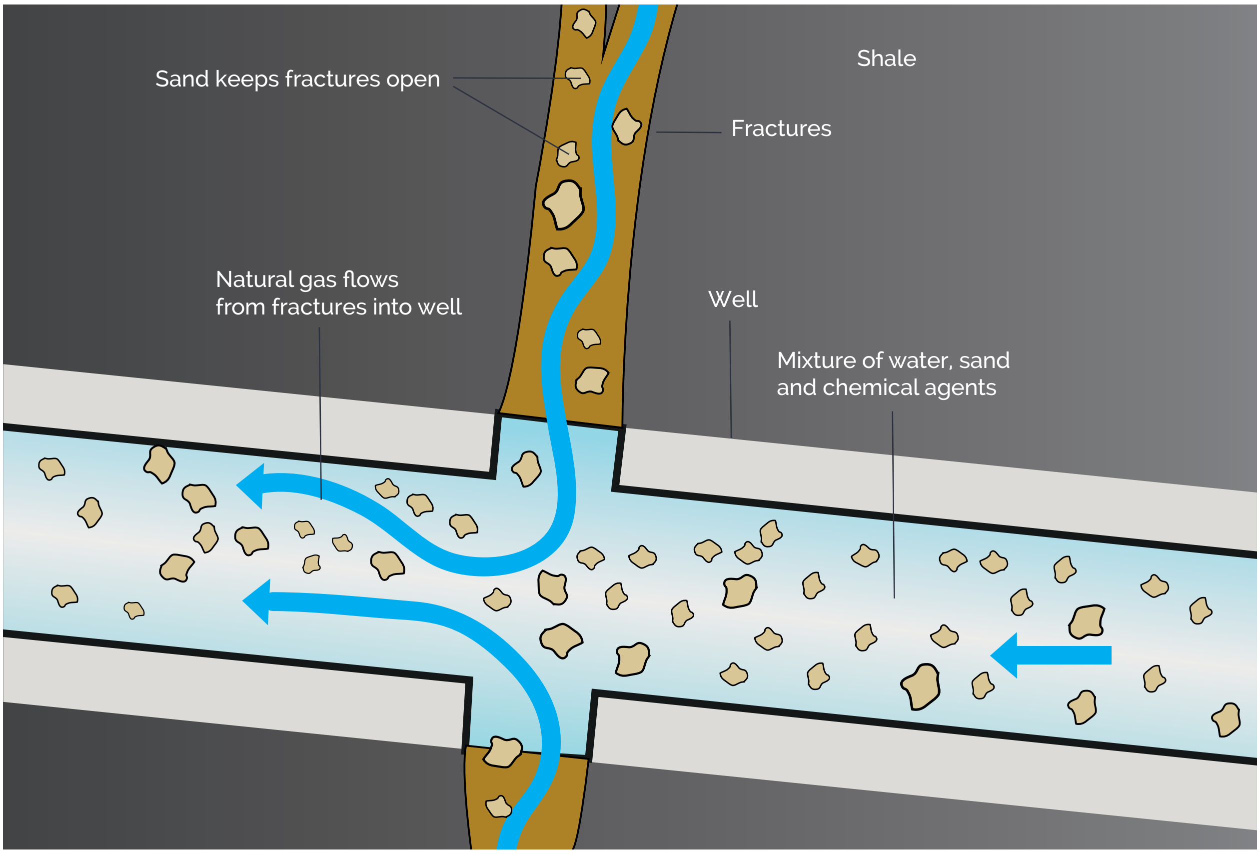
After the end stage is fractured, a plug is installed between that stage and the next furthest stage, and hydraulic fracturing fluid is injected again. This is repeated until the stage closest to the vertical section has been stimulated. Once all stages have been stimulated, the plugs are removed. The key operational feature of this approach is that the vertical wellbore is exposed to many cycles of pressurisation and depressurisation and needs to be designed to cope with this regime. As noted in Sections 5.4.2.2 and 5.4.2.3, this is a risk factor for well integrity.

New technologies are being developed and tested that involve the direct physical coupling of the hydraulic fracturing stage to the surface by a tubing string so that only that stage, and not the entire production casing up to the surface, is exposed to the cycling high pressure regime. This technology has the benefit of minimising the exposure of the production casing to cycling pressures and the risk this poses to the wellbore, especially in the context of bonding the outer cement sheath to the steel casing (Section 5.4.2.3). However, such technology is not yet in general use.

Once the hydraulic fracture has been initiated, further propagation is controlled by the fluid flow. Some of the hydraulic fracturing fluid drives hydraulic fracture growth, with the rest being injected or lost by absorption into the formation (a process known as 'leak-off'). The surface area of the hydraulic fracture increases as the fracture grows, thereby increasing the fluid loss into the formation. The hydraulic fracturing fluid injection rate is calculated to propagate hydraulic fractures to the desired size given the expected fluid loss into the formation.

At the start of the stimulation, the hydraulic fracturing fluid is injected without any 'proppant' to initially open a fracture wide enough to allow the proppant to travel along the hydraulic fracture. Proppant is added to the hydraulic fracturing fluid to hold the fractures open at the end of the treatment. At the end of the treatment stage, the wellbore is finally flushed to remove any residual proppant, leaving behind proppant-filled fractures that act as conductive channels through which gas can flow into the wellbore (**Figure 5.7**).

Figure 5.7: Proppant in action. Source: Modified from Granberg.[28]



After hydraulic fracturing is complete, a portion of the hydraulic fracturing fluid, will flow back up the wellbore and return to the surface. This return water is called 'flowback' and typically comprises 10–30% of the initial volume of hydraulic fluid that was used. [29] The composition, collection, treatment and reuse of this flowback fluid is covered in Sections 5.7 and 5.8 and Chapter 7 (Section 7.6).

5.3.2.4 Operational or production phase

Most shale gas wells are designed to keep producing hydrocarbons for decades. The main activities during production are the monitoring of the well's integrity and performance, and its maintenance. Wireline logging[30] is generally the only means of checking the integrity of casing and cement down a well. Abnormal pressures in the annulus between casing strings and changes in production rates can also indicate integrity issues.[31]

In some cases, it is necessary to re-enter a well (called a 'workover') to perform maintenance, repairs or replacement of components, for surveillance, or to increase productivity.[32] Such interventions can be critical to maintaining well integrity, and there are a range of technologies that can be applied to repair the casing and cement if integrity issues are detected.[33] Wells may also need to be hydraulically re-fractured to extend their production lifetime.

5.3.2.5 Well decommissioning and abandonment

The final phase in the well life cycle occurs when the wells are decommissioned and ultimately abandoned. As stated above, decommissioning involves: the removal of the well head; plugging the steel casing with cement and steel; the removal of all production equipment, production waste, pipelines and other infrastructure; capping the plugged well below the land surface, and the rehabilitation of all cleared areas.

28 Granberg 2008.
29 US EPA 2016a.
30 This is a technique whereby logging instruments are lowered down the well to measure the integrity of the casing, cement lining, or the geological formations: Jeffrey et al. 2017, Section 3.5.
31 ISO 2017.
32 ISO 2017.
33 Durongwattana et al. 2012; Roth et al. 2008; Ansari et al. 2017.

The goal of decommissioning a well and its final abandonment is to ensure well integrity in perpetuity, effectively re-establishing the natural barriers formed by impermeable rock layers originally drilled through to reach the resource.[34] The aims of decommissioning a well at the end of its productive life are to: [35]

- prevent the release of formation fluids, or well fluids, to the environment, including aquifers;
- prevent the flow of groundwater or hydrocarbons between different layers of rock; and
- isolate any hazardous materials left in the well.

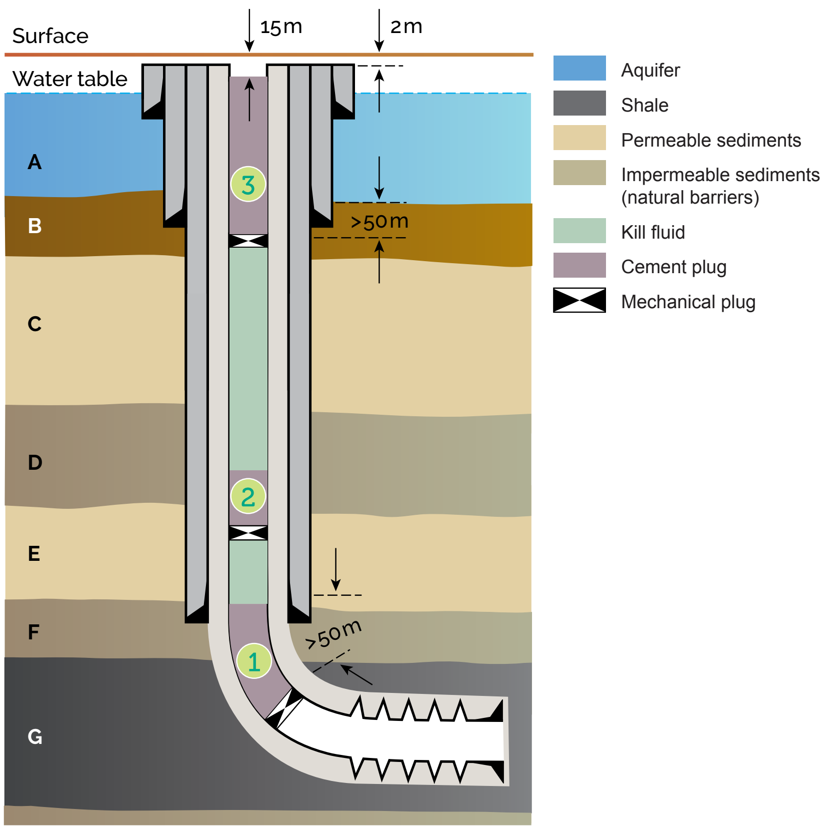
There are five phases involved in decommissioning a well:

- **stage 1:** decommissioning the well, including plugging, capping and burial below the surface;
- **stage 2:** monitoring the performance of the decommissioned well and applying further remediation if necessary;
- **stage 3:** relinquishment of decommissioned wells that are performing as specified to the Government;
- **stage 4:** post-relinquishment confirmatory monitoring or repair if required; and
- **stage 5:** abandonment.

The requirements for each of these phases are discussed further below.

A schematic of a properly decommissioned well is shown in **Figure 5.8**. The plugs which are in place to ensure zonal isolation typically consist of cement in conjunction with a mechanical plug. To provide long-term integrity, the cement (or other barrier material) must not shrink, be able to withstand the stresses in the wellbore, be impermeable, be impervious to chemical attack from formation fluids and gases, be able to bond with steel casing and rock, and not cause damage to the casing.[36]

Figure 5.8: A decommissioned well, showing the cement plugs that are placed in the well to prevent vertical flow of fluids. This figure is for illustrative purposes only, noting the precise locations and numbers of cement and mechanical plugs will depend on local geology and the design of the well. Not to scale. Source: CSIRO.[37]

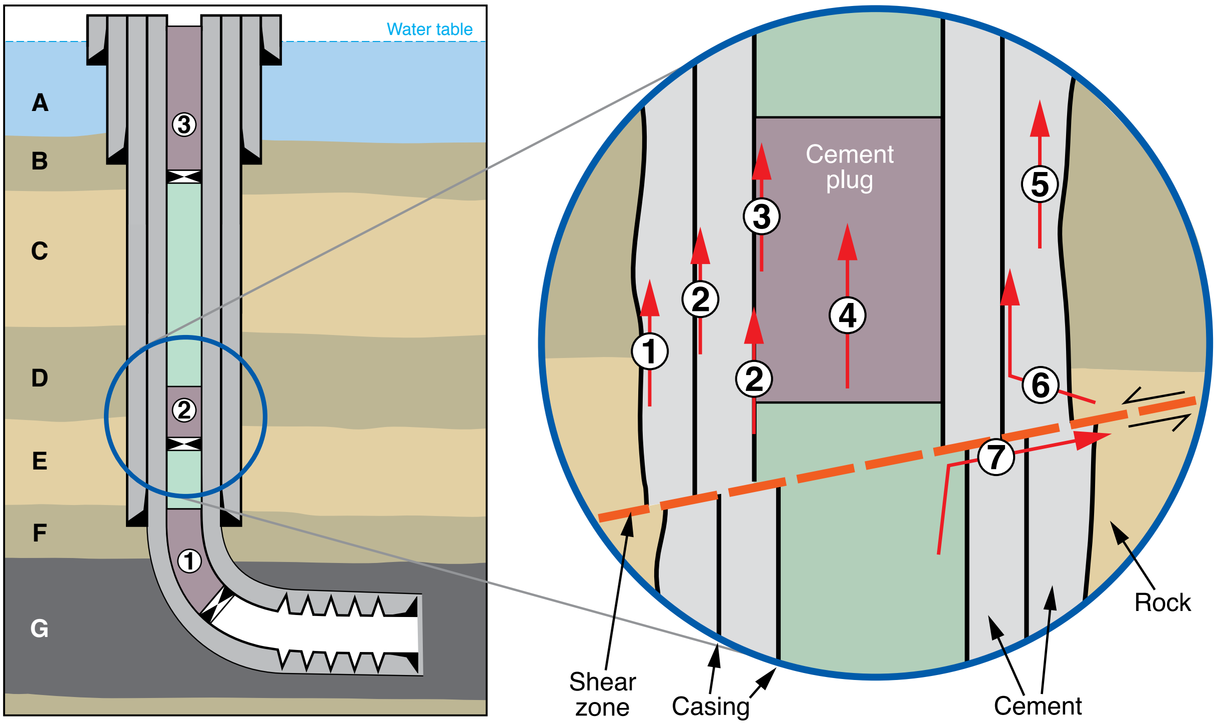


34 NORSOK D-010 Rev. 4; Kiran et al. 2017.
35 NORSOK D-010 Rev. 4; Kiran et al. 2017.
36 NORSOK D-010 Rev. 4, p 96.
37 CSIRO 2017.

For a leak to occur in a decommissioned well, whether the leak is to the surface or to the subsurface between different geological formations, three elements must exist:[38]

- first, a source formation where hydrocarbons or other fluids exist in the pore space;
- second, a driving force (due to a difference in pressure, temperature, salinity or buoyancy) between the source formation and surface in the case of a leakage to surface, or between different geological formations in the case of a subsurface flow; and
- third, a leakage pathway between the source formation and the surface, or between different geological formations.

Figure 5.9: Routes for fluid leakage in a cemented wellbore. Source: Modified from Davies et al.[39]



Path 1 – between cement and surrounding rock formations;
Path 2 – between casing and surrounding cement;
Path 3 – between cement plug and casing or production tubing;
Path 4 – through cement plug;
Path 5 – through the cement between casing and rock formation;
Path 6 – across the cement outside the casing and then between this cement and the casing; and
Path 7 – along a shear through a wellbore.

In common with operating wells, leakage or failure of decommissioned wells could occur by poorly cemented or deteriorating casing/hole annuli, faults in the interface between cement and the formation rock and casing failure.[40] Additionally, for decommissioned wells, the interface between cement plugs and casing has been identified as a preferential pathway for gas/fluid flow.[41] Migration of gas/fluid can also occur through fractures, channels, and the pore space in the cement sheath. In the latter case, gas/fluid flow will only occur when the cement sheath is degraded or did not form properly during the cementing process.[42] For shale gas wells decommissioned using current practices, it is highly unlikely that if any of these leakage pathways were to develop they would allow large gas/fluid flow rates, but some flow of gas would be more likely. The small cross-sectional areas and long vertical lengths of the pathways will strongly limit the flow of fluids, with the potential for upward migration of gas being additionally limited by the post-production depressurised state of the formation and the intrinsically low permeability of the shale itself.

38 Watson 2004.
39 Davies et al.2014.
40 Watson and Bachu 2009.
41 Gasda et al. 2004.
42 Zhang and Bachu 2011.

The low permeability of shale gas formations is also a factor mitigating the potential for adverse impacts due to loss of well integrity post well decommissioning. Pressures within the part of the reservoir accessed by the well will have been depleted by production, and the very low permeability of the shale will also act to prevent gas from other parts of the reservoir migrating to the well. Restoration of pore pressure in the reservoir is likely to be slow because of the low permeability preventing migration of any high-pressure fluids from outside the reservoir, and the geological time scale of processes that might increase pressures from within the shale. But some gas will remain in the part of the reservoir accessed by the well, and its buoyancy will provide drive for upward flow should pathways be available.

The combination of small cross-sectional areas, long vertical lengths of flow pathways and low driving pressure differentials means that overall, there is a low likelihood of substantial vertical movement of fluids post decommissioning.

Well decommissioning and abondonment is a global issue, with estimates that around 30,000 wells globally will need to be decommissioned and abandoned over the next 15 years.[43] It is highly likely that well decommissioning practices will experience innovation as the scale of decommissioning activity increases globally in the context of increased scrutiny of environmental performance.

The Panel has found that there is a paucity of information available on the performance of decommissioned and/or abandoned onshore shale wells (refer also to **Section 9.8**). Indeed, it appears to be only recently that specific attention has been paid to this issue by regulators. This issue was the subject of specific questions to expert consultants by the UK Royal Society and the Royal Academy of Engineering when it undertook an extensive review of shale gas extraction in the UK in 2012.[44] When asked about the long-term pressure behaviour of wells after they are decommissioned, Halliburton, one of the largest service providers worldwide to the shale gas industry, responded that pressures are not routinely monitored post decommissioning and that there is no statistically based data available to indicate the percentage of wells that fail. Halliburton continued, *"based on reported MIT failure rates in active wells, the percentage should be very low and may be less than 1%."* [45]

Even if the current moratorium is lifted, there is unlikely to be a substantial number of wells decommissioned in the NT in the near future, which provides an opportunity to establish a long-term decommissioned and abandoned well program. Such a program should assess well decommissioning options in the context of the NT's shale resources and consider:

- geological zones along the well which need to be isolated long term;
- reviewing and testing of the durability of cements and casing;
- the partial decommissioning of some wells to allow long-term monitoring;
- evaluation of post-decommissioning monitoring approaches;
- trials of novel decommissioning methods and materials; and
- the costs of decommissioning and ultimate abandonment to assist in the calculation of security bonds.

In this context, it should be noted that 236 oil and gas wells have been drilled over the past 50 years in the NT.[46] Out of this total, 145 have been decommissioned, 26 have been suspended for future data gathering or production, and 65 are currently producing from conventional reservoirs.[47] In the event that the moratorium is lifted, these existing decommissioned and suspended wells represent a starting point for implementation of a decommissioned and abandoned well assessment program.

In the NT, the rules around well abandonment are set out in the *Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (**Schedule**). A gas company must apply to the Minister for Primary Industry and Resources (**Minister for Resources**) to abandon a well, and the application must include a proposed abandonment program *"including the method by which the well will be made safe"*.[48] A well cannot be lawfully abandoned unless Ministerial approval is given.

43 Ouyang and Allen 2017.
44 Royal Society Report.
45 Halliburton Royal Society submission, pp 5-6.
46 Department of Primary Industry and Resources, submission 226 (**DPIR submission 226**), p 46.
47 DPIR submission 226, p 46.
48 Schedule, cl 328(5)(f).

However, the Schedule does not make explicit what the Minister must consider when making a decision about a proposed abandonment program. Clause 329 of the Schedule prescribes how a well must be abandoned, including that cement plugs are to be placed at certain intervals of the well.[49] It is not clear whether the terms of the approved abandonment program or the requirements of cl 329 will prevail in the event of an inconsistency. The Schedule also provides that, *"on completion of production activities and prior to the surrender of a production licence"* all wells must be decommissioned in accordance with an *"approved decommissioning plan"*.[50] Again, it is not clear how the approved decommissioning plan and the requirements of cl 329 interact. The Panel's concerns about the Schedule are discussed in further detail in Chapter 14.

Current practice in the NT, as stated by DPIR,[51] is that DPIR does not monitor wells that have been decommissioned. It was further noted by DPIR *"that it is not common industry/regulator practice to monitor wells that have been plugged and abandoned in line with current best practice methodology".*

The Panel considers that a mandatory period of monitoring is needed following the decommissioning of a well to determine if the well is leaking gas or other fluids. In the event that leakage is detected within this period, the operator must be required to carry out remedial works. Prudent practice is to reset the period required to demonstrate acceptable performance following confirmation that the remedial works have been successful. If no issues are found during the post-decommissioning surveillance monitoring (or reset) period, the gas company can apply to the regulator for relinquishment. Once the well is relinquished, custody for future stewardship of the well is transferred to the Government.

Ensuring that world-leading well decommissioning practices are used, and that ongoing assessment of abandoned wells is undertaken, represents a challenge for any regulator because it occurs at a time when the cash flow associated with the well has come to an end. The regulatory aim is to ensure that wells are abandoned safely, that there is funding available for ongoing monitoring, and that in the event that a well has not been decommissioned properly, that there is money available (from the gas industry) to ensure that problems can be remedied. In Chapter 14, the Panel recommends the establishment of an 'orphan well levy' (***Recommendation 14.14***) to ensure that long-term funding is available to monitor and, if necessary, repair wells that have not been decommissioned properly and to implement the ongoing monitoring program recommended below.

Recommendation 5.1

That prior to the grant of any further exploration approvals, the Government mandates an enforceable code of practice setting out minimum requirements for the decommissioning of any onshore shale gas wells in the NT. The development of this code must draw on world-leading practice. It must be sufficiently flexible to accommodate improved decommissioning technologies. The code must include a requirement that:

- ***wells undergo pressure and cement integrity tests as part of the decommissioning process, with any identified defects to be repaired prior to abandoning the well; and***
- ***cement plugs be placed to isolate critical formations and that testing must be conducted to confirm that the plugs have been properly set in the well.***

Recommendation 5.2

That the Government:

- ***implements a mandatory program for regular monitoring by gas companies of decommissioned onshore shale gas wells (including exploration wells), with the results from the monitoring to be publicly reported in real-time. If the performance of a decommissioned well is determined to be acceptable to the regulator then the gas company may apply for relinquishment of the well to the Government; and***
- ***implements a program for the ongoing monitoring of all orphan wells.***

49 Schedule, cl 329.
50 Schedule, cl 426.
51 Department of Primary Industry and Resources, submission 1191 (**DPIR Submission 1191**), p 4

5.4 Well integrity

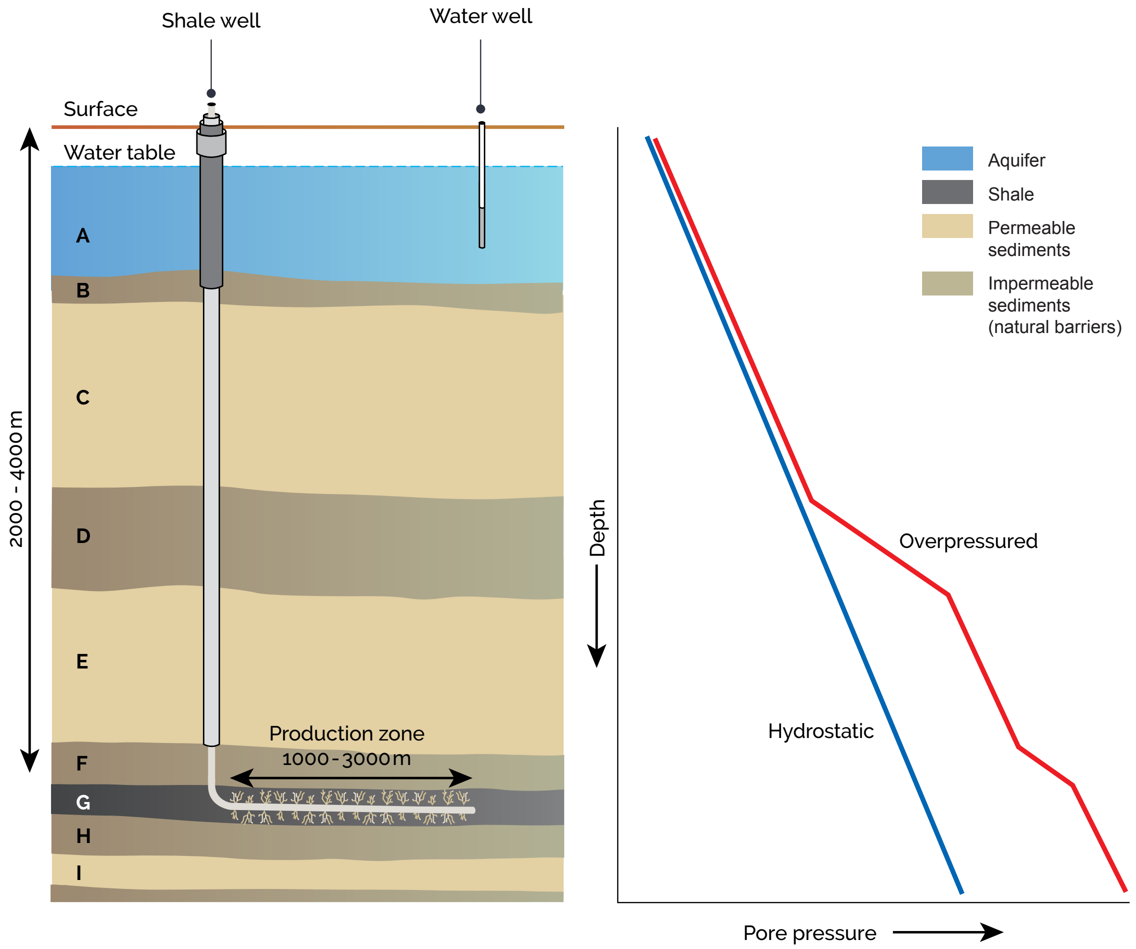
5.4.1 Overview

The integrity of any onshore shale gas wells has been a key issue raised during the Panel's consultations throughout the NT (see Chapter 3), with many comprehensive submissions received by the Panel on this topic.[52] Well integrity is crucial for the safe operation of a well and to ensure that aquifers are not contaminated. The International Standards Organisation (**ISO**) defines well integrity as follows:

> *"Well integrity refers to maintaining full control of fluids (or gases) within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment."*[53]

Knowledge of the processes that force fluids and gases to move to the surface from a shale layer is important to understanding how these may flow out of or into the well, or between layers of rock or to the surface by the well. **Figure 5.10** shows a simplified shale gas resource, consisting of the shale layer at the base, with overlying layers of various sedimentary rocks referred to as overburden. Overburden includes layers that can be classified as 'permeable', that is, that allow fluid to flow through them, and 'impermeable', that is, that form a barrier to fluid movement. Some of the permeable layers may be aquifers containing water that is used for agriculture or stock and domestic purposes, while others may contain salty water (brine). Hydrocarbons (oil and/or gas) may also be present in some rock layers.

Figure 5.10: Simplified shale gas resource. Source: CSIRO.[54]



Rock layers A-F are overburden that cover the shale resource (layer G). The graph shows the pore pressures in the rock, the gradient in blue is the hydrostatic gradient. The gradient in red shows the pore pressures in an overpressured scenario, with layer D and F trapping higher pressures below them. Not to scale.

52 For example, Don't Frack Katherine, submission 65; Dr Matthew Currell, submission 311; Jason Trevers, submission 409.
53 ISO 2017.
54 CSIRO 2017.

The pressure of the fluids in the rock (pore pressure) increases with depth, and if this is greater than the hydrostatic pressure (the pressure that is equal to the weight of the column of fluid above it), the overpressure provides the driving force for the fluids to flow vertically. Methane, which is lighter than water, will move upwards through the rock unless there is an impermeable barrier in between.

When considering fluid movement, the presence of overpressures is a significant contributor to well integrity. High overpressures, which drive vertical fluid movement, are not a common feature of shale resources, and the limited data collected in the Beetaloo Sub-basin indicates that this Sub-basin also has low overpressures.[55]

By contrast, the buoyancy and low viscosity of gas means that it is more likely to be able to move along these pathways. In addition, gas may also be present in shallower layers of rock as well as the target shale gas reservoir. Gas from any of these sources may move upwards along the well if a pathway is present. The rate at which fluid or gas can flow up a pathway will be limited by the aperture of the opening through which it flows. Where the annulus between the well casing and the rock is cemented, the size of any opening will be limited.

The integrity of the well drilled through the rock barriers between the surface and the shale deposit is crucial to ensuring that a new pathway is not created through which gas or fluids can travel to the surface, or to drinking water aquifers.

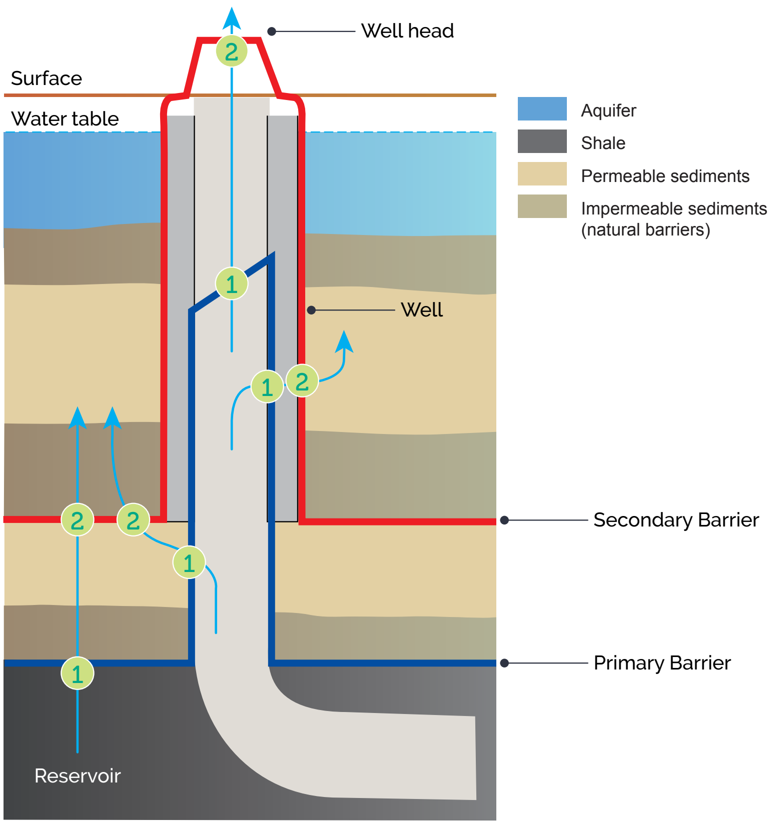
Discussed below are two broad categories of problems with well integrity:

- first, the unintended flow of fluids or gases between rock layers or to the surface along the outside of the well; and
- second, the unintended flow of drilling fluids or hydraulic fracturing fluid from inside the well into the surrounding rock, or from formation fluid or gas into the well.

5.4.2 Failure modes for well integrity

There are many elements that make up a well barrier system. All of these elements need to be tested to confirm well integrity. **Figure 5.11** shows examples of the (at least) two-barrier system that needs to be maintained throughout the well life cycle.

Figure 5.11: The two-barrier concept showing the two barriers to various pathways for fluid flow out of the well. Source: CSIRO.[56]



55 Close et al. 2016.
56 CSIRO 2017.

There are two types of well failures:

- **well integrity failure:** all barriers have failed, and a pathway exists for fluid to flow into or out of the well. In a dual-barrier design, both barriers must fail for a well integrity failure to occur; and
- **well barrier failure:** one barrier has failed but this does not result in a loss of fluids to, or from, the environment as long as the second barrier is intact.

CSIRO discusses in detail the three commonly considered well barrier failure mechanisms:

- first, failure during drilling and prior to casing;
- second, failure of the casing; and
- thrid, failure of the cement.

5.4.2.1 Failure mechanisms related to drilling

Drilling is the first step in constructing a well. Prior to the casing and cement being installed into the borehole, there are a number of potential risks to the early integrity of a well, such as loss of drilling fluid out of and into shallow aquifers or into the borehole, or distorted geometry of the wellbore (for example, enlargement of the borehole size). During drilling, the primary well barrier is the drilling fluid pressure exerted on the rock formation surrounding the well, with the drilling fluid density or mud weight playing a vital role in maintaining well integrity prior to a casing being cemented. Blowout of onshore shale gas wells is unlikely during drilling because of the very low permeability of shale gas reservoirs.

Risks of losses of drilling fluid during drilling can be reduced by the identification of geological hazards prior to drilling, the monitoring of drilling fluid pressure and volume, and the use of well control equipment.

5.4.2.2 Failure mechanisms related to casing

Failure of the wellbore casing could allow loss of fluid to the surrounding rock formations. Issues with casing can be caused through poor cementing placement, leaking through casing connections, corrosion of the casing, or casing unable to withstand the pressures during hydraulic fracturing.[57] Corrosion can potentially attack every metal component, including the casing, at all stages in the life of an oil and gas well.[58] Corrosion-induced casing damage and loss of well integrity have been widely reported.[59] The cement quality, cement sheath, and bonding integrity, play a critical role in protecting the casing from external corrosion. Cement degradation, failure of the cement sheath, and debonding of the interfaces along the casing and rock formation can expose the casing to corrosive fluids (if present), and casing corrosion can start. Corrosion rates depend on the type of steel used, with higher rates for mild carbon steel compared to lower rates for stainless steel or steel coated with corrosion-resistant material.[60]

Risks of casing failure can be reduced, however, by monitoring casing pressure, using multi-finger caliper logs and magnetic thickness tools to gauge casing integrity, employing borehole camera inspections, and casing patching and repair, if needed.

5.4.2.3 Failure mechanisms related to cement

Failure of the casing cement can create a conductive pathway and allow movement of fluid or gas up the cement annulus outside the casing. Potential failure modes include channels or voids in the cement, gaps between the wall of the wellbore and the cement, gaps between the cement and the casing for the inner layers of the multi-casing system, and poor adhesion to the casing. These issues can be caused through poor cement placement, leaking through casing connections, and cement sheath degradation.

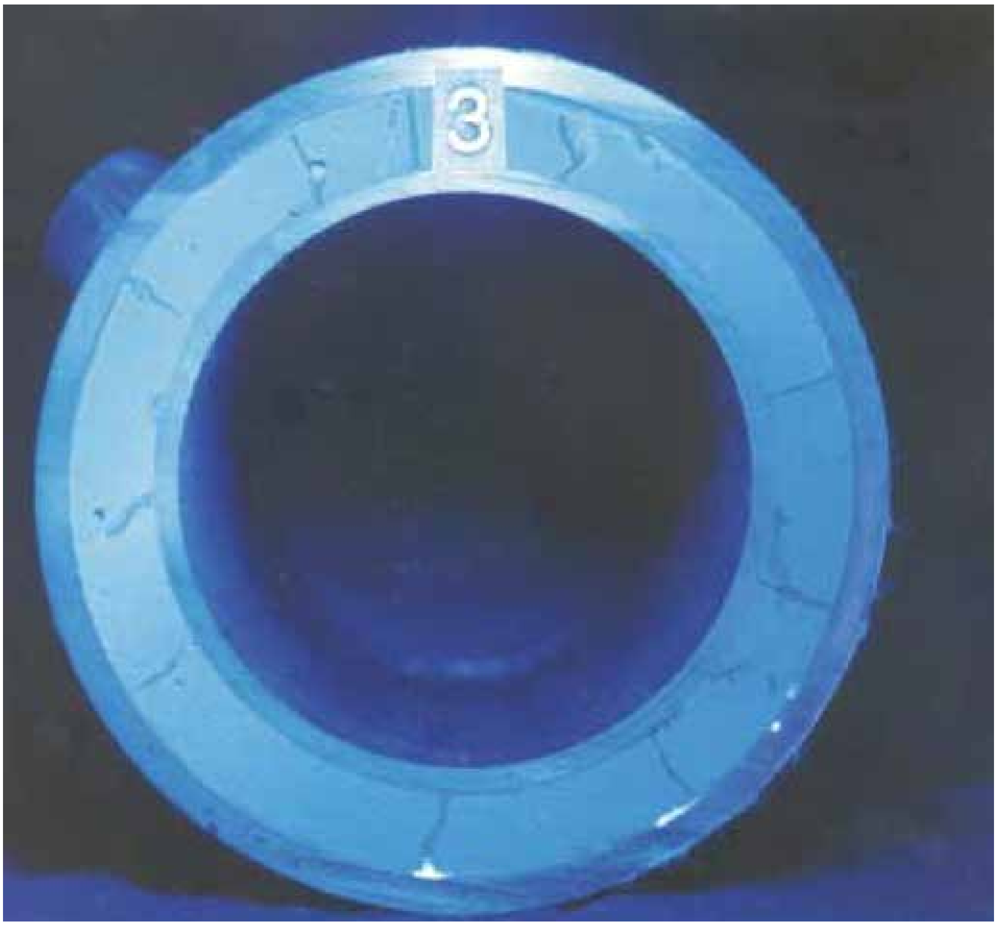
The consistency and quality of casing cement is assessed using a technique called a cement bond log (**CBL**).[61] This is based on the use of sound waves to detect flaws in the cement. Electronic measuring tools are lowered into the well to measure (or log) the cement along the

57 Ingraffea 2012.
58 Brondel et al. 1994.
59 Bazzari 1989; Vignes and Aadnoy 2010; Watson and Bachu 2009.
60 Kreis 1991; Elsener 2005.
61 Australian Petroleum Production and Exploration Association, submission 215 (**APPEA submission 215**), p 22; Jeffrey et al. 2017, Section 3.5; Cameron 2013.

depth of the well. Sound waves are used to look at how effectively the metal casing is held, or bonded, to the cement. The sound waveforms on the log are evaluated for how well the sound waves travel from a transmitter through the pipe, cement and rocks before returning to receivers located along the tool. If the cement bonding is good, sound will not easily transmit through the pipe. Conversely, if the cement bonding is poor, the pipe is free to vibrate, allowing for easy transmission of sound. In the event a problem is detected by the CBL, there are various techniques that can be used to repair the compromised zone.[62]

A good cement sheath is characterised as having very low permeability,[63] with strong bonds to the casing and rock formation surfaces, which means that fluids and gases cannot migrate within or through the sheath. However, even if the cement sheath is initially in very good condition, large perturbations of pressure and temperature caused by casing pressure tests and hydraulic fracturing can induce radial deformation of the casing and failures in the cement sheath, resulting in de-bonding on the interfaces between the cement sheath and the casing, and the cement and the formations, creating radial fractures (**Figure 5.12**) and migration pathways.[64]

Figure 5.12: Cement sheath failure, resulting in cracks developing from pressure cycling on the internal casing. Source: Watson et al.[65]



The impact of failure of either the cement sheath or the bonds with the casing or rock formations on well integrity will depend on the extent of such failure along the wellbore and specific geological conditions. For example, one study found that in the Gulf of Mexico there was no breach in isolation between formations with pressure differentials as high as 97 MPa (14,000 psi) as long as there was at least 15 m of high-quality cement seal between the formations to ensure sufficient vertical isolation between them.[66]

62 Durongwattana et al. 2012; Roth et al. 2008; Ansari et al. 2017.
63 Parcevaux et al. 1990.
64 Goodwin and Crook 1992; Watson et al. 2002.
65 Watson et al. 2002.
66 King and King 2013.

Risks of cement failure can be reduced by good quality geological information, including fractured formations or zones, and identification of hydrocarbon-bearing formations in the overburden and aquifers, good drilling practices to provide high-quality intact bore hole for cementing; cement bond logging to investigate the integrity of the cement sheaths; and remedial cement repairs applied to identified problem zones.

5.4.2.4 Long-term stability and integrity of cement

The cement used in well construction and abandonment is designed to have a long life span. There have been no studies on the long-term durability of cements of shale wells in Australia because the industry is only in its initial stages of development. However, there have been a number of overseas studies investigating the degradation of cement under simulated carbon dioxide (**CO_2**) geological storage conditions.[67] These have focussed on the behaviour of cement and the cement-rock and cement-casing bonding when exposed to high levels of CO_2, which is a much more corrosive environment than that found in a shale gas basin.[68]

A numerical model simulating the geochemical reactions between the cement seals and CO_2[69] was developed and validated using the laboratory experimental results by Satoh et al. prior to its application to abandoned wells.[70] The simulation of the geochemical reactions showed that the alteration length (that is, the length of cement with degraded properties) of cement seals after 1000 year exposure was approximately only 1 m, resulting in the conclusion that the length of the cement plug that was used would be able to isolate CO_2 (and therefore methane) in the reservoir over the long-term.

There have also been several relevant studies conducted to investigate the effect of well cement exposed to a mixture of acid gases (CO_2 and hydrogen sulfide (**H_2S**)).[71] The results have revealed that, given a moderate concentration of H_2S in the acid gas, increases in porosity and permeability of the cement are mainly determined by how much secondary carbonate mineral species are formed in the cement. Formation of sulphur-bearing minerals as a result of interaction between cement and H_2S does not result in significant porosity and permeability changes, and therefore, loss of mechanical strength of the cement.

Given that the extent of corrosion and cement degradation is likely to be much greater with CO_2 at high pressure than with methane,[72] the Panel has concluded that if any onshore shale gas wells are properly designed, installed and maintained, the risk of long-term leakage from the wells through degradation of the cement will be 'low'.

5.4.2.5 Potential impact of hydraulic fracturing on well integrity

The high pressures experienced during fracturing can damage the well casing and can lead to the escape of fluids. Therefore, to maintain integrity, the well and its components must have adequate strength to withstand the stresses created by the high pressure of hydraulic fracturing because if the well and casing are not strong enough to withstand these stresses, a casing failure may result.

Casing failures during hydraulic fracturing operations, or shortly following operations, have been reported in the US and Australia.[73]

In the NT, the Baldwin 2HST-1 well experienced a shallow casing failure during the first stage of hydraulic fracturing in 2012.[74] In this instance, the multiple casing design protected the shallow aquifer (according to groundwater monitoring data), noting, however, that the fluid in use at the time had minimal chemical content. The well was subsequently abandoned.

Multiple high-pressure events associated with hydraulic fracturing operations can also damage the cement sheath outside the casing and lead to fractures (cracks) within the cement sheath, or between the cement sheath and the casing or rock formation (debonding). If these cracks become extensive along the wellbore, they can allow migrations of fluid or gas. Gas (in particular, methane) migration is more likely than fracturing fluid migration because the lower density of

67 Satoh et al. 2013.
68 Satoh et al. 2013; Popoola et al. 2013.
69 Yamaguchi et al. 2013.
70 Satoh et al. 2013.
71 Jacquemet et al. 2012; Kutchko et al. 2011; Zhang et al. 2015.
72 Popoola et al. 2013.
73 US EPA 2015.
74 DPIR submission 226, p 55.

the gas provides a larger driving force for migration through these cracks than water. From the data available, methane migration along cracks appears to be the most likely well integrity issue caused by this process. However, the rate of methane leakage along any potential cracks is likely to be very low because of the limited aperture of this pathway and the limited driving force.[75]

5.4.2.6 Summary

Historically, the highest instance of well barrier integrity failure appears to be related to insufficient or poor-quality cementing coverage to seal aquifers and/or hydrocarbon-bearing formations. In older wells, this is likely due to lack of information on non-reservoir hydrocarbon bearing geological layers and the weak regulatory regime under which the wells were constructed. The other common well barrier integrity failure mechanism is associated with the degradation of the cement sheath and the cement bonds to the casing and rock formations. This failure mechanism can be exacerbated if the well is subjected to cyclic pressures, such as those experienced during hydraulic fracturing. There is also a growing body of research conducted on cement durability related to CO_2 storage that is relevant because CO_2 is considered more corrosive than methane gas. This research has indicated that even after 1,000 years, only a small fraction of the total available length of the cement seals will have been degraded. Well barrier integrity failure can also occur through corrosion of the well's metal casing. If a well barrier failure is observed, or suspected to have developed, technologies, tools and mitigation measures are available to conduct remediation operations (see the discussion in Section 5.2.3.4).

5.4.4 Well failure rates

5.4.4.1 Review of international published data

CSIRO has reviewed the well barrier and well integrity failure rates reported in the open literature.[76] Well barrier failure is identified in a number of ways, including by the sustained casing pressure, surface casing vent flow or requirements for remediation of barriers. Well integrity failure is identified by the detection of hydrocarbons in nearby water wells, gas migration outside the surface casing, or detection of solutes in groundwater. CSIRO notes that many studies of well integrity do not make the distinction between failures of individual barriers and well integrity failures, a distinction that is critical because a full integrity failure (that is, the failure of multiple barriers) is required in order to provide a pathway for any contamination of the environment.

CSIRO, largely using data sets from the US, found that the rate of well integrity failures that have the potential to cause environmental contamination is in the order of 0.1%, with several studies finding no well integrity failures, while the rate for a single well barrier failure was in the order of 1–10% (**Table 5.1**).

Table 5.1: Summary of published well integrity data specific to shale gas resource development. Source: CSIRO.[77]

Study	Time period	Number of wells	Well barrier issue rate	Well integrity failure rate
Pennsylvania	2010 - Feb 2012	4,934	7.6%	Not reported
Pennsylvania	2008 - August 2011	3,533	2.6%	0.17% blowouts and gas migration
Pennsylvania	2005 - 2012	6,466	3.4%	0.25% release to groundwater
Pennsylvania	2002 - 2012	6,007	6.2%	Not reported
Pennsylvania	2005 - 2013	8,030	6.3%	1.27% leak gas to surface
Colorado	2010 - 2014	973	0	0
Texas	1993 - 2008	16,818	0	0

75 Rocha-Valadez et al. 2014.
76 CSIRO 2017.
77 CSIRO 2017 and references therein, p 45.

Importantly, there are few studies that have investigated the correlation between well construction methods, geological conditions and failure rates.[78] Stone et al. found strong correlations between well construction category and well barrier failure rates, and well barrier failure rates and well integrity failure rates, with very few barrier failures observed for wells constructed to Category 9 (**Table 5.2**) or above, and no well integrity failures for that category (standard) of well construction.

Table 5.2: Wellbore barrier categories that are ranked from highest risk to lowest risk. Modified from Stone et al.[79]

Barriers	Category	Surface Casing	Intermediate Casing Strings	Level of top of production casing cement	Risk Level
1	1	Shallow		Below over pressured hydrocarbon reservoir	High
1	2	Shallow		Below under pressured hydrocarbon reservoir	↑
2	3	Shallow		Above top of gas	
2	4	Shallow		Above surface casing shoe	
3	5	Deep		Below under pressured hydrocarbon reservoir	
3	6	Deep		Above top of gas	
4	7	Deep		Above surface casing shoe	
5	8	Deep	1	Below top of gas	
4	9	Shallow	1	Above casing shoe	
6	10	Deep	1	Above top of gas	
6	11	Deep	1	Above casing shoe	↓
8	12	Deep	2	Above casing shoe	Low

The Panel notes Origin's submission that its *"internal standards would require a well to meet Category 6 requirements, at a minimum, during production operations and at least Category 7 for well abandonment. The design of Origin's Beetaloo wells align with the Category 9 requirements."*[80]

Origin also submitted that, *"Beetaloo wells are designed such that the surface casing is always set below the deepest aquifer and the intermediate and production casing strings are cemented to surface to ensure isolation between the hydrocarbon bearing formations and the aquifers. The design addresses the Environmental Protection Authority (EPA)'s two primary causal factors of aquifer contamination resulting from fluid migration pathways within and along the production well which are:*

- *Inadequate surface casing depth (that is, casing not set below the aquifer).*
- *Inadequate top of cement (that is, cement not set above the shallowest hydrocarbon bearing zone)."*[81]

The design of the Amungee NW-1H well is discussed further in Section 5.5.4 to illustrate what is meant by a Category 9 standard of well construction that incorporates cement casing from the shale formation to the surface.

Watson and Bachu demonstrated that well barrier failure rates reflect the geological conditions of the wells, the regulatory requirements in place during well construction and abandonment, the era of the well construction, the well type, the well purpose and history, and many other factors (such as oil price, equipment used, materials available, operators' technical competence in the well construction and abandonment).[82] They also found the occurrence of well barrier and well integrity failures decreased for newer wells.

78 Watson and Bachu 2009; Stone et al. 2016a.
79 Stone et al. 2016a.
80 Origin submission 153, p 56.
81 Origin submission 153, p 56.
82 Watson and Bachu 2009.

5.4.4.2 Queensland

The Queensland Gasfields Commission has published statistics on well integrity compliance audits undertaken from 2010 to 2015 on CSG wells.[83] During this period, 6,734 CSG exploration, appraisal and production wells had been drilled in Queensland, and approximately 3,500 wells were actively producing at the end of 2014. The non-producing wells had no gas flow at the well head. The audit involved both subsurface gas well compliance and surface well head compliance testing. For the subsurface equipment, no leaks were reported, and there were 21 statutory notifications (a rate of 0.3%) concerning suspect quality of down hole cement during construction. After remediation, the cement failure rate was determined to be 0%. For subsurface equipment, it may be concluded that the risk of a subsurface breach of well integrity in this jurisdiction can be assessed as very low to almost zero.

5.4.4.3 Western Australia

Patel et al. reported a study on well integrity issues for all the oil and gas wells drilled onshore in WA, and including offshore wells in State waters that have not yet been decommissioned.[84] The study found that 122 out of 1,035 non-decommissioned wells (that is, 12%) had compromised well barriers. Tubing failure dominated well barrier failure occurrences. Of the 1,035 wells studied, 86 wells had tubing failure (or 8.3% of the total wells studied). Tubing leaks can occur through holes corroded or eroded by production and injected fluid inside the tubing or from the twisting of the tubing. Casing failure occurs predominantly in production casing due to corrosion, pressure differential, and thermal effects, causing the pressure behind the production casing to exceed the collapse resistance of the casing. Approximately 22 out of the 1,035 non-decommissioned wells had production casing failure (or 2% of the total wells studied).

However, none of the 122 wells with single barrier failures had leakage to the external environment. That is, there was no evidence of well integrity failure.

5.4.4.4 South Australia

CSIRO could not locate any publicly available information on well integrity from this state. However, Santos provided to the Panel the full historical integrity record for the 2,736 wells it has drilled and fractured in the Cooper/Eromanga Basin of SA over the past 50 years.[85] Of this number of wells, 460 have been decommissioned. **Table 5.3** shows the relative well integrity risk level rating that Santos applies to the measured condition of the well barrier assembly.

Table 5.3: Santos well integrity risk level ratings. Source: Santos.[86]

Well integrity level	Condition of well barriers/integrity
1	As new well with all required barriers tested and verified.
2	Evidence of some degradation of any or both barriers.
3	Primary or secondary barrier failed. Remaining barrier intact - that is, single barrier failure.
4	Primary or secondary barrier failed. Remaining barrier suspect.
5	Both barriers failed - that is, failure of well integrity.

Although the formations targeted in the Cooper Basin are sandstone and not shale, the drilling and hydraulic fracturing processes used are very similar. The tight sandstones of the Cooper Basin are sufficiently similar from a well design standpoint to the NT shales due to similar formation depths and separation from aquifers, similar low formation permeability requiring hydraulic fracturing to produce gas, multiple fracture stages required per well, and similar requirements for casing design and cementing. Therefore, the historical performance of gas wells in the Cooper Basin provides a good analogy to what can be expected to occur if Santos's operational systems are approved by the regulator and implemented in the NT.

Only 11 (0.4%) of the total number of wells have been assigned a Level 4 rating at some stage over their life. Level 4 means that (at the time this rating was operating) one barrier remained

83 Queensland Gasfields Commission 2015a.
84 Patel et al. 2015.
85 Santos Ltd, submission 168 (**Santos submission 168**), pp 74-75.
86 Modified from Figure 36, Santos submission 168, p 75.

intact. This corresponds to the failure of a barrier, rather than the failure of well integrity (as described above). All the affected wells were either decommissioned or remediated to restore well barrier function to allow continued production. Only two (0.07%) of the wells were assigned a Level 5 rating (that is, failure of well integrity). Both of these wells were either remediated or decommissioned.

Since 1992, when improved well design specifications, cementing practices and an improved well integrity monitoring program were introduced, only one well out of the 1,727 wells (0.07%) drilled during this period reached a Level 4 rating, compared with 0.4% for the entire record of operations.

The statistics above are consistent with the conclusions of the CSIRO analysis using the much larger databases from the US, that is, the risk of failure of well integrity leading to contamination of groundwater is 'very low'.

5.4.4.5 Conclusions on well failure rates

Current industry practice for onshore shale gas well design is to have a minimum of two independent and verified physical barriers in place to maintain well integrity. A well integrity failure requires the failure of both physical barriers. Well integrity issues that include the degradation or the failure of one barrier in a multi-barrier system will not lead to the release of fluids from the well. The likelihood of a well integrity failure (that is, where all barriers fail), which is required for an actual release of fluids to the environment, is very low, typically less than 0.1%.

Recommendation 5.3

That prior to the grant of any further exploration approvals, in consultation with industry and other stakeholders, the Government develops an enforceable code of practice setting out the minimum requirements that must be met to ensure the integrity of onshore shale gas wells in the NT. This code must require that:

- ***all onshore shale gas wells (including exploration wells constructed for the purposes of production testing) be constructed to at least a Category 9 standard (unless it can be demonstrated by performance modelling/assessment that an alternative design would give at least an equivalent level of protection), with cementing extending up to at least the shallowest problematic hydrocarbon-bearing, organic carbon rich or saline aquifer zone;***
- ***all wells be fully tested for integrity before and after hydraulic fracturing and that the results be independently certified, with the immediate remediation of identified issues being required;***
- ***an ongoing program of integrity testing be established for each well during its operational life. For example, every two years initially for a period of 10 years and then at five-yearly intervals thereafter to ensure that if any issues develop, they are detected early and remediated; and***
- ***the results of all well integrity testing programs and any remedial actions undertaken be published as soon as they are available.***

5.5 Management of well integrity

5.5.1 Objective versus prescriptive regulation

The Government has signalled its intention to adopt an objective-based regulatory regime. In this regard, the Government introduced the objective-based Petroleum Environment Regulations in 2016, and has indicated that it will replace the highly prescriptive Schedule with objective-based resource management and administration regulations as soon as possible. The Petroleum Act and its subordinate legislation will be supported by guidelines and codes of practice that will assist in the interpretation and implementation the regulations.

The WA and Commonwealth unconventional gas regulatory frameworks are examples of objective-based regulation. WA's regulations require that a well management plan be in place for any well activities, and the regulations set out what must be included in a well management plan.[87] The regulations do not prescribe minimum technical requirements. Rather, the gas company must demonstrate that it is managing risks in accordance with *"sound engineering*

87 *Petroleum and Geothermal Energy Resources (Resource Management and Administration Regulations) 2016* (WA), cls 10 and 17.

principles, codes, standards and specifications" and "good oil-field practice".[88] In addition to the need for a well management plan under the regulations, there must also be an approved environment plan under WA's petroleum environment regulations, and the environment plan must demonstrate that the environmental risks and impacts associated with the well activities have been reduced to levels that are ALARP and acceptable.[89]

By contrast, Queensland and NSW have codes of practice that prescribe how well integrity is to be achieved. The codes were developed in consultation with industry and other stakeholders.

In Chapter 14, the Panel gives consideration to the risks and benefits of objective-based and prescriptive regulation. The Panel concludes that in the NT context, where any onshore shale gas development will be an emerging industry, some prescription is required to provide certainty to gas companies, the regulator and the community as to the performance standards and criteria that must be met. However, in Chapter 14 the Panel also proposes that prescriptive and enforceable codes of practice and guidelines should operate alongside objective-based regulation to ensure that world-leading practice is implemented in a timely manner, and to ensure that appropriate environmental protection is achieved.

5.5.2 Management of well integrity in the NT

5.5.2.1 Drilling petroleum wells

The current legal framework for drilling activities in the NT requires gas companies to describe components of well integrity management but does not explicitly require an overall well integrity management plan for the full life cycle of a well.[90]

A gas company must have Ministerial approval to drill a petroleum well.[91] To obtain approval, the gas company must submit an application,[92] which includes details about the proposed drilling program.[93] The Schedule does not make it clear how the Minister approves the application, when the application must be approved by[94] or what matters the Minister must be satisfied of to grant the approval. Further, it is implied, but not expressly stated, that the gas company must comply with the approved application and drilling program.

In addition to the requirement to have an approved application and drilling program in place, the Schedule prescribes that equipment and casing used to drill and construct the well must conform to American Petroleum Institute (**API**) standards,[95] that blowout prevention systems must be in place,[96] casing strings must be cemented to the surface,[97] and pressure testing must take place.[98]

With regard to well integrity, DPIR has implemented a process of continually assessing well integrity status during drilling operations.[99] Specifically, the *Well Integrity Verification Form,* which was developed following the Montara Commission of Inquiry, requires the regulator to evaluate the integrity of the well, confirming that the well has been constructed to levels exceeding API standards. This assessment is based on information provided by the tenure holder in daily drilling and other reports, in addition to the well planning information submitted in the application for approval for the drilling activity. More details on the extent of information required by the regulator are documented in the CSIRO report.[100]

5.5.2.2 Hydraulic fracturing

Hydraulic fracturing, like drilling, requires a separate approval under the Schedule.[101] An application to conduct hydraulic fracturing must be accompanied by a *"technical works program"*, which must include information about, among other things, the well status, any pressure

88 *Petroleum and Geothermal Energy Resources (Resource Management and Administration Regulations) 2016* (WA), cl 16(1)(c).
89 *Petroleum and Geothermal Energy Resources (Environment) Regulations 2012* (WA), cls 11(1)(b)-(c).
90 CSIRO 2017, p 64.
91 Schedule, cl 301(1).
92 Schedule, cl 301(2).
93 Schedule, cl 301(2)(i).
94 The *Well Drilling, Work-over or Stimulation Application Assessment Process* guideline provides that the *"project application"* will be processed in 30 days, however, it has no statutory force.
95 Schedule, cl 303(1).
96 Schedule, cl 308.
97 Schedule, cl 307.
98 Schedule, cl 309.
99 DPIR submission 226, p 34.
100 CSIRO 2017; DPIR submission 226, pp 28-33.
101 Schedule, cl 342(1).

tests, an interpretation of cement evaluation logs, design of the hydraulic fracturing program, and geological and geomechanical hazards.[102] DPIR uses the *Checklist - Well Work-over and Stimulation Program Assessment* to ensure all the relevant information has been provided,[103] but, the Checklist similarly has no legal basis and cannot be used to enforce compliance with the provisions of the Schedule.

Like the approved drilling program, the Schedule does not expressly require that an approved technical works program for hydraulic fracturing must be complied with, which can create problems in the event that the Minister for Resources attempts to enforce compliance with an approved program. Again, the Schedule does not prescribe how, or when, an application to conduct a hydraulic fracturing program will be approved, or the matters the Minister must take into account when approving such a program. Chapter 14 includes a discussion and recommendations regarding the use of the Schedule as a regulatory tool.

5.5.3 Well integrity management system

The management of well integrity throughout the well life cycle has become a focus in recent years because proactive well integrity management is key to reducing risks.[104] Wells must be designed cognisant of the potential hazards that might arise throughout their life cycle, including hydraulic fracturing. The operating life of a well can span several decades, and responsibility for the well is often passed between different teams within a gas company and third parties involved in well drilling and operations. The level of complexity in the design and operating parameters for wells means that there are risks associated with the transfer of responsibility throughout the life of the well. Life cycle well integrity management aims to minimise these risks by placing processes around well integrity management. Origin provided the Panel with information on the well integrity management system it employs.[105]

The focus on well integrity management has led to the development of an ISO standard (ISO 16530-1:2017), which states that:

> *"the well operator should have a well integrity management system to ensure that well integrity is maintained throughout the well life cycle by the application of a combination of technical, operational and organizational processes".*[106]

The NORSOK D-010 standard also requires management of well integrity requirement throughout the life cycle of a well.[107]

A well integrity management system (**WIMS)** provides a framework for managing the risks due to loss of well integrity over the life cycle of a well, and identifies the responsibilities of the organisation as a whole in safeguarding environmental assets and public health. CSIRO has listed the following as the key elements of a WIMS:[108]

- risk assessment that includes techniques to identify the well integrity hazards and associated risks over the life cycle of the well, methods to determine acceptable levels for risks, and to define control measures and mitigation plans for managing and reducing risks that exceed acceptable levels;
- an organisational structure with clearly defined roles and responsibilities for all personnel involved in well integrity management;
- well barrier documents that clearly identify and define well barriers (combination of components or practices that prevent or stop uncontrolled movement of well fluids), methods to combine multiple barriers and redundancies to ensure reliability, and administrative controls that provide information on controlling activities related to well integrity, such as design and material handling standards, procedures, and policy manuals;
- performance standards for people, equipment, and management systems;
- defined standards for well barrier verification, such as functional, leak and axial load tests, and well load case modelling verification to ensure that well barriers meet all acceptance criteria;

102 Schedule, cl 342(2).
103 DPIR submission 226, pp 224-235.
104 Wilson 2015; Connon and Corneliussen 2016; Sparke et al. 2011; Smith et al. 2016.
105 Origin submission 153, pp 55-68.
106 ISO 2017.
107 NORSOK D-010 Rev. 4.
108 CSIRO 2017, pp 50-51.

- a continuous improvement process that defines how knowledge and information should be communicated to personnel responsible for well integrity during the life of the well and how improvements can be implemented;
- a change management process to record changes to well integrity requirements for an individual well or the WIMS itself; and
- an audit process that demonstrates conformance with the WIMS.

A comprehensive system for well integrity management should also set out the regulator's responsibilities for review and assessment of a gas company's WIMS and an inspection regime to ensure compliance. The system should also specify the company's reporting requirements for well integrity incidents, in addition to establishing penalties for non-compliance.

Further, assessment of well integrity management on a well-by-well basis is necessary to address well-specific risks. Well integrity hazard identification and risk assessment is an important component of well integrity management.

Commonwealth and WA regulations require the development of well management plans by operators that outline the risk assessment approach used, the risks identified, and the well integrity management practices that will be used. The well management plans must be submitted to the regulator for assessment and approval. The present project application process for drilling activities in the NT contains requirements for the gas operator to describe components of well integrity management, but it currently does not explicitly require an overall well integrity management plan for the full life cycle of a well.[109] It is the Panel's opinion that it should.

Recommendation 5.4

That prior to the grant of any further exploration approvals, gas companies be required to develop and implement a well integrity management system (WIMS) for each well complying with ISO 16530-1:2017.

That prior to the grant of any further exploration approvals, each well must have an approved well management plan in place that contains, at a minimum, the following elements:

- ***consideration of well integrity management across the well life cycle;***
- ***a well integrity risk management process that documents how well integrity hazards are identified and risks assessed;***
- ***a well barrier plan containing well barrier performance standards, with specific reference to protection measures for beneficial use aquifers;***
- ***a process for periodically verifying well barrier integrity through the operational life of the well and immediately prior to abandonment, and a system for reporting to the regulator the findings from integrity assessments;***
- ***characterisation data for aquifers, saline water zones, and gas bearing zones in the formations intersected during drilling; and***
- ***monitoring methods to be used to detect migration of methane along the outside of the casing.***

5.5.4 The Amungee NW-1H Well in the NT

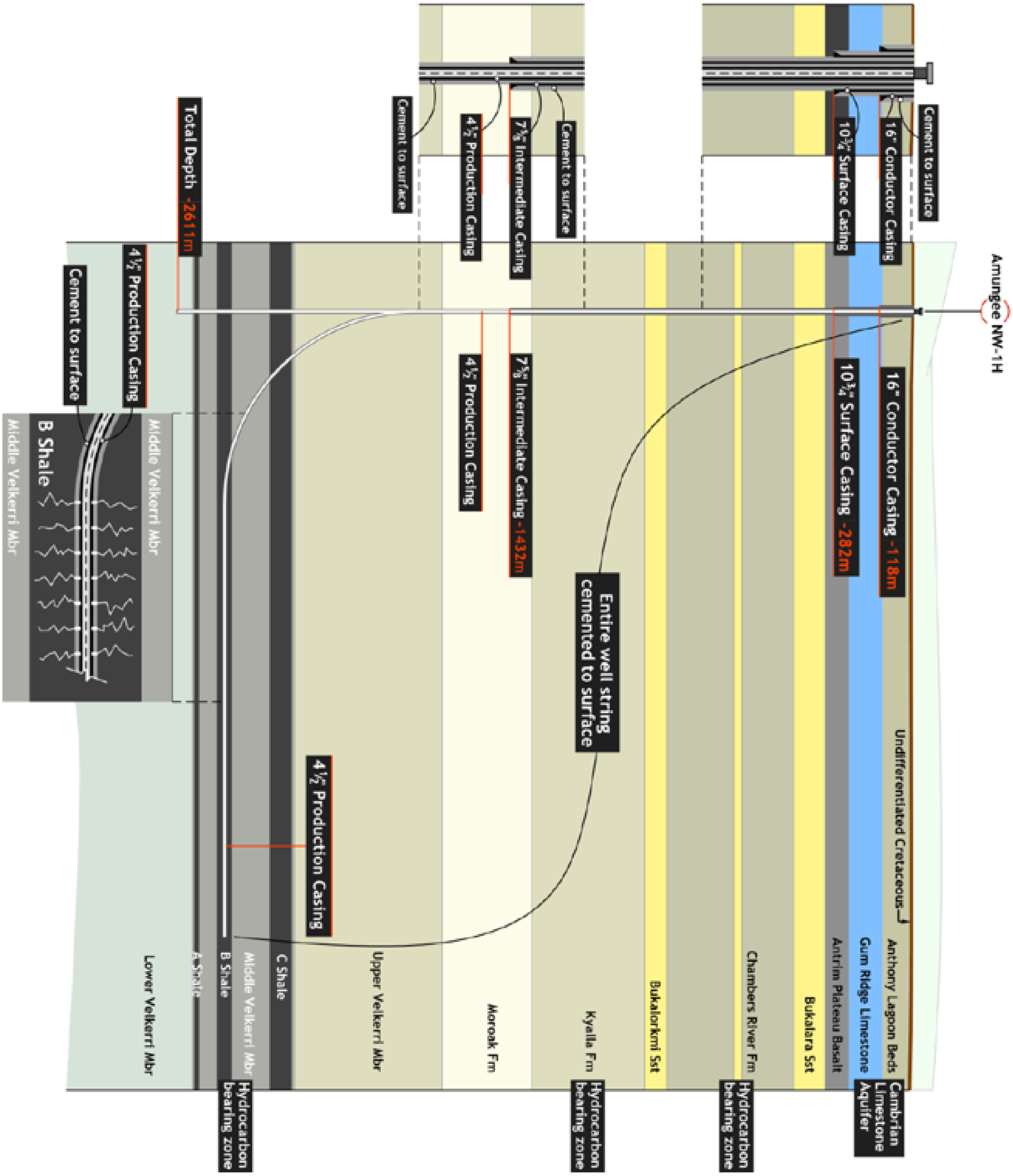
The preceding discussion concerning well design, construction, integrity, and the long-term management of wells has been drawn mostly from overseas sources and experience. Accordingly, the schematics used to illustrate the relationships of wells and their components to different types of geological strata have intentionally been of a generic nature. Specific information is available, however, about the construction and operation of the Amungee NW-1H well, the only horizontal well in the NT that has been hydraulically fractured and production tested. Detail is provided in Origin's Amungee NW-1H Discovery Evaluation Report.[110] This report was initially submitted to DPIR as required by the Petroleum Act and was subsequently released to the Australian Stock Exchange.

The Amungee NW-1H well is a horizontal well that deviates at depth from the original Amungee NW-1 vertical well (Figure 13). The well system was constructed to Category 9 equivalent

109 CSIRO 2017, p 59.
110 Origin Energy Limited, submission 233 (**Origin submission 233**), Attachment 2.

standard, with cementing completed along the entire vertical and horizontal sections of the well.[111] A schematic of construction details of the well, and key geological stratigraphic information are provided in **Figure 5.13**. The design process for the conductor and surface casings took into account the presence of two (Anthony Lagoon Beds and Gum Ridge) surficial aquifers at this location.[112]

Figure 5.13: Casing configuration for wells drilled in the Beetaloo by Origin that ensures isolation of aquifers and hydrocarbon bearing zones. This figure is an updated version of the original figure shown in the draft Final Report due to labelling errors that had been made in the original version. At the Panel's request, Origin produced a corrected version of the diagram. Source: Origin.[113]



111 Origin submission 153, pp 59–61.
112 Origin Energy Limited, submission 1248 (**Origin submission 1248**), Section 2.5.
113 Origin submission 153, p 57.

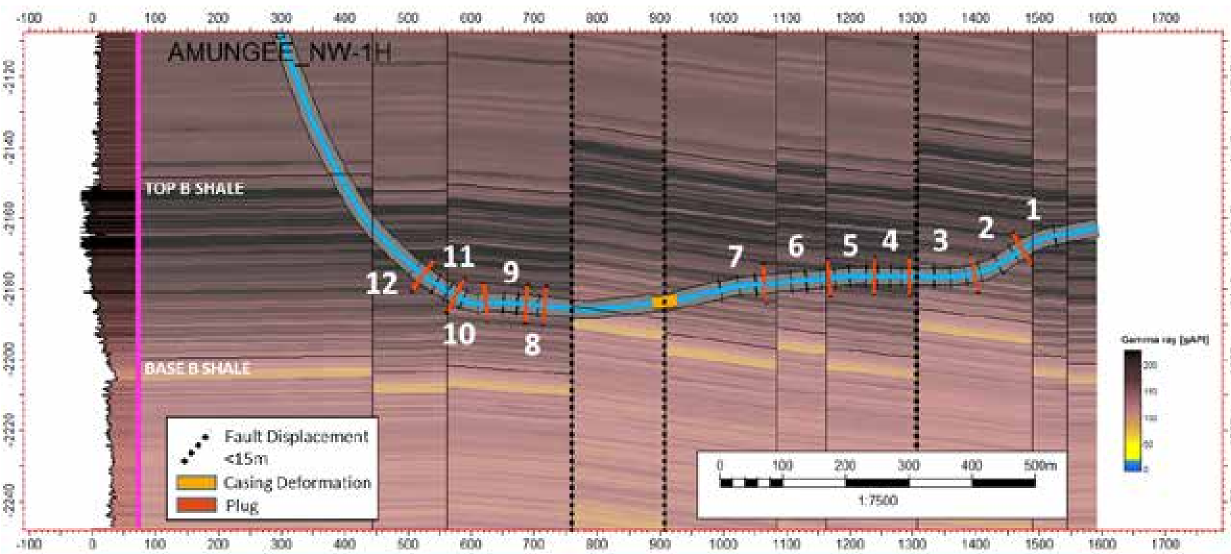
Figure 5.13 shows the importance of cementing the entire vertical section of the well because there are three hydrocarbon bearing zones at shallower depths than the current target Middle Velkerri Member (B shale). These are the overlying Velkerri C Shale, the major Kyalla Formation (another prospective target for gas and other hydrocarbons), and the Chambers River Formation, which is much closer to the surface and contains a relatively thin minor hydrocarbon bearing zone.[114] As noted in Section 5.4, one of the key reasons for gas migration to the surface occurring along wellbores in the US has been the lack of proper cement casing needed to isolate intermediate hydrocarbon-bearing or coal zones from the surface (see ***Recommendation 5.3***).

Well completion activities at Amungee NW-1H began in July 2016, with the preparation of the wellbore for hydraulic stimulation operations. A Cement Bond Log (**CBL**) was conducted to confirm the cement integrity behind the 4.5" production casing, along with a 10,000 psi pressure test of the production casing to verify wellbore integrity.[115]

In August 2016, a total of 11 stimulation stages were undertaken, effectively placing 1.1 million kg of proppant and 10.7 ML of fluid (**Figure 5.14**). The spacing and intervals selected for the stimulation stages were based on modelled reservoir properties and the locations of interpreted small faults (average 6 m of throw with a maximum ~15 m of throw) and a 20 m standoff from the faults was incorporated into the stage design.[116]

Following the seventh stimulation treatment interval, a casing deformation (location marked on **Figure 5.14**) was discovered during the pump down operation. After running well diagnostics, the remaining five fracturing stages were shifted along the wellbore to provide a greater separation distance between the fracture initiation point and potential bedding planes.

Figure 5.14: Location and distribution of fracture stimulation stages along Amungee NW-1H well cross-section. Source: Origin.[117]



As explained by Dr David Close from Origin to the Panel on 6 February 2018, the casing deformation midway along the horizontal section was a technical issue for Origin which has not affected the environmental performance of the well.[118, 119] The horizontal section of the well is designed to be perforated to allow passage of hydraulic fracturing fluid to fracture the shale and has no bearing on well integrity. It is the integrity of the vertical section of a well that is essential for maintaining vertical (zonal) isolation between the target shale formation and near surface groundwater. The Panel has found no evidence that this section of the well is not performing as designed.

As noted in Section 7.6.5, the occurrence of large faults that can allow vertical connection with the near surface is a risk factor that must be avoided as part of the well design phase. The gas

114 Fulton and Knapton 2015; Munson 2014.
115 Origin submission 153, pp 62–66.
116 Origin submission 1248, p 14; Origin submission 1269.
117 Origin submission 233, Attachment 2; Origin submission 1269.
118 Origin Energy Ltd and Lock the Gate Alliance Northern Territory submission 1075.
119 Origin submission 1248, pp 15–16.

industry is currently required to report the locations of such faults to DPIR and indicate how they will be avoided through the location and design of a proposed well (***Recommendation 7.15*** specifically addresses this issue). In addition, the effect of ***Recommendation 5.7*** is to further reduce the possibility of significant fault activation and the possibility of the excursion of hydraulic fracturing fluid to higher-than-planned levels.

Seismic surveys demonstrate that most of the Beetaloo Sub-basin contains relatively little internal faulting.[120] However, small inactive faults with limited vertical extent will occur, and these are unlikely to show up on seismic surveys. These faults are typically located during drilling, as was the case with the Amungee horizontal well (location of fault marked on **Figure 5.14**), but they are not a matter of concern for either well integrity or the potential for excessive upwards migration of fluids during the hydraulic fracturing operation.[121]

Origin has stated that a WIMS will apply to the ongoing management of its wells in the NT and is in line with the requirements for a WIMS documented in Section 5.5.3 and addressed by ***Recommendation 5.4***.[122]

5.6 Water use

Shale gas extraction requires the use of large quantities of water, which may be obtained from local surface or groundwater sources, or transported to the site from outside the region. This water is typically stored in large, above-ground double-lined ponds or tanks.[123]

There has been a substantial amount of data published over the past decade regarding the volumes of water used for drilling and hydraulic fracturing.[124] Considerable care needs to be taken in interpreting this information because of the rapid changes in technology that have occurred during 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 requires 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.[125]

The water-related risks associated with any onshore shale gas industry in the NT are covered in detail in Chapter 7.

5.7 Wastewater production and composition

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

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

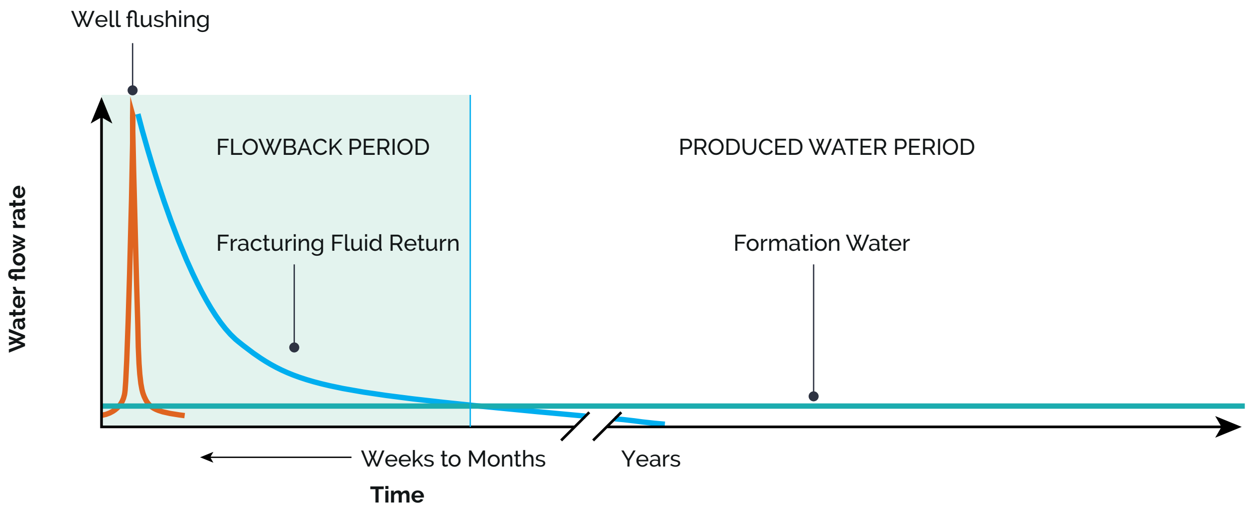
5.7.1 Wastewater production

The volume of wastewater produced from drilling a well represents the smallest volume (1–2 ML) of wastewater produced during well development. Drilling fluids (drilling mud) are an essential component of drilling operations, and are distinct from hydraulic fracturing fluids used during well stimulation.[126] These fluids provide cooling and lubrication to the drill bit and drill string, lift drill cuttings from the well, and provide a component of well control. Used drilling fluids are typically contained in lined sedimentation pits. The typically saline supernatant water is removed for treatment elsewhere, while the settled 'mud' component is recycled for use in other drilling operations.

120 Scrimgeour 2016, p 6; Origin submission 153, p 75.
121 BC Oil and Gas Commission 2012.
122 Origin Submission 153, pp 67–68.
123 Hoffman et al. 2014.
124 ACOLA Report; US EPA 2016a.
125 ACOLA Report; US EPA 2016a; APPEA submission 215.
126 Hossain and Al-Majed 2015, pp 73-139.

As described above, when a well is hydraulically fractured, this is done in stages, with each stage plugged while the next is being perforated and fractured. This creates an increase in pressure and a backup of both fluids and gas while further stages are being drilled. When the final stage is drilled, the fluids and gas are allowed to flow up out of the well for a period of up to two months (**Figure 5.15**). This is the 'flowback period', where the water returning from the well is composed partially of drilling and injected hydraulic fracturing fluids, and partially of formation brines that are trapped in the target formations and are extracted together with the gas.[127] Shown in **Figure 5.15** is the short 'flushing period' where the residual fluids and solids in the well, produced as a result of the hydraulic fracturing process, are cleaned out in advance of preparing the well for production. This water has been grouped with 'flowback', although it can be of such poor quality that it may be segregated for separate treatment or disposal, rather than re-use.

Figure 5.15: The difference between flowback and produced water.



The water generated after the flowback period during the lifetime of gas production is called 'produced water', the composition of which resembles the original formation water present in the shale layer.[128]

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. Therefore, for a typical 20 ML total volume of water used to hydraulically fracture a horizontal well, approximately 4–10 ML could come back to the surface as flowback water.[129] 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.[130] Once above ground, the flowback water is usually stored in either temporary storage tanks or ponds or conveyed by a pipeline to a wastewater treatment plant.[131] The method used depends on the rate of flow of the water, whether it is going to be re-used for fracturing another well on the same well pad, and the distance between the well pad and the collection/treatment facility.

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 typically a much smaller amount of produced water returns to the surface along with the gas produced.[132] Although the rate of flow is very much less than during the initial flowback stage, in aggregate, the volume of produced water can be quite substantial. Again, based on US experience, the ratio of volume of flowback to produced water is very dependent upon the formation.[133] The produced water also is usually collected and conveyed to a central storage or treatment facility for the life of the well.

127 Kondash et al. 2017.
128 Kondash et al. 2017.
129 ACOLA Report; US EPA 2016a.
130 Ziemkiewicz and He 2015.
131 US EPA 2016a.
132 Kondash and Vengosh 2015.
133 Kondash and Vengosh 2015; Kondash et al. 2017.

5.7.2 Composition of hydraulic fracturing fluid

The composition by volume of a typical water-based hydraulic fracturing fluid is 90% to 97% water, 1% to 10% proppant, and 1% or less of chemical additives.[134] The proportions of water, proppant, and additives in the fracturing fluid, and the specific additives used, can vary depending on a number of factors, including the rock type and the chemistry of the reservoir.

Hydraulic fracturing fluids are generally either 'slickwater' or gel-based.[135] 'Slickwater' formulations, which include polymers (for example, polyacrylamide) as friction reducers, are typically used in very low permeability reservoirs, such as shales. Because slickwater fluids are thinner (lower viscosity), they do not carry proppant into the fractures as easily, and therefore the larger volumes of water and greater pumping pressures are required to effectively transport the proppant into fractures. By contrast, gelled fluids are more viscous, and more proppant can be transported, with less water, compared to slickwater fractures. Gel-based fluids are used with more permeable formations.

The US EPA found that approximately 1,100 different chemicals had been used in hydraulic fracturing in the period between 2005 and 2013. [136] 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 US FracFocus database) of the chemical usage data in the US between January 2011 and February 2013 showed that only 5% (35) of the total identified number of chemicals previously used were used in most of the fracturing operations over that period.[137] Additionally, there has been a strong move over the last decade by the gas industry to use less toxic and more readily degradable chemicals, or so-called 'greener' chemicals. [138]

However, technology providers did not disclose the actual identity of 381 chemicals, and claimed those chemicals, or chemical mixtures, as confidential business information (**CBI**).[139] The use of CBI reduces the completeness of the data sets and the level of confidence 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 for the gas industry moving towards the use of non-proprietary chemicals that can be openly disclosed on databases like FracFocus.[140]

The Panel notes that public disclosure of *"specific information regarding chemicals"* used in hydraulic fracturing is required in the NT.[141] For example, the chemicals used for the eight unconventional wells[142] that have been hydraulically fractured in the NT are available on DPIR's website.[143] The 40 chemicals used (**Table 7.7**) for Origin's Amungee NW-1H production test well were disclosed by Origin to the Government and to the Panel.[144] This list is a subset of the much larger list compiled by the US EPA of the chemicals used in the US.[145]

5.7.3 Composition of flowback and produced water

The initial composition of the flowback water generated immediately after hydraulic fracturing ceases, and the pressure is relieved, is likely to more closely resemble depleted fracturing fluid because some of the chemicals are retained by adsorption in the shale bed. However, with time, the decreasing daily volumes of fluid produced will contain increasing quantities of the mobile (soluble) geogenic components present in the fractured rock and will ultimately resemble the original formation fluid in the shale layer.[146] Typically, the flowback water produced after the initial flush is quite saline (greater than 50,000 mg/L total dissolved solids (**TDS**)), especially if the target formation is of marine origin.

134 US EPA 2016a, pp 3-21.
135 US EPA 2016a, pp 3-21.
136 US EPA 2016a.
137 US EPA 2016a.
138 King 2012; BHP 2016; Halliburton Australia Pty Ltd, submission 221 (**Halliburton submission 221**), p 5.
139 US EPA 2016a.
140 www.FracFocus.org.
141 Schedule, cl 342(4).
142 DPIR submission 226, p 47.
143 At https://dpir.nt.gov.au/mining-and-energy/public-environmental-reports/chemical-disclosure-reports.
144 Origin submission 153.
145 US EPA 2016a.
146 Ziemkiewicz and He 2015.

Flowback water contains residual chemicals used in the hydraulic fracturing process plus geogenic chemicals that originate from the shale formation itself.[147] 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.[148]

In the US, approximately 600 discrete chemicals have been detected in flowback and produced waters, and of this, only 77 were components of the hydraulic fracturing fluids used.[149] This suggests that many of the hydraulic fracturing chemicals are either retained in place or are degraded or transformed into other chemical compounds (or not specifically measured). There is increasing evidence that such transformation reactions do occur between components of the hydraulic fracturing mixture and as a result of the reaction of hydraulic fracturing chemcials with geogenic compounds.[150]

A variety of volatile and semi-volatile organic compounds, including benzene, toluene, ethylbenzene and xylenes (**BTEX**), have been detected in flowback and produced water from shale reservoirs.[151] In particular, average total BTEX levels in shale flowback/produced water in the US have been found to be one to two orders of magnitude higher than in produced water 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 and applying them to flowback water from deep shales. There are, however, wide variations in the concentrations of organic compounds being measured across different shale plays,[152] which could result from lateral variations in the geology 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/produced waters that will be produced in the NT. Only over the past five years have more extensive (and intensive) measurements been taken in the US of the concentrations of organic compounds present in flowback and produced water. Knowledge of flowback and produced water compositions is therefore provided by a few studies on a relatively limited number of samples where the full range of inorganic and organic constituents have been determined. This has limited the capacity for meaningful risk assessments of flowback and produced 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 and produced water from onshore shale gas extraction in Australia, and this makes the need for empirical data from test wells all the more important. The overseas studies 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 moreover, that the majority of these additional compounds originate from the minerals and organic compounds present in the shale formation.[153] However, merely because a chemical is detected in flowback or produced water does not mean that it will be harmful to human health or to the environment.

The Panel notes that while the shale gas industry in the US is now largely 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 or produced waters.

147 Hayes and Severin 2012; Arthur and Cole 2014; Ziemkiewicz and He 2015; US EPA 2016a; Butkovskyi et al. 2017; Stringfellow et al. 2017.
148 Kondash et al. 2017.
149 US EPA 2016a.
150 Kahrilas et al. 2016; Tasker et al. 2016; Hoelzer et al. 2016.
151 US EPA Report; Butkovskyi et al. 2017.
152 Maguire-Boyle and Barron 2014.
153 US EPA 2016a.

This causes difficulties with the assessment of the status of water management practices in the gas industry, a situation that has been noted in recent publications on water sourcing, and treatment and disposal practices in the onshore shale gas industry in the US and Canada.[154]

A similar situation exists in the NT, where public disclosure of the composition of flowback or produced water is currently 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 and produced water must be available from the operator for disclosure.[155]

The Panel notes that DPIR supports the disclosure of analysis of flowback water and has developed guidelines stipulating baseline monitoring, testing and reporting requirements of hydraulic fracturing fluids and flowback water.[156] In addition, DPIR suggests that the testing of flowback water may not be necessary on every (production) well if hydraulic fracturing fluids and stimulated formations are the same.

A detailed discussion about the composition of hydraulic fracturing fluids and produced water in the NT context is provided in Section 7.6, drawing on the data acquired from the Amungee NW-1H production well. The Panel's recommendations for the public disclosure, management and handling of hydraulic fracturing fluids and flowback waters are contained in ***Recommendation 7.10***.

5.8 Wastewater management and reuse

5.8.1 Storage

Flowback water has typically been stored initially in open, lined surface ponds that may be constructed on the land surface or excavated below ground level.[157] In the US, there has recently been a move towards storing flowback water in special-purpose, above-ground tanks (see ***Recommendation 7.12***).[158] The same ponds or tanks that are used to store the water used to initially formulate the hydraulic fracturing fluid can also be used to store flowback water, depending on the volumes and quality of the water, and the extent of reuse.

The Panel notes that since 1–2 ML of water is required for each stage of hydraulic fracturing, and at least 20 stages of hydraulic fracturing are likely (based on developing industry practice), at least 40 ML of storage will be needed per well for a fully developed production scenario. This volume will not be cumulative for a multi-well pad configuration and will depend on the extent of reuse possible, noting that the fracturing stages for an individual well are completed sequentially. The wells located along a well pad will also be fractured sequentially rather than concurrently. The sequential nature of the operation will enable reuse opportunities to be maximised.

An example of the type of storage used and storage volumes required was provided by Origin in its environmental management plan for the Amungee NW-1H 11 fracturing stage test well.[159]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.[160]

154 For example, Alessi et al. 2017.
155 UK Onshore Oil and Gas 2016, section 9.3.
156 Department of Primary Industry and Resources, submission 424 (**DPIR submission 424**), p 5.
157 US EPA 2016a.
158 BHP 2016, p 5.
159 Origin 2016, p 21.
160 Origin submission 153, p 81.

An aerial view of the Amungee NW-1H well site showing the above-ground ponds during the flowback and production testing phase. Source: Origin submission 153.

5.8.2 Treatment and reuse

The Panel notes that there is currently no industrial wastewater receiving, treatment or disposal facility in the NT. The relatively small volumes of wastewater produced to date, including from the Amungee NW-1H production well, have been transported by road to Mt Isa in Queensland. In the event that the moratorium is lifted, storage and transportation issues will need to be addressed as a matter of priority given the increase in volumes of water requiring disposal. While programmed reuse (see below) of such water is likely to be an operational feature of a production environment with multi-well pads, this is unlikely to be the case for the exploration phase of the gas industry's life cycle. The Panel has noted in Queensland the consequences of not having a plan for the ultimate fate or disposal of water treatment brines in place at the start of the upswing in development of the CSG industry. It is also noted that the long-distance transport of wastewater and treatment brines is a risk factor that needs to be addressed by the gas industry (see Chapters 7, 8 and 10).

'Reuse' 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. Reuse 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 the well.

The extent of reuse of flowback or produced water depends on its quality, as certain contaminants can interfere with hydraulic fracturing performance.[161] 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 the 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 reuse because most of this polymer remains in the shale. However, slickwater treatments usually require substantially more water than gel-based systems.[162]

161 Vidic et al. 2013.
162 US EPA Report, pp 3-21.

Generally, some form of treatment of the wastewater will be required before it can be reused. The treatment method will depend on the chemical composition of the hydraulic fracturing wastewater and the desired reuse water quality. The development of cost-effective treatment systems for the complex mixture of inorganic and organic compounds contained in flowback waters is a rapidly evolving field.[163]

Salinity is usually not an issue for the treatment of shale gas wastewaters because high concentrations of ions, such as sodium and chloride, can be tolerated in reuse water. For example, sea water 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, which 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 reused.[164]

Flowback water also contains a diverse range of organic compounds, some of which may be difficult to treat.[165] However, many of these organic compounds are biodegradable and could be treated in a purpose-built biological treatment plant.[166] The effective removal of these organic compounds is necessary if flowback water is to be treated and disposed of off-site, 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.[167] 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, which have the potential to severely interfere with membrane-based treatment.

It is apparent from the published literature, from reports by regulators, and from some of the submissions received by the Panel, that the transport of wastewater across the landscape has resulted in contamination events, caused either by accident or by deliberate intent.[168] A specific measure to reduce the occurrence of illegal dumping of wastewater is to mandate an auditable chain of custody system to ensure that the wastewater that is picked up from one location is delivered to its intended location. In the case of pipelines, the volumes of water entering the pipeline and being delivered to a destination, such as a central storage facility or water treatment plant, must be continuously monitored so that the occurrence of a leak can be detected as soon as possible, noting that the pipelines will be buried.

Recommendation 5.5

That prior to the grant of any further exploration approvals, in consultation with the gas industry and the community, the Government develops a wastewater management framework for any onshore shale gas industry. Consideration must be given to the likely volumes and nature of wastewaters that will be produced by the industry during the exploration and production phases.

That the framework for managing wastewater includes an auditable chain of custody system for the transport of wastewater (including by pipelines) that enables source-to-delivery tracking of wastewater.

That the absence of any treatment and disposal facilities in the NT for wastewater and brines produced by the gas industry be addressed as a matter of priority.

163 US EPA 2016a, Appendix F.
164 Maguire-Boyle and Barron 2014.
165 Butkovskyi et al. 2017.
166 Kekacs et al. 2015; Lester et al. 2015.
167 Butkovskyi et al. 2017; Costa et al. 2017.
168 Laeur et al. 2016 ;Maloney et al. 2017; Kell 2011 ; Seed Indigenous Youth Climate Network, submission 1181.

5.8.3 Reinjection

Historically in the US there has been a very low percentage reuse of flowback water,[169] with more than 95% of all wastewater from oil and gas extraction having been disposed of through reinjection into disposal wells located in conventional petroleum reservoirs.[170] However, reinjection is being increasingly restricted because of the potential for groundwater contamination and induced seismicity. There are no known potential onshore sites for reinjection of flowback or produced water into conventional hydrocarbon formations in the NT outside the Amadeus Basin.[171] This issue is covered in greater detail in Chapter 7.

5.8.4 Wastewater management incidents

In 2016, the US EPA collated data from thousands of wells that have been drilled and hydraulically fractured over the past decade.[172] It concluded that there was no evidence of any widespread impact on shallow aquifers, and no demonstrated cases of contamination of drinking water resources from hydraulic fracturing at depth. However, the US EPA identified cases of drinking water contamination from spills of fracturing fluids or flowback water, and the contamination of aquifers as a result of failures of well integrity during and after hydraulic fracturing.

There is significant potential for accidental releases, leaks and spills of hydraulic fracturing chemicals and fluids and flowback and produced water that could lead to contamination of nearby surface water and seepage through the soil profile into shallow aquifers (see Chapter 7).[173]

Most spills are related to the storing of water and materials in tanks and pits, and in moving wastewaters in pipelines and other forms of transport (for example, road tankers) between equipment.[174] 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.[175] However, while there have been more than one million hydraulic fracture stimulations in North America, and more than 1,300 in the Cooper Basin in SA, there has been no reported evidence of fracturing fluid moving from the fractures to near surface aquifers.[176]

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 gasfield.[177] This is a separate issue from surface spills. It occurred as a result of an inappropriate use of municipal wastewater treatment plants to treat flowback water – a function for which they were not designed – followed by discharge of the partially treated water into rivers. This practice has now been banned by US federal regulation.[178]

Hydraulic fracturing has been taking place in the NT since 1967, but mainly as a process to enhance hydrocarbon production from conventional reservoirs in vertical wells.[179] Only since 2011 has very limited hydraulic fracturing of unconventional formations been undertaken. DPIR reports that these operations have had little impact on water resources, but no specific details were provided in its submission.[180] There has been no independent assessment and reporting of environmental performance by the onshore gas industry in the NT. In any event, the onshore gas industry in the Territory is relatively small and the performance data available is unlikely to be representative of full-scale development.

169 US EPA 2016a.
170 Rodriguez and Soeder 2017.
171 DPIR submission 226.
172 US EPA Report.
173 US EPA Report; Maloney et al. 2017.
174 Patterson et al. 2017.
175 Patterson et al. 2017.
176 Cooke 2012; US EPA Report.
177 Mauter et al. 2014; Mauter and Palmer 2014.
178 US EPA Report.
179 DPIR submission 226, p 46.
180 DPIR submission 226, p 53.

5.9 Proppant use in hydraulic fracturing

Proppant is the second most used component (typically 2–10% by volume) in hydraulic fracturing.[181] The function of proppant has been described above in Section 5.3.2.3. Depending on the geomechanical characteristics of the shale formation and its depth, the preferred proppant can be size-graded sand (primarily quartz) or synthetic ceramic-like material. Sand is the most commonly used proppant material in the US.[182]

As noted in several submissions, the sourcing of proppant could be of substantial environmental concern in the NT if sand is the preferred material.[183] This is because very large amounts would be needed. For example, in the single Amungee well that had 11 fracturing stages, approximately 1100 tonnes of graded sand was used.[184] For a 10 well pad with 40 fracturing stages per well, this could require 40,000 tonnes of proppant sand. To put this into perspective, a B-double road train can carry approximately 50 tonnes of material.

The potential sources of supply for proppant will therefore need to be clearly identified by gas companies because its extraction could result in a significant footprint of disturbance that will ultimately require rehabilitation. In addition, large numbers of truck movements will be needed to transport the bulk material. It is understood that potential sand deposits are documented in the DPIR database of mineral resources in the NT.

5.10 Solid waste management

The solids produced by drilling represent a substantial waste stream associated with the production of onshore 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 ground level when drilling is completed. Before this is done, excess liquids are typically evaporated, and the drilling muds are 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 concern given the nature of this material and its potential to leach organic and inorganic components into the near surface environment.[185]

The magnitude of the issue is exemplified by considering the example of an eight well pad, drilled to 3,000 m depth, with 3,000 m long horizontal sections for each well and with a 10 cm diameter wellbore. This well configuration would produce around 190 m^3 of shale material from each horizontal well and approximately the same amount of material from the vertical sections, depending on depth, excluding drilling cuttings from the larger diameter conductor and upper casings. Accordingly, approximately 870 tonnes[186] (dry weight) of shale and other material could 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 well pads it can comprise a substantial amount of material requiring appropriate management.

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

Submissions received from the gas industry in response to requests for further information from the Panel indicated that solid waste management was an issue that did need to be addressed.[187] Origin noted that, *"purpose built, engineered facilities would be required to safely manage some solid and liquid waste generated by commercial shale development within the NT. Whether these facilities are located centrally or on each of the lease pads will be assessed as a part of the development concept. It can be stated however, that these facilities will be designed to prevent the seepage of contaminants to the environment".*[188]

181 US EPA 2016a, p 5-7.
182 US EPA 2016a, p 5-8.
183 Environment Centre NT, submission 1254, p 2; Lock the Gate Alliance Northern Territory, submission 1250, p 3.
184 Origin Submission 233, Attachment 2.
185 Phan et al. 2015.
186 Assuming a density of 2.3 t/m^3.
187 Santos Ltd, submission 420 (**Santos submission 420**) p 5; Pangaea Resources Pty Ltd, submission 427 (**Pangaea submission 427**), p 15; Origin Energy Ltd. submission 433 (**Origin submission 433**), p 34.
188 Origin submission 433, p 34.

Protocols and procedures have been developed by regulators, the gas industry and commercial-waste handling facilities to screen drilling wastes for content of metals, NORM and hydrocarbons and to separate out cleaner fractions that can be used for other purposes, such as road base.[189] In particular, several independently owned and operated waste management facilities have serviced the solid waste management needs of the Queensland CSG industry for many years, and there is precedent for the development of such facilities in response to the demand from a full-scale gas industry.[190]

Recommendation 5.6

That in consultation with the gas industry and the community, specific guidance be implemented by the Government, drawing on protocols and procedures developed in other jurisdictions, for the characterisation, segregation, potential reuse and management of solid wastes produced by any onshore shale gas industry.[191]

5.11 Seismicity and subsidence

5.11.1 Seismicity induced by hydraulic fracturing

There is now considerable evidence from the US and UK[192] that low magnitude earthquakes may occur during hydraulic fracturing and that larger-scale (Richter scale magnitude greater than 2.0) earthquakes have occurred during the reinjection of wastewater.[193] With regard to the former, there is potential for induced seismicity to result from the uncontrolled propagation of fractures produced during hydraulic fracturing that can extend for up to several hundred metres in varying directions in the adjacent geological strata.

Induced seismicity associated with shale gas hydraulic fracturing has been reported in both the UK and the US.[194] The US experience is that the seismicity levels vary for individual shale gas basins, and will depend on the depth of the producing layers (shallower layers experience lower induced seismicity levels before shutdown of the hydraulic fracturing process occurs) and local geology (the degree of faulting in the area of interest).[195] The seismicity caused by hydraulic fracturing mostly has very low magnitudes (typically between M_W = -2-0) and is unlikely to be felt or cause infrastructure damage,[196] including damage to any wells drilled for hydraulic fracturing that have been specifically designed to withstand the stress of hydraulic fracturing. Overseas, findings to date also suggest that it is extremely rare for hydraulic fracturing stimulation to result in earthquakes of sufficient scale (Richter scale magnitude 2.0 or greater) to be felt locally or to cause even slight damage to buildings.[197]

Considerably larger earthquakes (M_w = 3-5.7) have, however, been associated with the injection of large volumes of fluid. For example, the disposal of produced water. These earthquakes often occur after high volumes of fluid have been injected into the rocks and at much lower fluid pressures than those required for hydraulic fracturing. These larger earthquakes generally have properties that suggest that they are often associated with the reactivation of existing faults rather than the creation of new hydraulic fractures. There is 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. Hydraulic fracturing should not occur in highly faulted areas. The potential to induce earthquakes through the disposal of wastewater down wells can be mitigated by proper management of formation pressures.

Based upon experience in the US and UK, the extent of fracturing can be monitored using sophisticated micro-seismic technologies, with the fracturing distance controlled by varying the pressure that is used.[198] The Panel considers that implementation of the trigger levels used

189 DEHP 2013; DEHP 2015.
190 Origin submission 433, p 34.
191 For example, DEHP 2013; DEHP 2015.
192 For example, de Pater and Baisch, 2011; Royal Society Report.
193 ACOLA Report; US EPA 2016a, p 66; Clarke et al. 2014; Warpinski et al. 2012, respectively.
194 Clarke et al. 2014; Warpinski et al. 2012, respectively.
195 Warpinski et al. 2012.
196 Drummond 2016; the unit of MW (moment magnitude) is equivalent to the Richter scale magnitude for the small to medium earthquakes referred to here.
197 SHIP 2017.
198 Royal Society Report.

in the UK *Traffic Light Monitoring System*,[199] which informs the gas companies as to the induced seismicity occurring during hydraulic fracturing by monitoring seismic activity in real time, can reduce the likelihood of induced significant felt seismic events (earthquakes). The rules state that hydraulic fracturing must be stopped if minor earth tremors of magnitude 0.5 or greater on the Richter scale occur.

In its submission, DPIR states that there is no evidence to suggest that the hydraulic fracturing process can produce measurable earthquakes in areas that do not contain susceptible faults.[200] The statement must, however, be qualified by the comment that Australia does not yet have any seismic risk data covering shale gas operations or a national record of seismic activity below magnitude 4 on the Richter scale.

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

Recommendation 5.7

That to minimise the risk of occurrence of seismic events during hydraulic fracturing operations, a traffic light system for measured seismic intensity, similar to that in the UK, be implemented.

5.11.2 Subsidence

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

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 highly 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 small 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 would contribute to subsidence. This contrasts with CSG operations, where a substantial proportion of the original void volume in the coal seam is removed as produced water, and there is a much greater possibility of subsidence given the closer proximity of the CSG activities to the surface.

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

199 UK Government 2017; Wong et al. 2015.
200 DPIR submission 226, p 56.

5.12 Conclusion

In conducting its review, CSIRO noted that many studies of well integrity do not make the distinction between failures of individual barriers and well integrity failure. This distinction is critical because full integrity failure (that is, failure of all the barriers) is required to provide a pathway for contamination of the environment. CSIRO found overall that the rate of well integrity failures that have the potential to cause environmental contamination is approximately 0.1%, with several studies finding no well integrity failures. The rate for a single well barrier failure, however, was much higher: approximately 1–10%. However, there were very few single barrier failures observed for wells constructed to Category 9 or above, and no well integrity failures for wells built to those categories. The Amungee NW-1H well that was constructed by Origin in the Beetaloo Sub-basin was of Category 9 standard, with casing cemented to surface along the entire length of the well.

CSIRO also found that for shale gas wells decommissioned using current practices, if any of the potential leakage pathways were to develop, it was highly unlikely that they would allow large fluid flow rates along the wellbore. The small cross-sectional areas and long vertical lengths of the pathways are expected to limit any flow. The low permeability of shale gas formations is also a factor mitigating the potential for impacts of loss of well integrity post-well decommissioning. Pressures within the part of the reservoir accessed by the well will have been depleted by production, and the very low permeability of the shale will prevent gas from other parts of the reservoir migrating to the well.

Although CSIRO concluded that the potential for serious post-decommissioning and abandonment integrity issues is low, the Panel has found that there is very little information available worldwide on the performance of decommissioned and abandoned onshore shale gas wells. The assessment of post-decommissioning or abandonment performance is an aspect that requires greater attention by both the regulator and the gas industry and is the subject of specific recommendations by the Panel.

Overall, the Panel concludes that provided a well is constructed to the high standard required for the particular local geology, and provided that it has passed all of the relevant integrity tests prior to, during, and after hydraulic fracturing, there is a 'low' likelihood of integrity issues. There does, however, need to be a program of regular integrity testing during the decades-long operational life of the well to ensure that if problems do develop, they are detected early and remediated quickly (as specified in ***Recommendation 5.4***). In particular, the well must pass a rigorous set of integrity tests prior to being decommissioned because once a well has been abandoned, it is difficult to re-enter it.

The nature of chemicals used for hydraulic fracturing is also of concern to the community. However, while there have been more than one million hydraulic fractures in North America and more than 1,300 in the Cooper Basin in SA, there has been no reported evidence of fracturing fluid moving from the fractures at depth to near surface aquifers, provided that hydraulic fracturing is not conducted in proximity to a major vertically transmissive fault or an adjacent improperly decommissioned deep gas or petroleum well. The former risk is addressed by ***Recommendation 7.15***, while the latter risk is unlikely to eventuate in the NT because so little prior exploration (and no prior production) for gas has occurred in the most prospective shale basins.

Unlike hydraulic fracturing fluids from depth, there is a significant potential for contamination from the surface. In particular, accidental releases, leaks and spills of hydraulic fracturing chemicals and fluids, and/or from flowback and produced water, can lead to contamination of nearby surface water and seep through the soil profile into shallow aquifers (see Chapter 7).

It also appears from the published literature, from reports by regulators and from some of the submission received by the Panel, that the transport of wastewater across the landscape has resulted in contamination events, caused either by accident, or in some instances, deliberately. To address this, the Panel has recommended that a wastewater management framework be developed, including an auditable chain of custody that enables source-to-delivery tracking (***Recommendation 5.5***).

The solids produced by drilling represent a substantial waste stream associated with the production of shale gas. A strategic management issue for any potential onshore shale gas industry in the NT is 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.

The possibility of hydraulic fracturing causing earthquakes of sufficient magnitude (2 or greater on the Richter scale) to cause structural damage has been considered. Based on an extensive review of the evidence, the Panel has concluded that this is unlikely to occur as a result of hydraulic fracturing. The only exception is if a fault is activated by the reinjection of fluid. By contrast, there have been many instances of higher magnitude earthquakes resulting from the reinjection of waste water into conventional petroleum reservoirs. These larger earthquakes are often associated with the reactivation of existing faults in the reservoir formation.

Finally, the development of sinkholes as a result of hydraulic fracturing has been raised by the community. The Panel considers that the likelihood of sinkholes developing is 'very low' as a result of hydraulic fracturing because of the large vertical distance (several thousand metres) between the hydraulic fracturing zone and the surface, a distance over which the intervening rocks will compensate for any small cavities produced by hydraulic fracturing.

ONSHORE SHALE GAS IN AUSTRALIA AND THE NORTHERN TERRITORY

6

6.1 Australian unconventional gas supplies and total energy use

From an international perspective, Australia is considered to have substantial resources of onshore unconventional gas, including CSG, shale gas and tight gas. While the development of CSG reserves has been under way for almost two decades in Queensland, the onshore shale gas industry in Australia is still largely in the exploration phase.

Although there are some potential oil and/or condensate resources in the NT (see Section 6.3 below), the Panel focussed its assessment on onshore shale gas, and not other forms of petroleum that could derive from shale, such as shale liquids (oil) and condensate. The reason for this is, first, because the Terms of Reference (see Appendix 1) limit the scope of the Inquiry to onshore shale gas only, and second, because, to date, exploration has produced only dry (liquid free) gas in the Beetaloo Sub-basin (Section 6.3.3). While there is known potential for liquids to be associated with a number of shale formations in the NT, to date the only declared contingent shale petroleum resource has been for dry gas from the Velkerri formation in the Beetaloo Sub-basin All other potential liquids resources remain insufficiently explored and/or unlikely to be economically feasible as an oil development.[1] Therefore, if there was shale liquids production it is likely to be primarily as a shale gas play with a small volumetric percentage of liquids also produced. If this occurred, in the Panel's view, this would not materially affect the mitigated risk assessments contained in this Report.

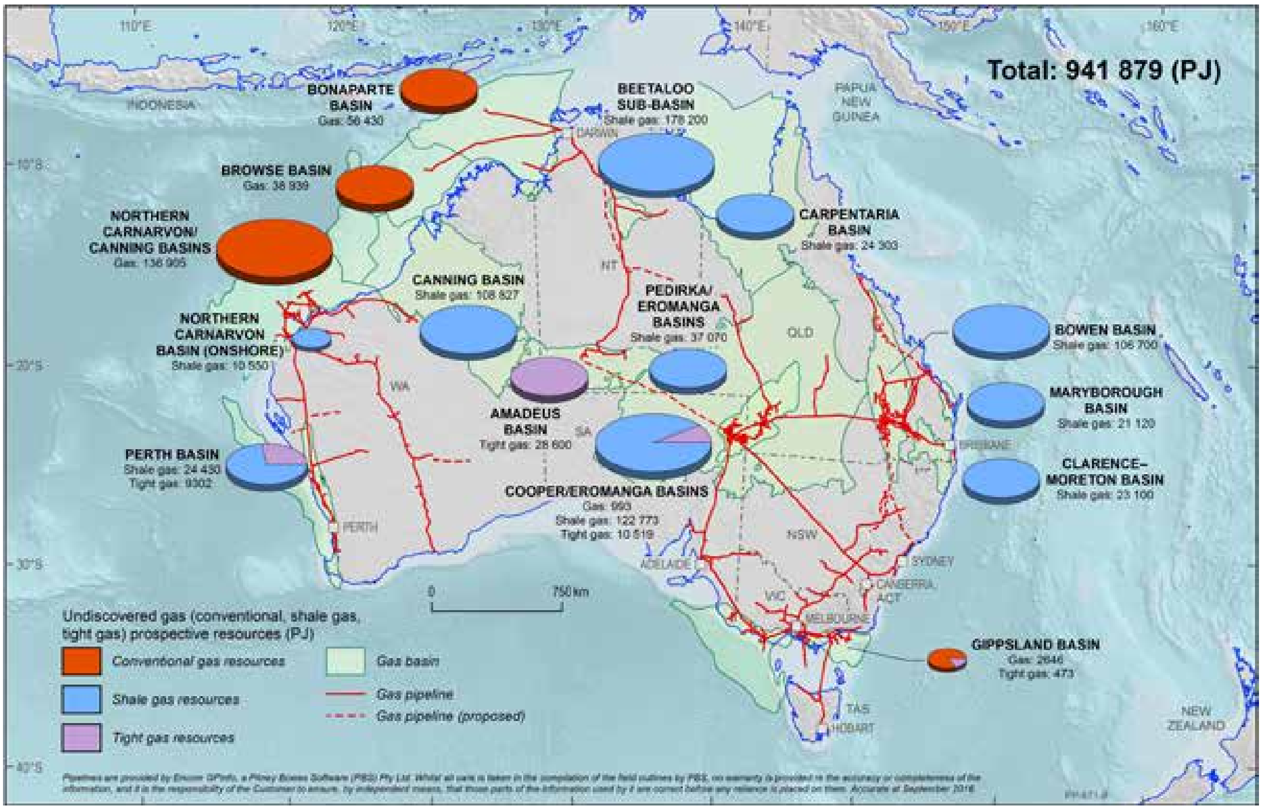
Geoscience Australia has assessed Australia's potential for unconventional gas (**Table 6.1** and **Figure 6.1**), including CSG, tight gas and shale gas. Its report indicates a 'contingent resource' of shale gas (that is, considered to be potentially recoverable but not yet mature enough for commercial 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. [2]

Table 6.1: Total Australian gas resources.[3]

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**

1 Australian Energy Resources Assessment.
2 Australian Energy Resources Assessment.
3 Australian Energy Resources Assessment.

Figure 6.1: Summary of Australia's prospective gas resources. Source: Geoscience Australia.[4]



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,[5] and ACOLA provides an aggregated resource of 1,100,000 PJ from 16 basins across Australia.[6]

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 NT's annual consumption over the same period was 85 PJ.[7]

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

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.[8]

4 Geoscience Australia submission 296.
5 COAG Energy Council 2015.
6 ACOLA Report.
7 Australian Energy Statistics 2016.
8 Lane et al. 2015.

However, recent exploration activities and the announced discovery by Origin in 2016 confirming a contingent commercial shale gas resource in the relatively unexplored Beetaloo Sub-basin of the McArthur Basin in the NT is significant for Australian (and the NT's) 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 under way. 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 under way in Queensland, SA, WA and the NT, all of which have shale gas prospects.[9]

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

6.3 Shale gas potential of the Northern Territory

According to Geoscience Australia,[10] total prospective shale gas resources in the NT 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 prospective 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.[11]

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 NT'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 locations and extent of 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 the Beetaloo Sub-basin.[12]

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 NT is still relatively unexplored, current geological knowledge suggests that shale gas is unlikely to occur outside the areas referred to here.

The nature of the geo-mechanical stress regime present in a shale formation is a key factor determining whether fracturing of the formation is likely to occur in the most effective and economic way to liberate the gas.[13]

It was suggested to the Panel that the stress regime in Australian shale formations may be different to that in the large American shale plays, and therefore, that American deposits are not a good analogue for Australia.[14] In particular, it was noted that the occurrence of a reverse stress regime could substantially reduce the effectiveness of hydraulic fracturing. Such a situation could result in a greatly increased numbers of wells (compared to the US) to produce the required volumes of gas.

9 Lazarus Report.
10 Australian Energy Resources Assessment.
11 Scrimgeour 2016.
12 Confirmed in Geoscience Australia submission 414.
13 Origin submission 153, pp 198-205.
14 Australian-German Climate and Energy College, University of Melbourne, submission 543, pp 4-5.

All of the available information about the Beetaloo Sub-basin, one of the NT's most prospective of the shale gas basins, indicates that the Velkerri shale formation has a normal stress regime, and that the Marcellus and Barnett basins in the US are therefore good comparisons for the likely effectiveness of any hydraulic fracturing process for onshore shale gas in the NT.[15]

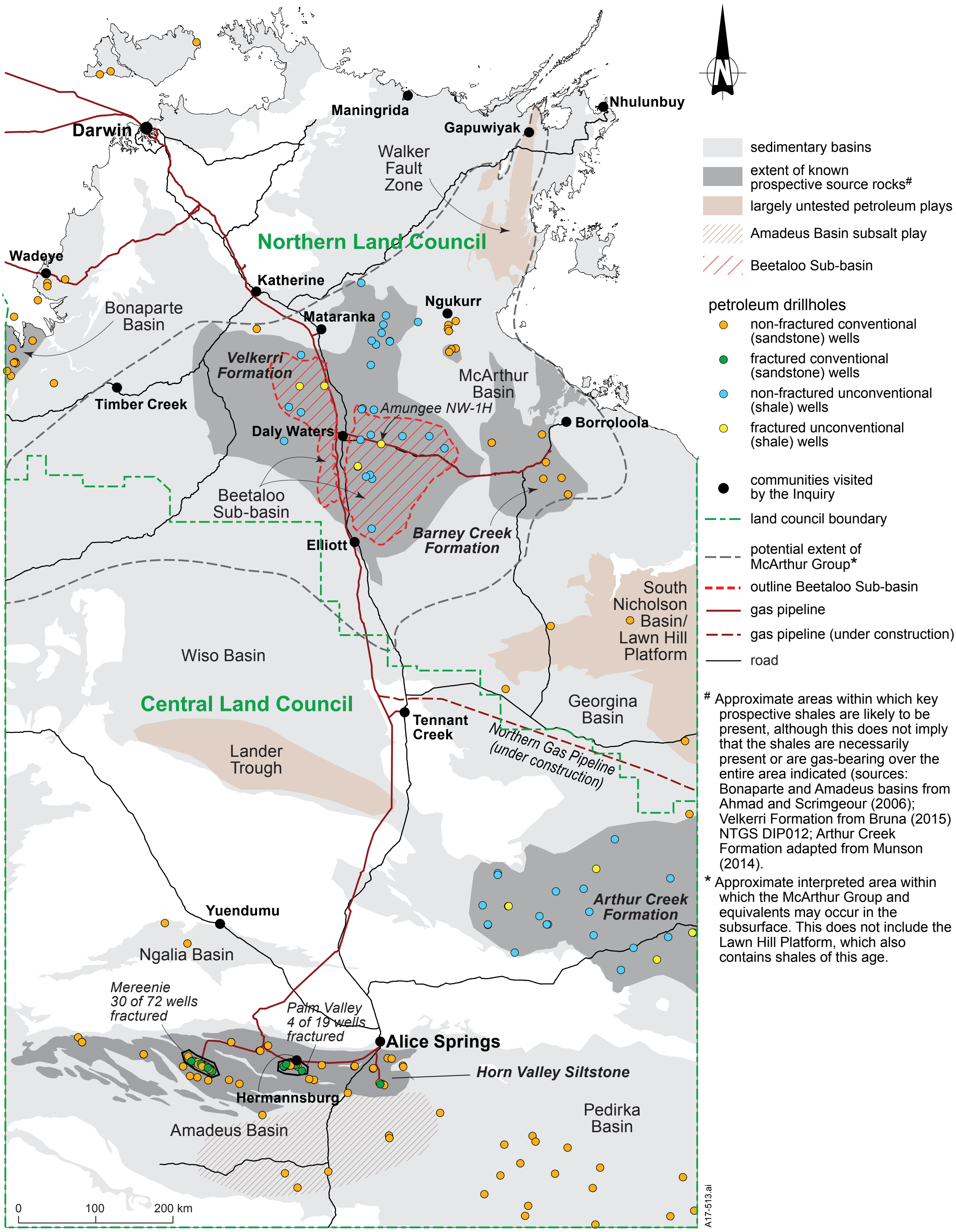
6.3.1 Amadeus Basin

The Amadeus Basin, south of Alice Springs, has had the highest levels of exploration in the NT and more than 30 years of continuous oil and gas production sourced from conventional and tight gas reservoirs. The Basin is large (170,000 km^2) and up to 14 km in thick, which contains numerous petroleum systems, and is the only producing conventional petroleum fields in the onshore NT (Mereenie oil and gas and Palm Valley and Dingo gasfields), 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 and tight gas 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 and tight gas plays.

15 Close et al. 2017, pp 93-94.

Figure 6.2: Petroleum wells in the Northern Territory showing the 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.



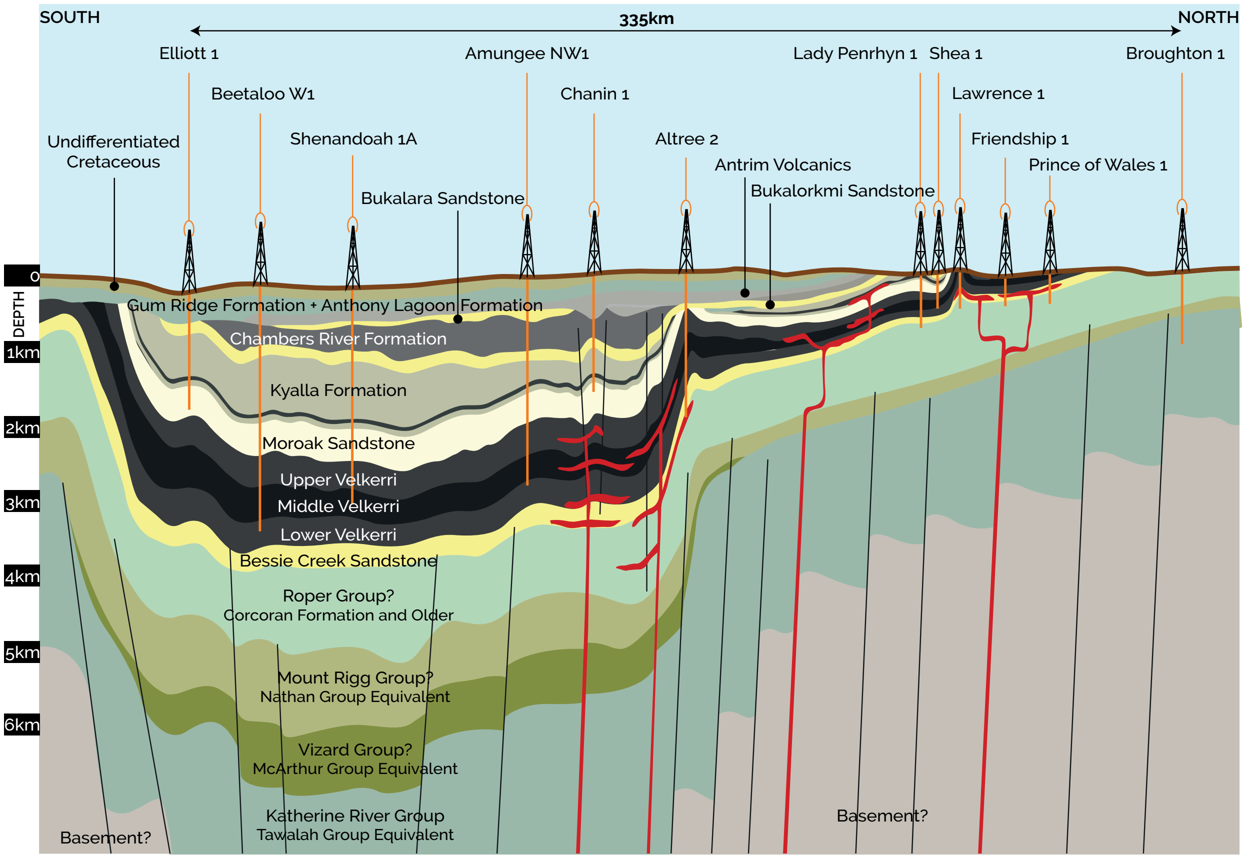
6.3.2 McArthur Basin

The McArthur Basin underlies much of the north-eastern NT 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 since 2010 as a potential gas province. 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 and they are considered to contain a much smaller potential resource than for the Beetaloo Sub-basin[16].

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 prospective/contingent 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 Northern 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**).

Figure 6.3: Schematic cross-section across the Beetaloo Sub-basin, showing exploration wells drilled to date. Source: Close et al.[17]



16 DPIR submission 281.
17 Close et al. 2017.

When the boundary of the Beetaloo Sub-basin was initially provided by DPIR to the Panel for use in the Interim Report, it was accompanied by a caveat that the boundary was poorly defined because it was a sub-surface transitional boundary that represents the approximate boundary where the sub-basin deepens and where it was likely to have high gas and oil potential. It noted that the Northern Territory Geological Survey may, in the future, further revise the boundary of the eastern part of the sub-basin as seismic data is incorporated into the 3D model.

Subsequent to the publication of the Interim Report, the boundaries of the Beetaloo Sub-basin were revised by DPIR based on assessment of additional data, with the margins of the Sub-basin being defined by the top of the Kyalla Formation at a depth of 400 m below the surface. This has had the effect of functionally splitting the Sub-basin into eastern and western domains separated by a faulted and uplifted zone (the Daly Waters Fault Zone) between Larrimah and Elliott.[18] Both the newly defined and previous boundaries of the Beetaloo Sub-basin are shown for comparison in **Figure 6.4**.

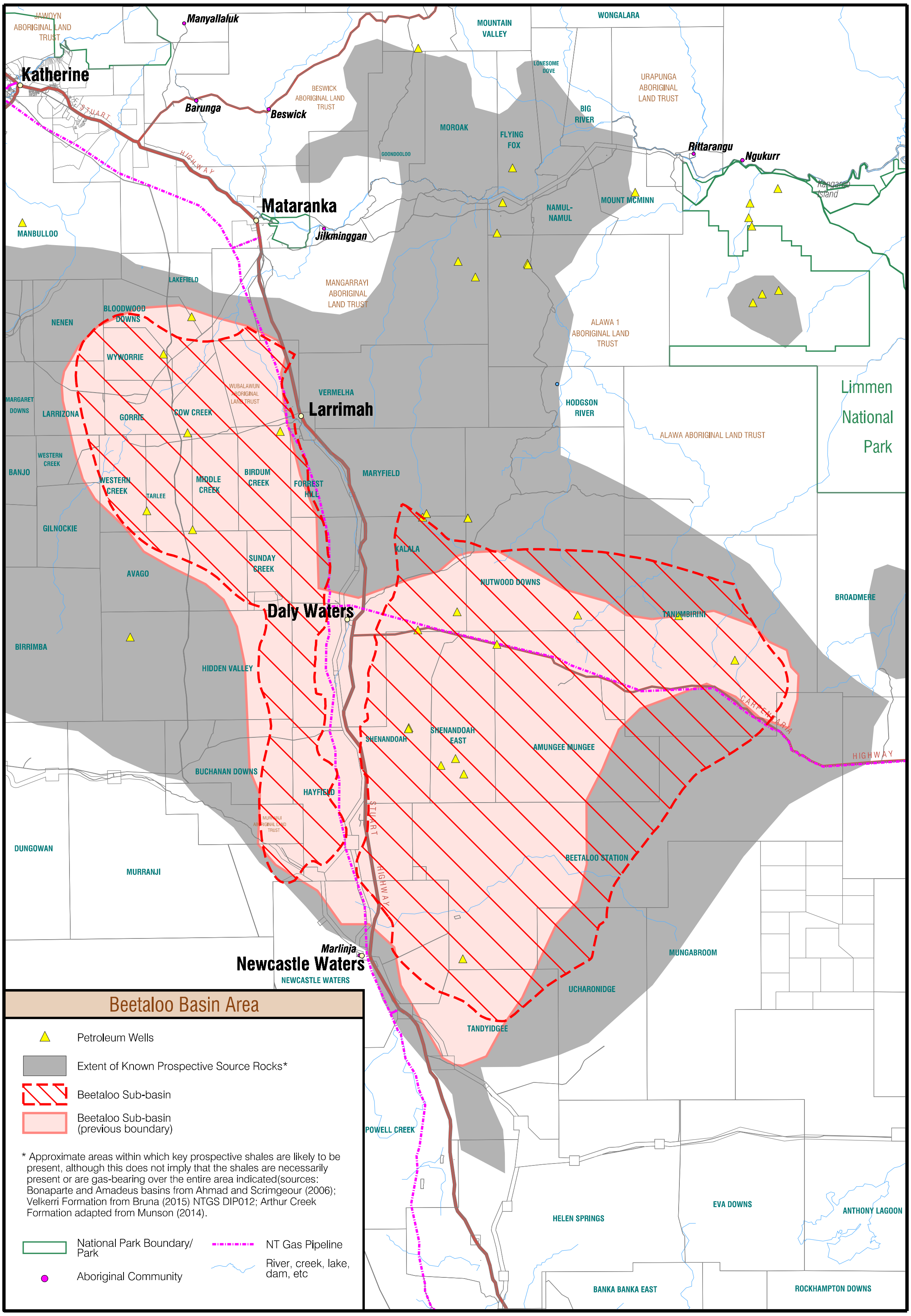
The Roper Group consists of a thick sequence of quartz sandstones, siltstones and mudstones, deposited in a variety of shallow-marine, nearshore to shelf environments.[19] The Roper Group sediments are essentially continuous and flat-lying, and range from thicknesses of 1,500 m over most areas to greater 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[20] and Santos.[21]

A geological cross section schematic showing the construction and orientation of Origin's Amungee NW-1H well, its relationship to the Cambrian Limestone Aquifer (CLA), and the location of the horizontal section in the Velkerri shale formation, is shown in **Figure 6.5**. This figure provides a primary reference point for subsequent discussion in Chapter 7 of the potential for sub-surface impacts on water quality. Details about the construction, drilling and hydraulic fracturing of the Amungee well are contained in Section 5.4.5.

18 Department of Primary Industry and Resources, submission 479 (**DPIR submission 479**).
19 Munson 2016 and references therein; Scrimgeour 2016.
20 Origin submission 153, p 31; Origin submission 233, Attachment 2; Origin submission 1269.
21 Santos submission 168.

Figure 6.4: Newly defined and previous boundaries of the Beetaloo Sub-basin. Source: DPIR.[22]



22 DPIR submission 479.

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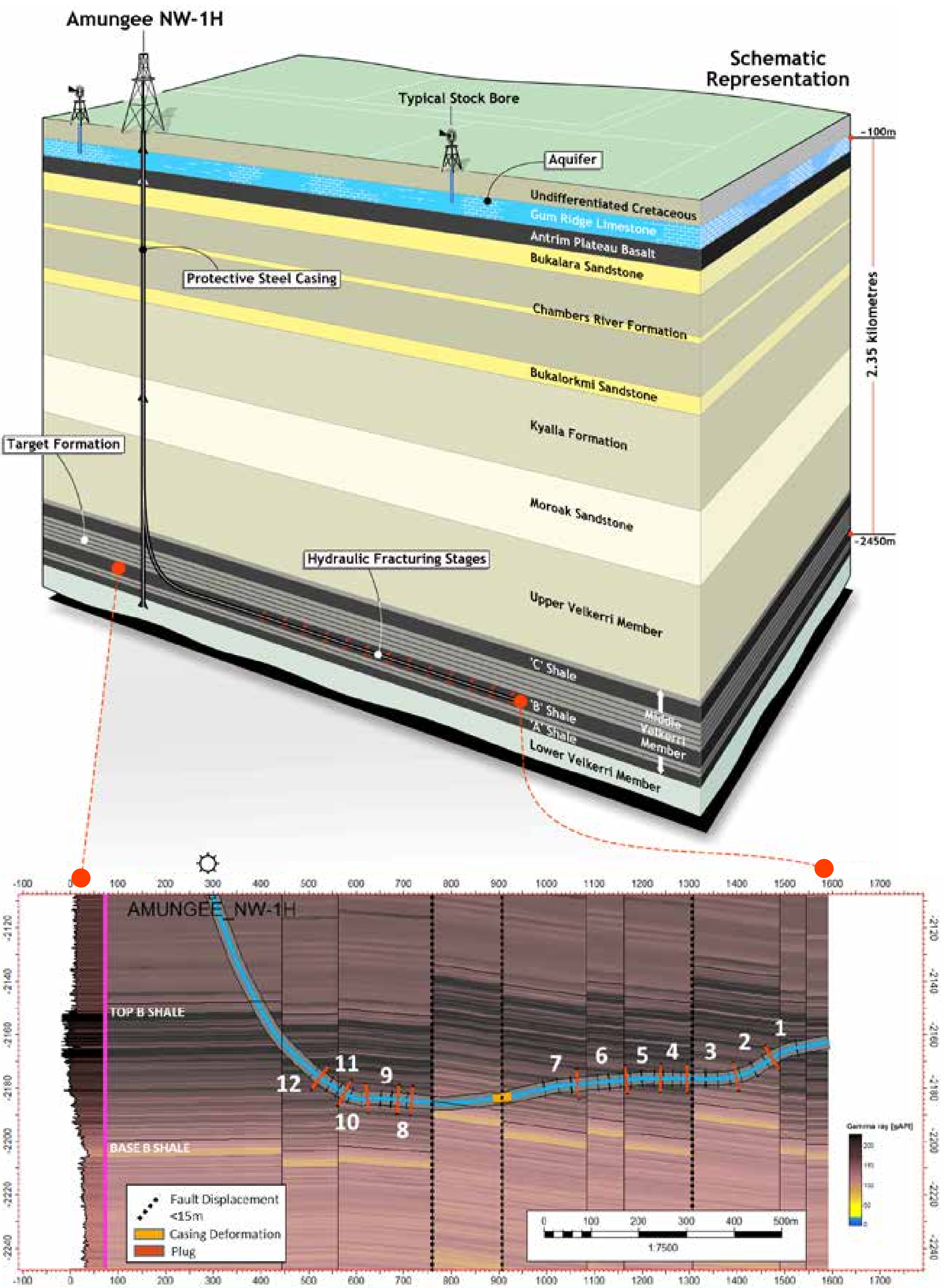
Figure 6.5: The Amungee NW1H well lateral section was landed and drilled through the 'B Shale' of the middle Velkerri approx. 2.3 km below the Cambrian Limestone Aquifer. Source: Origin.[23]



23 Origin submission 153, p 31; Origin submission 233, Attachment 2, p 6, amended in accordance with Origin submission 1269.

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 Northern 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 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 NT for oil and gas potential and to have world-class shale source rocks, but the Basin is under explored. 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 Northern 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. 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 Northern 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 2,000–3,000 m down to a maximum of 4,500 m.

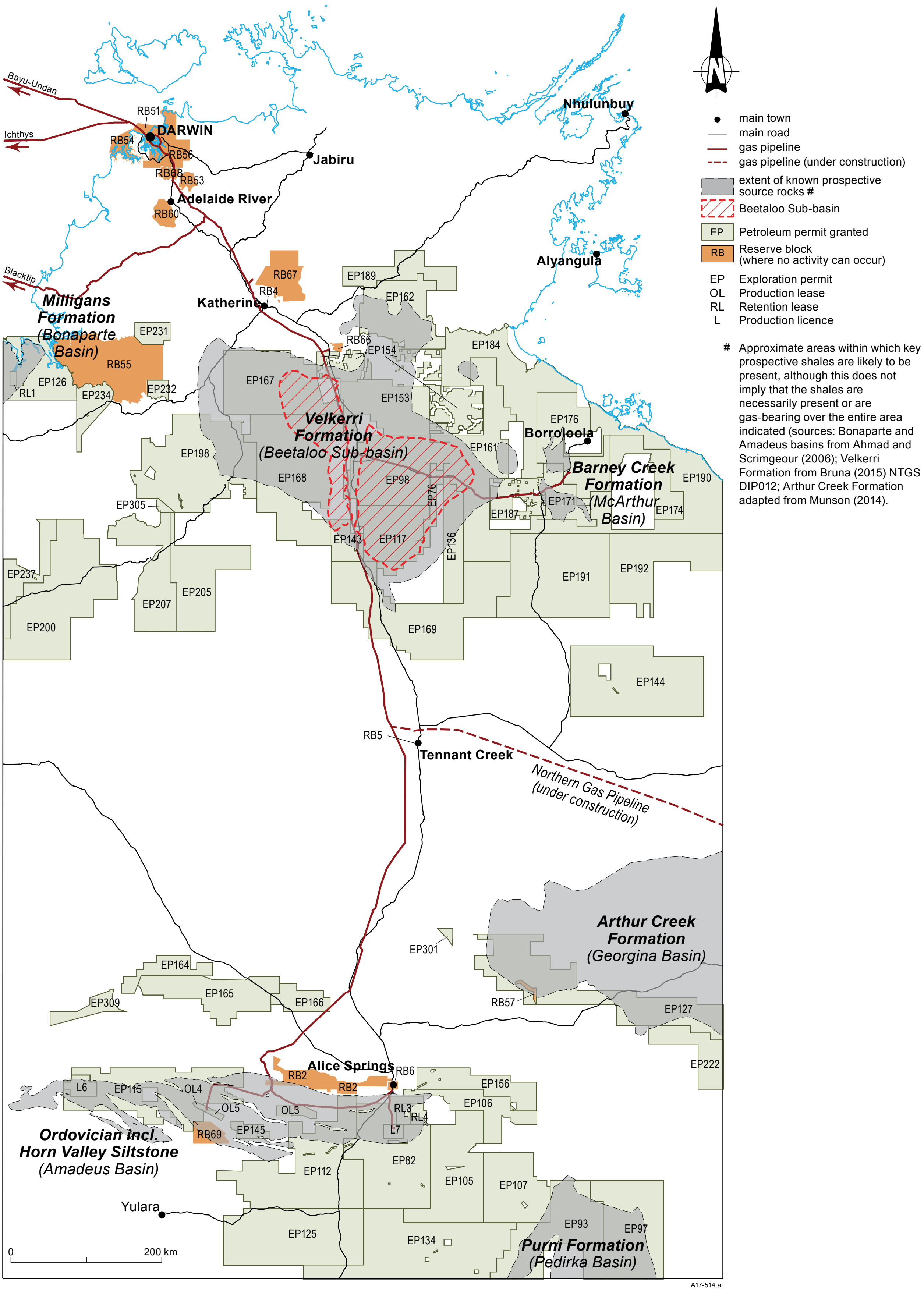
There is also limited geological information about the South Nicholson Basin and Lawn Hill Platform in the east of the NT. These contain interpreted stratigraphic correlatives of the McArthur Basin, and are considered to have potential for both conventional and unconventional hydrocarbons. Their correlations 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 NT

Figure 6.6 shows the current extent of granted petroleum titles in the NT 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.

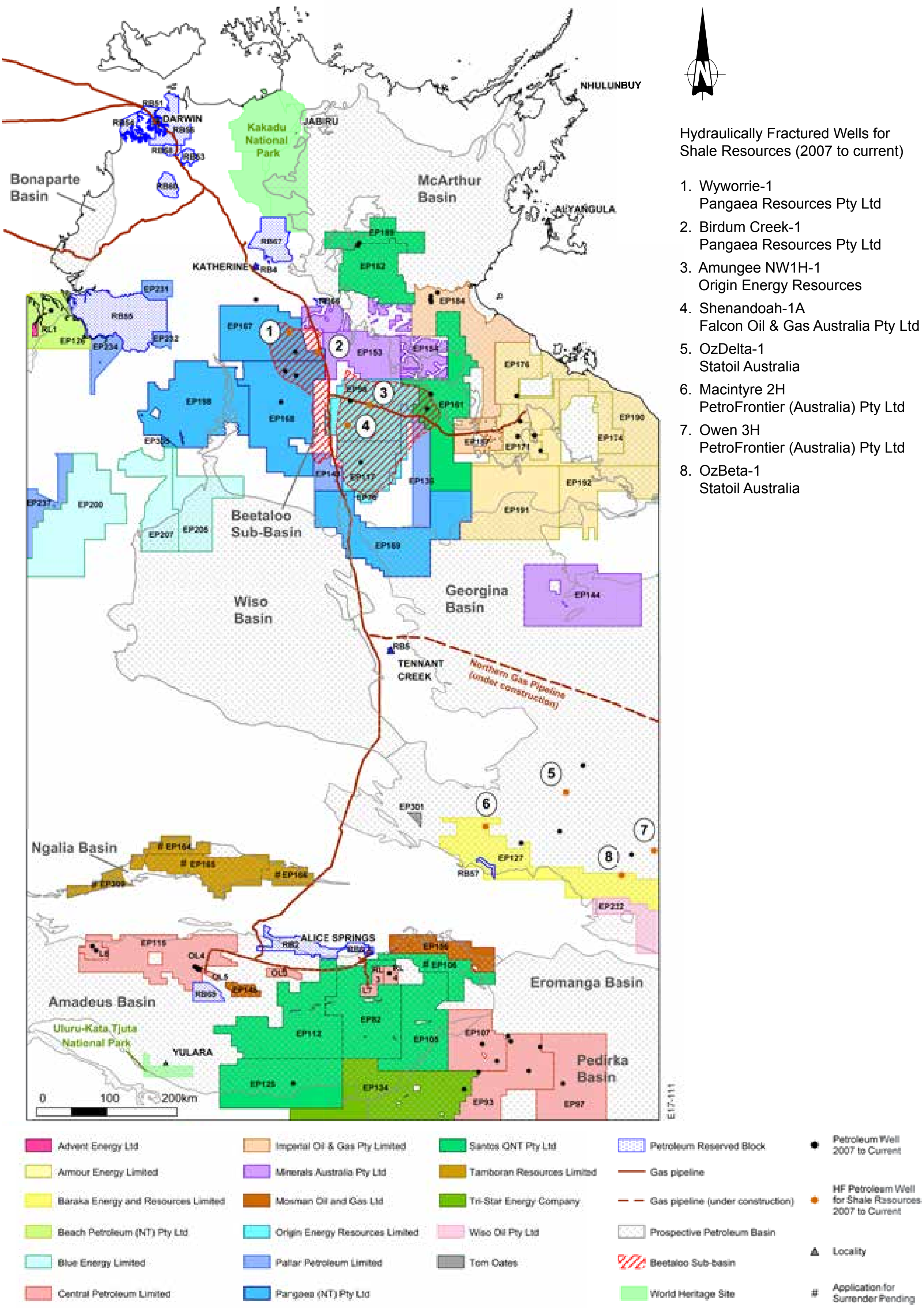
Figure 6.7 shows the interest holders for each of the granted petroleum exploration permits as well as the locations of hydraulically fractured unconventional wells. These have been focussed on the Beetaloo Sub-basin and the Georgina Basin. Not all have indicated the presence of shale gas reservoirs.

Figure 6.6: Granted petroleum titles and prospective shale gas areas. Source: DPIR.



NORTHERN TERRITORY GOVERNMENT

Figure 6.7: Interest holders for granted tenements and hydraulically fractured unconventional petroleum wells in the NT. Source: DPIR.



NORTHERN TERRITORY GOVERNMENT

In response to specific information requested by the Inquiry regarding the likelihood and timeframe for development of each basin, Geoscience Australia has noted that the Amadeus Basin is the only onshore basin in the NT with identified reserves and existing petroleum production infrastructure. Any new petroleum discovery made in this basin has the potential to take advantage of pre-existing infrastructure to provide a quick path to commercialisation. As seen with discoveries in areas such as the Cooper Basin, any new gas discoveries could technically be brought on stream within 12 months (not taking into account any regulatory matters to be resolved).

The potential of the Beetaloo Sub-basin has been highlighted by Origin declaring a contingent resource, signifying that the resource is not currently commercial and that more assessment of the resource is required prior to it being made a reserve, or that some other barriers to commercialisation need to be overcome. Given the current moratorium on hydraulic fracturing, this is enough of a barrier to commercialisation to prevent the resource being declared a reserve, let alone other potential factors. If the moratorium on hydraulic fracturing was removed, the resource would still require additional work prior to being reclassified as a reserve. This work would include additional drilling and reservoir modelling to understand the extent and nature of the resource, and would require at least another 12 months' work, possibly more. The decision to move to production in a region without pre-existing infrastructure is a well-understood assessment process involving significant investment decisions and regulatory compliance hurdles. It is therefore unlikely that there will be any shale gas production in the Beetaloo Sub-basin in fewer than three years.

Petroleum was first noted in the Georgina Basin in 1910 when petroliferous odours were recorded during the drilling of water bores. More than 70 wells (petroleum and stratigraphic) have been drilled in the Basin, but no resources have been identified. There remains a great deal of uncertainty about the ability of the rocks within the basin to generate and host significant volumes of hydrocarbons. In this respect, the Georgina Basin lags behind the Beetaloo Sub-basin, so any discovery made today would almost certainly be more than three years from commercialisation and potentially more than a decade.

All other basins in the NT would be in a similar situation to the Georgina Basin.

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

6.5 Possible development scenarios in the NT

To provide historical context for this section, it should be noted that the onshore petroleum industry has had a presence in the Northern Territory since 1959, when the first exploration well was drilled. Although having commenced more than 50 years ago, given its size, the industry is still in its infancy, with only 236 wells drilled so far.[24] Out of the total wells drilled, 145 have been decommissioned (plugged and abandoned), 26 have been suspended, and 65 are currently producing.[25] Presently, the NT has four fields that are in production. All are extracting hydrocarbons from conventional reservoirs.

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 Report, the Panel has used this information as possible development scenarios for any onshore shale gas industry in the Beetaloo Sub-basin, noting that these scenarios are presently uncertain.

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
High	Origin[21]	Beetaloo Sub-basin, around Amungee, near Daly Waters	98, 117, 76.	Large scale: 400-500 (approx. 50-65) Small scale: approx. 50-100 (6-12)	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 20-40 years Small: 50-100 TJ/d over 20-40 years
	Santos[22]	McArthur Basin, Beetaloo Sub-basin	161, 162, 189.	300-350 (approx. 30-35)	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: 400-800 TJ/d
	Pangaea[23]	Beetaloo Sub-basin, west of Stuart Hwy	167, 168.	Approx. 300 (approx. 24-40)	Approx. 400 km^2	600-900 ML/y for 7 years = 4,200-6,300 ML (or 4-6 GL)	200-300 TJ/d

1. See **Figure 6.6**.
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.

24 DPIR submission 226, p 46.
25 DPIR submission 226, p 46.
26 Origin submission 153, p 39.
27 Santos submission 168, p ii, pp 35-36; Santos Ltd, submission 1249 (**Santos submission 1249**), pp 2-3.23 Pangaea Resources Pty Ltd, submission 220 (**Pangaea submission 220**), p 21; Pangaea Resources Pty Ltd 1147 (**Pangaea submission 1147**), p 6.

6.5.1 Scale of development

The scale of development is difficult to establish at the current time. The estimates provided by the three 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 well pads.[28] However, the Energy Division of DPIR predicts that approximately 15,506 shale gas wells could be developed in the greater McArthur Basin, with possibly around 6,250 wells in the Beetaloo Sub-basin.[29] This estimate is more than one order of magnitude (10 times) larger than the industry projection. No explanation has been provided for these figures, and they do not conform with the estimates provided by industry.

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

- a small-scale development that 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 that 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 and 500 wells drilled on 50–65 pads over a 20–40–year period. Additional gas-gathering systems, gas plants, 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 fracturing of these 456 wells is estimated to be staggered over 24 years.[30]

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 onshore shale gas basins. Preliminary estimates (based on the area of 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, approximately 300 drilling rigs could be operational at any one time, with full development extending over several decades.[31] However, the availability of drilling rigs and hydraulic fracturing crews in Australia is currently limited and would slow the rate at which any industry could develop. It is therefore likely that only one or two onshore shale gas resources will be able to be developed in the NT in the foreseeable future.

ACOLA also estimated that one drilling rig could produce between 11 and 18 wells per year.[32] Allowing for wet season interruptions, this figure is optimistic for the NT. 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.[33] However, the proposed development by the three companies with leases in the Beetaloo Sub-basin is many times (almost 10 times) greater (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.

28 Assuming eight horizontal wells per pad.
29 DPIR submission 226, Addendum 1.
30 Origin submission 153, p 36.
31 ACOLA Report, p 75.
32 ACOLA Report.
33 ACOLA Report.

6.5.3 Infrastructure needs

Establishment of a full-scale shale gas industry in the NT 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 (see Chapter 8). This level of construction will have flow-on impacts to regional populations, towns and Darwin itself (see Chapter 12). There will be demands for heavy vehicles, plant and equipment, drilling rigs, hydraulic fracturing units and temporary accommodation, as is the case with any major construction.

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 potential 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. Gas pipeline infrastructure in the NT is currently inadequate to handle the potential magnitude of new discoveries in the McArthur Basin, of which the Beetaloo Sub-basin is a part. Accordingly, trucking, or possibly rail, may be the most practicable initial options to transport the gas.[34]

The actual infrastructure requirements (in particular, the numbers and ultimate density of well pads through time) will require careful scrutiny in the event the moratorium is lifted and a commercial supply of gas is developed. Experience in the US has shown that production from individual wells, and ultimately from a whole field, declines over time, requiring additional wells to be commissioned, or re-fracturing of existing ones, to meet demand. For example, the disparity between the forward estimates reported for the US shale gas plays used in projecting future production of shale gas plays and the real situation is analysed the US Energy Information Administration *Drilling Deeper Report*.[35] These production declines can have significant (initially unexpected) implications for the future spatial extent of a gasfield development as well as for increasing the original density of wells to maintain production within an initially defined footprint area. There is currently insufficient information available for any of the onshore shale gas basins in the NT to inform this long-term planning issue.

34 ACOLA Report, p 80.
35 Hughes 2016.

6.5.4 Conclusion

From the above discussion, it is apparent that there still remains considerable uncertainty about the likely scale and rate of development of any onshore shale gas industry in the NT. 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 any such development depends on external economic considerations (including international gas and other commodity prices. See Chapter 13), 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 Chapter 14), even if the moratorium on hydraulic fracturing were lifted by the Government immediately, full scale development in the Beetaloo Sub-basin would take at least 5–10 years to achieve.

WATER

7

7.1 Introduction

Water-related risks were the central concern raised in the submissions received by the Panel 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 applying to the shale gas industry in other countries are not necessarily comparable to those in the NT.

Concerns around the impacts of CSG development were also reflected in public anxiety about any onshore shale gas development in the NT. However, it is important to recognise that the process of CSG extraction is very different to that of shale gas extraction because large volumes of water need to be extracted from the coal seam aquifer during CSG operations prior to the start of hydraulic fracturing to ensure the gas flow (see Chapter 5).

Water is an essential part of traditional Aboriginal culture, both in terms of access for survival for groups living in remote areas, and also in terms of its spiritual link to Aboriginal sacred sites and religious customs. The NLC articulated the importance of water to the Aboriginal people, noting that,

> *"Water is both steeped in Aboriginal mythology and history and critical to the present day maintenance of life, culture and livelihoods. Water always has and always will be central to Aboriginal identity and, thus, to the continued maintenance of Aboriginal law and culture in this country."* [1]

The Aboriginal Areas Protection Authority (**AAPA**)[2] noted that the practice of shale gas hydraulic fracturing could have significant impacts on sacred sites arising from interference with either surface water or groundwater (see also Chapter 11).

The sustainable management of surface and groundwater resources will be crucial to the development of any onshore shale gas industry in the NT. Sustainable development involves the protection of three water-related environmental values: water quantity; water quality; and aquatic ecosystems. The protection of these values is realised by achieving the following three objectives: first, to ensure surface and groundwater resources are used sustainably; second, to maintain acceptable quality of surface and groundwaters; and third, to adequately protect ecosystems that are dependent on surface water or groundwater.

The Panel has assessed the water-related risks associated with any shale gas development in the NT using the risk assessment framework detailed in Chapter 4. In total, 20 risks to water supply, water quality, and aquatic ecosystems have been assessed.

The Panel has focussed its attention on the Beetaloo Sub-basin because this is the most prospective onshore shale gas region in the NT (Chapter 6), and, more importantly, it has been comparatively well studied. A number of the conclusions drawn for the Beetaloo Sub-basin have broader relevance across the NT. The paucity of information about regional surface water and groundwater processes in other regions of shale gas prospectivity in the NT has prevented the assessment of some risks more broadly. However, the assessment methodology used by the Panel for the Beetaloo region provides a good model for what must be applied to the other prospective shale basins to evaluate the location-specific risks posed by any shale gas development in those areas.

1 Northern Land Council, submission 647 (**NLC submission 647**), p 5.
2 Aboriginal Areas Protection Authority, submission 1150 (**AAPA submission 1150**).

7.2 Water in the NT

The climate in the NT ranges from tropical and monsoonal in the north, to arid or semi-arid in the southern and central regions. The rainfall ranges from around 2,000 mm per year in the north, to approximately 150 mm per year in the Simpson Desert (**Table 7.1; Figure 7.1**).

The wet season (October-April) monsoons totally dominate the rainfall from north of around Tennant Creek (500 mm/y), and there is virtually no rain during the dry season (May-September). During these wet season monsoons, aquifers are recharged, floodplains are inundated, and billabongs and waterholes are refreshed. Further south, the rainfall is also influenced by the monsoons, but there are also increasing relative amounts of winter rain so that the low rainfall of the southern NT becomes essentially a-seasonal.

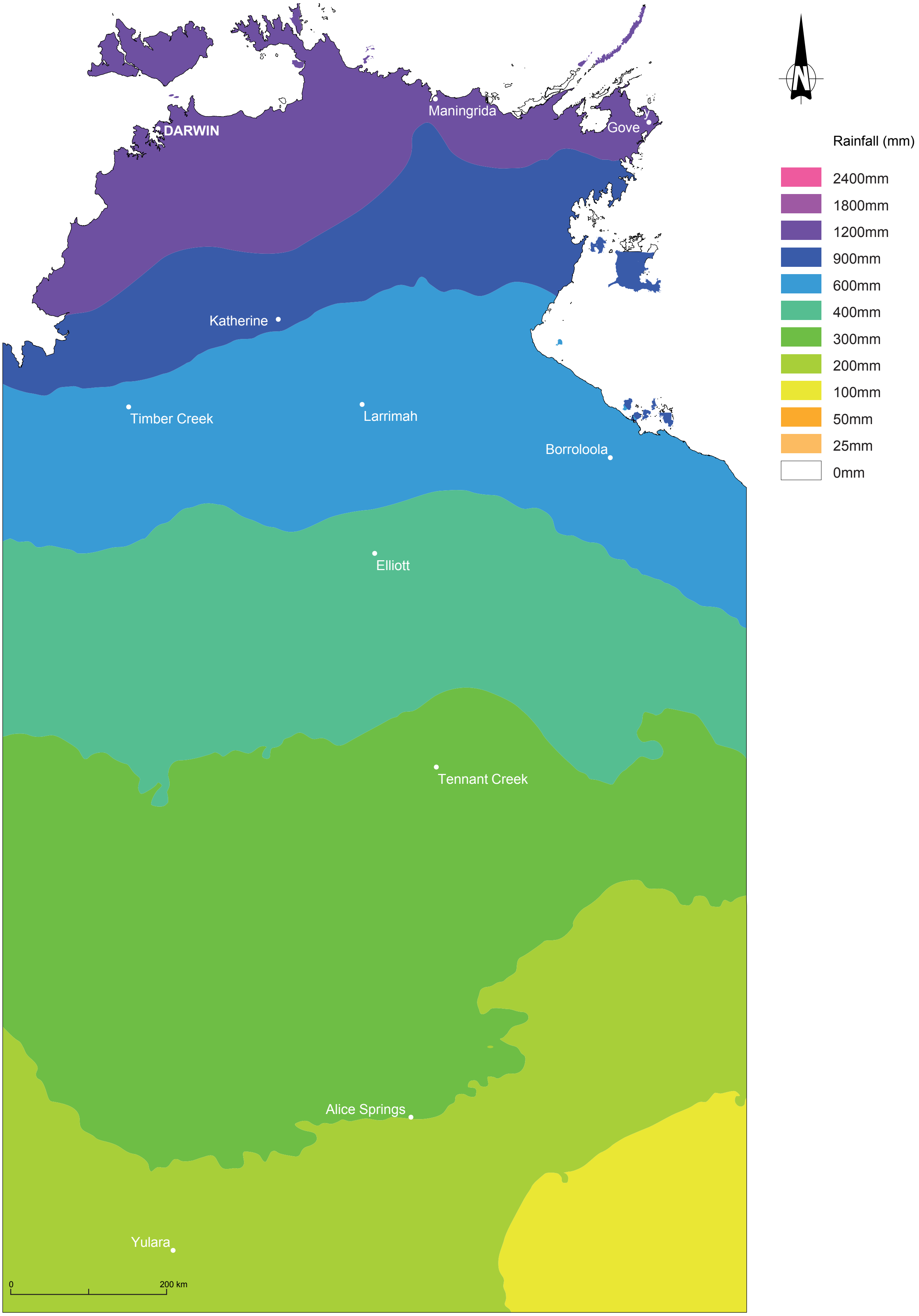
Given the multiple decades lifespan of any onshore shale gas industry, the Panel sought information from the Bureau of Meteorology (**BOM**) on the possible future changes of climate in the NT.[3] In summary, it is predicted that by 2050, there will be little change in the annual rainfall but increased intensity of extreme rainfall events, such as the wettest day of the year. Increased intensity during the wet season will increase runoff during storm events and influence streamflows. There is very high confidence that warming will continue across the NT, with different climate models predicting between 1.0-1.5 °C and 2.0-3.0 °C increases in mean annual surface temperature by 2050.[4] Not surprisingly, given the potential temperature increase, it is also predicted that evapotranspiration (water use by vegetation) will increase, although the magnitude of the change is unclear. The implications of climate change for groundwater processes and recharge rates are also unclear at this stage.

Table 7.1: Long-term average rainfall and evaporation levels. Source: BOM.[5]

Location (station number)	Rainfall (mm/yr) Years data were collected	Evaporation (mm/yr) Years data were collected
Darwin (14015)	1722 (1941-2017)	2454 (1957-2017)
Katherine (14903)	1088 (1943-2017)	2270 (1999-2011)
Daly Waters (14626)	675 (1939-2017)	2960 (1954-1970)
Elliott (15131)	589 (1949-2017)	2743 (1980-2010)
Alice Springs (15590)	284 (1941-2017)	3142 (1959-2017)

3 Bureau of Meteorology submission 475 (**BOM submission 475**).
4 BOM submission 475, p 3.
5 BOM submission 475, p 5.

Figure 7.1: Average annual rainfall in the NT over the period 1960-1990. Source: BOM.



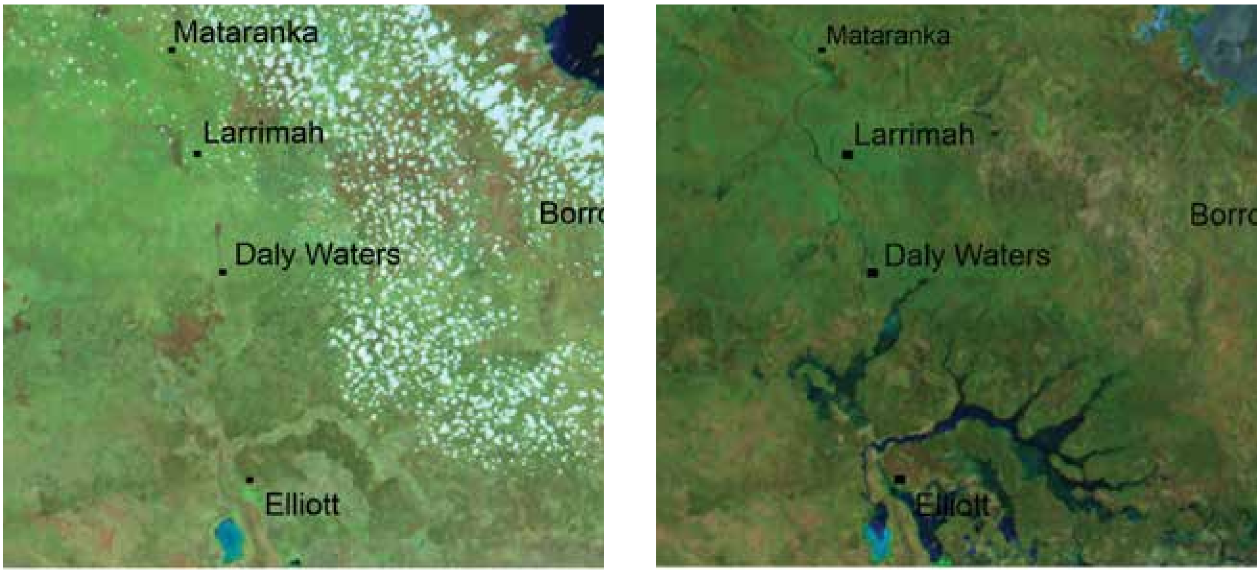
NORTHERN TERRITORY GOVERNMENT

7.2.1 Surface water resources

The surface water hydrology of the NT is reasonably well known. The two main sources of information are, first, the Department of Environment and Natural Resources (**DENR**) streamflow records for most major streams in the NT, and second, the extensive information on the surface water resources of northern Australia that was gathered in the Northern Australia Sustainable Yields Project undertaken by CSIRO in 2009.[6]

The northern, central, and southern regions of the NT are distinctly different, reflecting the contrasting patterns of rainfall amount and its seasonality. The northern region (Top End) has extensive river and wetland systems, whereas surface water is largely absent from the southern region, except for short periods during the wet season and isolated spring-fed systems.[7] The two largest perennial river systems in the NT, the Daly and the Roper, have their flow maintained during the dry season by discharges from the CLA groundwater system.[8] In the central semi-arid regions of the NT, stream flow is seasonal (wet season) and often does not occur for years. An insight into the permanence of water in the NT landscape has been developed by Geoscience Australia through collating satellite imagery collected since 1987, shown in **Figure 7.2**. The mainstream networks in the NT are shown in **Figure 7.3**. As noted below in Section 7.2.3, very little is known about the aquatic ecology of the temporary streams and water bodies in the semi-arid and arid regions of the NT.

Figure 7.2: Satellite images showing the variation in surface water occurrence between: (a) 1 October 2015 (late dry season), and (b) 3 January 2016 (following extreme monsoonal rains). Source: BOM.[9]

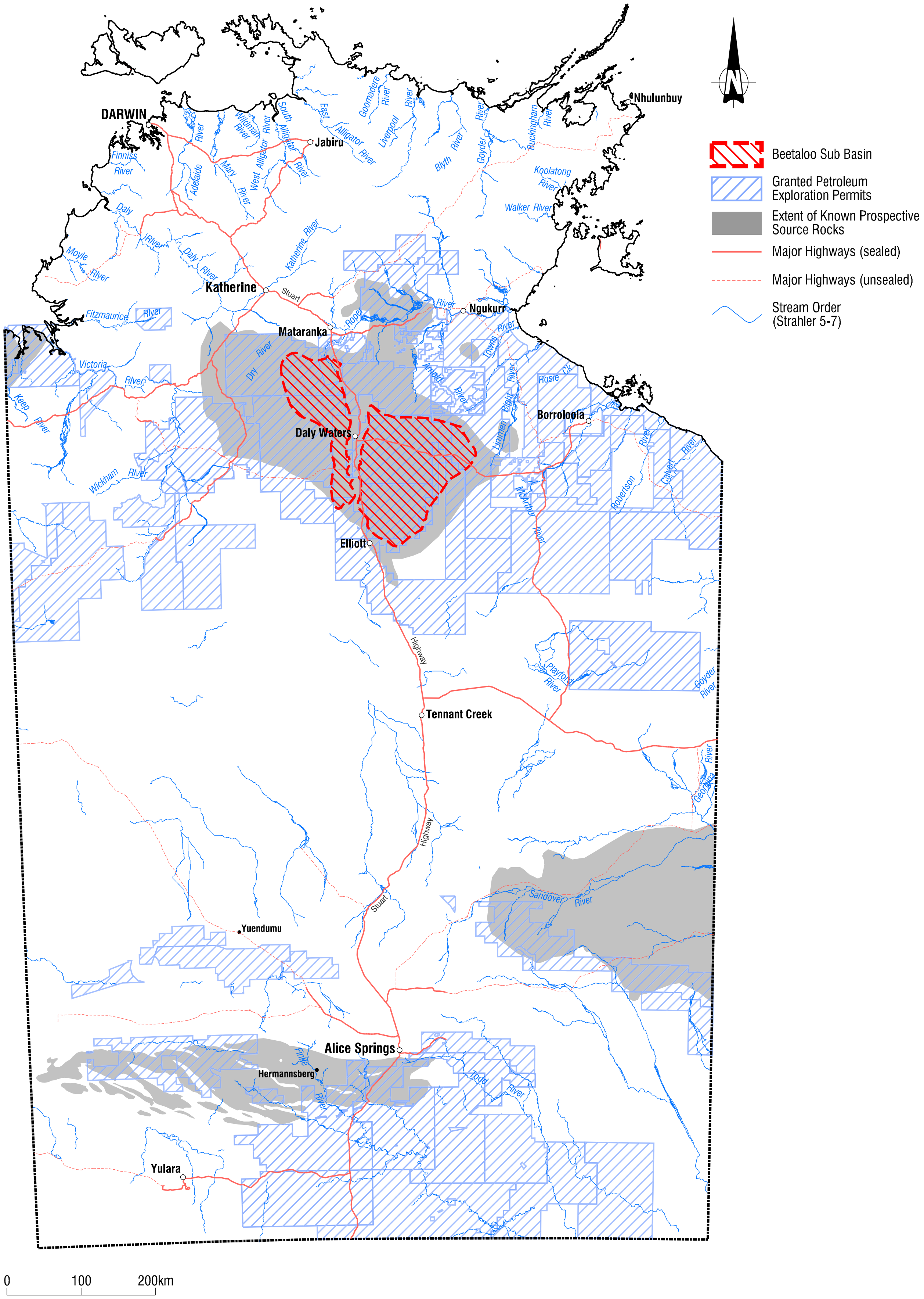


(a): Satellite imagery 1 October 2015.

(b): Satellite imagery 3 January 2016.

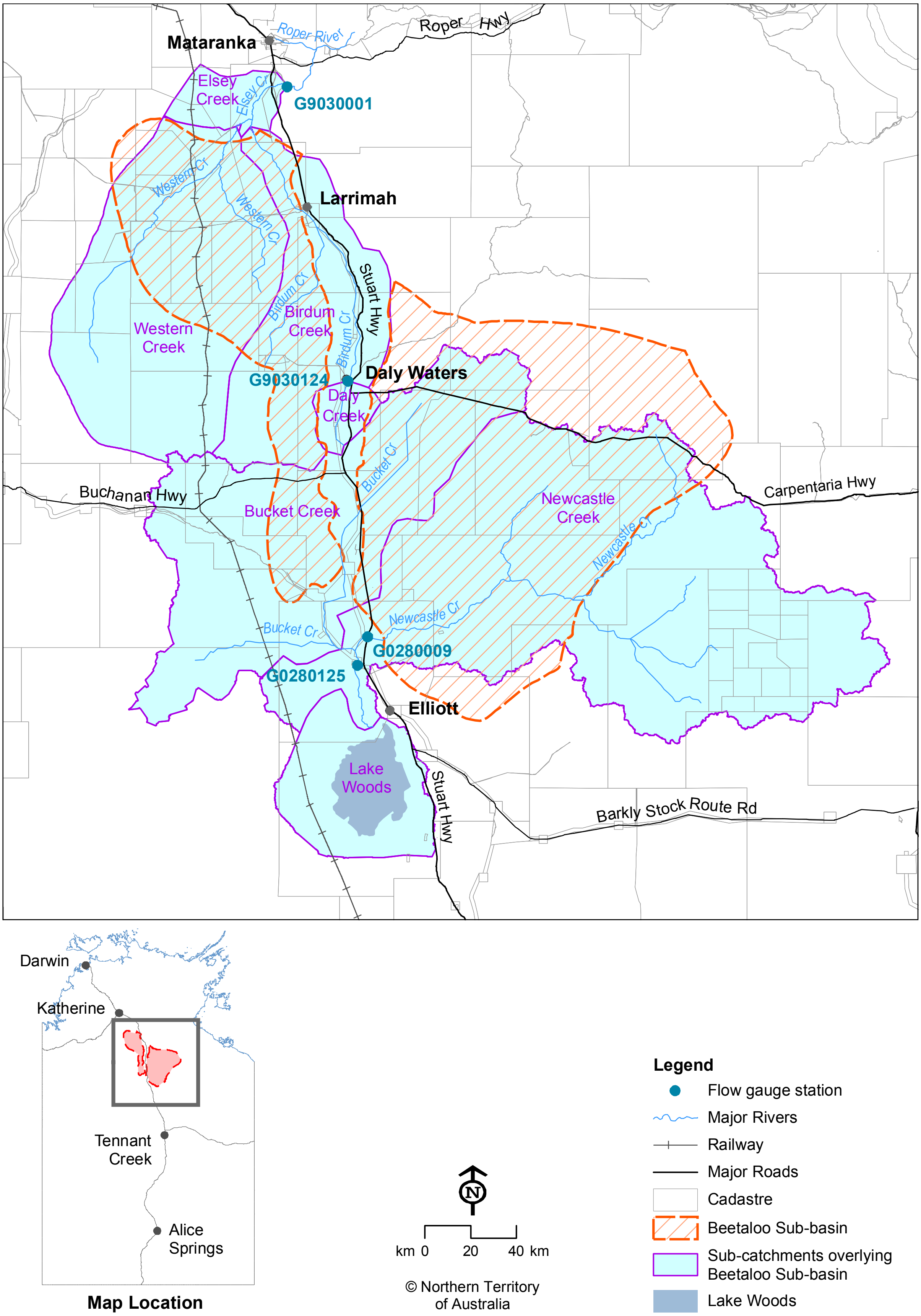
6 CSIRO 2009.
7 Department of Environment and Natural Resources, submission 449 (**DENR submission 449**); Gautam 2017.
8 Bruwer and Tickell 2015; Department of Environment and Natural Resources, submission 230 (**DENR submission 230**), Addendum 2.
9 BOM 2017a.

Figure 7.3 (a): Map of the rivers of the NT. Source: DENR.



NORTHERN TERRITORY GOVERNMENT

Figure 7.3 (b) Temporary rivers in three areas of the Beetaloo Sub-basin: (a) north-west region, (b) southern region, and (c) north-east region. Source: DENR.



7.2.2 Groundwater resources

Groundwater accounts for 90% of all of the NT consumptive water supplies,[10] a much higher proportion than for any other Australian jurisdiction.[11] The NT 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.[12] These basins have large storage capacities. The Daly Basin is seasonally recharged by monsoonal rainfall and the northern part of the Georgina Basin that is known to discharge into the Roper River.[13] For the other (more arid) basins, recharge is episodic and dependent on infrequent large rainfall events or recharge locations a long way from the NT for the Great Artesian Basin.[14] In these basins, groundwater quality decreases with reduced recharge rates, and in the semi-arid and arid zones is commonly brackish to saline, with elevated concentrations of ions such as fluoride and nitrate.[15]

These contrasting groundwater basins vary in their likely sensitivity to water demands of 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, and are replenished more frequently.[16] By contrast, impacts on arid zone groundwater systems are likely to be greater and occur for longer, because these systems are recharged far more slowly, if at all.

Predicting the likely impacts of any onshore shale gas development on groundwater resources in prospective shale basins requires a detailed understanding of their hydrogeological and hydrochemical characteristics under pre-development (baseline) conditions. Current understanding of these groundwater characteristics is reasonable for parts of the Beetaloo Sub-basin, but generally low for other prospective shale gas basins in the NT (for example, the Northern Amadeus Basin, the Arthur Creek Formation, the McArthur Basin and the Bonaparte Basin).[17]

Imperial Oil and Gas has also provided an internal company report on the hydrology of the McArthur Basin Central Trough.[18]

DENR has collated the available information and reports for the Daly, Wiso and Georgina Basins, which overlie the Beetaloo Sub-basin and surrounds, at depths of 100-400 m below the surface (**Figure 7.4**).[19] The various groundwater systems associated with these basins are broadly grouped as the CLA, a significant regional aquifer system comprising fractured and karstic rocks.[20] Karst systems are formed by the dissolution of soluble rocks such as limestone, dolomite and gypsum and are characterised by underground drainage systems with sinkholes and caves.

Table 7.2 summarises the current knowledge of the shallow aquifers (that is, down to a depth of approximately 200 m) in each of the prospective shale gas basins in the NT. Information is provided on the proximity of the aquifer(s) to the surface, the thickness and nature of the overlying strata, and the possible preferential pathways from surface to the aquifer. This latter information has been used in Section 7.6.3 to assess the possible contamination of surface aquifers from surface spills of wastewater from a hydraulically fractured shale gas operation.

10 Includes water for domestic use, irrigation, stock watering and industry.
11 DENR submission 230, p 3.
12 DENR submission 230, pp 3, 6.
13 Fulton and Knapton 2015, p 37.
14 DENR submission 230, p 3; Bruwer and Tickell 2015; Fulton and Knapton 2015; GHD 2016.
15 Yin Foo and Matthews 2000; Fulton and Knapton 2015; Bruwer and Tickell 2015; GHD 2016.
16 DENR submission 230, Appendix A.
17 Department of Environment and Natural Resources, submission 428 (**DENR submission 428**), pp 1-12.
18 Imperial Oil and Gas Pty Ltd, submission 1163 (**Imperial Oil and Gas submission 1163**).
19 Tickell and Bruwer 2017.
20 Fulton and Knapton 2015, p 32.

Table 7.2: Status of knowledge about shallow aquifers in each of the prospective shale gas basins: proximity of aquifers to surface, thickness and nature of overlying strata, possible preferential pathways from surface to aquifer. See **Figure 6.2** for the locations of the shale basins. Source: DENR;[21] Knapton;[22] Bruwer and Tickell.[23]

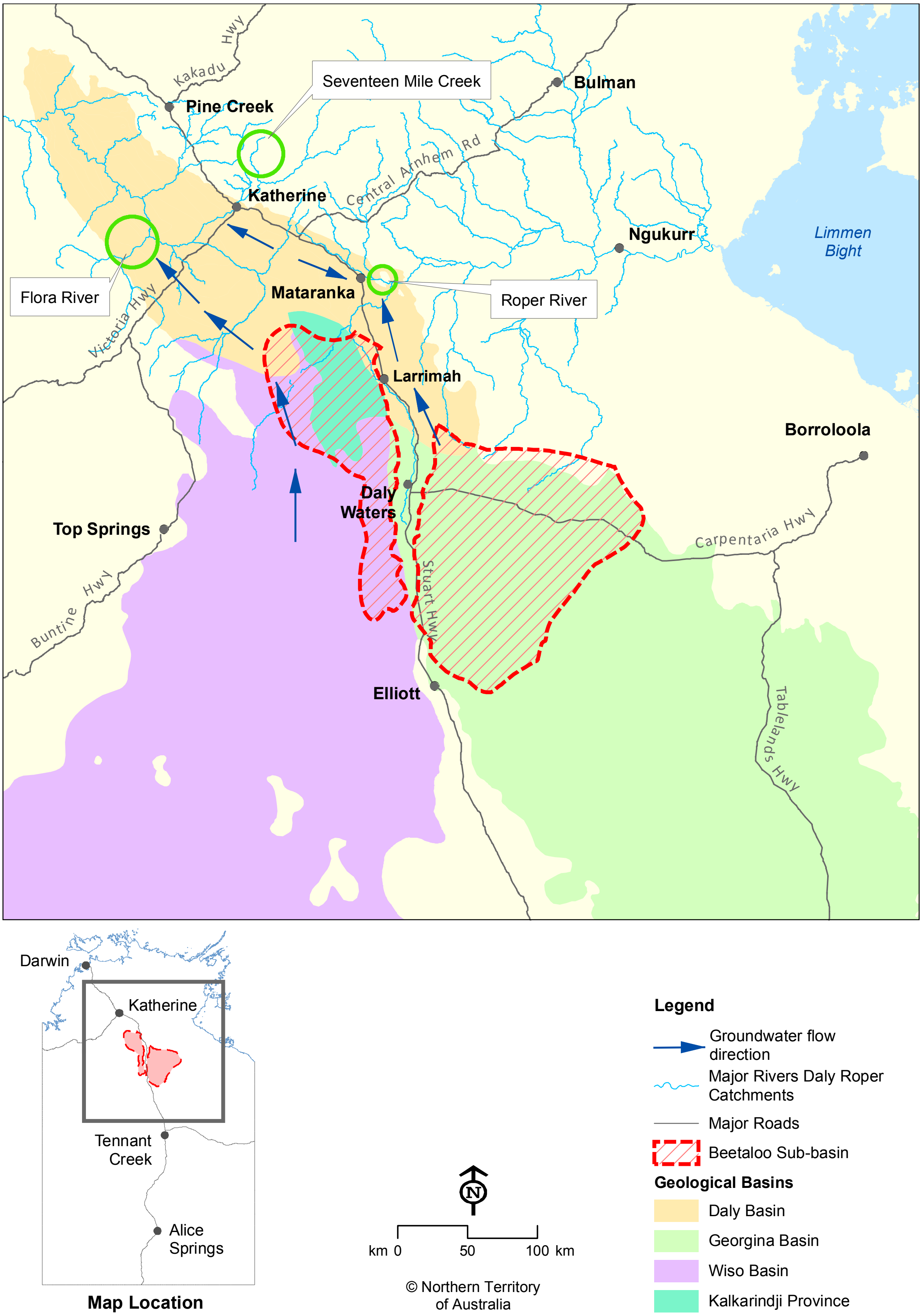
Shale basin	Aquifer	Summary
McArthur Basin Northern extremity of Beetaloo Sub-basin (Mataranka to Larrimah)	Tindall Cambrian Limestone Aquifer (CLA)	• Hydrogeology is considerably different in the area around Mataranka (20-40 km south) compared to the central and southern part of the Beetaloo Sub-basin. • Geology dominated by weathered Tindall Limestone with a thin cover of Cretaceous sandstone. • Water table is shallow with a thin unsaturated zone and reduced or no overlying clayey strata. • Evidence for preferential pathways with karstic formations.
McArthur Basin Beetaloo Sub-basin East of Stuart Highway (Larrimah to Daly Waters)	Tindall/Gum Ridge (CLA)	• Is the only known aquifer in this region - average depth to the formation is 30 m. • Water table is approximately 45 m deep and aquifer expected to be intersected within 15 m of the top of the water table (that is at 60 m). • Most of the region is covered by low permeability cretaceous sediments. • Surface expression of collapse structures in the underlying limestone exist, but open sinkholes that provide a preferential pathway to the aquifer are rare.
McArthur Basin Beetaloo Sub-basin East of Stuart Highway (Daly Waters to Elliott)	Anthony Lagoon Formation (CLA)	• This formation exists either below 50 m of Cretaceous sediment or sub crops at shallow depth at its margins. • Water table is at approximately 60 m and aquifers may be intersected within 60 m below the water table (that is at 120 m). • Low permeability black soils cover a large part of the Barkly Tablelands. • Collapse structures generally do not develop in this formation.
	Gum Ridge Formation (CLA)	• Mostly underlies the Anthony Lagoon Formation at depth (approximately 300 m) so at low risk from surface spills, but subcrops at shallow depth on the basin margins. • The two aquifers (Gum Ridge and Anthony Lagoon) are vertically separated by a low permeability layer. • At the centre of the basin, the top of the Gum Ridge Formation is approx. 300 m below the surface, while on the western margin near Elliott, the top of the Formation is at 40 m depth. • An aquifer could be expected to be intersected within 30 m of the top of the Formation (that is at 60 m). • The overlying layer is highly clayey with occasional disaggregated limestone beds - there is unlikely to be preferential flow pathways in this layer.
Wiso Basin West of Stuart Highway adjacent to Beetaloo Sub-basin	Montejinni Limestone (CLA)	• Extensive across the Sturt Plateau - overlain by approximately 50 m of Cretaceous sediments and bounded below at approximately 70 m depth by the undulating Antrim Plateau Volcanics. A much shallower aquifer system than the Anthony Lagoon Beds. • Water table is at 50 to 60 m below surface so aquifer is very thin in most places. Only prospective for water supply where it has infilled the troughs of the basement. • Significant number of collapsed structures in the limestone are expressed on the surface as sinkholes. However, open sinkholes that provide a preferential pathway to the aquifer are rare. • At Gorrie Station in the north, where the cretaceous sediments are thinnest (about 30 m) and where groundwater is intersected at 30 m, potential for preferential pathways to the aquifer may exist.
McArthur Basin	Barney Creek Formation	• Relatively few bores drilled in this region and only one detailed study for water supply in the vicinity of Borroloola. • Aquifers overlying the Barney Creek Formation generally occur at shallow depth and may be developed in shallow Cretaceous sediments, Proterozoic sandstone or in the karstic terrain of the Karns Dolomite Formation. • Water table may exist at approximately 20 to 30 m depth. • Surface layer is sand and clay soils. • Open sinkholes occur on the areas underlain by Karns Dolomite and these represent preferred flow pathways to the aquifer.

21 DENR submission 428; Department of Environment and Natural Resources, submission 481 (**DENR submission 481**).
22 Mr Anthony Knapton, submission 426 (**A Knapton submission 426**).
23 Bruwer and Tickell 2015.

Table 7.2: *Continued*

Shale basin	Aquifer	Summary
Georgina Basin	Arthur Creek Formation	• No hydrogeological studies have been undertaken in this region. • Hydrogeological knowledge is limited to bores drilled for stock watering purposes. • Aquifers overlying the Arthur Creek Formation mostly exist in limestone or sandstone. • Water table is at approximately 80 to 100 m depth. • The surface of the region is covered by a sandy and clayey weathered horizon to approximately 50 m depth.
Bonaparte Basin		• The only hydrogeological studies conducted in this region are near the Keep River Plains. • A palaeo-channel aquifer exists directly beneath the black soil floodplain and small fractured rock aquifers exist in the Proterozoic rocks surrounding the floodplain - the palaeo-channel aquifer may be intersected between 20 and 30 m below surface, while bores in the Proterozoic fractured rock aquifers typically intersect water below 30 m from surface. • Water table lies at approximately 10 to 20 m depth. • The black soil areas of the plains are low in permeability (recharge rate ~ 0.1 mm/y) and receive no fresh recharge, while the red soils which generally overlie the sandstone bedrock, receive moderate recharge (~ 40 mm/y) through the wet season. • No areas where sinkholes occur that represent preferential pathways to the aquifer.
Amadeus Basin		• Aquifers have developed in sandstones, dolomites and shales and occur in primary (intergranular) and secondary porosity (fractures, karst). • Depending on location, the depth to aquifers will vary from near surface (30 m) to over 100 m - water table may be from close to surface to below 100 m. • One permeability study undertaken in the Amadeus Basin over the Mereenie Sandstone in the Rocky Hill region. This region is outside the area mapped as overlying prospective shale gas source rocks, but results could be indicative of weathered Mereenie Sandstone across the Amadeus Basin. • Drainage rate was between 80 and 130 mm/y. • There are no features such as sinkholes, which could represent a preferential pathway to the underlying aquifer.
Pedirka Basin		• The aquifer overlying the Pedirka Basin comprises mainly sandstones within the sediments of the Great Artesian Basin (GAB). • The permeable of sediments that form the aquifer may be intersected from ground surface around the margin areas of the basin with the water table existing at approximately 60 m. • Beyond the sub cropping margins, the sediments of the GAB are overlain and the aquifer is confined by the impermeable mudstones of the Cretaceous aged Rolling Downs Group of rocks. • In the area underlain by the Pedirka Basin, the top of the GAB sediments may be intersected from surface in the western margin to hundreds of metres beneath mudstone towards the centre of the basin. • The sediments of the GAB are highly permeable where they outcrop. Where they are overlain by the Rolling Downs Group, the aquifer is confined and is not susceptible to surface infiltration.

Figure 7.4: Cambrian Limestone Aquifer overlying the three main Basins (Daly, Wiso, and Georgina) and the Beetaloo Sub-basin. Source: DENR.[24]



24 DENR submission 230.

Two other groundwater studies currently underway will provide additional information on the Beetaloo Sub-basin groundwater systems. Unfortunately, these studies will not be completed in time to be considered by the Panel. They will, however, contribute to the acquisition of baseline information that the Panel has recommended as a prerequisite to the commencement of production of any onshore shale gas industry (see Section 7.4.3).

The first of these studies is being undertaken by Geoscience Australia as part of its *Exploring for the Future* programme.[25] Geoscience Australia is studying the regional groundwaters in two regions: in the South Stuart Corridor (between Alice Springs and Tennant Creek), and the Northern Stuart Corridor (around Daly Waters). Both studies include the collection of targeted new baseline geoscience information, including geophysical surveys, hydrogeological mapping and groundwater chemistry analysis, to provide regional-scale estimates of aquifer volumes and groundwater quality (including salinity). These investigations will help identify potential recharge areas in all of the project areas, while also establishing baseline monitoring sites to better understand groundwater aquifers and processes, including relative rates of recharge. For the Northern Stuart Corridor, Geoscience Australia has advised the Panel that, *"there is reasonable data and understanding of the groundwater system north of Daly Waters, but very sparse data south of Daly Waters".*[26] Both the Northern and Southern Stuart Corridor studies will be completed by June 2020.

The second study is being undertaken by CSIRO, which has been engaged by Origin and Santos to characterise the groundwater environment, assess the flow mechanisms in the CLA, and assess the groundwater recharge rate and age of water in that aquifer.[27] This study is expected to be completed by mid-2018.

With all potential onshore shale gas areas in the NT, there is very little information about the nature of the deeper groundwater systems, and moreover, there is limited understanding (based on deep exploration drilling to date) of the deeper geological systems in these basins. The relatively impermeable nature of gas bearing shales, and their distance beneath potable water 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.[28]

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 NT, and are also critical ecosystems in many parts of the central and southern more arid regions.[29] Far northern Australia has one of the world's highest concentrations of free-flowing (undammed) rivers, and these, along with their associated wetlands, are of international significance because of their ecological intactness and high biodiversity values.[30]

Figure 7.3 illustrates the surface water networks in the NT. Most of the streams shown are temporary. Those in the north generally flow each year during the summer wet season (intermittent), while those in the southern semi-arid regions flow for only short periods of time during larger wet seasons (ephemeral), and those in arid regions may not flow for many years (episodic). Temporary water bodies (for example, waterholes and billabongs) also occur in the semi-arid and arid regions of the NT, but generally only for short periods of time after substantial rains.[31] They are particularly important in supporting biodiversity (aquatic and terrestrial) and provide valuable ecosystem services.[32]

25 Geoscience Australia submission 414.
26 Geoscience Australia submission 414, p 5.
27 Santos submission 420, pp 10-11.
28 US EPA 2016a, Chapters 6.50-6.52.
29 Duguid et al. 2005.
30 Lukacs and Finlayson 2008.
31 Duguid et al. 2005.
32 Acuna et al. 2017, pp 13-14.

While there has been considerable research undertaken over the past decade to improve the knowledge of surface water aquatic ecosystems in northern Australia,[33] there is still a need for this knowledge to be synthesised and collated into a coherent package for use in water resource and environmental management in the NT. There is limited understanding of the aquatic ecology of the temporary streams and waterbodies that dominate the semi-arid and arid regions of Australia,[34] or the environmental flows required to maintain most of Australia's tropical rivers in good ecological health.[35] One exception is the Daly River, where extensive hydrological research has been undertaken to underpin sustainable agricultural development.[36]

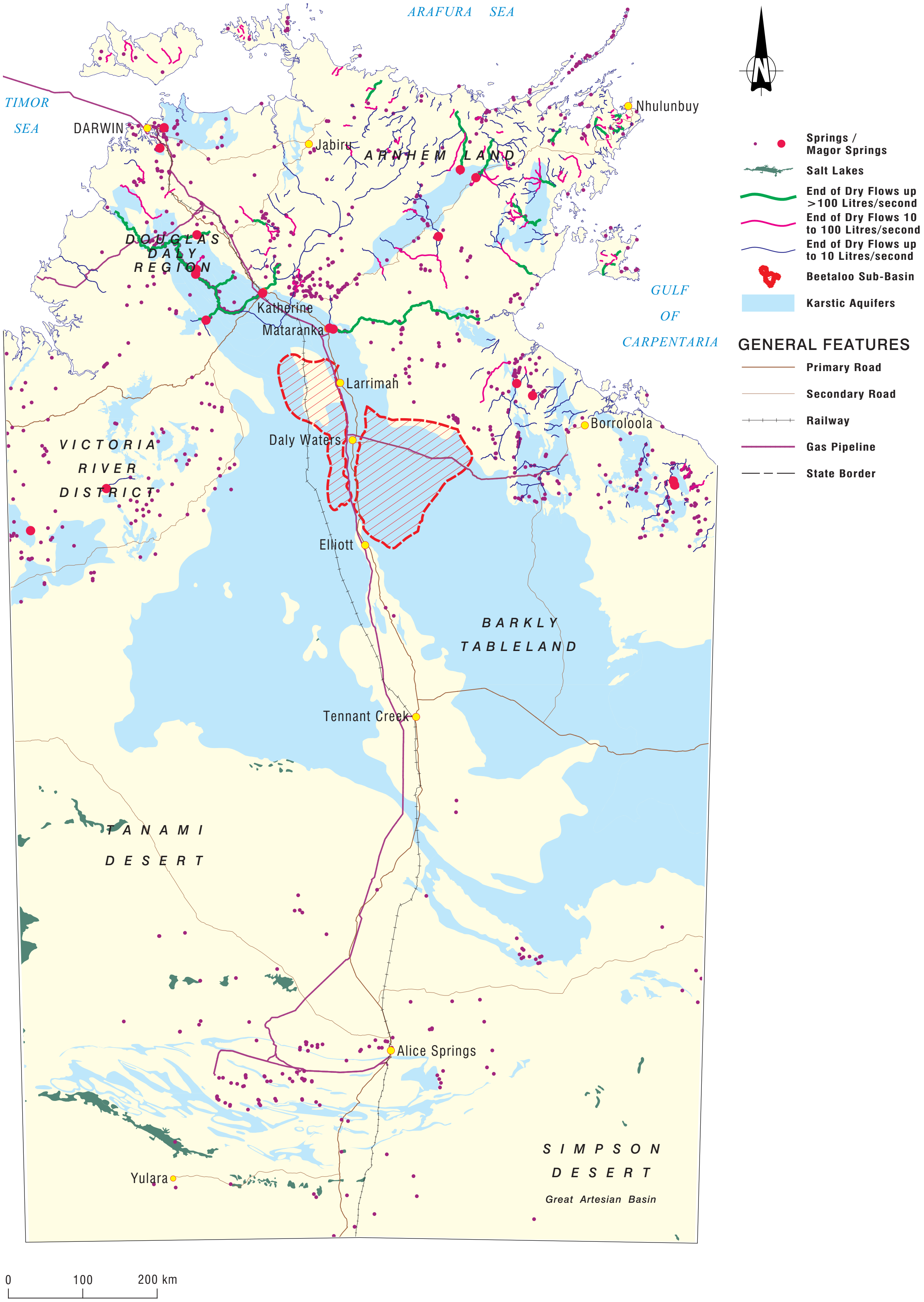
This lack of knowledge is not unique to Australia. Recently, Acuna et al. lamented the lack of effective recognition and management of temporary streams around the world.[37] They argued that temporary streams in arid and semi-arid landscapes are particularly important in supporting biodiversity, provide valuable goods and services, and should be managed as unique ecohydrological types, not as "second-class ecosystems".[38] In addition to acknowledging that they are unique ecosystems, there is a need to develop conservation targets and management action plans to ensure these temporary aquatic systems are not further degraded.[39]

The Panel has recommended that the improved understanding of the flow-ecology relationships of these systems be undertaken as part of the strategic regional environmental and baseline assessment process recommended in Section 7.4.3. (***Recommendation 7.5***) and Chapter 15.

There is limited knowledge about groundwater dependent ecosystems (**GDE**) in the NT (**Figure 7.5**). Many types of GDE exist, including surface water ecosystems that rely on the surface expression of groundwater, such as rivers, waterholes and springs, terrestrial ecosystems that rely on the subsurface presence of groundwater, and subterranean ecosystems, including cave and aquifer ecosystems.[40]

33 Pusey and Kennard 2009; Close et al. 2012; King et al. 2015; Waltham et al. 2013; Pearson et al. 2015.
34 Beesley and Prince 2010; Davis et al. 2017.
35 Warfe et al. 2011; King et al. 2015.
36 Erskine et al. 2003.
37 Acuna et al. 2014; Acuna et al. 2017.
38 Acuna et al. 2017, pp 13-14.
39 Acuna et al. 2017, pp 15-17; Boulton 2014.
40 BOM 2017a.

Figure 7.5: Map of the groundwater-dependent ecosystems in the NT. Source: DENR.



There is increasing awareness around Australia of the importance and need for protection of subterranean ecosystems, including stygofauna (the invertebrates living in aquifers). For example, in Western Australia, stygofauna are recognised as being of global significance due to high levels of endemism and substantial diversity.[41] They are known to occur in aquifers in limestone, sandstone and alluvium in the Kimberley region.[42] Recently, Queensland released guidelines for the assessment of stygofauna,[43] and NSW released risk assessment guidelines for groundwater dependent ecosystems.[44] The Panel is not aware of any studies of stygofauna within aquifers in the NT.

7.2.4 Water use and management

The NT supports a diverse range of water-dependent industries, including agriculture, horticulture, pastoralism, tourism and recreational fishing. The two largest 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.[45] The pastoral and horticultural industries are also heavily dependent on groundwater.

7.2.4.1 Water Act

Water resource planning in the NT occurs under the Water Act 1992 (NT) (**Water Act**). The Controller of Water and Minister for Environment and Natural Resources (**Minister for Environment**) have powers and decision-making functions under the Water Act and are supported by DENR.[46] The Water Act provides for statutory-based water licences (entitlements), the declaration of Water Control Districts (**WCDs**), and the development of water allocation plans (**WAPs**) within the WCDs.[47]

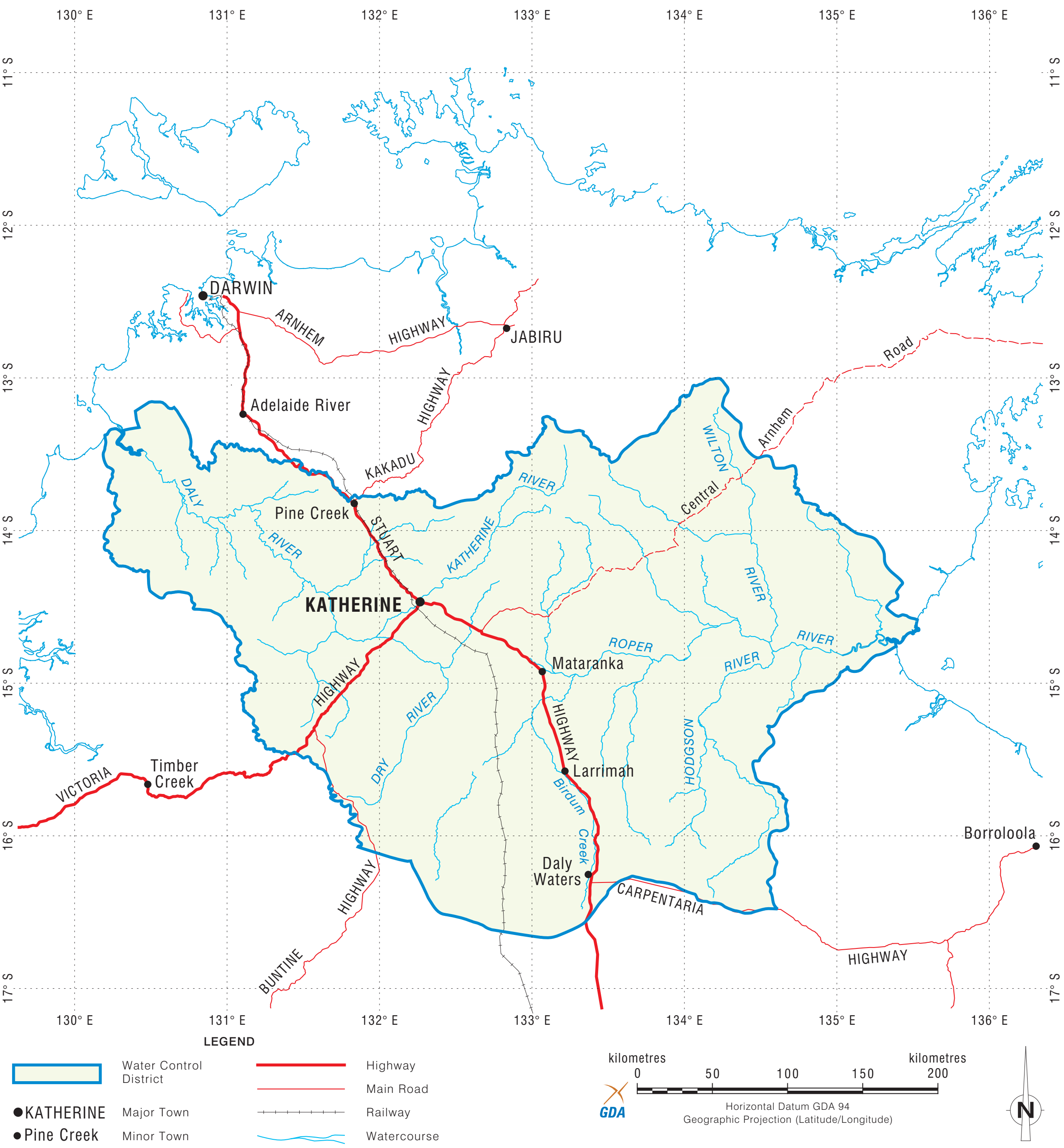
WCDs have been declared in areas of the NT where there is a need for improved management of water resources to avoid overusing groundwater, river flows, or wetlands. Currently, there are eight WCDs in the NT. Of particular relevance to this Inquiry is the Daly-Roper WCD covering the northern part of the Beetaloo Sub-basin (**Figure 7.6**)[48] and the Alice Springs WCD covering the western part of the Amadeus Basin.

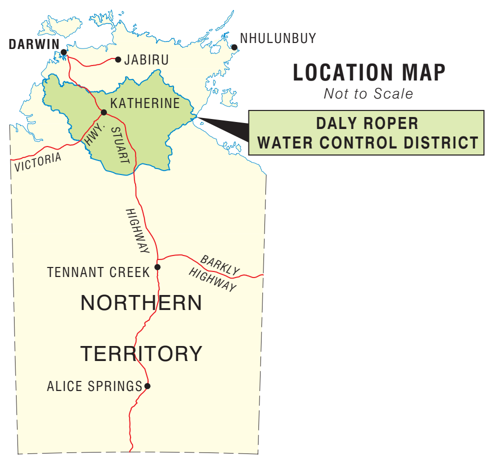
WAPs are developed in consultation with community and technical groups and outline how a water resource (for example, a river or an aquifer) is to be managed. They set out the objectives, rules and strategies, and monitoring and performance indicators for managing the water resource to maximise environmental, economic, social and cultural outcomes (a beneficial use).[49] WAPs set limits on the availability of water assigned to each beneficial use, and define rules for managing water licences (entitlements) and water trading.[50]

WAPs have been declared for Alice Springs, Western Davenport, Katherine and Berry Springs.[51] New WAPs are being prepared for Mataranka-Daly Waters, Oolloo, Howard and Ti Tree. Three WAPs will exist within the Daly-Roper Water Control District, Katherine, Oolloo and Mataranka-Daly Waters, with the latter covering the northern part of the Beetaloo Sub-Basin.[52]

41 WA EPA 2016.
42 WA EPA 2007; Humphreys 2006.
43 Queensland DSITI 2015.
44 Serov et al. 2012.
45 DENR submission 230, p 3.
46 DENR submission 230, p 4.
47 Water Act, s 22.
48 https://nt.gov.au/environment/water/water-control-districts.
49 https://denr.nt.gov.au/land-resource-management/water-resources/water-allocation-plans.
50 DENR submission 230, pp 1-7.
51 https://denr.nt.gov.au/land-resource-management/water-resources/water-allocation-plans.
52 DENR submission 230, p 6.

Figure 7.6: Daly-Roper water control district. Source: DENR.





Notes:

1. **Revocation:**
   Northern Territory Government Gazette No. G50 dated 17 December 2008 revoked on 8 December 2008 the Katherine Water Control District declared on 26 April 2007 and published in Gazette No. G19 dated 9 May 2007.
2. **Declaration:**
   Northern Territory Government Gazette No. G50 dated 17 December 2008 declared on 8 December 2008 the Daly Roper Water Control District.
3. **Purpose:**
   Daly Roper Water Control District declared for surface water and groundwater management purposes.

NORTHERN TERRITORY GOVERNMENT

The NT Water Allocation Planning Framework (**Framework**) provides a framework for how water must be allocated in the NT. The Framework requires that water be allocated first to non-consumptive purposes (that is, environmental and cultural purposes). Allocations for consumptive uses (that is, for agriculture and pastoral uses where the water does not return to the water resource system) are then made in respect of the remaining resource. In determining how much water should be allocated to consumptive and non-consumptive uses, the Framework provides that all available scientific data should be used. Where no scientific research is available, the Framework sets rules for how water is to be allocated. [53] For the Top End of the NT, these rules require that 80% of a river flow at any time, and at least 80% of the annual recharge of an aquifer must be allocated to the environment. For the arid zone (which includes the semi-arid zone), at least 95% of a river's flow at any time must be allocated to the environment, and for aquifers, there should be no deleterious change to groundwater dependent ecosystems, and total extraction over a period of at least 100 years should not exceed 80% of the total aquifer storage at the start of extraction.

The Government recently introduced a Strategic Aboriginal Water Reserve policy to provide Aboriginal people *"with increased opportunity to access water resources for their economic development. Strategic Aboriginal Water Reserves (SWRs) are a reserved percentage of water from the consumptive pool within a Water Allocation Plan area exclusively accessible to eligible Aboriginal people to use, or trade."* [54]

Many high yielding aquifers within the NT are close to full allocation against the prescribed contingent allocations.[55] 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.[56]

7.2.4.2 Application of the Water Act to petroleum activities

Petroleum activities (which would include the extraction of any onshore shale gas) are currently exempt from the application of certain provisions of the Water Act, including the requirement to have a water extraction licence (entitlement).[57] This also means that shale gas operations are not considered in WAPs. The exemption of shale gas developments has been the case since the introduction of the Water Act in 1992, reflecting Government's longstanding position that activities undertaken on petroleum tenements are appropriately regulated by petroleum legislation administered by DPIR.

On 18 November 2015, the previous Government announced its intention to amend the Water Act to remove this exemption so that the Water Act would also apply to mining and petroleum activities.[58] The current Government has also committed to remove the exemption to ensure that the mining and petroleum industries are subject to the same licence and permit requirements as all other water users.[59] To date, however, this amendment has not occurred.

If the Water Act is amended, the effect will be that gas companies will be required to obtain a water extraction licence for groundwater under s 30 of the Water Act. Gas companies would also require a licence from the Controller of Water Resources to drill or construct a water bore, discharge to a surface or groundwater system, build a dam or similar structure, interfere with a waterway, recharge an aquifer, or dispose of waste underground. The Water Act currently prohibits all these activities unless a person has a licence or exemption.

At this stage, it is unclear to the Panel what conditions the Controller of Water Resources would place on water extraction by gas companies should the relevant exemption under the Water Act be removed.

The Panel notes that under the current water legislation, water licences for consumptive uses are free, a situation that does not exist anywhere else in Australia.[60] The Panel is firmly of the view that the Water Act should be amended to require shale gas companies to acquire and pay for water extraction licences for their activities. For example, assuming that permanent licences for 3,000-5,000 ML /y of water are needed for the Beetaloo Sub-basin shale gas operations (see Section 7.3.1.4), at a possible cost of $1,000 per ML, this would raise $3 to $5 million for the Government.

53 DENR submission 230, Appendices A and B.
54 NT Government 2017c.
55 DENR submission 230, Appendices A and B.
56 DENR submission 230, p 6.
57 Water Act, s 7; DENR submission 230, p 7.
58 DENR submission 230, p 7.
59 DENR submission 230, p 10.
60 NWC 2015.

The Panel also notes a recent report by the Productivity Commission that the Water Act is still not compliant with the National Water Initiative. It recommended that, *"the Northern Territory should establish statutory-based entitlement and planning arrangements that provide for water access entitlements that are long-term, not tied to land, and tradable"*.[61]

Recommendation 7.1

That the Water Act be amended prior to the grant of any further exploration approvals to require gas companies to obtain water extraction licences under that Act.

Recommendation 7.2

That the Government introduces a charge on water for all onshore shale gas activities.

7.2.4.3 Petroleum Act

Currently, water use and extraction by gas companies is regulated under the Petroleum Act and supporting regulations. In terms of water extraction on a petroleum exploration permit, the Petroleum Act allows interest holders 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 program and other exploration"*.[62]

In the event that the water extraction in a petroleum permit area may have an adverse environmental impact, an environment management plan must be approved under the Petroleum Environment Regulations before the activity can proceed (see Chapter 14). It is open to the Minister for Resources to attach conditions to any approval of an environment management plan to ensure that the undertaking of the activity is consistent with the principles of ESD.[63]

At this stage, it is not clear what conditions the Minister would place on water extraction because the Minister has not considered any application under the Petroleum Environment Regulations to undertake hydraulic fracturing.

As noted above, the Panel has recommended that the Water Act be amended immediately, and in so doing, duplication in approvals for the same activity should be avoided.

7.2.4.4 EPBC Act

The *Environment Protection and Biodiversity Conservation Act 1999* (Cth) (**EPBC Act**) provides the legal framework to protect and manage nationally and internationally important flora, fauna, ecological communities, and heritage places. The Act can trigger a requirement for an environmental impact assessment of activities that are listed as having potential impact on matters of national environmental significance (**MNES**), including nationally threatened species and migratory species. If a MNES might be affected by a development, the project may require assessment under the EPBC Act.

In 2013, the Australian Government introduced a 'water trigger' into the EPBC Act through the *Environment Protection and Biodiversity Conservation Amendment Act 2013* (Cth). Specifically, this amendment provides that water resources are a MNES in relation to CSG and large coal mining development. An action that involves a CSG development or a large coal mine requires approval from the Commonwealth Minister for the Environment if that action has, will have, or is likely to have, a significant impact on a water resource. Currently, the water trigger in the EPBC Act does not apply to shale gas developments despite water resources clearly being of environmental significance to these developments. There is no good reason why that Act should not be amended to apply the water trigger to onshore shale gas.

Recommendation 7.3

That the Australian Government amends the EPBC Act to apply the 'water trigger' to onshore shale gas development.

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61 Productivity Commission 2017, p 24.
62 Petroleum Act, s 29(2)(d).
63 Petroleum Environment Regulations, cl 11(2)(a)(i).

7.3 Likely water requirements of any onshore shale gas industry in the NT

The onshore shale gas industry in Australia is still in its relative infancy, and the average volume of water needed to hydraulically fracture Australian shales is not as well known as the average volume required for CSG extraction.[64] The actual volume required for the hydraulic fracturing process in any given basin depends on the 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.

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,[65] although actual volumes can vary depending upon the particular conditions at a site, the length of the horizontal well, and the number of fracturing stages. For example, 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. This number has now increased to about 30 stages.[66] Origin has suggested that it will require 50-60 ML for drilling and stimulation per well in the Beetaloo Sub-basin, based on a 20-40 stage hydraulic fracturing program per well, while also noting that the industry is utilising longer laterals and an increased number of hydraulic fracturing stages.[67]

The water requirements for Origin's 2016 testing of the Amungee NW-1H well in the Beetaloo Sub-basin were consistent with this estimate, with approximately 11 ML required for the full 11-stage fracture stimulation program, and between 0.7 to 1.4 ML per stage.[68] Section 7.3.1.4 provides further details on the potential water requirements for drilling and hydraulic fracturing for a possible shale gas development in the Beetaloo Sub-basin.

DPIR has identified four major basins in the semi-arid and arid regions of the NT where onshore shale gas development could potentially take place (see Chapter 6).[69] Given that surface water resources typically only occur in these regions for a few months of the year, and even then only during large wet seasons, it is likely that groundwater will be the main water resource available for any onshore shale gas developments, at least in semi-arid and arid regions of the NT.

It is increasingly common practice for proponents to recycle as much of the flowback fluid from the hydraulic fracturing operations as possible.[70] This can comprise up to 30-80% of the water requirements for the operation, depending on the amount that reports as flowback,[71] and therefore, reduce the demand for groundwater. However, the extent to which this flowback water can be reused for hydraulic fracturing depends on its salt content and any residual chemicals. Origin, Santos and Pangaea Resources Pty Ltd (**Pangaea**) all expect to recycle in excess of 30% of the flowback fluid.[72] Origin has indicated that the composition of the flowback water from the Amungee NW-1H well would be compatible with reuse for subsequent hydraulic fracture operations.[73]

The Panel considers the major water use by any onshore shale gas industry would be for drilling and hydraulically fracturing. Although, as the Northern Land Council has indicated in its submission, the industry will need water for other uses including, *"water requirements for infrastructure, construction, dust suppression, maintenance and drinking".* [74]

64 ACOLA Report, p 114.
65 ACOLA Report, pp 113-114; US EPA 2016a, pp 4-10; APPEA submission 215, pp 45-46.
66 US EPA 2016a.
67 Origin submission 153, p 85.
68 Origin submission 153, p 86.
69 DPIR submission 226, p 2.
70 US EPA 2016a, Chapter 8.1.
71 US EPA 2016a, Chapter 8.
72 Origin submission 153; Santos submission 168, p 97; Pangaea submission 220, p18.
73 Origin submission 433, pp 20-26.
74 Northern Land Council, submission 471 (**NLC submission 471**), p 8.

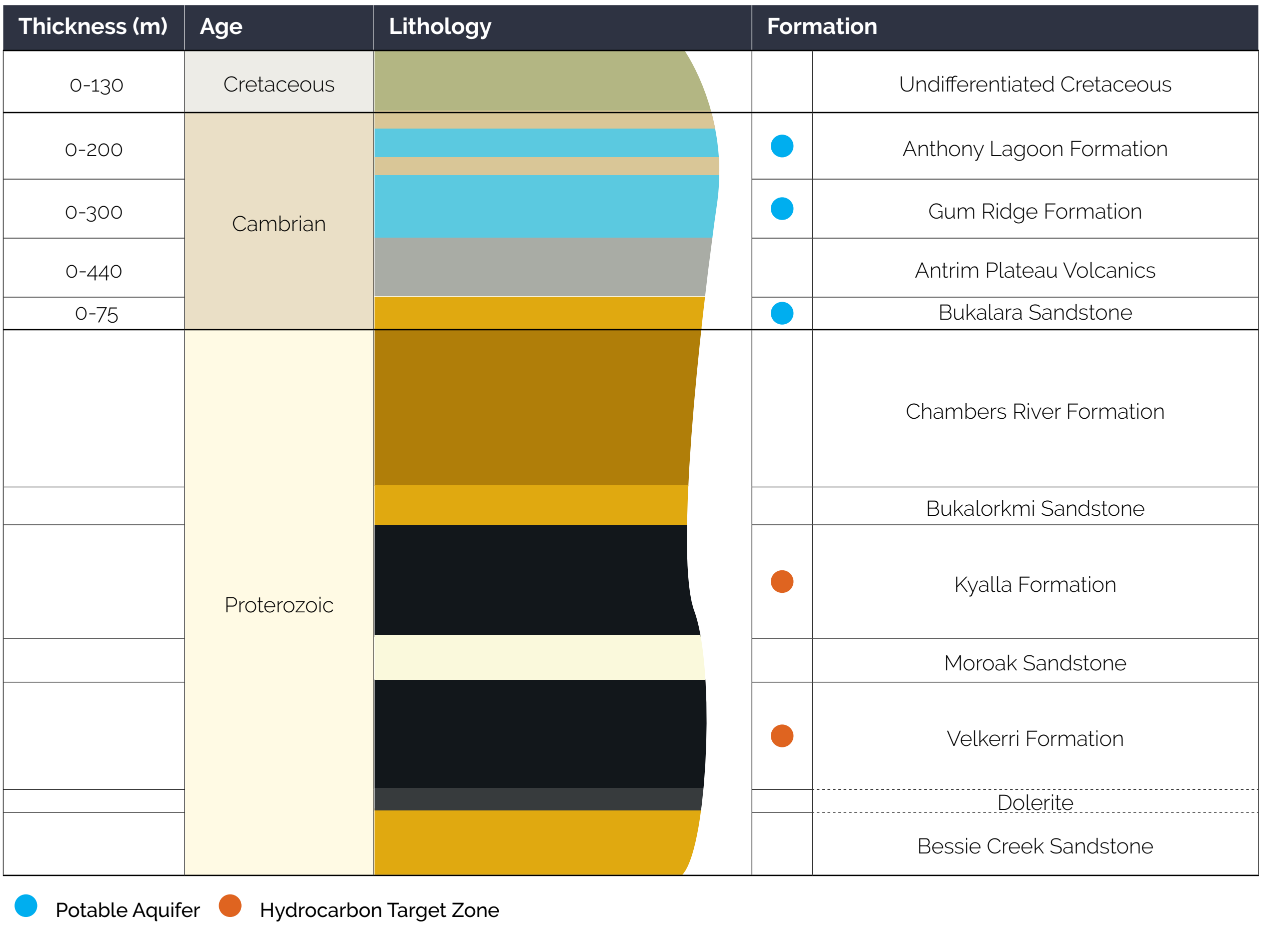
7.3.1 Beetaloo Sub-basin case study

7.3.1.1 General

As noted in Chapter 6, the Beetaloo Sub-basin is the most prospective shale gas region in the NT (**Figure 6.2**). It is also a region where groundwater resources have been relatively well studied, albeit with important knowledge gaps. As stated above, it is for this reason that the Panel has used the Beetaloo Sub-basin as a case study to better understand the water-related risks associated with any onshore shale gas industry in the NT.

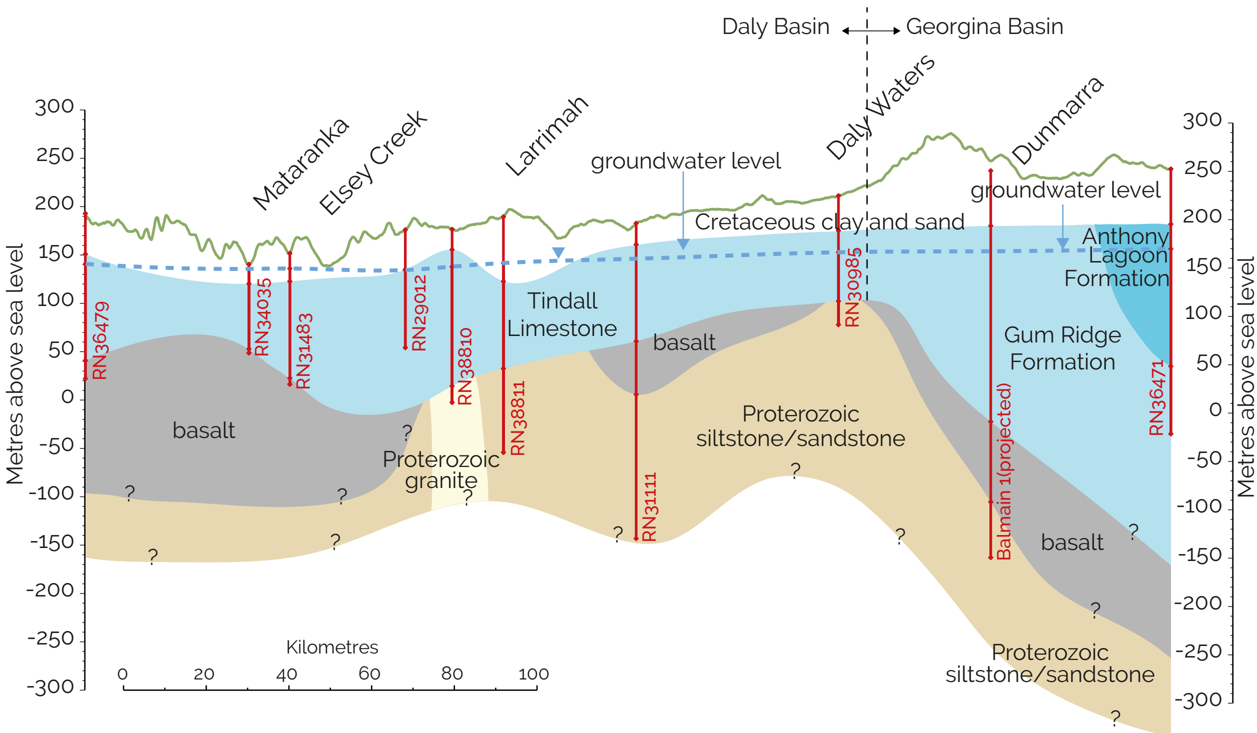
The Beetaloo Sub-basin is a subsurface basin within the broader McArthur Basin, with no surface expression or local outcropping of the rocks. The Sub-basin has a thickness of greater than 3,000 m below the overlying basins and the Sturt Plain (**Figure 7.7**). It underlies a relatively flat landscape (115-319 m Australian height datum (**AHD**)) and has an area of approximately 27,000 km². 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 800 mm in the north to around 600 mm in the south (**Table 7.1**). This rainfall is closely linked to the northern Australian monsoonal system, and falls largely between December and March each year.

Figure 7.7 (a): Stratigraphic section of the Beetaloo Sub-basin region showing the relative positions of the Anthony Lagoon Formation and Gum Ridge Formation aquifers. Source: Origin.[75]



75 Origin submission 153, p 54.

Figure 7.7 (b): Geological cross section from Mataranka to south of Daly Waters of the Cambrian Limestone Aquifer, showing the Tindall Limestone, the Gum Ridge Formation and the Anthony Lagoon Formation. Source: Tickell 2015.[76]



The Panel has received submissions from Imperial Oil and Gas and Hancock Prospecting Pty Ltd (**Hancock Prospecting**) expressing concern that they may be disadvantaged if only the Beetaloo Sub-basin is considered for the development of any onshore shale gas industry.[77] Imperial Oil and Gas argues that it has viable shale gas reservoirs covered by exploration permits in the McArthur Basin Central Trough.[78] Hancock Prospecting has two exploration permits (EP 153 and EP 154) east of Mataranka and outside the area of Beetaloo Sub-basin (see **Figure 6.6**).

Imperial Oil and Gas and Hancock Prospecting have also argued that the boundary marked on **Figure 6.6** is arbitrary and that additional drilling is likely to show the shale resource extending further to the north.[79] They also note that the Northern Territory Geological Survey is conducting work in this region. Hancock Prospecting EP 154 is close to the Roper River and Elsey National Park, and it is undoubtedly for this reason that Hancock Prospecting has informed the Panel that it will relinquish portions of EP 154 to allow a 25 km buffer from the Mataranka Hot Springs and the Roper River and a 15 km buffer from Elsey National Park.[80] Hancock Prospecting has indicated to the Panel that these buffer zone distances *"were a subjective assessment … of the distance required to provide comfort to the community that these areas were not at risk, rather than any reference to any scientific rationale."*[81] In response to the Panel's questions, Hancock Prospecting provided references to studies suggesting that hydraulic fracturing of shale gas resources was unlikely to cause problems to surface water aquifers.[82] However, these studies are not specific to the area covered by Hancock Prospecting's EP. Additionally, Hancock Prospecting has not provided any evidence that its use of the groundwater resources would not adversely affect groundwater-dependent ecosystems in this region (for example, Mataranka Hot Springs). The Panel also notes that Mataranka business owners, residents and Aboriginal communities have rejected this suggested buffer zone as *"not enough"*.[83]

76 Tickell 2015.
77 Imperial Oil and Gas Pty Ltd, submission 300 (**Imperial Oil and Gas submission 300**), p 5; Hancock Prospecting Pty Ltd, submission 461 (**Hancock Prospecting submission 461**).
78 Imperial Oil and Gas Pty Ltd, submission 408 (**Imperial Oil and Gas submission 408**).
79 Imperial Oil and Gas submission 300, p 5; Hancock Prospecting submission 461.
80 Hancock Prospecting submission 461, pp 1-2.
81 Hancock Prospecting Pty Ltd, submission 645 (**Hancock Prospecting submission 645**), p 3.
82 Hancock Prospecting submission 645, p 3.
83 The Katherine Times, 27 September 2017, p 7.

Mataranka Falls. Source: Max Rawlings.

7.3.1.2 Surface water

The Beetaloo Sub-basin consists of three surface water drainage basins (**Figure 7.3 (b)**):[84]

- first, the internally draining Newcastle Creek and Bucket Creek system that ends in Lake Woods;
- second, the north-west flowing Western Creek and Birdum Creek system that drains into Elsey Creek and then into the Roper River; and
- third, the largely east flowing creeks that drain towards the Gulf of Carpentaria, including Limmen Bight River, October Creek and Cox River.[85]

Although these creeks flow only for short periods during the wet season, there can be substantial flows and flooding depending upon the wet season, as is shown by the modelled one-in-10-year and one-in-100-year flood flows in Newcastle Creek, Daly Waters Creek and Elsey Creek in **Table 7.3**. Additionally, **Figure 7.8** shows the modelled extent of flooding for a one-in-100-year flood event, primarily for Newcastle Creek.[86] Ms Pauline Cass[87] provided information to the Panel to make the point that the Beetaloo Sub-basin is prone to severe storms and flooding during the wet season, making access to well pads and infrastructure difficult during these times, and also making wastewater ponds at risk of overflowing.

84 DENR submission 449; Gautam 2017, p 9, Fig 3.1.
85 Santos submission 168, pp 50-51. The headwaters of these streams are associated with the Santos EP161, located on the eastern edge of the Beetaloo Sub-basin.
86 DENR submission 449; Gautam, 2017, pp 10-14.
87 Ms Pauline Cass, submission 1152, p 2.

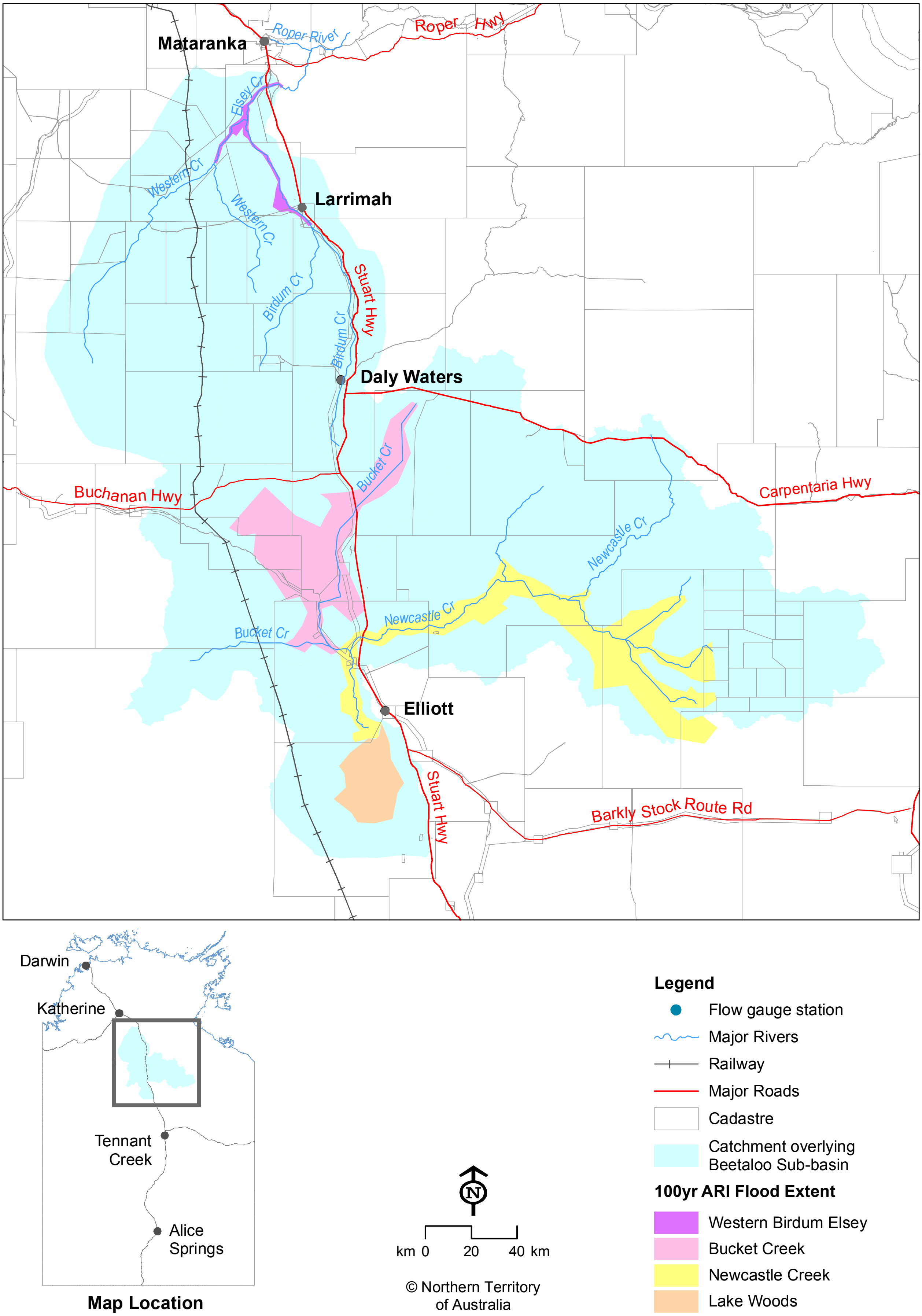
High flow in Newcastle Creek. Source: Dr. Matt Bolam.

Table 7.3: Flood frequency analysis for major creeks in the Beetaloo Sub-basin. Flows in ML/d. See **Figure 7.3** for gauging station locations. Source: DENR.[88]

	Newcastle Cr at Stuart Highway (G0280009)	Daly Water Cr (G9030124)	Elsey Cr at Warlock Ponds (G9030001)
1:100-year flow	362,000	12,000	126,000
1:10-year flow	53,000	2,200	26,000

88 DENR submission 449.

Figure 7.8: The extent of a 1:100 year flood in Newcastle and Bucket Creeks. Source: DENR.



NORTHERN TERRITORY GOVERNMENT

The CLA is critical for maintaining baseflow in the Roper River system and for sustaining Elsey National Park, Mataranka thermal pools, Red Lily Lagoon, and the riparian vegetation along the Roper River beyond the Beetaloo Sub-basin.[89] The Tindall aquifer extension of this system to the northwest also maintains base flow in the Daly River. However, the Panel has very little information on the location, hydrological characteristics and ecology of temporary water bodies more broadly in the Beetaloo Sub-basin. An exception is the recent report on the biology of Longreach Waterhole[90]. The Panel has recommended that this information be obtained as part of a SREBA (see Section 7.4.3 and ***Recommendation 7.5***).

7.3.1.3 Groundwater

The limestone formations, including the Tindall Limestone in the Daly Basin, the Montejinni Limestone in the Wiso Basin and the Gum Ridge Formation in the Georgina Basin, host the majority of the groundwater resources in the region (**Figure 7.4**).[91] However, no hydrogeological distinction is made between each of the formations, and they are considered to constitute a single, extensive aquifer system: the CLA.[92]

The Beetaloo Sub-basin groundwater system consists of two parts: east and west of the Stuart Highway (**Table 7.2**).[93] Groundwater systems hosted in the Georgina (east) and Wiso (west) Basins, respectively, overlie these parts. East of the Stuart Highway, the Georgina Basin hosts two groundwater systems: an upper system within the Anthony Lagoon Formation and a lower system within the limestones of the Gum Ridge Formation. To the west of the Stuart Highway, the Wiso Basin in the Sturt Plateau region is mostly shallow and hosts a single thin aquifer in the Montejinni Limestone.[94] In much of the Georgina Basin, the Gum Ridge aquifer occurs below the Anthony Lagoon Beds, approximately 35-220 m (average 105 m) below the surface (**Figure 7.7 (b)**).[95] 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 7.4**. It has been reported that the flow is greater in the north (steeper hydraulic gradient) and that the lower hydraulic gradient in the south is due to the more limited recharge due to lower rainfall. Groundwater flow rates vary considerably from tens of m/y around Katherine to 1 m/y and less in the Beetaloo Sub-basin.[96]

The Panel has been informed by DENR that no monitoring of groundwater levels is currently undertaken in either the Anthony Lagoon Formation or Gum Ridge Formation aquifers and *"hence, there is no knowledge of the behaviour and response to seasonal or event based recharge to the Anthony Lagoon Formation aquifer. Any inference of recharge in the Gum Ridge (Tindall Limestone) Formation basin is made through assessment of groundwater quality data and water isotope analysis which indicate fresher and younger groundwater on the western margin of the basin (approximately parallel to the Stuart Highway)."* [97]

An estimated 800 registered water bores in the Beetaloo Sub-basin[98] extract around 6,000 ML/y of groundwater, presumably from the shallow CLA, with most of this used for stock watering.[99] This aquifer also provides domestic water for several Communities, including Elliott, Newcastle Waters, Daly Waters and Larrimah. Just north of the Beetaloo Sub-basin, the towns of Mataranka and Katherine 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.[100]

There is limited information about the groundwater systems in rocks underlying the CLA and their connectivity with this groundwater system.

89 Bruwer and Tickell 2015; A Knapton submission 426.
90 Dr. Matthew Bolam, submission 523; Eldridge and Schubert 2017.
91 DENR submission 428, pp 7-8.
92 DENR submission 428, p 7.
93 DENR submission 428, p 8.
94 Fulton and Knapton 2015; Bruwer and Tickell 2015; GHD 2016; DENR submission 428, p 8.
95 DENR submission 428, p 8; Fulton and Knapton 2015, pp 38-40.
96 Department of Environment and Natural Resources, Submission 429 (**DENR submission 429**), pp 2-4.
97 DENR submission 230, p 2.
98 Origin submission 153, p 46.
99 Fulton and Knapton 2015.
100 DPIR submission 226, Addendum 2.

Water bore.

Groundwater processes

Knowledge of the recharge rate of an aquifer is important because it is used by water resource management agencies to estimate the 'sustainable yield' of an aquifer, that is, the volume that can be extracted annually for consumptive uses without causing short- or long-term adverse impacts on the aquifer.

Details of the processes controlling recharge of the majority of the CLA are poorly known,[101] 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. DENR suggests that recharge through the soil matrix only occurs if the total annual rainfall exceeds around 700 mm/y.[102] Bruwer and Tickell found that the observed groundwater levels around Mataranka (rainfall 1,035 mm/y) were seasonally responsive, while those at Larrimah (rainfall 860 mm/y) showed a muted response to rainfall.[103]

For the most studied northern part of the CLA, between Mataranka and Daly Waters, the recharge rate has been estimated at between 100,000 ML/y and 300,000 ML/y.[104] Jolly et al. derived a recharge rate of around 100,000 to 130,000 ML/y, largely on the basis of the dry season flow in the Roper River, assuming this is entirely groundwater fed.[105] However, Bruwer and Tickell used a number of empirical approaches to estimate a higher recharge rate for the region between Mataranka and Daly Waters of around 330,000 ML/y over the past 30 years.[106]

The area around Mataranka (that is, up to around 20 to 40 km away from the springs and Roper River area) has very different hydrogeology to that in the Beetaloo Sub-basin. The hydrogeological environment of the Beetaloo Sub-basin is characterised by a deep water table, thick unsaturated zone, intervening clay strata and lower rainfall, and therefore, recharge. The environment around Mataranka is dominated by weathered Tindall Limestone with a thin cover of Cretaceous sandstone, a shallower water table, a thinner unsaturated zone, and reduced clayey strata in the unsaturated zone, and a higher rainfall.[107]

101 Fulton and Knapton 2015, p 37.
102 DENR submission 428, p 12.
103 Bruwer and Tickell 2015, pp 32, 35.
104 Jolly et al. 2004; Bruwer and Tickell 2015; Fulton and Knapton 2015, p 38.
105 Jolly et al. 2004.
106 Bruwer and Tickell 2015.
107 Bruwer and Tickell 2015; A Knapton submission 426, p 3.

There is also evidence for preferential pathways from the surface to the groundwater as the geological environment around Mataranka is similar to that around Katherine with karstic formations and sinkholes evident.[108] The thinner and more permeable unsaturated layer, the possible preferential pathways, and the higher rainfall all contribute to the higher recharge of groundwater in this area.[109] Estimating recharge rates for surface aquifers in the southern region of Beetaloo Sub-basin from Daly Waters to Elliott is complicated due to the two-aquifer system in this region (that is, the Anthony Lagoon Formation aquifers overlying the Gum Ridge aquifers (**Figure 7.7 (b)**) and the lower rainfall (**Table 7.1**).[110] Geoscience Australia has noted that. *"there is reasonable data and understanding of the groundwater system north of Daly Waters, but very sparse data south of Daly Waters"*.[111]

Tickell and Bruwer suggest that the Anthony Lagoon Formation aquifers are most likely recharged through two possible mechanisms: direct infiltration of rainfall, or the infiltration of standing surface water accumulated in the shallow chain of lakes on the Barkly Tablelands following large rainfall events.[112]

Direct infiltration recharge to the Gum Ridge aquifers between Daly Waters and Elliott is not likely due to the confining sediments of the Anthony Lagoon Formation. Bruwer and Tickell suggest that the most likely recharge mechanism is through the sediments of the Ashburton Range, which forms the western boundary of this aquifer. Water quality analyses and carbon dating of groundwater in the Gum Ridge Formation support this mechanism, as fresher and younger groundwater occurs in the aquifer parallel to the western contact zone.[113]

The most recent information available to the Panel indicates that because of the very low hydraulic gradient and low recharge, the rate of groundwater flow over the bulk of the Beetaloo Sub-basin is unlikely to exceed 1 m/y.[114] This slow rate of movement has important implications for the design of monitoring systems as well as for assessing the risk likely to be posed by any contamination of the groundwater (see Sections 7.6.1, 7.6.2 and 7.6.3). By contrast, further to the north and closer to the discharge zone into the Roper River, the flow velocity has been estimated to be as high as 1,000 m/y.[115]

As noted earlier, both Geoscience Australia and CSIRO are currently undertaking regional and local-scale studies to improve understanding of recharge mechanisms and total aquifer storage and sustainable yield in the Beetaloo region. Unfortunately, these studies are not scheduled for completion in time for the Inquiry to deliver this Report.

Water quality

The near surface (that is 100-200 m deep) groundwater quality within the Beetaloo Sub-basin is quite good.[116] In the underlying Gum Ridge Formation, the total dissolved salts (**TDS**) concentration is around 500 mg/L, while the overlying Anthony Lagoon aquifer is saltier (TDS around 1,000 mg/L), but is used by pastoralists for stock watering because of the extra cost of having to drill into the deeper (lower salinity) Gum Ridge aquifer.

Fulton and Knapton and Tickell and Bruwer have summarised water quality data for the major groundwater basins, including the Beetaloo Sub-basin.[117] The major ion concentrations for the Gum Ridge and Anthony Lagoon aquifers in the Beetaloo Sub-basin are shown in **Table 7.4**. Both aquifers display a Na-Ca-Mg cationic signature and a HCO_3-SO_4 anionic signature. The high proportion of Ca-Mg-HCO_3 is expected in these limestone and dolomite aquifer systems.[118]

As discussed further in Section 7.5.2, it is possible that the gas companies could use deeper, poorer quality groundwater for hydraulic fracturing.

108 Karp 2008; A Knapton submission 426, p 3.
109 Bruwer and Tickell 2015; A Knapton submission 426, p 3.
110 DENR submission 428, p 14; Tickell and Bruwer 2017, pp 35-45.
111 Geoscience Australia Submission 414, p 5.
112 Tickell and Bruwer 2017, pp 19-21.
113 DENR submission 428, p 14; Tickell and Bruwer 2017.
114 DENR submission 429, pp 2-3.
115 A Knapton submission 426, p 2; Karp 2005; Karp 2008.
116 Fulton and Knapton 2015, p 38.
117 Fulton and Knapton 2015, p 39; Tickell and Bruwer 2017, pp 23-31.
118 Fulton and Knapton 2015, p 40.

Table 7.4: Groundwater quality of Beetaloo Sub-basin aquifers. Source: Fulton and Knapton 2015, Tickell and Bruwer 2017.[119]

Aquifer	No of samples	Conductivity (uS/cm)	Lab pH (mean)	Major ion concentration (mg/L)*					
				Na	Ca	Mg	HCO_3	SO_4	Cl
Gum Ridge	144	350-3000 (1390)	7.5	2-440 (130)	16-200 (86)	11-116 (53)	56-680 (440)	6-650 (150)	2-620 (160)
Anthony Lagoon	86	670-6470 (1590)	7.6	9-380 (150)	12-300 (88)	25-134 (57)	86-530 (330)	18-980 (230)	16-570 (210)

* mean concentration in brackets

Groundwater dependent ecosystems

There is insufficient information concerning GDEs in the Beetaloo Sub-basin or elsewhere in the NT. The SREBA recommended in Section 7.4.3 seeks to address this knowledge gap.

DENR suggests that groundwater dependent surface ecosystems are unlikely to occur in the Beetaloo Sub-basin because the groundwater table in this region is typically greater than 30 m deep and is not connected to the surface.[120] However, the Panel is not aware of any systematic survey to locate groundwater dependent surface ecosystems in this region and that it is possible that some may be present.

It is also possible that stygofauna are present in these aquifers, but again the Panel has not been able to identify any studies of stygofauna in that region. The potential importance of stygofauna has been highlighted in at least one submission.[121] Given the karstic nature of the landscape, the Panel's view is that there is considerable likelihood of groundwater dependent (including stygofauna) or groundwater influenced ecosystems associated with springs, sinkholes, caves and preferential groundwater flow pathways in the Beetaloo Sub-basin. Such groundwater dependent ecosystems are likely to be susceptible to excessive groundwater use and any contamination from shale gas hydraulic fracturing operations.[122]

As noted above, the Daly and Roper river systems are important groundwater dependent ecosystems. Their flows during the dry season are sustained by groundwater discharges from the CLA.[123] Although the Roper River system is outside the Beetaloo Sub-basin, concern has been expressed that this system could be adversely affected if the quantity or quality of the aquifer discharging into this system was influenced by any shale gas industry in the Beetaloo Sub-basin.[124] The Panel's assessment of the risks to surface and groundwater dependent ecosystems are contained in Section 7.7.

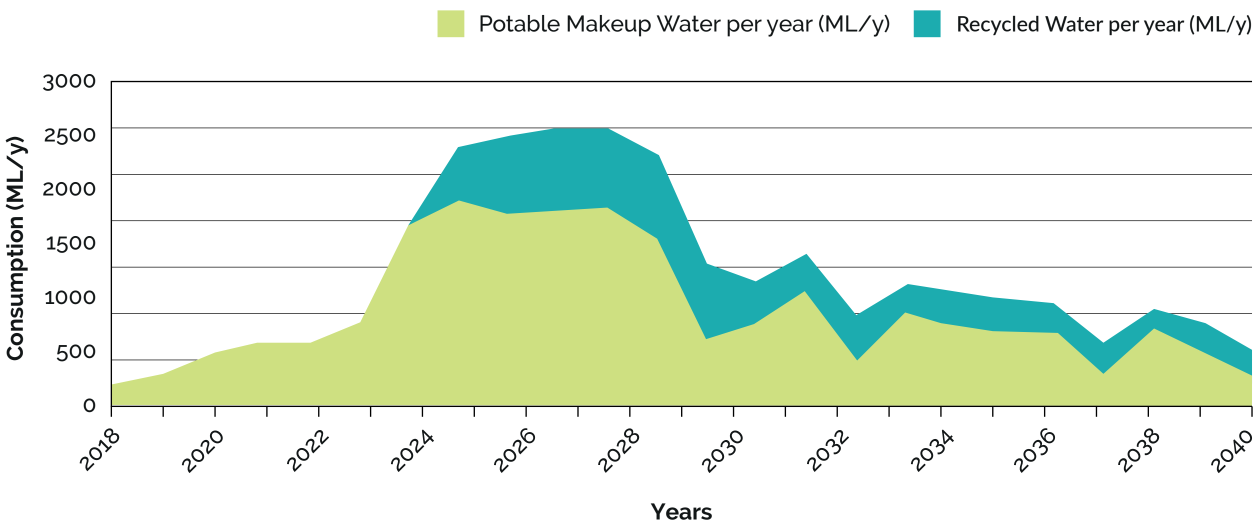
7.3.1.4 Possible development scenarios

The three petroleum companies currently with exploration activity in the Beetaloo Sub-basin, Origin, Santos and Pangaea, have provided the Panel with various possible onshore shale gas development scenarios.[125] Their estimates suggest a combined development over the next 25 years that could result in some 1,000 to 1,200 wells, associated with approximately 150 well pads.[126]

The development scenario proposed by the petroleum industry will require an average of 2,500 ML/y (up to 5,000 ML/y at peak demand) of water for well drilling and hydraulic fracturing,[127] or a total of 20,000-60,000 ML from the aquifer system over the 25 years. Origin provided indicative water requirements for a 450 well shale gas operation over 25 years, which will require an average of around 1,200 ML/y, reaching a maximum of around 2,500 ML per year between years five and nine (**Figure 7.9**).[128]

119 Fulton and Knapton 2015; Tickell and Bruwer 2017.
120 DENR submission 230, Addendum 1.
121 Stygoecologia Australasia, submission 407 (**Stygoecologia submission 407**).
122 A Knapton submission 426, p 2.
123 Bruwer and Tickell 2015.
124 Mr Michael Somers and Mrs Glenys Somers, submission 377 (**Somers submission 377**), p 1; A Knapton submission 426, p 2.
125 Origin submission 153, p 36; Santos submission 168, p 35; Pangaea submission 220, p 21.
126 Assuming eight horizontal wells per pad.
127 This assumes around 1-2 ML would be required for the drilling of each well and 1-2 ML for each hydraulic fracture stage or around 10-20 ML for a 10-stage stimulation of each well.
128 Origin submission 153.

Figure 7.9: Indicative water requirements for a 450 well shale gas operation over 25 years. Note this assumes 30% recycling of flowback water. Source: Origin.[129]



DPIR has also provided the Panel with estimates of the size of a potential onshore shale gas industry, and its water use, in the NT.[130] DPIR envisages a larger shale gas industry, possibly around 6,250 wells, for the Beetaloo Sub-basin,[131] although it should be noted that DPIR estimates do not include any assessment of the economic viability of the onshore gas industry, and are based solely on potential supply, rather than demand, scenarios with no cogent evidence supporting this estimate.[132] A development scenario that produces 53,250 PJ of gas over 40 years (around 6,250 wells, about 420 well pads), with each well producing 8 PJ of gas, would require 125,000 ML of water over the 40 years (or around 3,000 ML per year), assuming that each well requires 25 ML of water and that there is a 20% recycle rate.

7.4 Assessment of water-related risks

7.4.1 General

The Petroleum Environment Regulations[133] require that an environment management plan (**EMP**)[134] must be prepared and approved by the Minister for Resources prior to commencing hydraulic fracturing, because it is *"regulated activity"*.[135] The EMP must include an environmental risk assessment and strategies[136] to ensure that:

- onshore oil and gas activities are carried out in a manner consistent with the ESD principles; and
- environmental impacts and risks associated with onshore oil and gas development activities are reduced to a level that is ALARP and acceptable.

The Panel has used the risk assessment methodology set out in Chapter 4. For the purposes of describing the 'consequence' and 'likelihood' levels that are 'low', 'medium' and 'high', the Panel has developed the descriptions in **Table 7.5**.

129 Origin submission 153, p 86.
130 DPIR submission 226, Addendum 1.
131 DPIR submission 226, Addendum 1, p 4.
132 DPIR submission 424, p 7; DPIR submission 226, Addendum 1.
133 Petroleum Environment Regulations Guide.
134 Petroleum Environment Regulations Guide, p 20.
135 Petroleum Environment Regulations, cl 5.
136 Petroleum Environment Regulations Guide, p 26.

Table 7.5: Acceptability criteria adopted for the water-related risks.

Environmental value		Environmental objectives	Acceptability criteria
Water quantity	Surface water	To ensure surface water resources are used sustainably.	Low likelihood that water use will exceed 20% of flow at any time.(1)
	Groundwater - regional	To ensure ground water resources are used sustainably.	Low likelihood that water use will exceed 20% of the 'sustainable yield' at any time.(1)
	Groundwater - local	To ensure ground water resources are used sustainably.	Low likelihood that drawdown of water supply bores within 1 km of shale gas development will be greater than 1 m.
Water quality	Surface water	To maintain acceptable quality of surface water resources.	Low likelihood that any toxicant will exceed the NHMRC drinking water guidelines (human health) or ANZECC water quality guidelines (stock drinking, agriculture).(2)
	Groundwater	To maintain acceptable quality of groundwater resources.	Low likelihood that any toxicant will exceed the NHMRC drinking water guidelines (human health) or ANZECC water quality guidelines (stock drinking, agriculture) in water supply bores.(2)
Aquatic ecosystems	Surface water - use	To protect surface water dependent ecosystems.	Low likelihood that water use will exceed 20% of flow at any time.(1)
	Surface water - quality	To protect surface water dependent ecosystems.	Low likelihood that any toxicant will exceed the applicable ANZECC water quality guidelines for protection of aquatic life.(2)
	Groundwater - quality	To protect groundwater dependent ecosystems.	Low likelihood that any toxicant will exceed the applicable ANZECC water quality guidelines for protection of aquatic life.(2)
Aquatic biodiversity	Surface and groundwater resources	To protect surface water and groundwater aquatic biodiversity.	No significant long-term change in aquatic biodiversity.

(1) DENR water allocation rules (DENR submission 230, Appendix A and B).
(2) Note: some toxicity of some chemicals in shale gas wastewater to human health, stock or aquatic ecosystems are not yet known.

There are a number of national and international guidelines and standards for human and environmental risk assessment that can be used to guide the development of risk assessments for onshore shale gas developments. These include:

- Standards Australia/Standards New Zealand, Risk management - principles and guidelines;[137]
- Standards Australia/Standards New Zealand, Managing environment-related risk;[138]
- *Environmental Health Risk Assessment: Guidelines for assessing human health risks from environmental hazards;*[139]
- *Environmental risk assessment guidance manual for industrial chemicals;*[140]
- *Environmental risk assessment guidance manual for agricultural and veterinary chemicals;*[141] and
- *Chemical Risk Assessment Guidance Manual: for chemicals associated with coal seam gas extraction.*[142]

137 AS/NZS 2009.
138 AS/NZS 2012.
139 enHealth 2012.
140 EPHC 2009a.
141 EPHC 2009b.
142 Australian Department of the Environment and Energy 2017a-f.

Other useful guidelines and tools include:

- *National Environment Protection (Assessment of Site Contamination) Measure;*[143]
- *Australian and New Zealand Guidelines for Fresh and Marine Water Quality;*[144]
- *Australian Drinking Water Guidelines;*[145]
- The US EPA Risk Tools and Databases;[146]
- *OECD Environmental Risk Assessment Toolkit: Tools for environmental risk assessment and management;* [147]and
- *Inventory Multi-tiered Assessment and Prioritisation* (**IMAP**) *framework* through NICNAS.[148]

Together, these documents provide useful guidance on how to undertake detailed and robust human and environmental risk assessments for any onshore shale gas development in the NT, even if not specifically tailored to that industry.

7.4.2 Example environment risk assessments

The Panel has reviewed a number of relevant risk assessments with a view to providing advice on 'world leading practice' environmental risk assessment for any onshore shale gas development. Only one of these assessments was directly relevant to any hydraulically fractured onshore shale gas operations in the NT. The Panel has also reviewed a number of human health risk assessments in Chapter 10 (Section 10.1.1.4), again for the purpose of providing advice on world leading practice in respect of these assessments. Somewhat disturbingly, Lane and Landis report that in the US, only three environmental risk assessments have been published, despite the huge increase in hydraulically fractured wells over the past decade or so.[149]

7.4.2.1 Santos

Santos provided two human health and environmental risk assessments that the company had conducted for its Gladstone Liquified Natural Gas Queensland CSG project for drilling fluids and hydraulic fracking fluids.[150] A similar chemicals risk assessment for the Santos Narrabri CSG project is also available.[151] While these assessments were not directly relevant to shale gas, and did not fully consider all the potential exposure pathways, the Panel considers them to have used an appropriate approach for assessing the risk of water contamination by any onshore shale gas industry in the NT. The methodology used was consistent with Australian and international (primarily European REACH, WHO and US EPA) guidance documents and protocols,[152] and was an example of the type of formal risk assessment that could be used by the industry to better assess the risks for onshore shale gas in the NT context. That is, the risk assessment considered the compositions of hydraulic fracturing fluid mixtures, and flowback and produced waters in terms of their human and environmental toxicology, and considered in detail the probability of exposure of the various receptor species or groups of people to those waters through those pathways.

7.4.2.2 Origin

Origin has submitted to the Panel its EMP for the Amungee NW-1H hydraulic fracturing operation undertaken in 2016.[153] As part of this EMP, Origin commissioned AECOM Australia Pty Ltd (**AECOM**) to undertake a risk assessment for the hydraulic fracturing test program at the Amungee NW-1H well in the Beetaloo Sub-basin.[154] This used a similar methodology to the Santos risk assessments described above.

The AECOM risk assessment evaluated the toxicity of the individual chemicals used in the hydraulic fracturing process and estimated the cumulative risks of the total fluid mixture to humans, and terrestrial and aquatic biota. It also assessed the flowback waters using the

143 NEPC 2013.
144 ANZECC 2000.
145 NHMRC 2016.
146 US EPA 2017c.
147 OECD 2015.
148 https://www.nicnas.gov.au/chemical-information/imap-assessments.
149 Lane and Landis 2016.
150 Santos 2016a.
151 Santos 2016b.
152 Santos Ltd, submission 280 (**Santos submission 280**), pp 109-111, 134-135.
153 Origin submission 153.
154 Origin Energy Ltd, submission 466 (**Origin submission 466**).

measured chemical composition, which included the chemicals (geogenics) leached from the deep shale formation. The methodology incorporated an assessment of potential exposure routes to humans and environmental biota, with the following identified as the only potentially complete exposure pathways:

- incidental ingestion and dermal contact of flowback fluid by human trespassers at the flowback fluid storage ponds; and
- potential releases of flowback fluid to aquatic environments.

The Panel is critical of this risk assessment insofar as possible exposure pathways were excluded as not being complete (that is, one or more steps in the exposure pathway were assessed to be missing). But, surprisingly, based on the assumed success of the risk mitigation measures that Origin proposed, AECOM assessed that there were no pathways by which hydraulic fracturing chemicals could have an impact on beneficial groundwater in the project area. AECOM did assess that potential impacts to surface water ecosystems could occur if substantial releases of flowback water from the above ground flexi-ponds, due to integrity or piping failure or overflow due to high rainfall, resulted in overland flow to surface water bodies, but it found likelihood of that occurring as low due to the type of storage units used and the leak detection systems employed. Not surprisingly, given the very limited scope of this risk assessment, AECOM assessed the overall risk to human health and environment associated with the chemicals involved in hydraulic fracturing at the Amungee well as 'low'. It should be noted that this assessment, while designed to be somewhat generic, was developed for an exploration well, and was not a risk assessment for a multi-well production pad for a fully developed operational onshore shale gas production field.

7.4.2.3 National Chemical Risk Assessment

The Panel also received a submission of human health and environmental risk assessments and associated exposure pathway conceptualisations from the Commonwealth Department of the Environment and Energy,[155] the NCRA. The NCRA considers the potential risks to the environment (surface and near surface water environments) and human health of the 113 chemicals identified as being used for CSG extraction in Australia in the period 2010 to 2012.[156] The focus of the assessment is on the impacts of surface discharges (spill or leaks) on surface water and near-surface groundwater extending to potential down gradient effects on surface water through overland flow or discharge of the shallow groundwater into surface waterways. The concentration on surface issues is based on international experience that indicates the surface is the highest risk pathway for activities associated with the extraction of onshore shale gas.

Although scenario-based rather than fully probabilistic, and also for CSG and not shale gas, these risk assessments demonstrate that detailed assessments for any onshore shale gas development in the NT is both feasible and desirable. The package of products from the NCRA includes a national guidance document that provides world leading practice advice on approaches for human and environmental risk assessments for the coal and coal seam gas industries.[157]

In particular, the new risk assessment guidance specifies that naturally occurring geogenic chemicals mobilised by drilling or hydraulic fracturing, and found in drilling fluids and drilling muds, flowback and produced water, brines, and treated water, should be included as an essential component of any risk assessment. Also included are recommendations for direct toxicity assessments of complex mixtures, such as fracking fluids and produced waters, where use of toxicity values for individual chemicals may either overestimate or underestimate the toxicity of the mixture.[158] The approaches outlined in this guidance document could be readily adapted for any development of any onshore shale gas industry in the NT.

Recommendation 7.4

That the Government develops specific guidelines for human health and environmental risk assessments for all onshore shale gas developments consistent with the National Chemicals Risk Assessment framework, including the national guidance manual for human and environmental risk assessment for chemicals associated with CSG extraction.

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155 Australian Department of the Environment and Energy 2017a-f.
156 Australian Department of the Environment and Energy 2017a-f.
157 Australian Department of the Environment and Energy 2017a-f.
158 Australian Department of the Environment and Energy 2017a-f.

7.4.3 Strategic regional environmental and baseline assessment (SREBA)

As noted above, the Panel has sought to assess the water-related risks using the risk assessment framework detailed in Chapter 4. However, in attempting to do this, it is apparent that available knowledge and data on the NT's water resources (surface and groundwater) and their associated aquatic ecosystems is presently insufficient to permit the risks associated with the development of any onshore shale gas industry in the NT to be assessed with certainty. Accordingly, the Panel has applied the precautionary principle when developing its recommendations to mitigate risks.

It is therefore the Panel's view that there is a need for a SREBA so that the environmental impacts and risks associated with the development of any prospective onshore shale gas basin in the NT are fully understood and can be appropriately managed. The Beetaloo Sub-basin should be the first priority for a SREBA because this is the most likely area for an approval production licence to be granted for the purpose of producing onshore shale gas if the Government lifts the moratorium (see Chapter 6).

The need for baseline information has been referred to in many submissions, noting that without such information it is not possible to know whether future changes, for example, in groundwater quality or methane levels, are due to any onshore shale gas industry. The Environmental Defenders Offices of Australia (**EDOA**) in a submission to a Senate Inquiry into water use by extractive industries noted the need for

> *"improved standards for upfront environmental impact assessment should be developed, including: minimum standards for groundwater and surface water modelling; improved consideration of the capacity of a water resource to support mining operations, and ultimately rehabilitation activities, over time; a requirement that decision makers must not approve a project until the proponent has provided adequate baseline data and has adequately addressed any concerns raised by the regulator or independent assessors advising the regulator; and application of the precautionary principle."* [159]

The SREBA should focus on providing a baseline understanding of the surface and groundwater resources, hydrogeology, aquatic ecosystems and terrestrial ecosystems using data that is representative of the geographic, climatic, and hydrogeological characteristics of any prospective basin, and an assessment of the vulnerability of these systems to any hydrological changes associated with any onshore shale gas development. This vulnerability assessment will require the development of regional groundwater and surface water models of sufficient complexity to be able to predict the effects of water abstraction by the industry on availability of water for human, agricultural and pastoral, and environmental needs (see Chapter 15 for details on the objectives and scope of a SREBA).

In this regard, the Panel notes that in the May 2017 budget, the Commonwealth has extended the bioregional assessment program for CSG and coal mining to include shale gas development. Additionally, $30.4 million has been allocated for new combined geological and bioregional resource assessments in three (unspecified) onshore regions.[160] It is currently unclear how these initiatives will progress the understanding necessary to inform management of any onshore shale gas industry in the NT, although the Panel notes that the understanding of deeper groundwater systems is unlikely to be able to be sufficiently progressed without primary data acquired from the drilling of the deeper sequences containing shale gas.

The Panel received many submissions[161] and comments during the community forums suggesting that a SREBA should be undertaken before any exploration drilling and hydraulic fracturing occurs. Having said this, the Panel also received submissions from the gas industry arguing that current regulations are sufficient to allow exploration to occur during the conduct of the SREBA.[162] Having carefully considered all submissions and comments, the Panel has nevertheless retained its earlier finding that a SREBA can occur concurrently with exploration (see Chapters 15 and 16) (with respect to the Panel's recommendation to overcome 'exploration creep'

159 EDOA 2017, p 3.
160 Australian Government 2017b.
161 Lock the Gate Alliance Northern Territory, submission 1250 (**Lock the Gate submission 1250**).
162 Australian Petroleum Production and Exploration Association, submission 1251 (**APPEA submission 1251**); Origin submission 1248; Pangaea submission 1147; Santos submission 1249.)

see Chapter 14 in Section 14.7.5), with the caveat that if the Government lifts the moratorium, specific recommendations must be implemented prior to any further drilling and hydraulic fracturing occurring. Further details are provided in Chapters 15 and 16.

Recommendation 7.5

That before any further production approvals are granted, a regional water assessment be conducted as part of a SREBA for any prospective shale gas basin, commencing with the Beetaloo Sub-basin. The regional assessment should focus on surface and groundwater quality and quantity (recharge and flow), characterisation of surface and groundwater-dependent ecosystems, and the development of a regional groundwater model to assess the effects of proposed water extraction of the onshore shale gas industry on the dynamics and yield of the regional aquifer system.

7.5 Water quantity

The Panel's first environmental objective in assessing the water-related risks of any onshore shale gas industry in the NT is to ensure surface and groundwater resources are used sustainably.

There is considerable concern in the community that any onshore shale gas development in the Territory will use greater volumes of groundwater than can be sustained without causing adverse effects on groundwater levels both locally and regionally. As noted previously, it is unlikely that adequate reliable surface water resources exist in the Beetaloo Sub-basin, or other prospective regions of the NT, to sustain the annual water use requirements of an onshore shale gas industry.

To assess the potential scale of risks to groundwater resources, the Panel sought information on the potential water use by a shale gas development in the Beetaloo Sub-basin consisting of 1,000 to 1,200 hydraulically fractured wells (see Section 7.3.1.4). The Panel also sought information on the potential for the gas companies to reuse some of the treated or untreated wastewater (flowback or produced water), or to use more saline groundwater from deeper aquifers. Both these options are technically feasible, but whether they are adopted will depend upon detailed site investigations, consideration of possible environmental impacts, regulatory requirements, and cost.

Below the Panel has assessed the following risks to surface and groundwater resources that may arise in connection with the development of an onshore shale gas industry in the NT: first, unsustainable water extraction for well drilling and hydraulic fracturing; and second, potential adverse effects to surface or groundwater supplies from seismic activity caused by hydraulic fracturing or reinjection of wastewaters.

7.5.1 Unsustainable use of surface water

The Panel has concluded that the temporary nature of the surface water resources (rivers, streams and waterholes) in the semi-arid and arid regions of the NT makes it unlikely that surface waters are suitable for hydraulic fracturing. Additionally, such use would be undesirable because of the importance of these temporary systems to the functioning of aquatic ecosystems. The major companies with petroleum exploration permits in the Beetaloo Sub-basin area (Origin, Pangaea and Santos) have all assumed in their submissions that they will not use surface water resources for hydraulic fracturing.[163]

The Panel has assessed the likelihood that the gas companies will use an excessive amount of surface water for hydraulic fracturing as 'low'. This is because there is an insufficient amount of surface water available for much of the year and, when it is available, it is unreliable. However, there is still a possibility that any onshore shale gas development may seek to use surface water resources in wetter areas outside the Beetaloo Sub-basin, where surface water resources may be available during the wet season.

The Panel has assessed the consequences of excessive use of surface water resources as 'medium', an assessment primarily based on the unacceptable impacts that a lack of water may have on aquatic ecosystems, wildlife, and stock requirements. These impacts could occur during the wet season if the flow regimes of streams were changed, at the end of the wet season

163 Origin submission 153, pp 46, 85-86; Santos submission 168, p 95; Pangaea submission 220, p 8.

when less water may be available for waterholes and permanent aquatic refuges, and during the dry season where water may exist for short periods of time in waterholes and refuges.[164] This is further discussed in Section 7.7.1. In the absence of any information to the contrary, the Panel considers that these seasonally available surface water resources are critical for the maintenance of floodplain and riparian ecological processes.

Although according to the Panel's risk assessment methodology the risk to surface water supplies rates is 'low' (likelihood - 'low', consequence - 'medium'), the Panel's view is that the use of surface water resources for hydraulic fracturing should be prohibited for two reasons. First, because the resource will only potentially be available for part of the year (the wet season) with implications for the dry season if excessive amounts are extracted, particularly near the end of the wet, leaving less water to fill wetlands and waterholes. And second, because the timing and volume of stream flows during the wet season is highly variable, making the development of rules around when, and if, extraction should commence and conclude in any given year quite complex (for example, each river system will require its own set of rules), which will be challenging to regulate. However, to ensure that surface water resources are not used for hydraulic fracturing, it will be important that the use of surface water for hydraulic fracturing is prohibited.

In summary, the Panel's assessment is that there is a low risk that there will be insufficient surface water available for the environment, current water uses, and future water uses as a result of hydraulic fracturing operations. However, to mitigate this risk completely, the use of surface water should be prohibited.

Recommendation 7.6

That prior to the grant of any further exploration approvals, the use of all surface water resources for any onshore shale gas activity in the NT be prohibited.

7.5.2 Unsustainable use of groundwater

The Panel has assessed both the regional and local impacts of excessive groundwater use by any potential onshore shale gas industry.

7.5.2.1 Regional impacts

The Panel has assessed the risk that any onshore shale gas industry will use an excessive amount of groundwater, which could result in an unacceptable reduction in the amount of water available regionally for stock and domestic use, use by other industries, and for the maintenance of a healthy environment.

As discussed previously, groundwater is likely to be the most economically viable water source for hydraulic fracturing in semi-arid and arid areas of the NT. It is possible that water could be transported to well sites, but this would be an expensive operation for total water supply.

Industry experience 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 of around 1-2 ML for well drilling and around 1-2 ML for each hydraulic fracturing stage, or around 10-20 ML per well for a 10-stage fracturing operation (see above Section 7.3). For example, Origin suggests that it will require 50-60 ML for drilling and stimulation per well, based on a 20-40 stage hydraulic fracturing program per well, while noting that the industry is employing longer laterals with an increased numbers of hydraulic fracturing stages.[165]

To assess the likelihood that a possible shale gas industry could use excessive volumes of groundwater, the Panel compared the above indicative volume of water with the volume being recharged annually into the various aquifers in the Beetaloo Sub-basin (as presented in Section 7.3.1).

In summary, for the northern section of the Beetaloo Sub-basin (Mataranka to Daly Waters) the Panel is aware of three estimates for the recharge rate that range from 100,000 ML/y[166] to 330,000 ML/y. The Panel has no estimates for the recharge rate of the CLA in the southern part of

164 ACOLA Report, p 115; King et al. 2015.
165 Origin submission 153.
166 Fulton and Knapton 2015; GHD 2016, Appendix A; Bruwer and Tickell 2015.

the Beetaloo Sub-basin (around Elliott)[167], although the available evidence suggests there is very little recharge in this region.[168]

As noted in Section 7.3.1.4 above, the gas industry's 25 year development scenario of between 1,000 and 1,200 wells, associated with around 150 well pads, would require an average of 2,500 ML/y (up to 5,000 ML/y at peak demand between years five and nine) of water for well drilling and hydraulic fracturing.

From a regional perspective, the use of up to 5,000 ML/y from the groundwater system appears to be a relatively small proportion (<5%) of the suggested recharge rate of 100,000 to 330,000 ML/y of the northern section.[169] However, as indicated above, additional information will be required to better define the recharge rates and sustainable yields in the Beetaloo Sub-basin, particularly in the southern part of the basin where the extraction of 5,000 ML/y may well represent unsustainable use of the groundwater resource. This may also be the case in other arid and semi-arid prospective basins in the NT, and assessment of the sustainable yield of these groundwater systems is needed to inform understanding of the potential impacts of onshore shale gas production in these regions.

Based on this information, the Panel considers that it is unlikely that any onshore shale gas industry will use an unacceptably high amount of groundwater in the northern part of Beetaloo Sub-basin (that is, north of around Daly Waters) or in other regions where there is similarly relatively high rainfall. The Panel has been unable to form a view on this matter for the southern part of the basin because there is not enough information available.

The consequences of excessive use of groundwater resources in the northern Beetaloo Sub-basin have been assessed as 'medium' for domestic and pastoralist use and for any ecosystems shown to be groundwater dependent or groundwater influenced, with the caveat that additional information is required to identify groundwater-dependent or groundwater-influenced ecosystems. However, the consequences associated with extracting water from the Gum Ridge Aquifer in the southern part of the Beetaloo Sub-basin are more serious given the expected very low recharge rate in this area. In effect, this would amount to 'mining' a slowly recharged or potentially non-renewable resource.

Accordingly, on the basis of the available evidence, the Panel has assessed the resultant risk in the northern part of the Beetaloo Sub-basin and other regions with similar or higher rainfall as 'low' (likelihood - 'low', consequences - 'low' to 'medium'), but notes that there is considerable uncertainty associated with this assessment. For the southern Beetaloo Sub-basin, and other semi-arid to arid regions, the Panel's view is that groundwater extraction for shale gas production should be prohibited until the groundwater resource is better understood. This better understanding should emerge from the SREBA recommended for the Beetaloo Sub-basin and other prospective regions (see ***Recommendation 7.5***).

The Panel also notes that if this greater knowledge of the groundwater resources, particularly in the southern Beetaloo Sub-basin, indicates a high risk of unsustainable use of the surface aquifers by the shale gas industry, the possible use of deeper groundwater for hydraulic fracturing could be considered. Both Origin and Pangaea have indicated to the Panel that this could be an option.[170] Pangaea provided quite detailed information about the Jamison sandstone aquifer system that was identified in its lease area at depths of 200-500 m below the surface.[171] Further, Origin stated that,

> *"there is insufficient data on the permeability and storage of the deep, saline aquifers at this time to know whether they could be suitable for usage in hydraulic fracturing and other development activities; however, the data that are available are not encouraging regarding the suitability of deeper, saline aquifers. The Bukalara Sandstone, however, is a freshwater aquifer that in the Beetaloo area is used in a very small number of water bores north of Origin's permits and is not used by landholders in the core area of Origin's permits."* [172]

167 DENR submission 428, p 14.
168 Tickell and Bruwer 2017.
169 DENR submission 230, Addendum 1.
170 Origin submission 433, pp 32-33; Pangaea submission 427, pp 12-13.
171 Pangaea submission 427, pp 12-13.
172 Origin submission 433, pp 32-33.

The Panel's assessment is that the risk of unsustainable use of groundwater in the northern part of the Beetaloo Sub-basin and other regions with similar or greater rainfall is 'low', assuming a WAP is established for the basin and the 80:20 sustainable extraction rule is applied to any water extraction licence granted to a gas company. However, the risk for the southern part of the Beetaloo Sub-basin, and other potential shale gas producing basins in semi-arid and arid regions of the NT, cannot be assessed without additional information.

The Panel has concerns regarding two aspects of the management of the Beetaloo Sub-basin groundwater resources. First, there is no WCD that covers the full extent of the Beetaloo Sub-basin. The current Daly-Roper WCD should be extended south to include all the Beetaloo Sub-basin (**Figure 7.6**) and one or more separate Beetaloo WAPs developed. Other WAPs will also need to be declared for shale gas producing regions prior to gas production. This will provide the necessary legislative controls over the allocation of groundwater resources to the shale gas and other industries.

Second, the Panel has assumed that DENR will apply the current groundwater allocation rule used for arid regions of the NT to the Beetaloo Sub-basin, which would mean it would be permissible to use 80% of the storage capacity of the aquifer for consumptive uses over a period of 100 years.[173] If this rule was applied to an onshore shale gas industry, or any other extractive use in the region, this would again essentially permit 'mining' of the groundwater resource, and would be ecologically unsustainable, since the recharge rate of the groundwater in this southern part of the CLA aquifer system is very slow.

It is the Panel's view that sustainable extraction limits should be set on the basis of the outputs from a regional numerical groundwater model developed as part of the SREBA to manage poorly understood groundwater systems.

Recommendation 7.7

That in relation to the Beetaloo Sub-basin:

- ***the Daly-Roper WCD be extended south to include all of the Beetaloo Sub-basin;***
- ***that WAPs be developed for each of the northern and southern regions of the Beetaloo Sub-basin;***
- ***the new northern Sub-basin WAP provides for a water allocation rule that restricts the consumptive use to less than that which can be sustainably extracted without having adverse impacts on other users and the environment; and***
- ***the southern Sub-basin WAP prohibits water extraction for any onshore shale gas production until the nature and extent of the groundwater resource and recharge rates in that area are quantified.***

That in relation to other shale gas basins with similar or greater rainfall than the Beetaloo Sub-basin, WCDs be declared and WAPs be developed to specify sustainable groundwater extraction rates for shale gas production activities that will not have adverse impacts on existing users and the environment.

That in relation to other potential shale gas basins in semi-arid and arid regions, all groundwater extraction for any shale gas production activities be prohibited until there is sufficient information to demonstrate that it will have no adverse impacts on existing users and the environment.

7.5.2.2 Local impacts

The Panel has examined the risk that water use by any onshore shale gas industry will cause an unacceptable local drawdown of an unconfined or confined aquifer,[174] making it difficult for groundwater to be extracted for use in townships, on pastoral leases, by ecosystems or for cultural purposes. At the local scale, aquifer drawdown (that is, lowering of the water level) could be substantial, depending on the rate of pumping, the spatial extent of the bore field, and the flow rate (transmissivity) within the aquifer. The Panel has assessed that an unacceptable drawdown would occur if the groundwater dropped below the level where existing water supply bores could access water with current reliability.

173 DENR submission 230, Appendix A.
174 'Unconfined aquifers' are those into which water seeps from the ground surface directly above the aquifer; 'confined aquifers' are those in which an impermeable dirt/rock layer exists that prevents water from seeping into the aquifer from the ground surface located directly above.

Origin has provided some evidence of the fast recovery of the local drawdown of the Gum Ridge Aquifer when used to provide water for the hydraulic fracturing of the Amungee NW-1H well in 2016.[175] Water was extracted from a bore field consisting of three bores at a combined rate of 7.5-10 L/s, with a total water volume of around 10 ML extracted over a 38 day period (from 1 August to 7 September 2016). The local aquifer drawdown at the extraction well during pumping was around 2.6 m, with the aquifer level rebounding to the pre-pump level almost immediately after pumping was stopped. Additionally, there was no response noted during the period of pumping in the water level at an observation bore located three km away.

DENR also provided the Panel with modelled estimates of the local drawdown for a scenario with four bores in a square formation 1.5 km apart, pumping at a rate of 10 L/s over a period of 60 days.[176] This equates to an extraction rate of around 52 ML/d or a total volume of around 208 ML, which is about a 12 times higher extraction rate than used for the Amungee well above. **Table 7.6** shows the results, which indicate that the drawdown at each bore and the lateral extent of the drawdown are dependent upon the aquifer, whether it is confined or unconfined and the assumed hydraulic parameters for the aquifer. The extent of drawdown is greatest in the confined aquifer. DENR indicated that the time for these aquifers to recover back to the pre-pump level would be around 60 days.

Table 7.6: Theoretical estimates of the local drawdown in three aquifer types for a bore field of four bores (in square formation 1.5 km apart) pumping at 10 L per second for 60 days. Source: DENR.[177]

Aquifer	Transmissivity (m^2/d)	Storage coefficient (%)	Drawdown at each bore (m)	Drawdown at 1 km from each bore (m)	Maximum drawdown distance (km)
Unconfined Anthony Lagoon	530	2	1.9	0.2	1.8
Unconfined Gum Ridge	1,100	4	0.9	0.08	1.9
Confined Gum Ridge	1,100	0.001	0.9	0.7	10.4

These calculations suggest that for aquifers in the Beetaloo Sub-basin, except for the confined sections of the Gum Ridge aquifer, the local drawdown for a pumping scenario is around 10 times greater than expected for the scenario outlined in Section 7.3.1.4 and would be minimal further than 1 km from the bore field, and that the recovery after pumping ceased would be relatively rapid. These estimates are based on the cumulative effects of pumping from a bore field of only four bores, and will be improved as further baseline information on the various aquifers, and more detail on likely water extraction scenarios, are obtained. In other regions of the NT, understanding the significance of potential impacts of groundwater extraction upon local groundwater levels will require adequate baseline information and consideration of the effects on a case-by-case basis.

Therefore, the Panel's assessment is that the likelihood of excessive local drawdown of the groundwater beyond about a 1,000 m radius of a bore field extracting water for the purpose of hydraulic fracturing is 'low'. However, the consequences of excessive local drawdown on surrounding water supply bores has been assessed as 'medium', given that if this occurred, either townships or pastoralists could run out of drinking water or stock water for periods of time.

The Panel has assessed the risk of local drawdown greater than one m in water supply bores greater than 1,000 m from a shale gas groundwater bore field as 'low' (likelihood - 'low', consequences - 'medium'), although there is still uncertainty in these figures and the risk assessment given that only results from one field trial and modelled data are available.

The Panel considers that this uncertainty can be partially addressed if the following measures are implemented:

- no onshore shale gas water extraction bore field should be located within 1 km of groundwater users unless additional information indicates that a different buffer zone is appropriate or 'make good' arrangements can be negotiated with groundwater users to ensure maintenance of water supply;

175 Origin submission 153, pp 87-88; Origin submission 433, p 75.
176 DENR submission 230, Addendum 1. Assumes the aquifers are homogeneous and isotropic.
177 DENR submission 230, Addendum 1.

- the proposed new WAP (see ***Recommendation 7.7***) includes provisions that adequately control the rate, volume and location of water extraction by the gas companies to minimise impacts;
- gas companies are required, at their expense, to monitor drawdown in local water supply bores; and
- if this drawdown is found to be excessive (that is greater than 1 m), a 'make good' requirement should be invoked requiring the reduction or termination of groundwater pumping, or the making of other arrangements to ensure the affected bores can access the groundwater (for example, by either relocating the bores or increasing their depth).

Origin submitted that it *"is committed to making impacted stakeholders whole if they are impacted by our activities. If a landholder's business or well-being is adversely impacted, we commit to remediating and/or compensating for the financial loss or loss of amenity experienced."* [178] However, all 'make good' commitments by gas companies must be enforceable (see Chapter 14).

Recommendation 7.8

That the following measures be mandated to ensure that any onshore shale gas development does not cause unacceptable local drawdown of aquifers:

- ***that prior to the grant of any further exploration approvals, the extraction of water from water bores to supply water for hydraulic fracturing be prohibited within at least 1 km of existing or proposed groundwater bores (that are used for domestic or stock use) unless hydrogeological investigations and groundwater modelling, including the SREBA, indicate that a different distance is appropriate, or if the landholder agrees to a variation of this distance;***
- ***that relevant WAPs include provisions that adequately control both the rate and volume of water extraction by the gas companies;***
- ***that gas companies be required, at their expense, to monitor drawdown in local water supply bores; and***
- ***that gas companies be required to immediately 'make good' and rectify any problems if the drawdown is found to be excessive.***

7.5.3 Unacceptable changes to surface or groundwater flows due to possible seismic activity caused by hydraulic fracturing

The Panel has examined the risk of changes to the flow regimes of surface and groundwater as a result of seismic activity (earth movements) resulting from hydraulic fracturing. Such changes would be unacceptable if these earth movements resulted in surface water or groundwater moving from one area to another with unintended outcomes. For example, water could become unavailable for use if it migrates to an area that is not easily accessible. Further, low quality water could migrate into high quality water systems (or the reverse) meaning that water can no longer be used for its original purpose. The movement of fracking fluids from the shale layer to a surface aquifer is discussed in Section 7.6.5.

The available evidence relating to induced seismic activity from the hydraulic fracturing process is that while low level seismic activity can be associated with hydraulic fracturing, the magnitude of this activity is likely to be very small, with minimal or no damage to surface infrastructure.[179] The UK Royal Society identified two types of seismicity associated with hydraulic fracturing: microseismic events are a routine feature of hydraulic fracturing and are due to the propagation of engineered fractures; and larger (generally rare) seismic events induced by hydraulic fracturing in the presence of a pre-stressed fault.[180] Hydraulic fracturing induced seismic activity and fault reactivation has been recently reported for the Sichuan Basin in China.[181]

The factors affecting seismicity induced by hydraulic fracturing include:[182]

- **the strength of the shale:** the stronger the rock, the greater the magnitude of the seismic event;

178 Origin submission 153, p 46.
179 Costa et al. 2017; Davies et al. 2013; Royal Society Report, p 41; UK Task Force on Shale Gas 2015, 2nd Interim Report, p 9; BC Oil and Gas Commission 2012; Clarke et al. 2014; Schultz et al. 2015; Westwood et al. 2017.
180 Royal Society Report, p 41.
181 Lei et al. 2017.
182 Royal Society Report, p 42.

- **fault properties:** the magnitude of the induced seismicity depends upon the surface area of the fault (the larger the fault the greater the seismicity) and the degree to which the fault is pre-stressed; and
- **pressure constraints:** the magnitude of induced seismicity is affected by pressure changes in the shale formation near the well, with the volume of injected fluid and injection rate generating higher pressures, and the volume and rate of flowback fluid reducing pressures.

The US experience is that seismicity levels vary with the individual shale gas basins, reflecting a combination of the depth of the shale layer and the local geology, particularly the degree of faulting in the area.[183] This suggests that while there is a moderate likelihood of localised low level seismic activity occurring, the consequences of significant impacts, that is, impacts that measurably alter volumes of surface or groundwaters, are very low.

The UK Royal Society identified three measures to mitigate possible induced seismicity as a result of hydraulic fracturing:[184]

- initial surveys to characterise stresses and identify faults - this is already a requirement of hydraulic fracturing operations in the NT;[185]
- pre-fracturing injection testing - to better characterise the particular shale formation, a small pre-fracturing injection test with microseismic monitoring can be employed; and
- monitoring of seismicity - magnitude 1.7 M_L (M_L is the local magnitude scale = Richter scale) is taken as the cut off criterion and if the magnitude is above 1.7 M_L injection is stopped and monitoring continued.

The Panel's assessment is that the risk to the flow regimes of either surface or ground waters due to possible seismic activity caused by hydraulic fracturing is 'very low'. Existing shale gas industry requirements (listed above) are sufficient to minimise the risk of seismicity.[186]

7.5.4 Unacceptable changes to surface or groundwater flow due to possible seismic activity caused by reinjection of wastewater

The Panel has examined the risk of unacceptable changes to surface or groundwater flows as a result of seismic activity resulting from injecting wastewater into deep aquifers or conventional reservoirs.

There is potential for seismic activity, particularly fault reactivation, to be caused by the injection of large volumes of waste (for example, hundreds of ML) in deeper aquifers. This is most likely to occur through the reactivation of pre-existing weak faults that were not previously mapped, or whose physical properties and strength are not understood.[187]

There is a direct correlation reported between deep well reinjection and felt seismic activity.[188] Most recently, the US Geological Survey reported that reinjection of wastewater into depleted conventional reservoir wells (Class II aquifers) is the primary cause of the recent increase in low intensity earthquakes in certain areas of the central US.[189]

In the NT, the only current onshore conventional gas operations are in the Amadeus Basin, and these are the only conventional gas reservoirs that could be available for the disposal of flowback fluids or other wastewaters. It is possible that gas companies could seek to reinject treated or untreated wastewater into deep saline aquifers. The Panel has no information on the potential for seismic activity due to injection of wastewater into deep aquifers in the NT.

DPIR has indicated that while it *"does not support flowback water disposal, or any other wastewater, into freshwater aquifers ... If proven safe and environmentally responsible to do so under certain conditions, safeguards and water quality requirements, deep aquifers may be considered for use for the disposal of wastewater, but only if water in the receiving aquifer is non-potable and is not connected to any other aquifer system."*[190]

183 Warpinski et al. 2012; USGS 2017.
184 Royal Society Report, pp 43-44.
185 DPIR submission 226.
186 Royal Society Report, pp 40-45; USGS 2017; UK Government 2017.
187 Drummond 2016.
188 ACOLA Report; US EPA 2016a; Costa et al. 2017; USGS 2017.
189 USGS 2017.
190 DPIR submission 424, p 10.

The Panel is unable, on the evidence available, to assess the risk of seismic activity caused by the injection of shale gas wastewater into deep aquifers. Before such activity is permitted, there must be comprehensive reservoir (aquifer) engineering studies and baseline studies undertaken to determine pre-existing subsurface stress conditions. Further, injection activities need to be managed to ensure that the volumes of wastewater being injected did not exceed the critical pressures likely to trigger the reactivation of pre-existing faults,[191] or impact on usable groundwater resources (see Section 7.6.4 for a discussion of the more general issue of reinjection into aquifers).

In view of the uncertainty regarding the operational reinjection of hydraulic fracturing wastewaters, the Panel is of the view that in order for this practice to be permitted, exhaustive investigations are required to demonstrate that seismic activity is unlikely to occur for the particular activity, and for these investigations to be approved by the regulator.

Recommendation 7.9

That prior to the grant of any further exploration approvals, the reinjection of wastewater into deep aquifers and conventional reservoirs and the reinjection of treated or untreated wastewaters (including brines) into aquifers be prohibited, unless full scientific investigations determine that all risks associated with these practices can be mitigated.

7.5.5 Unacceptable changes to the flow characteristics of surface waters due to the discharge of wastewaters

There is a risk of unacceptable changes to the flow characteristics of normally ephemeral surface waters due to the discharge of wastewaters, which may be particularly significant in semi-arid and arid regions. This risk is discussed below in Section 7.6.7 as part of the assessment of the risk of contamination of surface waters due to discharge of wastewater.

7.6 Water quality

The Panel's second environmental objective in assessing the water-related risks of an onshore hydraulic fracturing shale gas industry in the NT is to ensure the quality of surface and groundwaters (aquifers) is maintained in an acceptable condition for all users (see **Table 7.5**).

The experience from overseas, especially in the US, is that onshore shale gas operations produce considerable volumes of wastewater, which pose a risk of contamination of surface and groundwaters.[192] The composition of these wastewaters (hydraulic fracturing fluids, flowback and produced water), and their management and potential reuse, has been detailed in Chapter 5.

Petroleum companies in the NT are required to disclose to DPIR, and to the general public, *"specific information"* regarding the chemicals used in the hydraulic fracturing process.[193] But the Panel is of the opinion that the regulatory framework must make it abundantly clear exactly what information must be disclosed. Presently this is not the case. This includes all chemicals that are proposed to be used, the reason for their use, and the measures by which the risks associated with their release into the environment (including spills) will be managed by the company and regulated.

The chemicals used by Origin for the hydraulic fracturing of the Amungee NW-1H well were disclosed and are documented for reference in **Table 7.7**. The Material Safety Data Sheets (**MSDS**) and other relevant human and aquatic ecosystem toxicological data for these chemicals are compiled in the *Beetaloo Project Hydraulic Fracturing Risk Assessment Amungee NW-1H* recently prepared by AECOM for Origin (Section 7.4.2.2).[194] Of the 40 chemicals (excluding water) in this list, 19 were also assessed as part of the NCRA (Section 7.4.2.3).[195]

191 Drummond 2016.
192 US EPA 2016a.
193 Schedule, cl 342(4).
194 Origin submission 466.
195 Australian Department of the Environment and Energy a-f.

Table 7.7: Total masses of chemicals used for hydraulic fracturing of the Amungee NW-1H well. Source: Origin.[196]

CAS[a] Number	Chemical name	Mass (kg)	Mass (%)
	Water	10,633,220	89
14808-60-7	Quartz, Crystalline silica (proppant sand)	1,204,412	10
9000-30-0	Guar gum	20,619	0.173
67-48-1	2-hydroxy-N,N,N-trimethylethanaminium chloride	17,736	0.149
7647-01-0	Hydrochloric acid	5,665	0.048
107-21-1	Ethylene glycol	4,107	0.035
31726-34-8	Polyethylene glycol monohexyl ether	2,436	0.021
1319-33-1	Boronatrocalcite	5,051	0.042
1310-73-2	Sodium hydroxide (impurity)	2,491	0.021
7783-20-2	Ammonium sulfate	880	0.007
91053-39-3	Diatomaceous earth, calcined	389	0.003
7789-38-0	Sodium bromate	1,764	0.015
38193-60-1	Acrylamide, 2-acrylamido-2-methylpropanesulfonic acid, sodium salt polymer	649	0.005
129898-01-7	2-Propenoic acid, polymer with sodium phosphinate	1,106	0.009
1330-43-4	Sodium tetraborate	425	0.004
7647-14-5	Sodium chloride	223	0.002
61789-77-3	Dicoco dimethyl quaternary ammonium chloride	102	0.001
10043-35-3	Boric acid	133	0.001
10377-60-3	Magnesium nitrate	78	0.0007
110-17-8	Fumaric acid	133	0.001
10043-52-4	Calcium Chloride	113	0.001
7704-73-6	Monosodium fumarate	133	0.001
57-13-6	Urea	43	0.0004
136793-29-8	Polymer of 2-acrylamido-2-methylpropanesulfonic acid sodium salt and	70	0.0006
26172-55-4	5-chloro-2-methyl-2h-isothiazolol-3-one	42	0.0004
67-63-0	Propan-2-ol	20	0.0002
7631-86-9	Non-crystalline silica (impurity)	61	0.0005
7786-30-3	Magnesium chloride	39	0.0003
2682-20-4	2-methyl-2h-isothiazol-3-one	13	0.0001
111-46-6	2,2''-oxydiethanol (impurity)	12	0.0001
7757-82-6	Sodium sulfate	10	0.00008
595585-15-2	Diutan gum	6.6	0.00006
14464-46-1	Cristobalite	7.6	0.00006
79-06-1	2-Propenamid (impurity)	2.1	0.00002
7447-40-7	Potassium chloride (impurity)	3.5	0.00003
67762-90-7	Siloxanes and silicones, dimethyl, reaction products with silica	1.2	0.00001
63148-62-9	Dimethyl siloxanes and silicones	1.2	0.00001
64-02-8	Tetrasodium ethylenediaminetetraacetate	1.4	0.00001
7758-98-7	Copper (II) sulfate	1.2	0.00001
540-97-6	Dodecamethylcyclohexasiloxane	1.2	0.00001
541-02-6	Decamethyl cyclopentasiloxane	1.2	0.00001
556-67-2	Octamethylcyclotetrasiloxane	1.2	0.00001
	TOTAL	**11,902,200**	**100**

[a] A CAS Registry Number, also referred to as 'CASRN' or 'CAS Number', is a unique numerical identifier assigned by the Chemical Abstracts Service to every chemical substance described in the open scientific literature (https://www.cas.org/content/chemical-substances/faqs).

196 Origin submission 153, pp 343, 344.

Currently, however, the identity and concentrations of geogenics (chemicals extracted from the shale as a result of the hydraulic fracturing and gas extraction process) do not currently require disclosure. In its joint submission with DENR to the Panel, DPIR indicated that it considers that full public disclosure of the composition of wastewater is in the public interest and aligns with government policy and, following industry consultation, plans to make the information publicly available.[197]

The Panel also notes that Dr Tina Hunter has recommended that, *"the NT Department of Resources should mandate full, transparent disclosure of all chemicals used in NT fracking operations. This disclosure should be made available on the NT DoR website, and should provide detailed information on the chemicals used and location of use."* [198]

Origin has provided details of the sampling program and chemical analysis of flowback water produced from the hydraulic stimulation of the Amungee NW-1H well.[199] Assessments of the geogenic chemicals (including NORM) that were measured are also included in the risk assessment completed by AECOM.[200] The inclusion of geogenics in this risk assessment represents a first for the Australian onshore gas industry.

The Origin flowback water monitoring results are from a single location in the Velkerri B shale, and ongoing sampling of additional stimulation activities will be required to fully characterise the spatial variability of flowback water quality in this formation. The Panel also notes that the gas produced from the Amungee well was 'dry' gas. That is, it did not contain a significant component of liquid hydrocarbons. Origin stated in its announcement of a material gas resource to the Australian Stock Exchange in February 2017 that the product from the Amungee well contained approximately 92% methane, 3% ethane and 5% carbon dioxide and other inerts.[201] In the event that a 'wet' gas containing hydrocarbon condensate was produced, then the flowback and produced waters would likely contain substantially higher concentrations of hydrocarbons.[202]

Notwithstanding these caveats, it is instructive to provide a summary of the findings for flowback water from the Amungee well because it can assist in informing the Panel's assessment. Flowback water was slightly alkaline (pH 8) and about as salty as seawater, with the maximum recorded electrical conductivity and total dissolved solids 72 mS/cm and 49,200 mg/L, respectively, with more detailed water quality indicators being that:

- sodium chloride was the dominant salt, with relatively low magnesium, potassium, calcium, bicarbonate, fluoride, sulfate and carbonate levels;
- elevated barium and boron levels were observed, which is consistent with a shale source rock;
- NORM levels were found to be at the lower end of those typically observed in US shales;
- low levels of phenolic compounds and C10-C40 hydrocarbons were found, with semi-volatiles such as polycyclic aromatic hydrocarbons absent; and
- BTEX compounds were measured at trace levels.[203] Of these, benzene was the most abundant with a maximum concentration of 6 µg/L. As a point of comparison the *Australian Drinking Water Quality Guidelines* specify that it should not be detected in drinking water at more than 1 µg/L,[204] noting that flowback water is not of potable quality.

The results from the Amungee NW-1H flowback water sampling program provide increased confidence that treated flowback water from the Velkerri B shale formation could have a high potential for reuse in hydraulic fracturing operations. The majority of the compounds and parameters analysed in this flowback water were at the lower end of the concentration range reported from the US Marcellus and Barnett shale regions.[205]

197 Department of Primary Industry and Resources and Department of Environment and Natural Resources, submission 492 (**DPIR and DENR submission 492**), p 5.
198 2012 Hunter Report, Recommendation 1, p 15.
199 Origin submission 433, pp 20-26; For a full data set see Origin submission 433, Appendix 1.
200 Origin submission 466.
201 Origin 2017, announcement to ASX 15 February, 2017.
202 Goldstein et al. 2014.
203 Benzene was not detected in the hydraulic fracturing fluid so must have come from the shale: Origin submission 433, p 23.
204 NHMRC 2016, Table 10.6, p 177.
205 Origin submission 433, Appendix 1.

Recommendation 7.10

That prior to the grant of any further exploration approvals, the following information about hydraulic fracturing fluids must, as a matter of law, be reported and publicly disclosed before any exploration activities and production activities are carried out:

- ***the identities, volumes and concentrations of chemicals (including environmentally relevant chemical species present as contaminants in the bulk chemicals) to be used;***
- ***the purpose of the chemicals;***
- ***how and where the chemicals will be managed and transported on-site, including how spills will be prevented, and if spills do occur, how they will be remediated and managed; and***
- ***the laws that apply to the management of the chemicals and how they are enforced.***

That the following information about flowback and produced water must be reported and publicly disclosed online as soon as it becomes available:

- ***the identity and concentrations of chemicals and NORMs found in that water;*** [206]
- ***how and where the chemicals and NORMs will be managed, transported and treated, including how spills will be prevented, and if spills occur, how they will be remediated and managed; and***
- ***the laws that apply to the management of the chemicals and NORMs and how they are enforced.***

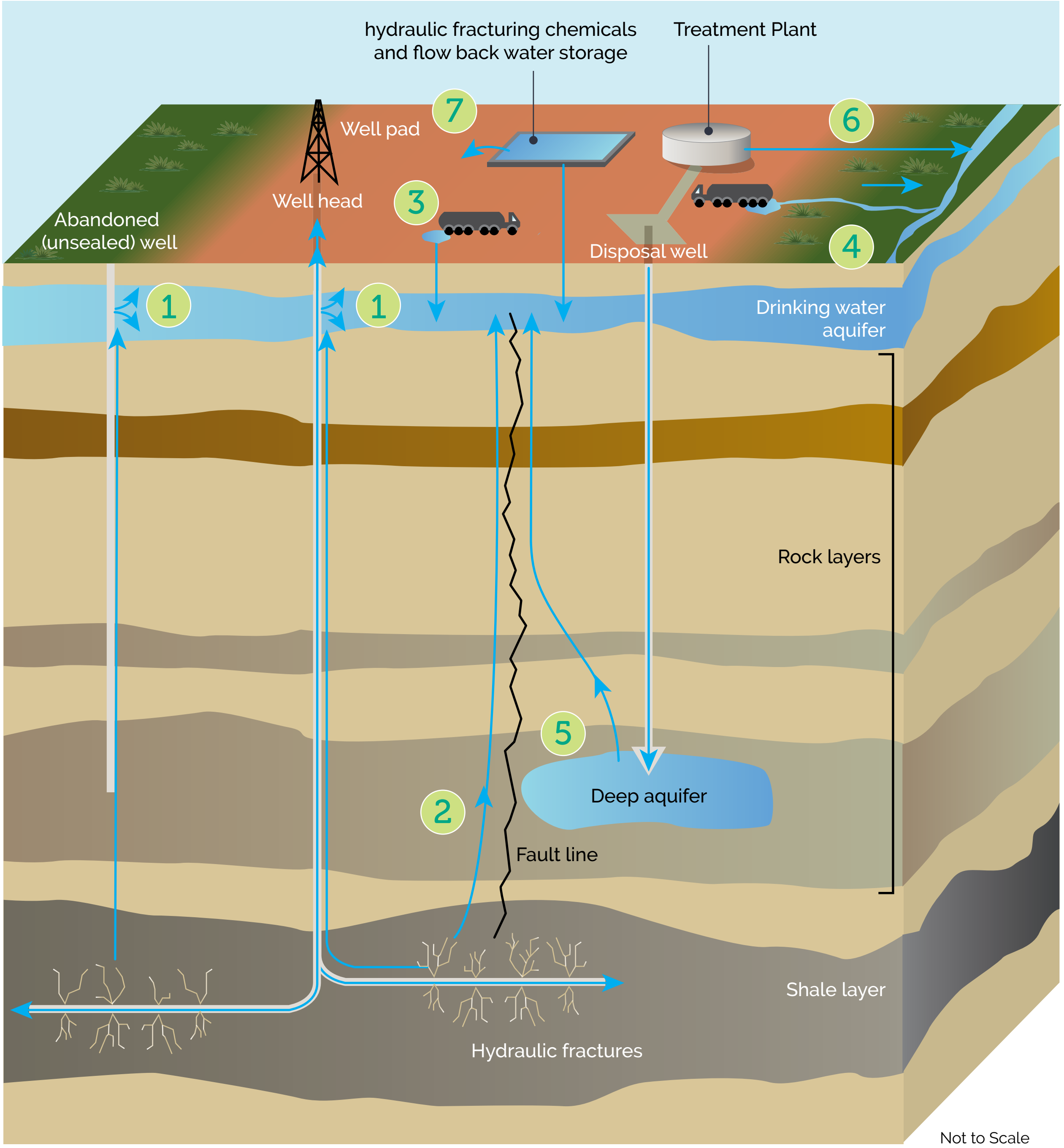
There are eight potential pathways by which onshore hydraulically fractured shale gas wastewater may contaminate groundwater or surface water (see **Figure 7.10**):

- **path 1:** leakage of hydraulic fracturing fluid, flowback or produced water, or methane from operating or abandoned wells;
- **path 2:** contamination of shallow groundwater through fractures induced by the hydraulic fracturing process by propagation of the fractures to the surface, connection of the fractures with faults, or by connection of the fractures with abandoned and unsealed deep exploration wells;
- **path 3:** surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water at the well site or other handling facility within the well pad area;
- **path 4:** surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water within the well pad that is washed off-site into a waterbody;
- **path 5:** reinjection of untreated wastewater to deep aquifers, with fault reactivation and induction of seismic activity with possible opening up of a communication pathway to the surface and/or disruption of surface flow pathways;
- **path 6:** direct discharge of treated or untreated wastewaters to surface waters or drainage lines;
- **path 7:** overtopping or failure of wastewater storage ponds or pits containing drilling fluids; and
- **path 8:** spills during transport of chemicals of wastewater from either road transports or pipelines (not shown).

The Panel has used the available evidence to assess the potential risks to the quality of surface and groundwater resources from each of these pathways, and the possible mitigation measures to reduce these risks (the risks to aquatic ecosystems are covered in Section 7.7).

206 See Australian Department of the Environment and Energy 2017c, Appendix A, for guidance on chemical species to be measured.

Figure 7.10: Schematic of the potential contamination pathways from a shale gas site.



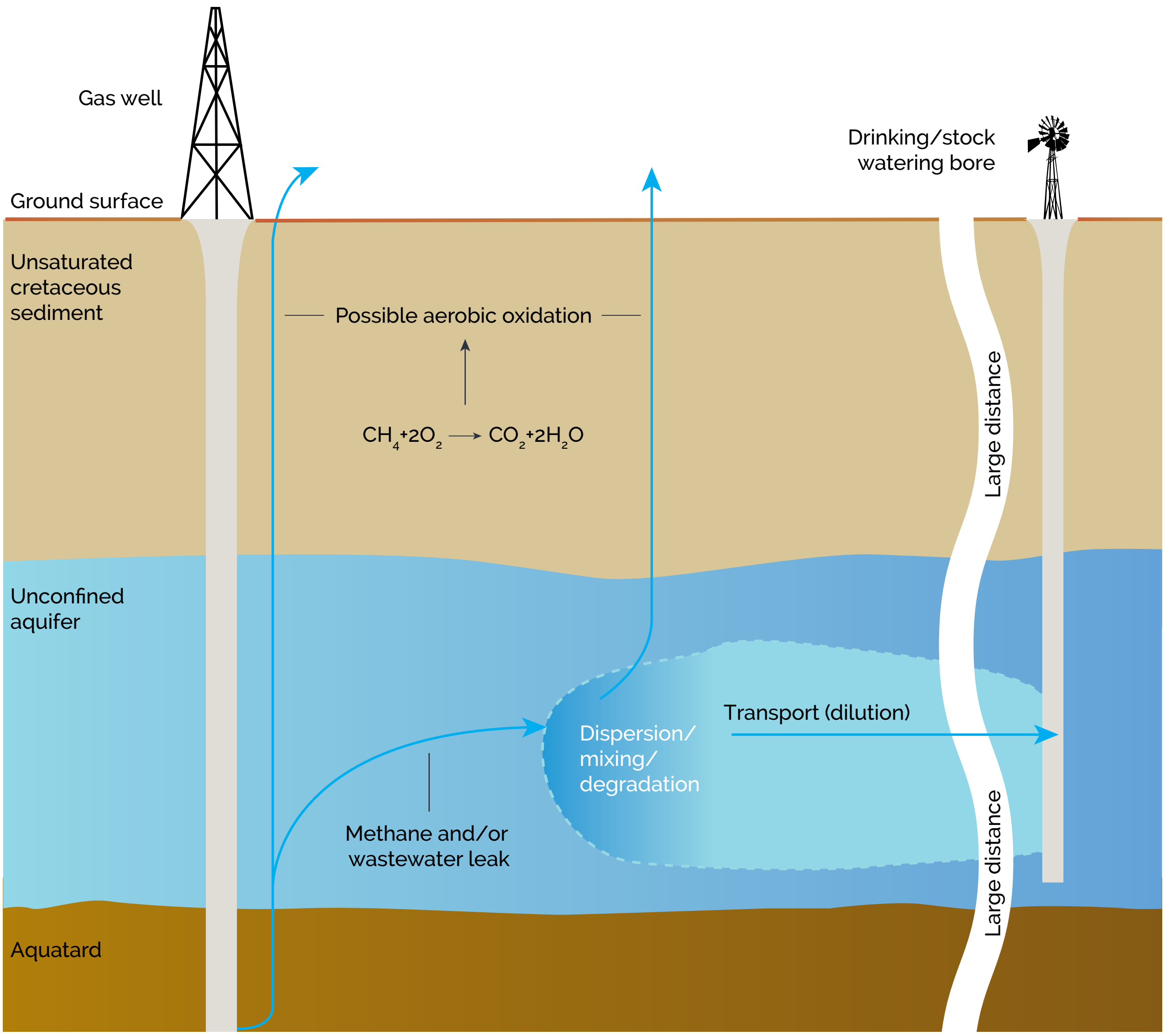
Path 1 - leakage of either hydraulic fracturing fluid, flowback or produced water, or methane from operating or abandoned wells;
Path 2 - contamination of shallow groundwater via fractures induced by the hydraulic fracturing process;
Path 3 - surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water at the well site or other handling facility within the well pad;
Path 4 - surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water within the well pad that is washed off-site into a waterbody;
Path 5 - reinjection of untreated wastewater to deep aquifers, with possible seismic activity and fault reactivation;
Path 6 - direct discharge of treated or untreated wastewaters to surface waters or drainage lines;
Path 7 - overtopping or failure of wastewater storage ponds;
Path 8 - spills during transport of chemicals or wastewater from either road transports or pipelines (not shown).

7.6.1 Unacceptable groundwater contamination due to leaky wells (pathway 1)

The Panel has considered the risk that groundwater could be contaminated as a result of leaky wells, and cause possible unacceptable changes[207] if this water is used for drinking or stock watering (the risk of unacceptable changes to aquatic ecosystems is covered in Section 7.7.2).

The Panel has distinguished between leaky wells that only leak methane, and those that leak both methane and wastewater.[208] Because it is a gas, methane can escape more easily than a fluid. Possible pathways for the migration of methane and formation water adjacent to a well are shown in **Figure 7.11**. Methane may contaminate surface aquifers and additionally vent to the atmosphere and contribute to the greenhouse gas impacts from shale gas operations (see Chapter 9).

Figure 7.11: Schematic of the potential pathways for methane and contaminated wastewater entering an unconfined aquifer from a leaky well.



The design, construction and operation of hydraulically fractured shale gas wells is covered in Chapter 5. As noted in that Chapter, it is now standard practice for a well to be lined with multiple layers of piping (casing), and with a specialised cement layer between each of the pipes and also between the outer pipe and the rock strata. These multiple casing strings are designed to prevent migration of fluids and gases between the well and an aquifer, while the cement layer is designed to isolate potential sources of saline water, hydrocarbons, flowback and produced water, from migrating up the outside of the well and contaminating freshwater aquifers.

207 See **Table 7.4**.
208 Dusseault and Jackson 2014.

The greatest potential for contamination of freshwater aquifers from a leaky well is if the leak occurs in the section of the well where it goes through the aquifer.[209] This can occur as a result of casing failure that occurs when the system is under maximum pressure during the hydraulic fracturing operation. It is this type of failure that has the greatest potential to quickly release large volumes of contaminants directly into the aquifer. The evidence presented in Chapter 5 has shown that the likelihood of this occurring is 'low'.

The second possible mechanism for contamination of groundwater is the upward migration of fluids as a result of faults in the integrity of the casing and/or cement seal around the well.

There has been considerable effort over the past decade by both the gas industry and regulators in Australia, the US and elsewhere, to improve the design, construction and operation of onshore shale gas wells. The evidence relating to the incidence of well leakage and other well failures is outlined in Chapter 5, and this demonstrates that the incidence of these issues has markedly declined as more modern methods of design, construction and regulation are implemented and is now relatively low.[210]

It is critical when assessing well performance that like is compared with like. In particular, the method and complexity of construction (that is, the category or standard of construction as discussed in Chapter 5 and illustrated in **Table 5.2**) is crucial. Comparing performance statistics through time can be misleading. It is clear that wells are now being increasingly completed to higher standards and are performing much better than those completed to lower standards. In this context, the Panel notes that the Amungee well was a Category 9 well with cement casing along the full length of the well casing to the surface.

A key distinction must also be made between the detection of methane at the surface and/or in groundwater, and the potential for that groundwater to be contaminated by chemicals from the formation water or fracturing fluids, which would cause it to become unsuitable for use for drinking or stock watering, or for general environmental use.

7.6.1.1 Contamination by methane

Methane in water is not classified as a toxic substance,[211] in contrast to various other chemicals (for example, heavy metals, metalloids and organic compounds) that may be in formation water. The limits for many (but not all) of these toxicants for human health, stock watering, agriculture and aquatic ecosystems are documented in Australian water quality guidelines.[212]

A highly quoted work on the topic of detection of methane contamination associated with shale gas wells was published by Osborn et al. in 2011, and was followed up by a publication by Jackson et al. in 2013.[213] These studies show there was methane contamination of drinking water in aquifers overlying the Marcellus and Utica shale formations of north-eastern Pennsylvania and upstate New York that was associated with shale gas extraction. Specifically, the closer (within around 2 km) a drinking water well was to an active hydraulic fracturing operation, the higher the measured methane concentration compared with non-hydraulic fracturing locations. However, it should be noted that the averages reported in these studies for sites both near and far from drilling were not materially different for groundwater in those locations sampled prior to the commencement of shale gas development.[214]

Methane has been detected in groundwater adjacent to shale gas bores in the Denver-Julesburg basin of north-eastern Colorado with a frequency that suggests a low to medium likelihood of occurrence.[215] The most recently published work on this subject concluded that most of this methane was microbially generated and likely to have come from shallow coal seams that occur in the basin, and not from the deep shale gas formations. Only 0.06% of sampled bores contained methane at depth.[216] The reason that methane was able to migrate upwards was because these shallow coal seams had not been effectively sealed off as part of the well construction process, thereby indicating the need for much closer attention to be paid to the identification of and planning for isolation of such sources during the well design phase of operations.

209 ACOLA Report; US EPA 2016a.
210 ACOLA Report; Origin submission 153; Santos submission 168; US EPA 2016a; Dusseault and Jackson 2014; King and King 2013.
211 US EPA 2016a, pp 9-46.
212 ANZECC 2000; NHMRC 2016.
213 Osborn et al. 2011; Jackson et al. 2013.
214 Vidic et al. 2013.
215 Ingraffea et al. 2014; Jackson et al. 2013.
216 Sherwood et al. 2016.

These near well detections of methane are consistent with the buoyant nature of the gas and its consequent physical behaviour, initially rising vertically close to a wellbore.[217] As the methane (in dissolved or free form) enters the groundwater it will be transported laterally, with the concentration decreasing with distance from the well as a function of dispersion, dilution, and attenuation by bacterial processes. If sufficient oxygen is present, methane can be oxidised to carbon dioxide and water (**Figure 7.11**).[218] Methane can also be oxidised under anaerobic (no oxygen) conditions if sufficient dissolved sulfate is present in the groundwater.[219]

The Panel is unable to assess the potential for microbial decomposition of methane within NT aquifers because there is insufficient information on depth profiles of dissolved oxygen and sulfate concentrations in aquifers. This information is needed to determine the thickness of aquifers likely to be able to sustain either aerobic or anaerobic degradation pathways.

As noted above, methane is not considered to be a toxic component in groundwater, however, the presence of methane can be an explosion hazard. Explosions can occur if methane accumulates to a sufficient concentration in an enclosed space (for example, in the air gap above the water in a water bore or the headspace in a tank). In this context, the US Department of the Interior advises (based on guidance developed by the US Geological Survey (**USGS**))[220] owners of wells with dissolved methane concentrations greater than 28 mg/L (approximately the solubility limit at ground surface) to immediately contact their local authorities to obtain assistance and guidance in venting the wellhead and for other possible remediation alternatives. It also recommends that methane concentrations ranging from 10 to 28 mg/L in water signify an action level where the situation should be closely monitored (and with concentrations less than 10 mg/L no action is required) other than periodic monitoring to see if methane concentrations are increasing.

These guidance values for methane concentrations are based on the potential for explosion risk under certain circumstances. They are not environmental or health risk guidelines based on the occurrence of methane in the groundwater. However, if the rate of methane flux is so high that it bubbles to the surface, or if there is a leaky well head, then there is the potential for fire at the surface. This is also an issue for greenhouse gas emissions (Chapter 9). In both cases rapid action is needed to stop the flow.

One issue that requires additional research is what happens to methane in groundwater when it is degraded by the action of special bacteria that are present and what are the consequences for groundwater quality. The aerobic (oxygen present)[221] oxidation of methane produces carbon dioxide, while the anaerobic (no oxygen present)[222] oxidation in the presence of sufficient sulfate generates bicarbonate and sulfide. While there is evidence that the oxidation of methane in groundwater can have secondary impacts on water quality close to a well, the available data suggests that this effect is of limited extent.[223]

The Panel is not able to provide any further assessment of the potential significance of the issue of methane oxidation in NT groundwaters for two reasons: first, there is insufficient data available on oxygen and sulfate concentration profiles in these aquifers and second, the occurrence of these processes and the potential for adverse impacts on groundwater quality will be very location specific. Additional information should become available as part of the SREBA recommended in Section 7.4.3 (***Recommendation 7.5***).

Rapid methods for determining methane concentrations in water are now available.[224]

7.6.1.2 Contamination by wastewater

Despite Osborn et al. having found elevated methane adjacent to shale gas wells, the authors also categorically state that they *"found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids."* [225] Specifically, there was no evidence of contamination of the shallow drinking water wells near active drilling sites from deep brines and/or fracturing fluids, with the concentrations of salts measured in these wells being consistent with the baseline historical water quality data. This conclusion is consistent with other published work.[226]

217 Dusseault and Jackson 2014.
218 Cahill et al. 2017.
219 Van Stempvoort et al. 2005; Schout et al. 2017.
220 Eltschlager et al. 2001.
221 Cahill et al. 2017.
222 Van Stempvoort et al. 2005.
223 Cahill et al. 2017; Van Stempvoort et al. 2005.
224 Gonzalez-Valencia et al. 2014.
225 Osborn et al. 2011, p 8175.
226 Vidic et al. 2013.

Recent comprehensive research using an array of geochemical fingerprinting techniques has also concluded that there is a lack of evidence for contamination of groundwater resources by deep water from shale gas formations.[227] Importantly, this study found that where there was evidence of aquifer contamination, the signature of the contaminants was consistent with that of surface spills of flowback or produced water, and not leakage from wells. That is, the contamination had occurred as a result of surface spills rather than from upwards migration through the well bore (see Section 7.6.3 for discussion of surface spills).

A recent study by CSIRO as part of the NCRA of chemicals associated with extraction of CSG (see Section 7.4.2.3 and Chapter 4 for a description of the NCRA) used computer modelling to investigate the possibility that chemicals remaining underground after hydraulic fracturing could return to the near surface environment and contaminate groundwater.[228] This study was undertaken for CSG, where the gas is extracted from a coal seam aquifer that is much closer to the surface than for a non-aquifer shale gas formation, accordingly, the results of the CSIRO study provide a more conservative assessment of likely risk given the much greater distance between the (near surface) aquifers and the very deep shale gas formations.

The following four plausible transport release scenarios for movement of chemicals from depth to near surface were developed and assessed by the CSIRO:

- **pathway 1:** fracture growth into an overlying aquifer - this scenario considered hydraulic fracture fluid loss into an overlying aquifer and site conditions that favour height growth of a vertical hydraulic fracture upward towards and into a shallower aquifer (equivalent to Path 2 in **Figure 7.10**);
- **pathway 2:** fracture growth into a well through pre-fracturing permeability and new fractures - this involves two wells within the same coal seam connected by a pre-existing hydraulic fracture (equivalent to abandoned exploration well path in **Figure 7.10**);
- **pathway 3:** well rupture during injection - this scenario considers rupture of a cased well during a fracturing injection operation (equivalent to Path 1 in **Figure 7.10**); and
- **pathway 4:** fracture growth into a fault - assessment of leakage potential through a fault that connects the coal seam to an overlying aquifer (equivalent to Path 2 in **Figure 7.10**) .

The CSIRO assessment concluded that these pathways are either unlikely (high to very high confidence for pathway 3), or extremely unlikely (less than 5% probability for pathways 1, 2 and 4), in an Australian context. Therefore, it is unlikely that chemicals remaining underground after hydraulic fracturing will reach surface aquifers in concentrations that would be unacceptable for domestic or stock water or aquatic ecosystems.

In summary, therefore, the Panel finds that based on the available evidence, the likelihood of contamination of NT groundwaters by the upward migration of contaminated fluids as a result of hydraulic fracturing is 'very low', whereas the likelihood of contamination by methane is 'low' to 'medium'. The consequence to water quality (specifically the impact on groundwater used for drinking or stock watering) from the occurrence of methane is rated as 'low' because methane in water is non-toxic. However, the presence of methane above a threshold value (10-28 mg/L) could result in an explosion risk under certain, albeit unlikely, circumstances.

The Panel has determined that contamination of groundwater is unacceptable if the concentration of chemicals (toxicants) in the groundwater exceeds human and stock health levels by the time the plume reaches any population centre or pastoral property drinking water or stock watering bore.[229] Currently, there is insufficient information available to assess whether this situation could arise as a result of any onshore shale gas industry in the NT. This requires site-specific modelling to be undertaken, a task that is not simple as noted by DENR for the Beetaloo Sub-basin when it stated that,

> *"the issue of water quality modelling and monitoring in karstic environments is problematic. Generally, without knowledge or mapping of the karstic features and structures near to the source of contamination, the immediate fate and transport of dissolved constituents is difficult to predict on a local scale. Further, study would need to be undertaken to characterise the advection, dispersion and diffusive properties of such aquifers to enable the modelled prediction of movement of a contaminant plume on a larger scale."* [230]

227 Harkness et al. 2017.
228 Mallants et al. 2017.
229 ANZECC 2000; NHMRC 2016.
230 DENR submission 428, p 15.

In practice, a rigorous groundwater monitoring system should be in place to provide early detection of any contamination, with rapid implementation of assessment and remedial action of the types summarised by Origin.[231] Origin indicated to the Panel that if a substantial spill of wastewater occurred, remediation would be undertaken using a variety of methods underpinned by an understanding of human and environmental risks. The process consists of three stages:

- **stage 1:** a detailed site investigation that uses intrusive methods to collect samples from the source and subsurface in accordance with Australian Standards (AS4482);
- **stage 2:** health and environment risk assessment performed in accordance with the National Environment Protection (Assessment of Site Contamination) Measure 1999; and
- **stage 3:** implementation of the remediation action plan and subsequent adherence to monitoring plans to demonstrate that remediation has been successful.

Remediation options that can potentially be adopted include:

- monitored natural attenuation, whereby the contaminants naturally reduce in concentration through dilution, adsorption on the mineral matrix, or biological degradation within an aquifer. This is an appropriate approach where there are a lack of nearby groundwater users and high potential for contaminants to be attenuated by natural processes;
- source removal, including installation of pump and treat systems to extract water from the aquifer for treatment on-site to meet water quality criteria before the treated water is disposed of off-site; and
- in-situ flushing, whereby uncontaminated water is pumped into the aquifer downgradient of the source where dilution, desorption, solubilisation and/or flushing of the contaminants can occur, followed by extraction of the flush water if needed.

Additionally, in response to a request from the Panel, Santos provided information on possible methods for remediation of aquifers that become contaminated from either leaky wells or surface spills of wastewater.[232] Santos' policy is to focus on avoiding the likelihood of contamination, but if contamination does occur, its remediation methods focus on the water-soluble chemicals, with extraction and treatment of the contaminated groundwater the most effective means of remediation.

In the specific case of the Beetaloo Sub-basin, the general movement of groundwater in the CLA is towards the north and is generally very slow. Estimates indicate that it would be only metres per year in the northern Beetaloo Sub-basin and considerably less in the southern Beetaloo Sub-basin.[233] This slow rate of movement means that it would take decades for water containing contaminants to travel even 100 m. Therefore, provided a leak is detected early by monitoring systems installed close to well pads, there is enough time to undertake remedial action before the contaminated plume reached domestic drinking or stock watering bores. However, as discussed in Section 7.3.1.3, considerably faster rates of up to 1,000 m/y have been measured in the northern CLA around Katherine, consistent with the preferential flow that can occur through limestone aquifers and through sinkholes and cavities. This would require more rapid remediation responses. However, with appropriately located monitoring systems and appropriate offset distances, any contamination is still likely to be detected in time to avoid domestic or stock water bores.

The Panel's view is that monitoring of key water quality indicators in the groundwater in close proximity (that is within 10-20 m) to each planned well or well pad is essential, and that this monitoring should commence prior to any well drilling, with subsequent monitoring being particularly focussed on the hydraulic fracturing stages. To this end, multi-level monitoring bores must be installed in advance (at least six months) prior to the drilling of a gas well and designed to ensure full vertical coverage of any aquifer(s) currently supplying, or potentially being able to supply, water for environmental or consumptive (stock or domestic) uses. The bore array must have a level of vertical resolution at least sufficient to be able to identify whether a leak of fluid or gas is occurring in the top, middle or bottom zones of an aquifer. At a minimum, electrical conductivity should be measured in real-time as an indicator providing 'early warning' of contamination, with the results telemetered from the site to the regulator and made available

231 Origin submission 433, pp 27-28.
232 Santos submission 420, p 4.
233 DENR submission 429.

to the public. The use of telemetry for other parameters should be reviewed every five years or as technological improvements become available. Additionally, other water quality indicators determined by the regulator must be measured quarterly, with the results made publicly available within one month of sampling. The combination of continuous and randomised spot monitoring should continue for three years, after which time its fitness for purpose should be reviewed by the regulator.

If the electrical conductivity or other measurements suggest that a leak has occurred, or is occurring, more detailed investigations must commence immediately, with remediation to be initiated as soon as practicable. Parameter values for setting action thresholds should be determined from the data collected during the SREBA, and reviewed periodically by the regulator.

The text above specifically refers to the installation and monitoring of all new exploration wells. However, there are already a number of explorations wells (including the Amungee NW-1H well) that exist. The Panel recommends that these wells also require the installation of multilevel bores prior to the approval of either first time or repeat hydraulic fracturing activity.

Notwithstanding monitoring systems being in place, a further level of protection should be provided by locating well pads a minimum distance from water extraction bores. Data from the US suggest the minimum offset distance between well pads and stock or domestic bores is 1 km.[234] Recent work by CSIRO on assessing groundwater transport away from CSG wells has suggested that 2 km is an appropriate minimum distance.[235] While these potential offsets are based on areas of particular hydrogeology in the US and from CSG fields in Queensland, they are nevertheless consistent with the maximum offsets in place for a number of jurisdictions.[236]

For shale gas developments in the NT, the minimum offset distance should be established on a region specific basis by the application of findings from groundwater modelling, and consideration of the potential for transport of contaminants, as well as the likely maximum drawdown extent as discussed in Section 7.5.2. However, as a default, and as a matter of caution, the Panel recommends that an offset distance of 1 km be used.

Recommendation 7.11

That prior to the grant of any further exploration approvals, in order to minimise the risk of groundwater contamination from leaky gas wells:

- ***all wells subject to hydraulic fracturing must be constructed to at least Category 9 (or equivalent) and tested to ensure well integrity before and after hydraulic fracturing, with the integrity test results certified by the regulator and publicly disclosed online;***
- ***a minimum offset distance of at least 1 km between water supply bores and well pads must be adopted unless site-specific information of the kind described in Recommendation 7.8 is available to the contrary;***
- ***where a well is hydraulically fractured, monitoring of groundwater be undertaken around each well pad to detect any groundwater contamination using multilevel observation bores to ensure full coverage of the horizon, of any aquifer(s) containing water of sufficient quality to be of value for environmental or consumptive use;***
- ***all existing well pads are to be equipped with multilevel observation bores (as above);***
- ***as a minimum, electrical conductivity data from each level of the monitor bore array should be measured and results electronically transmitted from the well pad site to the regulator as soon as they are available. The utility of continuous monitoring for other parameters should be reviewed every five years or as soon as advances in monitoring technology become commercially available; and***
- ***other water quality indicators, as determined by the regulator, should be measured quarterly, with the results publicly disclosed online as soon as reasonably practical from the date of sampling. This monitoring regime should continue for three years and be reviewed for suitability by the regulator.***

234 Osborn et al. 2011; Hill and Ma 2017.
235 Mallants et al. 2017.
236 NSW Chief Scientist and Engineer 2014.

7.6.2 Unacceptable groundwater contamination due to faulty decommissioned or abandoned wells (pathway 1)

The Panel has assessed the risk that groundwater could be contaminated from a decommissioned or abandoned leaky well, with unacceptable adverse effects on domestic drinking water or stock watering supplies. The process for decommissioning any onshore shale gas wells when production has ceased is discussed in Section 5.3.2.5.

An extensive review of decommissioned wells by NSW's Chief Scientist noted that, *"if designed, constructed and abandoned to best practice, wells that are decommissioned to current standards have a low likelihood of environmental damage, but that there is uncertainty in relation to the potential long-term impacts. Studies of CO2 subsurface storage wells suggest that cement would be able to isolate CO2 and upper aquifers over the long-term (1,000+ years), but there is scope for additional research to assess specifically the impact of abandoned CSG wells over extended timeframes. Legacy wells that have been abandoned may have been constructed or abandoned to inferior standards, increasing the likelihood of well integrity failure and consequences to the environment."* [237]

The Panel notes that even if well integrity degrades in abandoned wells over the long term, there is unlikely to be a hydraulic driver for leakage into groundwater supplies. Any fluid flow as the result of well integrity failure is likely to be towards the depressurised shale rocks (that is, downwards) rather than away from it (see Section 5.3.2.5 and Appendix 14, Sections 2, 5.14 and 8). Thus, the likelihood of groundwater contamination due to faulty abandoned wells is considered to be 'very low'.

The consequences of such contamination on human and stock drinking water supplies have been discussed above in Section 7.6.1. The consequences to water quality from methane were rated as 'low'. The consequences of other wastewater or geogenic chemicals to drinking water supplies will require detailed site-specific computer modelling to answer, but is likely to be 'low' given the very slow groundwater travel time and the attenuation processes (for example, dispersion, dilution, and microbial decomposition) occurring in the aquifer.

The Panel's overall assessment is that the risk of contamination of aquifers due to faulty abandoned wells is 'low' given the very low probability of this occurring with implementation of world leading practice design and at least current Category 9 construction standards being mandated, and provided that the well passes a rigorous integrity test prior to being decommissioned (see Chapter 5 and ***Recommendations 5.1*** and ***5.2***). In the event that a well does not pass this final integrity test, remedial action needs to be taken to address any identified issues prior to approval being given to decommission and abandon the well.

The question of who should pay for long-term monitoring of abandoned wells and for cleaning up any leaks that may occur is addressed in Chapter 14.

7.6.3 Unacceptable groundwater contamination due to surface spills of wastewater and fracking chemicals (pathways 2, 3 and 8)

The Panel has examined the risk that spills of wastewater and/or fracturing chemicals could cause unacceptable contamination of surface or groundwater systems. These spills can occur both on-site and off-site (transport and pipelines).

7.6.3.1 On-site spills

The likelihood of spillage of wastewaters is always present in resource extraction operations, and there are numerous examples of spillage from the onshore shale gas industry in the US,[238] and the CSG industry in Australia.[239]

With onshore shale gas operations there is potential for on-site accidental leaks and spills of chemicals, hydraulic fracturing fluids, flowback or produced water, including:[240]

- the loss of stored flowback or produced fluids due to the failure of wastewater storage ponds;

237 NSW Chief Scientist and Engineer 2014.
238 US EPA 2016a, Section 7.4; Maloney et al. 2017.
239 Santos 2012.
240 Santos submission 168, p 99.

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

The Panel has considered two factors in assessing the likelihood of a wastewater spill contaminating an aquifer: first, the likelihood of a spill actually occurring, and second, the likelihood that the contaminants would pass through the surface soil and rock layer to an the aquifer.

The evidence available to the Panel is unequivocal. On-site spills of chemicals and wastewater are very likely to occur on onshore shale gas well pads.[241] The causes of these spills are generally container and equipment failures, human error, blowouts, pipeline leaks, and inappropriate dumping or disposal of wastewater.[242] The spills are mostly relatively small in volume (that is, less than 1,000 L), confined to the well pad area (84% according to the US EPA) and capable of being rapidly cleaned up. The US EPA has noted that of the produced water spills (typically the largest volumes spills), 63% have resulted in soil contamination, 8% reached surface water resources, and 0.4% were documented as reaching groundwater.[243]

The largest spills can come from the failure (leakage), or overtopping of wastewater containment ponds, or from the rupture of pipelines transporting wastewater. The likelihood of leakage from containment ponds can be mitigated by the use of double lined systems with leak detection. However, there is still the very real possibility of overtopping of storage ponds during the wet season. Santos proposes to allow at least 0.3 m freeboard (distance between the water level and the top of the pond) to minimise the risk of pond overtopping during the wet season, however, it provides no detail on how this will be guaranteed.[244] Origin proposes that *"any open storage (tanks, pits, etc) that are in use to contain fluids other than fresh water during the wet season must have a freeboard equal to 150% of the maximum recorded frequency, duration, intensity event in that region to prevent overflow from any rainfall event."*[245] However, past experience with extreme weather events in the NT has shown that design must be based on the maximum probable precipitation event, coupled with an appropriate wet season maximum operating level. World leading practice is moving towards the use of closed tanks for the storage of wastewaters, which removes the risk of overtopping caused by input of rainwater.[246]

The likelihood of the occurrence of spills can be reduced with world leading practice chemical spill and wastewater containment facilities, well maintained equipment and comprehensive management strategies.

The Panel notes that even if a wastewater spill does occur, it will nevertheless need to penetrate the soil and rock layer to reach the groundwater, and that concentration of chemicals in the wastewater will be dependent on:

- the volume of spill;
- the depth to groundwater;
- the permeability of the rocks between the surface and the groundwater table;
- the interaction (sorption, microbial decomposition) of contaminants within the soil zone to reduce concentrations; and
- the effectiveness of engineering measures and clean up procedures to mitigate the possible transport of contaminants.

The Panel received two submissions that modelled the likelihood of a surface spill of wastewater reaching the CLA in the Beetaloo Sub-basin. The first, a report by EHS Support,[247] provided a modelled assessment of the rate of infiltration for three spill scenarios (1,000 L, 100,000 L and 1,000,000 L) through approximately 80 m-thick soil and rock layer (cretaceous siltstones and

241 Maloney et al. 2017; Patterson et al. 2017; US EPA 2016a.
242 US EPA 2016a, pp 7-42.
243 US EPA 2016a, Appendix A, p 18.
244 Santos submission 168, p 99.
245 Origin submission 476, p 2.
246 BHP 2016, p 5.
247 Santos submission 420, Appendix A, Report by EHS Support (**EHS Support 2017**).

mudstones) to the underlying aquifer in the vicinity of the Santos Tanumbirini exploration well. In this context, it should be noted that 10,000 L is considered to be a 'large' spill based on data from the US.[248] A number of even larger spills do occur noting that, for example, in North Dakota in 2015 there were 12 releases of 79,000 L or more out of a total of 609 spills.[249] The US data confirmed that the range of volumes spanned by the EHS Support assessment were realistic.

In the absence of any mitigation or management, the EHS modelling suggests that it would likely take at least 10 y for the 1 ML (1,000,000 L) spill to reach the groundwater. During this time, many of the concentrations of many of the organic and inorganic contaminants would be reduced by various attenuation pathways (microbial decomposition, adsorption to soil particles) during their through the soil layer.[250]

The second assessment, undertaken by Cloud GMS,[251] considered a different scenario and used a different modelling approach to that used by EHS Solutions.[252] It modelled the likely effect of leakage from a drill mud pit extending over 60 days, consistent with an unconstrained leakage for the entire operational life of the pit. This was a much larger volume of infiltration than the maximum modelled by EHS Solutions (35 ML, compared with 1 ML). However, the conclusions of the two studies were similar insofar as in this part of the Beetaloo Sub-basin, it would be unlikely that a large surface spill or leak of wastewater would reach the groundwater table in a period of less than 10 years.[253]

Cloud GMS also modelled what might happen if the entire load of a B-Double Tanker was to be discharged in this location as a result of a transport accident. Since the volume of the tanker (50,000 L) represents only one-thousandth of the volume in the simulated leak from the pits, the conclusion that this spill would not reach the groundwater table was consistent with the EHS Solutions assessment. Overall, Cloud GMS concluded that "based on the scenarios considered the likelihood of surface spillage migrating to the water table is low taking into account the water table depth (greater than 60 m), spill volumes, likely timeframe for spill containment/remediation and existing controls".[254]

The Panel notes that neither assessment factored in the potential effect of a major rainfall event following the spill. This could be an issue for a spill or leak that occurs toward the end of the dry (before clean up can occur) or during the wet. Additionally, DENR noted that, *"if a spill occurred in an area where the sediments overlying the karstic limestone were thin, or near a sinkhole, then infiltration could occur within days."*[255]

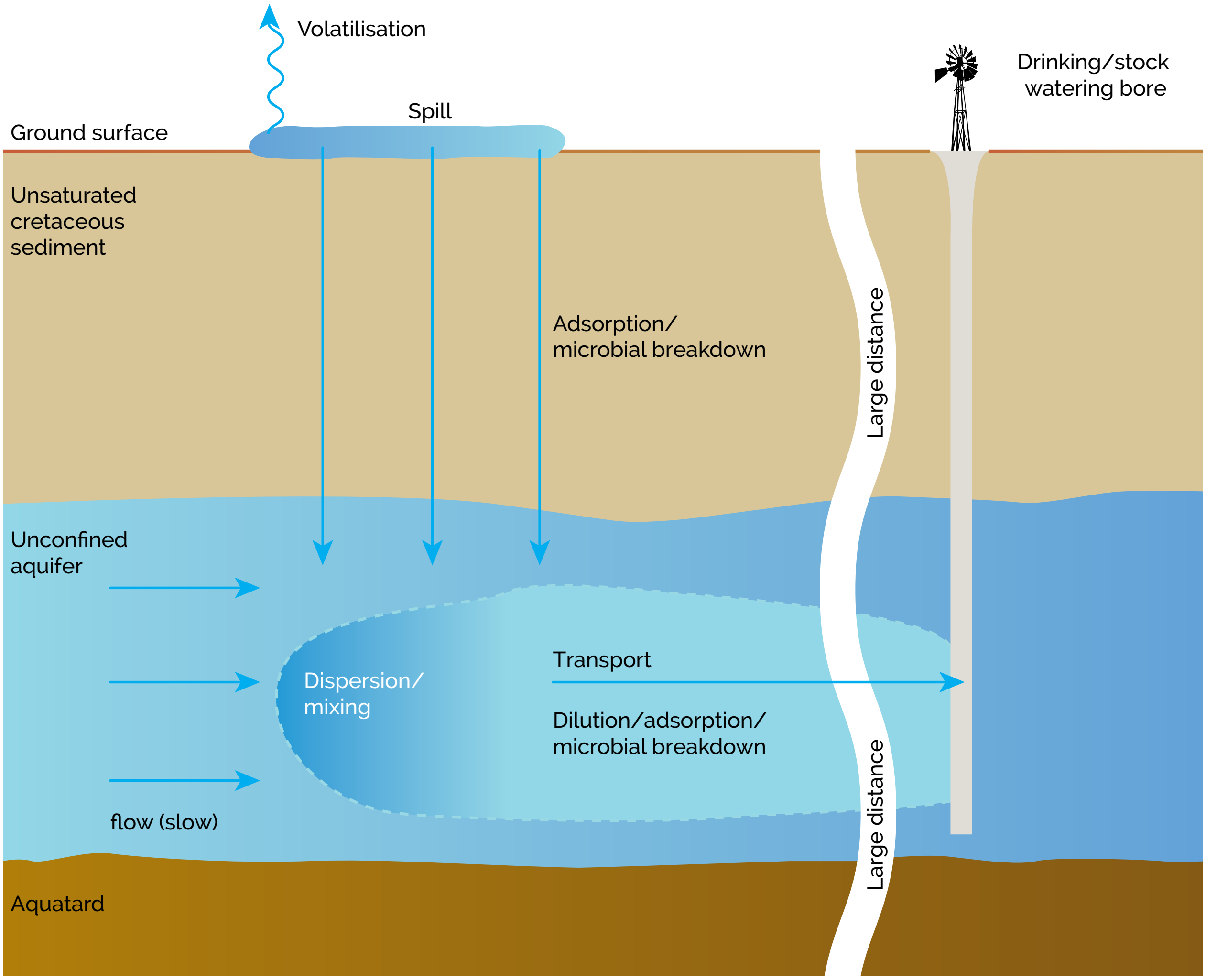
The downward transport of a surface spill to the groundwater will be location specific. The closer the groundwater is to the surface, and the more permeable the horizons from the surface to the aquifer, the higher the risk that the aquifer may be contaminated before remedial action could be effectively implemented. Each prospective gas producing region in the NT will need to be assessed separately based on site-specific characteristics.

While the Panel's assessment is that the likelihood of on-site spills occurring is 'high', the probability that these spills will contaminate groundwater aquifers is 'low', particularly in the Beetaloo Sub-basin. There is, however, one caveat on this finding, namely, that there may be preferential pathways in certain karst regions of the NT.

The consequences if a spill of wastewater reached an aquifer would be the same as those discussed above in Section 7.6.1. That is, the contaminants would be transported slowly within the aquifer (perhaps 1-2 m/y),[256] diluted by mixing, and the concentrations of many organic chemicals reduced by microbial degradation (**Figure 7.12**).

248 Maloney et al 2017; US EPA 2016a.
249 US EPA 2016a, pp 7-26.
250 McLaughlin et al. 2016.
251 Origin Energy Ltd, submission 469 (**Origin submission 469**), Appendix 3, Beetaloo Basin - Groundwater Impact Risk Assessment, prepared by Cloud GMS, September 2015, Appendix D. (**Cloud GMS 2015**).
252 Origin Amungee NW-1H Environmental Management Plan, Appendix 5.
253 Cloud GMS 2015; EHS Support 2017.
254 Cloud GMS 2015, p D21.
255 DENR submission 429, p 3.
256 DENR submission 429, pp 2-3.

Figure 7.12: Schematic of the potential pathways for an on-site spill of contaminated wastewater through the soil/rock layer to an unconfined aquifer and then within the aquifer.



The US EPA notes two reasons why the issue of aquifer contamination can be problematic.[257] The first is that groundwater contamination can only be detected if monitoring bores are installed in the area where contamination is most likely to occur, and the second is that groundwater contamination is difficult and expensive to remediate (see also discussion in Section 7.6.1).

The Panel considers that it is essential that a comprehensive wastewater spills containment and management plan is prepared by gas companies for each well pad using a rigorous set of world leading practice guidelines, with these waste management plans approved and enforced by the regulator.

In New Zealand, three levels of containment are required for all oil and gas sites to manage possible spills: the first is a containment of wastewater in tanks (and not ponds), the second consists of bunds around the site and the third consists of a stormwater pond to collect rainwater that falls on the site.[258] Additionally, some sites now have a geomembrane or low permeability compacted clay layer over the well site to reduce the probability of spills penetrating into the soil and rock layer overlying the aquifer. A rigorous groundwater monitoring program for each well pad (as recommended in Section 7.6.1) must be established, with the data made publicly available online as soon as reasonably practicable. In the case of any contamination, the gas company must act immediately to fix any problems.[259]

Secondary containment measures should also be put in place on work sites to mitigate the risk of a spill in the event that the primary containment fails, by preventing or mitigating any uncontrolled release of chemicals to the ground and to waterways. This can be achieved, 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.

257 US EPA 2016a.
258 NZ Report 2014, pp 51-52.
259 Ms Justine Johnson, submission 537.

The Panel has little information regarding what, if any, wastewater treatment facilities will be employed by the gas companies. Decisions about wastewater treatment must be made strategically, taking into account any development of the industry on a regional scale, and taking into account the views of landholders, local communities and the environment (see ***Recommendation 5.5***).

The Panel has also identified poor practices that can occur with the transport of wastewater (Section 5.8.2), and has recommended that a framework for managing wastewater transport be developed to include an auditable chain of custody system for any transport of wastewater (including by pipelines) that enables source-to-delivery tracking of consignments of wastewater (see ***Recommendation 5.5***).

Recommendation 7.12

That prior to the grant of any further exploration approvals, to reduce the risk of contamination of surface aquifers from on-site spills of wastewater:

- ***the EMP for each well pad must include an enforceable wastewater management plan and spill management plan;***
- ***enclosed tanks must be used to hold all wastewater; and***
- ***the well pad site must be bunded to prevent any runoff of wastewater, and be treated (for example, with a geomembrane or clay liner) to prevent the infiltration of wastewater spills into underlying soil.***

Recommendation 7.13

Upon a gas company undertaking any exploration activity or production activity, monitoring of the groundwater must be implemented around each well pad to detect any groundwater contamination, adopting the monitoring outlined in Recommendation 7.11. If contamination is detected, remediation must commence immediately.

7.6.3.2 Spills during transportation

The Panel has assessed the risk of contamination of surface waters due to off-site spills during transportation of chemicals and wastewater associated with any onshore shale gas hydraulic fracturing operations.

The development of any onshore shale gas industry in the NT requires that fracturing chemicals and fluid additives be transported to the various drill sites. This gives rise to a risk that spills may occur during transportation. The conduct of such transport is regulated by the *Australian Code for the Transport of Dangerous Goods by Road and Rail*, a code that is given legal effect to in the NT by the *Transport of Dangerous Goods by Road and Rail (National Uniform Legislation) Act 2010* (NT), which is administered by NT Worksafe.

Additionally, if wastewater is transported by pipeline for reuse, or to a treatment plant, there is a risk that spills may occur due to broken pipelines. Pipelines carrying waste require an approval from the NT EPA under the *Waste Management and Pollution Control Act 201*6 (NT) (**Waste Management Act**).

Road and rail transport

The largest number of road traffic accidents occurs during the dry season in the NT because of the heavy traffic caused by an influx of tourists.[260] However, it is during the wet season that road transport accidents are most problematic, with any spilt contaminants potentially being washed 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 roads and pipeline corridors (see Section 7.6.9).

The Panel notes that 15 of the 113 chemicals used for the extraction of CSG and assessed by the NCRA were identified as being of potential concern in the event of a direct (unmitigated) release of the chemical(s) to an aquatic ecosystem occurring as the result of a transport accident (spill).[261] These were the only circumstances identified in that assessment that could allow CSG

260 https://dipl.nt.gov.au/transport/transport-statistics-surveys-and-research/road-toll-statistics.
261 Australian Department of the Environment and Energy 2017a-f.

chemicals (and by implication some of those used for shale gas extraction, as documented in the list of chemicals used for the Amungee NW-1H fracturing operation) to potentially occur in surface water at concentrations toxic to aquatic organisms. The findings from the NCRA study underscores the importance of handling and transporting all chemicals in accordance with the relevant Territory (and State if being transported to or from the NT) regulations and industry codes of practice.

Current industry practice for the transportation of chemicals requires that both primary and secondary containment measures are in place.[262] Primary containment ensures that additives are stored and transported in properly designed materials (for example, high density polyethylene thermoplastic material) and protected by a steel cage to maintain the structural integrity of the container. Secondary containment measures should also be put in place to mitigate the risk of a spill in the event the primary containment failed. For example, Origin arranged for additives transported to the Amungee NW-1H lease to be transported in trucks that had secondary containment on the trailer beds.[263]

In Chapter 8, the Panel has noted that Pangaea has proposed the installation of a public benefit multi-user rail siding on the Adelaide to Darwin railway line that, *"would allow the efficient carriage of consumables, drill bits and other equipment for the entire Beetaloo Basin, lowering the use of trucks on main roads and highways."* [264] This suggestion warrants further consideration.

Recommendation 7.14

That the Government, having regard to the measures detailed in Recommendation 5.5, undertakes a review to determine whether:

- ***restrictions need to be placed on the transport of hydraulic fracturing chemicals and wastewater during the wet season, particularly on unsealed roads, to avoid the risk of spills; and***
- ***rail transport of some or all of the hydraulic fracturing chemicals and other consumables required, be used to avoid the risk of spills.***

Pipelines

The other possible source of off-site spills is from broken pipelines carrying 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.[265] The Panel has been told that gas pipelines will be buried,[266] but it is possible wastewater pipelines will be on the surface.

The Panel's assessment is that the likelihood of an off-site pipeline leak is 'low', provided that pipelines (gas and wastewater) are buried and that robust pipeline construction and management guidelines are developed and enforced by the regulator. The Panel also notes that pipelines carrying wastewater would also require an approval from the EPA under the Waste Management Act. The consequences if a spill does occur will depend upon the volume of the spill, the speed and effectiveness of clean up procedures and the time of year the spill occurs. If a pipeline spill occurs during the wet season, the clean up will be more difficult, and there will be a greater likelihood of contaminants being more widely dispersed and perhaps reaching a surface waterbody, albeit in a more dilute form.

7.6.4 Unacceptable contamination of surface aquifers due to the reinjection of treated or untreated wastewater (pathway 5)

The Panel has examined the risk of contamination of surface aquifers due to the reinjection of treated or untreated wastewater into other aquifers or wells associated with extraction of oil and gas from conventional reservoirs. Reinjection of wastewater is common practice by shale gas companies overseas, particularly in the US, where the US EPA found that in 2012 around 93% of

262 Origin submission 153, p 82.
263 Origin submission 153, p 82.
264 Pangaea submission 427, p 12.
265 US EPA 2016a, pp 7-26.
266 Origin submission 433, p 49.

the flowback and produced water from the oil and gas industry in that country was injected into Class II wells associated with conventional oil and gas reservoirs.[267] The US EPA also reported that this practice had been associated with seismic activity in several States.[268]

For this reason, the onshore shale gas industry in the US is now focussed on reusing more of its wastewaters for well drilling and hydraulic fracturing, or on treatment to reduce the volume requiring ultimate disposal. 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.[269]

There has been a limited pre-feasibility assessment on reinjecting CSG produced water in Queensland, which the Panel understands has now been discontinued due to technical issues.[270]

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 that there are no adverse chemical reactions with aquifer materials leading either to clogging of the injection bore or aquifer, or to the liberation of other chemicals in the aquifer material.[271]

In its submission to the Panel, Origin noted that is has not considered or planned for reinjection of flowback fluid and that it would not consider this option *"except where the water is treated to the same standard as the aquifer water and regulatory approval is provided"*.[272]

The Panel has insufficient information regarding any potential reinjection of wastewaters in the Beetaloo Sub-basin (or elsewhere) to make an assessment of the contamination risk associated with this practice. The information required to support an assessment of the risk caused by this practice would include the quality and volume of the treated or untreated 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 if reinjection occurred. Additionally, geological modelling of the actual site where reinjection is proposed needs to be undertaken before any approval to carry out such activity was granted. Accordingly, the Panel considers that the risks of contamination from reinjection of wastewater, were it to occur, are insufficiently understood, and therefore, it should not be permitted (see ***Recommendation 7.9***).

7.6.5 Unacceptable contamination of surface aquifers due to induced connectivity between hydraulically fractured shale rock formations and overlying aquifers

Claims were made both in written submissions and during community consultations that surface aquifers could be contaminated as a result of the hydraulic fracturing process by fracturing fluids travelling through the rock strata from the fractured shale area vertically to overlying aquifers containing high quality water.[273]

Movement of fluid between the shale layer and an aquifer requires both a physical pathway (for example, interconnecting pores within the rock matrix, or a fracture or fault in the rock) and a driving force.[274] Additionally, the potential for fluid migration will be different in the period following initiation of fracturing and prior to gas production, and after fracturing is complete and during production when the pressure in the fractures is reduced.[275]

The US EPA identified four possible pathways by which hydraulic fracturing fluids could migrate from the fractured shale region into a surface aquifer:[276]

- the migration of fluids out of the gas production zone through pore spaces in the rock;
- the migration due to fracture outgrowth out of the production zone;
- the migration through fractures intersecting with geological features such as permeable faults or pre-existing natural features; and
- the migration through fractures intersecting with nearby wells.

267 US EPA 2016a.
268 US EPA 2016a.
269 US EPA 2016a.
270 Healthy Headwaters 2011.
271 This is discussed in some detail in NRMMC 2009.
272 Origin submission 153, p 84.
273 Lock the Gate Alliance Northern Territory, submission 171 (**Lock the Gate submission 171**), p 10.
274 US EPA 2016a, pp 6-38.
275 US EPA 2016a, pp 6-39.
276 US EPA 2016a, pp 6-44.

In addition to the need for a physical pathway between the shale layer and the aquifer and a driving force, the potential for fluid migration will be different during hydraulic fracturing compared to the period after fracturing is complete and the pressure in fractures is reduced.[277]

The evidence is that it is highly unlikely that fracking fluids could reach a surface aquifer through the first potential pathway.[278] The large vertical separation distance (1,000 to 3,000 m) between the shale layer and the aquifer, together with the very low permeability of the intervening rock strata, make this a highly unlikely pathway without some fractures assisting the transport process.[279]

The second potential pathway is for fractures to extend out of the shale production zone into another formation. Again, the likelihood of fractures growing out of the shale rock region for distances of 1,000 to 3,000 m is extremely low.[280] For example, the majority of fractures in the Marcellus shale basin were found to have heights of less than 100 m, although fracture lengths up to approximately 600 m have been recorded.[281]

However, as Lock the Gate Alliance Northern Territory (**Lock the Gate**) has noted in its submission, 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.[282] US EPA, Reagan et al. and Westwood et al. have discussed this possibility in detail[283] and have concluded that the risk is low.

According to Origin, Pangaea and Santos, the location of faults is taken into consideration during the design and construction of each well and the 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.[284] This was the case for the Origin Amungee NW-1H well, where a section of the horizontal bore was not fractured because of the inferred existence of a small fault system.[285] Origin told the Panel that,

> *"prior to conducting the HFS operation at Amungee NW-1H Origin assessed the risk of induced connectivity between the hydraulically fractured shale formation and the aquifers. The risk was assessed as follows: first, what is the vertical offset between the target zone and the aquifers; second, are there barriers to fracture height growth between the target zone and aquifers; and third, do the barriers contain the fracture height growth for the designed pumping schedule?"* [286]

The other possible pathways identified above, that is, fractures intersecting with other wells (including active and abandoned wells), are not likely given that there are currently very few deep wells drilled in the NT. However, this is very unlikely to be an issue in the NT given the very low number of deep wells that have been drilled, and moreover, because those that exist are well documented. The US EPA has documented situations where unintended interactions between fractured wells on multi-well pads, called 'frac hits', can occur, most commonly if the lateral separation between wells is less than around 340 m.[287]

The Panel notes that apart from the hydraulic fracturing phase, simple groundwater hydraulics mean that it is highly unlikely that water would flow from the depressurised shale gas aquifer to an overlying aquifer that remains pressurised. The only hydraulically plausible opportunity for limited fluid migration along faults is during the intense pressurisation of the actual hydraulic fracturing. However, it is considered that with close monitoring and management of the pressurisation to ensure that only the desired interval is fractured, this scenario can be prevented. Accordingly, there is a low likelihood of aquifer contamination as the result of groundwater flow through faults as the result of, or exacerbated by, hydraulic fracturing.

The Panel has therefore assessed this risk as 'low', given the vertical distance between the fractured rocks and surface aquifers, and the hydraulic potential for flow between fractured rocks and surface aquifers, provided that fracturing operations avoid proximity to faults.

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277 US EPA 2016a, pp 6-39.
278 Origin submission 153, p 70; Fisher and Warpinski 2012; Flewelling and Sharma 2014.
279 APPEA submission 215; Origin submission 153, p 69; Santos submission 168.
280 US EPA 2016a, pp 6-57; Reagan et al. 2015.
281 US EPA 2016a, pp 6-53; Davis et al. 2012.
282 Lock the Gate submission 171, p 10.
283 US EPA 2016a, pp 6.66-6.69; Reagan et al. 2015; Westwood et al. 2017.
284 Origin submission 153; Santos, submission 168; Pangaea submission 220.
285 Origin submission 153, p 72; IESC 2014.
286 Origin submission 153, p 72.
287 US EPA 2016a, pp 6-71.

Recommendation 7.15

That gas companies must submit details of the locations of all faults that could compromise well integrity. The occurrence of any faults must be addressed in the well design plan submitted to the regulator for approval. The details of all faults and the well design plans must be publicly disclosed online as soon as they are available.

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

Extraction of water required for hydraulic fracturing from local groundwater can result in a decrease in the groundwater pressure in a particular aquifer, which may result in underlying or overlying groundwater bodies flowing into the aquifer and possibly changing its water quality. This is a potential issue of concern in some CSG operations.[288]

The Panel is aware that the volumes of water involved in the hydraulic fracturing of shale are likely to be much less than those involved in CSG operations, where the latter 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 in Section 7.3), the volume of groundwater required can be reduced.

While excessive use of groundwater for hydraulic fracturing has the potential to change groundwater pressures sufficient to impact groundwater flow pathways, and potentially aquifer water quality, it is not possible to quantify this risk to groundwater quality without considering the local hydrogeology and applying site specific predictive computer modelling. This potential risk has not been considered in any of the gas companies' submissions.

Accordingly, the Panel considers that the risks of contamination from possible changed groundwater pressures are insufficiently understood and that, therefore, appropriate local and regional groundwater modelling is required prior to any production approvals being granted (see Chapter 16).

Recommendation 7.16

That appropriate modelling of the local and regional groundwater system must be undertaken before any production approvals are granted to ensure that there are no unacceptable impacts on groundwater quality and quantity. This modelling should be undertaken as part of a SREBA.

A related issue raised during the community consultations was the possible cross-contamination between two shallow aquifers during the well-drilling process. In the Beetaloo Sub-basin, this is possible if gas companies need to drill through the Anthony Lagoon and Gum Ridge aquifers (see **Figure 7.7a**) to reach the Velkerri shale deposit below.

Origin faced this risk when drilling the Beetaloo W-1 well, which is located approximately 85 km south of the Amungee NW-1H well.[289] To mitigate the cross-flow risk, Origin used two casing strings to protect the aquifers: first, an outer hole was drilled (using the metal casing) to below the upper Anthony Lagoon aquifer; and second, the next hole was drilled inside this outer casing to below the Gum Ridge aquifer. In this way, both aquifers were protected from cross-contamination during the drilling.[290]

7.6.7 Unacceptable contamination of surface waters due to the discharge of treated or untreated wastewater (pathway 6)

The Panel has assessed the risk of contamination of surface waters due to the discharge of treated or untreated wastewater from shale gas hydraulic fracturing operations. The discharge of treated shale gas wastewaters to permanently flowing waterways is relatively common practice overseas, although it is decreasing as more flowback and produced water is reused in the hydraulic fracturing process.[291] However, in the Beetaloo Sub-basin, and other semi-arid and arid regions of the NT, surface waters are only present for short periods of time during the wet

288 IESC 2014.
289 Origin submission 1248, pp 16-18.
290 Origin submission 1248.
291 US EPA 2016a.

season. Some larger water bodies, such as Lake Woods and Longreach Waterhole, near Elliott, can persist for multiple years, although satellite imagery from Geoscience Australia indicates that water in these two water bodies was only present for approximately 20% of the time between 1987 and the present.

The Panel considers that the discharge of any onshore shale gas wastewaters to temporary surface waters is problematic because it is difficult to predict the behaviour of any contaminants discharged to such systems. In particular, the variable nature of these temporary streams (and temporary waterholes) makes it likely that discharged contaminants would be trapped in the waterholes left after the temporary streams ceased to flow.

In its submission to the Panel, DPIR indicated that discharge of hydraulic fracturing shale gas wastewaters to waterways are not permitted, stating that,

> *"current practice requires that wastewater from hydraulic fracturing activities is fully contained on site. The fluids may be held in double high density polyethylene (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."* [292]

The Panel has serious concerns regarding any discharge of untreated or treated wastewaters to temporary surface waters, particularly in the Beetaloo Sub-basin and other semi-arid and arid regions. The Panel notes that none of the gas companies have indicated that they would seek to discharge wastewaters (treated or not) to either drainage lines or waterways when these are present.

Recommendation 7.17

That prior to the grant of any further exploration approvals, the discharge of any onshore shale gas hydraulic fracturing wastewater (treated or untreated) to either drainage lines, waterways, temporary stream systems or waterholes be prohibited.

7.6.8 Adverse effects of linear infrastructure on the quality and distribution of surface waters across the landscape

The Panel has assessed the risks to the quality and distribution of surface waters across the landscape from the linear infrastructure that would be needed by any onshore shale gas industry in the NT.

The establishment of any onshore shale gas industry in the NT will require the construction of roads and pipelines (linear infrastructure) across the landscape. These and associated activities (for example, borrow pits excavated for the purpose of providing material for road construction) have the potential to interrupt water flows in the wet season and to increase erosion, with a resultant increase in sediment loads entering streams. Additionally, seismic survey lines can also have similarly disruptive effects, unless properly rehabilitated. Evidence from overseas indicates that well pad development causes far less disruption to the landscape than the extensive network of pipelines and roads required by shale gas development.[293] The construction of roads and other linear infrastructure can also affect small-scale water flows that can play important roles in terrestrial landscapes.

Participants at a community consultation session in Wadeye on 27 March 2017 told the Panel of one instance where the improper location of road embankments by the gas industry in the NT caused a backup of water and altered flow patterns across the landscape. Recent work published by CSIRO has indicated that subsidence of improperly backfilled and compacted buried CSG pipeline corridors resulting in increased erosion is a common occurrence in southwest Queensland.[294] The recent publication *On New Ground – Lessons from development of the world's first export coal seam gas industry*, by the Queensland Gasfields Commission makes specific

292 DPIR submission 226, p 5.
293 Drohan and Brittingham, 2012.
294 Vacher et al. 2016.

mention of erosion problems with installation of pipelines and other infrastructure during the wet season.[295] In addition, it is more likely that increased damage to unsealed roads will occur during intense wet season rainfall events in the Top End, with consequent increased potential for erosion and sediment runoff. Unsealed road crossings are particularly at risk of this occurring (see also Chapter 8).

A relevant study on the effects of road traffic on downstream sediment load (turbidity) and its implication for aquatic life in the NT was conducted in 1997 at an unsealed road crossing over Jim Jim Falls Creek located in Kakadu National Park.[296] A continuously logging data recorder was used to measure the downstream pulses of turbidity as vehicles passed over the crossing. Additionally, the abundance and diversity of fish and benthic macroinvertebrate populations were measured upstream and downstream of the crossing. The study concluded that a threshold level of turbidity for effects on invertebrates and fish was less than 30 NTU and that management strategies should aim to achieve levels below this value. Further, the study found that a turbidity monitoring program should be established to evaluate the effectiveness of any remedial measures implemented. Although the results from this older study are location specific, they do indicate the need for care to be taken in reducing vehicle-induced sediment scouring during periods when water is flowing. This study further indicates the need to more generally minimise erosion from road alignments where the runoff can enter streams.

The impacts on landscape and erosion processes by construction activities associated with the CSG industry in Queensland have been the subject of recent research by CSIRO.[297] It was noted that although industry and pipeline manufacturing guidelines exist on leading practice for effective pipeline installation, soil management, and re-compaction during backfilling, incidences of pipeline subsidence, and surface and tunnel erosion were quite common across the Surat and Bowen Basins.[298] The depression zone caused by subsidence (or tunnel erosion) increased the potential for additional runoff volumes by changing the natural flow of surface water from upslope catchment areas. As a result, substantial volumes of water can be added from the upslope catchment area, which increases the erosion potential. In addition to subsidence and tunnel erosion on trench lines contributing to increased potential for erosion at the field and catchment scales, impacts from soil surface disturbance (for example, vegetation clearance, compaction and soil mixing, or layer inversion) on right of ways can further exacerbate erosion processes. The Panel has assessed the likelihood of road and pipeline construction changing water flows across the landscape, and, therefore, increasing erosion, as ‘medium’.

The Panel has assessed the consequences associated with the disruption of landscape surfaces and increased erosion ‘low’ to ‘medium’, noting that the effects will depend strongly on the size of the region affected, and that these effects will likely be cumulative as the footprint of any shale gas industry expands.

The Panel has received submissions from Pangaea and Origin indicating that they adhere to the various codes of practice for the construction of roads and pipelines, and therefore, no issues are likely to arise.[299] However, community representations to the Panel, together with the extensive data that CSIRO has obtained from southern Queensland, suggests that adherence to construction guidelines does not always occur.[300] In particular, the high intensity and long duration of rainfall events in the NT means that much greater attention needs to be paid to reducing the potential for erosion and disruption of surface water flows during the wet season.

It has been noted by CSIRO[301] that knowledge of existing overland surface flow is essential to reduce impacts from the development of service roads, culverts, well pads, and pipeline corridors. It suggests that surface flow models derived from fine scale digital elevation models are an appropriate tool for monitoring impact of the wider gas industry footprint on surface hydrology, in identifying potential problems during early negotiation with landholders, and in planning and design of future infrastructure.

The Panel is of the view that the acquisition of this information is an essential component of the baseline information required before any onshore shale gas production can occur. The advent of

295 Queensland Gasfields Commission 2017, p 60.
296 Stowar et al. 1997.
297 Poulton et al. 2015; Vacher et al. 2014; Vacher et al. 2016.
298 Vacher et al. 2016.
299 Pangaea submission 220, Appendix 1, pp 51-54; Origin submission 153, pp 249-289.
300 Vacher et al. 2016.
301 Poulton et al. 2015.

(relatively) low cost LIDAR-capable drone technology over the past five years has revolutionised the capability of industry to easily and rapidly acquire high vertical resolution terrain data over lease areas.

Given that the impacts from roads and pipelines are likely to be cumulative, the design of these networks should be planned from the earliest stages of development and at a landscape scale, to avoid unforeseen consequences arising from the incremental (piecemeal) addition of linear infrastructure. This consideration applies to both individual operating leases and to the totality of operations on leases that together cover broad areas of catchment systems. A landscape-scale approach to design of infrastructure is especially critical for regions that have episodically flowing streams and which therefore typically do not receive as much consideration as systems in which water flow occurs for longer periods.[302] Chapter 14 discusses area-based regulation.

Recommendation 7.18

That to minimise the adverse impacts of any onshore shale gas infrastructure (roads and pipelines) on the flow and quality of surface waters, the Government must ensure that:

- ***landscape or regional impacts are considered in the design and planning phase of development to avoid unforeseen consequences arising from the incremental (piecemeal) rollout of linear infrastructure; and***
- ***roads and pipeline corridors must be constructed to:***
  - ***minimise the interference with wet season surface water flow paths;***
  - ***minimise erosion of exposed (road) surfaces and drains;***
  - ***ensure fauna passage at all stream crossings; and***
  - ***comply with relevant guidelines such as the International Erosion Control Association Best Practice for Erosion and Sediment Control and the Australian Pipeline Industry Association Code of Environmental Practice 2009.***

7.7 Aquatic ecosystems and biodiversity

Some of the major features of aquatic ecosystems in the NT were summarised in Section 7.2.3, where it was noted that most of the permanent or semi-permanent surface water bodies in the NT are found in the northern, high-rainfall regions (the Top End). The Panel has little specific information about the aquatic ecosystems sustained by those temporary surface water bodies, or about groundwater-dependent ecosystem in the Beetaloo Sub-basin, or elsewhere in the semi-arid and arid regions of NT.[303]

Accordingly, the Panel has recommended that a SREBA be undertaken before any approval is granted for hydraulically fractured shale gas production in the NT (see ***Recommendation 7.5***). These assessments should focus on improving the knowledge and understanding of water resources (surface and groundwater), aquatic ecosystems (surface and GDEs), and terrestrial ecosystems in potential shale gas basins in the NT.

Below, the Panel provides an assessment of the risks to aquatic ecosystems from any onshore shale gas industry, first, from over-extraction of water for hydraulic fracturing, and second from contaminated wastewater.

7.7.1 Water quantity

Water extraction can have potentially serious impacts on rivers, wetlands and other water-dependent ecosystems, including on aquatic wildlife.[304] Regulation and water extraction can affect all components of the natural flow regime of rivers, and result in ecological degradation.[305] For example, excessive water extraction can potentially cause perennial rivers to become intermittent or temporary,[306] 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.[307]

302 Acuna et al 2017.
303 Duguid et al. 2005.
304 Bunn and Arlington 2002; Burton et al. 2014; King et al. 2015.
305 Burton et al. 2014; King et al. 2015, pp 744-747.
306 Warfe et al. 2011; King et al. 2015.
307 King et al. 2015, p 747.

Tropical savannah rivers are characterised by highly seasonal and predictable flow regimes, but with high interannual variation in the magnitude, timing, and duration of low flows.[308] King et al. 2015 identified three phases of the seasonal flow regime for perennial and intermittent rivers in tropical savannah climates: the wet-dry transition, the dry season and the dry-wet season transition.[309] These hydrological phases are each ecologically important in different ways and will be affected differently by water extraction.

Similarly, adverse effects on the aquatic ecology may occur with discharges to a perennial or intermittent river, depending upon when the discharge occurs. For example, a discharge made towards the end of the wet season can extend the duration of flow and alter the ecosystem development over the wetting-drying cycle.

The Panel has recommended in Section 7.5.1 that extraction of surface water resources for hydraulic fracturing for shale gas should not be permitted in the NT (***Recommendation 7.6***).

The Panel has also assessed the risk of water extraction to groundwater-dependent ecosystems. There was considerable community concern that excessive groundwater extraction from the CLA aquifer could adversely affect the two largest permanently flowing rivers in the NT, namely, the Daly and Roper Rivers.[310] Both these rivers are located north of the Beetaloo Sub-basin, but have their dry-season flows maintained by groundwater inflows from the CLA.[311] There is evidence that the CLA 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.[312]

The importance of Elsey National Park (including Bitter Springs, Mataranka thermal pool and John Hauser Drive) as a tourist venue can be judged by the large number of annual visitors: 156,000 in 2015 and 171,000 in 2016.[313] Accordingly, the community is understandably concerned about the risks to these systems. As the owners of Bitter Springs Cabins and Camping at Mataranka told the Panel, *"we have based on two sets of springs, the Rainbow Springs which is at Mataranka Homestead and the Bitter Springs. They're both in Elsey National Park, just different sides. We all work off the Tindall Water Basin, the water system. Without them we are all out of work as water goes. All the town and other people in the area, we're basically nothing. So basically everybody's employed by those businesses so the whole town's finished if we lose our water, which is spring fed. That's the start. If the springs stop flowing the town will die and we all rely on the water in the springs, the river system, the ground water to survive as it all is one of the same."* [314]

The Panel has been provided with evidence showing that recharge of the CLA in Roper River region occurs locally (within 50 km of the river) during the wet season.[315] If this is the case, water extraction from this aquifer in the Beetaloo Sub-basin, approximately 150-200 km away, is unlikely to have an effect on groundwater inflows to the Roper River since the very low flows in the CLA (estimated to be metres per year) mean that this water would take hundreds to thousands of years to reach the Roper River.[316] However, as discussed Section 7.3.1.1, this may not be the case for any onshore shale gas development (for example, by Hancock Prospecting) closer to the Roper River.[317] Lock the Gate, therefore, has called for further study of the groundwater recharge areas in this region of the Roper River.[318]

Given its importance, the Panel is of the view that the boundary of the Beetaloo Sub-basin SREBA (see ***Recommendation 7.5***) should be expanded to include this region.

Recommendation 7.19

That the SREBA undertaken for the Beetaloo Sub-basin must take into account groundwater-dependent ecosystems in the Roper River region, including identification and characterisation of aquatic ecosystems, and provide measures to ensure the protection of these ecosystems.

308 King et al. 2015, p 744.
309 King et al. 2015, pp 747-753.
310 Somers submission 377.
311 Bruwer and Tickell 2015; DENR submission 230, Addendum 2.
312 Bruwer and Tickell 2015.
313 DTC 2017.
314 Somers submission 377, p 1.
315 Bruwer and Tickell, 2015; A Knapton submission 426, p 3.
316 A Knapton submission 426, p 3.
317 Hancock Prospecting submission 461, pp 1-3.
318 Lock the Gate Alliance Northern Territory, submission 437 (**Lock the Gate submission 437**), p 1.

The northern region of the NT has many GDEs, both aquatic and terrestrial, that may be affected by groundwater extraction.[319] However, this does not appear to be the case in the semi-arid and arid region of the Beetaloo Sub-basin, where the Panel has evidence that there are very few, if any, surface GDEs because the groundwater is typically greater than 30 m deep and is not connected to the surface.[320]

Previously, the Panel (Section 7.2.3) identified the increasing awareness in a number of jurisdictions in Australia of the importance of protecting stygofauna, the subterranean fauna that live in aquifers. The Panel is not aware, however, of any detailed baseline survey of subterranean aquatic ecosystems in the Beetaloo Sub-basin and recommends that such a study be included as part of any SREBA.

Recommendation 7.20

That the Beetaloo Sub-basin SREBA must identify and characterise all subterranean aquatic ecosystems, with particular emphasis on the Roper River region.

7.7.2 Water quality

The effective management of wastewaters (flowback and produced water) is a particularly important issue for aquatic ecosystems and their biodiversity.

7.7.2.1 Surface water ecosystems

As discussed above in Section 7.6, 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.[321] The Panel has recommended that the discharge of treated or untreated shale gas wastewater to surface water systems should be prohibited (***Recommendation 7.17***).

Spills that occur during the dry season, if not cleaned up, can result in contaminated water produced from dissolution of salts on the soil surface being flushed into temporary water bodies during the wet season. Increased erosion and transport of sediments into waterways due to the construction of roads and pipelines can also impact aquatic ecosystems.[322]

There has been limited study of the effects of contaminants on temporary water ecosystems, these being the main surface water bodies likely to be present in the Beetaloo Sub-basin and other semi-arid and arid regions on the NT. Two studies are available that have described potential effects from agricultural, urban land-uses and mining on temporary waters in Queensland and South Australia.[323] The Panel notes that there have been 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.[324]

The Panel has assessed the risks to surface water ecosystems from shale gas fracturing wastewater contaminants to be 'low', provided discharge of wastewaters to surface water bodies is prohibited and effective management practices are in place to prevent any accidental spills from well pads, road tankers or pipelines from entering these water bodies.

7.7.2.2 Groundwater-dependent ecosystems

The Panel has also considered the possible risks to GDE from contaminated aquifers. The two most likely mechanisms by which aquifers could be contaminated are, first, from leaky wells, and second, from on-site spills of chemicals or hydraulic fracturing wastewater (see Sections 7.6.1, 7.6.2 and 7.6.3). In both these cases, the Panel's assessment is that the likelihood of groundwater contamination is 'low', provided the design, construction and operation of hydraulically fractured wells follows regulatory guidelines, on-site wastewater management is effective and enforced, and any accidental spills are rapidly remediated.

319 BOM 2017.
320 DENR submission 230, Addendum 1, p 2; DENR submission 428, p 16.
321 Burton et al. 2014.
322 Entrekin et al. 2011.
323 Ramsay et al. 2012; Botwe et al. 2015.
324 Acuna et al. 2014.

The Panel is not able to comment on the potential consequences to any stygofauna present if an aquifer is contaminated because there is no toxicity data available for these animals. However, as stated above, a more detailed assessment of stygofauna should be part of the recommended strategic regional environmental baseline assessments recommended by the Panel.

7.7.3 Aquatic biodiversity

The Panel has not been able to assess the risk of any shale gas development to aquatic biodiversity in the NT because of the limited knowledge relating to NT aquatic biodiversity.

Having said this, biodiversity in surface waters should be adequately protected if the Panel's recommendations prohibiting the shale gas industry extracting surface water (***Recommendation 7.6***) and discharging treated or untreated wastewater into drainage lines, waterways or temporary stream systems (***Recommendation 7.17***) are accepted.

However, an assessment of the possibility that groundwater biodiversity (stygofauna and GDEs) may be affected by over extraction or contamination of groundwater can only be done after the recommended SREBA is completed (***Recommendation 7.5***).

7.8 Conclusion

The sustainable management of surface and groundwater resources is crucial to the development of any onshore shale gas industry in the NT. The Panel assessed the risks relating to the protection of three water-related environmental values: water quantity, water quality, and aquatic ecosystems. The Panel has focussed its attention on the Beetaloo Sub-basin because this is the most prospective shale gas region in the NT and its water resources have been comparatively well studied. This case study allows the Panel to draw a number of the conclusions that have broad relevance across the NT.

In total, the Panel assessed 20 water-related risks using the risk assessment framework detailed in Chapter 4. For most of these risks, the Panel identified mitigation measures, which if introduced and rigorously enforced will reduce these risks to an acceptable level.

However, the Panel has identified four high-priority issues from the 20 assessed in respect of which there is insufficient information to enable a full risk assessment to be conducted for the development of a mature onshore shale gas industry. These are: sustainable groundwater use; contamination of groundwater with hydraulic fracturing fluids and wastewater from leaky wells; groundwater contamination from on-site surface spills of wastewater; and the effect of these water quantity and quality issues on either surface and/or groundwater-dependent ecosystems.

The Panel has determined that detailed SREBAs are needed to provide the necessary data and knowledge. The Beetaloo Sub-basin should be the first priority for such a SREBA, and this must be undertaken before any production licences are granted for the purpose of any onshore shale gas industry in the NT.

LAND

8

8.1 Introduction

The NT has exceptional terrestrial biodiversity and landscape values, featuring a wide range of habitats and high levels of species diversity and endemism.[1] The high biodiversity values are to a large extent due to the continuing connectivity of landscape wide ecological processes because of limited intensive agriculture. The NT is internationally renowned for its vast and often spectacular scenery, much of which has outstanding wilderness values.[2] It is one of the few wild places on Earth that is readily accessible.[3] The wildlife and landscapes are integral to the NT's identity, and are especially important to the traditional practices and heritage of Aboriginal people, who retain a deep spiritual connection to land that has been fundamental to their culture for millennia (issues specifically relating to Aboriginal people, their land, and their culture are addressed in Chapter 11). Not only are landscapes important to Territorians,[4] they are why most tourists choose to visit, making landscapes fundamental to the NT's tourism industry.[5] The Panel heard from many Territorians who are passionate about protecting a lifestyle based on unspoiled vistas and an absence of landscape industrialisation.[6]

Using the risk assessment framework detailed in Chapter 4, the Panel has assessed the risks associated with any onshore shale gas development in the NT against two key land-related values: terrestrial biodiversity and ecosystem health; and landscape amenity. The Panel has assumed that the development of any onshore shale gas industry in the NT will only be acceptable if these two land-related environmental values are adequately protected. Development will be acceptable if the following environmental objectives are achieved:

- no regional-scale impact on the terrestrial biodiversity values of affected bioregions;[7]
- the maintenance of overall terrestrial ecosystem health, including the provision of ecosystem services, at the regional scale;
- any shale gas surface infrastructure does not become a highly visible feature of the landscape; and
- the volume of heavy-vehicle traffic does not have an unacceptable impact on landscape amenity and place identity.[8]

In total, eight risks to terrestrial biodiversity and ecosystem health and landscape amenity have been considered.

Similar to Chapter 7, the Panel has used the Beetaloo Sub-basin as a case study to focus attention on the land-related issues because that region is the most prospective onshore shale gas area in the NT.

8.2 Land in the NT

8.2.1 Terrestrial ecosystems

The NT has a very strong north-south gradient in mean annual rainfall, which ranges from 2,000 mm on the Tiwi Islands off the northern coast to approximately 150 mm in the far south (**Figure 7.1**). Rainfall is a dominant driver of the distribution of plants and animals and also has a major effect on ecosystem function in the NT.[9] In particular, the summer monsoon dominates

1 Woinarski et al. 2007a.
2 Woinarski et al. 2007a; Alice Springs Town Council submission 235, p 2.
3 The Pew Charitable Trusts 2017, p 1.
4 Coomalie Community Government Council, submission 15 (**Coomalie Council submission 15**); Ms Yolande Doecke, submission 25 (**Y Doecke submission 25**); Ms Lisa Gray, submission 354 (**L Gray submission 354**); Mr Mark Swindles, submission 364 (**M Swindles submission 364**), p 1.
5 Arid Lands Environment Centre, submission 88 (**ALEC submission 88**), p 5; Mr Brian Baker, submission 207 (**B Baker submission 207**), p 9; Katherine Town Council submission 257, p 3; Mr Allan O'Keefe, Ms Marilyn O'Keefe and Ms Jasmin O'Keefe, submission 355 (**O'Keefe submission 355**), p 3; M Swindles submission 364; Ms Heather McIntyre, submission 366 (**H McIntyre submission 366**), p 1; Somers submission 377.
6 For example: Mr Clinton Dennison, submission 5 (C Dennison submission 5); Ms Eleanor Wilson, submission 37 (**E Wilson submission 37**); Mr Tony Hayward Ryan, submission 41 (**T Ryan submission 41**); Ms Margaret Clinch, Planning Action Network, submission 51 (**PlAN submission 51**); Ms Sharyn Bury, submission 189 (**S Bury submission 189**); B Baker submission 207; Ms Jeananne Baker, submission 203 (**J Baker submission 203**).
7 Department of the Environment and Energy 2009.
8 Lee 2013.
9 Woinarski et al. 2007a.

the rainfall of the northern and central regions (north of Tennant Creek), producing extensive herbaceous growth, which dries out and burns during the dry season.[10] This distinguishes the tropical savannah landscapes in the northern and central regions from the desert ecosystems to the south. In the southern semi-arid and arid region, herbaceous production and subsequent fires are driven by decadal-scale periods of unusually high rainfall.[11] The desert-to-savannah transition occurs at an annual rainfall of about 500 mm/y and is the NT's primary biogeographic boundary, in terms of the composition of plant and animal species.[12] 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 around the latitude of Katherine.[13]

8.2.2 Terrestrial biodiversity

Almost all of the NT is covered by natural vegetation due to very limited agricultural development. There is extensive pastoralism,[14] but this has involved relatively little tree clearing, and terrestrial ecosystems are therefore in generally good condition, with the NT's biodiversity largely intact.[15] 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 extinct,[16] and species from the northern higher-rainfall zone have undergone recent population crashes, likely driven by predation by cats and exacerbated by the removal of shelter due to fire and high levels of grazing.[17]

In total, the NT has 90 plant species recognised as "*threatened*" under Commonwealth or Territory legislation.[18] It has 126 terrestrial animal species recognised as *"threatened"*, comprising 48 mammals, 31 birds, 12 reptiles, one frog and 34 invertebrates (30 land snails, three butterflies and a moth).[19]

The relatively intact savannah landscape of northern Australia, including the central and northern part of the NT, represents one of the very few large natural areas remaining on Earth,[20] and the larger-scale biodiversity value is due to the continuing connectivity of landscape-wide ecological processes. The world's largest expanse of tropical savannah woodland in good condition occurs in Australia, giving Australia's tropical savannahs global conservation significance.[21] They have a vastly under-described fauna, with fine-scale endemism equivalent to that in the rainforests of eastern Australia, and represent a major component of Australia's evolutionary heritage.[22]

In a study of the Mitchell grass plains of northern Australia, a feature of the Barkly Tablelands and southern parts of the Beetaloo Sub-basin in the NT, Fisher[23] noted that these grasslands were poorly represented in the national conservation reserve system and had been inadequately studied ecologically, but that they nevertheless formed a distinct zone of regionalisation for vascular plants, all invertebrate taxa, and some vertebrate groups. The understanding of the faunal diversity values of the arid zone landscapes further south is even more limited, although the existence of an unusually high diversity of some groups, such as lizards and ants, is well established.[24]

DENR has provided the Panel with information on terrestrial biodiversity in the Beetaloo and Southern Georgina Sub-basins.[25] It shows that the Beetaloo Sub-basin has been moderately well

10 Andersen et al. 2003.
11 Nano et al. 2012.
12 Andersen et al. 2015.
13 Andersen et al. 2015.
14 Mr Daniel Tapp, submission 11 (**D Tapp submission 11**); Mr Rohan Sullivan, submission 18 (**R Sullivan submission 18**); North Star Pastoral, submission 26 (**North Star submission 26**); Mr Tom Stockwell and Ms Tracey Hayes, Northern Territory Cattlemen's Association, submission 32 (**NTCA submission 32**); Mr Rod Dunbar, submission 75 (**R Dunbar submission 75**); Barkly Landcare submission 241.
15 Woinarski et al. 2007a.
16 Woinarski et al. 2007b.
17 Woinarski et al. 2011; Davies et al. 2017.
18 NT Government, Threatened plants list.
19 NT Government, Threatened animals list.
20 Woinarski et al. 2007a, pp 1, 45, 47, 50.
21 Woinarski et al. 2007a, p 1.
22 Moritz et al. 2013.
23 Fisher 2001.
24 Morton and James 1988.
25 DENR 2016.

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 no systematic invertebrate surveys in this 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, 10 of which are listed as *"threatened"*. Such limited information on the biodiversity assets of these prospective shale gas development regions represents a severe knowledge gap for assessing the risks of any such developments beyond the exploration phase.[26]

8.2.3 Bioregions

Bioregions are relatively large areas of land recognised as having a distinct climate, landforms, native vegetation and biota.[27] The Interim Biogeographic Regionalisation for Australia (**IBRA**) divides the country into 89 bioregions,[28] 24 of which (or parts thereof) occur in the NT (**Figure 8.1**). IBRA has been established to support the systematic development of a comprehensive, adequate and representative national reserve system. It is a tool supported by all levels of government to assist with identifying land for conservation as well as monitoring and evaluating natural resource management initiatives.[29] The Panel considers it appropriate to examine the development of any onshore shale gas reserves in the context of affected IBRA bioregions, and their associated values. The Panel notes Origin's suggestion that, *"the bioregion is considered an appropriate unit with which to assess the level of loss and/or fragmentation of habitat for fauna on a 'regional' scale"*.[30] IBRA bioregions were taken into account by Santos in the 2016 Southern Amadeus Seismic Program.[31]

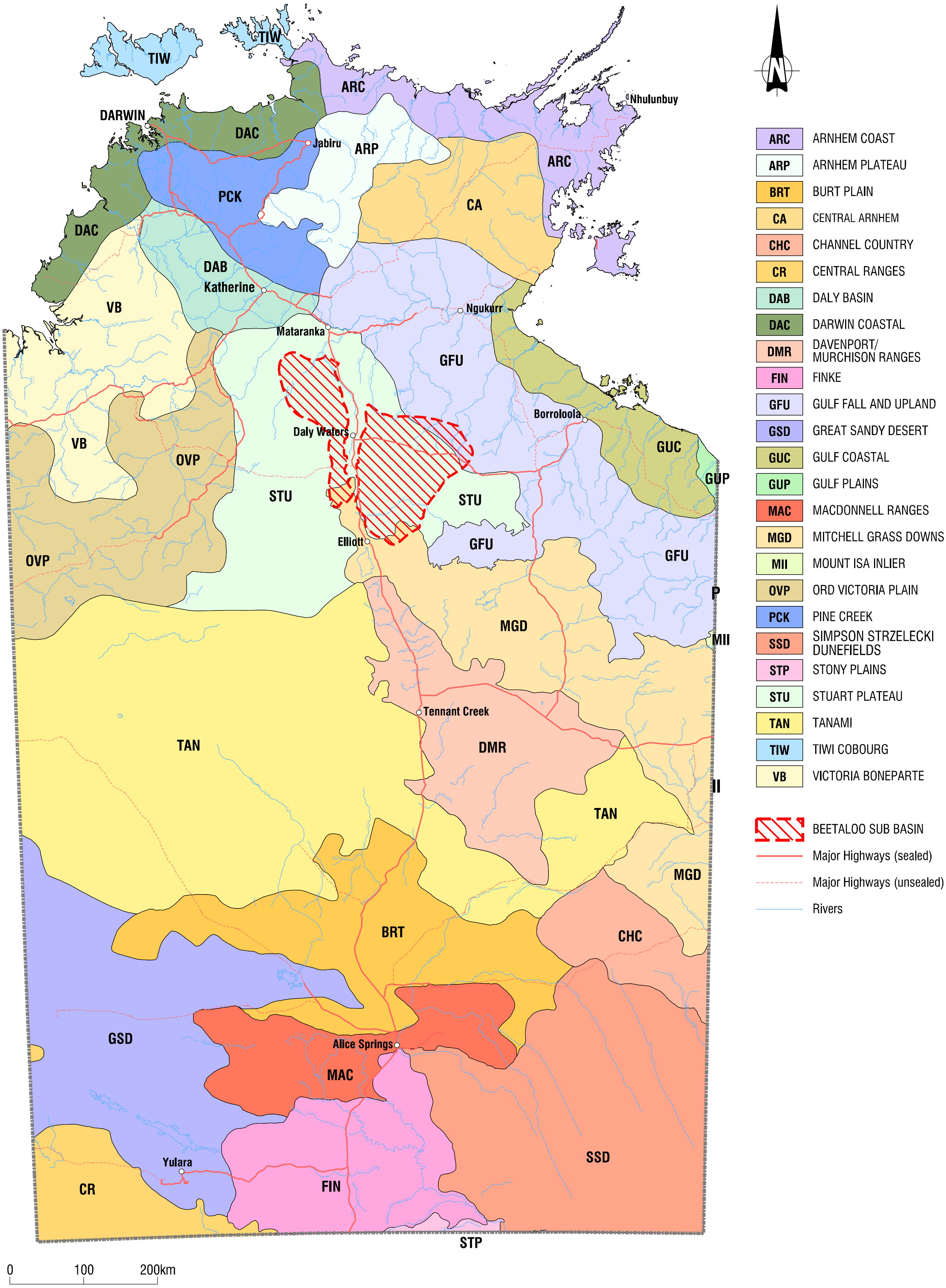
The Beetaloo Sub-basin (26,200 km^2) is located primarily within the Sturt Plateau Bioregion (an area of about 98,000 km^2), but extends into the Mitchell Grass Downs and Gulf Fall and Uplands at its southern and eastern extents. Gently undulating plains on lateritised Cretaceous sandstones, with predominantly neutral sandy red and yellow soils, dominate the Sturt Plateau Bioregion (**Figure 8.1**).[32] Elevation ranges from 100 to 300 m above sea level.[33] The most extensive vegetation is eucalypt woodland with tussock grass or Triodia understorey, but there are also large areas of lancewood (*Acacia shirleyi*) and bullwaddy (*Macropteranthes kekwickii*) thickets, and small areas of Melaleuca woodland over grassland.[34]

The Sturt Plateau, Mitchell Grass Downs and Gulf Fall and Uplands are all considered to be under-represented in the National Reserve System, with less than 1% of each protected in the NT.[35] For this reason, consideration must be given to protecting areas of high conservation significance that are not part of the reserve network.

Indicative dominant vegetation at Amungee NW-1 and Beetaloo W-1 wells in the Beetaloo Sub-basin. Source: Origin.[35]

26 Environmental Defenders Office (NT) Inc, submission 213 (**EDO submission 213**), p 10.
27 Department of the Environment and Energy 2009.
28 ILC 2013.
29 ILC 2013.
30 Origin submission 153, p 96.
31 DPIR submission 226, pp 8, 41.
32 Baker et al. 2005.
33 Baker et al. 2005.
34 Origin submission 153, p 92.
35 Thackway and Cresswell 1995.

Figure 8.1: Interim Biogeographic Regionalisation for the NT. Source: Department of the Environment and Energy.[36]



36 Department of the Environment and Energy 2009.

8.2.4 Land management

8.2.4.1 Legislation

The NT has a suite of legislation that is relevant to the development of any onshore shale gas industry (see also Chapter 14) which:

- determines where development may occur; for example, development cannot occur on reserved blocks (see Chapter 14);
- establishes a system of national parks, conservation reserves, heritage conservation areas and MNES that inform development proposals;
- establishes an environmental assessment framework; and
- provides for the conservation and management of land, including weed, fire and feral animal control.

Land management and the mitigation of potential environmental impacts by any onshore shale gas industry in the NT is governed by the following legislation:

- **the Petroleum Act** and **Petroleum Environment Regulations:** these laws ensure that onshore shale gas activities are carried out in a manner consistent with the principles of ESD and that environmental impacts and risks associated with the activities are reduced to a level that is ALARP.[37] To achieve this aim, interest holders must have an approved EMP in place before a regulated activity can be undertaken. Once approved, the EMP functions as an implementation and management tool for field operations and as a statutory compliance checklist for use by the regulator (see Chapter 14);[38]
- **the *Environmental Assessment Act 1982* (NT) (EAA):** proposed developments that could potentially have a significant environmental impact must be referred to the NT Environment Protection Authority (**EPA**) for assessment under this Act. To date, no exploration projects, including seismic survey and limited shale gas exploration drilling (including hydraulic fracturing), have been referred for assessment under the EAA;[39]
- **the EPBC Act:** the EPBC Act provides a legal framework to protect and manage MNES, including nationally and internationally important flora, fauna, ecological communities, and heritage places. If an action might have a significant impact on a MNES, the action may require assessment under the EPBC Act. The NT has a 'bilateral agreement' with the Commonwealth under the EPBC Act, which allows the EPA to undertake the assessment, but any decision regarding the approval of the action or any conditions on that approval remains the decision of the Australian Government Minister for the Environment.[40]

  Mining or the construction of new roads may require approval under the EPBC Act where they occur in areas where MNES are present. The Arnhem Plateau Sandstone Shrubland Complex is the only threatened ecological community listed as a MNES in the NT.[41] There are two Ramsar wetland site in the NT; the Cobourg Peninsula and Kakadu National Park. These sites do not, however, occur on shale gas source rocks. The EPBC Act also covers unique assemblages of plants and animals associated with Great Artesian Basin springs, which can occur in the south east of the NT, but have not been specifically identified in that part of the Basin.

  The EPBC Act also provides for the identification and listing of key threatening processes (**KTP**), which are processes that may threaten the survival, abundance, or evolutionary development of a native species or ecological community. [42] If a KTP is listed, a threat abatement plan (**TAP**) can be developed in response. TAPs establish a national framework to guide and coordinate Australia's response to KTPs listed under the EPBC Act. TAPs identify the research and management priorities necessary to assist the long-term survival of native species and ecological communities affected by key threatening processes;

37 DPIR submission 226, pp 8, 41.
38 DPIR submission 226, p 10.
39 DPIR submission 226, p 9.
40 Commonwealth of Australia and NT Government 2014.
41 SEWPaC 2012a.
42 EPBC Act, s 267.

- **the *Territory Parks and Wildlife Conservation Act 1976* (NT) (TPWC Act):** this Act enables the establishment of parks and reserves in the NT. Once established, a park or reserve affords legal protection to wildlife contained within it and protects the land from certain activities (unless undertaken in accordance with a management plan). Examples of activities that can only be done in accordance with the management plan are excavation, building construction and timber felling. Notably, the status of a park or reserve does not protect land from onshore shale gas exploration;[43] however, some parks in the NT, including Elsey National Park and Watarrka are recognised as Petroleum Reserved Blocks under the Petroleum Act, which means that no drilling or exploration for petroleum resources can occur in them (refer to **Figure 14.7** of this Report). The location of parks and reserves relative to prospective source rocks is discussed in Section 8.2.4.2.

  In accordance with the TPWC Act, the Minister must identify the conservation status of each species of wildlife in the NT, including threatened wildlife. Wildlife must subsequently be managed in a manner that accords with their classification. In the case of threatened wildlife, management must maintain or increase their population and the extent of their distribution in the Territory. Conversely, feral animals, declared under s 47 of the Act, must be managed in a way that reduces their population and/or extent and controls any detrimental effect they have on wildlife and the land.[44] Management programs for the control and management of feral animals can be established under the Act;
- **the *Heritage Act 2011* (NT) (Heritage Act):** the object of this Act is to provide for the conservation of the Territory's cultural and natural heritage; [45]
- **the *Weeds Management Act 2001* (NT) (Weeds Act):** the purpose of the Weeds Act is to prevent the spread of weeds in, into, and out of, the NT, and to ensure that the management of weeds is an integral component of land management. The NT has 139 declared weed species,[46] many of which are highly invasive and have already had a substantial impact on conservation and agricultural production. There are three classes of declared weed species, each requiring different management measures that generally correspond to the relative risk of a weed having significant negative economic, environmental and/or social and cultural impacts (weed risk), and the comparative ease or feasibility of being able to control the weed species in a given weed management region (feasibility of control).

  Weed Management Plans (**WMP**) are statutory documents that set out the legal obligations of landowners and occupiers to manage some of the highest risk and established declared weed species. There are currently 10 plans in force for: bellyache bush, cabomba, chinee apple, gamba grass, mesquite, mimosa, neem, prickly acacia, grader grass and athel pine;[47] and
- **the *Bushfires Management Act 2016* (NT) (Bushfire Management Act):** this Act provides the framework for managing bushfire in areas outside urban areas and major towns in the NT. The Act focusses on fire management rather than fire exclusion, in part by establishing a framework for bushfire management based upon bushfire risk and the preparation of regional bushfire management plans in consultation with landowners and other stakeholders. There is further discussion on fire in Section 8.4.3.

43 TPWC Act, s 17.
44 TPWC Act, s 31.
45 Heritage Act, s 3(2).
46 NT Government, Declared weeds.
47 NT Government, Statutory Weed Management Plans.

8.2.4.2 Parks, reserves, areas of conservation significance and Indigenous protected areas

The Parks and Wildlife Commission NT manages 87 parks and reserves established in accordance with the TPWC Act.[48] There are also two federally managed parks in the NT, Uluru-Kata Tjuta and Kakadu National Parks, which are recognised under the EPBC Act. National Parks and other formal reserves account for approximately 9% of the NT, but these areas have not been selected on the basis of a systematic assessment of NT's biodiversity values, and are not wholly representative of the NT's biodiversity.[49] For example, the Mitchell grass plains that are a feature of the Barkly Tablelands and the southern parts of the Beetaloo Sub-basin, form a distinct zone of regionalisation for vascular plants and some faunal groups, and yet are poorly represented in reserves.[50] There is increasing recognition within the community that the current reserve system does not adequately represent all of the NT's biodiversity.[51]

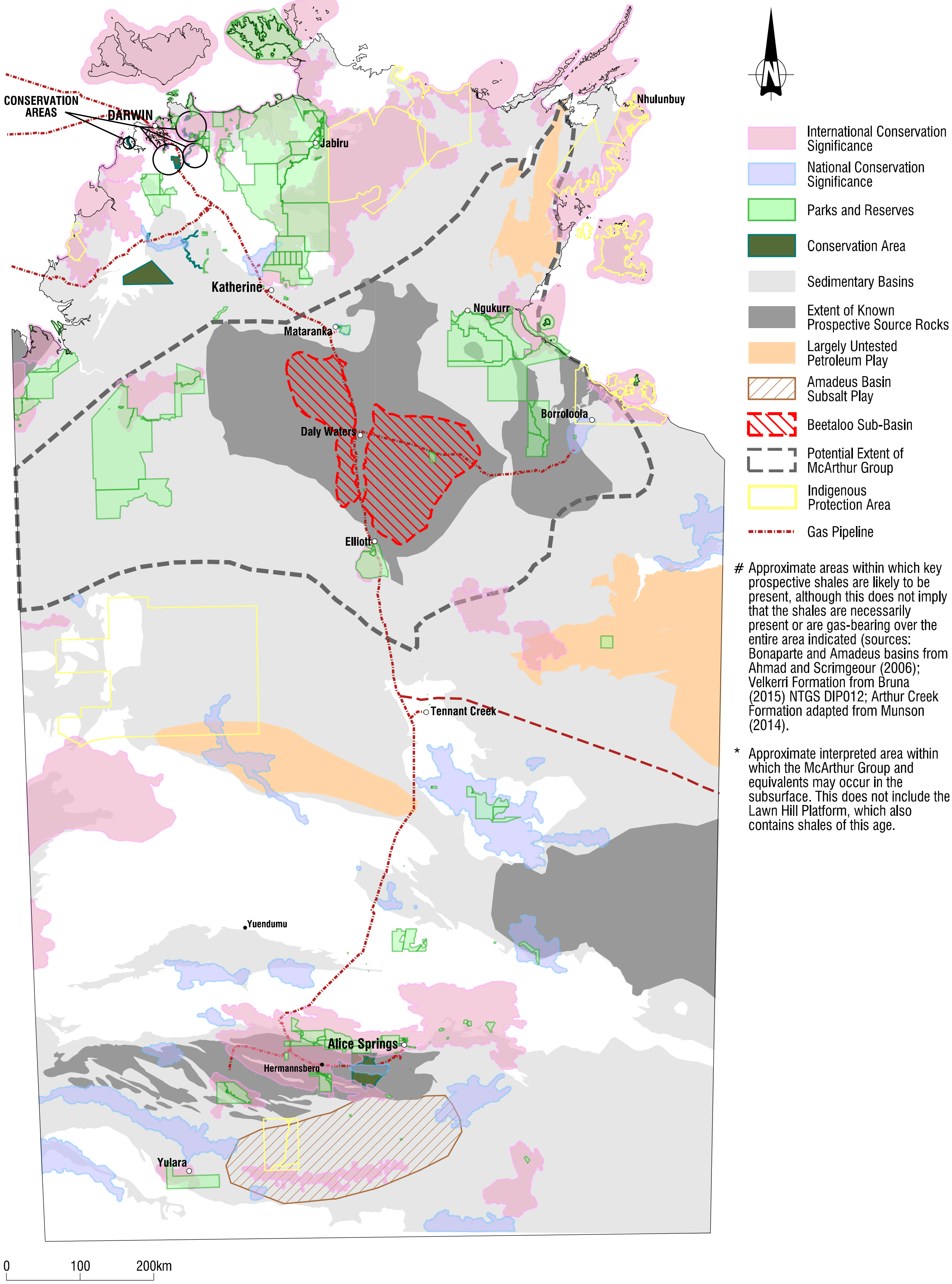
In 2009 the Government identified 67 sites of significance for biodiversity conservation in the NT. Twenty-five of these sites are considered to be of national significance and 42 of NT significance.[52] Conservation significance for biodiversity was determined using a broad range of factors, including wetland values, importance to migratory species, habitat for threatened species, endemism and other internationally accepted criteria.[53]

The NT also includes several Indigenous Protected Areas (**IPAs**), which are voluntarily dedicated by Aboriginal land and sea owners for biodiversity conservation, and are funded by the Commonwealth as an important part of the National Reserve System. One IPA, Angus Downs, adjoins the southern extent of the prospective shale gas areas in the NT.[54]

The conservation reserves and sites of conservation significance that currently overlap with, or are in close proximity to, prospective shale areas are shown in **Figure 8.3** (Beetaloo Sub-basin) and **Figure 8.4** (Central Australia).

48 *Territory Parks and Wildlife Conservation Act* (NT), s 12.
49 Ward and Harrison 2009, p 1.
50 Fisher 2001.
51 Ward and Harrison 2009, p 1.
52 Ward and Harrison 2009, p 6.
53 Ward and Harrison 2009, p 2.
54 Australian Government, List of Indigenous Protected Areas.

Figure 8.2: Locations of all national parks, conservation reserves and sites of conservation significance[55] in relation to shale-gas regions in the NT. Source: Northern Territory Government.



55 Harrison et al. 2009.

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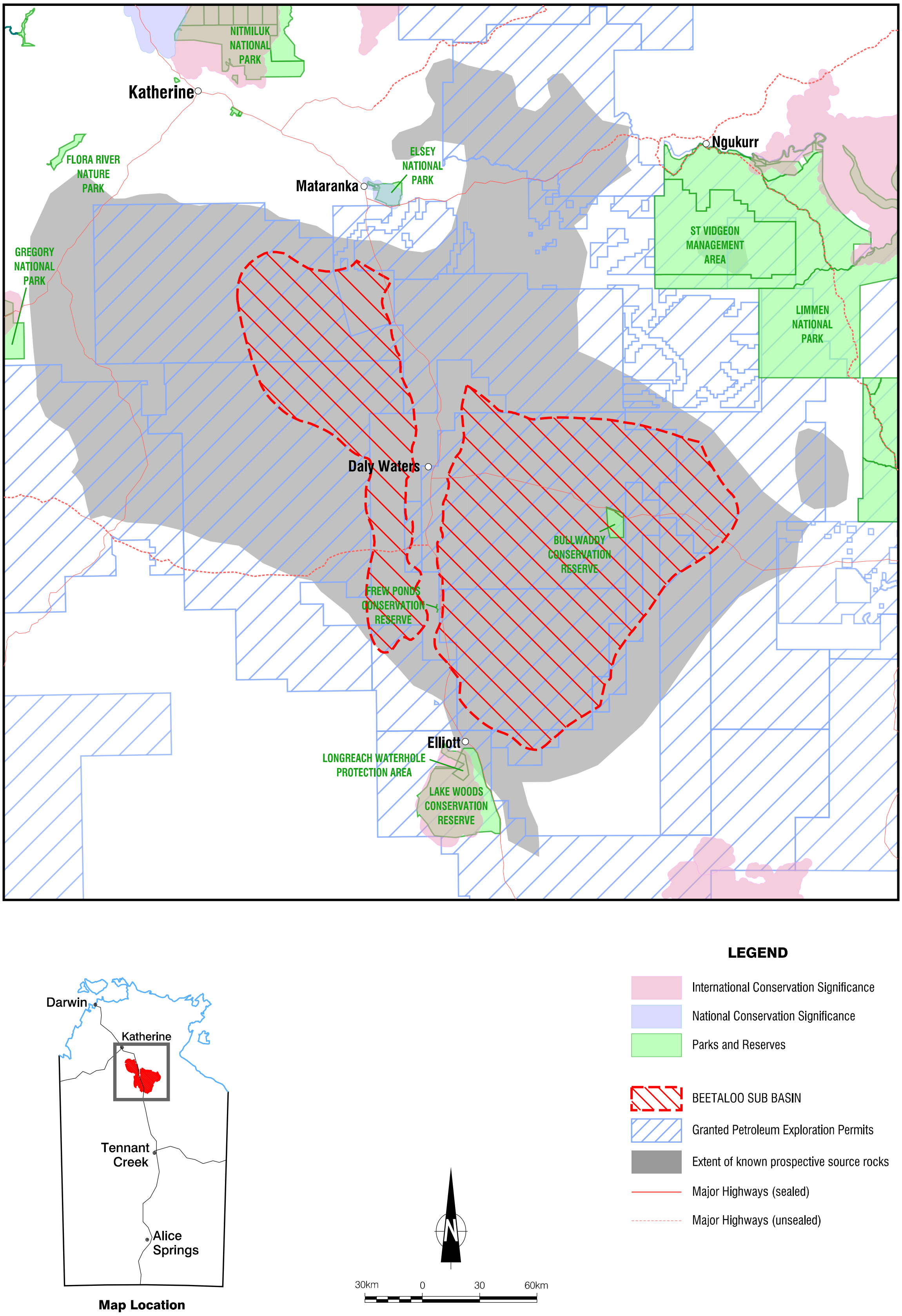
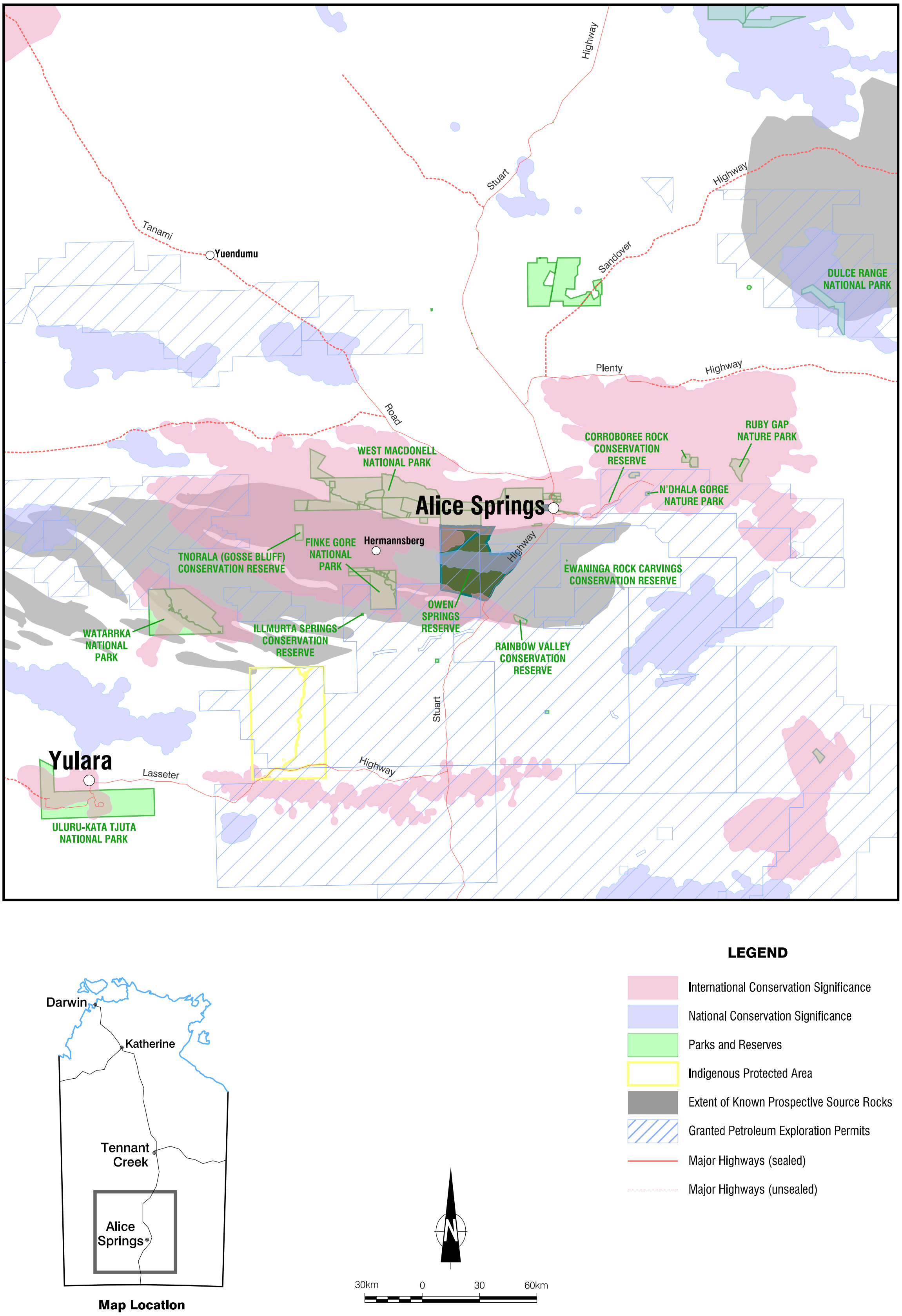
Figure 8.3: Locations of all national parks, conservation reserves and sites of conservation significance[56] in relation to shale gas regions in the vicinity of the Beetaloo Sub-basin. Source: Northern Territory Government.



56 Harrison et al. 2009.

Figure 8.4: Locations of all national parks, conservation reserves and sites of conservation significance[57] in relation to shale gas regions in the southern NT. Source: Northern Territory Government.



57 Harrison et al. 2009.

The following conservation reserves occur in, or close to, the Beetaloo Sub-basin:

- **Bullwaddy Conservation Reserve** (Portion 5680): located approximately 100 km east of Daly Waters along the Carpentaria Highway. The 115 km^2 reserve was relinquished from Amungee Mungee Station in May 1999 and is now freehold land held by the NT. The reserve represents the only declared conservation area within the Sturt Plateau region of the lancewood and bullwaddy vegetation types. The Reserve's management plan acknowledges that the conservation of Acacia woodlands is severely under-represented in protected areas, with less than 1% conserved in the Territory and 3% nationally;
- **Lake Woods:** this is an internationally significant semi-permanent wetland, which adjoins the southern tip of the Beetaloo Sub-basin. Lake Woods is one of the largest freshwater lakes in Australia, and typically has an area of approximately 350 km^2. During major rainfall and flooding events, it can extend to 1,000 km^2, when it can join the lower reaches of Newcastle Creek (see **Figure 7.8**). Lake Woods is identified as a site of significant refugia for biological diversity in arid and semi-arid Australia due to its importance as a breeding and migratory stopover location for waterfowl. The reserve is popular for conservation and recreation purposes;[58] and
- **Historical Frew Ponds Overland Telegraph Line Memorial Reserve:** established under the former *Heritage Conservation Act* 1962 (NT), this is a section of the original Overland Telegraph Line. The reserve is located on NT Portion 500 within Hayfield Station.

Pelicans at Lake Woods. Source: Matt Bolam.

58 Harrison et al. 2009.

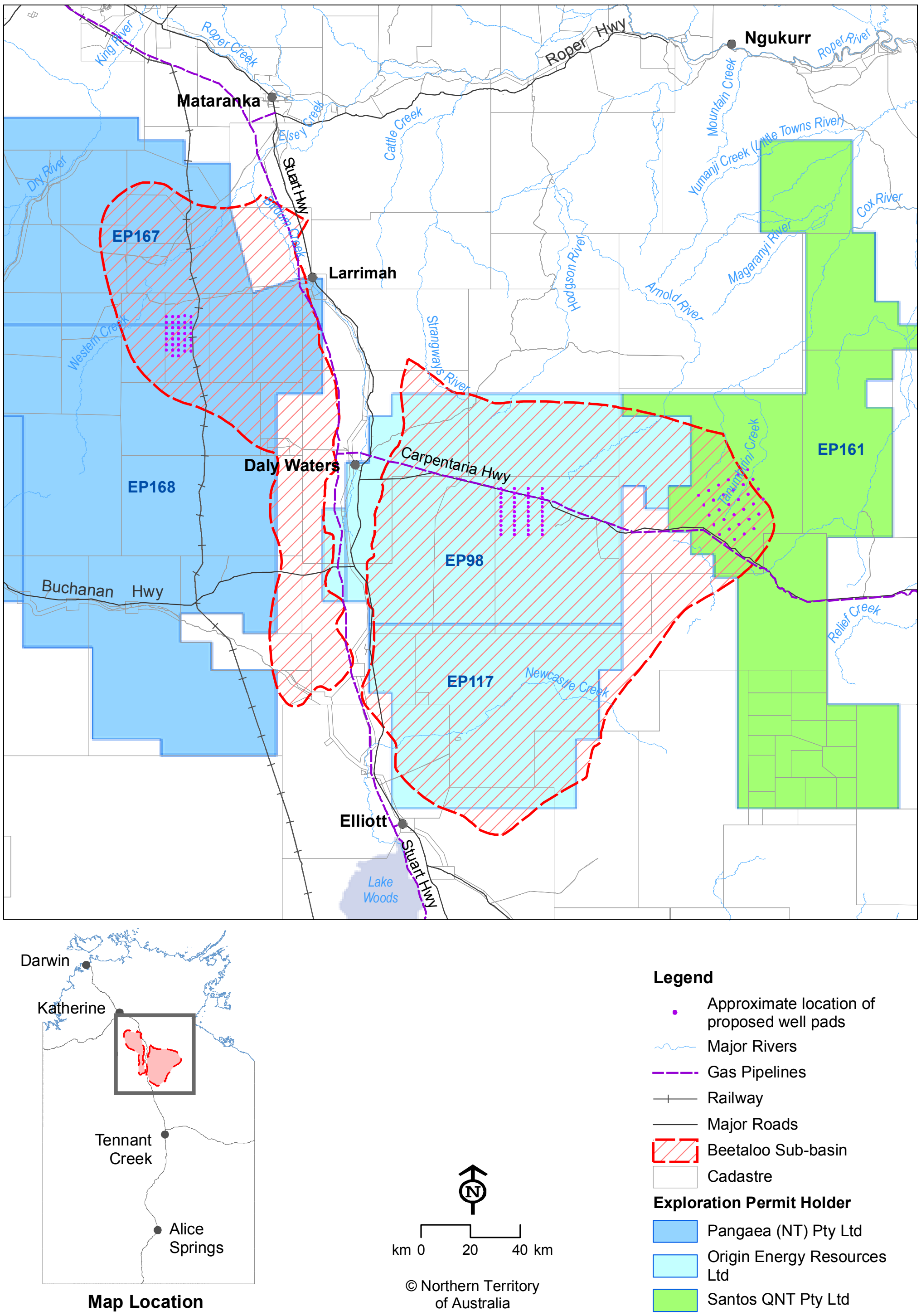
8.3 Infrastructure needs of any onshore shale gas industry in the NT

The infrastructure needs of any onshore shale gas industry will include on-site infrastructure, such as rigs for drilling and hydraulic fracturing, chemical mixing facilities, water and wastewater containment facilities, and off-site infrastructure, such as roads, pipelines, gas treatment facilities and perhaps worker accommodation.

As discussed in Chapter 7 (Section 7.3.1), the Panel has used the Beetaloo Sub-basin (**Figure 6.4**) as a case study to make a detailed assessment of water-related risks associated with an onshore hydraulic fracturing shale gas industry. The Panel has used the possible shale gas development scenarios provided by three petroleum companies - Origin, Santos and Pangaea - to develop a likely scenario of 1,000 to 1,200 wells, associated with around 150 to 200 well pads in three locations (**Figure 8.5**) over the next 25 years.

Multi-well pad infrastructure (CSG), Roma Queensland, as visited by the Panel, July 2017.

Figure 8.5: Map showing potential shale gas development scenarios in the Beetaloo Sub-basin as provided by Pangaea,[59] Origin[60] and Santos.[61] Pangaea has since indicated a seven year development scenario of 16 well pads, with 12 wells per pad.[62]



Disclaimer: These indicative development scenarios have been recreated from submissions made to the Inquiry by Pangaea, Origin, and Santos and are indicative only. To the Panel's knowledge the proposed scenarios have not been presented to the Northern Territory Government and are not currently subject to any type of government assessment or approved process. Any interpretation of the scenarios should take into account relevant information supplied in the respective submissions.

59 Pangaea submission 427, pp 10-12 (Adapted from Figure 1: *20 year indicative development scenario utilising Pangaea's 'NT Way' approach to develop the field for social and mutual benefit).*

60 Origin submission 153, pp 35-40 (Adapted from Figure 12: *Schematic representation of a large scale development project including key activities and infrastructure statistics).*

61 Santos submission 168, pp 35-42 (Adapted from Figure 24: *Ten-well lease development concept (to scale).*

62 Pangaea submission 1147.

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8.3.1 On-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 chemicals. This can involve thousands of truck movements per well site over many months, with directional drilling occurring over several months and hydraulic fracturing usually taking less than one month.[63] Accordingly, to drill and hydraulically fracture 8–10 wells per pad would take approximately one year. During this time, the site would comprise a drilling rig, large compressors, chemical storage facilities, water and wastewater storage ponds, and worker facilities.

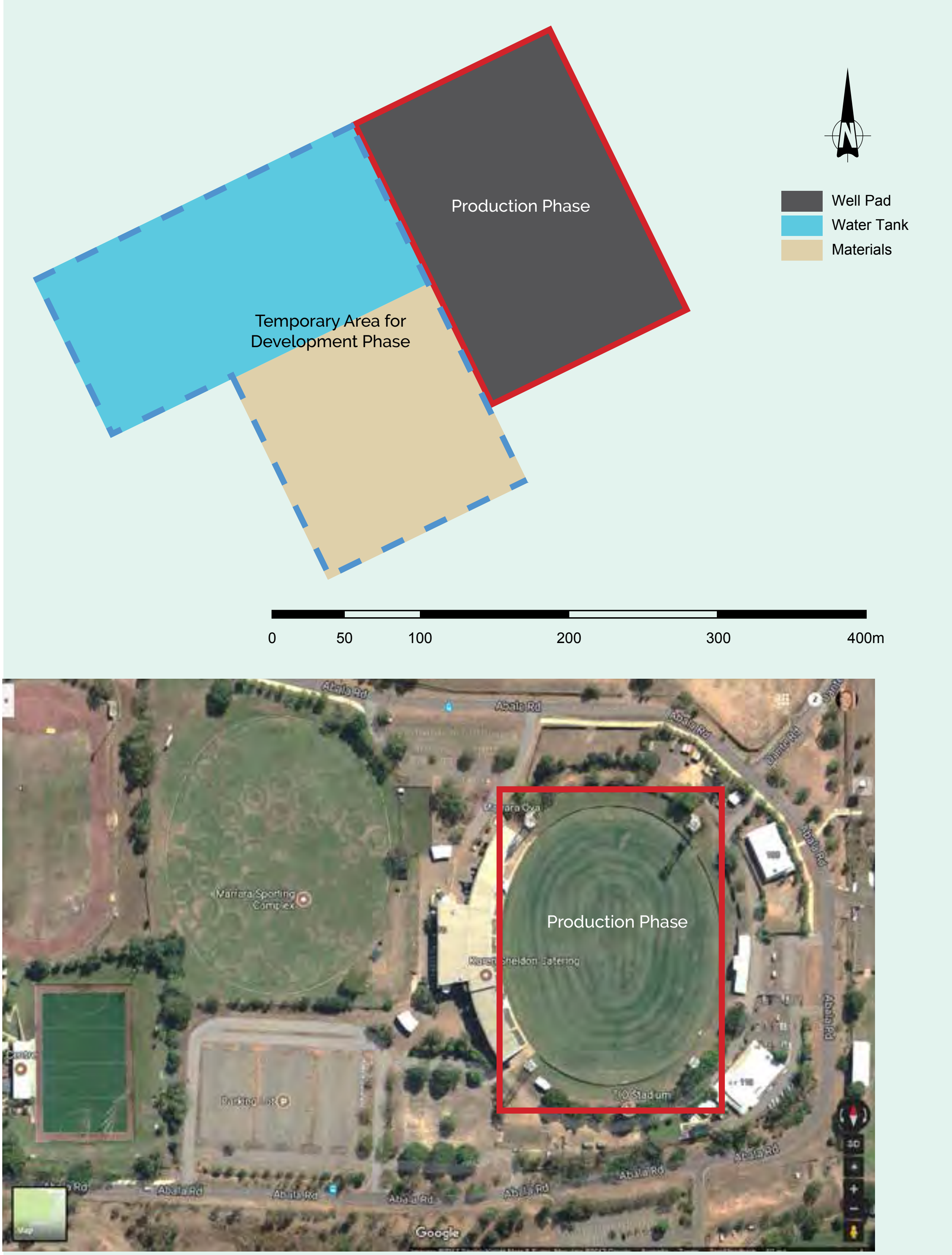
Drilling Rig at Kalala S-1 exploration well. Identical drilling rig also used at Amungee and Beetaloo well sites. Source: Origin.

After the completion of drilling and hydraulic fracturing, all heavy equipment is removed and permanent surface infrastructure constructed, including a cement well pad, a well head, a gas-water separator, a gas pipeline, storage facilities for produced water, and fencing to keep livestock and other animals away from the well.[64] The final footprint of the well and surface facilities is much smaller than the original drilling footprint.[65]

Origin provided the Panel with considerable detail of its expected on-site infrastructure needs over a 20 to 40 year period.[66] It identified three phases: exploration and appraisal (8–16 wells on 2–6 well pads over two to three years); delineation (24–48 wells on 3–6 well pads over two to four years); and development (400–500 wells on 50–65 well pads over 20–40 years).[67] Origin and Pangaea have assumed the size of each well pad during the initial two phases would be approximately 200 m x 200 m, but during production would reduce to around 100 m x 100 m.[68]

63 ACOLA Report.
64 Origin submission 153, pp 252-275.
65 Origin submission 433, p 49.
66 Origin submission 153, pp 35-44, 252-275; Origin submission 433, pp 49-52.
67 Origin submission 153, pp 35-36.
68 Origin submission 433, p 49; Pangaea submission 427, p 12; Santos have assumed a slightly large well pad area during production of 32,000 m^2; Santos submission 414, p 8.

Figure 8.6: Land use for a 10 well pad construction compared to Darwin's TIO Stadium. Source: Santos.[69]



Area used during production phase is slightly larger than a football ground (150 m x 200 m).

69 Santos submission 420, p 8.

The overall surface footprint of each development will depend upon the number of well pads and their spacing. For example, a 50 well pad development, with each pad 2 km apart, would result in a total footprint of around 500 km^2 (25 km x 20 km).[70] In addition, Origin estimated land disturbance between well pads due to pipelines (assumed to be 2.1 km long x 10 m wide) and roads (assumed to be 2.1 km long x 15 m wide). Pangaea provided indicative seismic line clearing widths of 5 m for the source lines and 3 m for the receiver lines. [71]

Therefore, the overall area of land affected by the shale gas operations of the three companies in the Beetaloo Sub-basin would be approximately 1,000 to 1,500 km^2 over the three locations out of a total area of 26,200 km^2 (that is, 4–6% of the area) (**Figure 8.5**).

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

8.3.2 Off-site infrastructure

In addition to the above on-site infrastructure, any shale gas development will require significant off-site infrastructure, such as roads, gas processing plants and pipelines. Three types of gas pipelines will be needed: between well pads, from the well pads to gas processing plants, and from these gas processing plants to either Darwin or the east coast of Australia. Additionally, it will be necessary to treat the wastewater (flowback fluids and produced water) left at the end of the hydraulic fracturing process and the produced water during the lifetime of the production phase. However, as discussed in Chapter 7, the Panel has no detail on these issues.

8.3.2.1 Roads

Origin has noted that roads and pipelines, not well pads, make up the majority of the surface footprint of onshore shale gas development in the NT.[72] It is well recognised that shale gas development will require additional roads to be constructed, and many existing roads will need to be upgraded. For example, Pangaea is progressing with the sealing of Western Creek Road (started in 2016), which will be of substantial public benefit.[73]

70 Origin submission 433, p 50.
71 Pangaea submission 220, p 42.
72 Origin submission 433, p 50.
73 Pangaea submission 427, p 11.

Origin has indicated to the Panel that access roads between well pads will be 2.1 km long and 15 m wide and will be constructed alongside buried pipelines. Accordingly, for Origin's large-scale development scenario, it is estimated that an additional 40–130 km of roads will be required, representing around 0.5 to 2.0 km^2 of land disturbance.[74]

As noted in Section 8.5.2, development of an onshore shale gas industry will inevitably lead to an increase in heavy-vehicle traffic on both major and minor roads. The Panel heard the concerns from local government regarding who will be responsible for the maintenance of these minor roads, many of which are not sealed.[75] The gas companies have some responsibility for maintaining roads they use, but the details of exactly what this entails needs to be worked out.

8.3.2.2 Gas processing facility

Any onshore shale gas development will require a gas processing facility to dehydrate the gas to remove any remaining water and to compress the gas before it is transported (piped) to a distribution hub.[76] These are large and complex chemical engineering plants, with infrastructure that can include a considerable amount of pipelines, compressors, electrical generation equipment, water storage and treatment facilities, site offices and staff accommodation camps.[77]

Condabri Central Gas Processing Facility. Source: Origin.

The Panel has no information on the possible location of any gas processing facilities associated with the three shale gas developments proposed by Origin, Santos and Pangaea, or whether these gas companies could build and operate a joint gas processing plant.

8.3.2.3 Pipelines

With the exception of roads, pipelines will have the largest impact on the landscape even though it is anticipated that these will be underground.[78] Origin has estimated that each well pad will require 2.1 km of pipeline and a cleared width of around 10 m. Access roads between well pads are likely to be constructed alongside the buried pipeline, these being 2.1 km long and 15 m wide.

Therefore, a 50–65 well pad development will require an estimated 250–300 km of connecting gas pipeline, with a further 60–80 km depending upon the location of the gas processing facility. Over the three potential developments mooted for the Beetaloo Sub-basin, there could be around 1,000 km of pipelines, resulting in around 10 km^2 of land clearing.

74 Origin submission 153, pp 40-41.
75 For example, Coomalie Council submission 15, p 2.
76 Origin submission 153, p 275.
77 Origin submission 153, p 275.
78 Origin submission 433, p 49.

In 2015, the Queensland Gasfields Commission undertook a major review of land rehabilitation and landholder engagement practices associated with the construction of the pipelines connecting the Surat Basin gasfields with the LNG facilities in Gladstone.[79] The combined length of these pipelines, constructed between 2012 and 2015, was almost 1,500 km. Key learnings from the review included the fact that communication with landholders was critical; levels of compensation needed to be relative to total impact; multiple pipelines required coordination and cooperation; weed management required joint effort; and fencing of easements was found to be a valued investment.[80]

8.4 Biodiversity and ecosystem health

In assessing the land-related risks of any onshore shale gas industry in the NT, the Panel's objectives are to ensure that there is no impact on the terrestrial biodiversity values at a bioregional scale[81] and that the overall health of terrestrial ecosystems, including the provision of ecosystem services,[82] is maintained at the regional scale.

There is extensive overseas scientific literature on the impacts of onshore shale gas, and other onshore oil and gas development, on terrestrial biodiversity and ecosystem health, and this has been the subject of several recent studies.[83] However, there has been relatively little analysis of these impacts in an Australian context.[84] The Panel received a number of submissions on the potential risks of any onshore shale gas industry to terrestrial biodiversity and ecosystem health.[85]

The Panel has identified the following key risks to the protection of terrestrial biodiversity and the maintenance of healthy terrestrial ecosystems in the NT:

- the location of onshore shale gas development in areas of especially high conservation values;
- the spread of invasive species;
- the impact of changed fire regimes;
- changes to native vegetation;
- disruption to the movement of water and nutrients due to the construction of roads and pipelines; and
- other impacts on wildlife.

8.4.1 Unacceptable location of shale gas development in areas of high conservation value

The Panel believes that any onshore shale gas development must be excluded from areas where regional conservation values are particularly high, such as areas of high biodiversity, significant levels of endemism, or where there is a critical occurrence of threatened species. In Chapter 14, the Panel recommends that national parks and conservation reserves,[86] with appropriate buffer zones, be declared reserved blocks under s 9 of the Petroleum Act. This means that those areas will never be released for onshore shale gas exploration or production ('no go zones').

However, given that the locations of these reserves have historically not been proclaimed on the basis of any systematic evaluation of regional biodiversity assets, it cannot be assumed that they are representative of broader regional biodiversity values or are fully protective of them (Section 8.2.3).[87] Most of the NT has never been systematically surveyed for flora and fauna, due to its vast size and remoteness.[88] Consequently, the distributions of most species (including those formally recognised as *"threatened"*) are known only in general terms at best, and there is very limited knowledge of geographic patterns of diversity and endemism.[89] Information is

79 Queensland Gasfields Commission 2015b.
80 Queensland Gasfields Commission 2015b.
81 Department of the Environment and Energy 2009.
82 Costanza et al. 1997.
83 Kiviat 2013; Brittingham et al. 2014; Souther et al. 2014.
84 A notable exception is Eco Logical Australia 2013.
85 For example, ALEC submission 88; Arid Lands Environment Centre submission 238 (**ALEC submission 238**); EDO submission 213; Environmental Defenders Office (NT) Inc, submission 456 (**EDO submission 456**); Department of Environment and Natural Resources, submission 473 (**DENR submission 473**).
86 DTC 2017.
87 EDO submission 213, p 20.
88 DENR 2016.
89 EDO submission 213, p 10.

particularly scant for terrestrial invertebrates,[90] which represent the great majority of the NT's faunal species and which play a critical role in the functioning of ecosystems.

All onshore shale gas activities must have an approved EMP in place (see Chapter 14).[91] However, EMPs are not the appropriate tool to ensure that a comprehensive, region-wide assessment of the biodiversity values of a permit area takes place. Localised and activity-based EMPs may not identify any areas that might be biodiversity hotspots or centres of endemism within a regional context.

The Panel's assessment is that the likelihood of onshore shale gas development occurring in currently undocumented areas of high conservation value in the NT is 'high', given the lack of comprehensive and systematic information on the biodiversity assets of prospective regions,[92] including virtually no information on invertebrate faunas. This poses a significant threat to species that might occupy highly restricted ranges within a development area, and therefore, the consequence is also rated as 'high'. Combining the likelihood ('high') and consequence ('high') gives an overall risk rating of 'high'.

This high risk can only be mitigated by implementing the findings from a strategic regional assessment of biodiversity values (as part of a SREBA: see Chapter 15) conducted prior to any shale gas development being approved. Bioregional planning based on strategic assessment is widely recognised (including by the EPA[93]) as the most appropriate basis for limiting the impacts on biodiversity of regional development. It is formally recognised under the EPBC Act.[94]

The Panel's assessment is that the risk of inappropriate location of any onshore shale gas development would be acceptably low provided that a strategic regional assessment of terrestrial biodiversity values is undertaken to ensure that development is excluded from any identified areas of high conservation value. These regional assessments should be comprehensive,[95] both in terms of space (covering all major vegetation types across the region) and biota (including all groups of vascular plants and terrestrial vertebrates, and representative terrestrial invertebrates).[96] The data should be assessed for patterns of species richness and endemism, and for the occurrence of threatened species.

A SREBA is likely to take 3–5 years (see Chapter 15 for further detail), and the extent of land clearing for exploration over this period would be small relative to existing rates of clearing. The EPA has determined that the exploratory processes associated with onshore gas development to date have not posed a significant risk to the environment.[97] The Panel's view is that the risks associated with land clearing during exploration over this time period are acceptable without the need for a strategic terrestrial biodiversity assessment. Therefore, the Panel's opinion is that such an assessment can occur in parallel with exploration activity should the moratorium be lifted, but must be completed prior to the grant of any production approvals.

Recommendation 8.1

That:

- ***strategic regional terrestrial biodiversity assessments be conducted as part of a SREBA prior to the granting of any further production approvals;***
- ***any onshore shale gas development be excluded from areas considered to be of high conservation value; and***
- ***the results of the SREBA must inform any decision to release land for exploration permits as specified in Recommendation 14.2 and, upon completion, must be considered by the decision-maker in the granting of any future exploration approvals.***

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90 ALEC submission 88, p 12.
91 Origin submission 153, pp 95-96; Santos submission 168, p 165; DPIR submission 226, pp 196-201; Origin submission 433, p 56.
92 Central Australian Frack Free Alliance, submission 505 (**CAFFA submission 505**), p 7.
93 Northern Territory Environment Protection Authority submission 417 (**EPA submission 417**), p 3.
94 Australian Government 2011.
95 EDO submission 456, p 27.
96 ALEC submission 88, p 16; ALEC submission 238, p 12.
97 DENR submission 449, p 2

8.4.2 Unacceptable increases in the spread or impacts of invasive species

8.4.2.1 Weeds

Nationally, weeds affect the structure and function of ecosystems and have a negative impact on native fauna and flora.[98] Weeds already pose a serious threat to biodiversity in the NT,[99] and throughout Australia's rangelands more generally.[100] If introduced into suitable habitat, weeds can rapidly compete with, and replace, native plant communities, transforming faunal habitat. Weeds can also indirectly change ecological function by altering fire regimes, light and water availability, and soil nutrients.[101] The NT has many established weed species that already affect conservation (and production) values, and are considered to be a core challenge of broad-scale land management. At least $15 million is spent each year on weed management in the NT.[102] The Panel is of the opinion that any onshore shale gas development must not result in the introduction or spread of any declared weeds.

For some weeds, the resource implications on conservation and Aboriginal-managed lands may be greater because grazing is not a management option. In northern Australia, gamba grass (*Andropogon gayanus*) was deliberately introduced as a highly productive and palatable fodder but has since proved to be highly invasive and damaging.[103] Gamba grass is now declared and recognised as a weed of national significance. It is extremely tall (up to 4 m) with exceptional herbaceous biomass. This fuels fires of unprecedented intensity in the natural landscape that cause major declines in tree cover and subsequent ecosystem functioning.[104] These fires represent a significant threat to people's lives and property[105] (see **Figure 8.7**). In 2009, the Australian Government listed gamba grass as a key threatening process under the EPBC Act.

This initiated the development of the *"threat abatement plan to reduce the impacts on northern Australia's biodiversity by the five listed grasses"* (Grasses TAP).[106] The Grasses TAP identifies these grass species as having the ability to change native species composition through competition and by promoting intense, late-season fire through increased fuel loads. Any spread of such grasses could threaten savannah burning programs for greenhouse gas emission abatement (see Section 8.4.3) due to the exclusion of affected areas.[107]

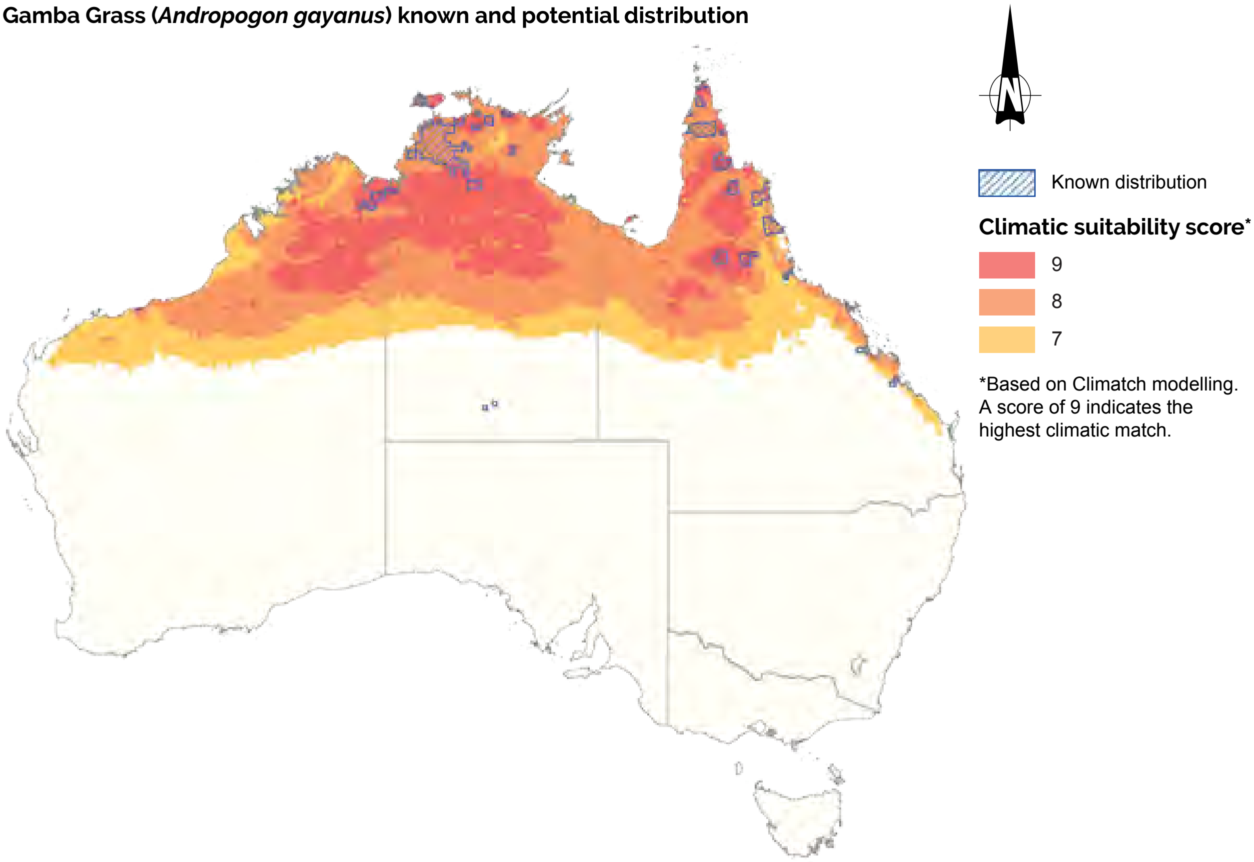
In arid and semi-arid regions of the NT, buffel grass (*Cenchrus ciliaris*), an undeclared grass used for pasture improvement and soil stabilisation in central Australia,[108] produces a high fuel load that supports more frequent and intense fires than these arid landscapes would otherwise experience.[109] The impacts of buffel grass fires on ecosystem function and biodiversity includes the loss of keystone (and iconic) species such as river red gums (*Eucalyptus camaldulensis*).[110]

Any onshore shale gas development has the potential to spread weeds into regions where they do not currently occur, and to exacerbate spread and density where weed establishment has already occurred (see Section 8.3 above). Biosecurity risks were among the greatest concerns for rural landholders in Queensland with CSG activity on their property.[111] Weed monitoring and prioritised management of newly established weeds divert resources away from standard farm operations.[112] Lock the Gate has noted that African love grass infestations, believed to have been introduced by gas companies, has affected productivity, profitability and land value.[113]

The Weed Management Branch in DENR has identified petroleum exploration as a high-risk pathway for weed spread, through the unintentional movement of seeds, plants, plant parts, or soil containing seeds, along with disturbance to the soil that increases the probability of seeds establishing.[114] DENR has advised the Panel that petroleum extraction has the potential to have an adverse impact upon biodiversity through land surface disturbance, including the spread of

98 Invasive Plants and Animals Committee 2016, p 6.
99 NT Weeds Management Strategy 1996-2005; ALEC submission 88, p 16.
100 Grice 2006.
101 DENR 2015.
102 DENR 2015.
103 DENR 2014.
104 Rossiter et al. 2003.
105 Setterfield et al. 2013.
106 SEWPaC 2012b.
107 Environment Centre NT, submission 1254 (**ECNT submission 1254**), p 3.
108 Edwards et al. 2008, P 111.
109 Marshall et al. 2012, p 8.
110 Edwards et al. 2008, P 111.
111 Queensland Gasfields Commission 2017a, p 56.
112 GISERA 2016a.
113 Lock the Gate submission 171, p 27.
114 DENR 2015.

Figure 8.7: The known and potential distribution for gamba grass in Australia. Source: Australian Government.[115]



Gamba grass spreading along an access track (new growth showing on perennial plants)

Gamba grass fire (late season controlled hazard reduction burn)

115 SEWPaC 2012b.

weeds.[116] Multiple submissions to the Panel identified this risk.[117] Submissions from pastoralists specifically identified weed introduction and/or spread as a problem that should not become their responsibility or be permitted to affect land condition.[118]

The Sturt Plateau is highly regarded as relatively free of weeds,[119] but a number of high-risk species not yet established in the NT are known to be climatically suited to the region. These include weeds of national significance, such as parthenium (*Parthenium hysterophorus*)[120] and rubber vine (*Cryptostegia grandiflora*).[121] In addition to their biodiversity impacts, these weeds would have severe implications for pastoralism. Both parthenium and rubber vine are toxic if ingested by stock, and parthenium can also produce serious allergic reactions in humans, including dermatitis, hay fever and asthma.[122] Grader grass (*Themeda quadrivalvis*) is already well established on many pastoral properties in the Katherine and Roper districts. This weed presents a range of challenges for landholders due to its competitiveness, short time frame to maturity and inaccessibility during optimal control periods.[123] Once established, its impacts include reduced productivity, increased high-intensity fires, and increased management costs.[124]

In arid and semi-arid regions of the NT, buffel grass (*Cenchrus ciliaris*), an undeclared grass used for pasture improvement and soil stabilisation in central Australia,[125] produces a high fuel load that supports more frequent and intense fires than these arid landscapes would otherwise experience.[126] The impacts of buffel grass fires on ecosystem function and biodiversity include the loss of keystone (and iconic) species such as river red gums (*Eucalyptus camaldulensis*).[127]

Weeds are currently regulated under the Weeds Act (administered by DENR), and there is also capacity for the Petroleum Environment Regulations (administered by DPIR) to regulate weeds. The Panel requested information from DENR and DPIR to determine how the current legislative structure is jointly administered, including monitoring, compliance and enforcement.[128] Their combined submission revealed a number of deficiencies; namely, that:

- only *"owners"* and *"occupiers"* are obliged to comply with statutory weed management plans under the Weeds Act, and gas companies are neither.[129] This means that even though gas companies can access, traverse and develop land, they do not have to comply with the same legal obligations as the underlying tenure holder to manage weeds;
- the Petroleum Act allows the Minister for Resources to place conditions on a petroleum interest.[130] For example, the Minister can attach a condition on a permit stating that, *"the permittee shall take such steps as are reasonably practical to prevent the spread of noxious weeds, including the washing down of vehicles and removal of grass seeds before moving vehicles and equipment to a new area."* [131] However, it is currently not a condition that there must be compliance with a statutory weed management plan; and
- under the Petroleum Environment Regulations all *"regulated activities"* (those with an environmental impact, irrespective of how small) must have an EMP in place.[132] Therefore, if there is a risk of weeds spreading as a result of an activity, the tenure holder must have a weed management plan as part of its EMP.[133] However, walking or driving on existing roads or tracks for the purposes of taking water or rock samples are exempt from these requirements. Such activities can nevertheless result in the introduction and spread of weeds, and should not be exempt from the requirement to have a weed management plan in place.

116 DENR submission 230, p 9.
117 Lock the Gate submission 171, p 27; EDO submission 213, pp 7, 11-12.
118 D Tapp submission 11, p 3; NTCA submission 217, p 3; Consolidated Pastoral Company Pty Ltd, submission 218 (**CPC submission 218**), p 7.
119 DENR 2017.
120 Agriculture and Resource Management Council of Australia and New Zealand 2001.
121 Australian Weeds Committee 2012.
122 Agriculture and Resource Management Council of Australia and New Zealand 2001.
123 Pastoral Land Board 2015.
124 Keir and Vogler 2006, p 197.
125 Edwards et al. 2008, p 111.
126 Marshall et al 2012, p 8.
127 Edwards et al. 2008, p 111.
128 Department of Primary Industry and Resources and Department of Environment and Natural Resources, submission 419 (**DPIR and DENR submission 419**).
129 Weeds Act, s 9(2).
130 See, for example, Petroleum Act, s 20(5).
131 Department of Primary Industry and Resources, submission 295 (**DPIR submission 295**), Attachment A, p 9.
132 Petroleum Environmental Regulations Guide; p 8.
133 DPIR submission 226, p 198.

In assessing the risk of the spread of invasive weeds by any onshore shale gas industry, the Panel has assumed that an acceptable risk is no incursion of new non-native plant species into any potential onshore shale gas development area, and no spread of non-native plant species that already occur in that area.

The Panel's assessment is that the likelihood of significant spread of invasive weed species is 'high' because of the large number of additional personnel (company and contractors), vehicles, and vehicle trips that will be associated with any onshore shale gas industry, and the limitations of the current weed management regulations. Even with best management practice in place (particularly with regard to hygiene, for example wash-down bays), the Panel is of the view that the introduction of new species is likely. The chances of weed establishment before detection and control are increased because of the remote location of these developments and the seasonal inaccessibility of many areas. In addition, monitoring and compliance will require considerable resources because of the potential distances and seasonal inaccessibility involved. The Panel has also assessed the consequences of the spread of invasive weed species as 'high' because such species have a history of significant impact on terrestrial ecosystems and other land uses in the NT. This gives an overall risk rating of 'high'.

Strengthening the current regulatory regime will help mitigate the risk of the spread of weeds. For example, gas companies can be made expressly liable for any non-compliance with statutory weed management plans by placing a relevant condition on an EMP.

It is currently open to the Minister for Resources to place conditions on any EMP. While gas companies are not *"owners"* or *"occupiers"* under the Weeds Act, the *Northern Territory Weeds Management Strategy 1996–2005* makes it clear that industries responsible for the spread of weeds should be responsible for their management. The Panel agrees.

The Panel is of the view that prevention of weed spread is the best approach to weed management. The Queensland experience shows that there is considerable value in anticipating some weed introductions and having an agreed process for management already in place. The Panel's opinion is that a baseline assessment of weeds must occur as part of a SREBA prior to any onshore shale gas exploration activities commencing, to monitor the types and extent of weeds already in existence in order to determine whether new species have been introduced or whether existing weed species have spread. The locations of weeds will also inform property and region-specific requirements for wash downs.

Where onshore shale gas infrastructure is constructed in areas already covered by an existing weed management plan, collaborative approaches to the prevention and management of weed spread should be negotiated with and between gas companies in consultation with landholders.

The Panel notes the fundamental importance of early detection in weed management, and the challenges this imposes for remote regions of the NT.[134] As noted by the NLC, *"early detention and response for invasive species remains a high concern which cannot be readily mitigated in remote localities."* Substantial resources will be required for effective weed surveillance should any onshore shale gas industry proceed. The Panel recommends that gas companies nominate a dedicated weeds officer with the role of monitoring well pads, roads and pipeline corridors for weeds. Additionally, all field workers should receive training in the identification of weeds, especially gamba and grader grass, and should report any suspected incursions to the weeds officer.

With the above mitigation measures in place, it is the Panel's view that the likelihood of significant incursions of invasive weed species will be substantially reduced. Ongoing monitoring and management will result in the detection and control of any incursions. This will result in a 'low' threat of the spread of invasive species as a result of any onshore shale gas development.

134 Environmental Defenders Officer (NT) Inc, submission 635 (**EDO submission 635**), pp 8–9.

Recommendation 8.2

That a baseline weed assessment be conducted over all areas that will be accessed by a gas company on an exploration permit prior to any exploration activities being carried out on that area and that ongoing weed monitoring be undertaken to inform any weed management measures necessary to ensure no incursions or spread of weeds.

Recommendation 8.3.

That, at all times, gas companies must have a dedicated weeds officer for each gasfield who is responsible for weed management and whose role includes:

- ***training all field workers in the identification of weeds, especially gamba and grader grass, and to establish an effective reporting system for any suspected weed incursions;***
- ***designing and implementing effective weed surveillance; and***
- ***ensuring prompt and effective management of any weed incursions in consultation with affected landholders.***

That the gas industry funds a dedicated officer responsible for weed management associated with any onshore shale gas development. This officer is to be located in the Government's Weed Management Branch in a regional centre. The officer will be responsible for:

- ***coordinating regional weed baseline assessments and subsequent weed surveillance; and***
- ***overseeing strategic and effective management of any weed incursions by gas companies.***

Recommendation 8.4

That gas companies must be required to have an approved weed management plan for any area the subject of an exploration permit prior to any part of that area being accessed for the carrying out of any exploration activities. The WMP must be consistent with all relevant statutory obligations and relevant threat abatement plans established under the EPBC Act.

8.4.2.2 Invasive ants

Exotic invasive ants are among the world's worst invasive species. Two species are already established in parts of the NT, with substantial impacts on native biodiversity:[135] the African big-headed ant (*Pheidole megacephala*) and the Yellow crazy ant (*Anoplolepis gracilipes*). Additionally, two other tropical exotic ants with serious environmental impacts elsewhere in the world, the Red imported fire ant (*Solenopsis invicta*) and the Little fire ant (*Wasmannia auropunctata*) exist in Queensland,[136] and therefore, have high potential for introduction into the NT.

The Panel has determined that there should be no incursion or spread of invasive ants by any onshore shale gas industry.

The Panel has assessed the likelihood of this occurring as 'medium' and the consequence as 'high', giving an overall risk rating of 'high'. However, exotic ant species are spread in the same way as weeds, namely, by transport of contaminated vehicles and equipment, and poor hygiene procedures. Measures that prevent the spread of weeds would therefore also mitigate the risk of spread of exotic ants. Such measures must be included in an EMP for all onshore shale gas activity (exploration and/or production) where the spread of invasive ants is a risk associated with that activity.

135 Hoffmann et al. 1999; Hoffmann and Saul 2010.
136 Lach and Barker 2013.

8.4.2.3 Feral animals

There is considerable evidence that feral animals are causing major environmental damage in the NT.[137] For example, Arabian camels, cane toads, cats, dogs, donkeys, foxes, pigs and horses are all known to be present in the Sturt Plateau bioregion, with camels, donkeys and horses present in high numbers, affecting the vegetation and water sources. Additionally, cane toads, cats, dogs and foxes are affecting biodiversity, but their distribution and the extent of their impact is uncertain.[138] Wild dog impacts on cattle production and management costs are significant, including on stations in the Sturt Plateau.[139]

However, these feral animals are already well established in the NT, and whether any onshore shale gas industry would affect the population dynamics or impacts of existing feral animals is unclear. A report by Bali suggests that the impact of feral cats and cane toads, particularly on already threatened species, may be increased due to the increased number of roads and cleared pipeline corridors.[140] The Panel notes that landholders in regions with gas development potential have legislative obligations to control feral animals.[141] In addition, there are TAPs established under the EPBC Act that apply to foxes, cats, pigs and cane toads.

The Panel is of the view that the risk of increased impacts from feral animals due to any onshore shale gas industry is both 'low' and acceptable.

8.4.3 Unacceptable changes to fire regimes

Fire-related conservation issues in the NT typically concern too much, rather than too little, fire,[142] and the Panel considers increased ignitions as posing the greatest risk to biodiversity and ecosystem health. As noted above, the development of any onshore shale gas industry in the NT will require the construction of a comprehensive interconnected network of access roads and linear infrastructure within previously contiguous landscapes. This network could:

- increase the number and timing of deliberate or accidental ignitions. Edwards et al. have noted that changing fire regimes in the NT often result in *"a concomitant increase in the number of fires associated with roads";* [143]
- increase the risk of fire due to flaring. The Panel notes that in NSW, the EPA only allows flaring of gas during total fire bans if that company has an exemption under the Rural Fires Act 1997 (NSW)[144] and
- act as physical barriers to the spread of fire, and therefore reduce its areal extent.

Fire is a much more important issue for any onshore shale gas development in the NT than is reflected in the overseas literature[145] because of the unusally high flammability of Australian ecosystems. The biota of the NT has a long evolutionary history with fire and is adapted to the habitat conditions created by it. Fire frequency is highest in the tropical savannah landscapes of northern Australia, which cover both the northern and central regions of the NT.[146] In the central and northern regions of the NT, including the Sturt Plateau, annual monsoonal rains generate considerable vegetative growth, which cures rapidly with the onset of each dry season to create vast areas of fuel. Hundreds of thousands of square kilometres within these areas are burnt each year, with most areas burnt every two to five years (**Figure 8.8**). DENR describes frequent, late season, large scale fires as a constant risk in the Sturt Plateau, Gulf and northern Barkly areas.[147]

Savannah fires are also important for Australia's carbon accounts because they release substantial amounts of greenhouse gases.[148] The use of prescribed burning 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.[149]

137 Craggs 2016.
138 Baker et al. 2005; EDO submission 213, Appendix D, p 13.
139 Wicks 2014.
140 EDO submission 213, Appendix D, p 13.
141 TPWC Act, s 31(3).
142 Andersen et al. 2005.
143 Edwards et al. 2008.
144 NSW EPA 2015.
145 Bradstock et al. 2012.
146 Andersen et al. 2003; DENR submission 473, p 1.
147 DENR submission 473, p 1.
148 Cook and Meyer 2009.
149 Russell-Smith et al. 2009; Russell-Smith et al. 2013; Richards et al. 2012.

The Environment Centre NT has raised concerns that an onshore shale gas industry will have an impact on successful existing Aboriginal fire management programs. [150] As at May 2017, there were 17 savannah burning carbon projects registered in the NT, with two of these occurring in the Beetaloo Sub-basin.[151]

Fire is less frequent in arid regions of the NT, with the interval between fires usually ranging from seven to 20+ years (**Figure 8.8**), driven by the high production of annual grasses that follows periods of unusually high rainfall.[152] An exception to this fire pattern occurs in landscapes dominated by the introduced pasture, buffel grass.[153] Buffel grass dries off between periods of growth enabling a high volume of dry plant matter to accumulate, which can fuel intense fires. Resilience to fire enables buffel grass to survive and quickly produce new growth after burning, providing fuel for more fires. Wildfires fuelled by buffel grass are particularly damaging to many central Australian native plant species, including trees, which are unable to cope with the increased fire intensity and frequency. They are also damaging to riparian systems and high conservation value aquatic ecosystems.[154] Additionally, these wildfires can result in serious economic losses, particularly in regions where effective fire management strategies are absent, including loss of cattle, reactive investment in fire fighting, damage to infrastructure, and loss of pasture that requires cattle to be moved, agisted or sold at sub-optimal times.[155]

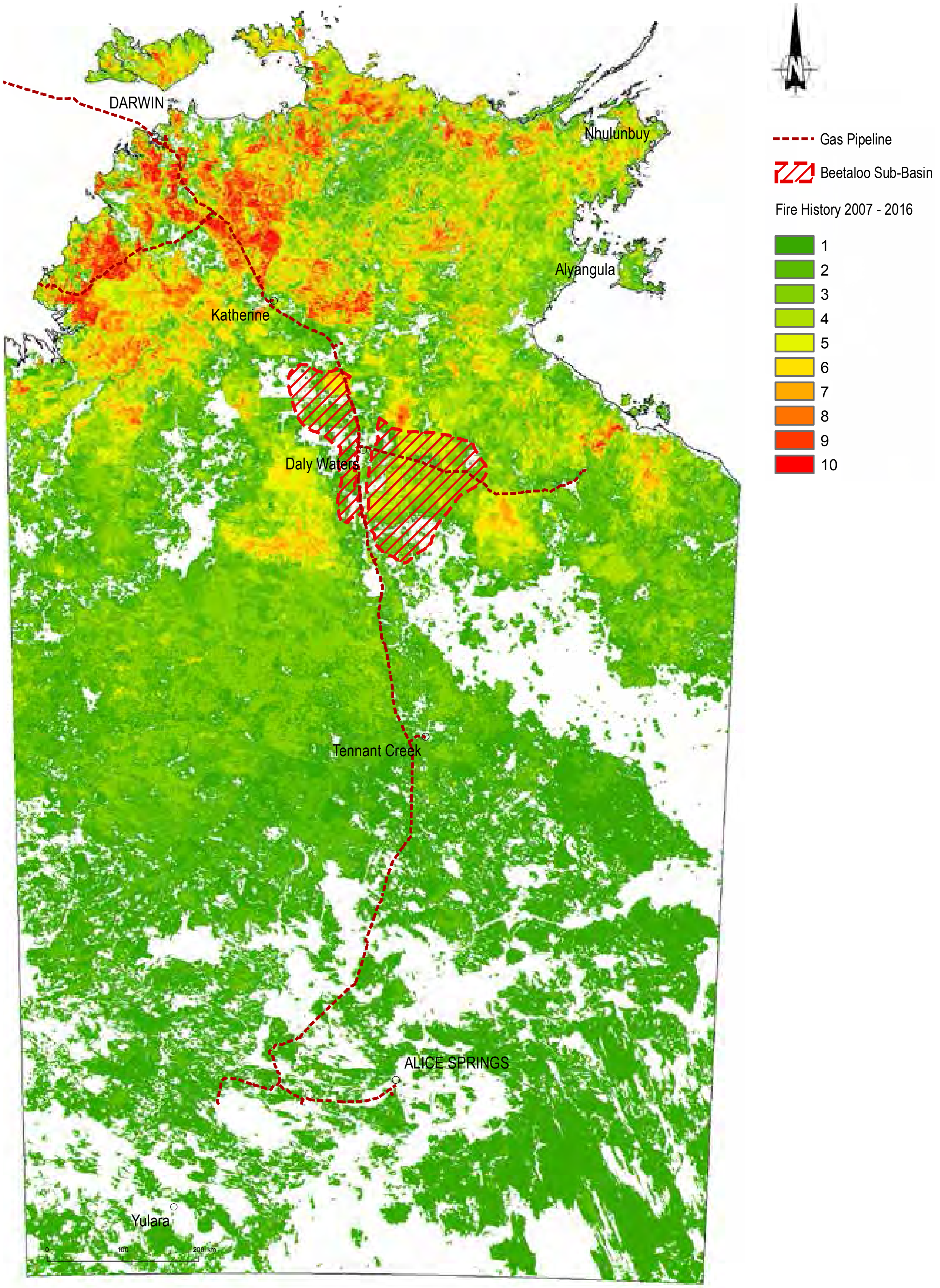
Landscape fire management is integral to Aboriginal culture, playing a fundamental role in hunting, the collection of bush tucker and fulfilling land stewardship responsibilities. Fire management also plays a key role in contemporary land management. This includes the management of conservation lands throughout the NT[156] and the management of pastoral lands by preventing wildfires, improving pasture, managing grazing, and controlling weeds.[157]

Fire can have different impacts on different terrestrial ecosystems. For example, the savannah biota of the NT needs frequent fire, being adapted to the open habitat conditions created by fire, such that long term fire exclusion and subsequent canopy closure leads to substantial biodiversity loss. However, the savannah landscapes also include vegetation types that require lower fire frequency.

Changes in fire regimes, particularly a high frequency of intense wildfires, can have serious impacts on vegetation, biodiversity, cultural and sacred sites, pasture and physical infrastructure.[158] For example, bullwaddy communities are extremely sensitive to frequent and intensive fires. Without management of the fire regime there can be a change in the vegetation communities from bullwaddy through to lancewood and then to a eucalypt dominated woodland. This process may be accelerated or exacerbated by the invasion of exotic pasture grasses such as buffel grass.[159]

150 Environment Centre Northern Territory, submission 188 (**ECNT submission 188**), p 6.
151 Territory Natural Resource Management 2016, p 5.
152 Edwards et al. 2008, p 111.
153 Edwards et al. 2008, p 111.
154 NT Government 2011.
155 Edwards et al. 2008.
156 Dyer et al. 2001, pp 3-4.
157 Department of Primary Industry and Fisheries 2010, p 62.
158 Edwards et al. 2008, p 111.
159 Northern Territory Parks and Wildlife Commission 2005, p 19.

Figure 8.8: Map of fire frequency between 2007 and 2016 in the NT. Source: DENR



Fire across the non-urban areas of the NT is managed under the Bushfires Management Act,[160] with statutory Regional Management Plans (**RMPs**) currently being developed in four of the five Fire Management Zones. These RMPs are developed in consultation with landholders and other stakeholders. They focus on a range of outcomes, including the protection of lives, property, assets and environmental values, and take into account how fire regimes vary according to climate, vegetation, land tenure, and land use.

The Panel notes that the current NT legislative requirements regarding weeds, feral animals and fire are focussed on landowners and land managers and not gas companies. However, it is highly desirable that the gas companies understand and comply with these requirements.

Aerial photo of a station on the Barkly Tablelands illustrating the capacity of access tracks to influence the path and extent of fire. Source: Scott Bridle, Australian Outback Photography.

The Panel's assessment is that any onshore shale gas development is likely to have greater impact on fire frequency in the tropical savannah landscapes of the central and northern regions of the NT rather than in arid regions because of the fuel available for fire every year in those regions.[161] However, the Panel is aware that while there is a lack of fuel in arid regions in most years, when fuel has accumulated over time, wildfires can cause serious ecological and economic damage unless active management is in place to reduce fuel loads.

The Panel has assessed the likelihood of increased fire frequency due to any onshore shale gas industry as 'medium', given increased human activity, and therefore, sources of ignition. This increase is likely to exacerbate the impact of feral cats on small mammals,[162] threaten fire sensitive ecological communities such as lancewood,[163] and lead to increased greenhouse gas emissions.[164] The Panel's assessment is therefore that the consequence of increased fire frequency is 'high', giving an overall risk rating of 'high'.

DENR is currently developing RMPs for each of the NT's five fire management zones, as required under the Bushfires Management Act.[165] These RMPs will specify arrangements for the mitigation, management and suppression of fire. Consultation has begun on four of the five RMPs (Savannah, Vernon Arafura, Arnhem and Alice Springs), with any onshore shale gas industry identified as a potential risk in all four regions. DENR has advised the Panel that this risk will be addressed under DENR's established risk matrix, and mitigation strategies developed where appropriate.[166]

160 DENR submission 473, p 2.
161 Nano et al. 2012.
162 Andersen et al. 2012; Davies et al. 2017.
163 Woinarski and Fisher 1995.
164 Cook and Meyer 2009.
165 DENR submission 473, p 2.
166 DENR submission 473.

Possible actions that can mitigate the risk of increased fire frequency include:

- limiting ignitions, especially those due to smoking by gas industry employees, in the field;
- compliance with relevant RMPs;
- undertaking annual fire mapping to monitor any increase in fire frequency due to any onshore shale gas industry, compared with a baseline established for at least the decade prior to commencement of any onshore shale gas development, using remotely sensed information that is readily available on the North Australian Fire Information website;[167]
- in consultation with landholders, implementing management actions, such as prescribed fuel reduction burns, to reduce fuel loads at strategic locations if fire frequency has increased due to shale gas activity; and
- gas companies assisting local volunteer fire brigades to increase regional capacity for fire management.

Assuming that these mitigation measures are implemented and enforced, the Panel's assessment is that the risk of changed fire regimes is both 'low' and acceptable.

Recommendation 8.5

That gas companies be required to comply with any statutory regional fire management plan within their area of exploration and/or production activity. The fire management plan must:

- ***address the impacts that any onshore shale gas industry will have on fire regimes in the NT and identify how those impacts will be managed;***
- ***establish robust monitoring programs for assessing seasonal conditions and fuel loads;***
- ***require that annual fire mapping be undertaken to monitor any increase in fire frequency due to any onshore shale gas development;***
- ***require that all existing baseline data for at least the decade prior to commencement of any exploration activity be collated and published;***
- ***implement management actions, such as prescribed fuel reduction burns at strategic locations, if fire frequency is shown to have increased due to onshore shale gas activity; and***
- ***facilitate support for local volunteer fire brigades to increase regional capacity for fire management.***

8.4.4 Unacceptable changes to native vegetation

Any onshore shale gas development will inevitably involve substantial vegetation clearing given that the NT is almost entirely covered by native vegetation.[168] Clearing of vegetation for infrastructure (well pads, roads and pipeline corridors) will result in direct habitat loss and in the fragmentation of fauna habitat not directly cleared.[169]

Pipelines and roads will require the largest amount of vegetation clearing. Origin has estimated that each well pad will require 2.1 km of pipeline and a cleared width of around 10 m. Access roads between well pads are likely to be constructed alongside the buried pipeline (2.1 km long and 15 m wide). Therefore, a 50–65 well pad development will require an estimated 250–300 km of connecting gas pipelines and roads, with a further 60–80 km network depending upon the location of the gas processing facility.

The current industry practice of multiple wells with extensive laterals results in substantially less vegetation clearing compared with past practices where individual wells were spread over a much greater surface area. The Panel has estimated the total area cleared within a development area for a range of well pad densities, based on an assumption of initial well pad size and the width and length of access roads and pipelines (**Table 8.1**). The Panel has not included areas cleared for exploration seismic lines. It is estimated that these lines need cleared widths of 5 m for source lines, and 3 m for receiver lines.[170] **Table 8.1** shows that the estimated percentage of total area cleared in a 50 x 50 km^2 development area when well pads are spaced by 1 km, 3 km and 5 km apart are 13%, 2.6% and 1.3%, respectively.

167 Australian Department of the Environment and Energy 2017l.
168 Eco Logical Australia 2013, pp. 16-19; EDO submission 213, Attachment D.
169 Racicot et al. 2014.
170 Pangaea submission 220.

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 to 4.4 km),[171] which would require vegetation clearing of approximately 1.5 to 2.5% of the development area, based on the figures in **Table 8.1**. Origin has estimated that the total surface footprint under their large scale development scenario would be 2% of the total development area,[172] while Santos has estimated a surface footprint of 1.4% of the total development area during the exploration and drilling phase, reducing to 1.2% during production following rehabilitation.[173] DPIR estimates a 3.7% surface footprint during exploration and development, reducing to 0.8% during the production phase.[174]

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

Area serviced per well pad	1 km^2	9 km^2	25 km^2
Well pad spacing (km)	1	3	5
Number of well pads	2,500	256	100
Well pad clearing at 10 ha/pad (km^2)	250	25	10
Total length of roads (km)	2,700	1,600	900
Road clearing at 20 m width (km^2)	54	31	18
Total length of pipelines (km)	2,300	800	500
Pipeline clearing at 10 m width (km^2)	23	8	5
Total clearing (km^2)	330	64	33
Total clearing (% total area (2,500 km^2))	13	2.6	1.3

Taking the 2% figure, the indicative total area cleared within a 2,500 km^2 development area is 50 km^2. If the moratorium were lifted, the total land area for gas development over the next 10 years in the Beetaloo Sub-basin is expected to be approximately 1,300 km^2 (Table 6.2). An indicative area of land clearing over this period is therefore 26 km^2. This is comparable to the area recently cleared annually in the NT by the pastoral industry.[175]

Vegetation clearing can also result in the fragmentation of faunal habitat,[176] which leads to a proliferation of habitat edges, with edge effects on the abiotic environment (including microclimate, light and wind) known to occur up to 500 m or more from cleared areas.[177] In the US, it has been estimated that the loss of core habitat through edge effects associated with onshore gas development can be at least twice that lost directly through vegetation clearing.[178] A 4.5% loss in forest cover in the central Appalachians due to shale gas development has been assessed as translating to a 12% loss in core forest once edge effects are considered, and this had a detectable impact on local bird communities.[179] 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.[180]

Most studies of abiotic edge effects have been conducted in forests, and their extent in more open habitats, such as those occurring in much of the NT, are poorly known. In open habitats, naturally clear areas will not be so ecologically different from small, anthropogenic clearings. The role of patch mosaics in heterogeneous landscapes remains poorly understood.[181] Similarly, the understanding of gap width effects on habitat fragmentation is largely based on studies of forests and similarly closed habitat types that have limited natural gaps. [182] There have been very few studies of the ecological effects of fragmentation in the NT, and those that do exist focus on

171 Origin submission 153, p 37; Santos submission 168, pp 38-42.
172 Origin submission 153, p 36.
173 Santos submission 420, pp 5-9. This assumes a well pad density of approximately one well pad per 19.4 km^2.
174 DPIR submission 424, pp 8-9.
175 EDO submission 635, p 7.
176 Racicot et al. 2014.
177 Zipperer 1993; Harper et al. 2005.
178 Slonecker et al. 2012.
179 Farwell et al. 2016.
180 Gillen and Kiviat 2012.
181 Fischer and Lindenmayer 2007.
182 Lindenmayer 2008.

small fragments remaining in transformed landscapes, rather than on the effect of linear corridors in otherwise intact landscapes.[183] The Panel is unaware of any studies of abiotic edge effects in Australia's savannah or desert landscapes.

The Panel concludes that the likelihood that an onshore shale gas development will lead to substantial native vegetation loss is 'high' at both the development and regional scales given that large areas will be cleared of vegetation. But the consequences of this vegetation loss have been assessed as 'low' to 'medium' depending on the conservation values of the land that is cleared. The Panel's assessment is that it is not possible to determine the risks from habitat fragmentation and edge effects due to vegetation loss along linear corridors until there is a better understanding of the sensitivities and critical effects thresholds for NT vegetation types. However, the Panel believes that it will be considerably lower than in forest habitats. The overall consequence of vegetation loss and habitat fragmentation is therefore expected to range from 'low' to 'medium' depending on the conservation values of the cleared land. Therefore, the Panel's assessment of the overall risk of unacceptable changes to native vegetation is 'medium'

There are a number of ways that the impact of vegetation and habitat loss can be mitigated, namely:

- obtaining improved information as part of a SREBA on key habitat patches at the regional scale that must be avoided by any infrastructure. This includes the mining of sand for use as proppant;[184]
- the identification of rare or threatened vegetation patches, or critical habitat along proposed corridors, with a requirement that they be avoided in corridor routes;
- limiting the extent of land clearing through efficient design of access roads and pipeline corridors, and through region-wide planning, including the co-location of shared infrastructure by different gas companies (see also Section 8.6)[185] and the use of existing roads and tracks on pastoral properties;
- monitoring any threatened species at risk from habitat loss and fragmentation and implementing appropriate management plans where required;
- effectively rehabilitating cleared areas immediately upon the completion of exploration and/or production activity so that vegetation is re-established and edge and fragmentation effects are ameliorated; and
- establishing appropriate offsetting to compensate for loss of vegetation and faunal habitat. The EAA makes no provision for environmental offsets; however, the EPA has published guidelines on environmental offsets and associated approval conditions.

An environmental offset is an action taken to compensate for unavoidable, negative environmental impacts that result from an activity or a development. Environmental offsets apply when the impacts of development cannot be avoided or mitigated. As noted by the EDO:

> *"from a bioregional planning perspective, it would be much more proactive and precautionary to nominate priority no go areas prior to the development of shale gas fields; these would form the core conservation areas to which future additions, including offsets, can be made".*[186]

The Panel has made recommendations with regard to 'no go zones' in Chapter 14. In the event an environmental risk cannot be avoided or mitigated, environmental offsets should also be considered. The Government does not currently have an offset scheme and, as stated above, the EAA makes no provision for environmental offsets or social or other community benefit as a part of any petroleum assessment or approval process.

For offsets to be effective, there must be a scientific approach to assessing the impact of development on biodiversity. The composition, structure and function of ecosystems, including threatened species, populations and ecological communities and their habitats, must be properly assessed.[187] Offsets may involve land where a suitable parcel of land is identified for protection and management. Alternatively, a management approach may be formulated that will benefit a

183 Rankmore and Price 2004.
184 ECNT submission 1254, p 3.
185 Eco Logical 2013, p 29; BC Oil and Gas Commission 2017a, p 13.
186 EDO submission 213.
187 NSW Department of Environment, Climate Change and Water 2009.

specific species or ecosystem that is being affected by the proposed development.

Where offsets are negotiated for areas of undeveloped land, the location, size and management of those offsets should be calculated using known biodiversity values rather than simple offset ratios (for example, 1:1 hectares or square kilometres). This is particularly relevant to any onshore shale gas development where the area of cleared land is disproportionate to the entire development area and the scale of activity.

The Panel notes that offset arrangements can be highly variable and innovative. For example, the Panel is aware of partnership agreements between traditional owners, Indigenous ranger groups and industry for the purposes of offsetting greenhouse gas emissions through strategic fire management in the NT.[188]

The Panel recommends that the Government develops and implements an environmental offset policy for any onshore shale gas industry. The Panel recognises that there is very limited scope for direct offsets through the re-establishment or rehabilitation of similar vegetation elsewhere (that is, no net vegetation loss) because so little of the NT has been cleared. Indirect offsets are therefore likely to be more appropriate.

With these mitigation measures in place, the Panel considered that the risk of unacceptable changes to native vegetation will be 'low' and acceptable.

Recommendation 8.6

That as part of a SREBA, a study be undertaken to determine if any threatened species are likely to be affected by the cumulative effects of vegetation and habitat loss, and if so, that there be ongoing monitoring of the populations of these species. If monitoring reveals a decline in populations (compared with pre-development baselines), management plans aimed at mitigating these declines must be developed and implemented.

Recommendation 8.7

That the area of vegetation cleared for infrastructure development (well pads, roads and pipeline corridors) be minimised through the efficient design of flowlines and access roads, and where possible, the co-location of shared infrastructure by gas companies.

Recommendation 8.8

That well pads and pipeline corridors be progressively rehabilitated, with native vegetation re-established such that the corridors become ecologically integrated into the surrounding landscape.

Recommendation 8.9

That to compensate for any local vegetation, habitat and biodiversity loss, the Government develops and implements an environmental offset policy to ensure that, where environmental impacts and risks are unable to be avoided or adequately mitigated, they are offset.

That the Government considers the funding of local Aboriginal land ranger programs to undertake land conservation activities as an appropriate offset.

8.4.5 Roads and pipelines as ecological barriers and corridors

As noted in Section 8.4.4, the construction of roads and pipelines can potentially cause substantial habitat fragmentation, as well as intersect important vegetation or habitat features in the landscape, if not designed to minimise these impacts. Additionally, pipeline corridors and roads can disrupt important ecological processes by (also see Section 7.6.8):

- disrupting the flow of water, sediment and nutrients across landscapes.[189] This can relate to water flow along drainage and creek-lines, or to the smaller scale run-off and run-on dynamics that are especially important in flat, semi-arid landscape;[190]

188 Tropical Savannas CRC 2017.
189 Drohan and Brittingham 2012; Brittingham et al. 2014.
190 Ludwig et al. 1996; Eco Logical Australia 2013, pp 21-22.

- accelerating, or otherwise altering, runoff and/or erosion processes due to the alteration of flow, geomorphic characteristics or vegetation cover, creating potential sedimentation and turbidity threats and flow connectivity related threats;
- preventing the spread of fire, which is an ecologically important agent of natural disturbance in many parts of the world[191] and a key driver of global vegetation dynamics;[192] as discussed in Section 8.4.3);
- the clearing of vegetation or habitat components that provide productivity hotspots, seasonal refugia or regionally significant feeding and breeding resources (see Section 8.4.4);
- the movement of fauna (see Section 8.4.4);[193]
- facilitating the spread of weeds along the road and pipeline corridors by transport on equipment and by providing disturbed ground for weed establishment (see Section 8.4.2.1); and
- acting as corridors to facilitate movement and hunting by predators (with cascading effects on their prey),[194] as well as the spread of exotic animals.[195]

Given the biodiversity value of the large scale, relatively intact ecosystems of the NT, if corridor impacts are substantial over the geographic scale of the likely development scenarios discussed above, the Panel's assessment is that the consequences would be 'medium' and the likelihood, given the uncertainty for savannah and grassland ecosystems, 'medium'. Therefore, with no further mitigation, the overall assessment of risk would be 'medium', and unacceptable.

There are, however, a number of measures that can assist in mitigating these risks, including:

- as discussed above, requiring gas companies to identify critical habitats during corridor construction and select an appropriate mechanism to avoid detrimental impact on them;
- keeping corridor widths to a minimum, with pipelines and other linear infrastructure buried, except for necessary inspection points, and the disturbed ground revegetated;
- using directional drilling under stream crossings in preference to trenching unless geomorphic and hydrological investigations confirm that trenching will have no detrimental impact on water flow patterns and waterhole water retention timing; and
- requiring roads and pipeline surface water flow paths to minimise erosion of exposed (road) surfaces and drains, and constructing all corridors to minimise the interference with wet season stream crossings and comply with relevant guidelines, such as the *International Erosion Control Association Best Practice for Erosion and Sediment Control* and the *Australian Pipeline Industry Association Code of Environmental Practice 2009* (see ***Recommendation 7.18***).

With these mitigation measures in place, the Panel's assessment is that the likelihood of corridor impacts would remain, but that the consequence would be minor to moderate with an overall risk of both 'low' and acceptable.

Recommendation 8.10

That gas companies be required to identify critical habitats during corridor construction and select an appropriate mechanism to avoid any impact on them.

Recommendation 8.11

That clearing for corridors, well pads and other operational areas be kept to a minimum, that pipelines and other linear infrastructure be buried (except for necessary inspection points), and that all disturbed ground be revegetated.

Recommendation 8.12

That directional drilling under stream crossings be used in preference to trenching unless geomorphic and hydrological investigations confirm that trenching will have no adverse impact

191 Bowman et al. 2009.
192 Bond et al. 2005.
193 Machtans 2006.
194 Howell et al. 2007; Latham et al. 2011.
195 Brown et al. 2006.

on water flow patterns and waterhole water retention timing.

Recommendation 8.13

That roads and pipeline surface water flow paths minimise erosion of all exposed surfaces and drains.

Recommendation 8.14

That all corridors be constructed to minimise the interference with wet season stream crossings and comply with relevant guidelines, such as the International Erosion Control Association Best Practice for Erosion and Sediment Control and the Australian Pipeline Industry Association Code of Environmental Practice 2009.

8.4.6 Other unacceptable impacts on wildlife

8.4.6.1 Wastewater or chemical spills

Any onshore shale gas industry requires at least the short-term local storage of substantial volumes of wastewater of variable quality (Chapter 5), which may be toxic to animals. There are two ways wildlife can gain access to contaminated water:

- open wastewater storage ponds; and
- on-site or off-site spills.

In Chapter 7, the Panel has recommended that enclosed tanks be used to hold wastewater in preference to open ponds (***Recommendation 7.12***), which would prevent access by wildlife. The mitigation of chemical spills has also been dealt with in Chapter 7.

8.4.6.2 Noise and light

Any onshore shale gas industry involves short-term increases in noise during site clearing, well drilling, and the construction of roads, pipelines and other infrastructure. It involves longer term increases in noise during production, particularly with pipeline compressor stations.[196] Chronic noise can influence wildlife in many ways,[197] with animals relying on vocal communication, such as birds, being especially affected.[198] Additionally, any onshore shale gas industry will involve sources of artificial light, which can have a range of effects on wildlife.[199]

Origin and Pangaea provided the Panel with information on how they would handle the risks to fauna from noise and light,[200] with Origin noting that there are no Government policies or other guidelines mandating noise limits for fauna in general.[201] As part of its EMP for Amungee, Origin conducted noise assessments considering the potential noise emissions, proximity to nearby sensitive features (habitat and landholders), and whether or not the relevant regulatory noise criteria was likely to be met. Where a sensitive ecological community was identified, a range of noise management measures were applied to reduce noise impacts to below acceptable levels. These included:

- the use of buffers to provide minimum distances away from sensitive features;
- the relocation of the noisy activity;
- the rescheduling of the noisy activity; and
- the selection of low noise emitting equipment or the use of noise attenuation devices.

Origin noted that there is little evidence that lighting from any onshore shale gas facilities has an impact on fauna likely to be present in the Beetaloo Sub-basin.[202] Assessment of the potential impacts from facility lighting is undertaken as part of the EMP. Mitigation measures include:

- the design of facilities to use low impact lighting (including light selection, light orientation, and the use of motion sensors);
- locating major facilities away from potentially sensitive habitat areas; and

196 Peterson 2015.
197 Francis and Barber 2013.
198 Bayne et al. 2008; Francis et al. 2011.
199 Rich and Longcoren 2006; Stone et al. 2009; Perkin et al. 2011.
200 Origin submission 153, pp 100-101; Pangaea submission 220, pp 45-46.
201 Origin submission 153, pp 100-101.
202 Origin submission 153, p 101.

- unmanned infrastructure (such as lease pads) to have minimal to no lighting because it will not be frequented at night.

The Panel has assessed that the effects of noise and light will be very localised, affecting a small part of a development area, and therefore, is unlikely to pose a significant risk to regional biodiversity values. Additionally, if it is assessed that there are sensitive species in the vicinity of any onshore shale gas operation, there are existing measures to mitigate any effects.

8.5 Landscape amenity

The Panel's other objective in assessing the land-related risks of any onshore shale gas industry in the NT is to ensure that residents and tourists continue to perceive the NT as a place of largely unspoiled landscapes. Two aspects have been assessed:

- the risk of landscape transformation, whereby surface infrastructure is located in areas of high scenic beauty and high tourist visitation, or becomes a highly visible and a dominant feature of the landscape due to the close spacing of well pads (as has sometimes been the experience with onshore gas developments overseas, especially in the US);[203] and
- the risk of very high volumes of heavy-vehicle traffic during the development phase, which can have a substantial impact on landscape amenity and identity with place, both within and beyond a development area.[204]

8.5.1 Unacceptable landscape transformation

The impacts of land transformation on landscape amenity are a function of, first, the location of any development in relation to scenic value and tourist visitation, and second, the scale and visibility of infrastructure within a development area. The Panel defines acceptable landscape change as a result of shale gas development as:

- no impact on the physical appearance of the NT's most scenic and highly visited outback landscapes; and
- minimal visibility of shale gas infrastructure from public roads in areas where development occurs.

The Panel recommends the exclusion of shale gas development from national parks or other conservation reserves, which contain many of the most scenic landscapes (see ***Recommendation 14.4***). However, there are other landscapes of high scenic and amenity value in the NT that currently would not be excluded from shale gas development. For example, the vast areas of the internationally significant Greater McDonnell Ranges and Cleland Hills coincide with known prospective shale deposits but are not currently afforded any protection from development.[205]

203 Lock the Gate Alliance (NT), submission 56 (**Lock the Gate submission 56**), pp 8-17.
204 Lee 2013.
205 Harrison et al. 2009, p 2.

Central Australian landscape.

The Panel's assessment of the likelihood of unacceptable impacts on landscape amenity is 'medium' given experiences with onshore gas development elsewhere. The Panel's assessment of the consequences of such impacts is 'high', given the importance of the NT's unspoiled landscapes. Therefore, the overall assessment of risk is 'high'. The Panel has identified two sets of possible mitigation measures, namely, the protection of scenic landscapes from any onshore shale gas development and minimising the visual impacts of any shale gas industry on landscape amenity.

The Panel considers that all NT landscapes with high landscape amenity value, not already protected in national parks or other conservation reserves, should be identified then considered as possible 'no go zones' for onshore shale gas development.

To assess the visual impacts of any onshore shale gas development, the Panel has used the Beetaloo Sub-basin, and information provided by the three companies, Origin, Santos and Pangaea, as a case study. The Panel has constructed a possible scenario of three developments, each consisting of 40–50 well pads and taking up an area of around 400–500 km^2 as shown in **Figure 8.5**. On the basis of the information provided by the three gas companies, these development sites would be separated by around 60–80 km, and would be unlikely to be visible from the Stuart Highway, the main north-south tourist route in the NT. During the drilling and hydraulic fracturing phases, rigs used for these purposes would be located on each well pad (assuming 8–10 wells per pad) for approximately one year, and depending upon the number of rigs deployed, they would be on the development site for at least 10 years. Since these rigs are 20–30 m high, they would be visible for some distance in the very flat Beetaloo landscape.

During the drilling and extraction phase, the Pangaea development would possibly be visible from Western Creek Road, the Origin development from the Carpentaria Highway (the main sealed road from the Stuart Highway to Borroloola, 26,000–33,000 vehicles used this highway in 2015[206]), and parts of the Santos development from the Carpentaria Highway. However, during the production phase, when the drill rigs are removed and the height of the remaining infrastructure is much less (approximately 2 m high), there will be limited visibility of any infrastructure from any major road.

The Panel's assessment is that the likelihood that the infrastructure associated with any shale gas development in the Beetaloo Sub-basin will be visible from public roads, particularly during the drilling and hydraulic fracturing stages, is 'medium'. However, the Panel finds it difficult to assess the consequences of this change to the amenity value for tourists or Territorians, because of their subjective nature.

206 DoT 2015.

The Panel heard community concerns regarding the potential for the landscape to be industrialised by any onshore shale gas industry.[207] The move to multi-well pads has significantly reduced the surface footprint of shale gas developments in the US,[208] and has the potential to also do so in the NT. As noted above (see Section 8.3.1), the development of any shale gas industry in the Beetaloo Sub-basin could result in approximately 150 well pads spread over three locations each being around 400-500 km^2 (20 km x 25 km) in area. These assume a distance between well pads of approximately 2 km.

The Panel received a number of submissions expressing concern that any onshore shale gas industry would result in over industrialisation of the NT landscape.[209] One way to address this is to mandate a minimum spacing between well pads. However, Origin argued to the Panel that, *"imposing pad spacing is inefficient and un-optimized … as the total surface area footprint per area of subsurface developed… will increase."* [210]

The Panel considers 2 km to be an appropriate minimum distance between well pads given that it is expected that 3 km (or more) long laterals will be drilled and fractured. It is the Panel's expectation that the gas companies will in fact increase the distance between well pads beyond 2 km. The gas industry is concerned that if a minimum well spacing is mandated, it could lead to both suboptimal recovery of gas reserves and to a larger surface footprint because of a need for longer roads and pipelines.[211] However, industry concerns about potential limitations of access to gas reserves must be balanced against the need to avoid unacceptable landscape industrialisation and any concomitant negative impact on tourism and community wellbeing.

There is no objective standard for well spacing that prevents perceptions of landscape industrialisation due to onshore shale gas development, given that perceptions of landscape amenity are highly subjective. In other jurisdictions, minimum spacing between well pads is sometimes included in codes of practice,[212] and occasionally regulation,[213] but generally not for the purpose of protecting landscape amenity. Given that the three gas companies with exploration permits in the Beetaloo Sub-basin have indicated that they would seek to develop well pads with a spacing of around 2 km,[214] it is the Panel's opinion that a minimum distance of 2 km between well pads should be mandated.

The second method by which the impacts of any onshore shale gas industry on landscape amenity can be ameliorated is to reduce the visibility of infrastructure within development areas[215] by ensuring that well pads are built away from major public roads. The gas companies should locate their well pads so that they are not seen from major public roads during the construction (clearing and drilling) and well stimulation (hydraulic fracturing) phases.

Recommendation 8.15

That to minimise the impact of any onshore shale gas industry on landscape amenity, gas companies must demonstrate that they have minimised the surface footprint of development to ALARP, including that:

- ***well pads are spaced a minimum of 2 km apart; and***
- ***the long-term infrastructure within any development area (exploration or production) has little to no visibility from any major public roads.***

8.5.2 Unacceptable increase in heavy-vehicle traffic

The scientific literature contains a range of estimates of heavy-vehicle requirements for transporting equipment and supplies during any onshore shale gas development, including up to 2,000 truck trips for a high volume hydraulic fracturing event,[216] more than 3,300 one-way truck

207 Lock the Gate submission 56, pp 8 - 19; ALEC submission 88, p 14.
208 Manda et al. 2014.
209 Lock the Gate submission 56, pp 8-19; ALEC submission 88, p 14.
210 Origin submission 433, p 50.
211 Santos submission 420, pp 7-8; DPIR submission 424, p 9; Origin submission 433, p 50.
212 Queensland DNRM 2017a, p 9.
213 Texas Railroad Commission 1976, p 91.
214 Origin submission 153, p 40; Santos submission 168, pp 41-42; Pangaea submission 427, p 10.
215 See, for example, Origin submission 433, p 55.
216 Hays et al. 2015; Goldstein et al. 2014.

trips for the development of each horizontal well,[217] and between 4,300 and 6,600 total truck visits to service a six-well pad.[218] Despite some inconsistencies in the above estimates, it is clear that any onshore shale gas development requires high volumes of heavy-vehicle traffic. This can have a significant impact on landscape amenity and place identity both within, and beyond, a development area,[219] including for residents of towns located on major highways and tourists travelling along them.[220] Impacts can be through traffic congestion on roads or through the visibility of large vehicles creating perceptions of landscape industrialisation.

The Panel has obtained estimates of the current annual traffic volumes along the Stuart and Carpentaria Highways, the two major roads in the Beetaloo Sub-basin.[221] In 2015, the estimated annual traffic volumes were:

- Stuart Highway near Daly Waters: 151,000–164,000 vehicles; and
- Carpentaria Highway near Daly Waters: 26,000–33,000 vehicles.

It is likely that a considerable number of these vehicle movements along the Stuart Highway are tourists.

The Panel is unable to make an assessment of the risk of heavy-vehicle traffic to landscape amenity because of a lack of relevant information on the estimated increases in traffic volumes that would result from any shale gas development in the Beetaloo Sub-basin, or elsewhere in the NT. Information is needed on the estimated increase in volume at various time of the year, types of vehicles (heavy vehicles compared with other vehicles), supply sources, and the cumulative effects of multiple development areas. The Panel recognises that the gas companies will be required to address traffic risks as part of their EMPs,[222] but these assessments do not consider the cumulative impacts of multiple developments.

Increased heavy-vehicle traffic along the Stuart and Carpentaria Highways will continue over an extended period of time. Without more information on the potential increase in heavy-vehicle traffic, it is not possible for the Panel to assess the consequences to residents and tourists, except to note that the greatest impacts are likely to occur during the dry season when most tourists will be travelling and when any onshore shale gas activity is likely to be highest.

The Panel has identified three measures that could assist in minimising the risks and inconvenience that will be caused by an increase in heavy-vehicle traffic, namely:

- upgrading major highways by constructing overtaking lanes and dual carriageways;
- requiring heavy vehicles to travel at night (although it should be noted that road kill of wildlife most commonly occurs at this time[223]), early morning, or late afternoon;[224] and
- examining the use of rail to deliver supplies to the region. Pangaea has suggested that the existing Adelaide to Darwin railway line could be used,[225] but there has been no analysis of the feasibility of this suggestion, or the extent to which it would reduce road movements.

Recommendation 8.16

That the Government assesses the impact that any heavy-vehicle traffic associated with any onshore shale gas industry will have on the NT's transport system and develops a management plan to mitigate such impacts. Consideration must be given to:

- ***forecast traffic volume and roads used;***
- ***the feasibility of using the existing Adelaide to Darwin railway line (or some other railway network) to reduce heavy-vehicle road use; and***
- ***road upgrade.***

217 Bureau of Oil and Gas Regulation 2011.
218 Broderick et al. 2011.
219 Lee 2013.
220 Alice Springs Town Council submission 235, p 2.
221 DoT 2015.
222 Petroleum Environment Regulations Guide, p 10; Pangaea submission 427, p 17; Origin submission 433, p 63.
223 Dique et al. 2003; Magnus et al. 2004, cited in Eco Logical Australia 2012.
224 Hubbard et al. 2000, cited in Eco Logical Australia 2012.
225 Pangaea submission 427, p 17; Origin submission 433, p 64.

8.6 Conclusion

The Panel recognises that the NT has exceptional terrestrial biodiversity and ecosystem value and is renowned for its spectacular landscapes. The Panel has considered the risks relating to the potential loss of terrestrial biodiversity, ecosystem function and landscape amenity if any onshore shale gas development proceeds in the NT. It has identified a range of measures for mitigating these risks, including designating areas of particularly high conservation or scenic value as 'no go zones', developing and implementing effective plans for weed and fire management, limiting vegetation loss and the impacts of roads and pipelines, reducing the visibility of infrastructure in development areas, and managing heavy-vehicle traffic. It is the Panel's conclusion that these mitigation measures can, if implemented and enforced, reduce these risks to acceptable levels.

GREENHOUSE GAS EMISSIONS

9

9.1 Introduction

The extraction and subsequent use, namely, 'the life cycle',[1] of shale gas results in the emission of greenhouse gases (**GHG**) such as methane (**CH_4**) and carbon dioxide (**CO_2**).

During the public hearings, community consultations and in submissions, concern was raised that these emissions will exacerbate climate change and contribute to the adverse impacts associated with global warming. Some suggested that development of any onshore shale gasfields in the NT should therefore not go ahead under any circumstances.

9.1.1 Shale gas

Shale gas is a form of natural gas. Natural gas ranks third (24%) in Australia in terms of domestic energy consumption after oil and coal, and second (16%) in terms of national energy production after black coal. In 2014-2015, natural gas production in Australia rose by 5%, underpinned by an increased CSG production.[2] While recognising the importance of natural gas as a source of energy, it is nevertheless a fossil fuel and during its life cycle (extraction and use), it will contribute to global warming through the emission of GHG such as CH_4 and CO_2.

Natural gas is primarily composed of methane,[3] but it can also contain ethane, propane, butane and heavier hydrocarbons, carbon dioxide and small amounts of nitrogen, hydrogen sulfide and trace amounts of water. Natural gas is a source of fugitive emissions, which is the intentional and unintentional release of (principally) CH_4 (but also includes CO_2 and other gases) during the production, processing, transport, storage, transmission, and distribution phases of the life cycle. Energy is also required for the production, processing and transport of natural gas, and this energy use results in the liberation of further GHG and particulates. Carbon dioxide is emitted when natural gas is burned. For example, when gas is used to generate electricity, heat, or steam. Carbon dioxide is also vented, sometimes in large quantities, in the natural gas production process when raw natural gas is treated and carbon dioxide is removed to ensure that the gas meets pipeline specifications.[4]

While shale gas is the focus of this Inquiry, and therefore, this Chapter, it is recognised that coproduction of shale oil (or natural gas liquids, that is, hydrocarbon liquids) can occur. This matter is discussed further in Sections 6.1 and 9.6.1.

The Panel has formed the view that the assumed levels of gas production adopted in this Chapter are plausible and relevant for the purposes of conducting the risk assessments.

9.1.2 Greenhouse gases

From a review of GHG and CH_4 emissions, and considering the potential impacts arising from GHG, the key findings are that:

- global atmospheric concentrations of the major long-lived greenhouse gases continue to rise. For example, since pre-industrial times, the global mean CO_2 level has risen 45% to 403.3 ppm with a 0.6% increase per year for the last 10 years. Similarly, CH_4 concentrations have risen 157% to 1.85 ppm with a 0.4% increase per year for the last 10 years;[5]
- the total sources of methane emissions are approximately 558 Mt/y, with natural sources comprising approximately 41%, and anthropogenic sources approximately 59%, of this total. Fugitive emissions from fossil fuels comprise 32% of the anthropogenic methane emissions (105 Mt/y);

1 The life cycle of gas has two stages: first, the upstream stage, which comprises natural gas production, processing, transmission, and delivery, and secondly, the downstream stage of the energy conversion phase of natural gas for commercial or industrial or domestic purposes.
2 Department of Industry, Innovation and Science 2016b, pp 7 and 16.
3 Methane is a colourless, odourless gas that is lighter than air and is non-toxic. As a gas, it is flammable over a range of concentrations (5.4 - 17%) in air at standard pressure.
4 Climate Council 2017, p 10.
5 Parts per million.

- total annual global anthropogenic GHG emissions comprise 76% carbon dioxide and 16% methane emissions (the balance is nitrous oxide and fluorinated gases);
- to limit total human-induced warming to less than 2°C would require cumulative CO_2 emissions from all anthropogenic sources since 1870 to remain below about 2,900 Gt CO_2 by 2100. This is referred to as the 'global carbon budget'. Total cumulative emissions from 1870 to 2016 were 2,199 Gt CO_2;
- in recent decades, changes in climate have caused impacts on ecosystems on all continents and across all oceans; and
- limiting the impacts of climate change will require substantial and sustained reductions in greenhouse gas emissions, which, together with adaptation, can limit climate change risks.

GHG warm the planet by absorbing energy and slowing the rate at which the energy escapes to space. They act like an insulating blanket for the Earth.[6] Different GHG can have different effects on the Earth's warming. Two key ways in which these GHG differ from each other are their ability to absorb energy and how long they stay in the atmosphere. The Global Warming Potential (**GWP**) parameter was developed to compare the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of a unit mass of a gas will absorb over a given period of time, relative to the emissions of unit mass of CO_2.

Global atmospheric concentrations of the major long-lived greenhouse gases, CO_2, CH_4, nitrous oxide (**N_2O**) and a group of synthetic greenhouse gases (such as perfluorocarbons, hydrofluorocarbons and sulphur hexafluoride), continue to rise.[7] For example, the global mean CO_2 level in 2016 was 403.3 ppm, a 45% increase from around the year 1750, and a 0.6% increase per year for the last 10 years[8]. This is likely to be the highest level in at least the past two million years. The impact of all GHG in the atmosphere combined can be expressed as an 'equivalent CO_2' (**CO_2e**) atmospheric concentration, which reached 487 ppm in 2015 and 489 ppm in 2016.[9] Analysis of the different types (or isotopes) of carbon in atmospheric CO_2 shows that the additional CO_2 since 1750 in the atmosphere results from human activities, predominantly the burning of fossil fuels.[10]

Between 1750 and 2011, cumulative anthropogenic CO_2 emissions to the atmosphere were approximately 2040 Gt CO_2. About 40% of these emissions have remained in the atmosphere. The rest were removed from the atmosphere and stored on land (in plants and soils) and in the ocean[11]. Anthropogenic GHG emissions, together with other anthropogenic drivers, are the dominant cause of the observed warming since the mid-20th century. In 2016, total global anthropogenic GHG emissions continued to increase slowly by about 0.5% (±1%) to about 49.3 Gt CO_2e, excluding emissions from land use, land-use change and forestry (**LULUCF**). When including LULUCF emissions, the estimated global total GHG emissions are 53.4 Gt CO_2e.[12] The total annual global anthropogenic GHG emissions comprise approximately 76% carbon dioxide and 16% methane emissions (the balance is N_2O and fluorinated gases).[13]

Total emissions for Australia for the year to December 2016 (including LULUCF of 1.2 Mt CO_2e) are estimated to be 543.3 Mt CO_2e. This figure is 2.0% below emissions in 2000 and 10.2% below emissions in 2005. For the year to December 2016, emissions increased 1.4% on the previous year. The electricity sector is the largest contributor (35%) to Australia's GHG emissions, followed by stationary energy (18%), transport (17%), agriculture (13%), fugitive emissions (9%), and industrial processes and product use (6%).[14]

6 US EPA 2017d.
7 BoM 2016b.
8 WMO 2017.
9 Fraser et al. 2017.
10 BoM 2016b.
11 IPCC AR5 2014, pp 4 - 5.
12 Olivier et al. 2017.
13 IPCC AR5 2014, pp 4 - 5.
14 Australian Department of the Environment and Energy 2017k, p 9 ff.

9.1.3 Global methane

Since pre-industrial times, CH_4 concentration has risen 157% to 1.85 ppm in 2016, and it has increased 0.4% per year for the last 10 years.[15] Accordingly, in the past decade, the rate of increase of methane emissions has decreased relative to the rate of increase in CO_2 emissions. It is estimated that CH_4 has accounted for about 21% of the cumulative man-made global greenhouse effect since the pre-industrial era (1750).[16] Methane emissions comprise natural sources (wetlands and other sources) and anthropogenic sources (agriculture, biomass burning and fossil fuels). The total sources of methane emissions are approximately 558 Mt/y (averaged over the period 2003 to 2012), with natural sources comprising approximately 41% and anthropogenic sources approximately 59% of this total. Fugitive emissions from fossil fuels (105 Mt/y) comprise 32% of the anthropogenic methane emissions.[17] From this data on methane sources and sinks, it has been estimated that the net growth of methane emissions is approximately 10 million tonnes in the atmosphere every year.[18]

9.1.4 Global climate change

During each of the last three decades, the climate has been successively warmer at the Earth's surface than any preceding decade since 1850. For example, 2016 was the hottest year on record globally for the third year in a row, and all of the world's 10 warmest years have occurred since 1998.[19] According to NASA data, 2017 was the second-hottest year on record, and was the hottest year without the short-term warming influence of an El Niño event.[20] The globally averaged combined land and ocean surface temperature data showed a warming of 0.85˚C over the period 1880 to 2012.[21] Ocean warming dominates the increase in energy stored in the climate system, accounting for more than 90% of the energy accumulated between 1971 and 2010.[22]

There is evidence of observed climate change impacts in many regions. It has been observed that

> *"in recent decades, changes in climate have caused impacts on natural and human systems on all continents and across the oceans. Impacts are due to observed climate change, irrespective of its cause, indicating the sensitivity of natural and human systems to changing climate". Further, that "changes in many extreme weather and climate events have been observed since about 1950. Some of these changes have been linked to human influences, including a decrease in cold temperature extremes, an increase in warm temperature extremes, an increase in extreme high sea levels and an increase in the number of heavy precipitation events in a number of regions". And that "continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems. Limiting climate change would require substantial and sustained reductions in greenhouse gas emissions, which, together with adaptation, can limit climate change risks".* [23]

Changing precipitation or melting snow and ice are altering hydrological systems, affecting water resources in terms of quantity and quality. Many terrestrial, freshwater and marine species have shifted their geographic ranges, seasonal activities, migration patterns, abundances, and species interactions in response to ongoing climate change. Several submissions identified the impact of climate change on human health.[24] For example, climate change affects the social determinants of health, such as clean air, safe drinking water, sufficient food and secure shelter. The consequential health impacts of climate change include human fatalities.[25] The World Economic Forum[26] has

15 WMO 2017.
16 This is based on the relative radiative forcing contribution from methane of 0.48 W/m² to the net anthropogenic radiative forcing function of 2.29 W/m² (IPCC WG I 2013, p 698).
17 Saunois et al. 2016.
18 Saunois et al. 2016.
19 Climate Council, submission 458, p 3.
20 Nuccitelli 2018.
21 IPCC AR5 2014, p 2.
22 IPCC AR5 2014, p 4.
23 IPPC AR5 2014, pp 6 - 8.
24 For example, R Schultz, submission 1180 and Tim Forcey, submission 548 (**T Forcey submission 548**).
25 World Health Organization 2017. The World Health Organization 2017 assessment, taking into account only a subset of the possible health impacts, concluded that climate change is expected to cause approximately 250,000 additional deaths per year between 2030 and 2050: 38,000 due to heat exposure in elderly people; 48,000 due to diarrhea; 60,000 due to malaria; and 95,000 due to childhood undernutrition. Globally, the number of reported weather-related natural disasters has more than tripled since the 1960s. Every year these disasters result in over 60,000 deaths, mainly in developing countries.
26 World Economic Forum 2017.

noted the pervasive nature of changing climate. It was rated the second most important trend that determines global developments, and the failure of climate change mitigation and adaptation was identified as the third most important interconnection between risks.

Models show that limiting total human-induced warming to less than 2˚C relative to the period 1861–1880 would require cumulative CO_2 emissions from all anthropogenic sources since 1870 to remain below about 2,900 Gt CO_2 by 2100.[27] This is referred to as the 'global carbon budget'.[28] Total cumulative emissions from 1870 to 2016 were 1,539 Gt CO_2 from fossil fuels and industry and 660 Gt CO_2 from land use change. The global emissions from fossil fuels and industry in 2016 were 36.3 Gt CO_2.[29] The global carbon budget concept has major implications for the future global use of fossil fuels.[30] Further, concern has been expressed at the current GHG trajectory. As noted in one submission from Climate Action Darwin,[31] the Director of the Fenner School of Environment and Society at the Australian National University has said that *"both observed temperature and sea-level rise are tracking at or near the top of the envelope of model projections"*.

GHG emissions are known to be the major contributors to climate change. In 2015, Australia signed the agreement negotiated at the UNFCCC Paris Climate Conference (**COP21** or **Paris Agreement**). The Paris Agreement's central aim is to *"strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius."* [32] As part of the Paris Agreement, the Australian Government committed to reducing GHG emissions to 26–28% below 2005 levels by 2030. This will be a challenging task. The Australian emissions are projected to be 592 Mt CO_2e[33] in 2030, which will require a reduction of 990 Mt CO_2e to 1055 Mt CO_2e in cumulative emissions between 2021 and 2030.[34]

As noted in the following Section, concerns were expressed to the Panel about the use of fossil fuels and their impact on global warming. A number of submissions were made, noting that fossil fuels should not be extracted and used, and that there should be no development of any onshore shale gas industry in the NT. For example, Steffen observed that, based on a global carbon budget approach (see above), the "*exploitation of any new Northern Territory gasfields is inconsistent with the Paris 2.0˚C target*".[35] In addition, The Australia Institute provided a submission[36] on behalf of 31 scientists and experts, strongly urging that onshore shale gas development not go ahead in the NT under any circumstances. This was based on arguments founded upon the carbon budget framework.

The United Nations Framework Convention on Climate Change (**UNFCCC**) recommends that for methane, a 100-year GWP value of 25 be adopted based on the Intergovernmental Panel on Climate Change (**IPCC**) Fourth Assessment Report from the IPCC.[37] The IPCC Fifth Assessment Report[38] indicates that over a short period, such as 20 years, the GWP of methane is much higher, namely, between 84 and 86. It is usually more common to use a 100-year time frame and if this time frame is used, the IPCC Fifth Assessment Report indicates that the GWP is between 28 and 36. In this Chapter, a GWP of 36 is used for a 100-year timeframe and GWP of 86 is used for a 20-year timeframe, unless otherwise stated. Therefore, if 1 gram of methane is emitted, and for a 100-year timeframe with a GWP of 36, the equivalent emission is calculated as 36 g CO_2e.

9.2 Key concerns

Cogent arguments were made, and documented evidence was presented, during the public hearings and community forums expressing concern over the impacts of GHG emissions during

27 IPCC AR 5 2014, p 10.
28 The global carbon budget is defined as the maximum amount of CO2 from human sources that can be released into the atmosphere to limit warming to no more than 2˚C above pre-industrial levels (Steffen 2015).
29 Global Carbon Project 2017. The global CO2 emissions in 2016 from fossil fuels and industry comprise: coal (40%); oil (34%); gas (19%); cement (6%); and flaring (1%).
30 To have a 50% chance of preventing a 2˚C rise in global temperature, it has been estimated that 88% of global coal reserves, 52% of gas reserves and 35% of oil reserves are unburnable and must be left in the ground (see Steffen 2015).
31 Climate Action Darwin submission 446, p 1.
32 UNFCCC 2016.
33 Mt CO_2e = million tonne of CO_2 equivalents.
34 Department of the Environment and Energy 2016a, p iii.
35 Professor Will Steffen, submission 596.
36 The Australia Institute, submission 1252 (**The Australia Institute submission 1252**).
37 IPCC AR4 WG I 2007.
38 IPCC WG | 2013, p 714.

the extraction and use of any onshore shale gas.[39] For example, people voiced concerns about:

- rising GHG levels in Australia;
- the impact of increased GHG emissions on global warming;
- the impact of increased GHG emissions on the environment and on human health;
- the fact that alternatives to gas (namely, renewable energy) were not included in the Inquiry's Terms of Reference;
- the need to consider GHG offsets;
- the fact that no GHG target is proposed by the Government;
- a lack of consideration of the cumulative impacts from multiple onshore shale gasfields; and
- a lack of any real time and online monitoring data for GHG.

In response to these concerns, the Panel has:

- examined GHG emissions from onshore shale gas operations and uses;
- estimated the emissions associated with the upstream stage that comprises natural gas extraction, processing, transmission and delivery, together with the combined upstream and downstream stage of natural gas, which is referred to as the 'full life cycle'. The downstream stage represents the energy conversion phase of natural gas for commercial, industrial or domestic purposes; and
- evaluated the quantity of these emissions from any new shale gasfield in the NT and the consequential impact on, and risks to, global climate change.

The Panel has reviewed the scientific literature on the levels of GHG emissions, including methane, from shale gas operations and use. This information has been used to estimate expected emission levels and to assess how lower levels of emissions can be achieved. This Chapter draws upon data and literature from overseas, including the US given the very large shale gas industry in that country. Reference is made to Australian data where relevant.

It should be noted that there are differences between the emissions from conventional gas and CSG wells, which are prevalent in Australia, and the emissions from shale gas wells. In assessing the risks from any onshore shale gas industry in the NT, the Panel has assessed fugitive methane emissions during upstream operations, life cycle GHG emissions, and fugitive methane emissions from decommissioned wells. These assessments were conducted within a risk assessment framework with current mitigation measures in place and subsequently with additional mitigation measures aimed to reduce emissions and to assess whether acceptable levels of risk could be achieved (see Chapter 4).

9.3 Upstream GHG emissions

Examining GHG emissions during the upstream stage, including both carbon dioxide and methane, the key findings are that:

- upstream GHG emissions for a US shale gasfield (pre-2012) are typically 15.5 g CO_2e/MJ of life-time natural gas production;
- the upstream methane emission rate is 11.9 g CO_2e /MJ (or 1.8% of lifetime production) and this represents 77% of the total upstream emissions; and
- the application of available and proven emission-reduction technologies can result in typically 23% lower upstream GHG emissions and an overall 31% reduction in methane emissions compared with historical practices for shale gas wells.

The US National Energy Technology Laboratory (**NETL**) has developed 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.[40] The model shows that for a typical shale gasfield in the US, the key contributors to GHG emissions are fugitive emissions from

39 Arguments and evidence that were presented in the final round of consultations and were contained in the recent submissions received by the Panel provided background to several changes that were made to the Draft Final Report. These include adding material on the global carbon budget and health effects from climate change in Section 9.1.4, the expansion of the risk assessment in Section 9.6.2, a revision of the "Risk Assessment Summary" in Section 9.9, and the addition of ***Recommendation 9.8***.

40 Skone et al. 2016; Littlefield et al. 2017. For example, the NETL report of Skone et al. 2016, which was prepared for the US Department of Energy, is a comprehensive and authoritative report that adopts results from many referenced sources.

transport and distribution systems (26%), episodic emissions from well completions (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[41] can be a large contributor (typically 25%) to total GHG emissions.[42] The total upstream emissions were 15.5 g CO_2e/MJ (90% confidence interval (**CI**) of 14 -18 g CO_2e /MJ)[43] for a representative US shale gasfield (the Appalachian field), using historical data before the introduction of reduced emissions completion regulations and strategies (see **Figure 9.1**). Methane accounted for 11.9 g CO_2e /MJ of these emissions, which is equivalent to a methane emission rate of 1.8% of the natural gas production, and they represent 77% of the total upstream emissions.

The implementation of new technologies and adoption of new practices will change the environmental burden of natural gas systems. For example, the US EPA introduced New Source Performance Standards (**NSPS**) rules in 2012 and 2016 that mandate reduced emissions during well completions and workovers and from production and processing equipment.[44] Consistent with these changes, the NETL conducted an evaluation of the next evolution of shale gas wells in the Appalachian field by adjusting the model parameters to reflect likely emission reduction technologies; for example, liquids unloading (100% use of plunger lifts compared with 55% previously), preferred practices such as increased flaring activity rather than venting for well completions (100% compared with 43–51% previously), and higher well estimated ultimate recoveries (**EURs**). This modelled well scenario produced GHG emissions of 12 g CO_2e/MJ, which are 23% lower than historical practices, and with a methane emission rate of 1.25% on a mass basis.[45] All emission reductions occurred at the extraction or production stage and were associated with methane reductions.

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

41 A majority of gas wells (conventional and unconventional) must perform liquids unloading to enhance gas recovery; this becomes more likely as the age of the well increases. While several technologies can remove liquids from wells, plunger lifts are the most common, but their efficiency varies greatly depending on whether the gas is vented or recovered.

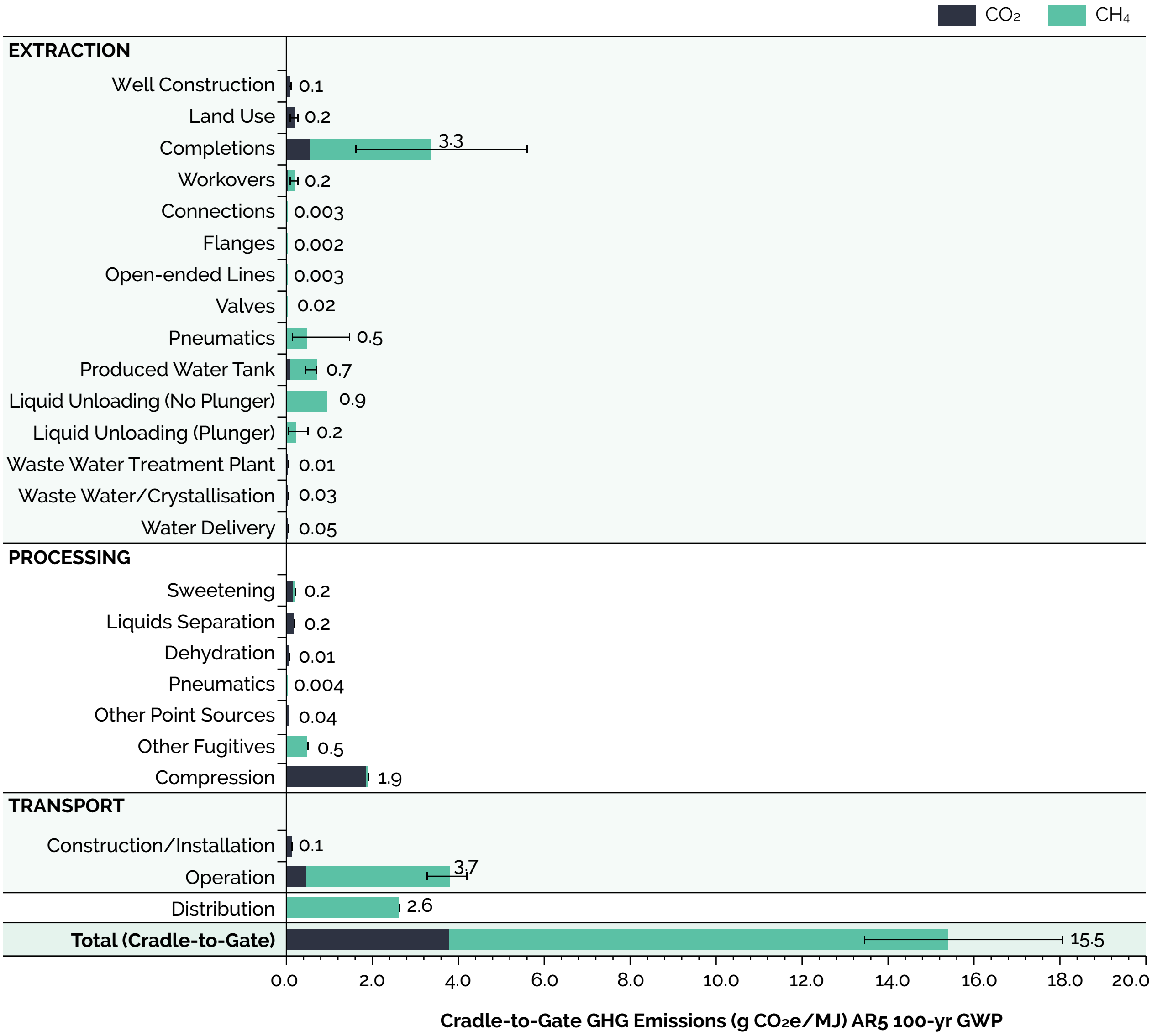
42 Skone et al. 2016, Table C-2.

43 The estimates of Skone, et. al. 2016 include consideration of approximately 25 different GHGs, including carbon dioxide, methane, butane, propane, nitrogen oxides and sulphur dioxide. The results are dominated by carbon dioxide and methane.

44 US EPA in 2012 published air pollution standards for VOCs and hazardous air pollutants, including sulphur dioxide from the oil and natural gas sector. These rules were designed to improve air quality and had the correlative benefit of reducing methane emissions. These rules required companies to reduce emissions from hydraulically fractured and re-fractured gas wells by employing reduced emissions completions; controlling emissions from storage vessels by 95%; using low or no bleed pneumatic controllers in the production segment; using no bleed controllers at gas plants; replacing reciprocating compressor seals on a regular basis; reducing wet seal centrifugal compressor emissions by 95%; and implementing more stringent leak detection and repair programs at gas plants (US EPA 2012); In 2016 the US EPA published additional NSPS that covered methane, VOCs and hazardous air pollutants. This included leak detection and repair programs at well sites; gathering and boosting stations and compressor stations; control of emissions from pneumatic pumps at well sites and gas processing plants; and control of emissions from compressors at compressor stations used for transmission and distribution (US EPA 2016c).

45 Skone et al. 2016.

Figure 9.1: Upstream GHG emissions for gas from a US Appalachian shale gasfield based on a methane GWP = 36. Source: Skone et al.[46]



9.4 Methane emissions

As noted above, methane emissions are the major contributor to upstream GHG emissions from shale gas operations. The key findings identified by the Panel are that:

- over recent years upstream methane emissions have been consistently reduced, so that current inventory estimates for Australia are about 0.7% and for the US, about 1.25%. These values underestimate field-based measurements, which range from 1.3–2.2% based on one comprehensive study. Further research is required to better understand the differences between these inventory and field-based estimates;
- emissions that are released during the shale gas exploration stage, such as venting during flowback, can be significant and they must be minimised;
- a large proportion of fugitive emissions come from a small number of high-emitting sources, but they also present opportunities for mitigation by applying industry best practices;
- methane emissions from a new gasfield in the NT (365 PJ/y) would be similar to the methane emissions from the enteric fermentation of the entire livestock herd in the NT and greater than the emissions from waste in the NT;

46 Skone et al. 2016, Figure 4-2, p 62.

- fugitive methane emissions from a new onshore shale gasfield in the NT (365 PJ/y) are estimated to be worth $62 million per year, indicating that there are environmental benefits and economic incentives for gas companies to reduce methane emissions;
- fugitive emissions from natural gas production in the NT are expected to be about 3% of Australia's Inventory methane emissions and 0.03% of the global anthropogenic methane emissions;
- based on global emissions, the consequential effect of fugitive methane emissions from any new onshore shale gasfield in the NT is assessed to be 'low;
- the risk of upstream fugitive methane emissions from a new shale gas industry in the NT, before any further mitigation, is assessed to be 'medium'; and
- because the assessed risk is 'medium', it is therefore necessary to mitigate this risk (see Chapter 4). One strategy is to introduce new standards and technologies as outlined in this Section. Further mitigation strategies are considered in Section 9.5.

9.4.1 Measured methane levels

Reviews of the literature[47] have reported methane emissions from natural gas production that vary by several orders of magnitude. For example, the Melbourne Energy Institute (**MEI**) quotes methane emissions ranging from 0.22 to 17% of total methane production.[48] The 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 between the many sources of emissions when considering the results from top down investigations. The high figure (17%) is not representative of average emissions from gasfield operations, because it represents only the highest value from a larger set of measurements within such a top-down study, some of which may have been further compromised by the presence of alternative sources of methane. The timeframe of each study is also important. Schwietzke et al.[49] noted that methane emissions from natural gas as a fraction of production have declined from approximately 8% to 2% over the past three decades. In the US, prior to 2012, the mixture of water and gas generated during shale gas well completions was often released directly to the environment (venting), which resulted in very large methane emissions. However, as previously noted, NSPS were introduced by the US EPA in 2012 and, starting in 2016,[50] have caused emission levels to fall by mandating reduced emission completions (**RECs**).[51] Reductions have also resulted from reduced compressor station emissions, increased use of plastic piping (which has lower fugitive emissions than other pipe materials), and upgrades at metering and regulating stations.[52] 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.[53] Both Schwietzke et al. and Brandt et al. suggest that the true emissions are 20 to 60% greater than these inventories,[54] suggesting a reduction from around 3.4% in 1990 to 1.9% in 2015. As noted previously, global fugitive emissions from natural gas production are estimated to be 35 Mt/y (over the decade 2003 to 2012), and this represents approximately 1.5% of current global natural gas production.[55]

A major recent study also noted that new data sources are necessary to reconcile the differences between bottom-up methods and other quantification approaches.[56] A synthesis of new methane emission data from a recent series of ground-based field measurements[57] was integrated with

47 For example, Brandt et al. 2014.
48 Lafleur et al. 2016.
49 Schwietzke et al. 2016, p 88.
50 US EPA 2012. It should be noted that the US EPA has stayed some elements of the NSPS to allow reconsideration after specific objections. These elements include the fugitive emissions requirements for low production sites and well-site pneumatic pump standards (see US EPA 2017).
51 Reduced emissions completions, also known as reduced flaring completions, is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is used to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the gathering pipeline. These assist in reducing methane, volatile organic compounds, and hazardous air pollutant emissions during well clean up and can eliminate or significantly reduce the need for flaring.
52 Lamb et al. 2015.
53 US EPA 2017a.
54 Brandt et al. 2014; Schwietzke et al. 2016.
55 Average global gas production was 2.2 Mt/y from 2003-2012; see BP 2016.
56 Littlefield et al. 2017.
57 Zavala-Araiza et al. 2015.

other data to estimate that 1.7% of methane is emitted (with a 95% CI of 1.3 - 2.2%) between extraction and delivery across the US natural gas supply chain, including both conventional and unconventional gas wells.[58] Littlefield et al. noted that, using data from basin-wide measurements, the total site-level emissions are higher than the sum of component emissions at production sites. This difference 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 well head maintenance events, or any combination thereof. The authors quantified these unassigned emissions as 0.3% (with a 90% CI of 0.1 - 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 it is a source of uncertainty that points to opportunities for further research.

Overall, this recent study concludes that 19% of all upstream methane emissions fall into this 'unassigned' or 'super emitter' category. The skewed nature 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. The top three contributors to these emissions are gathering systems, pneumatic controllers, and 'unassigned emissions'. Gathering facilities, a key connection between production and processing, are a significant methane emission source that has been omitted or undercounted in many studies to date.

Air measurements at natural gas production sites indicate that a large proportion of fugitive emissions come from a small number of high-emitting sources. For example, one study measured about 75,000 sources (such as well heads, valves, pipe welds and other sources within a natural gas production system and found that 58% of emissions came from 45 possible sources.[59] These few large leaks produce the majority of fugitive emissions and present opportunities for mitigation by applying industry world leading practices.[60]

9.4.2 Inventory levels

Australia reports its GHG emissions, including CO_2 and CH_4, through the National Greenhouse Gas Inventory[61] using a structure that is consistent with the IPCC Guidelines.[62] Most Australian corporations and facilities[63] are required to report their emissions through the National Greenhouse and Energy Reporting (**NGER**) scheme,[64] which provides the methodologies required for reporting. Similar to the US, the fugitive emissions reported from the oil and gas industry in Australia have declined as a per cent of production since 1990.

In many cases, the emissions reported through the NGER are based upon emission factors rather than direct measurement. In the National Inventory Report (**NIR**) 2015 published in May 2017,[65] new emission factors were introduced for the estimation of fugitive emissions from the gas supply chain. These methods bring Australia more into line with the methods developed by the US EPA and the NETL, which represents *"the largest and best dataset available globally"* and *"are expected to largely underpin a forthcoming update to the Intergovernmental Panel on Climate Change (IPCC) Guidelines for the preparation of national greenhouse gas inventories which will, in turn, become part of the international rules and guidance under the Paris Agreement on Climate Change"*.[66]

Australian emission factors for well completions and well workovers[67] for hydraulic fracturing are now identical to that of the US EPA (36.8 tonnes of methane with hydraulic fracturing, reducing to 3.2 tonnes for a REC and 4.9 tonnes for a well completion with flaring), thereby reducing the estimates for these emissions from previous approaches. The emission factors for gathering and boosting stations and for processing plants have increased to be in line with the recent study by

58 Littlefield et al. 2017.
59 Brandt et al. 2014.
60 Zavala-Araiza et al. 2017.
61 Australian Department of the Environment and Energy 2017h.
62 IPCC Guidelines 1996.
63 Facilities with over 25kt of emissions, or producing more than 100 TJ of energy; corporate groups with over 50 kt of emissions or producing more than 200 TJ of energy.
64 Australian Department of the Environment and Energy 2017g.
65 Australian Department of the Environment and Energy 2017h.
66 Australian Department of the Environment and Energy 2017i, p 4.
67 The process of performing major maintenance or remedial treatments on an oil or gas well to achieve enhanced performance. This can include the re-simulation or replacement of the production tubing string.

Mitchell et al.[68], and those for transmission and storage systems have increased to be consistent with Zimmerle et al.[69] The existing Australian emission factor is retained for pipelines, based on the premise that Australian pipelines are of relatively recent vintage, have been built to high quality standards, and are well maintained.

General leakage of methane during the shale gas production phase also remains at 0.047 t CH_4/kt of processed natural gas (~0.0047%), based on the 2009 American Petroleum Institute Compendium[70] and a CSIRO study.[71] However, this factor is well below the value (0.073%) estimated by Littlefield et al.[72]. The CSIRO study was conducted across a limited dataset of 43 CSG wells, and the report notes that the values measured are lower than observed for the US shale gas industry. For example, they found the leak rate from Australian pneumatic devices to be 0.12 ± 0.18 g/min, while Allen et al.[73] measure a value of 5.9 ± 2.4 g/min and the American Petroleum Institute 2009 Compendium[74] uses 4.6 ± 0.66 g/min.

The upstream methane emissions reported in the 2015 National Greenhouse Gas Inventory (**NGGI**)[75] for the Australian natural gas industry are 266 kt, while the emissions of carbon dioxide are 78 kt (**Table 9.1**). This translates to total emissions of 6,735 kt CO_2e (based on a GWP of 25). The 2015 NGGI report also breaks down these emissions into those for exploration (including flaring during exploration and emissions from well completions and workovers), production, processing and transmission and storage (**Table 9.1**). However, emissions reported from these sectors do not add to the total. The difference is reported as "*Other*" in **Table 9.1**.

The NGGI reports flaring and venting emissions separately at processing facilities. The combined emissions are 63 kt of CH_4 and 6,841 kt CO_2 giving total emissions for venting and flaring of 8,406 kt CO_2e (based on a GWP of 25). The large CO_2 emissions are associated with the removal of carbon dioxide from the raw gas during the natural gas processing stage. These emissions may be measured directly by the operating facility, rather than emission factors being utilised. In 2015, the combined upstream, venting and flaring emissions were 329 kt CH_4 and 15,141 kt CO_2e.

68 Mitchell et al. 2015.
69 Zimmerle et al. 2015.
70 API 2009.
71 Day et al. 2014.
72 Littlefield et al. 2017.
73 Allen et al. 2014.
74 API 2009.
75 Australian Government NGGI; see also Australian Department of the Environment and Energy 2017h.

Table 9.1: Annual inventory emissions of CH_4 and CO_2 and their total (as CO_2e) from both conventional and unconventional natural gas production in Australia in 2014/2015. Source: Australian Government NGGI.[76]

	CH_4 emissions (kt)	CH_4 emissions as a proportion of gas production (%)[77]	CO_2 emissions (kt)	Equivalent CO_2 emissions[78] CO_2e (kt)
Natural gas				
Exploration	3.9	0.01%	49.8	148
Production	117.5	0.25%	18.5	2,955
Processing	24.4	0.05%	4.1	614
Transmission and storage	25.2	0.05%	0.6	631
Other[79]	95.3	0.21%	5.4	2,387
Total	266.3	0.57%	78.4	6,735
Addition for venting and flaring	62.6	0.14%	6,840.8	8,406
TOTAL	328.9	0.71%	6,919.2	15,141

As shown in **Table 9.1**, the inventory fugitive methane emission rate as a ratio of natural gas production is about 0.7%[80] when venting and flaring is included. This level of emission is below values reported by the US EPA for the US's mix of conventional and unconventional wells (1.25% in 2015).[81] In particular, in **Table 9.1** the emissions from gas processing are 0.04%, whereas the NIR report itself quotes the Mitchell et al.[82] report as 0.1%. Similarly, the NIR report quotes Zimmerle et al.[83] for losses from transmission and storage as 0.2%, whereas the analysis above gives 0.05% (**Table 9. 1**). Further research is required to explain these discrepancies.

However, as was noted in one submission,[84] the inventory methane leakage rate for Australia is broadly comparable with inventory estimates for the UK and for Canada, and significantly higher than that reported by Norway. The upstream GHG footprint of 15.1 Mt CO_2e (**Table 9.1**) is equivalent to 5.7 g CO2e/MJ, (based on a GWP of 25), which is well below the scientific studies outlined previously. For example, Littlefield et al.[85] gives 13.8 g CO e/MJ with a GWP of 36, for the US gas industry, including conventional and shale gas wells. Adjusting this upstream emission value by removing emissions associated with gas compression, and changing the GWP to 25, the revised upstream fugitive emissions are estimated to be 11.4 g CO2e/MJ. This is double the rate of 5.7 g CO_2e/MJ applicable in **Table 9.1**. Furthermore, from **Table 9.1**, the annual rate of equivalent CO_2 emissions (15,141 kt) expressed as a proportion of natural gas production (46.2Mt) is 0.33. The equivalent mass rate for US emissions as a proportion of natural gas production is 0.39.[86] It appears that the reason that the US inventory emission rate data is closer to the Australian inventory emission rate data is because Australia has higher venting and flaring rates (probably from lower quality gas), and this tends to balance the lower methane emissions.

As the Commonwealth Department of Environment and Energy[87] noted in its submission, it is recognised that this area (fugitive emissions) is one of the more difficult parts of the NGGI to estimate and that some caution is advisable in relation to the conclusions to be drawn from international comparisons. The NGGI is open to ongoing improvement as new methods and data emerge.

76 Australian Government NGGI.
77 Total natural gas production in Australia for 2015/2016 is 56 Mt based on data from Department of Industry, Innovation and Science 2017a. This converts to 46.2 Mt for a natural gas density of 0.67 kg/m^3.
78 CO_2e emissions are the combination of methane emissions, converted using a 100-year GWP of 25, and the CO2 emissions.
79 This is understood to be the 'distribution' component of upstream emissions.
80 0.71% = (0.329 Mt CH4 emissions)/(46.2 Mt CH4 production).
81 US EPA 2017a.
82 Mitchell et al. 2015.
83 Zimmerle et al. 2015.
84 Australian Department of Environment and Energy, submission 1242 (**DoEE submission 1242**).
85 Littlefield et al. 2017.
86 DoEE submission 1242.
87 DoEE submission 1242.

9.4.3 Comparison of methane emission sources

To place the estimated methane emissions from any new shale gas operation into perspective, it is useful to compare those emissions with the level of emissions from alternative methane sources. In Australia, the agricultural (including pastoral) sector is the dominant source for both methane and nitrous oxide emissions.[88]

Table 9.2: Comparison of methane emissions from various sources.

Source of emissions	Australia (Mt CH_4/y)	NT (Mt CH_4/y)
Enteric fermentation in livestock[89] (mostly cattle and sheep)	1.95[90]	n/a
Enteric fermentation in cattle	1.17-2.51[91]	0.08-0.18[92]
Solid waste to land and waste water handling	0.47[93]	0.005[94]
Fugitive emissions from natural gas production	0.80-1.35[95]	0.09-0.15[96]

Table 9.2 shows that methane emissions from any new onshore shale gasfield in the NT (0.09–0.15 Mt CH_4/y)[97] would be similar to the methane emissions from the enteric fermentation of livestock in the NT, and greater than the emissions from waste in the NT. There are substantial incentives for gas companies to reduce the amount of fugitive emissions. Assuming that fugitive emissions represent 1.7% of production (Section 9.4.1), a gasfield producing 365 PJ/y at a gas price of $10/GJ, the cost of these fugitive emissions represent $62 million per year (the cost would be greater if a price was imposed on carbon emissions). If a substantial part of these fugitive emissions were prevented, then gas companies would achieve increased sales and profits, and the environment would benefit from reduced methane emissions.

In the upstream phase of any shale gas operation, methane dominates the emissions (77%, see Section 9.3). Given that more control can be exercised over methane emissions in the upstream phase (compared to combustion of gas in the downstream phase), it is appropriate to initially focus any mitigation strategies on methane emissions during the upstream stage. This focus also serves to reduce GHG emissions over the full life cycle.

9.4.4 Risk assessment

Table 9.3 contains the results of an assessment of the risk (see Section 9.9 for details on environmental values and objectives for the risk assessment) associated with upstream methane emissions from a possible new shale gasfield in the NT producing 365 PJ/y, expressed as a proportion of global methane emissions. The risk assessment is based on consideration of global methane emissions as these are an important component of global GHG, and therefore, a contributor to global temperature rise. The Panel has assessed the risk associated from methane emissions over the upstream stage as 'medium'.

88 Australian Government NGGI. Enteric fermentation from livestock represents 47% of Australia's inventory methane emissions.
89 Australian Department of the Environment and Energy 2017k.
90 Assuming that all reported CO_2e emissions are methane, GWP=25 and data is applicable to 2016.
91 Based on methane emissions for cows of 45-97 kg/y (DeRamus et al. 2003) and the Australian cattle herd of 25.9 million (Colliers International 2016).
92 Based on the Northern Territory cattle herd being 7% of the Australian cattle herd (Colliers International 2016).
93 Assuming that all reported CO_2e emissions are methane, GWP =25 and data is applicable to 2016.
94 A pro rata allocation based on the NT population being 245,000 and the Australian population of 24,385,000 (ABS 2016).
95 Based on Australian natural gas production of 3,394 PJ in 2015/2016 (Department of Industry, Innovation and Science 2017a, p 57) and assumed methane fugitive emission rates of between 1.3 and 2.2% (Littlefield et al. 2017).
96 Based on NT natural gas, new field production rate of 365 PJ/y and methane fugitive emission rates of between 1.3 and 2.2% (Littlefield et al. 2017). No allowance has been made for other natural gas production in the NT.
97 The range of fugitive emissions for Australian natural gas production in **Table 9.2** are larger than the value in **Table 9.1** (0.33 Mt CH_4/y) because more representative methane emission rates are used compared to the inventory results used in **Table 9.1**.

Table 9.3: Risk assessment for upstream methane emissions for a new shale gasfield producing 365 PJ/y (1,000 TJ/day).

Component	Assessment	Reason
Likelihood	High	Methane emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Low	Upstream methane emissions (from a possible new shale gasfield) will contribute 0.03% to global anthropogenic methane emissions; as these emissions are < 0.1%, they are assessed as minor/moderate (**Table 4.4**).[98]
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

Because the assessed risk is 'medium', it is necessary to consider how this risk can be mitigated. Based on the information presented in Section 9.3 and this section, the Panel has formed the view that the following mitigation measure must be introduced to reduce upstream methane emissions from any shale gas industry in the NT.

Recommendation 9.1

That to reduce the risk of upstream methane emissions from any onshore shale gas wells, the Government implement the US EPA New Source Performance Standards of 2012 and 2016.[99]

The application of these standards will also serve to achieve possible reductions in CO_2 emissions at the upstream stage. Additional strategies to reduce the level of methane emissions are considered in Section 9.5. It is important that the issues of methane emissions and risk, as given in this section, be considered in the broader context of GHG emissions; these are discussed in Section 9.8.

Flaring at a gas processing facility in Australia.

98 For a gasfield production of 1,000 TJ/day (365 PJ/y), and assuming the upstream gross fugitive methane emissions are 1.7% of production, Littlefield et al. 2017, this leakage represents 0.11 Mt methane/y (0.017x365= 6.2 PJ/y and converting using 55.5 MJ/kg). The Australian NGGI for methane emissions is 4.36 Mt CH_4/y (Australian Government NGGI; see also Australian Department of the Environment and Energy 2017h). The fugitive emissions from a new gasfield in the NT represent 3% (=0.11/4.36) of Australia's Inventory methane emissions. The annual global anthropogenic methane emissions are 329 Mt of CH_4 (= 558x0.59; refer to Section 9.1.2 for details). Accordingly, the fugitive emissions from any new gasfield in the NT represent 0.03% (=0.11/329) of the annual global anthropogenic methane emissions. At this level of contribution to anthropogenic global methane emissions (< 0.1%), the consequence for methane emissions from a gasfield is assessed as 'moderate/ minor' (**Table 4.4**), and therefore, the 'consequence' rating is assessed to be 'low': refer to Chapter 4.

99 US EPA 2016c.

9.5 Monitoring methane emissions

Given that the concentration of methane in the atmosphere is low, there are challenges in determining the methane levels that apply to a basin-wide shale gasfield. Consideration is given, therefore, to options for monitoring methane emissions, including coverage over different spatial dimensions. The key findings identified by the Panel are that:

- the accurate detection of methane concentrations, conversion of these emissions into a flow rates (fluxes), and assigning them to particular sources, is difficult and that further research is required. For this reason, the reporting of total facility-wide emissions for inventory purposes relies on using emission factor calculations and measurements;
- current inventory estimates underestimate basin-wide measurements of methane emissions and basin-wide methane measurements are not routinely undertaken;
- the assessed risk of non-detection of abnormal levels of fugitive methane emissions from a new shale gas industry in the NT, without any further mitigation, is 'medium'; and
- because the assessed risk is 'medium', it is necessary to mitigate this risk. Mitigation / strategies are identified, using basin-wide measurements of methane concentrations, to enable abnormal methane emissions (above background levels) to be detected and repaired quickly, before large releases of methane occur.

Baseline monitoring of methane levels in the soil and atmosphere in the vicinity of any new onshore shale gas development should be undertaken before any hydraulic fracturing associated with exploration commences. Other possible emission sources (including wetlands, landfills, sewage treatment facilities, and livestock, such as cattle and sheep) can mean that top-down measurements of fugitive emissions can substantially overestimate the emissions generated from gas extraction unless such a baseline is established. A study 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 arose from oil, CSG, or coal mining activities due to a lack of baseline data.[100] In some cases, the opportunity to gather such baseline data has passed, as hydraulic fracturing associated with exploration has already commenced. In this case, baseline measurements should therefore begin before further activities occur. These measurements should continue for at least 12 months to capture potential seasonal variations and be repeated over the production life of the field.[101] Baseline measurements can also provide a reference point assisting to establish closure criteria for emission levels for a gasfield at the end life for any shale gas project.[102]

Natural methane seepage can lead to elevated methane concentrations in the ambient air and in the soil.[103] 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.[104] 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).[105] In fact, the detection of such seeps is often used to identify potential drill sites for gas.[106] 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 extreme caution before attributing the source to unconventional gas 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. There is no conclusive evidence that this increase is related to CSG activities. It may relate to the migratory emissions described by the MEI,[107] but it could also relate to changes in river water flows or natural changes in groundwater flows.[108]

100 Lafleur et al. 2016.
101 Saddler and Gotham 2013.
102 Commonwealth Scientific and Industrial Research Organisation, submission 450 (**CSIRO submission 450**).
103 Saddler and Gotham 2013.
104 Saddler and Gotham 2013.
105 NSW Bore Water Data Package.
106 Saddler and Gotham 2013.
107 Lafleur et al. 2016.
108 CSIRO 2016.

GISERA has undertaken detailed measurements of methane concentrations in the Surat Basin of Queensland over the last three years that provide an excellent reference for future monitoring programs.[109] The Panel notes that Santos is also planning a baseline methane monitoring/assessment in the Beetaloo Sub-basin.[110]

9.5.1 Measurement of methane concentrations

Methane concentrations in the atmosphere are very low (1.8 ppm), and therefore, any detection method requires high precision and accuracy. For example, in a survey of Queensland mines, the maximum methane peak concentration was only 2.0 ppm.[111] Analytical techniques for measuring methane include catalytic oxidation, flame ionisation, infrared absorption, Fourier Transform Infrared Spectroscopy, photoionisation,[112] and cavity ringdown laser absorption spectroscopy. Isotopic analysis can determine whether the gas is 'biogenic' (from rotting vegetation and wastewater treatment) or 'thermogenic' (from oil or gas deposits) in origin.[113]

9.5.2 Leak detection and repair

Small leaks of methane from equipment such as valves, pumps and compressors, and pressure relief devices can be detected using portable instruments that rely on any of the above methods.[114] This is often referred to as 'Method 21', reflecting the relevant US EPA test method. More significant leaks can be efficiently detected using Optical Gas Imaging (**OGI**), which adopts passive infrared sensing technology to provide a visual image of methane plumes across a broader footprint. Origin[115] notes that the accuracy in determining methane concentrations using OGI could be only as good as 10,000 ppm.[116] That is, OGI equipment is not capable of accurately measuring concentrations below this range. The NSPS regulations introduced by the US EPA[117] indicate that methane leaks need to be repaired if they exceed 500 ppm when measured with a portable meter (Method 21), or if they are detected as a visible plume by an OGI instrument. These regulations enforce semiannual monitoring and repair of fugitive emission components at well sites and quarterly monitoring and repair at compressor stations, using either approach. Equipment leaks at natural gas processing plants must be monitored and repaired using the Method 21 approach. Submissions from industry[118] indicate that it has a preference for the Queensland Government's Code of Practice[119] approach to leak detection and repair. DPIR has indicated to the Panel that it will adopt this practice, with some possible customisation.[120] This Code of Practice requires that petroleum production operators carry and use personal calibrated gas detectors, but that formal leak inspections are only conducted every five years. An above ground *"reportable leak"* is defined as one that, at a measurement distance of 150 mm immediately above (and downwind) of the source, gives a sustained reading for a 15-second duration of greater than 5,300 ppm. A *"reportable leak"* must be corrected within 48 hours. However, the timeframe for repair of smaller leaks is at the discretion of the operator.

Other submissions have highlighted the regulations established by the Colorado Department of Public Health and Environment[121] as world-leading practice. These require natural gas compressor stations to be inspected for leaks at a frequency between monthly and quarterly, depending upon the anticipated emissions level calculated using *"emission factors"*. Similarly, well production facilities must undergo *"audio, visual and olfactory"* inspections for leaks monthly and using instrumentation at frequencies between "one time" and monthly, again depending upon the anticipated emission rate. Leaks requiring repair are those with emissions greater than 500 ppm if detected with portable instrumentation, while any leak detected by an OGI camera or *"audio, visual and olfactory"* inspection must be repaired.

109 Day et al. 2013; Day et al. 2015; Etheridge et al. 2017.
110 Santos submission 168, p 110.
111 Williams et al. 1993.
112 Santos submission 420.
113 Sherwood et al. 2017.
114 See Method 21-Determination of Volatile Organic Compound Leaks: US EPA 2016c.
115 Origin submission 433.
116 As indicated by the US Code of Federal Regulations, Title 40, Chapter I, Subchapter C, Part 60.
117 US EPA 2016c.
118 Origin submission 433 and Santos submission 420.
119 Queensland DNRM 2017b.
120 DPIR submission 424.
121 Colorado RAQC 2014.

9.5.3 Localised measurements

Flux towers can be used to monitor methane concentrations (ppm) at fixed points across regions of approximately 1 km^2. These towers also use an eddy covariance method to estimate the flow rate (flux) of methane from the land surface to the atmosphere from high-frequency measurements of the fluctuations in wind speed and concentration. GISERA has recently installed two such systems, upstream and downstream respectively, in respect of CSG operations in the Surat Basin, Queensland.[122] Each system consists of two towers. The first samples air for analysis from a height of 10 m and also records meteorological data such as wind speed, direction and humidity. The second, installed about 150 metres downwind of the first, contains the eddy covariance equipment, which determines the vertical methane flow rate from the land surface. Concurrent concentration measurement of gases such as carbon monoxide, ozone, VOCs, CO_2 and nitrogen oxides and particulates can assist in identifying the methane sources.[123] The GISERA program uses five sites that are separate from the flux towers to record this data.[124] Data for NO_2, CO_2, ozone and particulates is reported online in real time for three of these sites and a range of other sites throughout Queensland.[125] An alternative approach is being developed by the University of Adelaide in conjunction with the South Australian Roundtable for Oil and Gas Working Group.[126] There, an array of four methane spectrometers are connected to an atmospheric monitor, with the air mass exchange with methane concentration used to calculate a total methane flux.[127]

The 'static flux chamber' (a non-flow-through, non-steady-state chamber) method can be used for localised flux measurements of methane emissions from the ground. Essentially, this device consists of a chamber that is placed over an area of soil, with the gas composition recorded in the head space. This gives a flux result, but only over a very limited surface area, typically 0.1 to 0.5 m^2.[128] This small area means that many replicate measurements are required for high levels of accuracy.[129]

9.5.4 Regional measurements

Fixing continuous monitoring equipment to a vehicle allows a wider, more regional, area to be sampled. However, such monitoring needs to be completed regularly and at varying wind conditions. Santos and Maher[130] used this approach around the Tara region in Queensland in 2012, while in recent work undertaken by GISERA, a vehicle carrying a methane analyser covered more than 7,000 km on public and private roads within a region of 350 km x 300 km in the Surat Basin.[131] GISERA found that a disadvantage of this approach was that surveys were restricted to existing roads, which limited coverage. Such a restriction is likely to be of even greater concern in the NT, where the road network is restricted.

Although more expensive, the use of aircraft has the advantage that measurements across a range of horizontal and vertical distances can be made, allowing better detection of plume behaviour. However, because methane is much lighter than air (relative density of 0.55), it is readily dissipated from the point of emission.[132] This means that atmospheric measurements taken even a short distance from the source (as little as 100 m) can soon return to background levels. GISERA used a diode laser sensor mounted under a helicopter to monitor emissions in the Surat Basin, but noted that the narrow range of the instrument meant that many passes of the aircraft were needed to adequately cover the survey area.[133] The use of drones that can fly closer to the surface and at lower cost may prove more effective. These are being trialled in Queensland for the CSG industry for monitoring infrastructure by an Advance Queensland funded project.[134]

Remote sensing from either aircraft or satellites can be effective to determine larger-scale variations in methane. Differential Absorption Infrared Remote Sensing provides point

122 Day et al. 2015.
123 Etheridge et al. 2017.
124 Lawson et al.2017.
125 Queensland DEHP 2017.
126 SA Roundtable for Oil and Gas 2017.
127 Kennedy et al. 2013.
128 Pihlatie et al. 2013.
129 Denmead 2008.
130 Santos and Maher 2012.
131 Day et al. 2015.
132 Saddler and Gotham 2013.
133 Day et al. 2015.
134 CSIRO submission 450.

measurements of 1 m in diameter using pulsed laser light, from an altitude of around 150 m.[135] A similar, laser-based, remote sensing method is being developed by the University of Adelaide and Macquarie University.[136] The 'Methane Airborne MAPper' can provide point measurements of footprint of 23 × 33 m^2 for an aircraft altitude of 1 km and a ground speed of 200 km/h.[137] At the other extreme, the absorption spectrometer on board the Envisat satellite had a spatial resolution ranging from 30 × 60 km to 30 × 240 km.[138] This approach was used successfully to show increased methane emissions from the Four Corners region of the US over the period 2003–2009.[139] Data from the same spectrometer was recently used by GISERA to examine historical methane emissions from the Surat Basin. However, in that case, the spectrometer was unable to identify local scale impacts; rather, only regional trends could be identified.

The techniques described above can only measure the concentration of methane at a given point in time and space. Conversion of this data into a volumetric flow rate or flux is more difficult. These measurements need to be used in conjunction with meteorological models of wind patterns. These techniques are complex and require sophisticated expertise.[140] In Australia, AUSPLUME[141] is one of the most well-known models of plume dispersion, but AERMOD[142] is now the method of choice for the Victorian Environment Protection Authority and is supported by the US EPA. Others such as CALPUFF[143] and TAPM[144] are also used. Given sufficient meteorological data, these models can relate a concentration measured at some distance from a source of methane leakage to the flow rate from that source. An alternative approach can be to use a tracer gas, which is a stable gas unrelated to the source of methane. This gas can be released at a known rate, from the same location as the methane source. Measurement of both the tracer and methane concentrations downwind can give an accurate determination of the methane flow rate as the ratio of both concentrations multiplied by the tracer rate.[145] Even when a flux can be determined, associating this flow to a particular emission source can add greater uncertainty, especially in the absence of good baseline data and when concentration measurements are made a long way downwind of the potential source.[146] As noted by Saddler and Gotham,[147] *"methodologies to differentiate methane from a variety of background anthropocentric and natural background sources are still at an experimental stage"*. Schwietzke et al.[148] point out that most vehicular-based and aircraft-based methane concentration measurements are carried out during the middle of the day, which is also when activities such as liquid unloading and equipment maintenance occurs. Any concentration measurements made during these hours need to consider whether the methane concentrations would be lower in the middle of the night, before simply translating the data to a 24-hour basis.

9.5.5 Facility-wide emissions

The NGER scheme requires all operating facilities to report facility-wide emissions through a combination of direct measurement and the use of emission factors. The Australian Government's 'safeguard mechanism',[149] which commenced on 1 July 2016, is designed to ensure that emissions reported through this scheme do not increase over time and applies to both existing and new facilities that have direct emissions of more than 0.1 Mt tonnes of carbon dioxide equivalence a year, as reported through the NGER scheme. There are currently 340 facilities listed on the Clean Energy Regulator website as meeting this requirement.[150] Businesses must use Australian carbon credit units to offset emissions above their baseline levels, as determined by the Clean Energy Regulator. It is likely that any new onshore shale gas production facilities developed in the NT will be covered by the safeguard mechanism.[151] Rather than specifying actions to be taken to reduce

135 Zirnig et al. 2004.
136 Henderson-Sapir et al. 2016.
137 Gerilowski et al. 2015.
138 Saddler and Gotham 2013.
139 Kort et al. 2014.
140 Saddler and Gotham 2013.
141 Victorian EPA 1986.
142 US EPA 2016b.
143 Exponent 2014.
144 Hurley 2008.
145 Day et al. 2015.
146 Day et al. 2015.
147 Saddler and Gotham 2013, p 23.
148 Schwietzke et al. 2017.
149 Australian Department of the Environment and Energy 2017j.
150 Clean Energy Regulator 2017.
151 DoEE submission 445.

emissions, the Mechanism uses financial incentives to encourage companies to find their own least cost and effective emission reduction approaches.[152]

9.5.6 Towards a code of practice

The ability to detect methane concentrations accurately, to convert these emissions into a flow rate in g/h, and to assign these emissions to a particular source is difficult. This means that the reporting of total facility-wide emissions to the NGER will continue to rely substantially on emissions factor calculations. However, there are methodologies that can be undertaken to give confidence to the public that methane emissions are being correctly reported and that 'super emitters' can be detected and repaired quickly before large releases of methane occur.

The Panel has developed an outline of a mandatory code of practice for monitoring methane concentrations, which is described below. This code is based on reviews of existing codes of practice and GISERA reports and submissions to the Inquiry, as described in the preceding Sections 9.5.1 to 9.5.5. It is as follows:

- baseline monitoring should be conducted at least six months prior to hydraulic fracturing in the exploration phase, or in areas where hydraulic fracturing has already commenced, at least a year prior to any hydraulic fracturing for the purpose of production to ensure that seasonal variations are captured. This baseline monitoring is likely to consist of a combination of:
  - regional scale measurements of methane concentrations (greater than 100 km^2) using remote sensing and/or gas monitoring from drones, vehicles or aircraft. At least three such regional-scale surveys across a year are needed to cover seasonal variations in the baseline period. At least one regional scale survey should provide an isotopic analysis to separate thermogenic from biogenic sources of methane because this will assist to identify the source of major methane emissions;
  - localised measurements (approximately 1 km^2) through the establishment of a small number of flux towers (that is, fixed atmospheric monitoring stations combined with eddy covariance), or methane spectrometry arrays (as proposed by the University of Adelaide) upstream and downstream of the proposed production site to measure methane concentration and localised methane flux. Measurement results should be made available in real time and online for the public to view; and
  - a number of monitoring stations should also be established to monitor concentrations of other relevant gases (CO_2, NO_x and particulates). Measurement results should again be made available publicly in real time and online for the public to view;
- once production commences, the localised measurements and monitoring stations should continue to provide continuous data of CH_4, CO_2, NO_x and particulate concentrations in an online, real-time, publicly available format. This is to ensure community confidence that these emissions do not deviate significantly from the baseline. Any statistically significant deviation from the seasonally adjusted, steady-state concentrations recorded by these monitoring stations should require the gas company to immediately investigate the source of the deviation using portable instrumentation and/or OGI analysis;
- the regional scale measurements (>100 km^2) recorded during the baseline period should be repeated within the first six months of full-scale production commencing, and then at least once every five years (it is highly desirable that these measurements occur more regularly), to ensure that 'super emitters', and other emissions not detected by the flux towers and monitoring stations, can be observed. Again, any statistically significant deviation from the baseline regional survey should require the gas company to immediately investigate the source of the deviation;
- the monitoring program described above, should be undertaken by an independent regulator, (see Chapter 14);[153]
- methane emissions during well completions, well workovers, from vents and from flares should be monitored. This is possible using relatively simple flow meters and sensors.[154]

152 Australian Petroleum Production and Exploration Association, submission 421 (**APPEA submission 421**).
153 EDO submission 456.
154 CSIRO submission 450.

This monitoring should be the responsibility of the gas company, with by a oversight from an independent regulator; for example, the Commonwealth Clean Energy Regulator and

- detection of leaks from compressor seals, valves, pumps and gathering stations should occur as part of a leak detection and repair program.[155] A formal site-wide leak inspection and repair program should be conducted that is consistent with the US EPA NSPS standards.[156] Specifically, monitoring and repair of fugitive emission components at well sites should be conducted twice per year, with quarterly monitoring and repair at compressor stations, using either the Method 21 approach or OGI approach. Equipment leaks at natural gas processing plants must be monitored (and repaired) using the Method 21 approach at least annually, if not more regularly. While the Queensland Government's Code of Practice[157] indicates a program with five-year intervals, the Panel considers that the more frequent timeframes outlined in the NSPS are needed to ensure that emissions not detected by the monitoring stations are minimised and that community confidence is maintained. The threshold for localised emissions that are reportable should follow the US EPA NSPS regulation of 500 ppm for Method 21 and the detection of a visual plume using the OGI approach. This leak inspection and repair program should be the responsibility of the operating gas company, but with auditing, as outlined above, by an independent regulator.

9.5.7 Risk assessment

Current inventory estimates underestimate basin-wide measurements of methane emissions, and basin-wide methane measurements are not routinely undertaken. Accordingly, abnormal levels of methane emissions may not be detected. The risk assessment given in **Table 9.3** for methane emissions from a producing gasfield is broadly relevant to the risk of non-detection of abnormal levels of methane emissions. As the assessed risk is 'medium', it is necessary to consider how this risk can be mitigated. The Panel has formed the view that a mitigation strategy based on basin-wide measurements of methane concentrations is a key strategy that will enable abnormal methane emissions (above background levels) to be detected and repaired quickly, before large releases of methane occur. Other detection strategies are also relevant. Accordingly, and consistent with the discussions above, the following recommendations are made.

Recommendation 9.2

That prior to the grant of any further exploration approvals, a code of practice be developed and implemented for the ongoing monitoring, detection and reporting of methane emissions from any onshore shale gasfields and wells.

Recommendation 9.3

That baseline monitoring of methane concentrations be undertaken for at least six months prior to the grant of any further exploration approvals. In areas where hydraulic fracturing has already occurred, the baseline monitoring should be undertaken at least a year prior to the grant of any production approvals.

Recommendation 9.4

That baseline and ongoing monitoring be the responsibility of the regulator and funded by the gas industry.

Recommendation 9.5

That all monitoring results must be made publicly available online on a continuous basis in real time.

Recommendation 9.6

That once emission concentration limits are exceeded, as soon as reasonably practicable the regulator must be notified, an investigation must be undertaken by the gas company to identify the source or sources of the emissions, and make-good provisions be carried out by the gas industry.

155 CSIRO submission 450
156 US EPA 2016c.
157 Queensland DNRM 2017b.

The mitigation and assessment of risk associated with methane levels is further discussed in Section 9.9.1.

9.6 Life cycle GHG emissions from a new gasfield in the NT

Estimates are given for the quantities of life cycle GHG emissions for a new shale gasfield in the NT producing 73, 365 and 1,240 PJ/y respectively. These results are used in risk assessments by comparing the life cycle emissions from 365 and 1,240 PJ/y productions with Australian and global GHG emissions. The key findings identified by the Panel are that:

- GHG emissions from any new onshore shale gasfield in the NT producing 365 PJ/y would contribute around 4.5% of Australian GHG emissions, and on a global basis 0.05% of global GHG emissions;
- for gasfields producing 1,240 PJ/y (with LNG exports of 80% and domestic consumption of 20%), the Australian component of emissions is around 6.6% of Australian GHG emissions and 0.07% of global GHG emissions, and the total emissions (emitted in both Australia and overseas) is 0.17% of global GHG emissions; and
- the assessed the risk associated with life cycle GHG emissions is 'medium' for a gasfield producing 365 PJ/y; 'medium' for the Australian emission component associated with gasfields producing 1,240 PJ/y; and 'high' for the global emissions (both in Australia and overseas) associated with gasfields producing 1,240 PJ/y. These assessments represent unmitigated risk levels. The mitigation of these risk levels is considered in Section 9.9.

9.6.1 Quantity of GHG emissions

The life cycle GHG emissions estimates are based on production estimates[158] provided by industry where a potential shale gasfield is assumed to have production in the range of 800 - 1100 TJ/day (nominal 365 PJ/y) for a large gasfield development, or 100 - 220 TJ/day (nominal 73 PJ/y) for a small development. In addition, a further submission[159] provided a best estimate indicative later development scenario that equates to 3,400 TJ/day (1,240 PJ/y). In this later development scenario, it is assumed that 2,740 TJ/day is used for liquid natural gas (**LNG**) export and 660 TJ/day is used for domestic gas consumption. When gas is exported, there are additional upstream emissions in Australia associated with the conversion of gas to LNG, while emissions associated with transport, regasification and combustion occur in the importing country. Based on these three production scenarios, the estimated quantity of life cycle GHG emissions, which combine upstream GHG emissions with the downstream GHG emissions from the combustion of natural gas for end use application, are shown in **Table 9.4**. In the case of LNG, the emissions accounting is done for both Australian-only emissions and for combined Australian and overseas emissions. The data in **Table 9.4** represents the additional quantity of GHG emissions for given levels of any new shale gas production in the NT. They are applicable for the combustion of gas and apply irrespective of whether the gas is used for heating or electricity production. Further, the estimates in **Table 9.4** are total emissions and they do not take account of possible net emissions where gas may replace other fossil fuels.

158 Origin submission 153; Santos submission 168; Pangaea Resources Pty Ltd, submission 263 (**Pangaea submission 263**).
159 DPIR submission 281, pp 3-4.

Table 9.4: Quantity of life cycle GHG emissions and comparison to the total GHG footprint for Australia.

Total gas production TJ/day	Location of emissions	Life cycle GHG emissions[160] per year Mt CO_2e/y	Proportion of Australia's emissions for 2015[161] %	Proportion of global emissions %
	Based on a 100-year GWP (= 36)			
365 (1,000)[162]	Australia	26.5	4.5	0.05
73 (200)	Australia	5.3	0.9	0.01
1,240 (3,400)[163]	Australia	38.9	6.6	0.07
1,240 (3,400)[164]	Australia and overseas[165]	98.8	n/a	0.17
	Based on a 20-year GWP (= 87)			
365 (1,000)	Australia	31.6	3.9	0.04
73 (200)	Australia	6.3	0.8	0.01
1,240 (3,400)	Australia	56.2	7.0	0.07
1,240 (3,400)	Australia and overseas	116.3	n/a	0.15

The quantity life cycle GHG emissions in Australia from a shale gasfield producing 365 PJ/day is estimated to be 4.5% as a proportion of Australia's GHG inventory emissions[166] for a 100-year GWP of 36 (after Australian inventory results for methane are converted from a GWP of 25 to 36). In the case of gasfields producing 1,240 PJ/y (where approximately 80% of the gas is used for LNG export and approximately 20% is used for domestic consumption), the quantity life cycle GHG emissions in Australia is estimated to be 6.6% of Australia's GHG inventory emissions for this 100-year GWP (=36). Similarly, the GHG emissions are estimated to be 0.05% of global emissions for a shale gasfield producing 365 PJ/y, and for gasfields producing 1,240 PJ/y, the Australian component of emissions is 0.07% of global GHG emissions and the total emissions (emitted in both Australia and overseas) is 0.17% of global GHG emissions (when adopting a similar correction to adjust emissions to a common GWP).

To provide context for the gas production data given in **Table 9.4**, if a new shale gasfield in the NT were producing 365 PJ/y, this would represent 7.5% of Australia's estimated gas production in 2017/ 2018.[167] This production level (365 PJ/y) is representative of 670 wells (Gale scenario over a 25-year period: see Appendix 16). The higher production of 1,240 PJ/y is representative of 6,250 wells (or 4,170 wells with a higher EUR per well).[168] This later production estimate is higher than the industry estimates of 1,000 to 1,200 wells over 25 years as noted in Section 6.5.1. The higher production estimate (1,240 PJ/y) is considered representative of a significant cumulative development over a number of gasfields.

160 The downstream emissions from combustion of natural gas was assumed to be 57 g CO_2e/MJ; Steen 2001. Domestic consumption of gas upstream emissions were assumed to be 15.5 g CO_2e/MJ (100-year GWP) or 29.5 g CO_2e/MJ (20-year GWP); Skone 2016, Table C-1 & C-2 applicable to the Appalachian shale gasfield. The life cycle emissions are then 72.5 g CO_2e/MJ (100-year GWP) and 86.5 g CO_2e/MJ (20-year GWP).

161 Australia's total emissions are taken from the NIR for 2015 (Australian Department of the Environment and Energy 2017h). Australia's national inventory total emissions for 2014/2015 were reported as 537.9 Mt CO2e/y. The methane emissions were converted to CO2e by the GWP shown in the Table above. The NO and other emissions are left with the same CO2e value as in NIR for 2014/2015.

162 The production scenarios of 73 and 365 PJ/y are assumed to be 100% Australian domestic consumption: see previous footnote for life cycle emissions.

163 For the production scenario of 1,240 PJ/y, it is assumed that 240 PJ/y is consumed in Australia and 1000 PJ/y is exported via LNG processing. The Australian domestic consumption component has both upstream and downstream emissions of 72.5 g CO_2e/MJ (100-year GWP), see footnote above. The Australian LNG component has only upstream emissions of 15.5 g CO_2e/MJ + 5.9 g CO_2e/MJ. The later component represents the emissions from LNG production (Hardisty et al. 2012).

164 The Australian domestic consumption component is estimated using 72.5 g CO_2e/MJ (100-year GWP): see footnote above. The Australian LNG component has upstream emissions = 21.4 g CO_2e/MJ (as noted previously), plus overseas emissions of 1.6 + 1.3 g CO_2e/MJ for LNG shipping and regasification (Hardisty et al. 2012) and natural gas combustion of 57 g CO_2e/MJ (Steen 2001). This gives total emissions, both locally and overseas, for the LNG stream = 81.3 g CO_2e/MJ (100-year GWP).

165 In this case, the overseas emissions amount to 98.8 – 38.9 = 59.9 Mt CO_2e/y. It is not appropriate to account for these overseas emissions against Australian emissions, but rather against the importing country's emission inventory.

166 These may be an overestimate since they are based on a comparison of life cycle emissions, that are based (in part) on comprehensive basin wide measurements, with inventory estimates. As shown in Section 9.4.2, basin wide measurements are double inventory estimates for fugitive methane emissions.

167 Department of Industry, Innovation and Science 2017a, Table 7.1.

168 DPIR submission 281.

The Australia Institute has estimated[169] that shale gas operations in the NT would emit much higher GHG emissions than estimated above by assuming the full exploitation of shale gas resources in the NT. The resource estimate used by The Australia Institute is what is defined in Section 6.1 as a "prospective resource". Prospective resources[170] are estimated volumes associated with undiscovered accumulations. These are clearly unreliable and are an overly optimistic gas estimate of what can be recovered commercially. Accordingly, The Australia Institute estimates of GHG emissions are, in the Panel's view, highly inflated.

Some submissions have noted also the possible extraction of shale oil resources.[171] Increased levels of shale gas and shale oil production will result in larger contributions to GHG emissions from shale gas operations in the NT and a faster erosion of the global carbon budget[172] (see Section 9.1.4). Nevertheless, the Panel has deemed the assumed levels of production (365 PJ/y or 1,240 PJ/y) are plausible and relevant for the purposes of conducting the risk assessment (see also Section 6.1).

9.6.2 Risk assessment

It is appropriate to focus the risk assessment of GHG emissions over the full life cycle (which considers both CO_2 and CH_4 emissions for both upstream and downstream phases as a ratio of the global GHG emissions because it is these emissions that are a major contributor to global warming. **Table 9.5** contains the risk assessments for life cycle GHG for a gasfield in the NT producing 365 PJ/y and gasfields producing 1,240 PJ/y. The Panel assessed the risks associated from GHG emissions over the full life cycle as 'medium' for a shale gasfield producing 365 PJ/y, 'medium' for the Australian emission component associated with gasfields producing 1,240 PJ/y and 'high' for the global emissions (both in Australia and overseas) associated with gasfields producing 1,240 PJ/y. These assessments represent mitigated risk levels. The mitigation of these risk levels is considered in Section 9.9.

169 The Australia Institute, submission 627. The Australia Institute have estimated GHG emissions of some 20 or 32 Gt CO2e from the exploitation of a 257,276 PJ prospective resource base in the NT.

170 Prospective resources represent quantities of petroleum which are estimated to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have limited or no drilling. This class of resource represents a higher risk than contingent resources (and commercial reserves) since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be further evaluated and an estimate of quantities that would be recoverable under appropriate development projects prepared (Australian Energy Resources Assessment 2014).

171 T Forcey, submission 548 and Australian-German Climate and Energy College, submission 543.

172 T Forcey submission 548.

Table 9.5: Risk assessment to climate change for life cycle GHG emissions from possible new shale gasfield(s) in the NT.

A: Producing 365 PJ/y.

Risk assessment component	Assessment	Reason
Likelihood	High	Life cycle GHG emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Low	Life cycle GHG emissions) are 0.05% of global GHG emissions; these emissions are deemed assessed as minor/moderate (< 0.1%; see **Table 4.4**).[173]
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

B. Producing 1,240 PJ/y, Australian emissions only.

Risk assessment component	Assessment	Reason
Likelihood	High	Life cycle GHG emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Low	Life cycle GHG emissions (from a new field) are 0.07% of global GHG emissions ; these are assessed as minor/moderate (<0.1%; see **Table 4.4**).
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

C. Producing 1,240 PJ/y, global emissions.

Risk assessment component	Assessment	Reason
Likelihood	High	Life cycle GHG emissions occur mostly on a continuous basis but with some episodic releases.
Consequences	Medium	Life cycle GHG emissions (from new fields) are 0.17% of global GHG emissions; these are assessed as serious (<0.5%; see **Table 4.4**).
Risk	High	Based on the risk assessment matrix in Chapter 4.

9.7 Life cycle GHG emissions: technology comparisons for electricity production

Natural gas is used for heating purposes (domestic, commercial and industrial), electricity generation, and as a feedstock for the production of other materials. The focus in this Section is on the life cycle emissions produced from electricity generation by natural gas plants and other technologies. GHG emission results are presented in terms of the quantity of CO_2e per unit of electrical energy produced (MWh). The Panel's key findings are that:

- the downstream emissions from modern natural gas electric power generation plants represent 78% of the life cycle GHG emissions (and the upstream methane emissions represent 22% of the life cycle GHG emissions);
- the life cycle GHG emissions from shale gas-generated electricity are 50–60% of that from coal-generated electricity. Natural gas combined cycle gas turbine power plants[174] (**CCGT**) have a lower climate impact than supercritical pulverised coal power, provided methane emission rates are lower than 3.3%;
- the total life cycle GHG emissions from renewable energy sources are much lower (and generally less variable) than those from fossil fuels. For example, supercritical coal fired electricity releases about 20 times more GHG per megawatt-hour than solar electricity; and

173 For a gasfield production of 1,000 TJ/day (365 PJ/y), the gross life cycle GHG emissions (not allowing for any replacement of coal-fired electricity) is 26.5 Mt CO2e/y (**Table 9.4**) or approximately 5% of Australian GHG emissions (= 543.3 Mt CO2e/y). On a global basis, these represent 0.05% of global GHG emissions (= 26.5 Mt CO2e/y compared to 53.4 Gt CO2e/y). At this level of contribution to global GHG, the consequence for GHG emissions from a gasfield is assessed as 'minor/ moderate' (< 0.1%: see **Table 4.4**), and therefore, the consequence rating is considered to be 'low': see **Chapter 4**.

174 A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional simple open-cycle plant.

- in the short to medium term, the Australian National Electricity Market is likely to require higher levels of flexible, gas-fired generation, which can provide a reliable, low emissions substitute for ageing coal-fired generation, and can provide essential security services to rapidly respond to and complement variable renewable electricity generation.

9.7.1 Electricity production

The life cycle emissions of shale gas represent 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 for electricity production, which includes the operation of power plants and the transmission and distribution of electricity to the consumer. Skone et al. estimated that the life cycle emissions from CCGT are 497 kg CO_2e/MWh for 100-year GWP and 598 kg CO_2e/MWh for 20-year GWP.[175] Older style open-cycle gas turbine peaking plants have greater emissions.[176] Skone et al. also determined that the total life cycle GHG emissions for electricity generation are dominated by CO_2 from power generation. In the case of CCGT, the downstream power generation represents 78% of total life cycle GHG emissions and the upstream emissions account for about 22% of life cycle GHG emissions.

9.7.2 Comparison with 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[177] 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.

Heath et al. 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.[178] 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.[179] Even with greater consistency after harmonisation, variability in results remained because of intrinsic differences between the study conditions. Therefore, the validity of comparing individual results from different authors is highly questionable. Nevertheless, Heath et al. found that the median of GHG life cycle emissions from shale gas generated electricity from CCGT plants was less than half those from coal-fired electricity generation. The median estimates for the life cycle emissions of shale and conventional CCGT plants after harmonisation were nearly identical: 465 kg CO_2e/MWh for shale, and 461 kg CO_2e/MWh, respectively. 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 CCGT to be worse than supercritical, pulverised coal power generation for a 20-year GWP, or 10.0% for a 100-year GWP.[180] Use of an alternative procedure (Technology Warming Potential (**TWP**), that is independent of GWP timeframes) found that as long as CH_4 emission rates are lower than 3.3%, CCGT power plants have a lower climate impact (in terms of cumulative radiative forcing) than supercritical, pulverised coal power at all points in a time series.[181] **Table 9.6** provides estimates of the emissions from various forms of coal-fired and gas-fired electric power generation. Both forms of gas-fired generation represent substantial reductions on the average Australian National Electricity Market generation. Nevertheless, the life cycle emissions from new black coal-fired High Efficiency, Low Emission (**HELE**) generators can approach the emissions of open cycle gas turbines (**OCGT**).

175 Skone et al. 2016. p72.
176 An open cycle gas turbine plant uses only a gas turbine to produce electricity. This technology does not recover heat via a steam turbine and therefore has a lower efficiency and higher fuel use than CCGT. OCGT can respond quickly to changes in electricity demands, but modern CCGT plants can operate with a high degree of flexibility and fast response times.
177 US EIA 2017.
178 Heath et al. 2014.
179 Whitaker et al. 2012; Health et al. 2014.
180 Littlefield et al. 2016.
181 Littlefield et al. 2016.

Table 9.6: GHG emissions for various forms of electric power generation.

	GHG emissions, kg CO_2e/ MWh				
	Coal power generators			Gas power generators	
	Black coal supercritical HELE	Black coal ultra-supercritical HELE	Average National Electricity Market	Open cycle (OCGT)	Combined cycle (CCGT)
Downstream[182]	860	700	990	620	370
Upstream[183]	128	116	137	156	120
Life cycle	988	816	1127	776	490

As **Table 9.6** demonstrates, the best gas fired generation (CCGT) is approximately 60% as emission intensive as the most efficient coal fired plant (ultra-supercritical coal HELE generation) based on life cycle GHG emissions.

If natural gas is used to displace coal from electricity production in Australia, and the net unit CO_2e savings are in the order of 515 kg CO_2e/MWh of electricity[184] (see above) for 100-year GWP, there could be a reduction in Australia's GHG emissions of appromixately 1% from a 73 PJ/y production and 5% in the case of 365 PJ/y production.[185] However, it should be noted that the actual savings will be less than that estimated because not all of the gas supply will be used as a fuel for electricity generation. For example, gas may be used to supplement renewable energy sources and to assist with grid stability (where there are high levels of renewables); used to replace coal; exported as LNG (as considered previously); used for heating (domestic, commercial and industrial); and/or used as a feedstock chemical for industrial processes.

9.7.3 Comparison with renewable energy technologies

The National Renewable Energy Laboratory has carried out a comprehensive review of published GHG life cycle assessments of electricity-generation technologies. Approximately 2,165 references were collected, of which 296 passed screens for quality and relevance, and distributional information on the emissions was calculated based on the as-published data. The resultant data was published and the median emission results for a selection of renewable energy technologies are given in **Table 9.7**.

Table 9.7: Median GHG emissions for a selection of renewable energy technologies.[186]

Renewable energy technology	Life cycle GHG estimate kg CO_2e/ MWh	Renewable energy technology	Life cycle GHG estimate kg CO_2e/ MWh
Geothermal	45	Wind- onshore and offshore	12
Photovoltaic	46	Ocean energy	8
Concentrating solar thermal	22	Hydropower	4

The results in **Table 9.7** show that the total life cycle GHG emissions from renewables are much lower than those from fossil fuels. For example, the life cycle GHG emissions on a per megawatt-hour basis are about 22 times higher from supercritical coal fired electricity (**Table 9.6**) than from photovoltaic solar electricity.

It has also been claimed that it is cheaper to employ solar and wind power, and pumped hydro and batteries to provide baseload power and manage energy supply/demand fluctuations, which are the major functions of gas in the electricity system.[187] Estimates for the cost of producing

182 Figures are the estimated downstream emissions for new power stations (Finkel et.al. 2017, p 203) with the exception of the NEM; Based on data for the NEM (Brazzale 2016), the average emissions are 860 kg CO_2e/ MWh for black coal generators and 1250 kg CO_2e/ MWh for brown coal generators, and the combined average emissions (weighted on outputs) are 990 kg CO_2e/ MWh.

183 It has been estimated (Whitaker et al. 2012) that in the case of coal, upstream transmission and distribution accounts for some 5% to 10% of emissions and that coal-mine methane emissions yield a median estimate of 63 kg CO_2e/ MWh. Indicative estimates for the upstream emissions for OCGT (fleet peaking) and CCGT are 156 and 120 kg CO_2e/ MWh respectively, Skone et. al. 2016, Table C-4.

184 Heath et al. 2014.

185 Savings of 515 kg CO_2e/MWh of electricity, at 51% generation efficiency, converts to a savings of 72.9 g CO_2e/MJ of delivered gas. For example, a production of 73 PJ/y represents savings in emissions of 5.3 Mt CO_2e/y; this is approximately 1% of Australia's GHG emissions.

186 IPCC WG III 2012, p 190.

187 Climate Action Darwin, submission 446, p 9.

electricity in Australia for a range of technologies have recently been developed.[188] While these levelised cost of electricity (**LCOE**) results provide a different perspective, it is important to realise that investment decisions involve numerous other factors not reflected in the LCOE values.

9.7.4 Future electricity generation mix and the role of gas

In a recent review of the Australian National Electricity Market by Finkel et al., it was found that under a proposed Clean Energy Target (**CET**) policy setting, calibrated to achieve an emissions reduction target of 28% on 2005 levels by 2030, there is a need for a substantial change in the electricity-generation mix. Renewables are projected to have their proportion of generation increased from 28% in 2020 to 42% in 2030 and 70% in 2050; whereas, fossil fuels are projected to have their proportion of generation reduced from 72% in 2020 to 58% in 2030 and 30% in 2050. The proportion of gas generation will reduce from 6% in 2020 and 2030 to 4% in 2050.[189]

APPEA used recent research from the US and Europe to suggest that renewables and fast-reacting gas-fired power general technologies appear to be highly complementary and should be jointly installed to meet the goals of reduced emissions and stable supply.[190] However, concern has been raised about developing an overreliance on gas and renewables as an energy mix. For example, the Climate Council has observed that using existing gas-fired generators to complement wind and solar power, while scaling up a range of renewable energy technologies, energy storage and energy efficiency measures, can deliver a limited benefit, provided that the end goal is phasing out the use of all fossil fuels as quickly as possible.[191]

Since 2014, when gas-fired generation was contributing around 13% of electricity energy generation in the Australian National Energy Market, gas-fired generation output has been in decline due largely to higher gas prices, increases in variable renewable energy generation, and reduced electricity demand. As noted in the Finkel review,[192] access to a reliable and affordable gas supply is in the interest of all Australians given its direct use for heating, as a feedstock chemical for industrial processes, and as a fuel for electricity generation. Gas has an important role to play in supporting the continued deployment of renewable energy technologies. Rapid changes in power output from variable renewable energy generation need to be balanced with generation technology that has the ability to increase (ramp up) or decrease (ramp down) power output at the same time. Gas-fired generators have the ability to 'fast ramp'. Most of Australia's coal-fired generators, however, do not.

In the short to medium term, the Australian National Energy Market is likely to require higher levels of flexible, gas-fired generation, which can provide a reliable, low emissions substitute for ageing coal-fired generation, and essential security services to complement variable renewable electricity generation. Storage technologies, such as pumped hydro and batteries, will be able to play a role to support reliability as and when they are deployed at scale.[193] Over a longer timeframe, as Australia transitions to lower-emissions generation, natural gas may be replaced by zero emissions fuels such as hydrogen and biogas.

9.8 Methane emissions from post-production shale gas wells

Oil and gas wells can provide a potential pathway for subsurface migration and emissions of methane to the atmosphere (see Chapters 5 and 7). There are an estimated three million abandoned oil and gas wells throughout the US, with no regulatory requirement to monitor or account for their methane emissions in the national inventory.[194] Estimates are given in this Section for the quantity of methane emissions from plugged, unplugged and decommissioned wells. These results are used as the basis of a risk assessment based on comparing the emissions from 1,000 hypothetical decommissioned wells in the NT (should any onshore shale gas industry be established) with global methane emissions. The key findings are that:

- the evidence on methane emissions from decommissioned and abandoned gas wells is mixed. It is clear, however, that properly decommissioned wells (wells that have been

188 Finkel et al. 2017.
189 Finkel et al. 2017, p 93.
190 APPEA submission 215, p 8.
191 Climate Council, submission 458, p 5.
192 Finkel et al. 2017.
193 Finkel et al. 2017, p 109.
194 Kang et al. 2014. p 18173.

cut-off, sealed (plugged) and then buried under soil) have generally lower methane emissions than wells that have been not been properly (or at all) decommissioned and have been abandoned with well head infrastructure left above the surface;

- there is a need to improve the integrity performance of decommissioned wells over the long term, such as 1,000+ years, and that this needs further research;
- fugitive methane emissions from any onshore shale gas industry in the NT (for the case of 1,000 decommissioned wells) is estimated to represent 0.7% of Australia's inventory fugitive methane emissions and 0.005% of the global anthropogenic methane emissions from fossil fuels; and
- the assessed risk of fugitive methane emissions from decommissioned wells resulting from any new shale gas industry in the NT, without any further mitigation, is 'medium'.

The assessment of risk associated with methane levels is further discussed in Section 9.9.1

9.8.1 Quantity of emissions

Studies suggest that 4–9% of all wells drilled experience some form of gas leakage that is detectable at the surface.[195] The quality of the casing installations is considered the major potential pathway for fugitive gas seepage.[196] Any pathway outside the casing is of particular concern because it may lead to leakage from intermediate-depth gas zones, rather than from the deeper target reservoirs (see Chapter 5). Mitigation is possible. It is noted that hydraulic fracture stimulation a does not appear to be a significant risk of methane leakage, although problems can occur when stimulation induces a connection with legacy or offset wells that have not been plugged.[197] In another study,[198] it was noted that poor cementing may result in well integrity failure and potential leaks. This is influenced by three main factors: failure to bring the cement top high enough; failure to surround the casing completely with cement; and gas migration in the cement during cement setting. Direct measurements[199] of methane fluxes from 19 abandoned oil and gas wells in Pennsylvania were undertaken, with methane flow rates observed from all 19 wells and the mean well methane flow rate being 99 kg/y. Of the 19 measured wells, most were over half a century old, five (26%) were plugged and 14 (74%) were unplugged. The integrity of plugging was difficult to determine. Three out of the 19 measured wells were high emitters that had methane flow rates that were approximately three orders of magnitude larger than the median well flow rate of 0.5 kg/y. The maximum flow rate from a well was 753 kg/y. In this study, it was also found that methane flow rates from plugged wells were not always lower than methane flow rates at unplugged wells. Assuming the mean flow rate to be representative of all abandoned wells in Pennsylvania, it was estimated that the methane emissions from abandoned wells was 0.1–0.5 % of gross gas withdrawal in Pennsylvania. These measurements show that methane emissions from abandoned oil and gas wells can be significant.

In the UK, a study of 102 decommissioned wells (cut-off, sealed and then buried under 2 m of soil) from four onshore oil and gas basins reported that the mean methane flux at the soil surface was 15 ± 27 kg /well/y,[200] where the uncertainty is given as the standard deviation in the mean, with a 28% chance that any well would be a net sink of methane. In the case of one additional well that had not been decommissioned, the methane flux was 345 kg /y. The relative methane concentration above wells did not increase with age, and 40% of the most recent wells surveyed showed leaks, implying that leaks develop early (within a decade) in the post-production life of a decommissioned well.

In another study, direct measurement of methane emissions from 138 abandoned oil and gas wells found that nine (6.5%) wells had measurable methane emissions.[201] Only one of the 119 plugged wells was a positive source of methane, emitting 1.8 kg/y. By contrast, eight of the 19 unplugged wells were a positive source of methane, with an average methane emission rate of 209 kg/y. There was a skewed pattern of emissions, with a small proportion of measurements comprising the majority of emissions. The results indicate that plugging is essential for mitigation of methane emissions from abandoned wells. The majority of the wells had been drilled since the

195 Watson and Bachu 2009; Ingraffea et al. 2013.
196 Dusseault and Jackson 2014.
197 Dusseault and Jackson 2014.
198 NSW Chief Scientist and Engineer 2014.
199 Kang et al. 2014.
200 Boothroyd et al. 2016.
201 Townsend-Small et al. 2016.

1970s and 1980s, although a few had been drilled since the 1850s. It was found that abandoned wells made a small contribution (<1%) to regional methane emissions, and it was estimated that, when abandoned oil and gas wells were included, the US inventory would increase national CH_4 emissions from oil and gas activity by 1.9–4.3%.

A range of international industry experience and literature suggests that if the current methods prescribed in national and international codes and standards for petroleum well integrity (of which well abandonment/decommissioning is a component) are adopted, the risk of a petroleum well failing is considered to be low.[202] However, often these types of studies consider petroleum well integrity over a period of decades, with little research conducted on the potential longer-term impacts (over a 1,000+ year period). Some researchers have used simulations to determine the potential for degradation of the cement over the long term. One study considered cement seals over 1,000 years and concluded that cement would be able to isolate CO_2 and upper aquifers over the very long-term, while another study estimated cement plug degradation after 10,000 years and concluded that *"mechanical integrity of cement plugs and the quality of its placement probably is of more significance than chemical degradation of properly placed abandonment plugs"*.[203] These studies were conducted on wells intended for CO_2 storage. Shale gas in the Beetaloo Sub-basin contains very low levels of corrosive gases such as CO_2 and H_2S,[204] and therefore, the likelihood of chemical degradation is even lower.

A substantial proportion of petroleum wells in NSW are either suspended or abandoned. Current codes and standards may be adequate regarding abandonment of existing exploration or production wells, but were not in effect for historic petroleum wells (legacy wells). Like petroleum wells, mining or irrigation wells also have the potential to connect aquifers and emit fugitive emissions, including following abandonment, if their integrity is compromised. In Queensland, investigations are under way to locate, quantify the emissions, and remediate abandoned and legacy wells. For example, it has been noted that:

> *"during the Queensland GISERA greenhouse study in the Surat Basin, a number of legacy exploration boreholes were found to be leaking methane. Given the large number of such boreholes in Queensland, they represent a potentially significant source of methane in the region. As a result of that work, further research is currently under way in collaboration with the industry to locate and remediate leaking boreholes";[205] and*
>
> *"mobile ground surveys over a wide region between Chinchilla and Roma have surveyed approximately 1,000 abandoned boreholes sites. Downwind methane concentrations have been measured and local wind speed and direction data used to determine whether or not methane is leaking from the boreholes. Most of the boreholes examined are old coal exploration holes, but there have also be numerous plugged and abandoned CSG wells included in the dataset. So far, the majority of sites examined have shown no methane emissions. However, a handful of sites have shown some level of emission".[206]*

A recent review by the NSW Chief Scientist and Engineer on abandoned wells[207] noted that different jurisdictions regulate well abandonment in different ways. Some jurisdictions require companies to submit abandonment plans to the regulator for each project. These plans are then reviewed and approved in light of industry standards and field development plans. Other jurisdictions, such as NSW, Queensland and Alberta, have set up codes of practice, rules, or directives, governing well integrity and abandonment that must be adhered to by all companies. An overview of available oil well abandonment regulations for a selection of countries and jurisdictions found that a general distinction can be observed between European and non-European countries.[208] The main differences lie in the length requirements of the plugs near the deepest casing shoe. In Europe, the length of the cement plug is between 50 m and 100 m, and in evaluated non-European countries, the length of the plug is between 30 m and 60 m. The evaluated regulations primarily comprise prescriptive requirements for plugging and abandonment of oil and gas wells. In Colorado, all wells used for the injection of fluids must be pressure tested

202 NSW Chief Scientist and Engineer 2014.
203 APPEA submission 465, p 6.
204 DPIR submission 424, p 3.
205 GISERA 2016, p 8.
206 Etheridge et al. 2017, p 43.
207 NSW Chief Scientist and Engineer 2014.
208 IEA GHG 2009, Section 8.3.

at least once every five years for ongoing management of well integrity. In Alberta, a well bore integrity plan must include assessments of 3D hydraulic fracture propagation extent. In the UK, there is a recommendation for post-management monitoring to detect any well failure after abandonment.

The Queensland Department of Natural Resources and Mines has recently published a code of practice for the construction and abandonment of coal seam gas wells and associated bores.[209] This code includes principles and mandatory requirements based on industry good practice. While this comprehensive and prescriptive-based code is applicable to CSG wells, and not shale gas wells, it nevertheless specifies that cement plugs should be a minimum length of 30 m; whereas, European codes specify plugs to be 50 m to 100 m and do not include a requirement for ongoing monitoring of methane emissions post abandonment.

It is noted that research is being undertaken in Australia to develop cheaper and more effective measures to seal wells using bentonite (a clay).[210] Further, it is noted that under the NGER scheme, methods will be developed to account for decommissioned wells and wells where production has been temporarily suspended by considering empirical data. In addition, the results will be reported in the NIR.[211]

Based on the evidence above, methane emissions appear generally lower with plugged or decommissioned wells compared to unplugged wells. To further mitigate methane emissions, it is appropriate to require that all wells be decommissioned post production and that monitoring for possible leaks must be undertaken.

9.8.2 Risk assessment

Table 9.8 contains an assessment of the risk associated with methane emissions from decommissioned wells for a new shale gasfield in the NT, based on these emissions as a proportion of global GHG emissions. The Panel has assessed the risk associated from methane emissions from decommissioned wells as 'medium'.

Table 9.8: Risk assessment for methane emissions from 1,000 decommissioned wells in the NT.

Risk assessment component	Assessment	Reason
Likelihood	High	Methane emissions occur mostly on a continuous basis once leakage has commenced.
Consequences	Low	Methane emissions from decommissioned wells are 0.005% of net global anthropogenic methane emissions; as these emissions are < 0.1%, they are assessed as minor/moderate (**Table 4.4**).[212]
Risk	Medium	Based on the risk assessment matrix in Chapter 4.

Based on the findings contained in Chapter 5, and the discussion above, the Panel is of the view that to reduce fugitive emissions from post-production wells, all such wells must be decommissioned in accordance with world-leading practice. The Panel therefore repeats ***Recommendations 5.1*** and ***5.2***.

Because the assessed risk is 'medium', it is necessary to consider how this risk can be mitigated. The mitigation and assessment of risk associated with methane levels is further discussed in Section 9.9.1.

The number of decommissioned wells will increase during the production life of a gasfield and then remain essentially constant following the decommissioning of the gasfield. During the life of

209 Queensland DNRM 2017a.
210 UQ CCSG 2017.
211 Australian Department of the Environment and Energy 2017h.
212 Assuming that a gasfield in the NT will comprise 1,000 decommissioned wells and that the mean methane emissions from each well is 15 kg well/y (see Boothroyd 2014), then this mean leakage represents 0.015 Mt methane/y; this is about 10% of the methane emissions from a new gasfield. The Australian National GHG Inventory for methane emissions is 4.36 Mt CH_4/y (Australian Government NGGI; see also Australian Department of the Environment and Energy 2017h). The fugitive emissions from decommissioned wells in the NT represent 0.3% (=0.015/4.36) of Australia's Inventory methane emissions. The annual global anthropogenic methane emissions are 329 Mt of CH_4 (= 558x0.59; refer to Section 9.1.3 for details). Accordingly, the fugitive emissions from decommissioned wells in the NT represent 0.005% (=0.015/329) of the annual global anthropogenic methane emissions. At this level of contribution to global anthropogenic methane emissions, the consequence for methane emissions from decommissioned wells is assessed as 'minor/ moderate', therefore, the consequence rating is assessed to be 'low': see Chapter 4. During the decommissioned phase of a gasfield, emissions from decommissioned wells must be assessed as part of a new methane monitoring regime with possibly revised performance targets.

a gas production field, methane emissions from any decommissioned wells must be monitored (see Section 9.5). In the decommissioned phase of a gasfield, emissions from decommissioned wells must be monitored and levels above normal background levels should be investigated and remedial action taken if appropriate.

9.9 Risk assessment summary

The Panel has assessed the risks to climate change associated with life cycle GHG emissions, (including methane) and separately, the risks for methane emissions from possible new onshore shale gasfield(s) in the NT, namely:

- upstream methane emissions (Section 9.4);
- non-detection of abnormal levels of methane emission (Section 9.5);
- life cycle GHG emissions (Section 9.6); and
- methane emissions from 1,000 decommissioned wells (Section 9.8).

Given that the unmitigated risks were assessed to be either 'medium' or high, it is necessary to apply mitigation strategies that, first, achieve the environmental objective (namely, to "limit the emissions of methane and greenhouse gases to the atmosphere"),[213] and second (as outlined in Chapter 4), achieve a mitigated risk that is either 'low' and/or meets the acceptability criteria for methane and GHG emissions (refer to **Table 9.9**).

The decision on the extent of mitigation required to achieve an acceptable outcome was guided by the principles of ESD (Chapter 4), while nevertheless recognising:

- community concerns about the impacts associated with GHG emissions (including methane emissions);
- the community's expressed lack of trust with industry;
- the community's expressed lack of trust with the Government's ability to adequately regulate industry; and
- the lack of facility-wide measurements of methane levels.

Table 9.9: Environmental objective and acceptability criteria for GHG and methane emissions.

Environmental objective	Limit the emissions of methane and greenhouse gases to the atmosphere	
Theme	**Criterion**	**Measure of Acceptability**
Methane emissions	Minimise fugitive methane emissions	Set a methane concentration limit that is equivalent to methane emissions that are 1.7%[214] of dry production
GHG emissions	Minimise GHG emissions	Offset life cycle GHG emissions in Australia from shale gas produced in the NT to ensure no net GHG emissions

9.9.1 Methane emissions

The unmitigated risks associated with methane emissions were assessed as 'medium'. A number of recommendations were made to reduce methane emissions. Namely, that the NT's regulatory regime must limit the extent of methane emissions from any onshore shale gas industry's contribution to climate change through the introduction of the following methane mitigation measures:

- require the application of the US NSPS and related emission-reduction technologies to reduce fugitive emissions at the upstream stage of operations (see Sections 9.3 and 9.4 and ***Recommendation 9.1***);
- require baseline and ongoing monitoring and reporting of methane concentration[215] levels at any new gasfield (see Section 9.5 and ***Recommendations 9.2*** to ***9.6***); and

213 See Appendix 3, Risk assessment matrix.
214 This is based on the results of Littlefield et al. 2017.
215 It is acknowledged that measuring methane flux levels from a gasfield is difficult and the results unreliable. Therefore, measurement of methane concentrations is proposed.

require that all post-production wells be decommissioned in accordance with world-leading practice (see Section 9.8 and ***Recommendations 5.1*** and ***5.2***).

The implementation of these recommendations will mitigate the levels of methane emissions. Nevertheless, after mitigation, the assessed 'likelihood' will remain 'high' and, even with lower levels of methane, the 'consequences' are assessed to remain 'low'[216] (see **Table 4.4**). Accordingly, the mitigated methane risk remains 'medium' (**Table 4.2**).

There are also a number of supplementary risks that may prevent the achievement of lower levels of methane emissions. In **Table 9.10,** these risks are identified, together with the actions that can be taken to mitigate the risks.

Table 9.10: Mitigation of supplementary risks that may prevent lower levels of methane emission performance from being achieved.

Risk identification	Comment	Mitigation action
Regulations are not implemented.	Regulations are required for reduced emissions completions, compressor emissions and pneumatic controllers.	Ensure that world leading practice regulations are implemented that are known to achieve lower methane emissions.
Regulations may restrict the development or implementation of technologies that lower emissions.	Regulations may hinder the achievement of lower emissions.	Prescription-based regulation only, while achieving desirable outcomes, may restrict new technologies. There is a need to allow appropriate flexibility in the formulation of performance-based regulations.
Regulations are not fully complied with.	This may have the effect of allowing increased emissions.	Ensure that there are appropriate incentives for compliance and penalties for non-compliance.
Monitoring for compliance with regulations is not undertaken or is inadequate.	Monitoring by a regulatory authority may not occur because of lack of resources.	Ensure that there are appropriate requirements for monitoring regulatory compliance and that there are adequate resources.
Monitoring of both baseline emissions and emissions during production is not undertaken.	Monitoring emissions is a means of assuring compliance and to detect 'super emitters'.	Ensure that there are appropriate requirements for monitoring emissions.
Inadequate monitoring of both baseline emissions and emissions during production.	This may result in the inability or failure to detect abnormal emissions and lead to higher emissions..	Ensure that there are adequate resources to undertake monitoring and that this monitoring is undertaken by an independent organisation with the necessary expertise.
Failure of plant or equipment occurs during the lifetime of the well.	These are normally low likelihood events with consequences that can range from a minor to a catastrophic release of gas for a relatively short period over the life of a well.	These failure events can be mitigated by ensuring compliance with appropriate regulations, including undertaking rigorous risk assessment and ensuring that a formal leak detection and repair program is undertaken regularly.

The Panel has formed the view that to mitigate the supplementary risks identified in **Table 9.10**, the action measures identified in that Table should be introduced to further reduce fugitive methane emissions.

Recommendation 9.7

That the action framework outlined in Table 9.10 be implemented to lower fugitive methane emissions.

216 Mitigation of methane emissions can result in at least a 23% reduction in upstream GHG emissions (see Section 9.3). Nevertheless, with this reduction the resultant methane emissions remain at about 0.03% of global anthropogenic methane emissions. The consequences are deemed 'minor/ moderate' (<0.1%), and therefore, the consequence rating remains 'low'.

In summary, after the implementation of the mitigation measures contained in ***Recommendations 9.1*** to ***9.7***, methane emissions will be reduced to a level that is consistent with the achievement of the acceptability criterion for methane emissions given in **Table 9.9**. Nevertheless, the mitigated methane emission risk will remain 'medium'. The further mitigation of the risk of methane emissions is necessary and is considered in the broader context of mitigating GHG emissions as described in the following Section.

9.9.2 GHG emissions

After mitigation of methane emissions, the residual life cycle GHG emissions are reduced slightly but they remain significant.[217] These mitigated/residual life cycle GHG emissions have the same risk levels as previously assessed in Section 9.6.2, namely, either 'medium' or 'high'.[218] These are unacceptable risk levels (refer to Chapter 4). Accordingly, the Panel has determined that to meet the environmental objective (**Table 9.9**), the life cycle GHG emissions must have a 'low' risk (Chapter 4) and meet the acceptability criteria (**Table 9.9**). These objectives can be achieved by fully offsetting the life cycle GHG emissions, namely, that there is no net increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT.

Recommendation 9.8

That the NT and Australian governments seek to ensure that there is no net increase in the life cycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT.

The Panel recognises that while this recommendation may present a challenging task, it is based on the principles of ESD. It also reflects widespread and strongly held concerns that were articulated to the Panel regarding the impacts of increased GHG emissions. To achieve this outcome, the increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT (see **Table 9.4**) must be fully offset. For example, 26.5 Mt CO_2e/y must be fully offset for a gasfield producing 365 PJ/y and 38.9 Mt CO_2e/y must be fully offset in Australia for a gasfield producing 1,240 PJ/y. In the latter case, the residual emissions of some 60 Mt CO_2e/y are emitted overseas, and they should therefore be offset overseas.[219]

There are various existing energy and climate change policies and commercial and public initiatives that support the reduction of GHG emissions and assist in meeting Australia's obligations under the Paris Agreement to limit global warming to less than 2°C. Accordingly, fully offsetting these additional GHG emissions (see **Table 9.4**) may require strengthening existing policies and/or the introduction of new policies and initiatives to meet Australia's international obligations. There are a variety of strategies that may either be expanded or new strategies be implemented to achieve this recommendation, including: early retirement of coal-burning power plants; fitting of carbon capture and storage to gas or coal-fired power stations; higher emission standards for fossil fuel-burning vehicles; increased uptake of electric vehicles; international offsets; carbon credit offsets in agriculture and savannah burning; formal offset policies and markets; increased deployment of renewable energy; and reductions in deforestation. Any decisions to adopt such strategies and the implementation of mechanisms required to fully offset of GHG emissions from any onshore shale gas produced in the NT are, however, beyond the scope of this Inquiry when regard is had to the Terms of Reference.

217 Mitigation of methane emissions can result in at least a 23% reduction in upstream GHG emissions (see Section 9.3). This reduction in upstream emissions translates to a reduction of 5% in life cycle GHG for a 100-year GWP. Accordingly, the mitigated life cycle GHG emissions are similar to the unmitigated GHG emissions. Therefore, there is no change in the assessed risk.

218 The Panel has assessed the risks associated with GHG emissions over the life cycle as: 'medium' for a gasfield producing 365 PJ/y; 'medium' for the Australian emissions associated with gasfields producing 1,240 PJ/y; and 'high' for global emissions (both in Australia and overseas) associated with gasfields producing 1,240 PJ/y.

219 The total NT GHG emissions in 2014/15 were 12.8 Mt CO_2e (inventory estimate: see Australian Department of the Environment and Energy 2017g). By comparison, the estimated emissions from a gasfield producing 365 PJ/y is 26.5 Mt CO_2e (**Table 9.4**). Clearly, any offset of GHG emissions from any onshore shale gas operations in the NT must also involve the Australian Government. The NT Government had a Climate Change Policy in 2009 (Climate Action Darwin, submission 1159) which set emissions reduction targets. The NT Government has recently released a *Roadmap to Renewables* report as part of achieving a 50% renewable energy target by 2030 (Langworthy et al. 2017).

9.10 Conclusion

The Panel is of the opinion that the collective application of methane mitigation measures (including the introduction of NSPS, methane monitoring and reporting, well decommissioning, and the mitigation measures in **Table 9.10)** will result in lower levels of methane emissions that will meet the acceptability criterion for methane emissions. Nevertheless, the residual risk (after mitigation of methane levels) of life cycle GHG emissions remains either 'medium' or 'high', and this is unacceptable. Accordingly, the life cycle GHG emissions must be reduced to a 'low' risk for the GHG emissions and it is necessary to meet the acceptability criterion. This can be achieved by ensuring that GHG emissions are fully offset and that there is no net increase in the life cycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT. The Panel has formed the view that if there is a no net GHG emission increase, this would represent an acceptable outcome.

SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

PUBLIC HEALTH

10

10.1 Introduction

The Panel has assessed two broad categories of public health risk arising from any onshore shale gas industry:

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

In common with all of the other potential risks associated with onshore shale gas extraction, there has been a rapidly increasing coverage of public health over the past five years in the peer-reviewed literature.[1] There have been entire issues of journals that have addressed the topic[2] as well as review papers[3] and reports.[4] Most of these reviews analyse data from US operations, however, similar issues have been canvassed for unconventional gas extraction activities in the UK.[5] Submissions to the Panel, 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 has taken into consideration the most significant of these published papers, reports and submissions, in order to address the key risks identified by the Panel that impact upon public health.

Public submissions specifically relating to public health impacts included a 2017 critique by Professor Melissa Haswell from the Queensland University of Technology[6] of the issues raised in reports from WA Health in relation to unconventional gas exploration in WA,[7] and a 2015 critique of the report on CSG by the Chief Scientist of NSW.[8] Other submissions[9] addressed reports of adverse health outcomes associated with conventional and unconventional gas extraction (including from CSG reserves) in the US and Queensland. Some of these submissions and reports are discussed in more detail in Sections 10.3.3.1 and 10.3.3.2.

While comments and submissions made after release of the Draft Final Report in December 2017 were largely positive or neutral in relation to the Inquiry's assessment of public health risks, there were some exceptions. These included further criticism of:

- insufficient weight given to reports from the US and south-east Queensland;[10]
- insufficient weight given to psycho-social factors affecting individual or public health;[11]
- inappropriate weight given to the use of Human Health Risk Assessment (**HHRA**) reports commissioned by the gas industry to address concerns about public health impacts; and[12]
- insufficient weight given to the impacts of climate change on public health.[13]

The Panel's response to these criticisms is found in additional discussion in this chapter.

In terms of the risk assessment methodology outlined in Section 4.5 in Chapter 4, the environmental value addressed in this Chapter is the avoidance of adverse public health impacts associated with the hydraulic fracturing processes. The environmental objective is the

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1 Costa et al. 2017.
2 Bamberger and Oswald 2013; Stern et al. 2014; Barcelo 2016.
3 For example, Carpenter 2016; Finkel 2015; Hays 2016; Meng 2017.
4 Zucker 2014; Physicians for Social Responsibility 2016.
5 Kibble et al. 2014; Prpich et al. 2016; Watterson and Dinan 2016; Saunders et al. 2016; UK Task Force on Shale Gas 2015.
6 Haswell 2017.
7 WA Department of Health; WA Report.
8 Dr Wayne Somerville, submission 1170 (**W Somerville submission 1170**).
9 For example, Doctors for the Environment Australia, submission 96 (**Doctors for the Environment submission 96**); Doctors for the Environment Australia, submission 477 (**Doctors for the Environment submission 477**); Public Health Association of Australia, submission 107 (**PHAA submission 107**); Prof Madelon Finkel, submission 94 (**M Finkel submission 94**); Ms Pauline Cass, submission 33 (**P Cass submission 33**); Ms Pauline Cass, submission 192 (**P Cass submission 192**); Ms Pauline Cass, submission 463 (**P Cass submission 463**); Dr Geralyn McCarron, submission 53 (**G McCarron submission 53**); Dr Geralyn McCarron, submission 501 (**G McCarron submission 501**); Dr Geralyn McCarron submission 508 (**G McCarron submission 508**); K Marchment submission 438; Ms Helen Bender, submission 144 (**H Bender submission 144**).
10 For example, Health Professionals Against Fracking, submission 1179; Ms Helen Bender, submission 632 (**H Bender submission 632**); NT Greens, submission 1209.
11 For example, H Bender submission 632; issues raised at Darwin Hearings and community forum 6 and 10 February 2018.
12 Health Professionals Against Fracking, submission 1179.
13 For example, Doctors for the Environment, submission 1180.

identification and mitigation of specifically identified risks in order to maintain good health in potentially affected communities.

The key issues addressed here are whether any of the potential public health impacts identified can be attributed to specific causal factors in the environment resulting from activities associated with hydraulic fracturing to recover gas from deep shale deposits in the NT. The Panel notes that much of the information on health risks to the general public derives from studies and formal health risk assessments undertaken primarily in the US or in relation to the CSG industry in Queensland and NSW.

Many of the Panel's recommendations relating to protection of water quality (Chapter 7), protection of the land (Chapter 8), prevention of fugitive gas emissions (Chapter 9), avoidance of social impacts (Chapter 12) and strengthening of regulatory measures (Chapter 14) are also relevant to the protection of public health and are not repeated here.

10.1.1 Human health risk assessment and public health impacts

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, in a small group such as an individual family, or in a small community.

An important conventional tool for assessing public health impacts from environmental sources or activities is to conduct a formal HHRA. The methodologies for conducting an HHRA are well established. The 2012 enHealth[14] (the National Environmental Health Standing Committee) guidance normally takes precedence in the Australian context, but the Panel notes that HHRA guidance specific to processes associated with extraction of CSG have been developed by the Australian Government Department of the Environment and Energy[15] (discussed further in Sections 4.6.1, 7.4.2.3 and 10.1.1.4). This CSG guidance has been developed to be consistent with enHealth methodologies.

The two critical elements of an HHRA that must be present in order to aggregate and characterise the risks (the term 'risk characterisation' is used in enHealth guidance to describe this final component of an HHRA) are described below. They are, first, identification of and knowledge about the chemicals of concern, and second, identification of the potential exposure pathways.

10.1.1.1 Hazard risk assessment

Hazard risk assessment requires identification of 'chemicals of concern' (see Section 10.1.1.3) and knowledge of their intrinsic toxicity (toxicological profile). 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 having been 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

14 enHealth 2012.
15 Australian Department of the Environment and Energy 2017a.

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 exposure is 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.

10.1.1.2 Exposure assessment

A key element of the HHRA process is to identify and quantitate all of the potential exposure pathways by which chemicals could reach members of the general public. Exposure pathways relevant to this Inquiry include:

- the ingestion of contaminated drinking water or food;
- the breathing in airborne gases, vapours or dusts; and
- the direct skin contact with soil or other contaminated media, such as water.

In this context, it is conventional to construct a Conceptual Site Model (**CSM**) detailing all such potential pathways from a contaminated site to individuals or collectives of humans around that source (termed 'receptors' in the terminology of HHRA). Such a CSM is described graphically in **Figure 10.1** (Section 10.1.1.4 below). The CSM should include an assessment of how likely those exposure pathways are to be 'complete', that is, exposure has actually occurred, as opposed to a theoretical possibility. The Panel has been critical of the industry-generated HHRA reports (see Sections 7.4.2 and 10.1.1.4) that have generally failed to include risk estimates associated with exposure pathways they have assessed to be 'incomplete' based on an assumption that process controls and risk mitigation mechanisms are fully effective.

The exposure pathways that can result in broad community exposure are likely to be quite different to those by which onsite workers (occupational exposure) might occur. The magnitude of such exposure, 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 over the longer term, 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 NT. Managing the risks associated with on-site occupational exposures are considered to be industry responsibilities, and beyond the scope of this Inquiry. The Panel notes that the WA Health HHRA,[16] and the HHRA for the Amungee drilling program prepared for Origin by consultants AECOM[17] (detailed in Section 10.1.1.4 below), also excluded on-site workers, while the HHRA prepared by consultants EHS Support Pty Ltd[18] for the Santos Gladstone Liquified Natural Gas (**GLNG**) project in the Bowen and Surat basins in south central Queensland addressed only some on-site health risks for workers.

10.1.1.3 Sources of chemicals of concern

The chemicals of concern (**CoC**) in an HHRA associated with extraction of gas from shale are likely to be those added to the hydraulic fracturing fluid (**HFF**), as well as those extracted from the shale deposits and brought back to the surface in flowback and produced water. The need to identify these chemicals and to match them with information that could inform their potential health effects was recognised as early as 2014 in reviews[19] of the toxicology of chemicals used in HFF (see also the discussion in Chapters 5 and 7).

The information on the chemical composition of HFF and flowback water is now generally much more extensive than it was only two to three years ago. Industry submissions indicate that, while the specific composition of HFF may depend on the technical requirements of the specific site, the common elements (proppant, pH adjusters, biocides, corrosions and scale inhibitors, and foaming/de-foaming agents (see Table 1 Pichtel[20] and Section 5.7.2 and 7.6) are now generally well identified. An example of the disclosure of HFF chemicals is seen in **Table 7.7**, the list

16 WA Department of Health 2015.
17 Origin 2017.
18 Santos 2016b.
19 Goldstein et al. 2014; Wattenberg et al. 2015.
20 Pichtel 2016.

of chemicals used to stimulate the Beetaloo Project Hydraulic Fracturing Risk Assessment Amungee NW-1H.

A component of the NCRA[21] for CSG prepared by the Australian Government Department of Environment and Energy includes information identifying chemicals used in HFF in Australia and their toxicological profiles. Of the 113 chemicals used in for the extraction of CSG in Australia at the time of the assessment (2012), the NCRA reports[22] differentiated between 44 chemicals whose toxicological profiles were sufficiently low to be of no real concern for human health, and did not therefore require any further assessment. They summarised the available toxicological information on the remaining 69 chemicals that could be hazardous to human health. The Panel notes that the suite of chemicals used in HFF is likely to have been refined since 2012, and that more contemporary information on chemicals actually used in current HFF require disclosure to the regulator in the NT.

Chemicals extracted from shale and brought back to the surface in flowback and produced water (Section 5.7.3) are potentially of greater concern to human health. These can include inorganics (for example, heavy metals) and organics, such as aromatic hydrocarbons (for example, BTEX), other hydrocarbons, and naturally occurring radioactive material (**NORM**). These 'geogenic' chemicals were not included in the NCRA reports, or in the risk assessments undertaken by Santos for its GLNG project.[23]

Other CoC might 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.

10.1.1.4 Examples of formal HHRA reports

Five formal HHRA reports describing the risks associated with unconventional gas extraction in Australia were available to the Panel. Only one of these related to hydraulic fracturing for shale gas in the NT,[24] with another addressing water-related risks associated with shale gas extraction in WA.[25] The third addressed water and airborne chemical risks associated with gas extraction from coal seam deposits in Queensland,[26] the fourth was a health impact assessment for the CSG project around Narrabri, NSW,[27] and the fifth was a formal HHRA of BTEX in flowback water from wells in the Gloucester Basin in NSW.[28] All five reports provide useful information supporting the risk assessments undertaken by the Panel in this Report, and they are consistent with the Panel's consequence and risk assessment of 'low'. However, all five HHRA reports suffer from some significant limitations, principally that the Origin and Santos HHRA reports omitted potentially important exposure pathways on the grounds that they are likely to be incomplete due to operational controls. These, and other elements of the HHRA reports, are discussed below.

Origin

Origin commissioned consultants AECOM Australia to undertake an HHRA of its exploration program at the Amungee well in the Beetaloo Sub-basin.[29] As part of its identification of CoC, this report quantitated the concentrations and toxicological characteristics of chemicals used in HFF at the site, as well as some chemicals recovered in flowback water. Relevant drinking water guidelines and other health-based guidelines against which exposure could be compared in the risk characterisation phase were determined. A suite of exposure pathways were considered as part of the development of a CSM, including water-borne, airborne and direct ingestion or skin deposition pathways, along with the potential location(s) of human receptors likely to be exposed via these pathways.

The most lacking feature of this HHRA was that all but one of the potential exposure pathways (deliberate entry by trespassers into storage ponds) was considered by the consultants to be incomplete, based on OHS and operational procedures designed to limit exposures, and therefore, were not included in the risk estimates.

21 Australian Department of the Environment and Energy 2017a.
22 Australian Department of the Environment and Energy 2017a.
23 Santos 2016a.
24 Origin 2017.
25 WA Department of Health 2015.
26 Santos 2016a.
27 Santos 2016b.
28 EnRiskS 2015.
29 Origin 2017.

Santos

Santos commissioned consultants EHS Support Pty Ltd to undertake an HHRA of its gasfield developments in the Surat and Bowen Basins in south-west Queensland.[30] The HHRA report was peer-reviewed by an independent consultant (Environmental Risk Sciences, or **EnRiskS**). While the report relates to gas recovery from CSG sources, it does contain information on CoC from drilling fluids, including HFF, flowback water, and on-site water treatment processes. The report included relevant drinking water guidelines and other health-based guidelines against which exposure could be compared in the risk characterisation phase.

The conceptual exposure model (**CEM**) (analogous to a CSM) used was comprehensive for water and soil, but it did not address airborne contaminants because of the suggested low volatility of the identified CoCs. The model explored potential exposure pathways through transport, onsite storage and the use of drilling chemicals, with different classes of human and ecological receptors (for example, transport workers, accident first responders, landholders, agricultural workers, trespassers, livestock, aquatic and terrestrial fauna, and users of surface and groundwater resources) exposed under the different stages of the process (transport, spills, drilling and gas production).

However, similar to the Origin HHRA discussed above, not all of the potential exposure pathways were deemed to be complete and, therefore, included in the quantitative HHRA. In particular, exposures of human and ecological receptors resulting from accidental spills during transport and drilling fluid preparation, accidental releases of stored water (including geogenic chemicals in produced water) and the use of treated produced water for irrigation were the main pathways considered. Pathways leading to contamination of surface water and impacts on drinking water quality were deemed incomplete.

Santos also commissioned a health impact assessment (**HIA**)[31] and chemicals risk assessment for its CSG development in Narrabri, NSW.[32] The HIA was a desktop assessment prepared by EnRiskS, while the chemicals risk assessment was conducted by EHS Support Pty Ltd. The EnRiskS HIA represents a more limited assessment of public health risks associated with potential impacts on water, soil and air quality, as well as potential impacts of noise, fire and explosion hazards, and social and community wellbeing. The assessment was reasonably thorough, drawing on a range of associated technical reports on air and water quality, and social impact studies. However, it noted that the assessment relates to a project primarily in the development phase. The EnRiskS report relied on exposure information developed by other consultants addressing water quality, as well as the potential for surface and groundwater contamination. The assessments of health risks associated with airborne dusts associated with construction activities and airborne dispersion of gases and VOCs from the gas processing and power generating facilities were informed by air dispersion modelling. The modelling predicted that no health-based air quality guidelines would be exceeded. The assessment of water-borne chemical risks addressed interconnections with groundwater sources and surface spills for both HFF and produced water, with predictions that pathways would be either incomplete, or would result in exposure concentrations below health-based guideline value.

The chemicals risk assessment report for the Narrabri project had the same overall structure as the HHRA for the Gladstone project described above, and used the same methodologies. It specifically addressed CoC from drilling fluids, including HFF, flowback water and on-site water treatment processes. However, the conceptual exposure model for this project was more comprehensive, and extended coverage from that used in the Gladstone report to include the reuse of treated water for irrigation and dust suppression. Like the Gladstone HHRA, pathways involving contamination of groundwater and surface waters were found to be incomplete for all of the human receptors under consideration. Moreover, no off-site airborne pathways were considered.

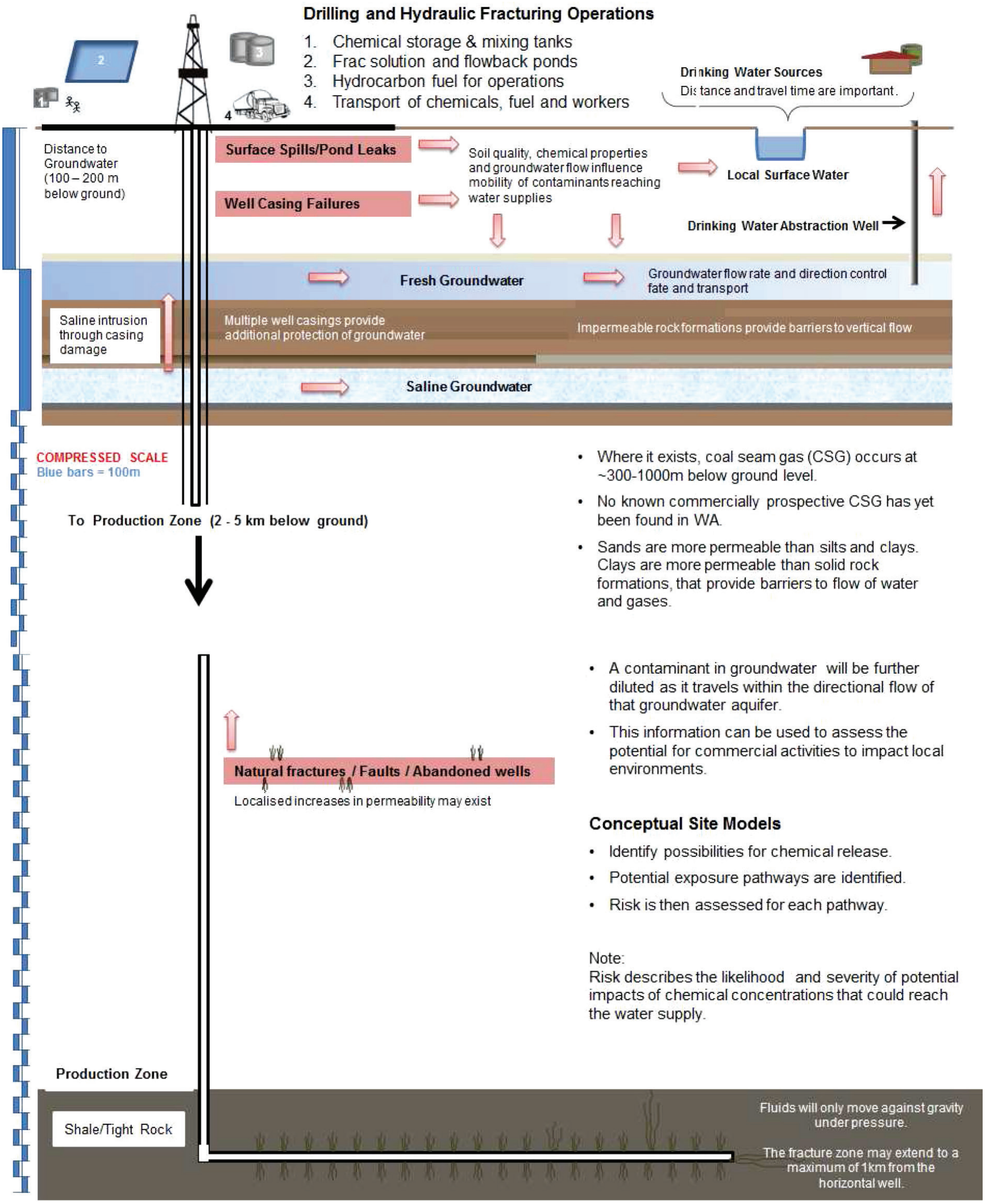
The overall conclusion from both the HIA and chemicals risk assessment was that the health risks to surrounding communities were low and manageable. However, the HIA acknowledged that this was dependent on effective implementation of the process controls and environmental management measures outlined in the environmental impact statement.

30 Santos 2016a.
31 The difference between an HIA and an HHRA is explained in enHealth 2012. In essence, an HHRA is a process that aims to identify and quantify health risks associated with a specific exposure scenario. An HIA is a broader systematic process by which a policy, program or project may be judged as to the effects it may have on the health of a population. An HIA assesses actual, potential, direct and indirect effects, as well as potential benefits and is usually undertaken at an early stage of a project so that a risk manager has options to avoid negative impacts on health, and to promote more positive health benefits.
32 Santos 2016b.

WA Department of Health

The HHRA report from the WA Department of Health specifically addressed the potential for groundwater contamination with the chemicals employed, or generated, in hydraulic fracturing processes used to extract gas from shale or other tight deposits. In common with the NT, WA relies on a significant proportion of its drinking water by extraction from groundwater aquifers. The CSM utilised in the WA HHRA is shown in **Figure 10.1**.[33] It depicts all of the potential exposure pathways noted in the introduction to this Chapter and discussed in Chapters 5 and 7.

Figure 10.1: Conceptual Site Model. Potential pathways for hydraulic fracturing chemicals to have an impact upon drinking water supplies. Source: WA Department of Health.[34]



33 WA Department of Health 2015, Figure 8, p 29.
34 WA Department of Health 2015.

The WA Health 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 well head to the drinking water source are key parameters influencing such an assessment.

The approach taken in the risk characterisation component of the HHRA merely compared the concentrations of chemicals reported in US flowback water with relevant health-based guideline values (for example, the Australian Drinking Water Guideline values[35]), of which there were very few indicators for the chemicals in hydraulic fracturing fluids or any other available benchmarks. This represented a 'worst case' analysis because actual exposures by drinking would not be at overly high concentrations due to the dilution effects occurring over the distance between the source of the chemicals and where the water was extracted for drinking (see Section 7.6).

The overall conclusions of the WA Health HHRA were 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 groundwater 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."*[36]

AGL Upstream Investment report

AGL Upstream Investment commissioned EnRiskS to assess the human and environmental health risks associated with BTEX in flowback water from wells WK12 and WK13 in the Gloucester Basin of the Waukivory CSG project in NSW. The report specifically addressed the potential for BTEX vapours from the holding tank to have an impact on nearby residential areas, with the closest residences located 490 m, 570 m and 600 m from the tank. The assessed risks only covered airborne transfer from the holding tank, and not leaks or spills to surface of groundwater, on the basis that there had been no reported spills at this site. Exposures were modelled based on measured BTEX concentrations in tank water, the surface area available for evaporation, and conventional air dispersion models to estimate the maximum 1 h BTEX concentrations that site workers and nearby residents might experience. The estimated workplace exposures were generally five times higher than those at the nearby residences. In all cases, the maximum predicted 1 h and annual average exposures were at least two orders of magnitude lower than relevant health-based guideline values, with benzene exposure the more critical of the estimates.

NCRA reports

Another significant document outlining an agreed Australian approach to risk assessment for CSG sites is the series of NCRA reports submitted to the Inquiry by the Australian Government Department of Environment and Energy.[37] A more detailed discussion of these reports is included in Sections 4.6.1 and 7.4.2.3. The reports include information on potential exposure pathways, proposed best-practice methodologies for carrying out a formal, site-specific HHRA, and a series of data sheets on 69 drilling and HFF chemicals where such HHRA were prepared.[38] The Panel notes that the risk assessments addressed health risks to both on-site workers, where there is a potential for higher exposures, and to the general public, when exposed through off-site contamination of water used for drinking or recreation. While geogenic contaminants of flowback water were identified in one of the reports,[39] they were not included in the formal risk assessments outlined above.

35 NHMRC 2016.
36 WA Department of Health 2015, p 1.
37 Australian Department of the Environment and Energy 2017a.
38 Australian Department of the Environment and Energy 2017a; Australian Department of the Environment and Energy 2017c.
39 Australian Department of the Environment and Energy 2017a; Australian Department of the Environment and Energy 2017d.

The recommended NCRA approach is in contrast to that outlined in the Origin - and Santos - commissioned HHRA reports described above, where off-site water pathways were considered to be incomplete, and therefore, were not included in the risk estimates. The generic guidance[40] on HHRA for CSG sites does recommend that a more comprehensive range of potential exposure pathways be considered, including off-site transport through surface and subsurface waterways, as well as airborne transfers by dusts, vapours, or gases.

In a comprehensive review of the risk assessment methodologies used by the gas industry in the US, the challenges associated with making meaningful estimates of probabilities for barrier failures, spill, leaks, and the associated volumes and exposure pathways were acknowledged.[41] The uncertainties inherent in determining data inputs for formal risk assessments for shale gas extraction, particularly at the early stages of the project, were also highlighted in a review that proposed a weighted qualitative assessment model covering technological and environmental sources of risk.[42]

The Panel therefore acknowledges the difficulties in including the off-site and early-stage exposure pathways that have been considered incomplete in industry-sponsored HHRA reports, but emphasises the importance of addressing the potential health impacts of such pathways in the unlikely event of the failure of process control measures designed to prevent such incidents.

10.2 Key risks

The issue of water security of aquifers essential in the NT for drinking water and for support of horticultural, agricultural and pastoral activities was consistently raised in public consultations and submissions as the primary area of concern (see Chapter 7). Protection of ground and surface waters from contamination associated with hydraulic fracturing and gas extraction activities is essential. The impact of unknown interactions and interlinkages between aquifers was also raised. The view consistently expressed in public consultations and submissions was that any contamination of an aquifer would be unacceptable and that it would result in 'poisoning' of the environment and people. There was also scepticism that flowback and produced water could be effectively collected and treated, or transported safely to other locations.

A more balanced view is that aquifer contamination would only be likely to become a real issue to public health or horticultural, agricultural, pastoral, and cultural activities if the amount of contamination is high enough to result in adverse health effects to people or fauna consuming the water, or if the level of contamination is such that it compromises organic farming certification of an affected landholding.[43] These issues are addressed below and are also discussed in detail in Chapter 7, along with the Panel's assessment of the level of several risks relating to water quality.

There was a common concern that the injection of large quantities of unknown chemicals into the ground would be an inevitable outcome of hydraulic fracturing, 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 that this water could then be treated to remove the chemical residues, including the chemicals leached from the shale (for example, BTEX, metals, minerals, and NORM).

The Panel's initial assessment in its Interim Report, confirmed in this Final Report, is that any evaluation of human health risks associated with contamination of drinking water resources can only be meaningful if it is carried out on a site-specific basis. This requirement for a site-specific HHRA, identifying the sources, exposure pathways and location of human receptors (as outlined in Section 10.1.1.2) is a crucial element of any HIA. It has been acknowledged in the submissions from Origin[44] and in the NCRA reports.[45]

40 Australian Department of the Environment and Energy 2017c; Australian Department of the Environment and Energy 2017f.
41 Torres et al. 2016.
42 Veiguela et al. 2016.
43 Barkly Landcare, Submission 241.
44 Origin submission 153, pp 123-125.
45 Australian Department of the Environment and Energy 2017c.

The importance of site-specific factors in evaluating risks to groundwater resources has also been well documented in the recent US EPA Report on the 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."* [46]

The Panel reaffirms its view that a site or region-specific HHRA should be part of the HIA for any onshore shale gas project seeking approval in the NT. Such a site or region-specific HHRA should cover operations at the exploration and production stages and also consider any health risks associated with decommissioned wells.

Recommendation 10.1

That formal site or regional-specific HHRA reports be prepared and approved by the regulator prior to the grant of any production approvals. Such HHRA reports must address the potential human exposures and health risks associated with the exploration for, and the production of, any shale gas development, off-site transport, and the decommissioning of wells, as recommended in NCRA guidance. The HHRA reports must include risk estimate assessments for exposure pathways that are deemed to be incomplete.

Among the concerns raised in some public submissions was whether knowledge of the toxicological profile of many of the chemicals used in HFF is incomplete (see Chapter 5 and the comment above). However, there may have been misconceptions on this matter 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."* [47]

The Panel notes that where adequate toxicological information is available, the majority of HFF chemicals that are used routinely appear to have low toxicity.[48] 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 potential health risk to industry workers. In the case of the low concentrations that are present in HFF or in flowback water, there would need to be continuous exposure to these lower concentrations over a much longer period to constitute a chronic health risk.

Industry submissions emphasised the technological developments that have occurred in the hydraulic fracturing industry in recent years, and confirm that the disclosure of chemicals used in HFF is now more common, including in Queensland and the NT, where it is mandatory. In the NT, specific information regarding the chemicals used in HFF must be released to DPIR and the general public. However, there is no requirement to report the composition of flowback water, noting that this is also the case for the FracFocus database in the US.[49] The Panel is of the opinion that this information should be publicly available. The Panel therefore recommends requiring the collection of information on the chemical composition of flowback and produced water from unconventional gas wells in the NT (see ***Recommendation 7.10***) and on the management and treatment of these waters (***Recommendation 5.5***).

A consistent theme in many of the public submissions and community forum comments was that it is crucial that adequate baseline data on public and environmental health be collected ahead

46 US EPA 2016a, p ES42.
47 WA Report, p 103.
48 Stringfellow et al. 2017; Elsner and Hoelzer 2016; Department of Environment and Energy 2017a.
49 FracFocus chemical disclosure registry; available at https://fracfocus.org/.

of any onshore shale gas development so that the future impacts of any industry can be reliably assessed. This point has also been raised in some published papers.[50] It is also an important element for informing claims for compensation for environmental damage by the holders of land upon which the activity takes place. The Panel has confirmed the importance of having a completed bioregional study of baseline health and environmental data before any onshore shale gas production occurs in the NT (see Chapters 15 and 16 and ***Recommendation 7.4*** in Chapter 7).

Other public health issues raised in submissions and during consultations relate to impacts associated with noise, trauma associated with increased road traffic, and impacts on social amenity, wellbeing and mental health. These risks are more difficult to quantitate, but to the extent possible, they are addressed in Sections 10.3.4 and 10.3.5, and Chapters 8 and 12 below.

10.3 Assessment of risks

The framework for systematically assessing the potential risks, mitigation measures and the resultant residual risk is outlined in Chapter 4. As stated in that Chapter, this framework essentially involves three steps: first, determining the resultant risk by using the 'likelihood' and the 'consequence' if the particular risk or threat occurs; second, defining possible mitigation measures to reduce the risk further if required; and finally, assessing the remaining, or residual, risk if these mitigation measures are applied.

A link between shale gas extraction activities and a number of adverse health effects has been raised in several submissions to the Panel, as well as being addressed in some published papers. The nature of the evidence and its relevance to any onshore shale gas development in the NT is crucial. In some cases, the Panel notes that the allegations are related to health effects associated with CSG extraction in Queensland.[51] Due to some crucial differences between the processes for extracting gas from shale and coal seams (as described in the Issues Paper and see also Chapter 5), in particular, that hydraulic fracturing has, until recently, been infrequently required in Queensland for CSG extraction, some of the alleged health risks associated with CSG extraction may not be directly relevant to gas extraction from onshore shale deposits using hydraulic fracturing. The health risks from Queensland that are more likely to be relevant to the NT are those associated with:

- contamination of groundwater and surface water from geogenic chemicals (Chapter 7);
- airborne gases and VOCs (addressed in Section 10.3.3); and
- socio-economic factors outlined in Chapter 12.

Although the NT environment and social structure has both similarities to, and notable differences from, those in Canada, the Panel observes that its overall assessment of the risks associated with hydraulic fracturing of shale for gas extraction are consistent with those reached by two expert panels reporting to the Nova Scotia Department of Health[52] and the Council of Canadian Academies.[53]

10.3.1 Assessment of risks related to contamination of water

The Panel's assessment of the water-related risks of shale gas development is discussed in detail in Chapter 7. Whether the source of human exposure is through contamination of surface waters or aquifers through any of the pathways described above, the overall risk estimates have generally fallen into the 'low' category for 'likelihood', with some of the estimates of 'consequence' falling into the 'low' to 'medium' categories. In some cases, the Panel has been unable to make a definitive assessment of the risks due to a lack of data, background information or understanding of the particular system.

These risk assessments are consistent with predicted risks from HHRA reports discussed above in Section 10.1.1.4. In the specific context of impacts on public health, the Panel's assessment of consequence is also in the 'low' to 'medium' category, except for geogenic chemicals, where a lack of specific information on potential flowback water concentrations at this time make the risk estimate 'unknown'. The Panel's risk estimates stand in contrast to the opinion expressed in many of the public hearings and submissions, that an outcome was that drinking water would be 'poisoned'.

50 For example, Schmidt 2011; Korfmacher and Elam 2014; Steinzor et al. 2013.
51 For example, Ms Katherine Marchment, submission 259 (**K Marchment submission 259**).
52 Wheeler et al. 2014.
53 Council of Canadian Academies 2014.

The limited available evidence does show that, even for flowback water, the water concentrations of many of the HFF and geogenic chemical constituents could be lower than the conservatively set health-based guideline values (for example, the Australian drinking water and recycled water guidelines,[54] or other similar toxicity reference values). Where the concentrations do exceed guideline values, or where there are no relevant health-based guideline values, human health may still not be significantly affected where dilution and attenuation occur between the emission source and the site where human ingestion can take place, or where a credible exposure pathway does not exist (see Section 10.1.1.2). A further factor is that conservatively set guidelines generally assume that ingestion occurs consistently over a lifetime, whereas exposure scenarios associated with surface or groundwater contamination, should it occur, would be of a shorter duration.

The six most likely pathways (see also Chapter 7) by which aquifers may 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 either during drilling, gas production, or after well decommissioning;
- reinjection of treated or untreated wastewater into aquifers where there is possible connectivity between aquifers;
- leakage of onsite storage of HFF chemicals, pooled flowback water, or a rain event leading to the overflow of storage ponds;
- 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 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, which are typically much closer to the surface. The latter issue of low probability of contamination by virtue of large separation is supported by the conclusions from the published literature (see Chapter 7 for more detail).

Some of the CoC reported in flowback and produced water may be more of a health concern than those initially added to the HFF. In particular, BTEX,[55] and other VOCs extracted from hydrocarbon deposits in the shale can reach concentrations that would exceed health-based water quality guideline values. However, a number of risk-mitigating factors, including dilution, adsorption on the rock matrix, delay in moving further along the aquifer and microbiological breakdown processes, all contribute to reducing the concentrations of these chemicals in an aquifer to a level that would not be of concern for exposure through ingestion.

The Panel's recommendations to mitigate the potential risks of contaminating a beneficial aquifer are addressed in more detail in Chapter 7 (see ***Recommendations 7.9, 7.11 and 7.16***).

In relation to the potential for contamination of surface waters, an analysis of incidents of surface water contamination associated with recorded spills and well failures in the US suggest a higher level of likelihood and risk and consequently, a greater need for effective risk management.[56] See ***Recommendations 7.12, 7.14*** and ***7.17***, which address mitigation of the potential risks of surface water contamination.

However, the Panel recognises the need for site-specific HHRA to better inform the management of risks associated with groundwater and surface water contamination.

The Panel acknowledges that there is generally insufficient definitive data on the presence and concentrations of NORM in flowback and produced water, although preliminary data in flowback water from the Amungee well indicates that the levels are at the low end compared with experience from US and international wells (see Section 7.6 for more detail). The presence

54 NHMRC 2016; NRMMC 2008.
55 Gross et al. 2013.
56 Mrdjen and Lee 2016.

of NORM in flowback water was also incorporated into the AECOM HHRA discussed in Section 10.1.1.4, although it was acknowledged that further testing would be needed to refine the risk assessment.

While there are some US reports that suggest discharge of radionuclides to local streams can result in significantly increased levels in stream sediments relative to background[57], there are also estimates that the efflux of this amount of NORM would be a somewhat rare event. Another report has suggested that such discharges to natural groundwaters in the UK could be less than those associated with other power-generating sources and that they would be unlikely to exceed the 1 mSv annual allowance for radioactivity exposure in the UK[58] or the 1.5 mSv annual background level for Australia.[59]

Accordingly, the Panel has concluded that the level of risk to public health from NORM, while difficult to determine in advance of any onshore shale gas development, would need to be considered on a site-specific basis. The likelihood of exposures, the level of consequence to human health, and the overall level of risk will be subject to the same constraints and respond to the same mitigation factors that apply to other geogenic chemicals from such sources.

10.3.2 Assessment of risks relating to contamination of food

During many of the community forums, concerns were raised about the potential for HFF and geogenic chemicals to contaminate local food sources (such as beef and fish), especially Aboriginal 'bush tucker'. There is relatively little published information about the potential for farm animals and crops to be contaminated by onshore shale gas recovery activities, and much of what has been published is based on conjecture or case studies of health impacts on farm animals.[60]

The Panel has noted the difficulty of estimating the risks of contamination through the food chain. This difficulty has also been acknowledged in the NCRA report[61] on HHRA for CSG-related chemicals, where the following was said:

> *"Exposure to these chemicals is also possible through the consumption of foods such as meat, milk, vegetables and cereals contaminated via uptake of contaminated water and/or direct airborne deposition of chemical particulates. However, currently no data are available on levels of chemical residues in food which could be linked to contamination by drilling and hydraulic fracturing operations. Therefore, because of the difficulty in establishing likely levels of contamination of foods linked to these operations, public exposure to drilling and hydraulic fracturing chemicals via food is not quantified in the current assessment".*

The Panel has assessed the risks of food contamination as 'low', although this will need to be confirmed by relevant site-specific HHRA. The initial assessment is based on an expected 'low' likelihood of contamination of nearby surface waters (see Chapter 7) and a 'low-medium' consequence, depending on whether the specific HFF chemicals, or those released from flowback or produced water, or in airborne plumes, would not be bioaccumulative, be degraded in the environment over time, or be subjected to metabolism in plant and/or animal tissues with a resultant reduction in toxicity. It is acknowledged that NORM and heavy metals of geogenic origin in flowback water are less likely to be detoxified by metabolism, although it is possible that they will be sequestered in tissues (for example, liver and kidney) or plant components less likely to be used in the conventional food chain.

57 For example, Warner et al. 2013.
58 Almond et al. 2014.
59 ARPANSA 2015.
60 Bamberger and Oswald 2012; Bamberger and Oswald 2015; Haswell and Bethmont 2016; Catskill Mountainkeeper.
61 Australian Department of the Environment and Energy 2017f.

10.3.3 Assessment of risks relating to airborne contaminants

The potential health risks associated with airborne chemicals from shale gas developments have been summarised in Goldstein et al.[62]

Table 10.1: Potential health effects of air pollutants associated with shale gas development.

Airborne pollutant	Potential health effects
Methane	Explosion and fire; asphyxiation in confined space; impact on global climate change.
VOCs (including BTEX)	Ozone precursors; haematological toxicity (including leukaemia - mainly from benzene); upper respiratory tract inflammation; central nervous system effects (mainly in confined spaces).
Oxides of nitrogen (NOx)	Ozone precursors; asthma and other acute respiratory irritancy effects.
Ozone and other photochemical oxidants	Asthma and other acute respiratory irritancy effects; effects on lung function; premature death.
Particulates (including diesel exhaust fumes)	Asthma and other acute respiratory irritancy effects; chronic respiratory diseases; premature death; cancer.
Silica dust	Silicosis and other chronic lung diseases (particularly among workers exposed onsite).

The epidemiological evidence relating to the public health impacts of many of these airborne pollutants is mixed (see further **Table 10.2**).

The Panel's assessment of the risks of shale gas development relating to airborne chemicals generally falls into the 'low' to 'medium' category for likelihood, and the 'low' to 'medium' category for consequence. In accordance with **Tables 4.2** and **4.3** and **Figure 4.1**, the overall risk category is 'low' to 'medium', with risk mitigation actions such as the clear identification of potential exposure pathways, and the establishment of buffer zones or setbacks likely to reduce the residual risk to 'low'.

Exposure pathways most likely to lead to potential impacts on public health would involve emissions of VOCs and NORMs from flowback water, whether through volatilisation from unenclosed on-site storage ponds, emissions of extracted gas (mainly methane), or the combustion products from 'gas flaring'. Other airborne emissions include diesel and petrol exhaust fumes from trucks and drilling equipment. The potential impacts of windborne particulates (dusts) from well heads and other land clearing sites are considered below in Section 10.3.3.1.

Methane is a non-toxic gas.[63] It is unlikely to pose a direct health risk at concentrations associated with fugitive emissions from leaking shale gas production fields or abandoned wells (see Section 7.6.1.1), pipelines or processing facilities. The Panel's assessment is that, while there is a relatively 'medium' to 'high' likelihood of there being fugitive methane emissions around gas wells and processing facilities, the consequence of such emissions directly affecting public health can be categorised as 'low' because of the intrinsically negligible toxicity of methane.

A more significant risk to public health may, however, occur if methane concentrations reach levels high enough to pose a flammability or explosion risk. Methane concentration in water cannot exceed its saturation concentration (28 mg/L at atmospheric pressure) and becomes flammable in air at around 5% by volume.[64] The likelihood of such a risk is discussed in more detail in Chapter 7 (Section 7.6.1.1), with US recommendations that methane concentrations in water between 10 and 28 mg/L or 3-5% by volume in air represent levels that should be monitored in order to reduce the flammability or explosion risk.

Submissions to the Panel emphasised the risks associated with methane emissions and the contribution of burning natural gas for power generation on global climate change, especially the significant impact of climate change on public health. Risks associated with greenhouse gas impacts on climate change are discussed in detail in Chapter 9 (Sections 9.1.4 and 9.9), including identifying some impacts of climate change on human health. The Panel did not attempt to categorise the specific risks to public health in the NT, because implementation of ***Recommendation 9.8*** should seek to ensure that there is no net increase in the lifecycle GHG emissions emitted in Australia from any shale gas produced in the NT.

62 Goldstein et al. 2014, Table 2, p 277.
63 US EPA 2016a, pp 9-47.
64 Eltschlager et al. 2001.

In common with the public health impacts of water-borne chemicals, the health risks associated with airborne contaminants depend on there being credible exposure pathways to nearby human receptors that can deliver chemicals at concentrations sufficiently high to have immediate or delayed adverse health effects. The Panel notes that distance from the emission site is likely to be a critical factor, not only in regard to the likelihood of exposure pathways being 'completed', but also the extent of concentration dilution that could occur as the emissions move away from the source.

The assessment of airborne risks is substantially informed by the published literature on experience with unconventional gas extraction overseas (mainly in the US) and from more recent Australian experience with CSG in Queensland and NSW. However, the Panel reiterates its view that the exposure scenarios described in the examples below (in Sections 10.3.3.1 and 10.3.3.2) are unlikely to be closely representative of any onshore shale gas extraction activities in the NT, because of the much closer proximity and higher density of habitation to the gasfields in the US and Queensland compared to any shale gas developments in the NT.

10.3.3.1 International health impacts in respect of unconventional gas extraction

A number of published papers have addressed the potential public health impacts of VOCs and other airborne chemicals in dusts that may travel off-site. Much of the evidence linking airborne emissions with adverse human health effects is based on surveys and reviews of health effects relating to unconventional gas extraction from shale gasfields in the US, particularly around Pennsylvania, Texas and Colorado.

There is strong evidence that proximity to unconventional gas activities is a crucial factor,[65] 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 those of closer residents (see below for more detail).[66] This is not surprising because airborne, dust-borne, and water-borne contamination can be expected to undergo dispersion as it spreads away from the site of release, resulting in a lower potential for human exposure.

However, the Panel has concerns that the US findings will not have the same relevance to any proposed onshore shale gas development in the NT. The Panel notes that most of the areas with shale gas development potential in the NT are in relatively remote areas distant from established communities, while most of the unconventional gas 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.[67] Based on the study by McKenzie et al.,[68] described in more detail below, Webb et al.[69] have recommended a shale gas well setback distance of at least 1 mile (1.6 km) from occupied dwellings, including schools, hospitals and other sites where children and infants may spend a substantial amount of time. The current NT guidelines for permitting of such activities merely exclude close proximity to residential areas, and a range of defined land uses and are not, in any event, enforceable.[70]

This point is reinforced in a review by Watterson and Dinan of the UK experience with unconventional gas extraction in which they stated that, *"globally accurate estimates of the human populations exposed to UGE [unconventional gas extraction] chemicals, by-products, and contaminants do not yet exist."* [71]

The strength of the US evidence on the health effects of airborne contaminants is mixed. **Table 10.2**, adapted from a recent review of health studies around Colorado,[72] illustrates this point. While there has been some criticism of the citation of this review,[73] the Panel found it to be a useful summary by a competent US Public Health authority of the weight of evidence behind such adverse health effects.

65 Meng and Ashby, 2014; Meng 2015; Meng 2017.
66 McKenzie et al. 2012.
67 Rogers et al. 2015.
68 McKenzie et al. 2012.
69 Webb et al. 2016.
70 DPIR submission 226, Appendix H, pp 335-336.
71 Watterson and Dinan 2016, p 486.
72 McMullin et al. 2017, Table 2.
73 Health Professionals Against Fracking, submission 1179.

Table 10.2: Summary of overall strength of evidence for epidemiological studies by health effect. Source: McMullin et al.[74]

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 (low birth weight and mean)	Mixed
Birth defects	1	Congenital heart defects	Insufficient
		Oral clefts	Insufficient
		Neural tube defects	Insufficient
Respiratory (eye, nose and throat (ENT) and lung)	6	Multiple, self-reported symptoms	Mixed
		Hospitalisations	Failing to show an association
		Asthma exacerbations	Limited
Neurological (migraines, dizziness)	5	Hospitalisations	Mixed
		Multiple, self-reported	Insufficient
		Migraine/severe headache	Mixed
Cancer	4	Overall childhood cancer incidence	Insufficient
		Childhood haematological (blood) cancers	Mixed
		Childhood central nervous system tumours	Insufficient
		Hospitalisations	Mixed
Skin (irritation, rashes)	2	Multiple, self-reported	Limited
Psychological (depression, sleep disturbances	4	Multiple, self-reported	Failing to show an association
		Hospitalisations	Insufficient
Cardiovascular (heart)	2	Hospitalisations	Insufficient
		Multiple, self-reported	Insufficient
Gastrointestinal (nausea, stomach pain)	3	Hospitalisations	Insufficient
		Multiple, self-reported	Failing to show an association
Musculoskeletal (joint pain, muscle aches)	2	Hospitalisations	Insufficient
		Multiple, self-reported	Mixed
Blood/immune	2	Hospitalisations	Mixed

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

Werner et al.[75] have also commented that the strength of the epidemiological evidence of health impacts associated with unconventional gas extraction remains tenuous, with many studies of health outcomes lacking methodological rigour. However, they also note that while the evidence is somewhat weak and is focussed more on acute health effects, rather than chronic ones, it is not possible to rule out a relationship between hydraulic fracturing and adverse health impacts. They point out that there are clear gaps in the scientific knowledge that require urgent attention, especially with respect to adverse health effects that may have a long latency.

74 McMullin et al. 2017, Table 2.
75 Werner et al. 2015.

The point is further reinforced by another recent review, concluding that:

> *"though many epidemiological studies used robust statistical methods to estimate changes in health outcomes associated with unconventional oil and gas development, all had shortcomings that were most often significant. These studies furthermore reported contradictory results for each impact. Some studies, for example, found increases in preterm birth, while others found decreases or no association. As is illustrated by the Community Risk-Benefit Matrix, all impacts had inconsistent findings across the literature for that outcome. Where the results did not contradict each other, the impact was only analyzed by a single study… As a result, even where good evidence is offered for a link between unconventional oil and gas development and health, the causal factor(s) driving this association are unclear".* [76]

It is common for health impacts of unconventional gas extraction activities to be assessed by self-reporting questionnaires. For example, a questionnaire-based study of residents around unconventional gas extraction developments in Pennsylvania showed an apparent association of unconventional gas extraction with nasal and sinus symptoms, headache and symptoms of fatigue. While the overall response rate was low (only 7,785, or 33%, of 23,700 survey recipients) and only 23–25% of these respondents reported symptoms, the calculated odds ratios (**OR**) achieved statistical significance for some of the outcomes. These OR (95% Confidence Interval) 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.[77] Consistent with the hypothesis that distance is a significant factor influencing the dose-response relationship, the spatial distribution showed higher rates of response in areas closest to unconventional gas extraction activity.

McKenzie et al.[78] carried out a conventional HHRA for both cancer and non-cancer effects around unconventional gas extraction 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 HFF used and which were presumably derived from flowback water). The calculated Hazard Indices (**HI**) (where a value greater than 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 less than 0.8 km from a gas well, and 0.4 for residents living greater than 0.8 km from a gas well. 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.

These findings were confirmed to some extent in a different type of study. Bunch et al.[79] 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. The nearby Barnett Shale deposits comprise one of the largest active onshore gasfields in North America, with an estimated 15,870 producing wells across 500 sq miles (1,295 km^2). 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 unconventional gas activities would represent a chronic health risk.

By contrast, community-generated air sampling at sites around unconventional gas sites in Wyoming revealed that of the 75 VOCs measured, eight of these (for example, benzene, formaldehyde, and hydrogen sulfide) exceeded Federal health-based air quality guidelines over different operational conditions.[80]

In a review of potential respiratory health risks to children and infants around US unconventional gas sites, Webb et al.[81] cited the extent to which airborne emissions of ozone, benzene and formaldehyde exceeded relevant US air quality guidelines (1 h and 8 h averages for ozone and, chronic exposure (>365 d) Minimal Risk Levels for benzene and formaldehyde). They also cited measured airborne levels of ozone, benzene and formaldehyde from various US studies where acute respiratory effects, including exacerbation of asthma, had been reported. In a more recent

76 Krupnick and Echarte 2017, p 1.
77 Tustin et al. 2017.
78 McKenzie et al. 2012.
79 Bunch et al. 2014.
80 Macey et al. 2014.
81 Webb et al. 2016.

paper, Webb et al.[82] singled out a group of five pollutants associated with the unconventional oil and gas industry in the US (the metals arsenic and manganese, particulate matter, polycyclic aromatic hydrocarbons, BTEX and endocrine-disrupting chemicals), and speculated on the health impacts these chemicals could have on the developing brains of newborns and young children.

The Panel notes that much of this air monitoring data in the above US studies is comparable with, or mostly somewhat higher than, monitored airborne VOCs around gasfields in south-west Queensland (discussed further in Section 10.3.3.2).

By contrast, Brown et al.[83] used measured airborne VOC and particulates (PM 2.5) around a Washington County, Pennsylvania, unconventional gasfield to model possible human exposure at a specific residence surrounded by three unconventional gas facilities (1 km, 2 km and 3 km distances) 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 least likely. This indicates the critical importance of when, and over what period, monitoring is done. The conclusion from this study is that human exposures leading to adverse health effects are possible in the scenarios described, although the authors made no attempt to compare the estimated peaks and average exposures to health-based guideline values.

In a review of 1.1 million birth records from Pennsylvania over the period 2004 to 2013, Currie et al.[84] found that in utero exposure to fracking activities resulted in poorer infant health outcomes, including lower birth weight, and that the distance from these activities was again a crucial factor. The highest impacts were noted where mothers lived less than 1 km from fracking sites, with effects also noted at up to 3 km, although the effects, as measured by an infant health index, were quite variable between 2–4 km from hydraulic fracturing sites.

Bamberger and Oswald,[85] in a longitudinal study of the health impacts in humans, companion animals, and food-producing animals around US unconventional gas extraction sites (21 human cases across five 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.

The issue of an appropriate distance for well heads and well pads to be 'setback' from human habitation was addressed by Haley et al.[86] They noted that previous attempts to regulate setback distances[87] were not based on data analyses or historical events. Rather the regulation was the outcome of compromise between governments, the gas industry, landowners, and environmental/citizen interest groups. They analysed health risks associated with blowouts, thermal modelling and air pollution around three major shale plays (Barnett, Marcellus and Niobrara) in the context of relevant State regulations in respect of setback distances from buildings: 200 ft (61 m) in Texas; 500 ft (152 m) in Pennsylvania; and 500–1000 ft (152 m – 305 m) (high-occupancy dwellings) in Colorado. These setback distances contrast with the 2000 ft (610 m) recommended in the Maryland health study,[88] the 1,500 m setback recommended by Webb et al.[89] to protect children and infants living in nearby dwellings and the average setback of 447 m estimated for houses in the UK.[90] The overall conclusion of Haley et al.[91] was that the setback distances analysed were inadequate to protect public health. While they were unable

82 Webb et al. 2017.
83 Brown et al. 2015.
84 Currie et al. 2017.
85 Bamberger and Oswald 2015.
86 Haley et al. 2016.
87 For example, Fry 2013; Maryland Institute for Applied Environmental Health 2014.
88 Maryland Institute for Applied Environmental Health 2014.
89 Webb et al. 2016.
90 Clancy et al. 2018.
91 Haley et al. 2016.

to recommend more generous setback allowances on the basis of the analysed data, they noted that distance is not an absolute measure of protection, and that other risk mitigation measures (for example, regulatory controls over all aspects of the processes: see Chapter 14) are needed to address public health concerns.

The issue of setback distances from unconventional gas facilities (from drilling or producing wells, pipelines, gas plants, to dwellings, rural housing developments, urban centres or public facilities) has also been addressed by the AER in Alberta, Canada.[92] These distances range from 100 – 1600 m, depending on the estimated gas release rates and H_2S content of the gas (odour impact).

Recommendation 10.2

That in consultation with the gas industry, landholders, Land Councils, local government and local communities, the Government mandates an appropriate setback distance from all gas well heads, pipelines and gas processing facilities to a habitable dwelling (including all buildings or premises where people reside or work, schools and associated playgrounds, permanent sporting facilities and hospitals or other community medical facilities) in order to minimise risks identified in HHRA reports, including potential pathways for waterborne and airborne contaminants. Such setback distances should not be less than 2 km and should apply to all exploration and production activities.

The distance of 2 km represents a reasonable upper limit of setback distances established in gasfields in overseas regions based on protection of human health from airborne chemicals. In the Panel's view, it represents a reasonable a compromise to the 5 km setback proposed in the submission from the Northern Territory Cattlemen's Association (NTCA), based primarily on protecting the amenity of pastoralists.[93]

10.3.3.2 Queensland health impacts experience with unconventional gas extraction

A number of submissions drew attention to alleged public health impacts associated with unconventional gas extraction in Queensland.[94] The Panel also obtained further information through interviews and site visits to Dalby, Roma and Miles in July 2017, and through meetings in relation to these impacts from with the Queensland Government, CSIRO, the University of Queensland and GISERA (see Chapter 2 for more detail on these visits).

The information provided to the Panel[95] described a range of health effects, from skin irritation and rashes to spontaneous nosebleeds, eye irritation, headaches and other relatively non-specific symptoms. More concerning were reports of deaths of livestock and serious development toxicity in farmed pigs.[96] Many of these reports are consistent with those documented in a survey of human and animal health impacts around US shale gas developments, although these resulted from a mixture of gas flaring events and exposure to contaminated surface waters.[97] The symptoms are consistent with exposure to irritant gases and vapours, and the impression given by the Queensland experience was that these events were more likely to be associated with gas flaring events.

However, there is a difficulty in correlating the incidents with atmospheric concentrations of any chemicals known, or likely to be, associated with gas flares[98] or with fugitive emissions from gas wells. During consultations with Queensland regulators in July 2017, the Panel's attention was drawn to ongoing real-time monitoring of a number of criteria air pollutants (carbon monoxide, nitrogen dioxide, ozone, sulfur dioxide and particulates) around CSG installations in south-west Queensland. The online air monitoring data (generally updated on an hourly basis) from monitoring stations at Burncluith, Miles airport, Hopeland and Tara provides some information on air quality in relation to health-based guideline values from the ambient air quality National Environment Protection Measure (**NEPM**).

92 AER 2015.
93 Northern Territory Cattlemen's Association, submission 639 (**NTCA submission 639**); Northern Territory Cattlemen's Association, submission 1203 (**NTCA submission 1203**).
94 For example, P Cass submissions 33, 192 and 463; G McCarron submission 53; K Marchment submission 438.
95 Interviews with Dr Geralyn McCarron and Mr John Jenkyn in July 2017; P Cass submissions 33, 192 and 463; G McCarron submission 53.
96 Interviews with Mr John Jenkyn and Ms Helen Bender, July 2017.
97 Bamberger and Oswald 2012.
98 Origin submission 469, Appendix E.

The Panel notes that the alleged health effects around Tara were investigated by Queensland Health, which concluded that, *"in summary, the most that can be drawn from the DDPHU [99] report is that it provides some limited clinical evidence that might associate an unknown proportion of some of the residents' symptoms to transient exposures to airborne contaminants arising from CSG activities."* [100]

Queensland Health also noted comments from an independent clinical assessment of the reported symptoms that:

> *"The reported symptoms, if due in any way to CSG emissions, are more suggestive of intermittent exposure to low-level irritants and odours, rather than exposure leading to significant systemic toxicological effects. It appears clear the reported symptoms are rapidly reversible based on the reports that symptoms improved when residents were away from the area."*

The DDPHU report noted that, *"as of 12 November 2012, there were no reported hospital admissions related to CSG exposure."* However, in submissions to the Panel[101], reported hospital admission data over the period 2007 to 2014 showed a sharp increase from around 2010–11 onwards. This upswing in acute hospital admissions (around 133% for circulatory conditions and 142% for respiratory conditions) appeared to coincide with the development of the CSG industry in the region and was mirrored by local emissions of particulate matter (PM10 and PM2.5), formaldehyde and other VOCs, as reported by CSG industries to the National Pollutants Inventor[102]. One curious aspect of the hospital admission statistics in the McCarron paper (2018) is that they appear to occur across all regions of the hospital catchment area, including areas where CSG development has not occurred (as shown by the graphical distribution of gas wells and flare sites in her paper). Queensland Health notes that, "further investigation of these statistics is required to determine impacts of other factors such as population growth, changes in demography and other social and environmental stressors".[103]

During development of the Santos GLNG project in Queensland, a report[104] submitted to the Queensland Department of the Environment outlined the gaseous and volatile chemicals likely to be emitted from CSG sites, including chemicals likely to result from gas flaring. The report included baseline data from two monitoring stations installed at Fairview and Roma, comparisons with air quality data from Toowoomba, along with modelling data for air quality in the region attributable to background and to gas compression, production wells, vehicle emissions and flaring activity. The modelling included estimates of air quality up to 5 km from the sites, and showed that estimated one hour averages for nitrogen dioxide and carbon monoxide were below relevant air quality standards, even when background emissions were included. The report also noted that airborne emissions would be highly variable, with emissions associated with well construction, decommissioning and rehabilitation being temporary.

While the air monitoring data suggests that the level of criteria air pollutants is well within NEPM guidelines, the Panel acknowledges the difficulties in matching the air monitoring data with any known flare events or other emissions from CSG sites.

99 Queensland Health 2013, Appendix 1, Dr Penny Hutchinson. (January 2013), The Darling Downs Public Health Unit (**DDPHU**) investigation into the health complaints relating to CSG activity from residents residing within the Wieambilla Estates, Tara, Queensland - July to November 2012. This was one of several reports considered by Queensland Health in its 2013 response to the issues raised.

100 Queensland Health 2013, pp 6-7.

101 G McCarron submission 53.

102 McCarron 2018; W Somerville submission 1170.

103 Queensland Department of Health, submission 654.

104 Santos GLNG gasfield development project; environmental impact statement, air quality impact assessment (report no 620.10745-R1, August 2014), cited in Santos submission 168.

10.3.4 Impacts associated with increased road traffic

The Panel notes that risks associated with increased road traffic were addressed in some of the submissions and have been raised anecdotally by some members of the public during community consultations. In particular, it has been noted in some industry submissions that driver training and promotion of safe work practices is a priority for addressing and mitigating this potential risk.[105]

The issues are canvassed more broadly in a review by Adgate et al.[106] and are also cited in the submission from the Public Health Association of Australia.[107] However, the Adgate et al. review cites evidence drawn from studies in the US, where the proximity of communities to unconventional gas sites may not be as relevant to the situation in the NT. In particular, the Adgate et al. review notes that an increased incidence of road accidents is primarily associated with increased truck traffic in residential areas.[108] Whether or not increased truck traffic will occur in residential areas of the NT will depend on where any proposed shale gas industry will be located and the routes used to access those locations.

Entry point to the Origin Amungee NW-1H exploration well lease pad on Amungee Mungee Station.
Source: Origin.

The Panel's assessment of the risks relating to increased road traffic is outlined in more detail in Chapter 8 (Section 8.5.2). While the Panel's analysis acknowledges that the lack of data on potential traffic movements makes it difficult to assess the likelihood and consequences of traffic-related impacts on land use and amenity, the potential public health impacts are equally difficult to categorise. The potential public health risks of increased vehicle and equipment transport activities are most likely to be associated with exhaust emissions and road trauma from accidents, although the stress of driving on roads crowded with heavy vehicles may be another factor affecting health. The magnitude of these potential risks will vary according to the scale of any gasfield development and according to the phase of any onshore shale gas development (higher during drilling and exploration, and lower during production). The gas industry provided some data on increased traffic movements related to CSG projects in Queensland, but comment was made that, *"projects in the NT will be less dependent on public roads due to the location of the fields. The findings of QLD assessments may not be directly relevant to the NT. If development was to proceed in the NT, similar modelling would be undertaken based on local conditions and development plans."*[109]

105 For example, APPEA submission 215, p 114.
106 Adgate et al. 2014.
107 PHAA submission 107.
108 Adgate et al. 2014.
109 APPEA submission 421, pp 5-6.

The Panel's assessment of the public health risks associated with diesel emissions from vehicles and other particulates (dusts) is that the likelihood is 'medium' (but likely to be of relatively short-term impact during the pre-production phase of well head and facility development), and the consequence is 'low' to 'medium' (which is likely to depend on controls over equipment movements and/or dust suppression measures). The overall risk level is therefore 'low' to 'medium'.

Mitigation of these risks will be addressed through the implementation of ***Recommendation 10.2***, namely, the setting of appropriate setback distances.

10.3.5 Impacts on social cohesiveness, mental health, and wellbeing

The Panel notes that this risk has been identified in some of the submissions and was raised by some people during the community consultations. The issues are discussed in more detail in Chapter 12, and in particular in Section 12.3, although the Panel has been unable to find a sufficient amount of cogent evidence that is required to evaluate the magnitude of this risk to public health. Psychosocial and socioeconomic impacts, both positive and negative, were reviewed by Adgate et al.,[110] with an emphasis on stressors such as increased truck traffic, noise pollution, accidents and psychosocial stress associated with community change, as well as the impacts of chemical stressors. Ferrar et al. (2013)[111] also reported on an interview-based survey of health effects and related psychological stress factors in communities around the Marcellus shale development in the US. Impacts of rapid sociological and economic changes have also been reviewed in mainly agricultural communities in the same region,[112] but again, the relevance of these largely US-based studies to any onshore shale gas industry developments in the NT is questionable.

However, the Panel also notes that in a recent review of health impacts of unconventional gas extraction, 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 **Table 10.2**).[113]

Finally the Panel notes that some of the submissions from the gas industry suggest more positive effects on wellbeing associated with improved employment opportunities and improved social benefits and facilities associated with an onshore shale gas development.[114] CSIRO, in collaboration with GISERA, has, for example, reported on the range of community responses to the social and environmental impacts of CSG development in the Western Downs region of Queensland.[115] For further detail, see the discussion in Chapter 12, particularly in respect of the need for a separate cultural and social impact assessment to be undertaken prior to any onshore shale gas production approvals being granted.

110 Adgate et al. 2014.
111 Ferrar et al. 2013.
112 Perry 2012; Brasier et al. 2014.
113 McMullin et al. 2017.
114 For example, APPEA submission 465; Origin submission 153; Central Petroleum Limited, submission 99 (**Central Petroleum submission 99**); Central Petroleum Limited, submission 442 (**Central Petroleum submission 442**); Oilfield Connect Pty Ltd, submission 174 (**Oilfield Connect submission 174**); Pangaea Resources Pty Ltd, submission 60 (**Pangaea submission 60**); Santos submission 168; Schlumberger Australia Pty Ltd, submission 460 (**Schlumberger submission 460**).
115 Walton et al. 2014, cited in APPEA submission 465.

10.4 Conclusion

Knowledge of the potential health risks associated with unconventional gas has evolved slowly over time, with some published reviews and reports acknowledging that the risks are still unresolved. For example, the 2015 review by Werner et al. summarises the gaps in knowledge at that time and points out why epidemiological studies had so far been unable to answer some of the key questions relating to health impacts.[116] The following quote from a Canadian review also makes this point, although since it was published in 2014, some of the issues have become less equivocal:

> *"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."* [117]

The conclusions of a UK review into shale gas relating to potential public and environmental health impacts were more succinct:

> *"Shale gas can be produced safely and usefully in the UK provided that the Government insists on industry-leading standards… The risk from shale gas to the local environment or to public health is no greater than that associated with comparable industries provided, as with all industrial works, that operators follow best-practice. Much of the negativity surrounding shale gas production originates from communities, largely in the US, where operator standards were lax. There is now strong evidence compiled by the Department of Energy in the US that shows that standards have improved dramatically in the last few years. There has been understandable concern – and even fear – as a result of the lax standards. However, the Task Force is convinced that this highlights issues with regulation and enforcement from which lessons must be learned, not issues with the process of hydraulic fracturing itself and subsequent gas production."* [118]

However, in its Second Interim Report, specifically addressing the impact of shale gas on the local environment and health, the UK Task Force noted that, *"the amount of evidence available is limited and largely based on pre-green completion (US) data. More research needs to be conducted and should continue to be conducted if an industry develops."*

As pointed out in a submission to the Panel,[119] the Scottish Minister for Business, Innovation and Energy[120] reached a similar conclusion about the status of the epidemiological research. This was used, however, to support a 2017 decision to implement a permanent moratorium on unconventional oil and gas development in Scotland.

Other reviews focussing on airborne emissions from unconventional gasfields (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 any unconventional gas development.[121]

The Panel's analysis and recommendations in this and other Chapters, acknowledges some of the knowledge gaps that will need to be addressed through the SREBA to better inform the HHRAs and predictions of potential impacts on public health. Among these are the need for better baseline information on regional public health prior to any gasfield development (discussed further in Chapter 15) and further information on proposed sites for well pad development, so that the proximity of human receptors in landholder housing and 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 the Panel that only HHRA determinations that are relatively site-specific will provide meaningful information on the public health risks to surrounding communities.

116 Werner et al. 2015.
117 Green 2014, p 24.
118 UK Task Force on Shale Gas 2015.
119 G McCarron submission 508.
120 Wheelhouse 2017.
121 Australian Department of the Environment and Energy 2017c.

The outcomes from the NCRA[122] also highlight the need to conduct site-specific risk assessments for identified higher-priority chemicals, because site-specific factors can either increase or decrease the level of risk that can be posed by their use. These factors include distance from the gas extraction well to the nearest creek line or sensitive surface water body, the permeability of the surface soil horizon in the vicinity of the well, and how well the soil is likely to bind to a released chemical.

The overall conclusion of the Panel with respect to impacts on public health of any onshore shale gas activity in the NT is that the risks associated with chemicals released to groundwater and surface waters will require appropriately robust management and regulatory controls, and that the risks of airborne gases, VOCs and dusts can be mitigated by the imposition of appropriate setback distances.

122 Australian Department of the Environment and Energy 2017a-d.

ABORIGINAL PEOPLE AND THEIR CULTURE

11

11.1 Introduction

> *"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 to three digits... People ask me for my story, but my story is your story."* [1]

Aboriginal people from regional communities who made submissions to the Panel almost universally expressed deep concern about, and strong opposition to, the development of any onshore shale gas industry on their country. The widespread perception was that if such an industry is established, irreparable harm will be done with no correlative benefits flowing to affected communities. This was based in large part on their experience with other mining projects. Aboriginal people from regional communities in the Beetaloo Sub-basin repeatedly told the Panel about environmental problems experienced as a consequence of the mines at Redbank and McArthur River and the haul-road built by Western Desert Resources.

In several communities, views were expressed to the Panel indicating a firm belief that the process of hydraulic fracturing would inevitably lead to cultural and environmental catastrophe. Mr Ned Jampijinpa Hargraves submitted that fracking *"is digging up my body, breaking my Tjukurpa."*[2] Mrs Nancy McDinny put it this way, *"you digging up my home - you get money - we, we got Dreaming."* [3]

In the course of community consultations, the Panel also heard evidence from younger Aboriginal people who oppose hydraulic fracturing as an essential expression of their commitment to their traditional culture and as a way of honouring their elders. Mr Stephen Rory told the Panel that, *"I have been told by my father, 'defend your country, defend your sites'"*.[4] In part, this connection has been reinforced through the online sharing of experiences and artistic responses; for example, the work of the late Ms Alice Eather in; *My Story is Your Story*, quoted above. The Panel was told at Borroloola that opposition to hydraulic fracturing on country was central to upholding traditional responsibilities and analogous to ancestral armed resistance to colonisation in the 1900s.[5] Mr Peter Dixon submitted that members of his congregation told him that, *"to mine [drill] is to spear family."* [6]

The wellbeing of Aboriginal people and their communities is underpinned by cultural traditions that ascribe significance to the landscape and link Aboriginal people to their country.[7] Moreover, in order to ensure that their ownership rights continue to be recognised, Aboriginal landowners must be able to maintain their cultural traditions relating to that land from one generation to the next.

In the NT, 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."*[8] As noted by Woodward J in his seminal report concerning Aboriginal land rights in the NT, *"too often in the past, grave offence has been given and deep hurt caused by their inadvertent destruction...It is hardly necessary to say that all relevant legislation must continue to protect Aboriginal rights of access to sacred sites."* [9]

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 Mr Ned Jampijinpa Hargraves, submission 1222. 'Tjukurpa' is the foundation of Anangu life and society. See http://aiatsis.gov.au/exhibitions/tjukurpa.
3 Mrs Nancy McDinny, community consultation, Darwin, 10 February 2018.
4 Mr Stephen Rory, community consultation, Jilkminggan, 15 February 2018.
5 Mr Gadrian Hussan, community consultation, Borroloola, 31 January 2018; Mr Keith Rory, Mr Nicholas Milyari Fitzpatrick et al., community consultation, Borroloola, 23 August 2017. See also Mr Raymond Dixon, Ms Eleanor Dixon, Ms Jeanie Dixon, Mr Shannon Dixon, and Ms Mary James, submission 381 (**Dixon submission 381**).
6 Mr Peter Dixon, submission 1230.
7 Aboriginal Areas Protection Authority, submission 234 (**AAPA submission 234**); Northern Land Council, submission 214 (**NLC submission 214**); NLC submission 471; Central Land Council, submission 47 (**CLC submission 47**).
8 Woodward Report, p 100.
9 Woodward Report, p 100.

Many submissions to the Panel noted that without appropriate mitigation measures, the development of any onshore shale gas industry could damage sacred sites and cause conflict both within Aboriginal communities and between Aboriginal people and any shale gas industry.[10] It was put to the Panel that: *"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."* [11]

Damage to sacred sites is one way that any onshore shale gas industry can have an impact on Aboriginal people, their culture and traditions. But Aboriginal culture and tradition is much broader than the meaning of 'sacred sites' as it appears in legislation. As noted by the NLC: *"the protection of culturally significant sites is important, it is but one of the multitude of aspects of Aboriginal society and culture that needs to be considered."*[12]

In addition to the possibility that sacred sites might be damaged, there is the risk that Aboriginal people are not able to maintain their cultural traditions relating to land from one generation to the next. Aboriginal people must transfer traditional knowledge across generations for their ownership rights in land to continue to be recognised. [13] Further, Aboriginal people must continue to be able to freely access traditional country both during and after the development of any onshore shale gas industry.[14]

There is also a risk that any onshore shale gas industry will inject *"stresses into the social and cultural fabric of land-owning groups,"* [15] because under the native title and land rights statutory processes described below, traditional owners are required to balance the economic returns associated with development with traditional cultural concerns.[16] Further, there is an issue surrounding the distribution of financial benefits. Under the relevant Commonwealth legislation, financial benefits from petroleum agreements flow to traditional Aboriginal owners and native title holders, not the broader Aboriginal community. The Land Councils are cognisant of these issues.[17]

In addition, the Panel heard that development can have a disruptive effect on social cohesion in Aboriginal communities. Tension can arise from various sources, including as a result of lack of information about hydraulic fracturing and any onshore shale gas industry more broadly. Aboriginal people have been *"recruited by individuals/organisations with an interest on either side of the [hydraulic fracturing] debate."* [18]

This Chapter has been informed by several major reports, including:

- the report into mining at Coronation Hill by Stewart J;[19]
- the review of laws protecting Aboriginal heritage by the Hon. Elizabeth Evatt QC;[20]
- the review of the Land Rights Act by Mr John Reeves QC;[21]
- Justice Mansfield's review of Pt IV of the Land Rights Act;[22] and
- PwC's review of the NT's Sacred Sites Act.[23]

10 Scambary and Lewis 2016, p 222; AAPA submission 234, p 21; Doctors for the Environment, submission 630, pp 8-9.
11 AAPA submission 234, p 16.
12 NLC submission 471, p 20.
13 For example, CLC submission 47; NLC submissions 214 and 471; AAPA submission 234.
14 NLC submission 217, p 37.
15 NLC submission 471, p 22.
16 NLC submission 471, p 22.
17 NLC submission 471, p 22.
18 NLC submission 471, p 17.
19 Stewart 1991.
20 Evatt 1996.
21 Reeves Review.
22 Mansfield Review.
23 Sacred Sites Review 2016.

Figure 11.1: Statement from Aboriginal Fracking Forum, 19 Nov 2017. Source: Seed Indigenous Youth Climate Network.[24]

BAN FRACKING, PROTECT COUNTRY

Statement from the Aboriginal Fracking Forum, 19 November 2017

We speak from Aboriginal communities right across the Territory. And we have come together to take a stand against fracking.

And we say no. We say no to fracking on our land, on our country.

We are concerned about the damage to our water, our country, our dreaming and our songlines.

This damage would be irreversible.

We don't want to see our rivers and waters poisoned. We want to be able to fish and hunt, gather bush tucker and bush medicines now and for all generations of people to come.

We have been told lies by gas companies, telling us there will be no impacts. That there will be one or two frack wells, not a gas field with hundreds or even thousands of wells.

Other states in Australia have banned fracking and so have many nations around the world because it's so risky.

We refuse to be lied to anymore.

We know that fracking will bring chemicals that will contaminate our water and damage our health. Drilling in one area has a bigger impact that just that place. It will damage neighbouring language groups on country and the entire water system.

We want our water to be clean and healthy. For all of us.

People and country are one and the same, any damage to our country impacts us, our identity and who we are.

We will not be divided by others who do not understand the lore of the land.

We will stand strong and stand together. We will do what it takes to see a permanent ban on fracking, there will be no sacrifice zones.

We represent a growing movement of Aboriginal people coming together to stop fracking and protect country.

We call on this Government to hear us and to take action.

We stand together, and we will do what we must to protect our country for future generations. Because without water and without clean country none of us can survive.

We are here and we are not going away until you hear us.

24 Seed Indigenous Youth Climate Network, Submission 1181.

11.2 Indigenous land in the NT

Around 98% of land in the NT is either Aboriginal freehold under the Land Rights Act, leasehold under the *Pastoral Land Act 1992* (NT) (**Pastoral Land Act**), or held under other forms of tenure that exist concurrently with native title, such as vacant Crown land.

As shown in **Figure 11.1**, all of the known prospective onshore shale gas areas, including the Beetaloo Sub-basin, are on areas that are either Aboriginal land under the Land Rights Act or where native title exists (**Indigenous land**). The effect of this is significant for any onshore shale gas industry and for Aboriginal people. Each time a gas company makes an application to the Government for the grant of a petroleum interest under the Petroleum Act, which includes an exploration permit, the statutory processes set out in the Land Rights Act and the *Native Title Act 1993* (Cth) (**Native Title Act**) must first be complied with. The Land Rights Act and the Native Title Act provide a legal framework whereby traditional Aboriginal owners and native title holders are informed about, and consulted in respect of, development on their land.

11.2.1 Aboriginal land under the Land Rights Act

Aboriginal land is a communally held and inalienable form of title established under the Land Rights Act, which is Commonwealth legislation that only applies in the NT. Approximately half of the NT land mass, and approximately 70% of the coastline, is Aboriginal land. Seven exploration permits have been granted on Aboriginal land.

11.2.1.1 Aboriginal Land Trusts and Land Councils

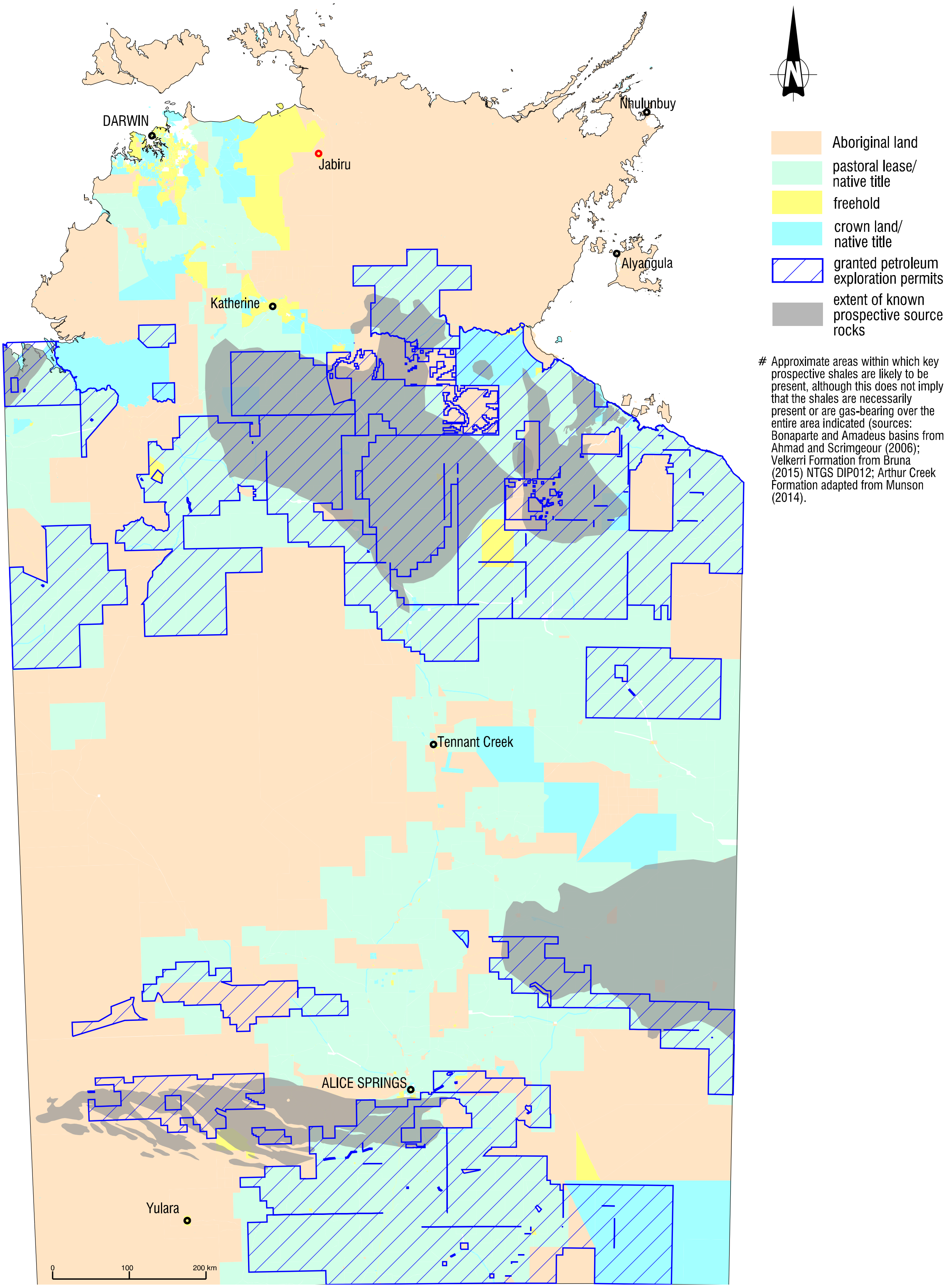
Aboriginal land is held by Aboriginal Land Trusts, which are statutory trusts that may acquire, hold, and dispose of real property.[25] Land Trusts can only exercise their powers and functions in accordance with the rules set out in the Land Rights Act and with a direction given to them by the relevant Land Council.[26]

11.2.1.2 Land Councils

The Aboriginal Land Rights Commission recommended that Land Councils be established as independent entities to carry out functions under the Land Rights Act for several reasons. First, during his Commission, Woodward J observed the lack of formal submissions received from Aboriginal people and saw the need for an institution to consult with, and express the views of, Aboriginal people.[27] Second, his Honour wanted to ensure that Aboriginal people's consent would be given without the risk of coercion or manipulation. He opined that Land Councils could assist Aboriginal people to negotiate against powerful and well-resourced extractive industry companies.[28]

25 Land Rights Act, s 4(3).
26 Land Rights Act, s 5(2).
27 Finlayson 1999, p 17.
28 Cullen 1991, p 159; Woodward Report, p 127; Mansfield Review.

Figure 11.2: Indigenous land in the NT and granted exploration permits.



NORTHERN TERRITORY GOVERNMENT

Land Councils are established by the relevant Commonwealth Minister. Council members must be *"Aboriginals living in the area"* of the Land Council who are "*chosen by Aboriginals living in the area*".[29] The Land Council's functions are set out in the Land Rights Act and include an obligation to:

- consult with traditional Aboriginal owners of, and other Aboriginals interested in, Aboriginal land in the area of the Land Council with respect to any proposal relating to the use of that land;
- provide assistance to Aboriginal people to protect sacred sites in the area of the Land Council;[30] and
- negotiate with persons wanting to obtain an estate or interest in land in the area of the Land Council on behalf of traditional Aboriginal owners (if any) of that land and of any other Aboriginals interested in the land.[31]

The NLC and the Central Land Council (**CLC**) represent traditional Aboriginal owners (and native title holders under the Native Title Act) of the land in all the prospective onshore shale gas basins.

11.2.1.3 Traditional Aboriginal owners and the Aboriginal community

Under the Land Rights Act, the term *"traditional Aboriginal owners"* is defined as *"a local descent group of Aboriginals who (a) have common spiritual affiliations to a site on the land, being affiliations that place the group under a primary spiritual responsibility for that site and for the land; and (b) are entitled by Aboriginal tradition to forage as of right over that land."*[32]

Land Councils must use this definition to determine who the traditional Aboriginal owners are for a particular area. Traditional Aboriginal owners have a statutory right to be consulted and to consent to the grant of an exploration permit. These rights are stronger than the rights given to ordinary freehold landowners and native title holders, who cannot say 'no' to development on their land. If the traditional Aboriginal owners do not exercise their right to say 'no' at the exploration stage then they cannot say 'no' at a later stage in the process, for example, at the production stage. The legal mechanisms by which traditional Aboriginal owners are consulted and consent is explained in Section 11.3.1 below.

The Land Rights Act also refers to other groups of Aboriginal people. These people are referred to as *"other Aboriginal groups", "affected Aboriginals",* or *"the Aboriginal community"*. These terms are not defined in the Act and, again, the Land Council determines the people that comprise these groups. Neither other Aboriginal groups nor the broader Aboriginal community have the right to say 'no' to development. These people have the right to be consulted and express their views to the Land Council on certain matters, but this is less than the right to consent, or refuse to consent, to development. Before entering into an agreement with a gas company the broader Aboriginal community must be given an *"adequate opportunity to express to the Land Council its views concerning the terms and conditions"* of any exploration agreement.[33]

11.2.2 Native title

The existence of native title in Australia was recognised by the High Court in *Mabo v Queensland (No 2).*[34] That case overthrew the longstanding legal fiction that Australia was *terra nullius*, or empty land, at the time of colonisation in 1788. The Commonwealth responded to the Mabo decision by enacting the Native Title Act the following year.

The term *"native title"* is defined in the Native Title Act 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.[35] Native title rights and interests are sometimes described as a 'bundle of rights', including, among other things, the right to hunt, fish and gather. Native title is not a leasehold or a freehold interest in land.

Most granted petroleum exploration permits, and areas that are prospective for onshore shale gas, are on land subject to native title, which is often also pastoral land (see **Figure 11.2**). In *The Wik*

29 Land Rights Act, ss 21(1), 29(1).
30 Land Rights Act, s 23(ba).
31 Land Rights Act, s 23(1); NLC submission 214, p 3.
32 Land Rights Act, s 3.
33 Land Rights Act, s 42(2)(b).
34 (1992) 175 CLR 1; [1992] HCA 23.
35 Native Title Act, s 223.

Peoples v The State of Queensland; The Thayorre People v The State of Queensland [36] the High Court of Australia held that native title could coexist with pastoral land. Where a petroleum exploration permit application is made over land subject to both native title and pastoral interests, both land access regimes apply. The land access regime for pastoral leases is set out in Chapter 14.

The legal mechanisms by which native title holders are consulted in respect of development on native title land are discussed below in Section 11.3.

11.3 Laws protecting Aboriginal culture, traditions, and sacred sites

Two Commonwealth Acts, the Native Title Act and the Land Rights Act, together with complementary NT legislation, the *Northern Territory Aboriginal Sacred Sites Act 1989* (NT) (**Sacred Sites Act**) as well as the EAA and the *Heritage Act*, establish a legal framework that enables Aboriginal people to maintain cultural traditions, including, but not limited to, protecting sacred sites from the adverse impacts of resource development.

This section, first, describes the laws and processes that must apply under Commonwealth legislation (the Land Rights Act and the Native Title Act) that must be complied with prior to the grant of an exploration permit or activity. Second, it describes the NT laws that work to protect sacred sites, namely, the Sacred Sites Act and the EAA.

11.3.1 Land Rights Act

The Land Rights Act gives traditional Aboriginal owners the right to be consulted about, and to consent or refuse to consent to, the grant of a petroleum exploration permit on Aboriginal land. The Land Rights Act protects culturally significant places by allowing (but not mandating) traditional Aboriginal owners to carve out areas from a granted petroleum exploration permit for any reason, including that they may contain a sacred site. In other words, traditional Aboriginal owners can say 'yes' to development in some areas and 'no' to development in others. It is a level of control over land that is not seen in any other Australian jurisdiction for any other type of tenure.

Part IV of the Land Rights Act contains the provisions relating to petroleum development. Part IV is prescriptive about what must occur prior to a petroleum exploration permit on Aboriginal land being granted. The process is designed to ensure that petroleum exploration permits are only granted if the traditional Aboriginal owners of the relevant country and the relevant Land Council have given their informed consent to exploration. The process is set out below and in **Figure 11.3** and explained below.

A gas company makes an application to the Government for an exploration permit (**Step 1**) and the Minister for Resources consents to the gas company entering into negotiations with the relevant Land Council to reach an exploration agreement (**Step 2**).[37] The purpose of the exploration agreement is to set out the areas where exploration can and cannot occur and, where it can occur, the rules for how exploration must occur.[38] Any provision in an exploration agreement that purports to allow traditional Aboriginal owners or the Land Council to veto production is unlawful.[39]

Once the Minister for Resources has consented to the commencement of negotiations, the minister is no longer involved in the process until the negotiations between the land council and a gas company are completed and there is evidence of an agreement between those two parties. Neither the Government nor the Commonwealth has any involvement in, or control over, the processes outlined below regarding how Land Councils identify and consult with traditional Aboriginal owners or other Aboriginal people.

36 (1996) 187 CLR 1; [1996] HCA 40.
37 Land Rights Act, s 41.
38 Land Rights Act, s 42(2)(a)(ii).
39 *Northern Territory of Australia v Northern Land Council and Others* (1992) 81 NTR 1.

Figure 11.3: The process for the grant of a petroleum exploration permit on Aboriginal land.

Step 1	Gas company applies to NT Government for an exploration permit.
Step 2	NT Government consents to gas company negotiating an agreement with the Land Council.
Step 3	Gas company lodges a 'section 41 application' with the Land Council.
Step 4	Initial Meeting: Land Council consults TOs about whether they want to make an agreement with the gas company.
Step 5	If TOs say 'yes' the Land Council negotiates an agreement with the gas company. If TOs say 'no' the land goes into a moratorium period for five years.
Step 6	Final Meeting: when the Land Council and gas company reach an agreement it is presented to the TOs.
Step 7	If TOs understand and consent to the agreement and the Land Council thinks the terms are reasonable, the Land Council can enter into the agreement. If TOs say 'no' to the agreement the land goes into a moratorium period for five years.
Step 8	The Federal Minister consents to the grant of the exploration permit.
Step 9	The NT Government grants the exploration permit.

Upon the consent of the Minister, the gas company lodges an application (sometimes called a 's 41 application') with the relevant Land Council setting out details about the proposed exploration work (**Step 3**).[40] The Land Council identifies the traditional Aboriginal owners for the application area and consults with them about whether or not they are interested in exploration happening on their country and, if so, whether they consent to the Land Council negotiating an agreement with the gas company (**Step 4**). This meeting is often referred to as an 'initial meeting'. If the traditional Aboriginal owners say 'no' to exploration at this point, then the process comes to an end and the application area is placed into a moratorium and gas companies cannot apply to access the land for five years, at which point traditional Aboriginal owners have an opportunity to say 'yes' to negotiations or institute another five-year moratorium.

40 Land Rights Act, s 41(6); CLC submission 47, p 10.

If traditional Aboriginal owners say 'yes' to the Land Council negotiating an agreement with the gas company at the initial meeting, the Land Council and the gas company negotiate the terms of an exploration agreement (**Step 5**). The parties negotiate for 22 months. In practice, this period can be, and often is, extended beyond this timeframe. During the negotiating period, the Land Council works with traditional Aboriginal owners to undertake a survey of the application area to identify parcels of land that traditional Aboriginal owners want to be excised from the granted permit area.[41] The carving out of certain areas explains why some tenements on Aboriginal land look fragmented (see, for example, EP 154 depicted in **Figure 11.4**).

The exploration agreement reached between the gas company and the Land Council will typically be conjunctive, which means that it covers the terms of exploration and production. Exploration agreements on Aboriginal land are conjunctive probably because traditional Aboriginal owners and Land Councils do not have the right to say 'no' to the grant of a production licence on Aboriginal land. All of the bargaining power is concentrated in the exploration phase of any development. Land Councils use this bargaining power to negotiate terms that will apply to production as well as exploration.

Once the agreement between the Land Council and the gas company has been finalised, the Land Council formally presents the agreement to traditional Aboriginal owners at a private meeting (**Step 6**). The meeting is sometimes referred to as a 'final meeting' or a 's 42 meeting' because s 42 of the Land Rights Act prescribes how the meeting must occur. Gas companies are allowed to present at the final meeting only if the traditional Aboriginal owners agree.[42]

The Act provides that the Land Council must be satisfied that traditional Aboriginal owners *"understand the nature and purpose of the terms and conditions [of the agreement] and, as a group, consent to them."* [43] If traditional Aboriginal owners understand and consent to the terms and conditions of the exploration agreement and the gas company's exploration proposals at the final meeting, and if the Land Council is satisfied that the terms of the agreement are reasonable, then the Land Council may enter into an agreement with the gas company (**Step 7**).[44] If the traditional Aboriginal owners say 'no' to the agreement, or otherwise do not understand the terms of the agreement, then the Land Council cannot enter into the agreement.[45]

Traditional Aboriginal owners are not a party to the agreement that is entered into. The only parties to the agreement are the Land Council and the gas company. The Land Rights Act does not expressly provide that traditional Aboriginal owners can, or must, see and read the exploration agreement. However, in *Gondarra v Minister for Families, Housing, Community Services and Indigenous Affairs*[46] Kenny J held that traditional Aboriginal owners are entitled to see copies of the relevant agreements, whereas Aboriginal communities and affected groups are not entitled to see the agreement.[47]

The responsible Commonwealth Minister must also consent to the grant of the exploration licence (**Step 8**).[48]

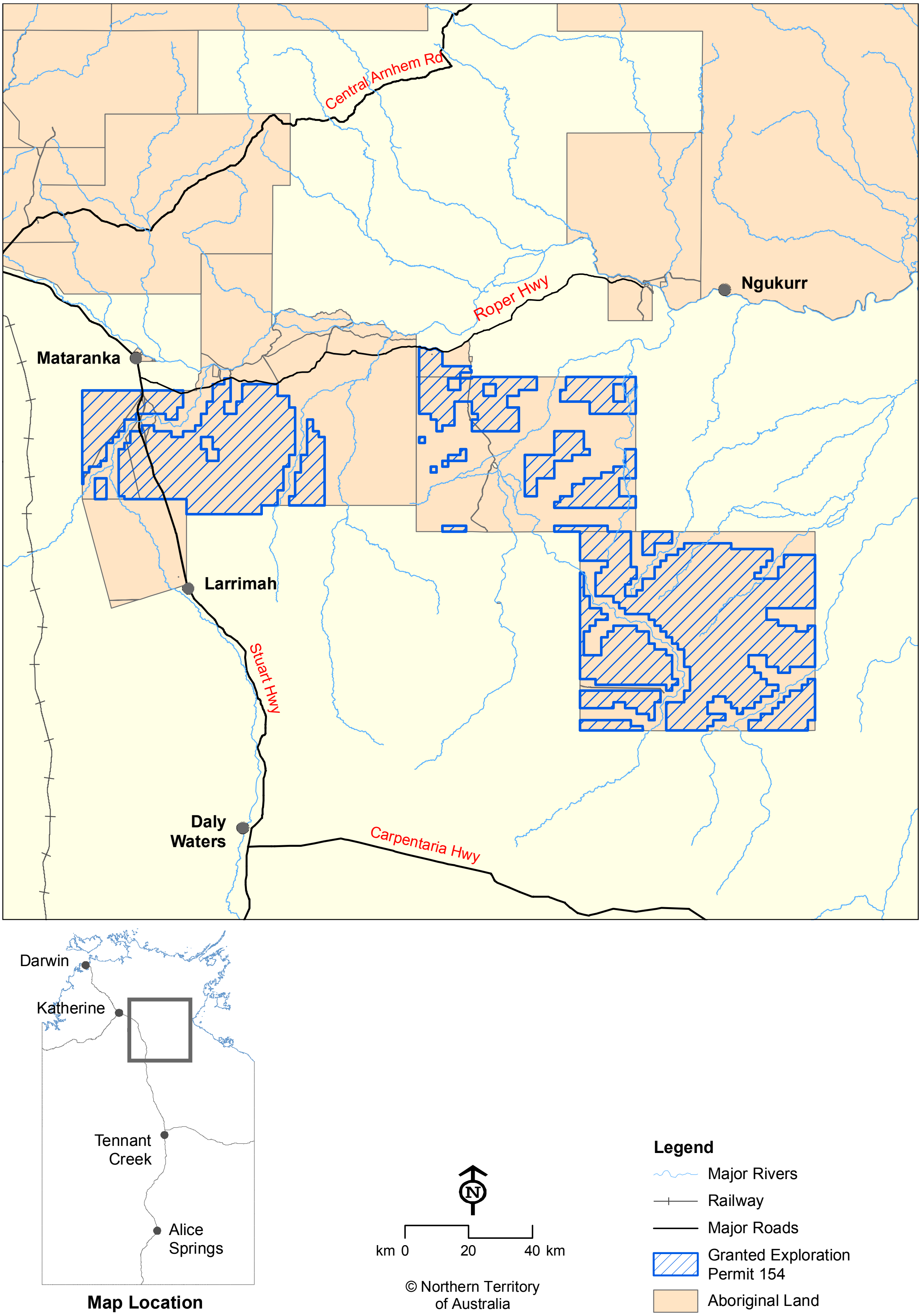
Once the agreement has been executed by the gas company and the Land Council, and the Commonwealth Minister has consented to the grant, the Minister for Resources can grant the application (**Step 9**).

The process above for any onshore shale gas development presents challenges to Land Councils and AAPA that distinguish it from other types of extractive development, including mining and conventional gas projects.

First, petroleum exploration permit applications and exploration work programs (for example, seismic survey work) cover vast areas. The CLC notes that applications for petroleum exploration permits can extend to areas of up to 16,000 km^2. The applications may include multiple Aboriginal land trusts and many Aboriginal language groups, and the Land Council may need to consult with, and obtain the consent of, up to 20 different estate groups.[49] This renders the consultation process complex, time consuming, and expensive.

41 NLC submission 214, p 36.
42 Land Rights Act, s 42(4).
43 Land Rights Act, s 42(6)(a).
44 Land Rights Act, s 42(6).
45 Land Rights Act, s 42(6).
46 [2014] FCA 25.
47 [2014] FCA 25 at 92, 100.
48 Land Rights Act. s 40.
49 CLC submission 47, Attachment p 4.

Figure 11.4: Exploration permit 154 showing areas that have been vetoed by traditional Aboriginal owners under the Land Rights Act.



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Second, the impact that any unconventional gas industry has on underground resources is different to mining and conventional gas projects. The extraction of gas from deep shale formations involves not only drilling a deep vertical well into the ground, but also the horizontal drilling of wells several kilometres out from the vertical well. The horizontal wells may go underneath areas where there are sacred sites (noting that the onshore shale reservoirs are around 3–4 km below the surface: see Chapters 5 and 6).[50]

Third, a large amount of water is required for hydraulic fracturing, and the use of water from underground aquifers may have an impact on sacred sites that are, or rely upon, this water resource (see Section 11.4.1.2).

Fourth, the extraction process is highly technical, which is often difficult to communicate to people that have English as a second (or third or fourth) language (see Section 11.4.2.1).

Fifth, the extensive uncertainty surrounding any potential underground impacts means that many Aboriginal groups may be affected by and involved in decision-making. It was put to the Panel that, according to Aboriginal tradition, the aquifers underlying country which may give rise to springs and other naturally occurring water sources can be associated with the travels of ancestral beings and link neighbouring Aboriginal groups, connecting people across the landscape. In the area surrounding the Beetaloo Sub-basin, for example, these connections find expression in the kujika song cycles.[51] Kujika are central to the major ceremonies linking Aboriginal groups across the region. The songs link people with sites in the landscape, celebrating the exploits of ancestral beings as they travelled above and below the ground. Further, this cultural interconnectedness, mirroring underground water systems, was put to the Panel as grounds for requiring a broader group of landowners to be consulted, not just the group associated with the land directly above the areas proposed for any shale gas wells. [52]

This adds a layer of complexity to statutory consultations. The kujika reinforce the concept of mangalalgal, or *"the way of the dreaming"*, which is an explicit imperative to honour and maintain cultural traditions.[53] Traditional Aboriginal owners have submitted that they are connected with neighbouring Aboriginal groups by *"underground culture."* [54]

McArthur River mine was used as an example of why downstream landowners must be consulted about proposed works on country upstream, even if the works are located on land traditionally belonging to another group. The Panel was told that, similarly, groups who share a common aquifer are connected and must therefore be involved in decision-making that could affect the integrity of that aquifer.

Both the NLC and the CLC submitted that notwithstanding the challenges described above, they were sufficiently experienced and accomplished in this area, and had entered into various exploration agreements where traditional Aboriginal owners and native title holders had given their consent to petroleum activities.[55]

11.3.2 Native Title Act

Native title holders under the Native Title Act do not have the same level of control over development on native title land as traditional Aboriginal owners have under the Land Rights Act. Native title holders do not have a statutory right to veto the grant of an exploration permit by the Government. Native title holders can, however, create contractual arrangements in native title agreements whereby gas companies are prohibited from entering into certain areas of a permit. These are called 'restricted areas', or 'no go zones'.

Native title holders have the right to make an agreement with a gas company. The grant of a petroleum exploration permit by the Government under the Petroleum Act is a *"future act"* for the purposes of the Native Title Act.[56] That is, the grant of the permit is an act that will affect native

50 NLC submission 214, p 29.
51 Dixon submission 381; Mr Keith Rory, Mr Nicholas Milyari Fitzpatrick et al., community consultation, Borroloola, 23 August 2017; Mr Walter Rogers, community consultation, Ngukurr, 24 August 2017.
52 Mr Walter Rogers et al., community consultation, Ngukurr, 24 August 2017; Mr Keith Rory and Ms Maria Fitzpatrick, community consultation, Borroloola, 23 August 2017; Dixon submission 381, p 9.
53 Mr Walter Rogers et al., community consultation, Ngukurr, 24 August 2017. Mr Ned Jampijinpa Hargraves told the Panel of the obligation to *"pass the 'Tjukurpa' on to our children"*. A similar concept exists in Anangu traditional law that encompasses the relationships between people, all living things and the physical landscape: N Hargraves submission 1222.
54 Dixon submission 381; Mr Keith Rory, Mr Nicholas Milyari Fitzpatrick et al., community consultation, Borroloola, 23 August 2017; Mr Walter Rogers, community consultation, Ngukurr, 24 August 2017; Ms Eleanor Dixon et al. community consultation, Elliott, 14 February 2018.
55 NLC submission 214, p 5.
56 Native Title Act, s 233.

title with respect to the right to, among other things, hunt, gather and fish. Where a *"future act"* is proposed, the *"future act"* provisions of the Native Title Act must be complied with for that 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.[57] Once notice has been given, the Government, the native title party, and the gas company (each a **negotiating party**) 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."* [58] The Native Title Act does not prescribe what must go into the agreement. If an agreement cannot be reached within this period, any party negotiating can make an application to the National Native Title Tribunal (**NNTT**) for the matter to be arbitrated.[59] The NNTT cannot make a determination about the payments that will go to native title holders,[60] which means that native title holders are incentivised to reach an agreement with the gas company in order to secure financial benefits. To date, there has been no application made in the NT for the NNTT to arbitrate, which suggests that the parties negotiating have been able to reach agreement.

The negotiating parties and 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.[61] Separate to the tripartite agreement is an 'ancillary' agreement between the native title party, the Land Council, and the gas company, which deals with land access, sacred site protection, remuneration and other matters. The Government is not a party to this agreement. A copy of the tripartite agreement is provided to the NNTT and the Commonwealth Minister.[62] There is no statutory requirement that agreements made under the "*future act"* provisions of the Native Title Act be made publicly available. The agreements are confidential, and the Panel has not sighted any of them.

11.3.3 Agreements under the Native Title Act and Land Rights Act

Sections 11.3.1 and 11.3.2 above describe the statutory processes whereby traditional Aboriginal owners and native title holders are given an opportunity to negotiate an agreement about how petroleum exploration and production must occur on Indigenous land in the NT. The Panel has not sighted any of these agreements, however, the Panel understands that the agreements cover topics such as sacred site matters, environmental protection, roads, airstrips, cultural and social impacts, liquor and employment opportunities. The NLC and CLC have described the agreements as *"a cornerstone of traditional owner informed consent and control over use of their land."* [63]

With regard to sacred site protection, the Panel understands that exploration agreements include, *"specific terms and conditions… designed to ensure that companies cannot access land or undertake exploration activities without first having those activities present to and discussed by affected traditional Aboriginal owners."* [64]

This means that traditional owners have ongoing opportunities to have input into gas companies' work programs once the permit has been granted. It is clear from the submissions made by the Land Councils and gas companies that the agreements ensure that traditional owners have oversight of activities that are undertaken on country on a work-program-by-work-program basis. The NLC submitted that, under the terms of NLC agreements, traditional owners are consulted and their advice is sought to ensure that sacred sites and other culturally sensitive areas will not be impacted by a proposed works program. Amendments to the proposed works can be requested by the Land Council if it is apparent that such sites are likely to be affected, however, this should not be interpreted as a broad approval process.[65] As noted previously, Land Councils and traditional Aboriginal owners do not have the right to stop production once they have agreed to the grant of an exploration permit.

Origin provided the Panel with an outline of the consultation process that resulted in approval for activities associated with Amungee NW-1H well, which is on native title land and subject

57 Native Title Act, s 29.
58 Native Title Act, s 31.
59 Native Title Act, s 35.
60 Native Title Act, s 38(2).
61 DPIR submission 226, p 23.
62 Native Title Act, s 41A(1).
63 Mansfield Review, para 165.
64 NLC submission 214, p 37.
65 NLC submission 214, p 37; NLC submission 471.

to a native title agreement. Before activities commenced, *"Traditional Owner engagement on the abovementioned activities, and their consent, was sought by working with Traditional Owners and their statutory representative body. Origin received the final endorsement and consent for the horizontal well and hydraulic fracture stimulation at an On-Country meeting…Traditional Owners held a private meeting to discuss Origin's request for permission to drill on the cleared sites, and the result returned was a unanimous 'yes'."* [66]

Origin described how *"annual survey scouting and cultural heritage work"* was undertaken prior to deciding upon well locations and that native title holders' *"guidance and advice on where activities may or may not be suitable is factored into the decision-making process."* [67]

Santos' submission further indicated that native title agreements provide for ongoing consultation and consent with native title holders after the exploration permit has been granted:

> *"AAPA certification is the final approval we seek after carrying out extensive scouting and cultural heritage clearance work with traditional owners, who during these activities are supported by their statutory representative body, the northern land council. SANTOS has negotiated almost 50 agreements relating to cultural heritage, native title, and access to land based on early and fully informed consent without arbitration. We have not and we will not conduct activities until traditional owners have agreed to those activities, and sacred site certification is in place."* [68]

11.3.4 NT sacred sites legislation and AAPA

The Land Rights Act protects sacred sites on all forms of land tenure.[69] 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.[70] The Land Rights Act allows the Government to make laws, *"providing for the protection of, and the prevention of the desecration of, sacred sites in the Northern Territory."* [71]

The Government introduced the Sacred Sites Act in 1989. The Act is subsidiary legislation (that is, NT legislation) arising from s 73(1)(a) of the Land Rights Act, which establishes both the legislative basis for the protection of sacred sites and the powers of the Government to establish a body to administer that protection.[72] In its recent review of the Sacred Sites Act, PwC noted that, *"2016 marks the 27th year of operation of the NTASSA [the Sacred Sites Act]. During that time there has been no substantive changes made to the NTASSA and it has served its purpose of providing protection of sacred sites whilst allowing development on land to occur."* [73]

11.3.4.1 Sacred Sites Act

The Sacred Sites Act has been described as giving *"arguably the strongest cultural heritage protection powers in Australian legislation."* [74] The strength of the Act derives from, among other things, the statutory separation of AAPA from the Government, and the independence and Aboriginality of AAPA Board (see Section 11.3.4.2).[75]

The Sacred Sites Act is essentially a risk management framework for the protection of sacred sites in the NT. It establishes a system that protects sacred sites while providing for the development of land.[76] The Authority Certificate process (described in Section 11.3.4.3) balances the protection of sacred sites with development, by defining conditions for the protection of sacred sites in relation to proposed developments. The policy underpinning the Sacred Sites Act is to ensure that there are mechanisms in place dealing exclusively with sacred sites, as opposed to land use more generally (which is what the Land Rights Act and Native Title Act do).[77] AAPA submitted the following to the Mansfield Review, namely, that *"the Sacred Sites Act is the preferable means to protect sacred sites, because, inter alia, it "provides for decisions regarding the protection of sacred sites to be made independently from considerations regarding land access and land use."* [78]

66 Origin submission 469, p 15.
67 Origin submission 469, p 15.
68 Santos Ltd, submission 266 (**Santos submission 266**), p 17.
69 Land Rights Act, s 23(1)(ba).
70 Land Rights Act, s 3.
71 Land Rights Act, s 73(1)(a).
72 AAPA submission 234, p 4.
73 Sacred Sites Review 2016, p 21.
74 AAPA submission 234, p 7; Evatt 1996, pp 263-264, 314-320.
75 McGrath 2016, p 10; AAPA submission 234, p 7.
76 Sacred Sites Review 2016, p 17.
77 Sacred Sites Review 2016, p 16.
78 Mansfield Review, para 112.

11.3.4.2 AAPA

AAPA is a statutory body established under the Sacred Sites Act to administer sacred site protection in the NT. AAPA is governed by a 12-member board, 10 of whom are highly respected senior Aboriginal people that are custodians of sacred sites in the NT.[79]

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;[80]
- 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, that is, Authority Certificates.

11.3.4.3 Authority Certificates

The Sacred Sites Act makes it an offence to enter or remain on a sacred site,[81] work on a sacred site,[82] or desecrate a sacred site.[83] It is a defence to prosecution under that Act if the work was carried out in accordance with an Authority Certificate.[84] The requirement for an Authority Certificate is not mandatory under the Sacred Sites Act. A gas company can undertake a petroleum activity, such as drilling or hydraulic fracturing for onshore shale gas, without an Authority Certificate.[85]

Neither the EAA nor the Petroleum Act require that Authority Certificates be issued and complied with. The EPA, which administers the EAA, developed a guideline detailing when a petroleum project should be referred to it for an assessment.[86] The guideline provides that if certain criteria are met, the EPA will not assess the activity under the EAA. All of the answers to the criteria must be 'yes', or the proposal will be referred for assessment.[87] One criterion is whether the gas company has submitted an application to AAPA for an Authority Certificate. But there is no guarantee that the gas company will keep the application going once the assessment is complete, or that an Authority Certificate will ever be granted. The EPA and the Minister for Environment can only recommend to the *"responsible"* Minister (the Minister for Resources) that the gas company should be required to have an Authority Certificate prior to development, but the Minister for Resources is not required to adopt that recommendation. Currently, the only condition placed on petroleum permits by the Minister for Resources is that, *"Prior to carrying out any work in the permit area the permittee must consult with the Aboriginal Areas Protection Authority and inspect the Register of Sacred Sites. A permittee wishing to carry out work may apply for an Authority Certificate."* [88]

It is clear that gas companies are electing not to get an Authority Certificate to undertake petroleum activities. AAPA submitted that, *"In reviewing applications for Authority Certificates related to hydraulic fracturing for the purposes of this submission it has come to light that despite Authority Certificates being a key requirement of broader environmental approvals, a number of proponents have, upon receipt of other approvals, subsequently withdrawn their applications for Authority Certificates."* [89]

The issuing of Authority Certificates by AAPA has been described as the *"key"* process for protecting sacred sites in the NT.[90] AAPA can only issue an Authority Certificate if it is satisfied that either, *"(a) the work or use of the land could proceed or be made without there being a substantive risk of damage to or interference with a sacred site on or in the vicinity of the land; or (b) an agreement has been reached between the custodians and the applicant."* [91]

In other words, AAPA must be satisfied that one of the above two requirements has been met

79 AAPA submission 234, p 5.
80 Sacred Sites, Act, s 19F.
81 Sacred Sites Act, s 33.
82 Sacred Sites Act, s 34.
83 Sacred Sites Act, s 35.
84 Sacred Sites Act, s 34(2).
85 AAPA submission 234, p 23.
86 NT Environmental Assessment Guidelines.
87 NT Environmental Assessment Guidelines, p 6.
88 Department of Primary Industry and Resources, submission 298 (**DPIR submission 298**), Attachment A, items 16 and 17.
89 AAPA submission 234, p 21.
90 AAPA submission 234, p 18.
91 Sacred Sites Act, s 22(1).

before an Authority Certificate can be issued. Authority Certificates can be issued following consultations between AAPA and custodians whereby custodians provide instructions on what can and cannot be done in and around sacred sites.[92]

The Land Councils and the gas industry support the principle of ensuring that sacred sites are identified and appropriate protection measures put in place at an early stage of any onshore shale gas development process.[93] However, the CLC submitted that mandating that gas companies be required to obtain an Authority Certificate prior to undertaking any onshore shale gas activity could lead to duplication in the approvals process, specifically with respect to obtaining agreements under the Land Rights Act and Native Title Act.[94]

The Panel notes that it is existing practice for issues relating to sacred sites to be dealt with as part of the agreement-making process under the Land Rights Act and Native Title Act and that, *"Land Councils usually take the approach that, for major projects, issues relating to sacred sites are negotiated simultaneously with compensation and royalties."* [95] Such agreements, negotiated by the Land Councils in accordance with their functions under the Land Rights Act or the Native Title Act (see Sections 11.3.1 and 11.3.2 above), are "agreements" within the meaning of s 22(1)(b) of the Sacred Sites Act, and therefore, grounds for AAPA issuing an Authority Certificate without any duplication of the consultation process. The Panel further notes that the Sacred Sites Act is complementary legislation to the Land Rights Act, and in relation to agreements relating to a specific sacred site, gives pre-eminence to the wishes of the *"Aboriginal who, by Aboriginal tradition, has responsibility for that site."* [96] The Panel concludes that a requirement mandating the gas industry to obtain an Authority Certificate provides certainty for the industry and will not lead to unworkable duplication or *"diminish the rights of host traditional owners by giving rights to non-host stakeholders."* [97]

For AAPA to issue an Authority Certificate on the basis of the agreement, AAPA needs to be satisfied that the "*custodians"* of the particular site, who may be different from the traditional Aboriginal owners or native title holders that were consulted in respect of the agreement, consent to the terms that relate to protection of sacred sites. If AAPA is satisfied, it can issue an Authority Certificate on the basis of the agreement reached with traditional Aboriginal owners and the gas company.

While there are strong legal mechanisms under the Land Rights Act and the Native Title Act, whereby traditional owners can negotiate provisions to be inserted into an agreement to protect sacred sites, the law does not mandate that those agreements include provisions about sacred sites and the Panel cannot confirm that they exist, or if they do, that they are adequate.[98] Therefore, evidence of an agreement under the Land Rights Act or Native Title Act is not *prima facie* evidence that sacred sites will be protected, especially when such agreements are confidential.

The Sacred Sites Act has been designed with the express purpose of protecting sacred sites on a case-by-case basis, and the issuing of an Authority Certificate provides certainty that:

- the "custodians" for the site have been consulted;
- impacts to sacred sites have been considered independently from any other matters that are dealt with in native title and land agreements; and
- AAPA is able to enforce the conditions of the Authority Certificate.

As Santos submitted, *"the Sacred Sites Act in its current form is functional legislation that ensures best practice in identification and protection of sacred sites."* [99] It is the Panel's view that the gas industry should use the sites avoidance procedures offered by the Sacred Sites Act on all areas of land other than inalienable freehold title (that is, Aboriginal land) within the meaning of the Land Rights Act.

92 AAPA submission 234, p 8.
93 NLC submission 647; Central Land Council, submission 1151 (**CLC submission 1151**); Origin submission 1248; Santos submission 1249.
94 CLC submission 1151.
95 Sacred Sites Review 2016, p 40; see also Mansfield Review, para 112.
96 Sacred Sites Act, s 3, definition of custodian.
97 Santos submission 1249.
98 Land Rights Act, s 73(1)(a).
99 Santos submission 1249.

Recommendation 11.1

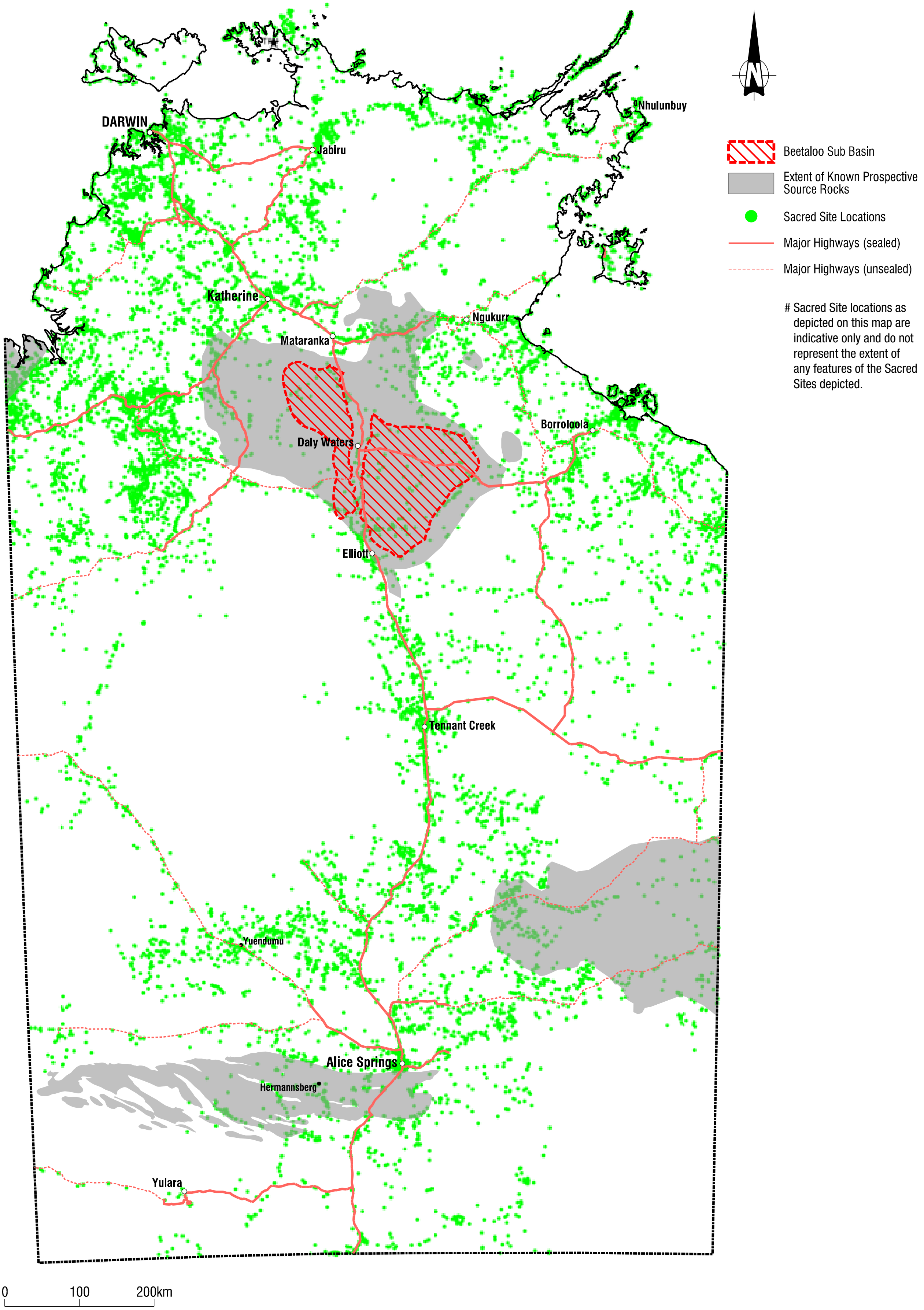
That gas companies be required to obtain an Authority Certificate prior to the grant of any exploration and production approvals.

11.3.4.4 Registration of sacred sites

AAPA records the features and narratives of sacred sites in the Register of Sites. The Act prescribes that the Authority shall do this by consulting the Aboriginal custodians of the sacred site who are the holders of the associated knowledge or story, song and ceremony and who have responsibilities in accordance with Aboriginal tradition for the care of the sacred site. The benefit of registration is that it is *prima facie* evidence of a sacred site and provides certainty to all stakeholders about the existence of a sacred site, the geographic extent of a sacred site, and who its custodians are.[100] AAPA holds records of more than 12,000 sacred sites in the NT (see **Figure 11.5**). Of these, approximately 2000 are registered sites. The records held by AAPA represent a fraction of sacred sites in the NT, with vast numbers yet to be documented.[101]

100 AAPA submission 234, pp 8-9.
101 AAPA submission 234, pp 8-9.

Figure 11.5: Potential shale gas resources and recorded sacred sites in the NT.



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11.3.5 Environmental assessment legislation

Petroleum developments that will have a significant environmental impact must be assessed under the EAA.[102] The definition of *"environment"* in that Act includes *"all aspects of the surroundings of humans, including…cultural aspects"*. This means that the EPA is required to consider cultural matters when making its assessment. In practice, cultural matters are dealt with by the EPA by ensuring that an application has been made to AAPA for an Authority Certificate under the Sacred Sites Act in respect of the proposed activity (see Section 11.3.4.3), and by giving AAPA an opportunity to comment on an EIS.

The Panel's view is that this process does not ensure that cultural matters are adequately addressed. AAPA noted that while it is invited to comment on an EIS, its comments *"are confined to matters of sacred site protection and typically highlight whether an Authority Certificate application has been lodged, or not, in relation to the proposal."*[103]

The process required by the Sacred Sites Act *"runs in parallel and exclusive of the environmental approvals process."*[104] The Panel's view is that cultural matters must be considered in conjunction with, and not separate from, other environmental matters. In light of the significant impacts (including social impacts) that damage to sacred sites will have on Aboriginal people and their communities, the cultural impacts of any onshore shale gas development should be an early consideration for custodians, gas companies and the regulator.

The Panel received submissions that the current framework for the protection of underground sacred sites and culturally significant places in the NT is restricted because AAPA has limited technical and scientific expertise to understand and interpret the hydrogeological impacts that horizontal drilling and large water extraction will have on sacred sites. AAPA has observed that it *"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."*[105]

If AAPA does not understand these impacts then it is very difficult to explain them to custodians (which, in turn, inhibits their ability to give informed consent), provide meaningful input into the environmental assessment process, or to draft and place appropriate conditions on Authority Certificates. Central to the effective management and protection of subsurface sacred sites is transparent, trusted, reliable and clear information about the impact that drilling and hydraulic fracturing for onshore shale gas will have on the subsurface environment. Only if this information exists and is provided to AAPA for early consideration can AAPA effectively perform its function of protecting sacred sites. As AAPA stated, *"In order to impose such conditions, the Authority must have clear knowledge of the hydrology of the area, and also of the potential impacts of the activity on the hydrology and associated sacred sites in the vicinity of the application area."*[106] Accordingly, there must be *"a coordinated formal approvals process that would allow the Authority to access necessary technical appraisals from other regulatory bodies and build these into the Authority Certificate process."*[107]

Recommendation 11.2

That AAPA:

- ***be provided with a copy of any application to conduct hydraulic fracturing for onshore shale gas under petroleum environment legislation at an early stage of the assessment and approval process;***
- ***be given an adequate opportunity to explain the application to custodians; and***
- ***be given an adequate opportunity to comment on the application and have those comments considered by the decision-maker.***

102 EAA, s 4.
103 AAPA submission 234, p 20.
104 AAPA submission 234, p 20.
105 AAPA submission 234, pp 2, 18, 22.
106 AAPA submission 234, p 18.
107 AAPA submission 234, p 22.

11.4 Risks to Aboriginal culture and traditions

11.4.1 Sacred sites

Concerns were expressed in a number of submissions and at all the community consultations that the development of any onshore shale gas industry will damage sacred sites and other places of spiritual significance to Aboriginal people.[108] A particular issue is damage to culturally significant features that exist underneath the surface.

If sacred sites, including sub-surface sites, are damaged, or there is a disruption to traditional practices, the adverse consequences for Aboriginal people, particularly the adverse social consequences, may be high. As AAPA noted, *"sanctions apply in a corpus of Indigenous law to the use and protection of such places, and transgression of these is likely to cause significant socio-cultural repercussions."*[109]

The loss of the amenity value of a sacred site for the education of future generations could result in a feeling of powerlessness and failure engendered in the custodians of the site. The potential for this arises because of the direct personal responsibility Aboriginal people have for looking after country. An inability to protect a sacred site is likely to invoke a feeling of loss of control.[110] 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. AAPA summarised these effects as follows,

> *"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."* [111]

11.4.1.1 Subsurface sites must be protected

It is widely acknowledged that sacred sites can, and do, extend underground. AAPA told the Panel that, *"Aboriginal beliefs about the sanctity of land encompass beliefs, knowledge and sanctions… 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."* [112]

The Panel is aware of cases in the NT where traditional owners have rejected mining proposals because of their traditional beliefs about what lies beneath the surface.[113] The Panel notes a document on land management published by the CLC in the mid-1990s with a section entitled *"Dreamings go underneath"*, which evidenced the fact that Aboriginal people in the study area considered that the rocks and minerals beneath the ground were 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'."* [114]

That report goes on to quote an Aboriginal person who stated 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."* [115]

The CLC records that these views were expressed by Aboriginal people at Yuendumu, Lajamanu and Tennant Creek, where it is claimed that an earthquake was attributed to underground mining

108 See generally, NLC submissions 214 and 471; AAPA submission 234; CLC submission 47.
109 AAPA submission 234, p 12.
110 AAPA submission 234, p 16.
111 AAPA submission 234.
112 AAPA submission 234, p 14; NLC submission 471, p 20.
113 Scambary and Lewis 2016; Stewart 1991.
114 Rose 1995; CLC submission 47, p 141.
115 Rose 1995; CLC submission 47, p 141.

activities. The Panel heard comparable stories about the Tennant Creek earthquake during its community consultations. At a meeting between the Chair and the Board of AAPA, several board members expressed views similar to those recorded by the CLC.

AAPA has expressed the opinion that there is some uncertainty about whether subsurface formations can be features of, or comprise, a *"sacred site"* within the meaning of existing site protection legislation in the NT.[116] It is arguable that only surface sites are protected by the Sacred Sites Act. By contrast, the NLC has stated that, *"under Northern Territory legislation all sacred sites are protected, including the sacred sub-surface elements of these places."* [117] The Panel's strong view is that it should be put beyond doubt that features of a sacred site, and sacred sites themselves, can be underground, and must be protected.

The NTCA holds a contrary view, submitting that:

*"The pastoral industry strongly opposes this recommendation [**Recommendation 11.3**] for the following reasons:*

1. *The term 'sub-surface formations' is subjective, and is difficult to quantify because it is under the ground and unable to be seen, and therefore cannot be reliably quantified. The term has the potential to include anything under the surface. Pastoralists access sub-surface formations, mainly through water bores, to extract water for stock and domestic purposes. This is a fundamental right, and this is critical for pastoral operations. Therefore, changing the Sacred Sites Act to include sub-surface formations has the potential to grant Aboriginal people the right to veto this fundamental right to water.*
2. *Under the current Sacred Sites Act, if clearance is required for any kind of work, including construction of a road, fence, water bore or yards (for example) an Aboriginal Areas Protection Authority Clearance Certificate is required. To acquire such a certificate takes considerable time (sometimes between six months and two years), at considerable cost and inconvenience to the pastoralist.*
3. *If, during daily operations artefacts are uncovered, they become instantly protected and work must cease immediately as part of current legislation. This indicates that the Sacred Sites Act in its current form is sufficient to protect sacred sites."* [118]

The Darwin Major Business Group was also opposed to ***Recommendation 11.3***.[119] However, Santos has given the Recommendation in-principle support,[120] and Origin submitted that it would accept the changes proposed in ***Recommendation 11.3*** subject to *"a clearly defined framework in place that defines what formations or features meet criteria".* [121]

AAPA, after considering the NTCA's submission, acknowledged the need for full consultation with stakeholders before determining how to give effect to this Recommendation but maintains its support for the amendment:

"The Authority has expressed in its supplementary submission to the NT Hydraulic Fracturing Inquiry its willingness to explore the legal and policy implications of such an amendment to the Northern Territory Aboriginal Sacred Sites Act. Further the Authority refutes the assertions of the NTCA that inclusion of Recommendation 11.3 in the final report of the NT Hydraulic Fracturing Inquiry will cause any disruption, detriment, increased regulation and cost to the pastoral industry. Rather than creating conflict between Traditional Owners and pastoralists the Authority is of the view that exploration of the issues surrounding this recommendation may promote greater understanding between traditional owners and pastoralists, and may elucidate common values surrounding the protection and management of water. Removal of this recommendation at this time would prevent the detailed analysis that is required to determine the viability of this idea and thus the Authority believes the recommendation should remain." [122]

The Panel has carefully considered the submissions from industry, other relevant stakeholders, and AAPA. The Panel notes that the definitions and processes under the Sacred Sites Act ensure that there must be a demonstrable basis, according to Aboriginal tradition, for a sacred site to be protected. These processes will apply in respect of sub-surface site features. Having regard to

116 AAPA submission 234 p 2.
117 NLC submission 471, p 20.
118 NTCA submission 1199, p 1.
119 Darwin Major Business Group, submission 536.
120 Santos Ltd, submission 1198 (**Santos submission 1198**).
121 Origin submission 1248.
122 Aboriginal Areas Protection Authority, submission 1150 (**AAPA submission 1150**), addendum.

the support for this recommendation received by the Panel, including in the course of community consultations, the Panel has retained ***Recommendation 11.3***, but notes that the usual practice of stakeholder engagement should take place before initiating changes to legislation.

Recommendation 11.3

That the Sacred Sites Act be amended to protect all sub-surface features of a sacred site.

11.4.1.2 Groundwater must be protected

Water is important both in terms of resource use, and its associated cultural value, and there are numerous instances of water being a key feature of sacred sites.[123] Water as a life source is also integrally associated with identity, country and conception:

"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." [124]

Some Aboriginal people refer to themselves as 'freshwater' or 'saltwater' people, and use water to introduce themselves and strangers to country to ensure that the ancestors who are imbued in the landscape recognise them and do not harm them:

"Our water is part of our native title through our cultural and ceremonial practices that are part of the birds, animals, plants and us." [125]

Aboriginal custodians have identified many water sources and waterbodies as sacred sites in the records held by AAPA. Contamination of these water bodies and water sources is a matter of significant concern, with a common belief that ritual cycles and the meaningful exchange of resources between clans may be threatened. Aboriginal people commonly attribute fertility and the health of humans to the health and ceremonial maintenance of sacred sites. These are the wider potential cultural impacts that comprise the relationships between people, the land, sacred sites, ritual activities, and interpersonal and wider inter-group social responsibilities.[126]

This special relationship makes Aboriginal people, and therefore, Aboriginal communities, particularly vulnerable to degradation of the landscape and the ecological systems that it supports. Particular concern was therefore expressed about the potential risks to surface and groundwater sources: *"groundwater-fed rivers, springs, waterholes and stream are not only of ecological importance, but, in many cases hold cultural significance."* [127]

Water extracted from groundwater for use in hydraulic fracturing may cause an aquifer to be depleted and a spring that is sacred under Aboriginal tradition to dry up. Not only will there be no more water and the sacred site destroyed, but there will be other social costs.[128] AAPA submitted that, *"intensive inland hydraulic fracturing activity has the potential to bring significant pressure on permanent water sources, which are likely to be of cultural significance to Aboriginal people including specific sacred sites."* [129]

The Panel notes that the policy and legislative framework for water allocation in the NT recognises a special benefit provided by certain water sources for *"the condition of places that provide physical and spiritual fulfilment to Indigenous people"*, which are referred to as "*cultural flows*".[130] Under the Water Act, the Minister for Environment is able to declare a *"beneficial use"* for water in a WCD (see Chapter 7).[131] The use of water for cultural purposes, including to *"provide water to meet aesthetic, recreational and cultural needs"*, is a *"beneficial use"* of water. [132] The Minister for Environment can declare WAPs to ensure that water is allocated to the beneficial uses that have been declared. There are consumptive and non-consumptive beneficial uses for water, and non-consumptive water is allocated as a priority under the NT Water Allocation Planning Framework.[133] In the absence of scientific data supporting some other type of allocation, non-consumptive uses, including environmental and cultural uses, are allocated 80% of the recharge rate or resource.[134] Consumptive water uses are those that are allocated for domestic or industrial consumption. These uses cannot exceed 20% of the recharge rate or resource.

123 AAPA submission 234, p 14.
124 AAPA submission 234.
125 NLC submission 214, p 15.
126 AAPA submission 234, pp 14-15.
127 NLC submission 214, p 15.
128 Watts 2008.
129 AAPA submission 234, p 16.
130 Tindall Aquifer Water Allocation Plan.
131 Water Act, s 22B.
132 Water Act, s 4(3)(e).
133 Water Allocation Planning Framework.
134 Water Allocation Planning Framework; DENR submission 230, p 2.

Cultural uses of water are often inextricably linked with environmental uses and treated as the same allocation.[135] The Tindall Aquifer Water Allocation Plan assumes that the: *"provision of discharge for environmental protection will also maintain the condition of places that are valued by Indigenous people for cultural purposes."*[136]

However, the Plan also recognises that cultural and environmental objectives may not always be in conformity and that *"it is recognised that cultural flow requirements may not align entirely with environmental requirements and any research that becomes available in this regard will be considered as part of the review process."*[137]

The Panel is satisfied that the current regulatory framework ensures that cultural uses of water are factored into the water allocation process. The Government recently announced a Strategic Aboriginal Water Reserve, which will allow Aboriginal people to have water allocated to them for economic development (different to cultural uses).

11.4.2 Traditional Aboriginal owners, native title holders, and their right to be consulted and consent to any onshore shale gas development

International law recognises the right of Aboriginal people to be informed and consulted in respect of the resource development occurring on their country. The *International Labour Organisation's Indigenous and Tribal Peoples' Convention 1989* (**Convention 169**), which is the only international treaty specifically dedicated to Indigenous peoples, has provisions mandating that Indigenous people be consulted with respect to development on their land. Article 15 of Convention 169 requires that member states consult Indigenous people *"with a view to ascertaining whether and to what degree their interest would be prejudiced, before undertaking or permitting any programmes for the exploration or exploitation of such resources pertaining to their lands."*[138] The Australian Government has not, however, ratified Convention 169.

Another example of Indigenous peoples' right to be consulted about resource development on their land is the *United Nations Declaration of the Rights of Indigenous Peoples* (**UN Declaration**), which was adopted by the General Assembly in 2007. More than 143 countries, including Australia, have endorsed the UN Declaration, which contains an express obligation for member states to *"consult with an cooperate in good faith with the indigenous peoples… to obtain their free and informed consent prior to the approval of any project affecting their lands or territories and other resources, particularly in connection with the development, utilisation or exploitation of minerals, water or other resources."*[139] While the UN Declaration is not legally binding in Australia, it nevertheless has the power to influence domestic law-makers and decision makers. Convention 169 and the UN Declaration make it clear that Indigenous people have an international law right to be consulted in good faith about development on their land. These instruments do not, however, provide any definitive statement that Indigenous people have the right to consent, or refuse consent (veto), to development on their land. The right to be consulted about the development of a resource is something less than the right to consent and does not amount to the right to say 'no'.[140]

There is an emerging principle that Indigenous people should have the right to consent, or refuse consent, to resource development on their land. It is often referred to as the principle of free, prior and informed consent (**FPIC**) and there are various international examples where this principle has been adopted.[141] The Land Rights Act is referred to in the literature as a high-water mark of how domestic law can operationalise the principle of FPIC.[142] The Panel heard, however, that the absence of a veto right at the production phase of any onshore shale gas development (see Section 11.3.1) means that the Land Rights Act falls short of implementing the principle of FPIC. Traditional Aboriginal owners can only exercise their veto right at the exploration phase. If traditional Aboriginal owners say 'yes' to exploration they also say 'yes' to production, even if they

135 Tindall Aquifer Water Allocation Plan, p 5.
136 Tindall Aquifer Water Allocation Plan, p 8.
137 Tindall Aquifer Water Allocation Plan, p 8.
138 Convention 169, Art 15(2).
139 UNDRIP, Art 32.
140 See, for example, McGee 2009, p 578.
141 Many papers provide summaries outlining the growing acceptance of the principle of FPIC. See Doyle and Carino 2013, p 26; Ward 2011, p 54.
142 Sosa 2011, p 6; World Resources Institute 2007, p 9 stating that *"FPIC has… been incorporated in the mining law in Australia's Northern Territory"*; Rumler 2011 stating that *"the legislative provisions and practice together provide a good model for the implementation* of the principle of FPIC."

know very little about the scope and scale of the project.[143] Therefore, if traditional Aboriginal owners want development on their country, they are forced to make a decision at a time where there is limited information available about what the size of the final project will be.[144]

Justice Mansfield considered this matter in his 2013 review of Pt IV of the Land Rights Act. His Honour considered the arguments for and against the removal of the exploration veto and also considered whether the veto would be better placed at the production phase of any project.[145] His view was that the exploration veto should be retained because, as noted by Woodward J,[146] *"to deny to Aborigines the right to prevent [development] on their land is to deny the reality of their land rights."* [147] However, to impose a veto at the production stage of any petroleum development would *"provide no certainty for applicants, and could discourage [exploration applications] on Aboriginal land entirely".*[148] In other words, gas companies need certainty that they will be able to get a production licence provided that they comply with all permit conditions and negotiate a production agreement with traditional Aboriginal owners and the relevant Land Council, as is required by the Land Rights Act.[149] In this context, it should be noted that there used to be a production veto in the Land Rights Act but that it was removed for this purpose.[150]

11.4.2.1 Consultation under land rights and native title legislation

The Panel is satisfied that the consultation processes required under the Land Rights Act and the Native Title Act ensure that traditional Aboriginal owners and native title holders are informed and consulted about development on their country.[151] While there is no statutory right of veto in respect of the grant of an exploration permit under the Native Title Act, the Panel has been told, and accepts, that the *"future act"* provisions of that Act ensure that native title holders are informed and consulted about activities that are occurring on native title land. Accordingly, the NLC submitted there is a *"negligible risk that a project would be able to proceed without the knowledge of, or without prior consultation with, Aboriginal people."*[152]

Traditional Aboriginal owners and native title holders are consulted at least two times in connection with a petroleum exploration permit on Aboriginal and native title land. The NLC described the process for consultation on native title land and Aboriginal Land as follows,

> *"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."* [153]

The CLC submitted that the consultation and agreement making process under the Native Title Act can be strengthened. Under the Land Rights Act gas companies must provide Land Councils with a comprehensive proposal of the exploration activities proposed to be undertaken if the permit is granted to assist them in negotiating an exploration agreement ('s 41 applications').[154] A cognate requirement is not contained in the Native Title Act. The CLC submitted that the absence of this requirement in the Native Title Act undermines the ability of native title holders to fully understand the nature of the development proposed. [155]

143 EDO submission 213; Dixon submission 381. The Panel notes that the Dixon family do not claim to be traditional owners of the area of the Origin Energy Amungee NW-1 lease area and, as such, they were not directly involved in the negotiations conducted by the NLC for the agreement with native title holders prior to the issue of the licences under the Petroleum Act: Dixon submission 381, p 6.
144 The Tiwi Land Council made similar arguments to the Mansfield Review. See Mansfield Review, para 148.
145 Mansfield Review, para 6.
146 Mansfield Review, paras 415, 429.
147 Woodward Report, para 568.
148 Mansfield Review, para 427.
149 Land Rights Act, s 46.
150 Mansfield Review, para 417, 426.
151 In *Gondarra v Minister for Families, Housing, Community Services and Indigenous Affairs* [2014] FCA 25 Kenny J held that a requirement to *"consult"* meant that the Land Council must "*confer with*" traditional owners and give them *"a meaningful opportunity"* to present their views.
152 NLC submission 214, p 35.
153 NLC submission 214, p 35.
154 Land Rights Act, s 41(6).
155 CLC submission 47, pp 10-11.

Recommendation 11.4

That gas companies be required to provide a statement to native title holders containing information of the kind required under s 41(6) of the Land Rights Act for the purposes of negotiating an onshore shale gas exploration agreement under the future act provisions of the Native Title Act.

Concerns were raised from various stakeholders, including Aboriginal people, about whether traditional Aboriginal owners and native title holders understand the terms and conditions of the agreements that are entered into under either the Land Rights Act or the Native Title Act.[156] In particular, and as the Panel has experienced during community consultations, communicating complex technical aspects of any onshore shale gas industry, including hydraulic fracturing, is challenging. The Land Councils highlighted the difficulties associated with consulting on technical scientific and engineering matters stating that, *"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."*[157]

The Panel notes the submission from Origin Energy that ***Recommendation 11.5*** should include the proviso that, "*where requested by land councils and host traditional owners.*"[158] However, the Land Councils have strongly supported the Recommendation as it stands:

The CLC recommended that, *"In discussing a shale gas industry and/or hydraulic fracturing process, interpreters are essential as many traditional Aboriginal owners speak their own languages with English a second or third language."*[159]

The Panel's experience when engaging in community consultations was that interpreters are necessary when explaining complex scientific subject matters. Based on the Panel's first-hand experience, there is no reason to suggest that common sense will not prevail in circumstances where stakeholders make it tolerably clear that they understand what is being presented without the aid of interpreters.[160]

Recommendation 11.5

That interpreters be used at all consultations with Aboriginal people for whom English is a second language. Interpreters must be appropriately supported to ensure that they understand the subject matter of the consultation.

11.4.3 The broader Aboriginal community

As described in Section 11.3, the Land Rights Act and the Native Title Act set out a legal process that ensures traditional Aboriginal owners and native title holders are informed and consulted about the grant of a petroleum exploration permit on Aboriginal and native title land. Traditional Aboriginal owners and native title holders, however, form part of a broader community that will be affected by the development of the onshore unconventional shale gas industry. As the NLC observed, *"Indigenous traditional landowners and native title holders with rights to country over which there is a current petroleum title application comprise only a small portion of the Northern Territory's Indigenous population."*[161]

The broader Aboriginal community, like any community, is entitled to accurate, trusted, and accessible information about any onshore shale gas industry in order to understand the consequences of a development or industry so that they can make informed decisions about how their community can benefit from it. The Panel received an abundance of evidence that the broader Aboriginal community was not being appropriately informed about hydraulic fracturing or the potential for an onshore shale gas industry more broadly:

- the NLC, CLC and AAPA all raised concerns about the increased stress and social disharmony in Aboriginal communities where hydraulic fracturing has been proposed. This has arisen in part as a result of a lack of reliable and accessible information about the shale gas industry and a general lack of understanding about how the current legislation

156 EDO submission 213, Mr Daniel Tapp, submission 405 **(D Tapp submission 405)**, p 2.
157 CLC submission 47, p 8.
158 Origin submission 1248.
159 CLC submission 47, p 8.
160 CLC submission 47, pp 8-10.
161 NLC submission 471, pp 18-19.

(including the Land Rights Act, Native Title Act and Petroleum Act) provides opportunities to redress concerns about the effects of that industry on Aboriginal culture;

- evidence from the Aboriginal environmental group Seed (an affiliate of the Australian Youth Climate Coalition), which had travelled to Aboriginal communities in the Barkly region to explain the nature and purpose of any onshore shale gas industry,[162] that Aboriginal people from these communities have inadequate knowledge about the industry. Seed found that the Aboriginal people they spoke to had no knowledge of the techniques used in the horizontal drilling and hydraulic fracturing of deep shale rock, and when these facts were put to Aboriginal people they expressed great concern; and[163]
- the response to presentations by the Panel at community consultations on the processes involved in hydraulic fracturing for onshore shale gas suggests that knowledge of the likely impacts of this industry within the Aboriginal community in the Beetaloo Sub-basin, and more widely, is wholly inadequate.[164]

The lack of trusted, reliable, and accessible information about hydraulic fracturing specifically, and more generally, about any onshore shale gas industry in remote Aboriginal communities has resulted in: first, communities feeling disempowered; and second, communities being divided between those in favour of hydraulic fracturing and those against it. The conflict is largely the result of either 'pro-fracking' or 'anti-fracking' groups that have filled an information void with misinformation. The NLC noted that, *"the direct engagement or recruitment of Aboriginal persons by individuals/organisations with an interest on either side of the [fracking] debate may pose a risk to social cohesion and to relationships/roles associated with traditional kinship systems that may exist between such individuals."* [165] And further that, *"the politicisation [of petroleum consultations] can and does have an incredibly disruptive effect on Aboriginal culture and society and on local group decision-making processes."* [166]

The CLC also warned that information being provided to Aboriginal groups "*tends to be industry or anti-fracking centric and subject to bias and misinformation.*"[167] The Panel was told that some Aboriginal people in remote communities had been given "*misinformation*" and "*unsubstantiated propaganda*"[168] specifically designed to frighten them about any onshore shale gas industry in the NT.

The Panel agrees with the NLC's observation that, *"there is an urgent need for the dissemination of relevant, accurate information targeting Aboriginal communities, in respect of both hydraulic fracturing and the onshore petroleum industry in general."* [169] This gives rise to a question about which is the appropriate agency or organisation to deliver information to Aboriginal communities about any onshore shale gas industry and how the information dissemination process should be implemented.

The Land Councils submitted that they had implemented a variety of measures to increase understanding of any onshore shale gas industry in Aboriginal communities. For example, the CLC noted that it had undertaken site visits, panel sessions, and presentations to their members, as well as community information presentations.[170] The NLC, however, made it very clear that, in its opinion, it was not the statutory responsibility of the Land Councils to ensure that the broader Aboriginal community was informed about hydraulic fracturing:

"general public or community education is not a function contemplated by the Lands Right Act or the Native Title Act, the NLC is not resourced to undertake pre-emptive public or regional education campaigns".[171]

162 Seed Indigenous Youth Climate Network, submission 267 (**Seed submission 267**).
163 Seed submission 267.
164 See, for example, Dixon submission 381.
165 NLC submission 471, p 17.
166 NLC submission 471, p 19.
167 CLC submission 47.
168 Mr Jim Sullivan, submission 73; Frederika Saltmarsh, submission 644.
169 NLC submission 471, p 18.
170 CLC submission 47, p 5.
171 NLC submission 471, pp 18-19.

Land Councils are not currently funded to perform this task. The NLC submitted that, with respect to informing Aboriginal people about any onshore shale gas development, the statutory role of the Land Councils is,

> *"limited to providing information to Aboriginal people in respect of specific petroleum exploration and production tenement applications and where agreements are in place for granted tenements. The dissemination of information to the Indigenous public in respect of a growing onshore petroleum industry does not fall within the scope of Land Council's statutory functions and as a result the NLC is currently neither mandated nor resourced to undertake this work".*[172]

The NLC has indicated to the Panel that it is "*prepared to assist in consultation with Aboriginal people across lands with the potential to be impacted by the onshore petroleum industry in the NLC region. Provision of adequate funding to achieve the task is a critical proviso in this undertaking, as it is important that the NLC's organisational resources and capacity to fulfil statutory functions under the NTA and ALRA are not compromised."*[173]

The unique expertise and long-term relationships built up over many decades held by AAPA and the Land Councils place them in a unique position to provide the expertise and experience necessary to conduct, design and implement a process for wider consultation, provided that they are sufficiently resourced, and provided the Land Councils work in collaboration with both Government and the gas industry.

Community members at the Inquiry's Jilkminggan community forum in August 2017.

Recommendation 11.6

That in collaboration with the Government, Land Councils and AAPA, an independent, third-party designs and implements an information program to ensure that reliable, accessible, trusted and accurate information about any onshore shale gas industry is effectively communicated to all Aboriginal people who will be affected by any onshore shale gas industry.

That the program be funded by the gas industry.

172 NLC submission 471, p 17.
173 NLC submission 647, p 20.

Concerns were raised about the lack of transparency surrounding petroleum exploration agreements made under the Land Rights Act and Native Title Act.[174] The Panel heard that the confidentiality of agreements negotiated with the gas industry has contributed to a widespread belief among Aboriginal people that these agreements do not represent the wishes of traditional Aboriginal owners who have affiliations with the relevant country and that there are Aboriginal people who are the beneficiaries of these agreements and who have given their consent without fully understanding the nature and impact of the proposed works contained in them.[175] The Panel heard from Aboriginal people who believed that they were not entitled to a copy of an agreement to which they were signatories.[176] Lack of transparency appeared to be the cause of tension and conflict.

As stated above, the only people entitled to see copies of negotiated and signed agreements under the Land Rights Act are the traditional Aboriginal owners. Elsewhere in this Report, the Panel has recommended the mandatory public disclosure of all draft and approved management plans, Ministerial approvals, and statement of reasons relating to the development of any onshore unconventional shale gas industry (Chapter 14). The Panel's view is that full transparency is essential to increasing the community's trust in, and knowledge about, any onshore shale gas industry, but the Panel also accepts the argument that, *"the privacy and confidentiality of an agreement is a matter for the parties of any given agreement to negotiate."* [177]

While it is ultimately a matter for the Land Councils, traditional Aboriginal owners and gas companies, the Panel recommends that Land Councils, traditional Aboriginal owners and gas companies consider making all, or if this is not appropriate, part, of petroleum exploration agreements publicly available so that the Aboriginal community has some understanding of the contractual obligations contained within them, especially with respect to the protection of sacred sites and the environment. Methods such as the redaction of sensitive information ought to be able to be used to maintain an adequate level of confidentiality.

Recommendation 11.7

That Land Councils, traditional Aboriginal owners and gas companies consider making all, or if this is not appropriate, part of petroleum exploration agreements publicly available.

Another source of potential stress in Aboriginal communities is the different benefits (for example, compensation payments or employment opportunities) that flow to individuals within a community. Traditional Aboriginal owners and native title holders are entitled to financial benefits resulting from the private contractual arrangements entered into under the Land Right Act and the Native Title Act, but as noted by the NLC, *"the injection of benefits and opportunities into particular land owning groups or local communities arising from resource development projects, where such developments are major, can create local and regional discrepancies in wealth. This can cause intra and inter family/community stress among Aboriginal people, who are typically bound to particular economic modes and relationships within and between families and communities by kin-based systems."* [178]

The Panel is of the view that distribution of financial benefits under the Native Title Act and the Land Rights Act is a matter for Land Councils (as one of their core statutory functions) and traditional Aboriginal owners. While the Land Councils are cognisant of the social impacts that royalty distributions can cause in a community , they do not *"have capacity to redress or mitigate all the attendant impacts and effects of the distribution of such benefits. This should be the subject of consideration by social and cultural impact assessment specialists and as part of the EIA process during a targeted analysis of the impacts of any given proposal."* [179] The cumulative impact of the distribution of royalties and other benefits within affected communities is an important component of the comprehensive assessment of social and cultural impacts that forms part of the Panel's proposed SREBA (see Chapters 12 and 15 and ***Recommendation 11.8***). Another source of tension felt by traditional Aboriginal owners is the stress associated with decision-making under the relevant legislation. This arises when traditional Aboriginal owners are required to consider economic returns from new uses of the resources on their country balanced against the need to protect traditional culture:

174 Ms Monica Napper, submission 455 (**M Napper submission 445**), p 3.
175 M Napper submission 455, p 1; Dixon submission 381, p 6. This issue was also raised at community consultations in Jilkminggan and Katherine.
176 Ms S Baker, community consultation, Jilkminggan, 15 February 2018.
177 NLC submission 647, p 21.
178 NLC submission 471, p 22.
179 NLC submission 647, p 21.

"while Indigenous people aspire to local and regional economic growth, opportunities for employment and other potential benefits, they also have responsibilities to consider the custodianship of their country and traditional law and custom which are inalienable, and will be inherited by their descendants for all time. In this context decisions and consultations around onshore petroleum proposals will at times inject stresses into the social and cultural fabric of land-owning groups, and can impact upon the decision making process itself. This risk can be realised where a group is required to make decisions in respect of communal land ownership in response to development proposals under both the NTA and ALRA." [180]

This highlights the need for a comprehensive social and cultural impact assessment to be undertaken prior to any onshore shale gas production in all affected Aboriginal communities. The cultural risks associated with any onshore shale gas development must be fully understood and quantified at an early stage so that they can be properly managed. This assessment should occur in conjunction with the social impact work described in Chapter 12.[181]

The Panel notes the submission by Origin Energy that cultural impacts should *"be completed prior to approval of any development"* [182] and APPEA's submission that, *"approval of a development and production activity"* should replace *"grant of a production licence"* in ***Recommendation 11.8***.[183]

The Panel understands that a thorough assessment of cultural impacts could take several years, however, it is persuaded by the argument that this work can take place concurrently with exploration but prior to the granting of any production approvals (see Chapter 16). This approach is supported by the NLC, which states that, *"on lands subject to the ALRA, at this stage consent will necessarily have already been granted by traditional land owners. In addition to* ***Recommendation 11.8*** *cultural impacts should also be assessed during the exploration permit application stage so that Traditional Owners can give full consideration to the potential cultural impacts of any development when making a decision about whether or not to consent to an exploration proposal and to better inform the agreement negotiation process in the case consent is granted."* [184]

Recommendation 11.8

That a comprehensive assessment of the cultural impacts of any onshore shale gas industry must be completed prior to the grant of any production approvals. The cultural assessment must:

- ***be designed in consultation with Land Councils and AAPA;***
- ***engage traditional Aboriginal owners, native title holders and the affected Aboriginal communities, and be conducted in accordance with world-leading practice; and***
- ***be resourced by the gas industry.***

11.5 Conclusion

The Panel understands that the cultural traditions that connect Aboriginal landowners with their country underpin the social fabric of remote communities and go beyond concerns about areas that meet statutory definitions of a 'sacred site'. At risk is the ability to freely access traditional country, the capacity to transfer traditional knowledge, and the maintenance of social cohesion in communities where the benefits and opportunities associated with any shale gas industry may not be equitably distributed.

The right to protect culturally significant places is recognised as part of native title and land rights law, and is also given statutory expression in both Commonwealth and Territory legislation. The nature of this right is that it can be asserted at any time. It has been put to the Panel that there is a risk of disputes between Indigenous landowners and the gas industry, notwithstanding the existence of agreements relating to the issue of onshore shale gas permits.[185] Submissions to the Panel by Indigenous landholders emphasised the importance of maintaining the capability, as a

180 NLC submission 471, p 17.
181 NLC submission 471, p 24.
182 Origin submission 1248.
183 APPEA submission 1251.
184 NLC submission 647. See also the statement by the CLC that they currently undertake an assessment of cultural impacts as part of their process of negotiating agreements: CLC submission 1151, p 6
185 Scambary and Lewis 2016, p 222, Cited in AAPA submission 234. See also AAPA submission 234, pp 7, 21.

group, to transmit traditions relating to sites on their land across generations.[186]

The incremental nature of the way that any onshore shale gas industry is likely to develop in the NT means that for specific works (for example, drill pads, pipelines and related infrastructure), the approval process under the relevant legislation[187] that provides the legal protection to Aboriginal people to maintain their cultural traditions is likely to extend over several years and long after agreements have been negotiated. This has potential to exacerbate stress for Aboriginal communities. As Dr John Avery reflected, based on his many decades of experience:

> *"The marginal position and relative poverty of many Aboriginal people in this country should not be forgotten. Conflicts over sites can provide a point of focus for a range of grievances which are not intrinsic to site issues. Custodians may, for example, have environmental concerns for their traditional territories or they may have outstanding land claims on lands where substantial projects are planned. For people living in remote areas of Australia the prospect of large-scale changes can lead to resentment if such developments are perceived as being imposed without consideration for local people. In the absence of any institutional structure for dealing with the recurring frustrations of Aboriginal people then a range of separate concerns can meld with concerns about sacred sites in such a way that they are not easily abstracted."*[188]

The recommendations in this Chapter are designed to mitigate the risk that Aboriginal people who may feel marginalised and/or aggrieved because of what they perceive as an encroaching extractive industry that affects their cultural, physical and mental wellbeing will seek legislative redress to limit the development of any onshore shale gas industry on their country.

186 For example, CLC submission 47; NLC submission 417; AAPA submission 234.
187 In particular, the laws protecting sacred sites.
188 Avery 1993, pp 113-129.

SOCIAL IMPACTS

12

12.1 Introduction

This Chapter examines the social impacts of any onshore shale gas industry in the NT using a social impact assessment (**SIA**) framework (methodology) developed specifically by Coffey Services Australia Pty Ltd (**Coffey**) and a case-study of the Beetaloo Sub-basin undertaken by Coffey. The Panel commissioned the framework and case-study to better understand the likely social impacts of any onshore shale gas industry and how best to manage them.

The scope of works (at Appendix 15) required Coffey to:

- develop a leading practice SIA framework for the identification, assessment and management of the social impacts associated with the development of any onshore shale gas in the NT;
- apply that framework to the Beetaloo Sub-basin to identify the people, or groups of people, that are most likely to be affected by any development of shale gas resources in and around that region and, in consultation with those communities, to identify the impacts, risks and benefits, and the ways to avoid or manage (mitigate) those impacts and risks; and
- discuss the concept of an SLO (social licence to operate) and its application to the NT.

Coffey, working in partnership with CSRM and CSIRO, provided the following reports to the Panel in January 2018 (at Appendix 16) (**Coffey reports**):

- *A framework for Social Impact Assessment of shale gas development in the Northern Territory*, Final Report, November 2017 (**CSRM Report**);
- *Beetaloo Sub-basin Social Impact Assessment Summary Report*, 17 January 2018 (**Beetaloo Sub-basin SIA Report**);
- *Beetaloo Sub-basin Social Impact Assessment Case Study*, 17 January 2018 (**Beetaloo Sub-basin Case Study**); and
- *Social licence to operate in the Beetaloo Basin and Northern Territory* (**CSIRO Report**).

It must be noted from the outset that the Coffey reports are not, and were never intended to be, an SIA. Nor was Coffey asked to determine if any onshore shale gas industry holds an SLO in the NT. Consequently, it did not undertake this task. In this regard, it is acknowledged that many of the people attending the public hearings and community forums were firmly of the opinion the gas industry does not hold an SLO and expressed concern over the ability of the Government and the gas industry to appropriately manage the risks associated with hydraulic fracturing.[1] For this reason, the Coffey reports have effectively assumed that any potential onshore shale gas industry does not currently hold an SLO.

The Panel notes a concern contained in some of the submissions it received and in the feedback at the community consultations, that making specific mention of the social impacts on some groups of people to the exclusion of other groups, such as pastoralists, was somehow unfair.[2] Similarly, the CLC opined that, *"the report does not make a distinction between holders of property rights (traditional owners and native holders as decision-makers) and affected communities. Affected communities are often (but may not always be) comprised of the traditional owners of the land the subject of a project. A community may also comprise many other residents from neighbouring estate groups and other language groups. The statutory arrangements under the ALRA take this important distinction into account and are unique to the NT and must be properly considered in SIA Reports."*[3]

An essential element of any SIA is to ensure that baseline data is collected on impacts identified and derived from the specific concerns of each local community. Ensuring participation of all affected stakeholder groups is necessary in any SIA. It was neither the intention of the Panel to single out any one specific subgroup within a community (or as between communities), nor to ignore specific statutory arrangements governing particular types of landholders, whether

1 H Bender submission 632, Ms Pauline Cass, submission 1162 (**P Cass submission 1162**).
2 NTCA submission 639.
3 CLC submission 1151.

Aboriginal or non-Aboriginal. Rather, any reference to 'community' in this Chapter is intended to be inclusive unless otherwise indicated. The aim of the SIA framework is to ensure that every potentially affected stakeholder, particularly those most vulnerable to social change, has the ability and freedom to participate in, and be appropriately engaged and consulted on, all relevant social impact matters.

Having said this, any attempt to understand social impacts and social change in NT communities as a result of any shale gas development must consider the complex and fraught history of various federal and Territory Government interventions and policies designed to bring about social change and economic development in these communities. This includes an awareness of an ongoing legacy of trauma, grief and loss among Aboriginal people—the cumulative impacts of colonisation, dispossession of and removal from traditional lands, discrimination and paternalistic social policies. In particular, the expulsion of Aboriginal people from cattle stations in the 1960s concentrated the Aboriginal population of a large area onto the traditional country of only a few, and brought with it social complexity as family groups attempted to both maintain their individual cultures and identities, and live harmoniously together.[4]

This Chapter discusses the Coffey SIA framework and its application to the unique circumstances of the NT. It emphasises the importance of undertaking an SIA that accommodates the cumulative social impacts that are likely to arise as a result of multiple onshore shale gas projects occurring at the same time. The Coffey reports provide a snapshot of the social environment within which any onshore shale gas industry in the Beetaloo Sub-basin will operate. In doing so, the reports highlight the issues and community concerns expressed to Coffey during its consultation process. While Coffey developed the framework specifically for use in the NT, it also draws from SIA experience in other jurisdictions, in addition to world leading practice. The Panel's central recommendation is that if the Government lifts the moratorium, the SIA framework described in this Chapter must be implemented prior to the grant of any production approvals (see Chapter 16), and separate from any environmental impact statement (**EIS**). In addition to an analysis of the potential social impacts identified during the course of the Panel's consultations, key elements of what an SLO for any onshore shale gas industry in the NT, and particularly in the Beetaloo Sub-basin, might look like are examined.

12.2 Submission analysis

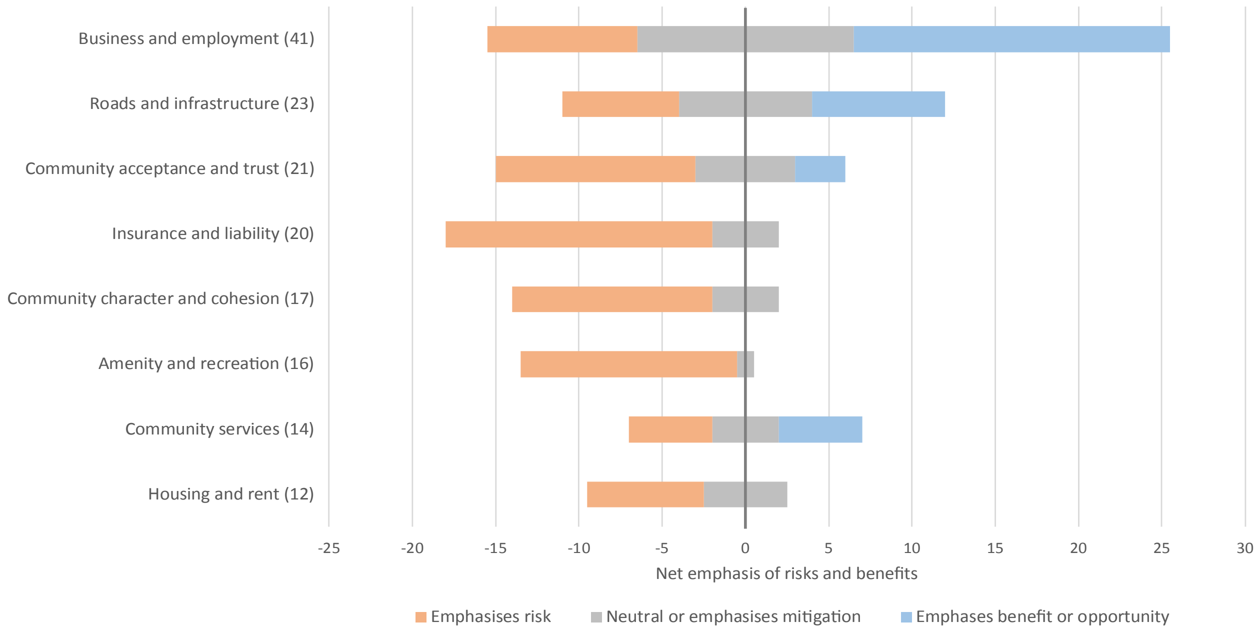
A content analysis of most of the submissions received by the Panel was performed using the computational technique Latent Dirichlet Allocation.[5]

Discussions of social impacts, both positive and negative, featured in at least 175 of the written and verbal submissions and almost all of the public hearings.[6] While the issues raised were diverse, several overarching themes and concerns were identified, as shown in **Figure 12.1**. In this context, it should be noted that there were more than 582 pro forma (see Chapter 2) letters received during the submission process. For the purposes of the thematic analysis, only one of each variety was included in **Figure 12.1** in order to not distort the data.

The graph below shows how many submissions emphasised the positive or negative aspects of each social impact, and how many submissions acknowledged the existence of risks but expressed the view that they could be managed. In this regard, it should be observed that the latter was predominantly from the industry proponents. Several of the social impacts identified in the submissions overlap with other chapters and are therefore covered in that chapter rather than discussed here (for example, see Chapters 10, 11, 13 and 14).

4 Ross 1990.
5 Blei et al. 2003.
6 For the purposes of this Chapter, a submission was counted if it included at least 150 words about or devoted at least 25% of its content to social impacts.

Figure 12.1: Number of submissions emphasising risks and benefits to social impacts.



12.3 Social impacts and SIA

12.3.1 The assessment of social impacts

A social impact 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."* [7] The CSRM Report[8] proposes a similar definition, describing social impacts as the changes experienced by people and communities as a result of projects and activities that affect the way they live, work, relate to one another, relax and organise themselves.[9] Social impacts can be both positive and negative. They include "*changes to the norms, values and beliefs that guide and rationalise their cognition of themselves and their society*".[10] Social change is not recognised as an impact until it has an effect on people. Because a social impact is conceived as being anything linked to a development that benefits, affects, or concerns any affected stakeholder group, almost any change can potentially have a social impact provided that it affects something that is valued by, or important to, a specific group of people.[11] Consequently, it is difficult to pre-emptively narrow the scope of any analysis.

Major resource projects can generate multiple impacts and/or contribute to existing stresses within social systems.[12] Project-specific social impacts vary greatly in their nature, causation, magnitude and other characteristics (see **Table 12.1** below). Depending on the context, different receiving environments (such as a social or cultural group, or a geographic region) may experience the same impacts differently.[13] As such, it becomes the responsibility of the gas company, in consultation with affected people and other stakeholders, to ensure that all the relevant issues and impacts are identified and considered.

7 Geurs, Boon and Van Wee 2009; Vanclay 2003.
8 CSRM Report.
9 Burdge and Vanclay 1996.
10 IOGCP 2003, p 231.
11 Vanclay et al. 2015, p 2.
12 Franks et al. 2010a.
13 Franks et al. 2010a.

Table 12.1: Classification of social impacts.[14]

Category	Descriptor	Examples and explanation
Nature	Tangible	Improved access to health services, better living standards, shortage of affordable housing options.
	Intangible	Breakdown in social cohesion due to population movement.
	Perceived	People's subjective perceptions or experiences of impacts.
Directionality	Positive	Improved access to health services, new recreational areas, upgrades to community facilities, and improved education and employment opportunities.
	Negative	Increased crime rates, higher cost of living and increased health risks caused by pollution.
	Mixed	The impact of some changes is positive in some respects and negative in others, for example, population increase.
Causation	Direct	Directly connected (in space and time) to the activity, for example, resettlement, project-related employment and road construction.
	Indirect	Impacts that occur due to actions resulting from direct impacts. These are usually less obvious, later in time or further away from the source of direct impact, for example, increased income to tradespeople as project employees upgrade houses.
	Induced	Cause is several times removed from project activities, for example, loss of access to land due to market speculation
	Cumulative	Successive, incremental and combined impacts of one or more projects on society, the economy and the environment. These can arise from the compounding activities of a single project or multiple projects and from the interaction with other past, current and future activities. The overall effect being larger than the sum of the parts.[1]
Magnitude	Intensity	The scale of change from the existing condition as a result of the impact, for example, major/critical, high, moderate, minor, negligible.
	Geographic extent	Spatial concentration (for example, site-specific, local, regional, widespread) and[2] distribution (for example, localised, dispersed, contained).
	Duration	Short term (for example, the noise arising from the operation of equipment during construction), medium term, long term (for example, the inundation of land by a dam). Temporary (for example, during construction), fixed term, permanent.
	Frequency	Intermittent (for example, blasting), continuous (for example, electromagnetic fields caused by electricity lines).
	Rate of change	Immediate, delayed, incremental, rapid, gradual.
	Reversibility	Reversible, irreversible/residual.
Probability	Likelihood	Unlikely, possible, likely, certain.
	Confidence	The level of reliability in the estimates of likelihood and consequences.

[1] The word 'cumulative' anticipates a consideration of not just the development the subject of the application, but also the development in combination with other developments in the locality and the effect that the accumulation of such development and successive developments of a similar type will have on the community.

[2] Project-specific SIA is more focussed on potential social impacts on site-specific, local and regional, as opposed to widespread (State level, national and international) levels of analysis.

To evaluate the social impacts of projects on people, and on the ways in which people and communities interact with their socio-cultural, economic and biophysical surroundings, SIA is the usual framework of analysis.[15] SIA is also a field of research and practice comprising a body of knowledge, techniques and values.[16] As a methodology, SIA is used by governments, companies and communities to identify, assess and manage the social impacts of project activities, and to ensure that projects are conducted in a socially responsible manner. It is best understood as the process of analysing, monitoring and informing the management of intended and unintended social consequences of planned interventions, and any social change processes invoked by those interventions on affected communities, from the earliest stages of the planning process to future generations.[17] The objective of the SIA process is to identify, measure, predict and assess the effects of a development on the surrounding population's quality of life, culture, health, social interactions and livelihoods.[18]

14 Adapted from IRMA 2016; Burdge and Vanclay 1996; Franks et al. 2010b; Joyce and MacFarlane 2001.
15 Vanclay 2003.
16 Vanclay 2003.
17 Vanclay 2003; Franks 2012, p 6.
18 Vanclay 2003.

The NLC confirms the need for a participatory practice focussed on affected communities, as reflected in the definition below (which, it is noted, draws from the same authors that informed the SIA framework used in this Chapter):

> *"it is participatory; it supports affected peoples, proponents and regulatory agencies; it increases understanding of change and capacities to respond to change; it seeks to avoid and mitigate negative impacts and to enhance positive benefits across the life cycle of developments; and it emphasises enhancing the lives of vulnerable and disadvantaged people."* [19]

Leading-practice SIA involves identifying and managing the social issues that arise from development activities. This includes the effective engagement of potentially affected communities in participatory processes of identification, assessment and the development of strategies to manage social impacts. Although SIA is still used as an impact prediction mechanism and as a decision-making tool in regulatory processes to consider the social impacts of a project in advance of a permitting or licensing decision, it has an equally important role in contributing to the ongoing management of social impacts throughout the whole lifecycle of the project (in this case, the development of any new onshore shale gas industry), from conception to post-closure.[20]

SIA is widely practised internationally as a predictive study that is part of the regulatory approval process for resources projects. Many resource-rich jurisdictions have a regulatory regime in place to ensure that the social impacts of resources projects are assessed and managed. This includes statutory requirements in place to undertake SIAs, either as a separate procedure, or as part of a broader EIS. According to a 2012 survey, some form of SIA is mandated in 191 of the 193 nations of the world.[21] Despite this widespread and longstanding practice, in most cases SIA remains included as a component of an EIS. Initially, SIAs were narrowly conceptualised, and therefore, applied mainly at the project level and were limited to prediction of the negative consequences of development. This understanding of SIA continues to dominate policy, regulation and procedures in many jurisdictions.[22]

Project-based SIAs rarely adequately account for cumulative impacts that arise after the main construction period is over, or for the impacts of several projects or several industries operating in the same region.[23] A more detailed description of a fit-for-purpose SIA framework for any onshore shale gas development in the NT that takes into account the lifecycle of the industry, the regional and cumulative impacts of multiple projects, and the complex and data-poor nature of the receiving environment is expanded upon below.

12.3.2 An industry lifecycle approach

A SIA is generally required by regulators to assess the potential social impacts of a project before implementation. The primary focus of SIA to date has generally been on predicting impacts that will occur in response to a distinct project, activity or other proposed action. As the government and gas companies are bound to deal first with impacts of most significance or urgency, SIA is often focussed on the impacts that occur in the most intensive phases of development, namely, the 'construction' phase.

However, it is recognised that social impacts begin as soon as new information about a potential project becomes available, as various actors begin to compete to define, influence and respond to the opportunities and threats that may be presented by the project.[24] Impacts can also continue after the development or activity has ended, particularly where former 'booming' communities face a downturn and local businesses must adjust to a smaller and changed clientele, as is now the experience in some Queensland towns. An SIA framework must:

- identify and respond to impacts that occur across different stages of development;
- account for a paucity in statistical social and economic data in remote and Aboriginal communities;
- be culturally sensitive;

19 NLC submission 647, p 10. See also Esteves, Franks and Vanclay 2012; Goldman and Baum 2000.
20 Vanclay et al. 2015.
21 Morgan 2012.
22 Vanclay 2006.
23 Witt et al. 2017.
24 Gramling and Freudenburg 1992.

- identify strategies to maximise benefits and minimise disturbance that are aligned with the needs and aspirations of affected stakeholders;
- inform a more strategic and collaborative approach to development of the region; and
- engage affected individuals and communities in identifying and managing the impacts without placing undue burden on them.

A fit-for-purpose SIA framework for shale gas development in the NT that takes into account the life-cycle of the industry, the likelihood of multiple projects, and the complex and data-poor nature of the receiving environment is shown in **Figure 12.2**.

The steps that comprise an effective and efficient SIA framework are set out below:

12.3.2.1 Step 1: a strategic assessment

A SIA framework should place project-level SIA within a strategic context. A government-led strategic SIA should be conducted in the early stages of any industry development, once feasibility has been established (that is, an adequate resource base has been proven and considered economically viable). Such an assessment is currently under way for offshore gas development in the NT and in SA, and was completed for the terminated Browse LNG project in WA. Given that environmental values are linked strongly with Aboriginal culture, pastoral production, tourism, and social values in the NT, this type of assessment should be undertaken.

The first strategic challenge that any government faces is whether to develop the resource or to leave it in the ground. This is a decision that needs to be arrived at through a transparent and inclusive process, which will improve the quality of decision making as well as build community acceptance for the industry. There may also be occasions where the environmental, social, or cultural context is too sensitive, or where insufficient scientific evidence exists on the potential negative impacts of development. In these cases, the choice is made more complex by the high levels of uncertainty involved.

The objective of any strategic assessment proposed is to generate and disseminate the information needed to make a decision about allowing development that is consistent with the public interest. That information will also enable a planned approach to development, rather than allowing market forces to predominantly determine the scale and pace of development, which was the case in Queensland and in the US.

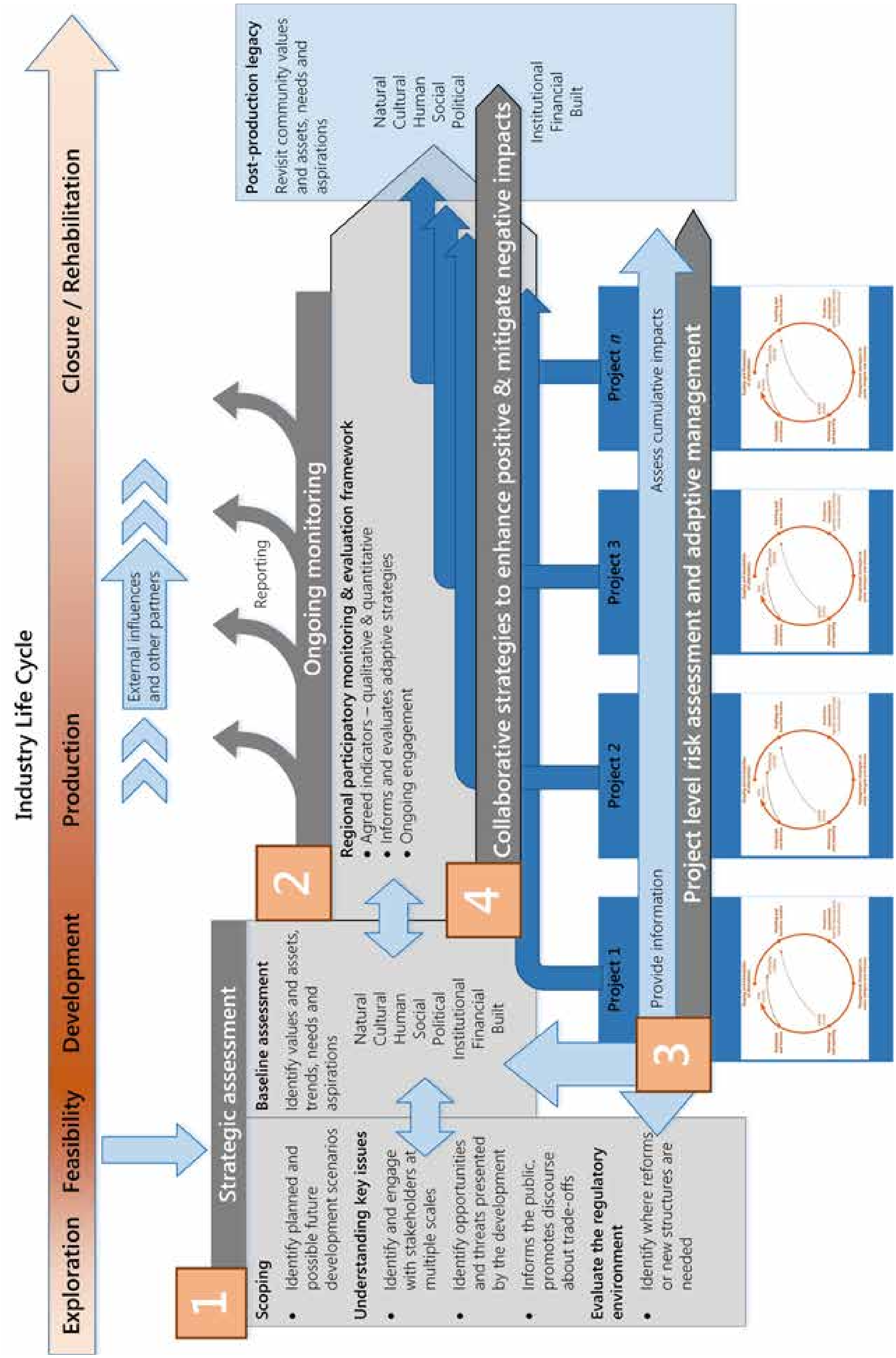
While there is a high degree of uncertainty at this early stage, there is a clear need to gather and provide relevant and reliable information about the industry and its potential impacts to reduce uncertainty to an acceptable level. It is important not to ‘pretend to know everything’ or to try and ‘buy’ social acceptance through the promise of jobs, infrastructure and economic benefits.

The strategic SIA stage involves four key components: (1) scoping – identifying possible future development scenarios and their trade-offs; (2) understanding key issues – identifying opportunities and threats presented by the development to a range of stakeholders, and stakeholders’ concerns; (3) evaluating the regulatory environment – identifying any regulatory reform, or new governance structures needed; and (4) baseline assessment – identifying values and assets, trends, needs and aspirations for potentially affected regions. These are expanded upon below.

Strategic assessment ensures a transparent and inclusive process. The body of information gathered in this initial step is the starting block for an ongoing, open-access repository of social and industry-related data that is updated and expanded regularly as monitoring and project-level reports are generated (step 2). The suggested stages include:

- **scoping and boundary setting:** first, the strategic assessment seeks to understand the scale and scope of proposed development. This is done by collating information from the individual gas companies about where and how they intend to proceed, and how they might respond under different circumstances. The regulatory body overseeing the strategic assessment (see Chapter 14) should have powers to request such information (similar to the Queensland Gasfields Commission). Companies are hesitant to report this information publicly in the early phases of development as development scenarios can change. They may also not wish to divulge their strategies to other gas companies for loss of competitive advantage. Industry-specific information will inform the setting of meaningful and practical geographic boundaries for the subsequent studies, which might be in terms of geological basins or sub-basins, administrative boundaries, or ‘impact’ zones. Industry information is also used to identify planned and possible future development scenarios;

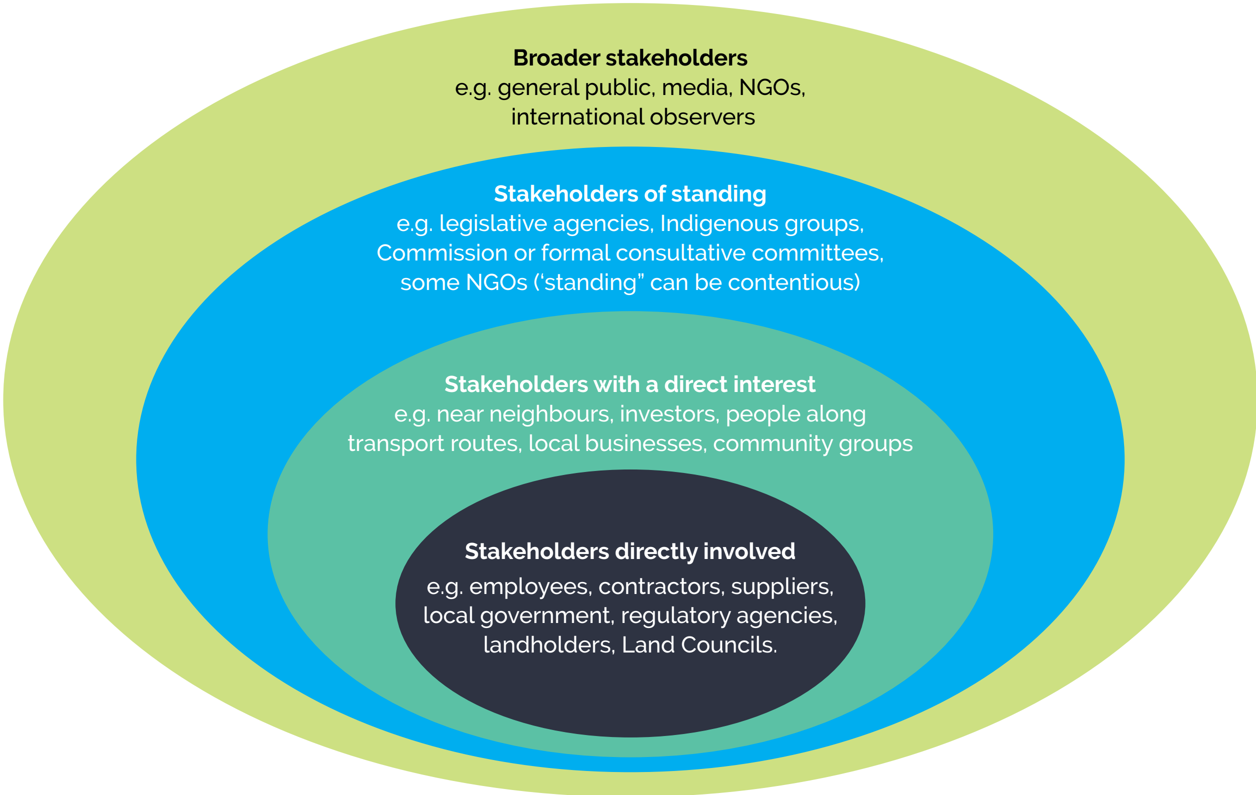
Figure 12.2: Conceptual model of a framework for SIA for any onshore shale gas industry in the NT. Source: CSRM Report.[25]



25 CSRM Report. p 36.

- **understanding the key issues:** with an understanding of what the proposed development might 'look like', the next step is to identify and understand the issues and trade-offs involved under different development scenarios, including identifying the people and organisations that may be affected. The stakeholder engagement component of this step is critical, and must follow leading-practice stakeholder engagement methods with skilled personnel. A 'nested' approach to identifying directly and indirectly affected stakeholders and interested parties should be used. Information about the concerns and interests of these stakeholders can be organised at local, regional, Territory, national and global scales.

Figure 12.3: Stakeholder identification by nature of interest and impact. Source: CSRM Report.[26]



Providing information and promoting discussion about the onshore shale gas industry, its activities and the trade-offs involved, is of crucial importance in the early stages of any development. In Queensland, a lack of freely available, trusted information about the onshore CSG gas industry in terms of the technology used, its requirements for labour, services and resources, and the types of opportunities and impacts it could generate, created a space for controversy and conflict. This was so notwithstanding multiple and lengthy EIS and regulatory reports. With the paucity of locally relevant information, those who wanted to know more about an industry will look to experiences and practices from elsewhere, often with little regard to important contextual differences, such as geology and hydrology, technological advances, institutional arrangements and population characteristics.

In the US, the National Wildlife Federation prepared a series of documents to help people engage in decisions about the oil and gas industry. The publication, *Fuel for Thought: a citizen's guide to participating in oil and gas decisions on your public lands,* outlines the lifecycle of a well, the environmental impacts, the legal framework, the roles and responsibilities of regulating bodies, as well as how to be 'an effective advocate'.[27] The guide provides a good example of the type of information that people require in order to hold an informed opinion about any onshore unconventional gas industry in their local area;

- **regulatory assessment:** a strategic assessment of any onshore shale gas industry must also evaluate the regulatory and approvals processes in place and identify reforms that may be needed. This includes addressing the challenges faced in gaining different types

26 CSRM Report.
27 Zimmerman 2008, p 30.

of consent, and especially those relating to fairness in any land access agreements and benefit sharing arrangements (see Chapters 11 and 14).[28] The emphasis on ensuring that there is a robust regulatory regime is deliberate. Previous inquiries into the impacts of any unconventional gas industry in Australia have concluded that the risks are manageable provided that the industry is properly regulated.[29] Chapter 14 makes recommendations about how the regulatory framework in the NT should be strengthened; and

- **baseline assessment:** arguably the largest component of the strategic assessment is the collation of baseline data.

  The initial baseline data collected is for regions and/or local communities where development is imminent and will involve significant participation by local residents. Regional baseline data should also be collected. This baseline data includes identification of stakeholder values and current assets in different types of capital 'stocks', as well as assessing trends, and aspirations for these stocks. The Community Capitals Framework (**CCF**) is well established in community development literature and practice.[30] The CCF measures community development in relation to seven types of capitals, including:

  - **natural:** the condition of place-specific elements, biodiversity, amenity, beauty;
  - **cultural:** traditional knowledge and languages, rituals and festivals, heritage;
  - **social:** networks, trust, norms of behaviour, giving, neighbourliness, cooperation;
  - **human:** skills, knowledge, health, abilities, leadership;
  - **political:** influence, having a voice, self-determination;
  - **financial:** credit, savings, income, assets; and
  - **built:** infrastructure, housing, roads, sewerage, sports facilities, lighting.

In addition, it has been suggested that institutional capital be included (for example, community organisations). That is, the effectiveness of local and regional institutions as another important consideration for any SIA framework.

As census and other statistical data is limited or flawed for many of the NT's remote communities (it tends to underrepresent the Aboriginal population), the collection of baseline data for these capitals must be a participatory process and part of any SREBA for a particular region (see Chapter 15). A leading practice model developed by CSRM and the CCSG is of relevance in this context, namely, the UQ Boomtown Toolkit and its supplementary annual reports on Queensland's gasfields communities. The UQ Boomtown Toolkit outlines a tested approach to identifying community assets and values, and importantly, for identifying indicators for measuring those values that are meaningful and relevant to multiple stakeholders. For example, it uses collaborative methods to identify indicators that any gas industry needs for compliance and for monitoring social impacts; that the community needs to represent their concerns, values and aspirations; and that the Government wants in order to monitor cumulative impacts and regional development outcomes. For remote NT communities, social indicators may need to be 'bespoke', and more qualitative. They may require local 'data stewards' to report changes in bespoke indicators on a regular basis. For example, an indicator of household wealth might be how many funerals/cultural events are attended in a year, rather than economic measures of disposable income. This 'shared measurement' approach is world leading practice in program evaluation and has clear relevance to impact assessment in data-poor regions. The need to develop bespoke indicators when working with affected communities in the NT was highlighted by the NLC.[31]

The baseline assessment identifies initial stocks of capital, but also trends where possible, and importantly, identifies local and regional goals and aspirations in relation to this capital. This information is used by gas companies, who still need to submit a comprehensive social risk assessment for the approvals process that outlines how the proposed activities will affect, either positively or negatively, the community capital stocks and the strategies proposed to either enhance or mitigate them. The ongoing monitoring and measurement of performance, and the social and cumulative impacts can be openly shared on a dashboard and reported annually in a public document as evidenced by the annual report on the Boomtown Indicators website.[32]

28 Note that in Queensland, the majority of land access issues are in relation to freehold land. This is quite different in the NT, where Indigenous land and pastoral leases are the main forms of land tenure.
29 CSRM Report.
30 Emery and Flora 2006.
31 NLC submission 647.
32 https://boomtown-indicators.org/.

12.3.2.2 Step 2: regional participatory monitoring and evaluation framework

World leading practice in SIA has regional and systems level monitoring for resource areas in place, particularly where social and economic impacts extend well beyond the geographic location of a single operation and where there are interacting impacts from multiple extraction activities.[33] Developing an online, public, open-access data repository for all industry-related information, including monitoring and compliance data, is a positive action for building trust in the industry, which is essential for building and maintaining public acceptance and an SLO.

An additional value of the ongoing, participatory regional monitoring and evaluation database is that it reduces the risk of 'consultation fatigue' as multiple gas companies seek information to inform their social risk assessments. In Queensland's CSG communities, multiple and extensive consultation events (from EIS/SIA consultants, resource companies, various levels of government, media and researchers) have placed high demands on people's time and caused additional stress at a time of rapid change and mixed emotions. As the 'boom' period ended, so did the outside interest. Unsurprisingly, local people reported feeling 'forgotten' and 'abandoned' by many of the consulting agencies.

The online database becomes an open-access resource for information. Each project-level risk assessment is uploaded, and any new indicators and data about communities are added to the database. Ideally, communities themselves can provide and upload data updates to the relevant indicator timeline. This gives communities ownership of the data. As the UQ Boomtown Toolkit has demonstrated, the data can also be used by communities for funding applications, to allocate resources, to argue a need for investment, or purely to advocate for themselves and their needs.

In addition to the open-access resource, there should be a mechanism for periodic reporting out of key information, with accompanying analysis and interpretation of findings. This is important for industry transparency and to build and maintain trust in the industry as indicated in the CSIRO Report. This reporting work is best conducted by an inter-disciplinary and purpose-specific research institution, such as CCSG or GISERA. CCSG produces annual reports for Queensland's gasfields communities, which are widely used by local and State governments, CSG companies and community groups.

A strategic and regional approach to cumulative impact assessment enables gas companies to form partnerships with other companies, service providers and communities and to ensure that the community can play a role in securing outcomes to their benefit. Strategies for social impact mitigation or enhancement can then align with existing community development programs and be targeted toward the needs and aspirations of local communities. This monitoring framework is designed to enable adaptive responses. Each development will provide information about intentions for future development. This allows industry forecasting and amendment to initial development scenarios generated in a strategic assessment. The lifespan of the monitoring framework should last throughout the lifecycle of the industry, that is, approximately 40–50 years. However, the frequency of data updates must be flexible and determined by institutional capacity, sequential development of projects, and the transitioning of projects to another phase.

While this is an ideal model, it is recognised that it places additional burden on government resources, particularly in the early phases of strategic assessment, before any royalties from resource production have been generated. A lower cost version is to create an online data repository, have all data from project-based EIS/SIAs uploaded, with conditions in place for any future projects in the region to adapt to new information and facilitate collaboration. The monitoring framework sets the agreed indicators to be monitored, with sufficient flexibility to adapt to emerging issues as they arise. Responsibility for the data updates, once the baseline is established, is shared by the gas companies and local communities (similar to the UQ Boomtown Toolkit).

The Government could recover costs for the strategic and ongoing assessment by increasing the cost of petroleum approvals or moving towards a full regulatory fee recovery model (see Chapter 14 for further discussion).

The main function of the ongoing collaborative monitoring framework is to provide a structured mechanism for collaboration and adaptive management, and to facilitate processes for capturing learning that leads to continuous improvement. Importantly, it also allows for coordinated responses to other influencing factors, both from within any onshore shale gas industry, such as price fluctuations, and externally, such as biosecurity alerts.

33 Franks et al. 2009.

12.3.2.3 Steps 3 and 4: project-level risk assessments and collaborative strategies

Under the proposed SIA framework each proposed onshore shale gas project will submit an SIA with a comprehensive risk assessment that considers:

- the whole lifecycle of the project and the types of activities involved in each phase;
- the people or groups of people likely to be affected (with attention to vulnerable groups);
- the likely social impacts – both positive and negative;
- the significance of the impacts in terms of likelihood, severity, and ability to be mitigated or enhanced;
- the likely effects of mitigation and enhancement strategies (in relation to baseline assessment of capitals and aspirations for these capitals, but also in relation to strategies that may already be in place by other projects in the region);
- the assessment of residual risks; and
- standardised reporting.

Strategies for enhancing positive outcomes and mitigating negative impacts should be targeted towards the aspirations and needs of communities identified in the strategic SIA and should be in partnership with community organisations and institutions. The social baseline data will be used from the strategic SIA baseline data and updated or expanded to suit the EIS/SIA requirements. This minimises the need to collect baseline data multiple times directly from communities, which contributes to consultation fatigue. Stakeholder engagement processes are critical in prioritising concerns and developing workable agreements for mitigation or enhancing strategies. This approach is detailed in the Beetaloo Sub-basin SIA Report (at Appendix 16).

12.4 Lessons learned from SIA experiences elsewhere

In addition to the Queensland experience, there are a number of lessons that have emerged in other countries that provide useful consideration for the NT. Some of these are summarised below.

12.4.1 Queensland unconventional gas experience

The CSRM Report made the following relevant observations based on similar unconventional gas development in Qld, namely, that:

- the scale and pace of development determines the significance of social impacts. Likewise the pre-existing/pre-project social, economic, political and cultural environment;
- social impact mitigation strategies should not be bilateral agreements (for example, government placing conditions on gas companies), nor overly prescriptive (for example, the gas company must construct 50 new houses). Instead they should involve local communities (and other key stakeholders that have a role to play), be aligned with their aspirations and needs and be 'outcomes-focussed';
- the social impacts of unconventional gas development are unevenly distributed. Those with capacity and information can prosper while inflexible or vulnerable groups can be negatively affected;
- social impacts, such as impacts on local social cohesion, and psycho-social stress, arise well before there is a project, and these are often not adequately addressed in SIA processes;
- there is low trust in the onshore unconventional gas industry worldwide. Trust is time-consuming and difficult to earn but quickly and easily lost. In developed countries like Australia, mass media, including social media, can have a large influence on the process. This highlights the importance of managing relationships at the ground level, especially in remote areas;
- local institutions need to be strengthened (ideally prior to any development occurring) to address the challenges and harness the benefits that the industry can bring. SIA needs to identify existing levels of capacity within these institutions and those that would need attention;
- underlying much of the public concern about hydraulic fracturing and the unconventional gas industry generally has been a lack of engagement of affected people in meaningful ways. All affected communities require detailed information about the proposed activities and likely impacts of any industry to make informed decisions;

- a single strategic SIA should include various specialist assessments. However, due to the interconnectedness of Aboriginal people and their country, predicting the significance of social impacts requires the consideration of social, environmental, economic and cultural impacts (see Chapter 11);
- collaboration and coordination between projects, and between gas companies, government and community organisations is necessary for effective assessment and responses to cumulative impacts. A platform for such collaboration (such as a multi-stakeholder working group) should be linked with the ongoing monitoring platform and come under the jurisdiction of the regulator (see Chapter 16);
- clear guidelines for negotiating land access agreements should be produced that outline the rights of both the landholder and gas company. Considerable stress and negative impact has been associated with misunderstood rights and perceived disrespect for attachments to, and interests in, land;
- identify strategies to build local institutional and business capacity early. To best capture the potential economic benefits of any onshore shale gas development, adequate lead-time and institutional, business and individual capacity is required;
- negotiations with traditional Aboriginal owners must be inclusive and transparent. General consent is insufficient. Details of activities must be fully explained to ensure that these landholders properly understand the terms of the consultations and the proposed development's impacts, benefits and management strategies. The process for such negotiations should be fully documented (see Chapter 11 for further discussion in this regard); and
- perceptions or evidence of negative impacts on the spiritual wellbeing and social cohesion in Aboriginal communities must be given high priority.

12.4.2 US shale gas experience

As stated in the Interim Report, the US shale gas 'revolution' was characterised by its rapid pace of development and is a cautionary tale for the NT. In the overriding agenda to become self-sufficient in energy supply as quickly as possible, social (and sometimes environmental) impacts of development were largely overlooked (until there was local backlash) and regulatory frameworks were largely insufficient (until they were challenged and amended).[34] A review of the risks posed to communities from shale gas development in the US identified four key areas of risk:

- rapid industrialisation of communities ('boom and bust');
- uneven distribution of costs and benefits from the development;
- community conflict; and
- social-psychological stress and disruption.[35]

The most effective responses to the negative social impacts of shale gas development were led at the community level. These required the development of community-scale and consensus-based decision-making processes.[36] The need to assess local institutional capacity was identified in the proposed SIA framework baseline assessment.

In the NT, local and State governments and Land Councils will need to establish participatory planning processes and prepare planning documents that reflect the views and aspirations of local residents if any onshore shale gas development is to proceed.

12.4.3 South Africa's strategic environmental assessment for shale gas

The South African Government has made a high-level public commitment to shale gas exploration. The potential future economic and energy security benefits of a large resource of natural gas in the Karoo region of South Africa may be substantial. But so too could the negative social and environmental impacts. In order to make well-informed decisions and to ensure that decisions are broadly accepted by stakeholders, a strategic environmental assessment for shale gas development was commissioned. The key aim of the project was to develop an integrated decision-making framework to enable South Africa to establish effective policy, legislation, and sustainability conditions, under which shale gas development could occur.

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34 Brasier et al. 2014.
35 Jacquet 2014.
36 McElfish and Stares 2014.

There were three project phases over the 24-month period:

- **the conceptualisation and methodology phase:** the objectives of this phase were to set up and implement all project management structures, convene the project governance groups, recruit authors and experts to the multi-author teams and release a draft approach report at the end of phase 1 for expert review. This document was also made available to the public online;
- **the scientific assessment phase:** this was the component of the study where the scientific assessment by the multi-author teams for all strategic issues took place. At the end of this phase, draft and final strategic environmental assessment reports were released for expert and public review. The expert review included peer-reviews from international experts; and
- **the decision-making framework phase:** the final phase translated the outputs from phase 2 into operational guidelines and decision-making frameworks. It was undertaken by the project team in close consultation with the various affected government departments. It commenced with initial drafts after the delivery of the first draft of the assessment report and ended with final drafts after the delivery of the final assessment report.

The project teams were separated between phase 2 and 3. The experts involved in phase 2 were not asked to make decisions about the development of shale gas. Rather, they were asked to give an informed opinion on the consequences of different options. The decisions were to be made by mandated government authorities who contracted various science councils to help formulate the framework and content of such decisions. The assessment process culminated in November 2016 with the publication of the report, *Shale Gas Development in the Central Karoo: A Scientific Assessment of the Opportunities and Risks.*[37]

The extensive report identified a number of potentially significant social risks, particularly those relating to increasing social division and inequity between already marginalised populations and those better positioned to capture opportunities from the shale gas industry.

Building public trust remains a key issue for the industry in South Africa. It is too early to determine whether the exercise has resulted in greater trust in government and industry or broader public acceptance of shale gas development in South Africa. However, the scientific rigour, detail and transparency associated with the assessment exercise has undoubtedly provided a significant contribution in this respect.

12.4.4 Canadian shale gas experience

The Council of Canadian Academies was asked to assemble an expert panel to assess the state of knowledge about the impacts of shale gas development in Canada. In response, the Council recruited a multidisciplinary panel of experts from Canada and the United States to conduct an evidence-based and authoritative assessment supported by relevant and credible peer-reviewed research. In 2014, the Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction published its report, *Environmental Impacts of Shale Gas Extraction in Canada.*[38]

One of that panel's main findings was that, compared to conventional gas, the greater scale of development and concentration of infrastructure required to produce shale gas meant increased land impacts and land use conflicts, and that the only effective way to manage such cumulative effects was at the regional, and not local, scale.[39] The panel noted that management of cumulative effects requires effective implementation of strategic impact assessment processes. At the same time, the implementation of a regional strategic impact assessment to reduce cumulative effects of shale gas development requires a significant investment in human and financial resources.[40]

The panel also found that shale gas development poses particular challenges for governance because the benefits are mostly regional, whereas adverse impacts are mostly local and distributed across several levels of government. Engagement of local citizens and stakeholders was identified as a key element of an effective framework for managing risks posed by shale gas development. Accordingly, the panel stressed that public engagement is necessary not

37 Scholes et al. 2016.
38 Council of Canadian Academies 2014.
39 Council of Canadian Academies 2014, p 205.
40 Council of Canadian Academies 2014, p 128.

only to inform local residents of development but to receive their input on what values need to be protected, reflect their concerns and earn their trust.[41] As experience in several US states and Canadian provinces has shown, the manner in which local people are engaged in decisions concerning shale gas development is an important determinant of their acceptance of the development. Moreover, public acceptance is situation-specific: practices that are acceptable in one situation may not be in another. Therefore, the panel recommended that any public engagement strategy needed to reflect these differences and be oriented to local context, capacity, and concerns.[42]

In the Canadian social and political context, any shale gas development must also recognise the importance of addressing First Nations' treaty rights, interests and concerns. The legal relationship between the Crown and First Nations people is defined by the courts through clarification of the existing Aboriginal and treaty rights. Many First Nations are uncomfortable with tripartite negotiations between the provincial, federal and First Nations governments because they see such negotiations as a derogation of the bilateralism established when the treaties were first negotiated. First Nations argue that the cumulative impacts of past authorisations for resource development in Canada have infringed on their Aboriginal and treaty rights. Specifically, they point to instances where the Crown assigned certain procedural aspects of consultation to proponents and asked for amendments to project plans to avoid impacts on Aboriginal and treaty rights.[43] The panel stressed that the impact of First Nations' opposition to other major resource development in Canada indicates that the effect that Aboriginal resistance or support on future shale gas development cannot be overemphasised.[44] As many of the known commercially accessible shale gas deposits in Canada are in accepted or claimed traditional First Nations territories, the panel recommended that First Nations need to be consulted meaningfully and early in any shale gas development process and in full respect of their Aboriginal and treaty rights.

12.5 Implementation of an SIA in the NT

12.5.1 The NT's unique socio-demographic context

To better understand which social impacts are likely to be a priority for those living in the NT, it is necessary to have regard to its particular demographics.

12.5.1.1 The NT's unique statistical population context

At the most recent census, the NT reported a population of 245,740 people, of which 51.8% were male and 48.2% were female. The proportion of the population who identify as Aboriginal or Torres Strait Islander is the highest in the NT, at 25.5%, or 58,247 people. The NT is sparsely populated, with a population density of 0.02 people per hectare.[45] Managing this vast landscape are 17 district councils, ranging in population size from approximately 209 people in the regional council of Belyuen, to more than 140,000 people in the urban council of Darwin.[46] The NT also contains four Aboriginal Land Councils: the NLC, the CLC, the Tiwi Land Council and the Anindilyakwa Land Council.[47]

Comparisons of economic performance to other jurisdictions indicates that overall the NT has consistently low rates of unemployment (on average) and high rates of economic growth and construction work, but poor forward-looking indicators relating to population growth, business investment and housing finance.[48] The majority of Territorians are employed in the greater Darwin region, an estimated 61.5% of employees. The fastest growing industries are in agriculture, retail and utility services, while the largest sectors for employment are public administration, construction, healthcare, education and retail.[49]

The Territory's average rate of unemployment is low, at 5.3%, but these statistics differ between regional and urban areas, and between non-Aboriginal and Aboriginal people. For example,

41 Council of Canadian Academies 2014, p xix.
42 Council of Canadian Academies 2014, p 208.
43 Council of Canadian Academies 2014, p 31.
44 Council of Canadian Academies 2014, p 31.
45 ABS 2017.
46 ABS 2017.
47 NT Government 2017a.
48 CommSec 2017.
49 NT Government 2017b.

the unemployment rate of Aboriginal people in the NT is high, at 24.4%. This is significant when examining labour force participation rates (or the proportion of people in the population engaged in the workforce, either employed or looking for work). This was most recently reported at 48.7% for Aboriginal people, compared to 85.5% for non-Aboriginal people.[50] Aboriginal people were more likely to be employed if they were living in an urban centre, rather than a remote region. With 49% employment in urban areas compared to 36% in remote areas. This is particularly relevant in the NT where 79% of the Aboriginal population reside in remote areas.[51] The statistics suggest there is a lack of employment opportunities for those living in remote areas, particularly for the Aboriginal population. These populations may therefore benefit from the introduction of, and involvement with, any employment opportunities in remote regions of the NT occasioned by any onshore shale gas industry.

12.5.1.2 The NT's unique land tenure context

In order for Aboriginal people to claim rights to traditional land and to have those rights recognised under the Land Rights Act or the Native Title Act, they must be able to demonstrate a continuous connection with the land through regular access and traditional cultural practices from one generation to the next (see Chapter 11). Being able to access, utilise and care for country, thereby maintaining a connection to traditional land and practices, is vitally important to Aboriginal people (whether they are formally recognised as traditional Aboriginal owners or not under the law). Any fragmentation or degradation of the landscape translates directly into social and cultural impacts for Aboriginal people.

Despite recent approaches to social and economic policy that are more holistic and inclusive of Aboriginal people and their culture, there remain significant inequalities in health and wellbeing between Aboriginal and non-Aboriginal people.[52] The implication for SIA in the NT is a learned mistrust of projects that promise improved social and economic outcomes. For SIA and social performance practitioners, mitigation measures and social investment strategies must be developed with active involvement by Aboriginal people.[53]

Furthermore, under the current agreement-making processes in the NT (see Chapter 11), there is the potential for significant inequality between those receiving compensation and benefits and those who do not. This in turn can, and does, lead to increased social unrest and conflict, both inter-community and intra-community and conflict aimed at other entities, such as gas companies or the Government. The strategic and participatory approach to SIA recommended in this Report is an attempt to address this inequality, through a focus on community benefits and capital building, and by developing strategies to mitigate negative impacts and enhance positive impacts.

The main consideration surrounding land tenure is that different landholdings require different forms of 'consent' in order for project activities to proceed without interference or interruption from dissatisfied stakeholders. These range from broader community acceptance to individually negotiated agreements with pre-identified, or 'qualified' communities (see **Table 12.2**).[54]

50 ABS 2016a; ABS 2016b.
51 ABS 2016a.
52 Osborne et al. 2013.
53 Osborne et al. 2013.
54 O'Faircheallaigh 2007. 'Qualified' communities are those who have been through a formal process of identification and verification as being traditional Aboriginal owners of land under the Native Title Act.

Table 12.2: Land tenure in the NT and types of 'consent'. Source: CSRM Report.[55]

Land tenure	Type(s) of 'consent'	Principles/pathways	Challenges
Crown Land (about 50% of land mass - *which includes 44%* pastoral lease)	'Contingent' consent.[56] Often (mis)understood as a 'social license to operate.'[57]	Community acceptance on the basis that net social benefits outweigh the harms. As long as the balance is such, the project is more likely to be supported by the public and their representatives in the public service and government.	Relies on estimation of net benefit or harm when impacts are known to be unevenly distributed. The 'voice of many' can over-ride the voice of those directly impacted.
Freehold (0.5% of land mass)	Land Access Agreements. Includes a right to object to the granting of an exploration permit through written sub-mission – no right to refuse access to permit holders.	Over-riding public good. Fair compensation for surface rights holders. Not within 200m of dwelling.	Capacity to negotiate a fair compensation package varies between individuals. Landholder unaware of rights and obligations.
Aboriginal freehold (about 50% of land mass)	Exploration and Mining Agreements with relevant Land Council. Free Prior Informed Consent.	Includes a right not to permit activities. Indigenous Land Use Agreement. UN Declaration on the Rights of Indigenous Peoples.	Excludes those not identified as 'qualified' from benefit sharing[58] A bilateral agreement not conducive to cumulative impact assessment or collaboration with other 'development' partners.
Pastoral leasehold (44% of land mass)	Land Access Agreements. Includes a right to object to the granting of an exploration permit through written submission – no right to refuse access to permit holders. Indigenous Land Use Agreement- where land held under Native Title.	Negotiation of compensation and conduct agreements.	'Compensation' for damages in excess of normal operations only.

12.5.2 The need for a separate strategic SIA in the NT

There are currently no regulatory requirements or provisions for undertaking a separate strategic SIA in the NT, although the need for an overarching strategic SIA of any onshore shale gas industry has been proposed in prior reports (see, for example, the 2015 Hawke Report) and by the EDO. One pathway for such an assessment is to define a specific development area (such as the Beetaloo Sub-basin) and outline a program for any onshore shale gas development in that area. Where MNES are potentially affected, the Australian Government can be approached to enter into a Strategic Assessment Agreement with the NT under the EPBC Act, as part of a bilateral agreement. However, these agreements are limited in scope and the type of assessment recommended by the Panel in this Chapter (see also Chapter 15) should instead be implemented.

Social baseline assessments must be undertaken by trained and experienced SIA practitioners who also have an understanding of industry activities associated with the different phases of any onshore shale gas development. Such specialised expertise can be found, for example, in the CCSG and at GISERA. While both these research institutions rely partly on industry funding, researchers work under strict codes of conduct and national guidelines for the ethical conduct of research. A similar centre could be established in the NT at Charles Darwin University or another local institution.

The baseline assessments for the SIA framework proposed in this Chapter most closely resemble those undertaken by the CCSG or CSRM for cumulative social and economic impact assessment,

55 CSRM Report, pp 31-32.
56 Levi (1997, p 8) in Owen and Kemp 2012.
57 Owen and Kemp 2012.
58 Stevens 2003.

insofar as they involve generating timeline charts for a tailored set of locally meaningful indicators. This approach is most relevant to the NT because it allows Aboriginal communities to choose their own set of indicators rather than relying on census data, which may be of little relevance to their specific circumstances. Using this method, communities are able to participate in the development of indicators, data collection and reporting, and the design of mitigation strategies that are outcomes-focussed for their needs and aspirations. This requires some local institutional capacity and leadership which may need to be fostered. Local governments and Land Councils should have participatory community planning documents prepared that outline local values and other intangible assets that people would like to see protected and enhanced, together with any issues that they would like to see resolved.

12.5.3 Key components of a leading practice SIA framework for any onshore shale gas development in the NT

There are a number of key findings that arose from the CSRM Report that provide useful insights around the necessary considerations for monitoring and assessing the social impacts of any onshore shale gas industry in the NT. The key components of a leading-practice SIA framework for any onshore shale gas industry in the NT are as follows:

- **strategic assessment**: to develop a program that clearly identifies the goals of the program and defines the scale (and staging) of development in terms of balancing economic, social and environmental impacts at local, Territory and federal scales;
- **strategic approach:** that aligns individual projects and their outcomes with the objectives of the NT Economic Development Framework and community values and aspirations;
- **coordination and collaboration between multiple projects:** in order to minimise negative cumulative impacts, minimise the 'footprint' of any development in the placing of associated infrastructure (including workers' accommodation) and maximise long-term social and economic benefits to local and regional communities;
- **human rights issues:** attention to human rights and the rights and vulnerabilities of Aboriginal people;
- **independently led social baseline assessment:** using agreed indicators to measure impacts and sustainability outcomes (the indicators should be selected in consultation with local people, communities, and stakeholders) with participatory, ongoing monitoring of impacts and outcomes;
- **independently led community engagement program:** using affected stakeholder groups to discern the significance of impacts and to co-develop acceptable and appropriate mitigation and enhancement strategies;
- **open data policy:** regular and open reporting on the social, economic and environmental performance of the onshore shale gas industry; and
- **cumulative impacts:** each additional project should provide an adaptive SIA risk assessment that specifically addresses cumulative impacts and its contribution to the project's program's objectives.

Recommendation 12.1

That a strategic SIA, separate from an EIS, must be conducted for any onshore shale gas development prior to any production approvals being granted.

Recommendation 12.2

That the strategic SIA be funded by the gas industry.

Recommendation 12.3

That the strategic SIA must be conducted comprehensively and in such a manner that it will anticipate any expected impacts on infrastructure and services and to mitigate potential negative impacts.

Recommendation 12.4

That early engagement and communication of the findings of the strategic SIA be systematically undertaken with all potentially affected communities, all levels of government and potentially affected stakeholders, including Land Councils, to ensure that unintended consequences are limited, and that shared understanding of roles and responsibilities, including financial responsibilities, can be developed.

Recommendation 12.5

That ongoing monitoring and measurement of social and cumulative impacts be undertaken, with the results being made publicly available online as soon as they are available.

12.5.4 Reforms required to enable an SIA framework in the NT

For the proposed steps in an SIA to be operational, a number of structural innovations are required. These include:

- introducing regulatory mechanisms for a separate strategic SIA. A strategic SIA is needed to manage the social impacts associated with any onshore shale gas development. The SREBA recommended in Chapter 15 is central to this reform;
- establishing a regulator (see Chapter 14) with powers to request information from and to facilitate collaboration between gas companies, government agencies (including local government), Land Councils, communities and affected landholders;
- establishing a long-term participatory regional monitoring framework overseen by the regulator, with secure funding (raised from industry levies) and able to endure multiple election cycles (see Chapter 14); and
- periodic and standardised reporting to communities on the social, cultural, economic and environmental performance of the onshore shale gas industry through an independent source, either the regulator or a specialised research institution. This includes information from the monitoring of key indicators and an industry-wide complaints and escalation process (the experience of CSG in Queensland is that each of the CSG projects reported complaints differently, which made it impossible to gauge industry performance).

Recommendation 12.6

That a strategic SIA be conducted as part of any SREBA to obtain essential baseline data.

Recommendation 12.7

That in order to operationalise an SIA framework in the NT, the Government must:

- ***give the regulator power to request information from, and to facilitate the collaboration between, individual gas companies, government agencies (including local government), Land Councils, communities and potentially affected landholders;***
- ***establish a long-term participatory regional monitoring framework, overseen by the regulator, with secure funding from the gas industry and able to endure multiple election cycles; and***
- ***establish periodic and standardised reporting to communities on the social, cultural, economic and environmental performance of the industry through either the regulator or a specialised research institution. This includes information from the monitoring of key indicators, and an industry-wide complaints and escalation process.***

12.6 Summary of identified social impacts of any onshore shale gas development in the NT

12.6.1 Impacts on public infrastructure and services

The submissions and public consultations identified a variety of ways in which any onshore shale gas industry could both positively and negatively affect infrastructure and services in the NT. There was general agreement that increases in population and industrial activity would place pressure on many types of existing infrastructure and services. For example, by increasing the amount of heavy vehicle traffic on public roads or the demand on health services and schools. Views varied about whether such pressures presented a threat or an opportunity for communities in the NT.

Some submissions emphasised the potential improvements to infrastructure and services that can flow from resource developments, whether as a result of direct investment from resource companies, or through royalties that add to public revenue. Among these submissions were several from pastoralists or pastoral service providers, who described the challenges of conducting business in remote areas with minimal public infrastructure and utilities. As Mr David Armstrong of Terrabos Consulting explained:

> *"Key infrastructure developments that pastoralists are always asking me about are road upgrades, mobile phone coverage, improved internet service and mainstream power. Currently the cattle industry is a world leader in beef production operating in third world conditions. I would encourage any business owner to imagine their life without mobile phone coverage, generating their own power at a cost upwards of $200 per day, with very poor internet connection, roads that can become inaccessible for a number of months of the year."* [59]

Similarly, Mr Tom Stockwell and Ms Tracey Hayes from the NTCA noted that while pastoralists have a variety of views about hydraulic fracturing, they are united on the need for better roads and other supply chain infrastructure. [60] As well as benefiting pastoralists, there is a view that improvements to roads and other infrastructure would stimulate the development of industries and ultimately be of benefit to remote communities and, therefore, all of the NT.

Some submissions expressed the opinion that onshore shale gas development presented a good opportunity for these utilities and services to be improved. This belief was founded, in some cases, on the perception that such improvements had rarely occurred in the past without investment from mining companies.[61] Widely cited as an example of what onshore shale gas development could deliver in the NT was the sealing of the Western Creek Road, a project that Pangaea had planned to complete prior to the moratorium being announced.[62] In relation to services, APPEA and other gas industry proponents highlighted contributions that CSG companies had made to health and education services in Queensland. For example, by funding healthcare initiatives and emergency services, and by investing in school-based traineeships and apprenticeships.[63]

Many submissions, however, expressed doubt that the potential benefits to services and infrastructure would materialise, or that they would be sustained beyond the initial stages of development. Much of this scepticism derives from accounts of impacts of the CSG industry on regional communities in Queensland, especially in the Darling Downs. These accounts include peer-reviewed research from the University of Queensland (**UQ**) and CSIRO, as well as news stories and anecdotes. For example, submissions from the Lock the Gate and The Australia Institute cite findings from UQ researchers suggesting that built capital, including transport and communications infrastructure, has deteriorated in regions in southern Queensland where the CSG industry is present.[64]

Taking a broader economic perspective, the written and verbal submissions from The Australia Institute note that mining royalties account for a relatively small proportion of revenue in the NT,

59 Mr David Armstrong, Terrabos Consulting, submission 180 (**Terrabos Consulting submission 180**).
60 Northern Territory Cattlemen's Association, submission 261 (**NTCA submission 261**).
61 Mr Bill Sullivan, Sully Pty Ltd, submission 160 (**B Sullivan submission 160**).
62 Mr Rohan Sullivan, Cave Creek Station and Birdum Creek Station, submission 243 (**R Sullivan submission 243**); B Sullivan submission 160.
63 APPEA submission 215; Santos submission 168; Origin, submission 153.
64 Lock the Gate Alliance submission 171; The Australia Institute, submission 158 (**The Australia Institute submission 158**).

and that allowing onshore shale gas development would not substantially change the amount of funds available for improving services and infrastructure.[65] Mr Rod Campbell of The Australia Institute also cautioned against depending on the gas industry to build public infrastructure, noting that, *"State governments end up building things for resource industries rather than the other way around".*[66]

Other submissions questioned the likely public benefit of infrastructure built by gas companies. Ms Helen Bender's submission noted that new roads would service the locations used by gas companies and not those most used or most needed by the public. [67] With new roads, and the increasing use of existing roads, comes increased maintenance costs, which, as the Central Desert Regional Council noted, the gas industry cannot presently be compelled to pay for.[68]The issue of road maintenance and upkeep was raised when the Panel visited communities in Queensland.

As well as increased maintenance costs, concerns were expressed that increased traffic use could lead to a higher rate of road accidents, increased pollution, noise, and impacts to wildlife (see Chapters 8 and 10). [69] Road use and safety was also an issue present with the expansion of the CSG industry in Queensland. Issues acknowledged by the Queensland Gasfields Commission included that:

> *"significant increases in traffic flows, truck movements on school bus routes, large/wide transports on regional highways and the generation of dust and noise on unsealed roads. Many existing roads in the Surat Basin required upgrading to withstand the change in traffic type and frequency."* [70]

Although these impacts are relevant to the NT, given the remote location of many of the roads and the lack of built up areas in much of the Territory, the extent of these negative impacts will depend on the location of any onshore shale gas development.

Early in the development of the CSG industry in Queensland there were examples of gas company employees and contractors exhibiting a lack of safe driving behaviour. For example, not complying with speed restrictions, driving long distances without adequate breaks, and noise from employees reversing from their homes early in the morning. These risks were mitigated by gas companies implementing a number of initiatives including 'In Vehicle Management Systems', which monitored the speed at which vehicles were being driven, as well as mandated rest periods every two hours. It is noted in the submissions from several gas companies that they propose to implement 'Traffic Management Plans' [71] as part of any onshore shale gas development to ensure adequate preparation for potential high or increased traffic.

The Academy of Medicine, Engineering and Science of Texas (**TAMEST**) also reported an order of magnitude increase in road traffic (not only trucks) and road accidents, as well as clearly observed degradation of roads and roadside infrastructure.[72] TAMEST noted that in Texas:

> *"Not only have there been considerable increases in truck traffic across the state, other modes of transportation have also experienced a surge in traffic, as evidenced by the significant increase in energy-related activities at transportation facilities such as ports, railroads, and pipelines."* [73]

TAMEST also acknowledged that the level of funding allocated to address the impact on road infrastructure and traffic safety was low when compared to the magnitude of impact. This mirrors findings from Queensland where the upkeep and maintenance of roads over the longer term fell to local government.

65 The Australia Institute submission 158; The Australia Institute, submission 322 (**The Australia Institute submission 322**).
66 The Australia Institute submission 322.
67 H Bender submission 144.
68 Central Desert Regional Council, submission 76 (**CDRC submission 76**).
69 P Cass submission 192; Lock the Gate submission 171.
70 Queensland Gasfields Commission 2017a, p 80.
71 Pangaea submission 427, p 17; Origin submission 433, p 63; Armour Energy Ltd, submission 23 (**Armour Energy submission 23**), p 2; Santos submission 168, p 66.
72 TAMEST 2017.
73 TAMEST 2017, p 22.

Concerns were expressed about the Government's ability to cover all of these necessary costs in a sustainable way (see also the discussion in Chapter 8 in Section 8.3.2.1 and Chapter 10 in Section 10.3.4). One suggestion from the EDO was to create a mechanism in the Petroleum Act allowing the Government to require contributions from gas operators for the purpose of road maintenance.[74] Similarly, North Star Pastoral suggested that there should be an "*annual roads maintenance financial contribution that will cover the gas companies' share (based on the percentage of tonnage hauled along that road) of the road maintenance costs for the life of the project*". There were also several suggestions around relevant Austroad standards, which have been incorporated in the recommendations.[75]

Recommendation 12.8

That as part of any strategic SIA and prior to any significant increase in traffic as a result of any onshore shale gas industry, consultation must be undertaken on road use and related infrastructure requirements that results in road upgrades and work schedules to the appropriate Austroad standards and commensurate with the anticipated vehicle type required for any onshore shale gas industry.

Recommendation 12.9

That gas companies provide the necessary funds to ensure the ongoing maintenance requirements for road infrastructure are met for the life of any onshore shale gas project. These should be based on the individual gas company's percentage of tonnage hauled along the roads.

Recommendation 12.10

That road use agreements between gas companies and local NT road authorities be mandated to include safety considerations and to ensure monitoring for compliance and reporting requirements.

The literature cites both potential positive and negative impacts on services in the community. Research has shown that rapidly increased population can bring a variety of new services and businesses to a region. These might include new restaurants and hairdressers, as well as an increased range of retail goods.[76] A negative effect, however, can materialise by increasing pressure on health services,[77] a service that is often already strained in regional and remote areas. Several studies report increased wait times for hospitals and doctors' services, an impact that was exacerbated in several south-west Queensland regions by an increase in mental health issues in connection with the CSG development throughout that region.[78]

These findings were also recognised in a recent Queensland Gasfields Commission report on lessons learned.[79] The report noted, however, that impacts around health and emergency services can be made worse through cumulative impacts arising not only from a growth in the gas industry but also combined with significant weather related events or downturns in other industries. It also acknowledged that it is not just local communities that are impacted but also FIFO workers. Several gas company employees reported mental health issues as a direct result of living away from their families.

The positive impacts were that communities were seen to benefit through gas company funds directed to local hospitals, the introduction of mobile health clinics and increased emergency response and aeromedical services such as CareFlight.[80] However, the report identified that companies were unprepared for *"government expectations that they must fund a range of community, health and other services."* [81] Managing such expectations from the beginning is essential.

74 EDO submission 456.
75 North Star Pastoral, submission 535 (**North Star submission 535**).
76 SA Report, p 20.
77 Bec, Moyle and McLennan 2016.
78 Hossain, Gorman, Chapelle et al. 2013; Bec, Moyle and McLennan 2016; Lai, Lyons and Kyle et al. 2017.
79 Queensland Gasfields Commission 2017a, p 82.
80 Queensland Gasfields Commission 2017a, pp 84-85.
81 Queensland Gasfields Commission 2017a, p 82.

Studies conducted in the US suggest additional challenges for education services, such as accommodating higher intakes of students as populations increase or updating curricula in a way that increases job opportunities. Managing these challenges was reported to be difficult and US schools reported no significant beneficial impacts from the resource development.[82] Conversely, anecdotal evidence in the Surat Basin suggests that investment by some gas companies in local school science programs has had positive impacts, resulting in an over subscription to senior science programs at the high school level, which is unprecedented in many schools around Australia. Another benefit that emerged in Queensland was that some local children who left to obtain university degrees were able to return to their hometowns where their qualifications made them perfect candidates for jobs with some of the gas companies.[83] Reversing the exodus of young people from rural communities is beneficial, with many rural towns in decline due to a lack of employment opportunities for youth.

Recommendation 12.11

That gas companies be required to work closely with all levels of government, Land Councils and local communities early in any onshore shale gas development project to quantify the potential impacts on health and educational services and ensure steps to mitigate adverse impacts are implemented.

12.6.2 Impacts on housing and rental prices

The potential for rents and housing prices to rise and fall sharply with a 'boom and bust' cycle was referred to in several submissions.[84] Also noted was the potential for council rates to increase.[85] Citing experiences in Queensland and other places where unconventional gas development had occurred, these submissions expressed the concern that the initial rise in prices would squeeze out many local residents, while the subsequent fall could leave houses vacant and/or worth less than prior to the boom. However, housing issues in the NT are not uniform across the Territory. Some remote communities already suffer from a lack of adequate housing, which means housing impacts will be location dependent. Potential impacts on housing and rent were acknowledged in submissions from the gas industry, and cited as a major reason for the use of FIFO/DIDO workers and temporary housing.[86] The submission from the CLC also highlighted the dire nature of housing for some Aboriginal people in the NT and wanted this, and related health indicators, to be considered as threshold factors for any onshore shale gas project approval:

> *"remote communities in Central Australia already face significant issues relating to housing and maintaining connection to land. Rates of homelessness in the NT are higher than any other Australian State or Territory, significantly higher amongst Aboriginal people, and are expected to worsen. Homelessness, overcrowding and poor living conditions can have a profound impact on economic, social and health indicators".*[87]

The literature provides examples of increased pressure on housing availability in communities experiencing 'boom and bust' development. The large demand on housing can dramatically raise prices for both buyers and renters.[88] Those who are employed locally may be forced out of a market that they can no longer afford, especially if they are not receiving comparable salaries to those in the gas industry. In some cases, this results in the displacement of local residents to the outskirts of town, or further, in search of more affordable living, as was reported in the town of Roma in Queensland.[89]

Conversely, research showed that in Queensland individual property owners were able to profit from a temporary demand increase in accommodation, but that they also risked economic loss if the demand is not sustained.[90] These effects can be mitigated by gas companies ensuring that a temporary housing shortage does not arise. Ensuring temporary housing accommodation in

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82 Schafft, Borlu and Glenna 2013.
83 Schafft, Borlu and Glenna 2013.
84 Lock the Gate submission 171; P Cass submission 192; H Bender submission 144.
85 G McCarron submission 53.
86 APPEA submission 215.
87 CLC submission 1151.
88 Benham 2016.
89 Bec, Moyle and McLennan 2016.
90 Benham 2016.

various camps before the need for a construction workforce will assist in easing potential housing pressures,[91] although it should be acknowledged that mining camps bring their own challenges, both for the workers who reside in them and also for the communities nearby. Finding the balance can be challenging. Gas companies need to take a proactive and responsible approach to solving the housing needs of its workforce to ensure adequate coverage of all housing requirements.[92] Although this may increase construction time, and therefore, reduce profits, it will help to mitigate the risk of over inflated prices for real estate in communities.

Recommendation 12.12

That any strategic SIA anticipate the long-term impacts and requirements for housing (not just through the construction phase) to adequately mitigate the risk of inflated real estate prices and shortages within a community.

Recommendation 12.13

That in consultation with all local community stakeholders, Land Councils, local government and the Government, gas companies be required to provide accommodation, whether temporary or permanent, which must be completed prior to the granting of any production approvals.

Valuation of agricultural properties can also be affected, depending on how the activities are perceived in the region. With industries such as agriculture or pastoralism, where landholdings tend to be intergenerational, this creates concern for landholders. If the value of the property is perceived to decrease due to the presence of shale gas activity, it is likely that the next generation will be reluctant to assume responsibility for properties because they see less potential value. This may result in them being more inclined to move away from the region for other employment opportunities.[93] The most effective way to mitigate such risks is by ensuring that the gas companies are operating in a responsible way. In Queensland, legislation exists to ensure that landholders are compensated for a range of activities including loss of property value and other uses that may have occurred on the land.[94] Chapter 14 outlines a number of considerations and recommendations in respect of land access to mitigate these risks.

12.6.3 Impacts on employment and businesses

As with impacts on infrastructure and services, the submissions expressed a wide range of views about the potential impacts on employment and businesses. Several submissions were positive about the potential jobs and economic activity that onshore shale gas projects would generate in the NT. The Urban Development Institute of Australia (NT) suggested that, *"becoming a gas hub offers the Northern Territory the greatest chance of achieving the economic growth we currently need"*.[95] According to Ms Teresa Cummings of North Australian Rural Management Consultants Pty Ltd (**NARMCO**):

> *"The exploration activity generated by the Natural Gas Industry using hydraulic fracturing methods, to date has seen a range of local businesses being engaged, both in Katherine and Mataranka. Transport operators, civil construction companies, environmental consultants, accommodation and hospitality providers, engineers, and many more types of businesses have already benefited."* [96]

Contrary to fears about the cyclical nature of any onshore shale gas industry, the submissions from NARMCO suggest that such development will have a stabilising economic influence in the NT:

> *"The seasonal nature of some of the key local industries creates significant economic challenges for local businesses. … It is extremely difficult for many employees to remain in the seasonal industries long term, as there are limited opportunities for stable career path. … A shale led Natural Gas Industry … will provide stable contract options for local business and provides real potential for local businesses to overcome their seasonal volatility."* [97]

91 Hossain, Gorman, Chapelle et al. 2013; Morrison, Wilson and Bell 2012.
92 Morrison, Wilson and Bell 2012.
93 Hossain, Gorman, Chapelle et al. 2013.
94 Queensland Gasfields Commission 2017a, p 42.
95 Urban Development Institute of Australia (NT), submission 436 (**UDI submission 436**).
96 North Australian Rural Management Consultants Pty Ltd, submission 186 (**NARMCO submission 186**).
97 NARMCO submission 186; Ms Teresa Cummings, submission 249 (**T Cummings submission 249**).

NARMCO also noted the potential for employment benefits in remote and Aboriginal communities:

> *"I'm convinced that allowing natural gas industry to develop in the remote areas in the NT will bring many economic and social benefits to indigenous people. There aren't many local opportunities out there. When you start talking about remote regions like Elliott, it's extremely limited, and this will be one industry that will actually have strong potential to overcome that."* [98]

A submission from APPEA cited increases in employment and business expenditure that were attributable to CSG development in Queensland as a reason to anticipate positive outcomes in the NT.[99] Unsurprisingly, a similar sentiment was expressed by Elengas and Pangaea which, based on their own modelling (which is far more optimistic that the ACIL Allen study discussed in Chapter 13), suggest that an onshore shale gas industry will be critical in light of the NT's declining population growth.[100] However, other submissions drew on similar comparisons to suggest a less optimistic economic outlook. A submission from Mr Tom Measham of CSIRO noted from his own study of the Surat Basin in Queensland that, *"while net employment increases overall, there can still be reductions in some sectors as people move out of one sector (e.g. agriculture) into another"*. Furthermore, that the number of jobs flowing to local residents varies on a case-by-case basis.[101] The same submission also claimed that the job creation effects claimed by industry have often been exaggerated. A finding also cited by several other submissions to the Panel.[102] The CLC submission expressed caution when estimating employment opportunities, noting that in some instances it can have a negative impact on community cohesion.[103]

> *"While resource activities can result in increased training, employment and community development opportunities for Aboriginal communities, the CLC notes that these opportunities have the potential to affect community cohesion (Draft final report, p. 278) and that previous initiatives, particularly around employment, have not delivered benefits to communities to the extent anticipated."*

The Australia Institute expressed further scepticism about purported benefits to business and employment. Citing a study by UQ about the impacts of CSG in the Darling Downs in Queensland, it noted that, *"far from mining and unconventional gas providing economic benefits, local businesses felt that it had reduced financial capital, human capital, infrastructure, social capital and natural capital"*. In addition:

> *"Local businesses have to compete with inflated gas industry wages in order to recruit and retain staff and they experience increased rent and competition for services (particularly trade and mechanical repairs)."* [104]

The potentially short-term nature of positive employment impacts was also observed.[105] Citing job figures from Queensland Treasury, Lock the Gate argued that, *"the scale of the 'bust' after the short unconventional gas construction period ends is severe, and long-term job opportunities are extremely limited"*.[106] The economic modelling prepared by ACIL Allen for the Panel (see Chapter 13) indicates a number of jobs will be generated, but that this will vary depending on the size of any onshore shale gas industry. In their final response to the Panel, Santos provided comprehensive details of the economic benefits and number of jobs created by their presence in Southwest Queensland:

"For example, over the past two years, Santos has paid more than $140 million (M) to South West Queensland postcodes in wages and purchases from small businesses".[107] It also claimed that "*there have been 62 apprentice and trainee opportunities across the GLNG business*". Santos

98 T Cummings submission 249.
99 APPEA submission 215.
100 Pangaea submission 1147; Elengas, submission 470.
101 Mr Tom Measham, Commonwealth Scientific and Industrial Research Organisation, submission 77 (**T Measham submission 77**).
102 Lock the Gate submission 171; P Cass submission 33; H Bender submission 144.
103 CLC submission 1151.
104 The Australia Institute submission 158.
105 K Marchment submission 438; Barkly Landcare submission 241; H Bender submission 144; P Cass submission 33.
106 Lock the Gate submission 171.
107 Santos submission 1249.

provided an estimated breakdown of the expected jobs and likely local business opportunities in relation to each of the different onshore shale gas activity phases in the Beetaloo Sub-basin if the moratorium is lifted. This included targeting local businesses for procurement opportunities, as well as specific training and employment to enhance Aboriginal participation.

Concern was raised that hydraulic fracturing for onshore shale gas would harm tourism, fishing and other long-term businesses that were dependent on the amenity, environmental health and natural image of the NT.[108] As Ms Petrena Ariston from Top Didj Cultural Experience and Art Gallery explained:

> *"An extensive line of oil fracking wells dotted throughout the outback could undermine the tourism brand that Tourism NT and tour companies market nationally and internationally. … I think, as a tourist, the very presence of well-drilling sights and flares burning gas will not only disfigure the beauty of the NT and its small communities, but will definitely discourage them to come back or recommend us as a destination."* [109]

The literature similarly presents many discussions around the effect on jobs and economic development, although there is less information regarding the effects on tourism. Economic activity can be accelerated due to the higher salaries of gas company employees being injected into local communities.[110] However, this can also generate challenges for a community because some local businesses may find it hard to compete with the higher salaries, and a shortage in skilled workers can result. This was noted as an issue in Roma where one local business owner remarked that, *"we had a small business in town that closed because of mining and the gas. Firstly, they took the workers, then they cranked all the rental properties up and it killed it. We've just closed it down."* [111]

While there tends to be a net increase in employment, skill shortages can have a negative effect on pre-existing industries, particularly in agricultural regions. These effects were recognised in the Marcellus shale development in Pennsylvania in the US.[112]

But the literature also shows that the increased demand for workers can provide unique opportunities for younger people and remote Aboriginal communities.[113] There have been instances of economic support for training and development programs through the local TAFE institutions. For example, there was support of a Certificate II in Plant Operations supported by Santos in Roma to provide additional opportunities for local employees.[114] These financial contributions tend to be seen as positive development. This investment can prevent the next generation from moving away from the community toward urban centres, because it provides them with an opportunity for employment stability and career development within the gas industry.[115] This can be particularly beneficial for younger remote Aboriginal populations, as was observed by Buru Energy in Western Australia:

> *"Our experts looked at Buru's plans and let us know this is a safe activity if it is done properly. We trust Buru to do this properly. It has been great to see our young people work closely with Buru and we have that connection."* [116]

But equally it has been acknowledged that there is a risk that the number of jobs can be overestimated. This is particularly so if the majority of the workforce is sourced externally through a FIFO or DIDO arrangement.[117] This type of workforce creates its own unique set of challenges and requires thoughtful mitigation. A transient workforce can affect community cohesion and can contribute to its loss if workers are unable to positively contribute towards the community.[118] Understanding exactly what the implications might be for businesses and employment will be

108 P Cass submission 192; Ms Jean McDonald, submission 182 (**J McDonald submission 182**); Ms Monica O'Connor, submission 3 (**M O'Connor submission 3**); Amateur Fishermen's Association of the Northern Territory, submission 190 (**AFANT submission 190**).
109 Ms Petrena Ariston, Top Didj Cultural Experience and Art Gallery, submission 269 (**P Ariston submission 269**).
110 Bazilian, Brandt and Billman et al. 2014.
111 Bec, Moyle and McLennan 2016.
112 Schafft, Borlu and Glenna 2013.
113 Norman 2016.
114 SA Report, p 24.
115 Brasier, Filteau, Mclaughlin et al. 2011.
116 WA Report, p 173.
117 Fleming and Measham 2015.
118 Haswell and Bethmont 2016; Vojnovic et al. 2014; Bec, Moyle and McLennan 2016.

a critical component of any SIA conducted in advance of any shale gas industry roll out and by project proponents themselves.

There can also be overestimations in relation to the economic benefits available to local businesses within a community. Smaller towns in Queensland reported no positive impact as a result of the increased activity because the gas companies tended to rely on larger regional centres, like Toowoomba, to provide project supplies.[119] More recent analysis by UQ has shown that although there was some downturn after the major construction phase, overall local businesses have experienced a net positive change in their average income since onshore CSG gas industry was established.[120]

Critical for maximising the benefits that return to local communities, is to ensure that all gas companies implement a 'buy local' strategy. This can range from everything to supporting the local supermarket and newsagents (assuming one exists within a community) to working with local business groups and chambers of commerce to identify ways that local businesses might be considered as suppliers for various contracting and other work. One finding from Queensland is the importance of gas companies working with local businesses to ensure that they have the skills, pre-qualifications, and other requirements needed early in the process to allow local businesses time to prepare.[121] Again, although many NT communities are very different from Queensland communities, the findings that have emerged reflecting upon how the CSG industry developed in Queensland are helpful for businesses and communities in the NT who will seek to benefit from any emerging onshore shale gas industry. Accordingly, the key findings are replicated below:

1. *Find out about projects and the local market;*
2. *Know the rules of engagement for your tier level;*
3. *Understand how work packages will be advertised and awarded;*
4. *Work with others;*
5. *Promote your business capabilities;*
6. *Be ready to adapt to change in the industry; and*
7. *Prepare for contractual negotiations."* [122]

Recommendation 12.14

That to the extent practicable, gas companies be required to source goods, services and workers from local communities. This must include the development of training programs for Aboriginal and other local workers to develop the necessary skills and expertise to maximise opportunities for local employment in any onshore shale gas industry.

Recommendation 12.15

That gas companies work proactively with local businesses, local government, Government, Land Councils and communities to ensure that local businesses are able and adequately skilled to compete for contracts, and to assist local businesses to be ready to participate in any economic opportunities that may emerge.

12.6.4 Insurance and 'make good' agreements

Several submissions expressed concern that landholders are unable to obtain insurance against damage caused to their property due to onshore shale gas operations, including damage to infrastructure and livestock, in addition to the contamination of soil, surface water and groundwater resources.[123] Lexcray Pty Ltd, a cattle business in Daly Waters upon which Origin wants to conduct exploration activities, provided an account of this difficulty, while other submissions cited similar cases in Queensland and NSW.[124] As well as citing the need for more comprehensive pollution liability insurance, some submissions called for the establishment of

119 Bec, Moyle and McLennan 2016.
120 UQ Boomtown Toolkit 2016; Queensland Gasfields Commission 2017a, p 70.
121 Queensland Gasfields Commission 2017a, p 67.
122 Queensland Gasfields Commission 2017b.
123 ALEC submission 88; Mr Daniel Tapp, Big River Station, submission 242 (**D Tapp submission 242**); Ms Katherine Marchment, submission 2 (**K Marchment submission 2**).
124 Lock the Gate submission 171; The Australia Institute submission 158.

an *"eternal insurance fund"*[125] or *"orphan well trust fund"*[126] to cover the remediation or repair of any legacy damages to water and other resources. In Queensland, legislation exists to ensure that landholders are compensated for a range of activities including any damages or losses to property or from conducting activities on the land.[127] The submission from NARMCO argued that pastoralists should be compensated through land access agreements for any "*direct operational and capital impacts.*"[128] Chapter 14 discusses and makes specific recommendations in respect of land access agreements and compensation (see Section 14.6).

12.6.5 Community cohesion

Concern was expressed that the development of any onshore shale gas industry in the NT could affect the overall character and cohesion of communities, and that it may also affect people's relationships, mental health, and sense of identity and place.[129] Citing studies and anecdotes about unconventional gas development in Queensland and overseas, these submissions opined that the nature and pace of changes brought about by unconventional gas development can lead to feelings of anxiety, anger, injustice and betrayal within communities:

> *"Production ramps up with drilling and fracking, with its 24-hour lights, noise, privacy invasion, odours, tree clearing and truck movements - causing some people to feel a deep sense of loss of control, loss of place and loss of peace and a feeling of being trapped and unable to escape. All of these phases present risks of depression, anxiety and increased use of alcohol and other drugs for coping."*[130]

The potential for people to experience solastalgia (a sense of powerlessness and lack of control amid change) that has been observed in other communities affected by resource booms, was referred to.[131] A related issue was the perception that negotiations between gas companies and communities, or individuals, did not take place on a level playing field (see the discussion at Section 14.6).

As Mr Warwick Giblin explained:

> *"There is a power imbalance, unequivocally, and this is the root cause of the angst. I really can't say it more plainly than that, but this is the fundamental issue that the broader community and broader society has. And in the case of pastoralists, but at the same goes for all stakeholders, we don't have the time, the technical knowledge, the economic capacity, or the political clout compared to the gas companies."*[132]

A similar point was made in relation to Aboriginal communities, which often have little or no knowledge about hydraulic fracturing and onshore unconventional gas processes (see Chapter 11).[133] Notably, however, positive relationships between gas companies and pastoralists were reported in some submissions, including from pastoralists themselves.[134]

Many observed that the debate about fracking in the NT has itself been a source of division within the community. People on both sides have reported feeling intimidated or unwelcome within certain businesses or social circles as a result of a position that they had taken.[135] Examples of this effect are reinforced by the literature.

Moreover, with a large FIFO workforce, it can be difficult to integrate employees into the community. Residents in a range of regions experiencing unconventional gas development report feeling a loss of community following rapid change and the influx of FIFO workers.[136] Landholders have reported feeling stress regarding their alleged lack of rights in providing land access

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125 Ms Charmaine Roth, submission 191 (**C Roth submission 191**).
126 S Bury submission 189.
127 Queensland Gasfields Commission 2017a, p 42.
128 North Australian Rural Management Consultants, submission 1264 (**NARMCO submission 1264**), p 3.
129 PHAA submission 107; Ms Rachel Tumminello, submission 187 (**R Tumminello submission 187**); Lock the Gate submission 171; Y Doecke submission 25.
130 Prof Melissa Haswell, submission 183 (**M Haswell submission 183**); NARMCO submission 1264. p 3.
131 R Tumminello submission 187; Lock the Gate submission 171.
132 North Star Pastoral, submission 260 (**North Star submission 260**).
133 Mr Tony Hayward-Ryan, submission 54 (**T Hayward-Ryan submission 54**).
134 Ms Helen Armstrong, Gilnockie Station, submission 48 (**H Armstrong submission 48**); Terrabos Consulting submission 180; Mr Mark Sullivan, Flying
135 Ms Annette Raynor, submission 67 (**A Raynor submission 67**); T Cummings submission 249.
136 Brasier, Filteau and Mclaughlin et al. 2011; Curran 2017; Bec, Moyle and McLennan 2016; Haswell and Bethmont 2016.

(see Chapter 14). There is a perception that landholders are being forced to allow exploration and development, which has resulted in landholders feeling helpless and has resulted in a heightened risk of mental health issues.[137]

These negative impacts have contributed to an anti-shale gas sentiment, which has in turn contributed to tension and division within a community. On the other hand, many people appreciate the economic benefit that an onshore shale gas industry may bring, and therefore, view development as a positive thing for the region.[138] This divergence of opinion can create tension among those groups who are not supportive, and those who are.[139] The division between those who oppose, and those who support, leads to tension within different groups which further disrupts community cohesion. For example, this has occurred in Gloucester in NSW.[140]

Another potential impact on community cohesion is an increase in crime based on observed correlations between crime and CSG development in Chinchilla, Queensland, and in shale gas development areas in the United States.[141] There have been increases in petty crime and public nuisance related arrests, which tend to be associated with the increase of a typically young and single male workforce of transient nature. An increased police presence is usually necessary, which may place a strain on services.[142] Women may report feeling less safe in this environment, although there is no significant statistical increase in cases of sexual assault.[143] One explanation for this may be that women in the community are venturing out less due to their decreased feeling of safety in the community.[144]

With the distinct differences between communities across the NT and their sometime stark contrast in socio-economic status, there is likely to be even greater potential for disruption of community cohesion which will need to be well managed and monitored over time through the implementation of ongoing participatory SIA as recommended in the CSRM Report.

There are examples of successful management of this issue that are best demonstrated in a CSIRO study of Chinchilla, Queensland.[145] A community group was established with assistance from the police with the intent of solving drug and alcohol related issues. The group worked proactively with the gas company and their contractors, with whom they had a well-established relationship, to facilitate terms within employment contracts that would result in the employee losing their job if they were arrested for any public disorder offences. A co-regulation and zero tolerance approach was also adopted by all publicans in the town so that an offending individual could be banned for three months from all hotels. The gas company also contributed funds towards the re-establishment of a youth-focussed alcohol education program. This approach was found to be highly effective in managing alcohol-related issues.[146] This highlights how increasing community cohesion and participation can be encouraged alongside an emerging onshore shale gas industry.

Recommendation 12.16

That gas companies must establish a relationship with communities to determine how to best facilitate community cohesion on an individual and collective level. This should be done in consultation with all landholders, Land Councils and local government, to ensure that the needs of all stakeholders are accommodated.

Recommendation 12.17

That a representative community advisory group be established to act as a conduit for ongoing monitoring of community cohesion.

137 Bec, Moyle and McLennan 2016.
138 Fleming and Measham 2015.
139 Norman 2016.
140 Lai, Lyons, Kyle et al. 2017.
141 H Bender submission 144; Lock the Gate submission 171.
142 Brasier, Filteau and Mclaughlin 2011.
143 Benham 2016.
144 Benham 2016.
145 Walton et al. 2013.
146 Walton et al. 2013.

Recommendation 12.18

That gas companies must develop and implement a social impact management plan for communities, detailing how they will optimise the relationship with a community prior to the grant of any production approvals. This plan should be developed in consultation with all landholders, Land Councils and local government to ensure that it meets community needs. The regulator must consent to the plan prior to the grant of any production approvals.

The CLC endorses these recommendations but stresses that they must take into account the unique characteristics of the NT, including the high percentage of Aboriginal people, Aboriginal land tenure, the remoteness of communities, the cultural diversity, and the high rates of homelessness and inequality:

"The CLC adds that a clear, structured framework is required prior to commencement of the relationship building to ensure the correct approach is taken in the cultural setting and in response to the land tenure and ownership for a Project." [147]

12.6.6 Intergenerational equity issues

Intergenerational equity was a priority for many of those attending the consultations, both Aboriginal and non-Aboriginal. Participants stressed that allowing any onshore shale gas extraction was contrary to urgently needed climate change mitigation and they did not accept that industry cared about the interests of future generations. ALEC 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."* [148]

12.6.7 Social licence to operate

The concept of an SLO relates to community acceptance or approval of a project, company, or industry (see Section 12.8). Several submissions explicitly discussed the concept of an SLO and the question of whether any onshore shale gas industry has, or could gain, an SLO in the NT. Most submissions discussing this issue were of the view that the industry lacked an SLO and this was also echoed by those present at the community forums. As Mr Daniel Leather put it:

> *"Industry, regulators and governments of all levels have both failed in their responsibilities of maintaining and presenting any valid argument for gaining, let alone maintaining community consent, as the industry is viewed as potentially being worse than coal or even nuclear, a perception that should have been impossible."* [149]

For some, the lack of trust also extended to a lack of faith in the Government's capacity to regulate any such industry.[150] Given this, many felt that the onshore shale industry would only gain acceptance if it was overseen by a regulator tasked with aspects of the industry's governance such as handling public enquiries and concerns, reviewing performance, collecting and analysing scientific data, and administering funds to address legacy impacts.[151]

Also perceived as a major obstacle to gaining an SLO is the manner in which the gas industry engages with, and relates to, the community. Formal engagement processes have been characterised as tokenistic and one-sided, with one-to-one negotiations described as intimidating or unfair, and discourse with opponents as dismissive and adversarial.[152] Gas companies in the NT were criticised for being impersonal in their dealings with the community, principally as a result of not having a single point of contact. The practice of interfacing with the

147 CLC submission 1151, p 6.
148 ALEC submission 88.
149 Mr Daniel Leather, submission 40 (**D Leather submission 40**).
150 Environmental Defender's Office (NT) Inc, submission 253 (**EDO submission 253**).
151 Lock the Gate submission 437; Mr Rod Dunbar, submission 297 (**R Dunbar submission 297**); DR Johns, submission 154; A Raynor submission 67; Armour Energy submission 23.
152 Dr Errol Lawson, submission 216 (**E Lawson submission 216**); North Star Pastoral, submission 155 (**North Star submission 155**).

community through contractors or rotating personnel was also perceived as a way of hiding from risk and responsibility.[153]

Not all submissions shared this view. Central Petroleum describes a range of positive and arguably successful efforts by that company to accommodate and benefit the local community.[154]Pangaea also highlighted its successes in engaging pastoralists and the broader community.[155]

The most effective way to mitigate the risk of not obtaining an SLO, according to the literature, is by successful and thoughtful community engagement. The region of Chinchilla presents a case study of early and continuously developing engagement that has significantly increased levels of trust.[156] This engagement was driven equally by the community and the gas companies. The community formed several interest groups, which were able to come together and present their concerns in a respectful format, and which allowed the company to provide responses and solutions to the issues ventilated. The engagement was also assisted through so-called 'enterprise evenings', where local businesses could interact with the larger contracting firms and identify shared business opportunities.[157]

Similar levels of engagement were cited as successful examples of acceptance by a spokesperson for Santos, giving evidence to a South Australian inquiry into hydraulic fracturing. Commenting on the behaviour in the communities of the Cooper Basin, Santos stated the following:

> *"We establish a physical presence, open shopfronts in town, contribute to the local causes in the town and employ local people to make sure that, through the informal contact that those people have with their schools, sporting clubs and other activities in town, we become part of that community and that we are understood and accepted. We think that is the framework that enables us to succeed in building our business."* [158]

The employment of local community members, particularly in roles related to land and environmental management, also builds trust and acceptance. This was demonstrated in a CSIRO study of the Bowen and Surat Basins in Queensland, where a survey participant noted that, "the landholder relation officers they are using are local graziers. I mean, they are smart with who they have chosen to do this."[159] As the community already knew and trusted these people it felt assured that the gas company was 'doing the right thing', which further contributed to the successful development of the relationship.

The resilience of a community can also be a large determinant of the acceptability of any onshore shale gas development and the community's ability to manage any consequential challenges. In the literature, 'resilience' has been described as the ability of a community to build up strength to deal with external shocks and changes that may occur in and around it.[160] Resilience is built and developed through engagement between different groups within the community, and between those groups and the government and industry. The submissions from the CLC and the NLC draw attention to the marginalised nature of many Aboriginal people in the NT, indicating that some Aboriginal communities are likely to be far from resilient, and therefore, potentially more at risk than other communities in different jurisdictions.[161]

The gas industry can help to build resilience in the communities that it will be working with by supporting community development and by ensuring a respectful and informative discourse that enables and integrates community feedback. The gas industry can assist by ensuring adequate planning is in place and that development occurs at a rate that can be managed by the community without negative consequences. By enabling a genuinely vested interest in the long-term wellbeing of the region, any onshore shale gas developer should be able to ensure the provision of a wide range of social and economic benefits to a community.

153 Coomalie Council submission 15; E Lawson submission 216.
154 Central Petroleum submission 99.
155 Pangaea submission 220.
156 Walton et al. 2013.
157 Walton et al. 2013.
158 SA Report, p 35.
159 Parsons and Moffat 2014.
160 Barr and Devine-Wright 2012.
161 CLC submission 1151; NLC submission 647.

Recommendation 12.19

That gas companies be required to develop a social impact management plan that outlines how they intend to develop, obtain and maintain their SLO within communities. This must be developed in conjunction with any SIA, and should be implemented prior to the grant of any further production approvals, to ensure that any potential changes can be identified in advance to allow communities time to adapt and prepare for the changes.

12.7 Case study results of the Beetaloo Sub-basin

Given the focus on the Beetaloo Sub-basin, with its high proportion of Aboriginal people, the key socio-demographics identified by Coffey in the Beetaloo Sub-Basin Case Study of the potentially "*affected communities*" in that region are detailed in this Section.

12.7.1 Beetaloo Sub-basin-affected communities

The Aboriginal people of the Beetaloo Sub-basin are living on country in communities that arose out of a combination of structural changes in the pastoral industry and post-war shifts in Aboriginal policy. Aboriginal employment in the Beetaloo Sub-basin collapsed 50 years ago after the award of equal wages to Aboriginal station workers and the mechanisation of the cattle industry. Between 1955 and 1975, federal government policy evolved from assimilation to recognition of culturally based land-rights and self-governing communities. Central to this was the recognition of traditional land tenure under the Land Rights Act and Native Title Act. Today, Aboriginal people have a form of traditional ownership rights to most land proposed for any development of an onshore shale gas industry in the Beetaloo Sub-basin.

Aboriginal communities in the Beetaloo Sub-basin, in common with other remote Aboriginal populations in the NT, have young populations. A consequence of this is a diminished capacity of the adult population to transmit cultural knowledge and generally educate and socialise emerging generations. These structural issues are magnified by inadequate housing, chronic health problems, such as diabetes, and the corrosive effects of widespread alcohol and substance abuse. As a consequence, social and educational development is not uniform, education attainment is low and youth suicide levels are high.

There are few elders still living who remember when whole communities were employed in the cattle industry. Two generations have grown up in communities where unemployment is the norm. With few local employment opportunities, those with skills or sufficient educational levels have tended to move to larger townships in the region (Katherine and Tennant Creek), or further afield to Alice Springs or Darwin. The welfare of the growing number of young Aboriginal people who now make up the population of the Beetaloo Sub-basin must be the central concern of a SIA of the effects of the development of an onshore shale gas industry in this region.

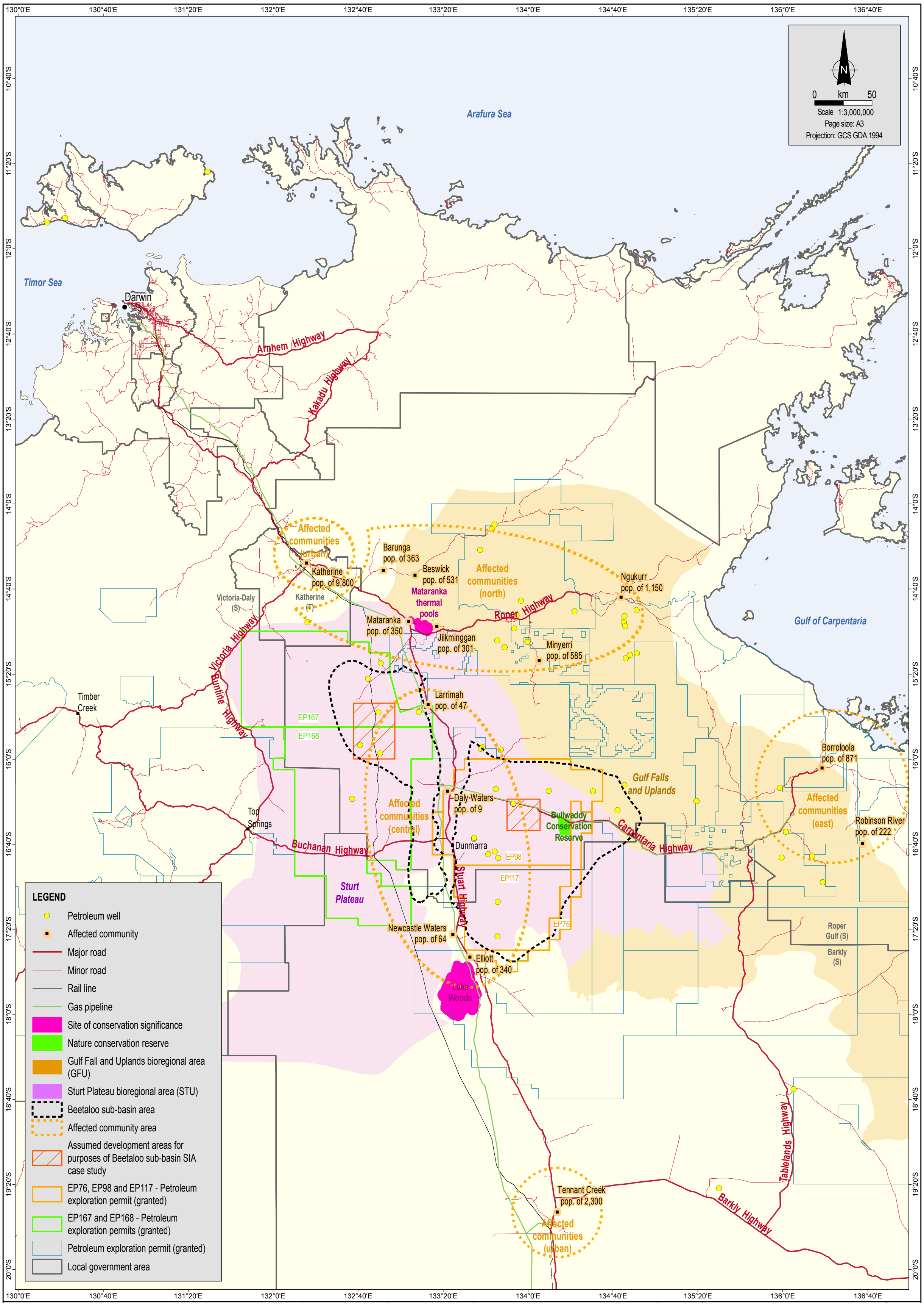
Coffey examined a range of individual communities across the Beetaloo Sub-basin and grouped the affected communities into four areas, which are shown in **Table 12.3** below. The demographics of these areas are expanded on below.

Table 12.3: Social catchments and affected communities. Source: Beetaloo Sub-basin Case Study.[162]

Social catchment	Affected communities
Affected communities (urban).	Katherine (town). Tennant Creek.
Affected communities (north).	Barunga. Beswick. Mataranka. Jilkminggan. Minyerri. Ngukurr.
Affected communities (central).	Larrimah. Daly Waters. Dunmarra. Newcastle Waters. Elliott.
Affected communities (east).	Borroloola. Robinson River.

162 Beetaloo Sub-basin Case Study, Appendix A, p 3.

Figure 12.4: Map showing affected communities and their populations. Source: Coffey Source.[163]



163 Beetaloo Sub-basin Case Study, p 18.

12.7.2 Affected communities (urban)

12.7.2.1 Katherine township population and demographics

According to the 2016 census, Katherine township has a population of 9,717 persons with a median age of 33, which is older than the other areas of the Katherine region due to its relatively lower proportion of Aboriginal people (22% compared with 49% for the region) who tend to have a lower median age. The total population has exhibited steady growth over the last decade. The average household size is 2.8 persons per household since the 2006 census, with an average of one person per bedroom. This is due to Katherine largely being comprised of working-age non-Aboriginal residents, and school age and older working age Aboriginal residents.[164] The age-sex pyramid for Katherine for 2016 shows that the town's population tends to be between 25 and 54 years of age, with relatively fewer children and young adults. The population turnover (the sum of intra-Territory, interstate and overseas migration as a percentage of the resident population) is high, reaching 63% in 2011. This suggests a certain level of demographic instability, possibly leading to fluctuating needs of the Katherine township over time. Non-Aboriginal migrants tended to migrate to and from other Australian states, while Aboriginal migrants tended to be intra-Territory, moving to and from Roper Gulf, Victoria River, Daly, and Darwin.[165]

12.7.2.2 Tennant Creek population and demographics

Tennant Creek is the NT's fifth largest town, with 2% of the Territory's population. It is located on the Stuart Highway. The traditional Aboriginal owners of the area surrounding Tennant Creek are the Warumungu people. The two main Aboriginal languages spoken are Warumungu and Walpiri. The other main languages in the region are Walmanpa, Alyawarra, Kaytete, Wambaya and Jingili[166] Tennant Creek is located in the Barkly region and serves as the region's key service centre. In addition to the major towns and major populations, the Barkly region includes eight minor communities, 70 family outstations, 49 pastoral stations, mining operations and commercial properties.[167]

Tennant Creek has a population of 2,991 and has seen a 2% decrease in population of since 2011. The median age in Tennant Creek is 33, which is slightly higher than the NT average, and the age bracket of 25 to 34 years of age is the largest.[168]

While non-Aboriginal residents tend to migrate to and from the town to interstate, Aboriginal residents migrate in from the surrounding region, and out to Darwin and interstate. Tennant Creek makes up close to half of the Barkly region's population of 6,893, which is estimated to increase by 8.9% by 2021–2026.[169] Aboriginal residents make up approximately 50% of the population.

12.7.2.3 Affected communities (north)

There are six communities in this social catchment: Mataranka; Barunga; Beswick; Jilkminggan; Minyerri; and Ngukurr. These communities are all serviced by the Roper Gulf Regional Council. This region is largely rural and has a number of small towns and Aboriginal communities and outstations. The Roper Gulf Regional Council area encompasses a total land area of nearly 186,000 km^2, with roughly one person for every 26 km^2. The Roper Gulf Region in 2016 had a population of 6,505. The region is demographically young with a median age of 26 years. The population has grown at approximately 1.3% each year since 2006. It shows a generally balanced population, with the exception of low numbers of children four years old and younger. It is unclear why this pattern is recorded.

164 Northern Institute 2014.
165 Beetaloo Sub-basin Social Impact Assessment Case Study, Appendix A
166 Northern Institute 2013.
167 Barkly Regional Council 2011.
168 Northern Institute 2013.
169 ABS Population Projections 2008.

Figure 12.5: Aboriginal and non-Aboriginal population of affected communities (north). Source: Beetaloo Sub-basin Case Study.[170]

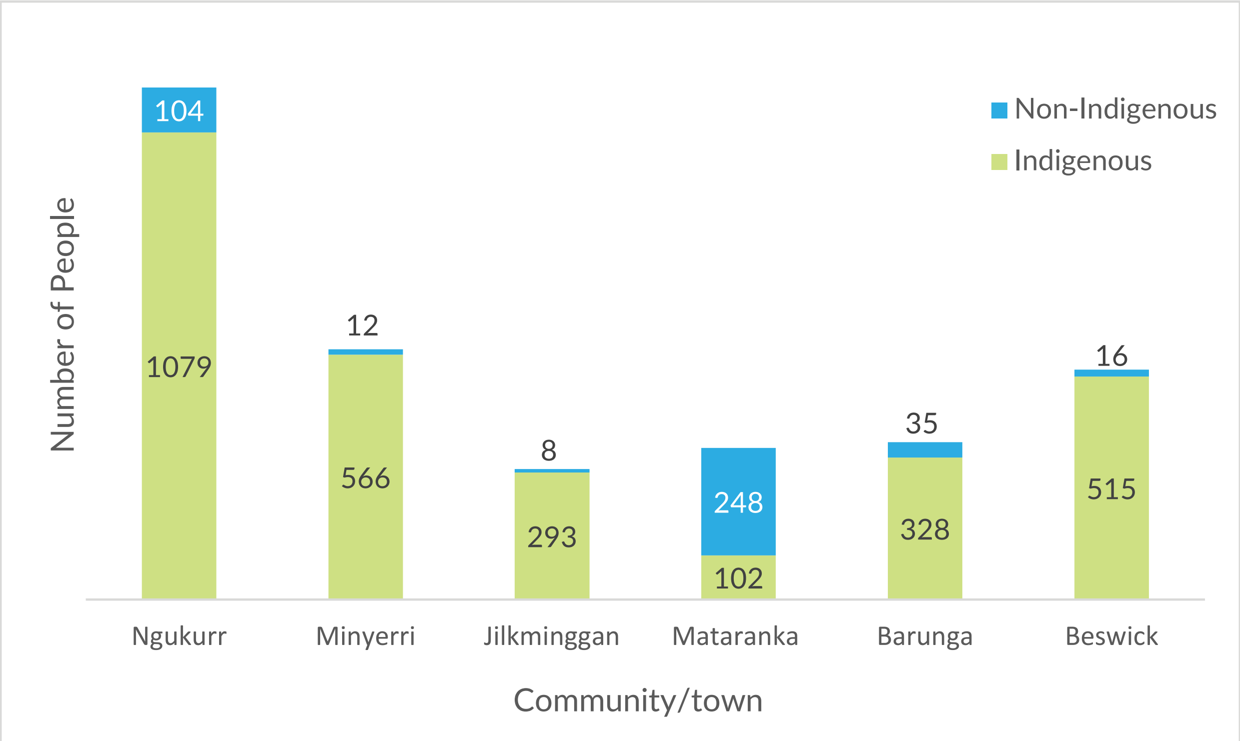
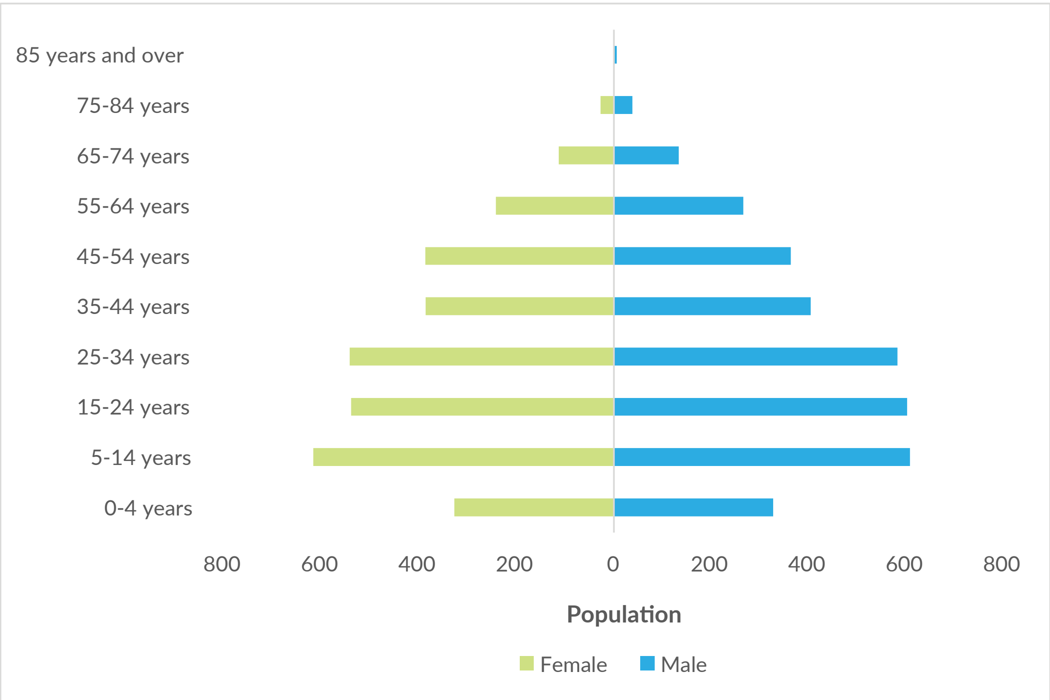


Figure 12.6: Age-sex pyramid of Roper Gulf region. Source: Beetaloo Sub-basin Case Study.[171]



170 Beetaloo Sub-basin Case Study, Appendix A, p 29.
171 Beetaloo Sub-basin Case Study, Appendix A, p 28.

12.7.2.4 *Affected communities (central)*

There are four communities and towns located along the Stuart Highway in this social catchment: Larrimah; Daly Waters; Newcastle Waters; and Elliott. Larrimah and Daly Waters have very small populations. According to the 2016 census, the population of Larrimah is 47 (median age of 41) while the population of Daly Waters is 9 (median age of 54). The key feature of Daly Waters is the Daly Waters Pub, which services locals and acts as a tourist information centre. The surrounding district is known as Birdum and has 86 people with a medium age of 34. There were 12 families in the area recorded in the 2016 census with an average of 1.3 children per family.[172]

Elliott and Newcastle Waters are located within the Barkly Shire along the Stuart Highway. The traditional name for the township of Elliott is Kulumindini. Elliott is the Barkly region's second largest town and sits on the edge of Newcastle Waters Station. Elliott is a stopover point on the Stuart Highway for tourists and local people.[173]

A small, self-sufficient community, the majority of the population of Elliott lives in two town camps, known as Gurungu and Wilyuga. The Aboriginal people residing in these camps are of the Mudburra/Djingila, Wambaya, Kutanyi and Wagai clans.[174]

Newcastle Waters is a historic township located on Newcastle Waters Station. There is an Aboriginal community (Marlinja) located on the station. The Aboriginal population in Elliott and Newcastle Waters is significantly greater than that of Larrimah and Daly Waters. The median age of Elliott (24 years) and Newcastle Waters (22 years) is significantly younger than Larrimah (41 years) and Daly Waters (54 years), and is more comparable to communities in affected communities (east) and affected communities (north). Larrimah and Daly Waters have significantly higher median ages compared to all affected communities. This high median age is likely to be a reflection of these communities acting as a service centre, rather than a residential community.

12.7.2.5 *Affected communities (east)*

This social catchment comprises two communities, Borroloola and Robinson River. Borroloola is located approximately 972 km southeast of Darwin, 655 km southeast of Katherine and 940 km northwest of Mount Isa in Queensland. Borroloola is designated as a 'major remote town' by the Government. Due to its size (871 people according to the 2016 ABS Census[175], it functions as a regional hub and service area for surrounding communities, outstations and pastoral properties. Borroloola has four camps: Garawa Camp One; Garawa Camp Two; Yanyuwa Camp; and Mara Camp. There are 26 outstations located in the surrounding regions that rely on services from Borroloola.[176] There are four main Aboriginal language groups in Borroloola: the Yanyuwa; Garawa; Mara; and Gurdanji.

Borroloola has a median age of 26—lower than the NT average of 31 years. Household sizes have decreased in the last 10 years. At 3.9 persons per household, the average household size is lower than the Roper Gulf average of 4.2. Overcrowding exists in some households, and the Government has planned for the construction of 22 new houses to alleviate housing issues, including overcrowding.[177]

The age-sex pyramid for 2016 shows a roughly pyramidal shape, except for disproportionately low numbers of children four years old and under. Borroloola has a mostly Aboriginal population, with the 2016 ABS Census reporting 77% of the population identifying as Aboriginal. Borroloola is an open township which has a steady tourism industry and is largely influenced by the McArthur River Mine.

172 ABS Census 2016.
173 Barkly Regional Council 2017.
174 Remote Area Health Corps 2009.
175 ABS Census 2016.
176 McArthur River Mine 2017.
177 Beetaloo Sub-basin Case Study, Appendix A, p 37.

Figure 12.7: Aboriginal and non-Aboriginal populations in Katherine, Tennant Creek and Borroloola (2006–2016). Source: Beetaloo Sub-basin Case Study.[178]

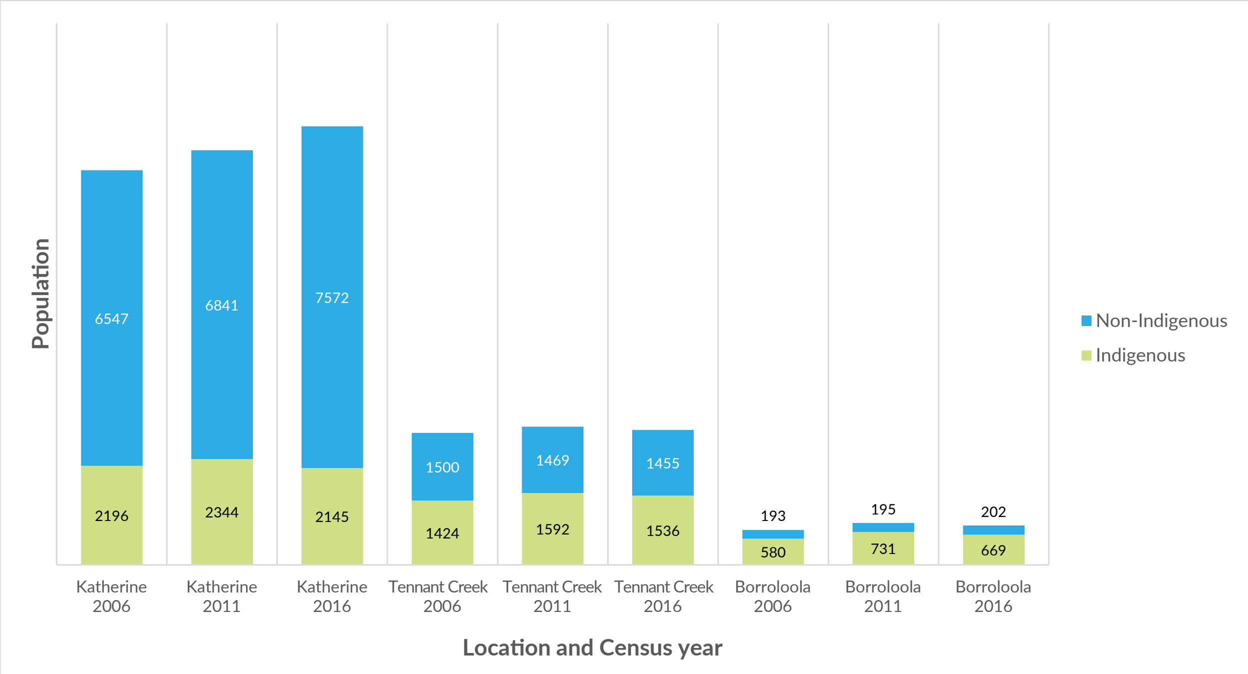
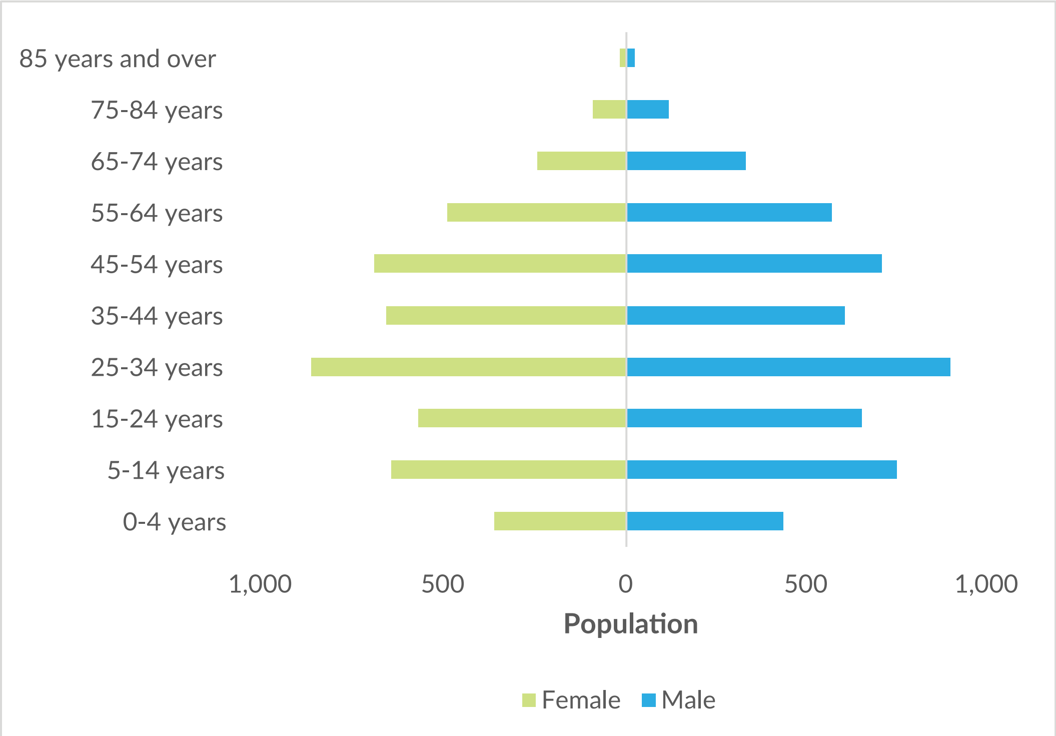


Figure 12.8: Katherine age and gender pyramid (2016). Source: Beetaloo Sub-basin Case Study.[179]



178 Beetaloo Sub-basin Case Study, Appendix A, pp 14, 23, 38.
179 Beetaloo Sub-basin Case Study, Appendix A, p 15.

Figure 12.9: Tennant Creek age and gender pyramid (2016). Source: Beetaloo Sub-basin Case Study.[180]

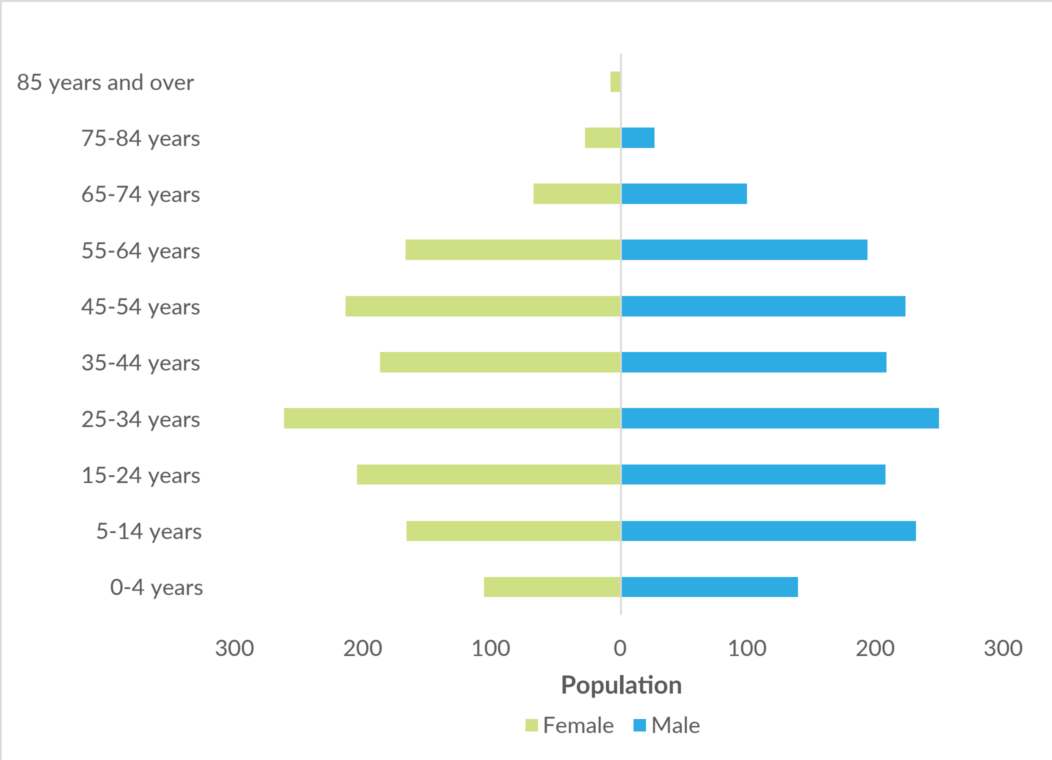
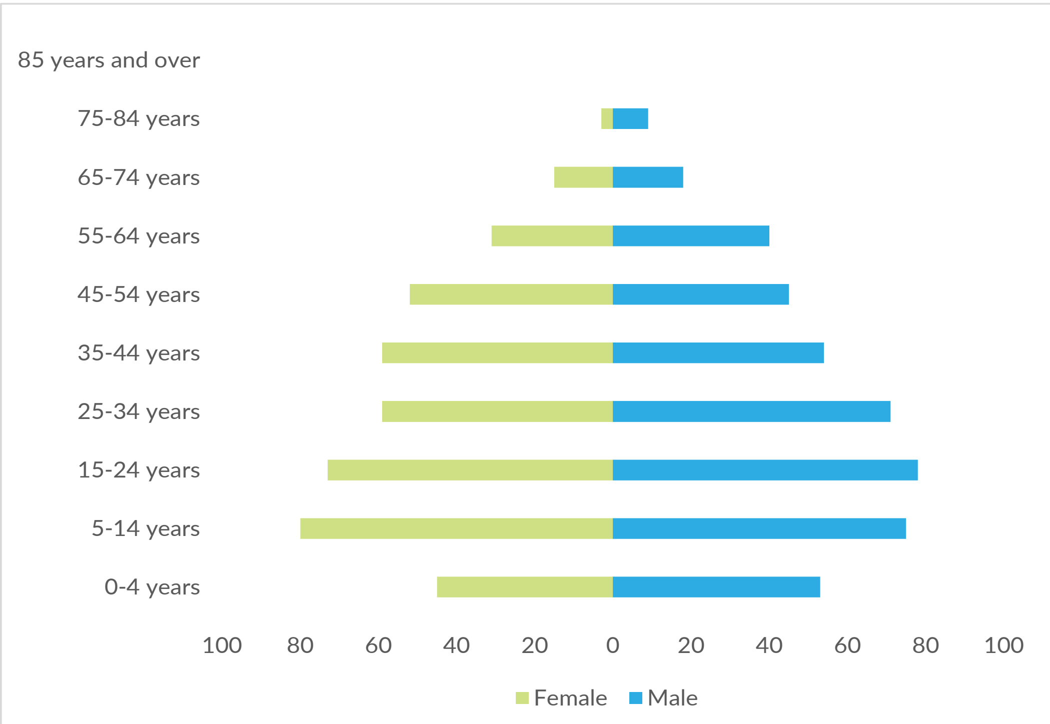


Figure 12.10: Borroloola age and gender pyramid (2016). Source: Beetaloo Sub-basin Case Study.[181]



180 Beetaloo Sub-basin Case Study, Appendix A, p 22.
181 Beetaloo Sub-basin Case Study, Appendix A, p 38.

12.7.3 The social context of the affected communities

In addition to the socio-demographics presented above, this Section describes key characteristics and considerations that arose from the Beetaloo Sub-basin Case Study that have a bearing on the likely social impacts across the Beetaloo Sub-basin. The Sub-basin is located between Katherine and Tennant Creek and covers an area of approximately 7,000 km^2. Land use in the Beetaloo Sub-basin comprises Aboriginal land, pastoral leases (which co-exist with native title rights and interests), horticultural enterprises, oil and gas transmission infrastructure, a railway, highway towns, cattle stations and remote Aboriginal communities. The Australian Defence Force also operates the Tindal RAAF Base located near Katherine and has a strong presence around that community.

Within the affected areas, there are stark contrasts between those living in the urban areas and those living in the more remote and regional areas, with the ratio of Aboriginal to non-Aboriginal people rising rapidly in the remote communities. This change in ratio impacts many of the social issues from age, education, schooling attendance, unemployment and health outcomes. Across the Sub-basin, those communities with a predominantly Aboriginal population have a much younger median age of around the mid-20s. Mortality rates in the Roper Gulf region are higher than the Australian average, and life expectancy is much lower. In many of the regions, school attainment levels are much lower than the NT average. For example, in the northern region, 53% of students left school during or before completing Year 10, and only 13% completed Year 12 and nearly a quarter of people indicated progressing no further than Year 8. This is significantly less than attainment rates within the Katherine region, where Year 12 was the most common level of education achieved (28%). The eastern region's educational attainment rates are similar to the Katherine region levels. Within the central region, due to the small population size, the School of the Air provides educational services to communities in this social catchment.

In Borroloola, a key issue in the community is a lack of recreational activities, facilities and infrastructure for young people. The cost of living in the Roper Gulf region is higher than Darwin and Katherine, but personal average weekly income is less than half of the NT average at $279. On the other hand, Borroloola has a personal average weekly income of $424, influenced by employment opportunities at the McArthur River Mine. Housing and health also vary across the region and need to be considered on a case-by-case basis for any onshore shale gas projects.

Some of the locations are tourist destinations, which attract large numbers of visitors each year, and therefore, tourism is an important part of those towns' income. Most communities have Telstra mobile network coverage, however, limited service is available outside the towns and communities. The majority of local roads are not sealed, although some communities have sealed streets. Much of the road network is subject to seasonal closure because of flooding.

12.7.4 Key concerns and opportunities

Coffey reported that the major concern across all communities – urban, Aboriginal and pastoral – was the potential impacts of hydraulic fracturing on groundwater, both quality and quantity. This issue is addressed in detail in Chapter 7. Other concerns that frequently arose during its consultations included the potential to create massive income disparity through the receipt of royalties in remote Aboriginal communities. The concern was that such royalties, unless managed well, could negatively affect relations between different traditional Aboriginal owner groups.

Particular challenges when undertaking both strategic and project-level SIAs in the Beetaloo Sub-basin include the remoteness of communities (influencing the time available to consult effectively), and the cultural diversity and differing world views of the major stakeholder groups (Aboriginal communities and pastoral leaseholders). The significance of these challenges is amplified due to the limited understanding of the nature of the onshore shale gas industry, and of the technologies that would be deployed to extract shale gas and manage potential environmental and social impacts. Distrust of the Government and its capacity to regulate any shale gas industry was also a matter of concern.

Despite these challenges, none of these risks are considered to be incapable of being mitigated and managed. But effective management will require close collaboration between the gas companies, Government and the community to ensure that responsibility for management and reporting on Sub-basin impacts is clear, and that mechanisms for community feedback and responses are widely known and effective.

Coffey identified a number of opportunities that may emerge from any onshore shale gas industry. The first was the potential for increased employment, training and a broadening of the skills base of the local workforce. Given the unemployment and younger average age of the population living in and around the Beetaloo Sub-basin, developing a local workforce and providing opportunities for meaningful employment was seen to be important, with potential flow-on benefits. For example, if the workers saw Katherine or Tennant Creek as a desirable place to live, it could lead to modest population increases. The opportunity, through local procurement of inputs for shale gas development, to diversify the economic base of regional support towns was also seen positively.

Other suggested opportunities included the development of regional support facilities through worker accommodation or upgrades to airstrips, which could be used for tourism, training and employment opportunities for Aboriginal communities in the area, co-development of infrastructure, and regional environmental monitoring through participation by natural resource management groups and Aboriginal ranger groups.[182] However, central to realising these opportunities is to ensure that the SIA framework is implemented at the earliest opportunity to gather essential baseline data from which to measure progress.

Recommendation 12.20

That as part of the SREBA for the Beetaloo Sub-basin, a strategic SIA be conducted to obtain essential baseline data prior to the granting of any further production approvals.

12.8 Social licence to operate in the Beetaloo Sub-basin and the NT

An SLO is critical for any successful onshore shale gas industry. The origins of the concept of an SLO trace back to the mining sector around the mid-1990s. It emerged in response to a number of highly publicised conflicts with communities over failures of chemical spills and tailing dams.[183]Although it has no agreed formal definition, the concept is 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".* [184] Due to the intangible nature of an SLO, many argue that it is easier to know when an industry or project does not hold an SLO, than when it does.[185] A failure to gain or hold an SLO can often lead to political intervention and sometimes project failure.[186]

Trust is a critical element of an SLO. While trust takes time to be established, it can very easily and very quickly 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, cognisance of the cultural differences and the requirements of different stakeholder interests involved, or intersecting with the project, must exist in some way.[187] 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.[188] If historical evidence suggests that poor regulatory conditions have prevailed, or there is a track record of industry failure to uphold explicit commitments to stakeholders and the environment, it will result in low trust in both the government and the associated industry. This will limit the ability of those project operators, and often the associated government, to gain an SLO.[189]

12.8.1 SLO in the NT

Research conducted over several years has now identified a common set of relational variables that underpin social acceptance, or SLO, at local, State and national scales. These critical relational variables (that is, focussing on stakeholder interactions) include: contact quality between gas company personnel and community members at the local scale; distributional fairness (particularly in relation to benefits) across scales; procedural fairness across all scales;

182 Beetaloo Sub-basin Cast Study, p xv.
183 Thomson, Boutilier and Darling 2011.
184 Moffat and Zhang 2014.
185 Parsons, Lacey and Moffat 2014.
186 Prno and Slocombe 2012.
187 Serje 2017.
188 Bradbury et al. 2009.
189 Gallois, Ashworth et al. 2016.

and citizen confidence in the governance arrangements around extraction at the State and national scale. Each of these variables is summarised below.[190]

12.8.1.1 Contact quality between gas companies and community members

At the local scale, the quality of contact between gas company personnel and community members can have a significant influence on the quality of interactions between a gas company and a community. For example, in a longitudinal survey of community attitudes to CSG extraction in Queensland, the quality of contact between gas company personnel and community members was a significant predictor of the community's trust in the company and acceptance of its operation.[191] What made little difference to trust and acceptance was the amount of contact between the gas company and the community.

12.8.1.2 Distributional fairness

Distributional fairness refers to the extent to which the benefits of an extractive operation are perceived to be distributed fairly within a community or society more broadly.[192] In the extractive context, the fair distribution of industry related benefits has been shown to be a significant predictor of trust and acceptance of both local operations and the industry.[193] For example, communities may benefit through direct compensation, royalty payments or participation in joint ventures.[194] Other benefits may include industry's contribution to employment and training opportunities,[195] or investment in local and regional infrastructure.[196]

12.8.1.3 Procedural fairness

Procedural fairness in a non-legal sense routinely requires the implementation of processes that are considered to be fair by all involved, are transparent, are inclusive of diverse perspectives and priorities, and allow the public to access information and to feel respected and listened to in that process.[197] Given the increased participation of communities in decision-making about how extractive resource operations and other large infrastructure projects will be developed, designing and implementing fair processes (including a reasonable access to justice: see Chapter 14 for further discussion) has become a critical part of creating equitable participation, creating meaningful dialogue among stakeholders, diffusing conflict and achieving sustainable resource management decisions.[198]

12.8.1.4 Governance

When the public believes that the governance arrangements in place are not capable of ensuring responsible resource development, its attitude toward extraction tends to be less favourable. Research has shown that public perceptions of the regulatory arrangements around extractive industries moderate the relationship between their concerns over environmental impacts and their acceptance of industry.[199] More specifically, when citizens strongly believe that existing regulation and legislation has the capacity to hold extractive industries to account for their actions (that is, strong governance), there is an increased likelihood of acceptance of that industry compared to those who perceive governance arrangements as being weak, irrespective of their views on the environmental impacts of the industry.[200] Chapter 14 discusses how the current regulatory framework can be strengthened to increase the community's trust in the shale gas industry and in the Government.

12.8.2 NT results of a national survey

CSIRO conducted a survey in late 2016 and early 2017 across Australia that focussed on attitudes toward extractive industries. The following summarises the findings of the 227 participants that participated from across the NT. With such small numbers, particularly in those areas that are

190 CSIRO Report.
191 Moffat and Zhang 2014.
192 Kemp et al. 2011; Zhang, Moffat, Lacey et al. 2015.
193 Moffat, Zhang and Boughen 2014.
194 O'Faircheallaigh 2002.
195 Measham and Fleming 2014.
196 Michaels 2011.
197 Lacey, Carr-Cornish, Zhang et al. 2017.
198 Kemp et al. 2011; Holley and Mitcham 2016; Lacey, Edwards and Lamont 2016.
199 Zhang and Moffat 2015.
200 Zhang, Moffat, Lacey et al. 2015.

likely to be most affected by any onshore shale gas industry, drawing any conclusions from the survey needs to be treated with extreme caution. However, the data does provide some insights into issues of concern that Government, regulators and gas companies need to be mindful of when considering the implementation of any onshore shale gas industry.

In general, residents of the NT perceive governance capacity significantly poorer than those respondents from all other States and Territories. This was something that the Panel heard repeatedly both in submissions and at the various hearings and community forums. NT residents have low trust in extractive industries and the Governments, marginal trust in advocacy groups, but higher trust in research organisations relative to residents in all other States. Low trust in the Government is a common phenomenon across all States, as is low trust in the extractive industries. NT residents, however, trust the extractive industries significantly less than residents do in other jurisdictions.

Low trust perceptions are underpinned by low perceptions of procedural and distributional fairness. Perceptions of procedural fairness (feeling heard, respected and included in decision making processes) and distributional fairness (that the benefits of extractive industries are spread fairly) were significantly lower in the NT when compared to all other States.

Although trust and the perceptions of extractive industries was low, impacts and benefits relating to regional infrastructure, employment and local community benefits were particularly favourably perceived in the NT. However, financial benefits at the individual, family, and general public levels were less influential. Perceived adverse environmental effects were the most negatively viewed industry impact, which was followed by impacts on living costs, and impacts on other sectors (for example, tourism and manufacturing).

Good governance was significantly more important for social acceptance of any extractive industry in the NT than for residents in the rest of Australia. This highlights the need for the Government to accept and implement the recommendations made in Chapter 14. Governance was approximately as important as trust in the petroleum industry as a direct predictor of social acceptance, and it was also an important predictor of trust. Governance, therefore, has both direct and indirect effects on social acceptance of extractive industries. Trust in the petroleum industry is also influenced by perceptions of procedural and distributional fairness. Since both of these are rated unfavourably in the NT, improving these perceptions create opportunities for improving trust in, and social acceptance of, extractive industry in the NT, including any onshore shale gas industry.

However, the most important predictor of social acceptance was a perceived balance of benefits over the impacts of the petroleum industry, or its 'value proposition'. The perceived employment benefit from extractive industries along with financial community benefits, were the highest predictors of the 'balance of benefits over impacts' variable. This is particularly important in the NT, which is experiencing increasing inequality in family income. Any potential royalty payment scheme for any new onshore shale gas industry must therefore be designed carefully to ensure that sharing economic benefits does not exacerbate underlying trends in family income inequality in novel ways (see Chapter 13).

12.8.3 Improving SLO

Discussed below are findings from the CSIRO Report, including interviews and fieldwork with representatives from a range of industry, community and government stakeholders in the NT.

The conversations identified a number of concerns and areas for improvement relating to SLO. Community members expressed strong interest in resolving, or at least addressing, their uncertainty through accessing information from the gas industry and the Government regarding the use of hydraulic fracturing technologies in the Beetaloo Sub-basin, but also expressed frustration that there appeared to be no one to ask.[201] By contrast, it is clear that gas industry representative bodies have been providing opportunities to the public in more populated centres of the NT to access relevant information from technical experts. There appears, therefore, to be a gap in who is actively seeking information to resolve uncertainty and where this information is being made available.

Oilfield Connect[202] was adamant that the claims by Lock the Gate were particularly damaging to the NT's trust in the industry, the Government and the Inquiry's findings. It recommended

201 CSIRO Report, p 35.
202 Oilfield Connect Pty Ltd, submission 1164 (**Oilfield Connect submission 1164**).

that, "*the Inquiry panel may consider that there needs to be a new recommendation to the NT government for a 'post-Inquiry public awareness campaign', which more clearly articulates the facts learned by the Inquiry about the onshore shale gas industry, and also point out the many nonfactual misinformation and false allegations, such as evident in this incident by the LTGA.*" [203]

Similarly,[204] Origin made reference to the lack of understanding around the terms *"conventional"* and *"unconventional"* gas plays, which was evident in submissions to the Panel. There was a call to ensure that factual information was made available to those living in the NT to counter some of the misinformation that had been promulgated by some activists.

The gas companies conducting exploration in the Beetaloo Sub-basin that were interviewed by CSIRO reported strong engagement locally with potentially affected community members and traditional Aboriginal owners. Gas companies indicated that where they were able to meet regularly with community members to discuss uncertainties and explore opportunities for future benefits, relationships were more positive. However, comments from the community regarding the lack of engagement in areas alongside, or even overlaying, the exploration permits demonstrate the need for a broader and more inclusive definition of who is the 'community' in this context.

All stakeholders stated that the role of the Government was critical to how any onshore shale gas industry will, or will not, progress.[205] There was a perception that the Government had been largely absent from the discussion about onshore shale gas development in the NT for some time, and that greater involvement was not only welcome, it was necessary to meet the challenges that communities might face with the introduction of this new industry.

Constructively, interviewees discussed ways in which the Government could be more effective. First, regulation had to be creative, modern, and based on the experiences of other jurisdictions. Second, the need for careful and deliberate planning was seen as important. While planning around infrastructure and regional industry capacity is well developed within governments generally, skills around planning for social infrastructure and capacity are less well developed but are nevertheless as important. What services will be required to build the capacity of community members for work and participation in any new onshore shale gas industry, to support a potential influx of construction personnel, and to support changing community dynamics were all areas that were seen to be important in managing SLO issues through good planning. Third, there was a desire from the community and from some industry participants for the Government to play a more active role in engaging the community.

The need to develop any new onshore shale gas industry in a manner consistent with 'the NT way' was emphasised in all of the community consultations. There was a clear view that the NT has unique characteristics and cultural norms that meant that lessons from other jurisdictions were not able to be directly applied without reflection. However, research on SLO in many contexts around the world indicates that there are usually many more similarities in the way community acceptance is developed and maintained over time than there are differences. The issues of relevance to other communities (for example, water quantity and quality) and the factors that are known to be important in building trust and acceptance (for example, procedural and distributional fairness and contact quality) will also be central in the NT. But how strategies for their management are executed will benefit greatly from contextualisation.

203 Oilfield Connect submission 1164.
204 Origin submission 1248
205 CSIRO Report, p 35.

Community members from the Gurdanji, Mara, Garawa and Yanyuwa clans groups from Borroloola.
Source: Seed.

12.8.4 Measuring SLO in the NT

Measuring and monitoring community sentiment has value because community voice is often largely absent from discussions and decision-making processes that shape development trajectories in extractive industries. This lack of voice is at the heart of much community and gas company conflict. Less formal consultative processes are often felt by communities to have pre-determined outcomes, while communities also express concerns about 'survey fatigue', with multiple companies or governmental agencies often regularly asking the same communities questions over time.

Critically, community members must be reassured that any research is being conducted under conditions that protect them as participants. This can be managed through provisions around informing participants about research purpose, seeking informed consent, limiting the use of incentives for participation, incorporation of culturally sensitive methods, assurances that participants can withdraw from the research at any time without consequence, and reassurances that any personal information or data that may identify them is appropriately managed and secured. Proper mechanisms for seeking more information about the work and/or lodging a grievance are also important in building trust in the process that the community is invited to participate in.

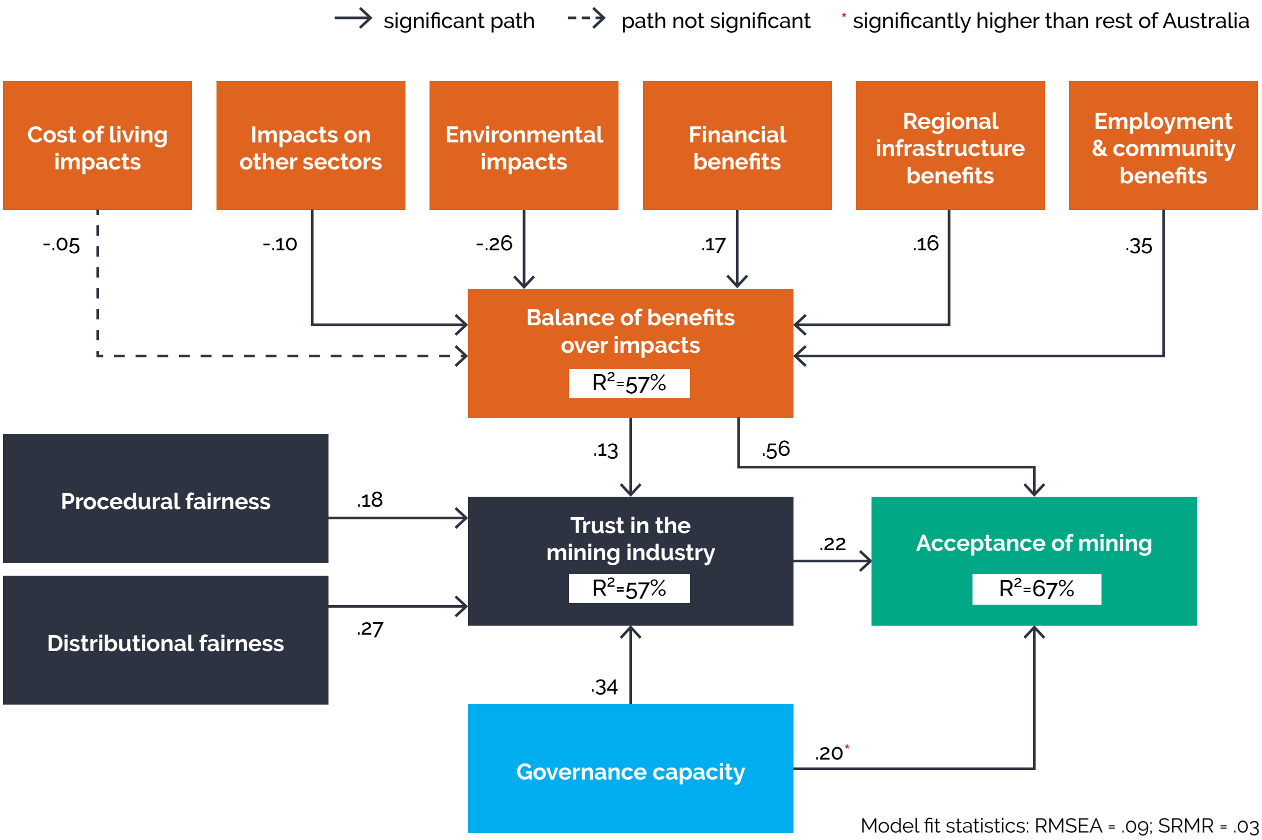
CSIRO's own practice, supported by 'listening tours' conducted by the Queensland Resources Council,[206] suggests that it is not fatigue with participating in survey research that communities are frustrated by, but the lack of even basic feedback or transparency about the way their data is used and how it has, or has not, affected decision-making processes. By successfully measuring and modelling the critical elements leading to social acceptance, gas companies can also prioritise their activities and investment in a way that maximises the creation of trust between its activities and the communities affected by those activities.

What may be more helpful in this regard is a measurement and monitoring framework that seeks to understand and reconcile the multiple perspectives that are held. For research focussed on SLO to be seen as relevant to all stakeholders, it is advantageous to also consider the role of a trusted third party.

206 Queensland Resources Council 2016.

In the CSIRO Report, a statistical technique called 'structural equation modelling' was used to establish the relative importance of key drivers of trust and acceptance in the NT. A comprehensive model of trust and social acceptance of extractives was developed by CSIRO at the national level, and this model was applied to the NT data. At both the national and NT level, the model performed well, predicting more than half the variation in individual levels of trust, perceptions of benefits over impacts, and the respondents' overall social acceptance of the industry in the NT (57%, 57%, and 67%, respectively: see **Figure 12.11** below).

Figure 12.11: Comprehensive model of NT data predicting trust and acceptance of the extractive industries. Source: CSIRO Report.[207]



There is great opportunity for the NT to determine the conditions under which any future onshore shale gas industry is developed, taking the best and most current lessons from other jurisdictions and implementing them in 'the NT way'. With respect to SLO, any new shale gas industry will not be possible without achieving some level of acceptance in local communities and in the Territory more broadly. But SLO is not a tangible, one-off requirement. SLO is about relationships, sharing decision-making power and supporting communities to have constructive ways of influencing development trajectories.

207 Moffat et al. 2017.

12.9 Conclusion

The Beetaloo Sub-basin Case Study identified that significant disparity exists across the Beetaloo Sub-basin between the regional service centres and Aboriginal communities due to their remoteness. This affects access to services, housing, access to a functioning labour market, and accounts for critical differences in health and education status. A key issue will be how affected communities realise opportunities from any onshore shale gas development.

From the submissions and the information shared with the Panel at the consultations, it is clear that many Territorians hold a range of concerns in relation to the social impacts of any onshore shale gas industry. Most people who appeared before the Panel did not believe that the gas industry held an SLO. Different stakeholder groups do not share the same concerns. Similarly, many of the concerns are location specific, while others relate to the whole of the NT.

Key issues important for any SIA undertaken in the NT include impacts on housing and infrastructure, employment, business income, education and skills development, community cohesion, crime rates, transport, and the transient nature of the workforce. What is critical to ensure that the social impacts are acceptably mitigated is the need for strong regulatory structures that include necessary consultation and engagement with all affected stakeholders.

Through open and transparent processes and strict governance structures, the Panel's view is that the social impacts can be mitigated to an acceptable level. However, to obtain an SLO for any onshore shale gas industry in the NT, considerable resources will be required when planning and implementing the SIA framework. Extensive participation and engagement of all stakeholders will be critical for the industry to succeed.

An independent strategic SIA with specific attention to social, cultural, economic and environmental values is an essential starting point. Critical for success is to ensure that any engagement is well managed and coordinated across the affected regions to mitigate the potential for cumulative impacts and consultation fatigue. The creation and maintenance of an open and shareable database of information collected over time will help to build trust in how the projects are being monitored. Such transparency, together with careful attention to procedural fairness and distributive justice, will be critical for the success of any shale gas industry. Finally, adequate monitoring and engagement through a reflexive and ongoing process will also be fundamental to build an SLO for any onshore shale gas industry.

ECONOMIC IMPACTS

13

13.1 Introduction

The NT Budget 2017–18 estimates that the NT population is approximately 245,000, which equates to 1% of Australia's population. The structure of the NT's economy substantially differs from that of the national economy, reflecting its abundant natural resources, a large public sector, a sizeable armed services presence, and a small private sector that is significantly influenced by major projects.[1]

Over the past 12 years, the NT economy has benefited from multiple major projects. Gross State Product (**GSP**), often referred to as real output, has grown from $15.2 billion in 2004–05 to $25.4 billion in 2016–17. However, economic growth is forecast to be moderate as the Territory moves from investment-led growth to predominantly export-driven growth. The relatively modest rate of growth in the short term reflects a transition to more historical levels of private investment.[2]

The Australian Petroleum Production and Exploration Association (**APPEA**) argued that resource development brings the potential for a substantial and stabilising public benefit. It further asserts that new industries are needed to support the NT economy as the Ichthys LNG project transitions from construction to production.[3] Multiple submissions from industry described the potential for substantial benefit to the Territory's economy by the development of an onshore shale gas industry based on the geological extent of prospective source rocks. For example, Falcon Oil and Gas Australia, which holds a 30% interest in exploration permits EP 76, EP 98 and EP 117 (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."*[4] Other submissions outlined how the growth of an onshore shale gas industry in the NT would see the establishment of supply hubs (a centre for excellence or other educational centres) that provide an avenue for local people to obtain training, development and accreditation for employment in the gas industry and other sectors.[5]

There is, however, considerable community concern that any onshore shale gas industry could have significant negative economic consequences, including a rapid increase 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.[6] Many submissions expressed a concern that a shale gas industry in the Territory was unlikely to provide significant economic benefit and comes with substantial risks.[7]

13.2 Key issues

The final list of issues lists seven possible economic risks, including cumulative impacts, that are associated with any development of onshore shale gas reservoirs in the NT (see Appendix 2).

The Panel has received a variety of submissions on how the development of any unconventional shale gas industry might benefit or have an adverse impact upon the Territory's economy. The following discussion provides additional detail around known risks and proposed measures to mitigate those risks.

13.2.1 Distribution of potential economic benefits

Origin describes an extractive business's role as that of a developer, namely, to *"facilitate the transformation of a natural asset, which is a publicly owned good, into social or economic benefit for*

1 NT Budget Economy Book, p 3.
2 NT Budget Economy Book, p 5.
3 APPEA submission 215, p 4.
4 Falcon Oil and Gas Australia Pty Ltd, submission 79 (**Falcon submission 79**), pp 2-3.
5 Pangaea submission 1147, pp 28, 67; MS Contracting, submission 1238 (**MS Contracting submission 1238**), p 12.
6 ALEC submission 88, p 13.
7 The Australia Institute, submission 539 (**The Australia Institute submission 539**), p 3.

shareholders, governments and host communities." [8] 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. 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"* [9] and 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."*[10]

It is for this reason that 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."* [11]

13.2.1.1 Government revenue

Approximately 70% of the Government's annual income comes from the Commonwealth, with the remaining 30% from the Territory's own source of revenue. Changes to Goods and Services Tax (**GST**) funding allocation and national economic volatility have the potential for a greater negative impact on the NT's financial sustainability. Growing the NT's financial base will reduce this risk, by reducing the NT's reliance on the Commonwealth.

While multiple submissions support onshore shale gas development as a means of gaining greater independence from the Commonwealth and to strengthen the NT economy, The Australia Institute nevertheless noted that, *"mining and gas royalties are not a major source of funding for Australian state and territory governments."*[12] It describes declining payments received under the Petroleum Resource Rent Tax and went 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."* [13]

13.2.1.2 Employment

In its 2015 report, Deloitte Access Economics (**Deloitte**) presented two scenarios (success and aspirational) for potential onshore gas development in the NT. Associated predictions for employment were between 4,200 and 6,300 full time equivalent (**FTE**) jobs above the base case by 2040.[14]

Industry has expressed an intention to invest in providing local training, jobs and business support, particularly in remote and regional areas.[15] Origin stated that its *"approach to living local and buying local will ensure economic benefits accrue in our areas of greatest activity and impact."*[16] Pangaea also advocated an approach that supports a long-term focus towards community integration. Examples of 'local content' provided in its submissions include employing pastoralists in seismic operations, Aboriginal people in civil access and construction works, local civil earthworks

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8 Origin submission 153, p 147.
9 Northern Territory Cattlemen's Association, submission 217 (**NTCA submission 217**), p 1
10 NTCA submission 217, p 5.
11 NTCA submission 217, pp 2, 5.
12 The Australia Institute submission 158, p 7.
13 The Australia Institute submission 158, p 7.
14 2015 Deloitte report, p 5.
15 Falcon submission 79, p 3.
16 Origin submission 153, p 147.

contractors, local waste disposal companies, and local camp and accommodation companies.[17] Multiple submissions received from a variety of Territory-based businesses agreed on the need for local content with respect to employment.[18]

The NLC advises that many Aboriginal communities are remote and are largely dependent on welfare. Its submission describes 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.[19]

However, a range of submissions questioned the long-term employment benefits to rural and remote communities in the event that any onshore shale gas industry is established. Models reliant on a largely FIFO workforce were widely criticised by the community during consultation sessions for their lack of contribution at a community or regional scale. The Northern Territory Chamber of Commerce and Industry also highlighted its concerns around the potential use of FIFO workers, demanding that gas companies be socially responsible by avoiding the use of such a workforce in order to maximise local employment and business opportunities.[20] The Australia Institute expanded upon these concerns, predicting that Territorians will have to compete with the many experienced workers no longer employed in the Queensland CSG sector as a result of that industry's decline since 2015.[21]

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

Origin states that production royalties would substantially increase and diversify the NT revenue base without affecting critical existing industries, such as cattle exports and tourism. Its submission argues 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.[22] Having said this, the Panel notes concerns raised by the public that the presence of the 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 NLC.[23]

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 any onshore 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.[24] The Darwin Major Business Group stated that development of any onshore shale gas industry will attract investment in roads and regional infrastructure and deliver significant long-term benefits and opportunities to businesses and regional communities across the Territory.[25] Conversely, the NTCA cautioned that in underdeveloped regions where there is limited infrastructure, substantial capital costs may deter valuable private investment.[26]

The NLC 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 ease the economic pressures currently faced in remote, and too often welfare dependent, Aboriginal communities.[27]

13.2.1.5 Royalties

The NT 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% of gross value at the well head on petroleum production. The Territory's royalty*

17 Pangaea submission 220, p 5.
18 B Sullivan submission 160, pp 1-2; Mr Mark Sullivan, Flying Fox Station, MS Contracting, submission 166 (**MS Contracting submission 166**), pp 4, 8; Terrabos Consulting submission 180, p 4.
19 NLC submission 214, p 33.
20 Northern Territory Chamber of Commerce and Industry, submission 493 (**NTCCI submission 493**), p 1.
21 The Australia Institute submission 158, p 13.
22 Origin submission 153, p 147.
23 NLC submission 214, p 34.
24 MS Contracting submission, p 10.
25 Darwin Major Business Group, submission 494 (**DMBG submission 494**), p 1.
26 NTCA submission 217.
27 NLC submission 214, p 33.

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." [28]

During community forums held by the Panel, questions were raised about 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 requested that a 'Royalties for Regions' program should be considered. The NTCA, for example, 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."* [29]

13.2.2 Property values

Multiple submissions referenced the negative influence of any onshore shale gas development on, and in close proximity to, residential and agricultural properties.[30] Examples of the presence of CSG 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.[31] The Panel notes, however, that this evidence has been challenged by the Commonwealth Bank of Australia.[32]

Lock the Gate Alliance also 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."* [33]

But the notion of declining property values has been rejected by some stakeholders on the basis that infrastructure improvements can benefit remote cattle stations.[34] For example, Mr Rohan Sullivan of Birdum Creek Station advised of *"understandable anger"* in relation to the current moratorium because it had halted Pangaea's 2016 infrastructure program worth $100 million, 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.[35]

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. Locals may not benefit from the direct income increases and may instead suffer from increased rents, poverty, and outmigration, especially in lower income households.[36]

In a 2016 report to the Council of Australian Governments, APPEA stated that there was no clear quantitative evidence that the onshore gas industry was having an impact, whether negative or positive, on rural property values.[37] However, APPEA did report that the Queensland GasFields Commission had identified some rural property listings that had underlined the benefits of the value of compensation payable by the CSG industry to those properties and the economic opportunity that comes from being located in proximity to the gas industry.

APPEA also opined 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 to resident workers rather than non-resident (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 decrease, excess housing supply can cause

28 NT Petroleum Royalty Overview, p 1.
29 NTCA submission, 217 p 7.
30 D Tapp submission 11, p 2; R Dunbar submission 75, p 8.
31 Lock the Gate submission 171, p 60.
32 Origin Energy Ltd, submission 544 (**Origin submission 544**), p 19.
33 Lock the Gate submission 171, p 58.
34 B Sullivan submission 160, p 5.
35 R Sullivan submission 18.
36 T Measham submission 77, p 8.
37 Australian Petroleum Production and Exploration Association, submission 1178 (**APPEA submission 1178**), p 30.

problems.[38] APPEA advised that the gas industry needs to work closely with regulators, local government, and the local community, to collaboratively address housing needs.[39]

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.[40]

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."*[41] It acknowledged that the considerable shale gas reserves located within the NT provide significant economic enticement to the Government (present and future), however, it noted that, *"fossil fuel reserves are finite, while livestock production and agriculture generally will operate in perpetuity."*[42]

Consolidated Pastoral Company Pty Ltd advised that, *"any adverse impacts on access to groundwater or the quality of groundwater would have a significant impact on the company 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."*[43]

Lock the Gate listed the deleterious impacts of known onshore unconventional gas development on 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."*[44] In relation to CSG development, it observed the potential for further economic losses from disruption of agricultural operations, spills and leaks of wastewater, or the spread of weeds.[45]

In addition, tourism is a large driver of the NT economy. It was regularly stated that, *"our long-established reputation as a unique tourism destination centered around our extraordinary natural landscapes and rich aboriginal culture"* may be affected by the onshore unconventional oil and gas industry.[46] The tourism industry in Central Australia is described as being highly vulnerable to any onshore shale gas development because of the brand perception that it has *"pristine, wild and natural landscapes."*[47] Tourist operators from Mataranka expressed concern regarding the viability of the tourism industry, in particular, the impact any onshore shale gas industry might have on the Roper River region and the water source that tourism operators rely upon.[48] The Amateur Fishermen's Association of the Northern Territory (**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."*[49]

13.2.3.2 Regional employment

A review of the socioeconomic impacts of CSG 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."*[50]

38 APPEA submission 215, p 78.
39 APPEA submission 215, p 75.
40 ALEC submission 88, p 13.
41 NTCA submission 217, p 1.
42 NTCA submission 32, p 2.
43 CPC submission 218, p 12.
44 Lock the Gate submission 171, p 6.
45 Lock the Gate submission 171, p 64.
46 P Ariston submission 269, p 1.
47 ALEC submission 88, p 14.
48 Somers submission 377.
49 AFANT submission 190, p 9.
50 Lock the Gate submission 171, p 50.

The review hypothesised that negative shifts from the agricultural sector could be a result of direct migration into mining jobs or because of 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 from CSG companies, especially at peak times such as planting and harvest.[51]

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 cost associated with either remediation, or potentially irreversible environmental damage, is understandably a significant issue for the community, particularly where those costs are perceived to be likely to be borne by the public (that is, Government or local authorities), and not the gas company responsible for the pollution and harm. This potential cost must be considered when determining whether any onshore shale gas industry will result in a net economic benefit to the NT.[52]

13.2.4 Energy security

Multiple submissions described how the NT's entry into a potentially volatile global gas market could have implications on local electricity prices. 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 Northern Territory."*[53]

Many 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. That 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."*[54] In response, Deloitte argues that the experience of the US suggested that shale and tight energy sources will play a vital role in meeting future demand.[55]

The NTCA proposed that the Panel investigate the merits of a gas reservation policy on behalf of all Territorians to ensure that NT residents have access to clean and affordable gas in the foreseeable future.[56] Conversely, other submissions argued that, *"fracking will inhibit investment and growth in the renewables sector."*[57]

13.3 Modelling economic impacts of hydraulic fracturing

To meet its Terms of Reference (see Appendix 1), the Inquiry is required to determine the economic risks and impacts of hydraulic fracturing in the NT. The Inquiry therefore engaged an economic consultant, ACIL Allen Consulting Pty Ltd (**ACIL Allen**), to assess the economic risks and impacts of hydraulic fracturing in the NT. The Panel had oversight of all aspects of the consultancy, from preparing the scope of services (see Appendix 18), to approving assumptions and clarifying the update scenarios to be modelled.

The remainder of this Chapter discusses the modelling process and provides an overview of ACIL Allen's key modelled results from its report, *The Economic Impacts of a Potential Shale Gas Development in the Northern Territory* (at Appendix 17).[58]

It must be noted that all economic modelling involves applying a set of assumptions to quantitative models, and is therefore subject to uncertainty and should be treated with caution. ACIL Allen advises that the modelling undertaken for the Inquiry is subject to higher than usual uncertainty because the development of any onshore shale gas industry in the NT is at such an early stage.

51 Lock the Gate submission 171, p 50.
52 R Dunbar submission 75, p 4.
53 The Australia Institute submission 158, p 3.
54 Robertson 2016, p 3.
55 Deloitte 2015
56 NTCA submission 32, p 2.
57 ALEC submission 88, p 14.
58 ACIL Allen 2017.

13.3.1 Engaging ACIL Allen

In April 2017 the Inquiry released a public tender for an economic impact assessment of the potential onshore unconventional gas industry in the NT. The tender documentation required an assessment under the following three scenarios:

- **scenario 1:** (the baseline scenario): where 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 NT; and
- **scenario 3:** the development of unconventional shale gas reservoirs in the Beetaloo Sub-basin only.

Also required to be considered were the:

- economic risks associated with the three development scenarios, describing the actual and possible adverse impacts on and risks to the NT economy under the current regulatory regime; and
- the impacts of development on other industries in the NT, such as tourism, agriculture, horticulture and pastoralism.

Six tenders were submitted, which were carefully assessed against the NT Procurement framework. The tender was awarded to ACIL Allen. The cost of the tender was $287,719.

13.3.2 Change to the scope of works

The development scenario modelling sought to identify what would happen if the moratorium was lifted by the Government. However, early in the consultancy it became clear that there was very limited information regarding the shale resource given the embryonic stage of shale gas development in the NT. To date there has been one fracture stimulated horizontal well that has been tested in a near-production setting, namely, Origin's Amungee NW-1H well in the Beetaloo Sub-basin. This well has delivered a positive production test result, but significant further testing is required to determine the scale, scope and qualities of any shale gas production potential in this Sub-basin alone, irrespective of the remainder of the NT.

In consultation with the Panel, ACIL Allen modified the initial scope of works to undertake economic modelling on the following development scenarios over a 25-year timeframe:

- **Baseline scenario:** the moratorium remains and nothing changes;
- **Calm scenario:** the moratorium is lifted, but only exploration and appraisal activity occurs for a period of three years and development is found to not be commercially viable;
- **Breeze scenario:** the moratorium is lifted, exploration and appraisal activity occurs and a small-scale development (100 terajoules per day (**TJ/day**)) (or 36.5 PJ per annum) takes place;
- **Wind scenario:** the moratorium is lifted and a moderate-scale (400 TJ/day) (or 146 PJ per annum) development occurs; and
- **Gale scenario:** the moratorium is lifted and a larger-scale (1,000 TJ/day) (or 365 PJ per annum) development occurs.

Given the absence of reliable data regarding the shale resource, the development scenarios make an assumption that the quantity of any onshore unconventional gas is not a constraint, rather, any constraint on the size of any potential development is on the demand side and is contingent on the development of a quantity of gas that can meet certain price points in the market.

In addition to the uncertainty regarding the scale of commercial quality shale gas reserves, ACIL Allen was confronted with a significant challenge in developing a set of underlying assumptions that would allow it to model onshore unconventional gas industry in the NT. Typically, economic modelling is conducted using a project or industry-level financial model. However, the nascent stage of development of a shale gas industry in the NT means that this information was limited and largely held in commercial confidence by potential industry participants.

The scope variation meant ACIL Allen's assessment was based on a perspective on what an industry 'could' look like, rather than an expectation of what it 'would' look like. It is also important to note that the change in the modelled scenarios meant that the results are 'location agnostic' insofar as they do not relate to development in a particular area; for example, the Beetaloo Sub-basin.

13.3.3 Information challenge

Typically, economic impact assessment modelling has a sound understanding of key variables such as the:

- total commercial gas reserve;
- daily/monthly/yearly production estimates;
- capital and operating expenditure required to produce gas;
- pipeline and other supporting infrastructure requirements;
- overall gas unit costs; and
- sales plan.

Given the very early stage of any onshore shale gas industry in the NT, this information was not available to support the modelling.

To conduct the economic impact assessment modelling, ACIL Allen had to develop a commercial financial model of an onshore shale gas industry in the NT. This was built using a range of assumptions, It is important to note that the economic modelling undertaken by ACIL Allen does not represent an assessment of the commercial viability of an onshore unconventional gas industry development in the NT.[59]

To articulate the potential economic impacts of an onshore unconventional gas industry in the NT, ACIL Allen consulted broadly to develop a set of conservative estimates of what a successful development might look like. This included considering:

- the views of the Government, industry, non-gas industry stakeholders, traditional Aboriginal owners, non-government organisations, including environmental groups, and other representative bodies;
- its own expertise in gas markets and economic modelling;
- the experience of shale gas industry development in analogous regions across the world, particularly in the Marcellus Basin shale gas play in Pennsylvania. Both the Marcellus Basin and the Beetaloo Sub-basin plays exhibit similar geological characteristics (that is, they are assumed to be a mostly dry gas play, have a similar shale formation, have a similar depth and have a similar geology); and
- the latest research, data and insights of shale gas industry economics, including using information from the Marcellus Basin, where more than 2,000 wells are drilled every year.

These estimates were presented to, the approved by, the Panel in July 2017 prior to modelling commencing.

13.3.4 Modelling process

Given the lack of information regarding any onshore shale gas industry for the NT, ACIL Allen conducted a cascading series of four modelling activities regarding gas markets, project development and project cash flow. Outputs from these modelling exercises were inputs to the economic impact assessments modelling.

13.3.4.1 Gas market modelling

After setting three scales of development with respect to gas production (Breeze, Wind and Gale), ACIL Allen conducted base-level gas market modelling, where volumes of gas were offered to the market at $0.25 incremental pricing, starting at $2/GJ. This modelled market took up a portion (or all) of the gas at that price based on market demand and how competitive the NT gas was. To determine final sales quantities and values, ACIL Allen calculated the revenue maximising sales mix per annum (quantity and price), and adopted this as the target rate of sales for the industry.

13.3.4.2 Project development modelling

Project development modelling was undertaken to understand the production and infrastructure requirements to meet the volume of gas to be placed in the market, using a bespoke shale well production schedule model.

59 ACIL Allen 2017, p IX.

The model required two major inputs: first, an assumed single average type curve of a hypothetical shale well (different for each scenario); and second, a series of assumptions regarding the infrastructure required to enable production to occur (wells, pads, gathering pipes, roads, water, camps and labour). This occurred in two streams and involved ACIL Allen creating two hypothetical companies to produce and transport shale gas under the four development scenarios. These hypothetical companies are:

- **ProjectCo:** which explores, appraises and develops the shale gas industry in the NT; and
- **PipelineCo:** which builds, owns and operates new pipeline infrastructure required to facilitate the sale of ProjectCo shale gas to market.

ProjectCo and PipelineCo are separate entities but interact through tariffs paid by ProjectCo to PipelineCo for the provision of pipelines to transport gas to market.

Key project development assumptions in the modelling are:

- **timing:** the development scenario modelling assumes the moratorium is lifted by the end of 2017–18, exploration and appraisal is undertaken in the period to 2019–20, development commences in 2020–21, and production begins in 2021–22;
- **gas quantity:** the volume of gas in situ is not a constraint, but the size of the market is;
- **dry gas:** all gas is 100% 'dry gas', with no higher value hydrocarbons, such as butane, ethane, propane or crude oil, targeted or available for extraction. A 'liquids rich' shale gas play results in a small increase in operating costs and a potential large increase in production revenue. The net effect of a liquids rich development is to significantly improve project economics. While gas companies are of the view there is likely to be a liquids rich shale in the Beetaloo Sub-basin, it is too early to estimate the types or quantities of liquids available for extraction. Given this uncertainty, ACIL Allen did not model any liquids; and
- **a single, average type curve:** which represents how much gas is produced from a single well at any point in time. ACIL Allen developed a single, average type curve based on advice from potential shale gas operators, information from similar fields in the USA and the Government. A typical shale gas type curve is a hyperbolic decline function, where the production of a well in the first period (typically reported in months) is very high relative to the average monthly production over the life of the well. A well's production declines rapidly from this initial production rate and continues to produce for a long period of time at very low levels.

ACIL Allen built an average type curve for production wells under each development scenario, where gas production occurs based on assumptions regarding:

- **initial production rate:** the volume of gas produced in the first month of the well's life;
- **decline rate:** the speed in which the well's production declines per month;
- **estimated ultimate recovery:** the ultimate volume of gas that will be extracted from the well over its useful life; and
- **well life:** the useful production life of each well.

The parameters of ACIL Allen's development type curve assumptions are reported in **Table 13.1**.

Table 13.1: ACIL Allen type curve assumptions. Source: ACIL Allen.[60]

Scenario	Initial Production (mmscf/month)	Decline exponent	Decline rate (% per month)	EUR (Petajoules per well)	Well life (years)
Breeze	160	1.0	5.3%	8.4	20
Wind	160	1.0	3.8%	10.6	20
Gale	240	1.0	5.4%	12.7	20

60 ACIl Allen 2017, p 38.

This information was then used to estimate, for each development scenario where gas production occurs, a drilling schedule of how many wells would need to be built and when. The drilling scenario informed the need for well pads, roads, pipelines, labour and worker camps. The cost estimates to deliver infrastructure requirements were based on ACIL Allen's research and stakeholder feedback (see Chapters 5 and 6 of ACIL Allen's report at Appendix 17). Key elements of the project development include:

- to facilitate development and send gas to market, additional transmission pipeline infrastructure must be built. PipelineCo must build, own and operate all pipeline infrastructure for industry development;
- explicit development costs are included for wells/pads (drilling, roads, gathering pipelines and work camps);
- there are assumed 'learnings' where ProjectCo is able to reduce its cost per drilling operation over time (and therefore, cost per GJ of gas extracted) through repetition and incremental improvement;
- labour inputs by activity;
- pipeline specification and tariffs; and
- debt-to-equity ratio and debt terms, payments to Aboriginal landholders and pastoralists, government charges, local content and key macroeconomic variables.

Many stakeholders in ACIL Allen's consultations identified that water consumption associated with hydraulic fracturing could have negative economic and social impacts in the NT. ACIL Allen has used water consumption assumptions that are considered an upper limit of water used for hydraulic fracturing activities. In doing so, ACIL Allen has assumed that there is no water recycling in its industry development scenarios, whereas gas companies in submissions to the Panel have assumed a recycling factor of 30-50% of water used for fracture stimulation. The Government does not currently charge for the extraction of groundwater undertaken by any industry, including mining and onshore energy companies. In line with the Inquiry's requirement to conduct the economic modelling on the basis of current policy ACIL Allen assumed the only cost associated with water was a notional extraction cost borne by ProjectCo to access groundwater (but see the Panel's discussion and recommendations in relation to charging for water extraction in Chapter 7).

13.3.4.3 Project cash flow modelling

ACIL Allen developed a cash flow model to estimate financial flows. The modelling suggests that:

- under the **Breeze scenario**, there will be an initial rate of 33.4 TJ/day ramping up to 90 TJ/day in 2034 (and less than the 100 TJ/day target);
- under the **Wind scenario**, the maximum amount of gas that is sold is 315 TJ/day (less than the 400 TJ/day target). The majority of the gas is sold into the east coast market, and this requires the development of additional gas pipeline infrastructure; and
- under the **Gale scenario**, the volume of gas and economies of scale in production mean NT gas is more competitive in east coast markets and as a feedstock for the production of liquefied natural gas, with production reaching 1,000 TJ/day by 2034.

The results of the financial modelling formed the basis for inputs to the economic impact assessment modelling.

13.3.4.4 Economic impact assessment modelling

Summary inputs and outputs of the ProjectCo and PipelineCo cash flow modelling were converted to a national accounting framework and processed through ACIL Allen's *TasmanGlobal* computable general equilibrium (**CGE**) model.[61] The four development scenarios were compared to the Baseline assessment of the future growth of the NT economy, to produce estimates of the potential economic impacts of each development scenario.

61 CGE economic models use economic data to estimate how an economy might respond to changes in policy, technology, or other external factors. CGE models are dynamic, and use elasticities to model how the response to an economic shock might change over time.

13.4 Economic impact assessment results

ACIL Allen used its in-house TasmanGlobal CGE model to model economic impacts of the development of any onshore shale gas industry in the NT. In line with the scope of works, modelling outputs are presented for three regions: the NT, the Rest of Australia, and Australia. (which is the combined sum of the NT and the Rest of Australia). This was undertaken for the following macroeconomic variables:

- **real income:** which is a measure of the income that is available for consumption or saving after adjusting for inflation. It is a measure of economic welfare. Real income accrues to the owners (and taxers) of land, labour and capital. As such, if capital is sourced from interstate or overseas, real income growth attributable to this capital is reported as accruing to the source of that capital (that is, interstate or overseas) and not reported as real income growth in the NT. Similarly, for taxation, revenue will be allocated to the jurisdiction that receives the revenue;
- **real output:** which is a measure of value adding that occurs in the geographic area of an economy (for example, the NT or Australia) after accounting for changes in the prices of goods and services produced, and essentially comprises salaries paid to employees and profits accruing to businesses. Real output is often referred to as 'the economy', 'Gross State Product (**GSP**)' for the NT or 'Gross Domestic Product (**GDP**)' for Australia. Unlike real income, where the added value is attributed to the source of the input (for example, capital or labour), real output captures the added value that occurs in the region, irrespective of the source of the inputs
- **real final demand:** which is a measure of the value of goods and services consumed in an economy, irrespective of where those goods and services are produced;
- **real employment:** which is full time equivalent employment. An FTE of 1.0 is equivalent to a full time worker, while an FTE of 0.5 signals half a full workload;
- **real population:** which is the resident population; and
- **real taxation:** which is taxation accruing, separately, to the NT and Commonwealth.

The economic impact assessment was run under five scenarios: the Baseline scenario and the four development scenarios which represent deviations from the Baseline scenario. **Table 13.2** reports key metrics for the Calm, Breeze, Wind and Gale development scenarios.

Table 13.2: Summary of economic impact assessment results for Calm, Breeze, Wind and Gale 2018–2043. Source: ACIL Allen

	CALM		BREEZE		WIND		GALE	
	Total	Average	Total	Average	Total	Average	Total	Average
REAL INCOME								
Northern Territory	$35.2m	$1.4m	$937.2m	$36.0m	$2,818.1m	$108.4m	$5,777.5m	$222.2m
Rest of Australia	-$15.4m	-$0.6m	$3,339.9m	$128.5m	$9,120.0m	$350.8m	$12,508.8m	$481.1m
Total Australia	**$19.8m**	**$0.8m**	**$4,277.2m**	**$164.5m**	**$11,938.1m**	**$459.2m**	**$18,286.3m**	**$703.3m**
REAL OUTPUT								
Northern Territory	$4.1m	$0.2m	$5,107.9m	$196.5m	$12,126.1m	$466.4m	$17,534.7m	$674.4m
Rest of Australia	-$12.2m	-$0.5m	$406.5m	$15.6m	$3,011.7m	$115.8m	$1,732.1m	$66.6m
Total Australia	**-$8.2m**	**-$0.3m**	**$5,514.4m**	**$212.1m**	**$15,137.8m**	**$582.2m**	**$19,266.9m**	**$741.0m**
REAL FINAL DEMAND								
Northern Territory	$539.1m	$20.7m	$3,277.7m	$126.1m	$8,851.0m	$340.4m	$16,173.7m	$622.1m
Rest of Australia	-$19.7m	-$0.8m	$2,042.2m	$78.5m	$7,869.6m	$302.7m	$11,320.7m	$435.4m
Total Australia	**$519.4m**	**$20.0m**	**$5,319.9m**	**$204.6m**	**$16,720.6m**	**$643.1m**	**$27,494.4m**	**$1,057.5m**
REAL EMPLOYMENT (FTEs)								
Northern Territory	119	5	2,145	82	6,559	252	13,611	524
Rest of Australia	-119	-5	-2,145	-82	-6,559	-252	-13,611	-524
Total Australia	0	0	0	0	0	0	0	0
REAL EMPLOYMENT BY INDUSTRY (FTEs)								
Agriculture	-2	0	103	4	345	13	1,023	39
Mining	-10	0	-265	-10	-843	-32	-1,722	-66
Petroleum	-1	0	910	35	2,384	92	4,384	169
Manufacturing	-24	-1	-100	-4	-56	-2	-18	-1
Electricity and water	-1	0	-19	-1	-34	-1	-62	-2
Transport services	57	2	253	10	765	29	1,511	58
Construction services	17	1	141	5	671	26	1,538	59
Retail and wholesale trade	71	3	526	20	1,437	55	2,850	110
Government services	18	1	462	18	1,461	56	2,985	115
Other services	-6	0	133	5	429	17	1,124	43
Total industry employment	**119**	**5**	**2,145**	**82**	**6,559**	**252**	**13,611**	**524**
REAL POPULATION								
Northern Territory	262 persons	10 persons	5,061 persons	195 persons	15,480 persons	595 persons	32,252 persons	1,240 persons

Table 13.2: *Continued*

	CALM		BREEZE		WIND		GALE	
	Total	Average	Total	Average	Total	Average	Total	Average
REAL TAXATION								
NORTHERN TERRITORY								
Payroll tax	$3.5m	$0.1m	$74.8m	$2.9m	$227.2m	$8.7m	$288.2m	$11.1m
Royalties	$0.0m	$0.0m	$309.2m	$11.9m	$894.6m	$34.4m	$1,793.8m	$69.0m
Derived GST	$8.7m	$0.3m	$372.9m	$14.3m	$972.7m	$37.4m	$1,640.2m	$63.1m
Total Northern Territory	$12.2m	$0.5m	$757.0m	$29.1m	$2,094.4m	$80.6m	$3,722.2m	$143.2m
COMMONWEALTH								
Direct profits based tax	$0.0m	$0.0m	$162.3m	$6.2m	$602.1m	$23.2m	$935.8m	$36.0m
Other federal profits based tax	$36.6m	$1.4m	$988.8m	$38.0m	$3,437.5m	$132.2m	-$136.5m	-$5.3m
Other state and federal tax	$4.5m	$0.2m	$154.4m	$5.9m	$541.7m	$20.8m	$950.2m	$36.5m
Total Commonwealth	$41.1m	$1.6m	$1,305.4m	$50.2m	$4,581.3m	$176.2m	$1,749.5m	$67.3m
Total Australia	$53.3m	$2.0m	$2,062.4m	$79.3m	$6,675.7m	$256.8m	$5,471.6m	$210.4m

The economic impact assessment modelling suggests that there will be limited impact on sectors outside of any onshore shale gas industry and its supply chain. Significantly, the relatively modest labour requirement of any onshore shale gas industry means there is limited crowding out in the NT labour market as industries compete for the same labour.[62]

In addition, any onshore shale gas industry is likely to disturb a small surface area relative to the size of the NT (estimated 67 km^2 for Breeze, 232 km^2 for Wind, and 476 km^2 for Gale) compared with the NT's total land area of 1,421,000 km^2. This means that the impact of any onshore shale gas industry on other key NT industries is likely to be minimal in terms of land use. This does not suggest land use impacts will be non-existent, rather it implies that, depending on the type of existing use, there may be scope to readily mitigate impacts.

13.4.1 Baseline scenario

In the Baseline scenario, the hydraulic fracturing moratorium remains in place, and the key driver of the NT economy is the ongoing impact of the Ichthys LNG project. There are also assumptions made regarding a number of additional projects on the NT's horizon (for a discussion of the results of the Baseline scenario, see Chapter 7 of ACIL Allen's report at Appendix 17). The scenario largely results in key macroeconomic variables for the NT returning to long-run averages.

Following the ramp-up of the Ichthys LNG project, ACIL Allen forecasts that there will be a period of slightly above average growth through the 2020s as the Territory's aquaculture and horticulture industries grow faster than the rest of the economy and the Government's *10 Year Infrastructure Plan* is carried out. The impact on NT real output of any new offshore gas development to backfill Darwin LNG[63] will be limited because the majority of infrastructure construction and supplies and services for an offshore development will be imported.

ACIL Allen's Baseline modelling projects that the NT's real output (the value-adding that occurs in the NT reported as the accumulated value of wages and profits to produce goods and services in the economy) will grow by an average of 2.9% per annum over the 25-year modelled period (2018–43). Growth in real output is forecast at 8% in 2019 as the Ichthys LNG production exports lift. Beyond this initial spike, the NT economy is expected to grow by 2.9% per annum on average through the end of the next decade, before the annual average growth rate weakens to 2.5% per

62 ACIL Allen 2017, p 136.
63 Construction of the Darwin LNG plant commenced in June 2003, with the plant being officially commissioned in January 2006. Gas is sent by a 502 km pipeline from the Bayu-Undan field to the plant at Wickham Point, where it is converted into LNG for sale to Tokyo Gas and JERA (a joint venture between Tokyo Electric and Chubu Electric) in Japan. The facility has the capacity to process 3.7 million tonnes of LNG per annum.

annum to the end of the study period. Employment growth averages 1% per annum over the 25-year modelled period. It falls in the short term as the construction phase of the Ichthys LNG project nears completion.

Beyond the 2020s, ACIL Allen projects that the NT economy will grow in line with population, labour force participation and productivity growth. Real output is projected to grow from a $23.4 billion economy in 2018 to a $47.9 billion in 2043.

13.4.2 Calm scenario

In the Calm scenario, it is assumed the moratorium has been lifted, but ProjectCo does not proceed to development as a commercial-quality shale gas resource is not found. ProjectCo undertakes a three-year exploration and appraisal program, but fails to progress to production.

The Calm scenario is also the basis for the first four years of the development scenarios where gas production occurs (Breeze, Wind and Gale), but instead of the assumption that no commercial-quality shale gas reserve is discovered, it is assumed that commercial resources are discovered.

Under the Calm scenario, real final demand (the value of goods and services consumed in the NT) is estimated to increase by $539 million over the 25-year modelled period, with all of this occurring in the four-year appraisal period. Real output (the value-adding that occurs in the NT, which is essentially the value of wages and profits in the economy) is estimated to increase by only $4.1 million because the vast majority of inputs in this early stage are assumed to be imported to the NT. Real income impacts are minimal at only $20 million over the 25-year modelled period. The NT also collects an additional $12.2 million in taxation revenue, and the Commonwealth collects an additional $41.1 million in taxation revenue over the 25-year modelled period, with all of this occurring in the period to 2021. The activity generated by the Calm scenario results in a requirement for additional labour resources equal to an average of some 30 FTEs per year for direct and indirect employment above the baseline and over the four year Calm scenario.

13.4.3 Breeze scenario

In the Breeze scenario, it is assumed that the moratorium on hydraulic fracturing is lifted and that exploration and appraisal occurs in the period from 2018 to 2021, and that shale gas production commences in 2021–22. At the end of 2020–21, the facilities required to link to the Amadeus Gas Pipeline have been built and linked to the east coast market by the Northern Gas Pipeline (**NGP**). Gas is produced at an initial rate of 33.4 TJ/day in 2022, increasing to 90 TJ/day in 2034.

In this scenario, the development of an onshore unconventional gas industry has an impact on real income, which is a measure of economic welfare (or purchasing capacity), in both the NT and, most notably, in the rest of Australia. The real income impact of any onshore shale gas industry is largely accrued through the profits generated by the industry once it is operational, which also determines the level of profits-based taxation paid by that industry. Overall, the majority of the real income impact of the development under the Breeze scenario is transferred from the NT to the rest of Australia. This is in the form of Commonwealth taxes (income tax, company tax and royalties), and because the equity ownership of the industry is assumed to be largely on the east coast of Australia (that is, because it is assumed the capital investment to develop the industry is largely sourced from the rest of Australia, modelled real income returns associated with this investment are allocated back to the rest of Australia).

The real income impact in Australia is estimated to be $3.34 billion over the 25-year modelled period at an average of $128.5 million per annum. In the NT, the real income impact is estimated to be $937 million over the 25-year modelled period at an average of $36 million per annum. Real income impacts in the NT are realised through increased employment and a redistribution of additional taxation payments to the Commonwealth being distributed back to the Government. Modelled royalty and payroll tax payments made to the Government, and payments made to pastoralists and Aboriginal landholders also contribute to the real income impact in the NT.

Under the Breeze scenario, real final demand in the NT is estimated to increase by $3.3 billion over the 25-year modelled period (at an average of $126.1 million per annum), with real output estimated to increase by $5.1 billion (at an average of $196.5 million per annum over the 25-year modelled period). Real output is expected to increase over the modelled period consistent with increases in the level of production.

The activity generated by the Breeze scenario results in a requirement for additional labour resources equal to an average of 82 FTEs (2,145 job years)[64] for direct and indirect employment in a given year over the baseline. While modest overall, this employment increase for the Breeze scenario represents the capital intensive nature of the shale gas industry.

Over the modelled period, the NT collects an additional $757 million in real tax revenue (at an average of $29.1 million per annum over the 25-year modelled period), which includes $309.2 million in additional royalties, and the Commonwealth collects an additional $1.31 billion in tax receipts.

Information on the modelled impact of the Breeze scenario on a range of economic variables is reported in **Table 13.2**.

13.4.4 Wind scenario

In the Wind scenario, the target production rate increases to 400 TJ/day, with the majority of gas being placed into the east coast market, and requiring additional pipeline infrastructure to be developed as the capacity of the existing NGP is reached. The following investment into transmission gas pipelines is assumed to occur:

- tie in to the Amadeus pipeline;
- Amadeus duplication;
- NGP duplication; and
- Carpentaria Gas Pipeline duplication.

The real final demand impact in the NT under the Wind scenario is largely accrued through the investment needed to fund an onshore shale gas industry's capital requirements and the additional investment needed for transmission gas pipelines. For the rest of Australia, the impact largely results from the household consumption impacts that accrue from rising real incomes resulting from the development, as well as further investment in transmission gas pipelines in eastern Australia.

Similar to the Breeze scenario, the Wind scenario has an impact on real income, in both the NT and the rest of Australia. The real income impact in Australia is estimated to be $9.12 billion over the 25-year modelled period at an average of $350.8 million per annum. In the NT, the real income impact is estimated to be $2.82 billion over the 25-year modelled period at an average of $108.4 million per annum.

Under the Wind scenario, real final demand in the NT is estimated to increase by $8.85 billion over the 25-year modelled period (at an average of $340.4 million per annum), with real output estimated to increase by $12.13 billion (at an average of $466.4 million per annum over the 25-year period). Real output growth largely changes in line with initial investment and then ongoing production patterns.

The activity generated by the Wind scenario results in a requirement for additional labour resources equal to an average of 252 FTEs (6,559 job years) for direct and indirect employment in a given year over the baseline. While modest overall, this employment increase for the Wind scenario represents the capital intensive nature of the shale gas industry.

Over the 25-year modelled period, the Government collects an additional $2.09 billion in real taxation revenue (at an average of $80.6 million per annum), which includes $894.6 million in additional royalties, and the Commonwealth collects an additional $4.58 billion in tax receipts.

Information on the modelled impact of the Wind scenario on a range of economic variables is reported in **Table 13.2**.

13.4.5 Gale scenario

In the Gale scenario, it is assumed that the onshore shale gas industry has the volume of reserves and competitive production to enable it to progressively replace the offshore Bayu-Undan field as the gas feedstock for Darwin LNG, allowing Darwin LNG to continue to produce LNG at current

64 A 'job year' represents the number of hours of work to facilitate the projection of economic growth. A 'job year' is not the same as an FTE job, the latter of which is a physical position and implied permanency, whereas the former is a calculation of labour effect. For example, ACIL Allen's modeling indicates that in order to produce $100 million additional GDP over 10 years, the economy will require an extra 100,000 hours of labour across all sectors of the economy.

volumes beyond 2022–23. This necessitates investment to expand the Amadeus Gas Pipeline to allow more gas to flow north to Darwin LNG.

For the economic modelling, it is assumed that Darwin LNG will continue to produce LNG at its current rate with or without gas from any onshore shale gas industry. In the Baseline scenario where the hydraulic fracturing moratorium stays in place, it is assumed that a new offshore development occurs and this gas backfills Darwin LNG. This is a critical assumption because it means that there is no incremental value associated with LNG production attributable to an onshore shale gas industry. The incremental value is the change to the production profile, profitability, and local content of gas required to backfill Darwin LNG in an onshore scenario compared to an offshore scenario.

It is also assumed in the Gale scenario that due to increasing economies of scale in production, falling costs allow for increased gas sales into the east coast gas market, potentially including partial backfill of an LNG train at Gladstone. The effect of large scale onshore shale gas production also results in a reduction in the wholesale price of gas in the east coast market, with the 'ripple' effect of the injection of more gas flowing west to east leading to less gas produced in Queensland fields moving south. Similar to Darwin LNG, there is no incremental value associated with LNG backfill. This necessitates further investment in the NGP and Carpentaria Gas Pipeline over and above the investment assumed to be required to meet Wind scenario east coast exports. As a result, the industry is able to fulfil its full target production of 1,000 TJ/day by 2035.

The Gale scenario has an impact on real income in both the NT and the rest of Australia. The real income impact in Australia is estimated to be $12.51 billion over the 25-year modelled period, at an average of $481.1 million per annum. In the NT the real income impact is estimated to be $5.78 billion over the 25-year modelled period, at an average of $222.2 million per annum.

Under the Gale scenario, real final demand in the NT is estimated to increase by $16.12 billion over the 25-year modelled period (at an average of $622.1 million per annum), with real output estimated to increase by $17.53 billion (at an average of $674.4 million per annum over the 25-year period). Real output is expected to increase over the 25-year modelled period consistent with increases in production, until 2036 when there is a transfer between onshore and offshore gas for Darwin LNG feedstock.

The activity generated by the Gale scenario results in a requirement for additional labour resources equal to an average of 524 FTEs (13,611 job years) for direct and indirect employment in a given year over the baseline. While modest overall, this employment increase for the Gale scenario represents the capital-intensive nature of the shale gas industry.

Over the 25-years modelled period, the Government collects an additional $3.72 billion in real taxation revenue (at an average of $143.2 million per annum), which includes $1.79 billion in additional royalties. The Commonwealth collects an additional $1.75 billion in tax receipts.

Information on the modelled impact of the Gale scenario on a range of economic variables is reported in **Table 13.2**.[65]

13.4.6 Policy scenario probability matrix

ACIL Allen's modelling and development scenarios (Breeze, Wind and Gale) were developed with gas production targets with a varying range of 36PJ per annum (Breeze), 150PJ per annum (Wind) and 365PJ per annum (Gale). ACIL Allen created a Policy Scenario Probability Matrix (**Matrix**), which outlined the likelihood of each development scenario being able to produce the target amount of PJ per annum, based on the known current resource of shale reservoirs in the NT.[66] It has been well documented by ACIL Allen and the Panel that the infancy of the shale gas industry, and the limited amount of knowledge of the shale gas basins and the gas reserves contained in those basins, means that the modelling conducted by ACIL Allen is subject to more than usual uncertainty. This is demonstrated in the Matrix at **Table 13.3** where under a full lift of the moratorium, there is a 'high' probability that the Breeze scenario will result in 36PJ of gas production occurring per annum. By comparison, a full lift of the moratorium has been evaluated as a 'low' probability that the Gale scenario will result in 365PJ of gas production occurring per annum. This 'low' probability is the result of the existing known shale resource data

65 The Net Present Value for each of the financial parameters (including Real Income, Output and Final Demand) are given in Tables 8.1 (Calm), 9.1 (Breeze), 10.1 (Wind) and 11.1 (Gale) of Appendix 17).

66 ACIL Allen 2017, p 136.

gained through exploration. Increased exploration and more accurate knowledge of the shale gas basins will either increase the likelihood of that development scenario producing 365PJ of gas per annum or it will remain a 'low' probability. ACIL Allen has stated that the Matrix is not an assessment of the commercial prospect of any shale gas industry in the NT. It was not requested to assess this.[67]

Table 13.3: Policy Scenario Probability Matrix for baseline and development scenarios. Source: ACIL Allen.

			POLICY SCENARIO PROBABILITY MATRIX		
INDUSTRY DEVELOPMENT SCENARIO	Production Profile	Production Cost Regime	PERMANENT MORATORIUM	PARTIAL LIFT	FULL LIFT
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	**Scenario 1** Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	**Scenario 2** Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	**Scenario 1** Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

13.5 Comparison with Deloitte report

The only other relevant research investigating the impact of an onshore shale gas industry developing in the NT is the 2015 Deloitte report, *Economic impact of shale and tight gas development in the NT*, commissioned by APPEA.[68]

The Deloitte research examined two potential growth scenarios based on the supply of shale and tight natural gas to the NT, east coast, and export markets between 2020 and 2040.

Both the ACIL Allen and Deloitte analyses used in-house CGE models, but they varied quite significantly in terms of the assumptions used in the modelling exercise and the subsequent modelled outputs. A comparison of the assumptions and modelled outputs is contained in **Table 13.4** below.

67 ACIL Allen 2017, p 136.
68 2015 Deloitte report.

Table 13.4: Comparison of ACIL Allen and Deloitte assumptions and modelled outputs. Source: ACIL Allen.[69]

Item	APPEA/Deloitte		ACIL Allen		
Case name	"Success"	"Aspirational"	"Breeze"	"Wind"	"Gale"
Development modelling approach	Deloitte took the price of LNG, subtracted cost of processing and transmission pipeline, and used that to determine its target gas price. From there, it scaled CAPEX & OPEX estimates from a starting position that would allow all gas to be sold assuming a their market price, and had a different breakeven price for three market demand tranches (NT, East Coast and LNG). Deloitte assumed no market constraints.		ACIL Allen began by sizing its developments based on market tolerance, using *GasMark*. From there, ACIL Allen build its developments from the ground up using data to build a single average type curve, a well scheduling model, development cost assumptions by key components, and pipeline assumptions combining current pipeline capacity and new pipelines. ACIL Allen did not assume gas would be used to facilitate any new LNG development, and instead assumed in its base case that an offshore development would be required to backfill the DLNG facility.		
Economic impact assessment modelling approach	In-house CGE model		In-house CGE model		
Volume of gas (peak PJ/annum)	586 PJ/annum in 2040	910 PJ/annum in 2040	36.9 PJ/annum (2041)	108.3 PJ/annum (2042)	365 PJ/annum in 2043
Incremental LNG?	Yes, 100% incremental LNG. Two additional LNG trains to be built, with capital costs included in the economic impact assessment.	Yes, 100% incremental LNG. Three additional LNG trains to be built, with capital costs included in the economic impact assessment.	No LNG in this scenario.	No LNG in this scenario.	No incremental LNG in this scenario. It is assumed the onshore development displaces an offshore development.
CAPEX per well	$6.2m - $9.75m		$19.1m on average (including learnings)	$16.3m on average (including learnings)	$12.7m on average (including learnings)
OPEX per GJ	$0.53 - $0.89/GJ		$1.77/GJ on average (including learnings)	$1.59/GJ on average (including learnings)	$1.46/GJ on average (including learnings)
Wellhead cost per GJ (maximum case)	$1.90 - $2.67/GJ		$6.07/GJ on average	$5.03/GJ on average	$4.01/GJ on average
GTP impact (deviation from baseline in final year of study)	+$5.1bn (2040)	+$7.5bn (2040)	+$0.30bn (2043)	+$0.64bn (2043)	+$0.72bn (2043)
FTE impact (deviation from baseline in final year of study)	+4,195 FTE (2040)	+6,321 FTE (2040)	+80.1 FTE (2043)	+221.5 FTE (2043)	+558.1 FTE (2043)

Lock the Gate has suggested that the 2015 Deloitte modelling used a set of overly optimistic assumptions about how an onshore shale gas industry might develop in the NT, particularly with respect to demand and employment and cost.[70] The Panel agrees.

There are a number of critical differences between the Deloitte and ACIL Allen assumptions. Deloitte uses lower capital and operational costs, meaning that more gas can be produced competitively under its development scenarios. Additionally, and significantly, the Deloitte modelling included the construction and commissioning of additional LNG facilities in the NT, with capital costs and production making a significant contribution to growth in reported variables, such as real output and employment.

In the Panel's opinion, the ACIL Allen assumptions and modelling represent a much more realistic approach to estimating the economic impacts of any onshore shale gas industry in the NT.

69 ACIL Allen 2017, p 138
70 Lock the Gate submission 171, p 50.

13.6 Policy implications

ACIL Allen was required to describe the options available to the Government, whether through policy, regulatory reform, or other mechanisms, to maximise and sustain the benefits to Territorians if the moratorium is lifted and onshore shale gas development commences. This included:

- undertaking a literature review of leading practice and options;
- providing relevant case studies where options have been implemented and an assessment of lessons learnt;
- describing options for how revenue from development can be retained in the regions affected by any onshore shale gas development, without impeding investment; and
- considering local procurement requirements, local training programs and other mechanisms to improve local capacity, as well as any 'Royalty for Regions', or similar programs, including case studies, examples, and lessons learnt relevant to the NT.

ACIL Allen identified three key issues that policy makers must consider: how to maximise the capture of benefits; how to distribute the benefits; and how to manage and minimise any downside risks.

For a small and narrow economy like the NT's, with a limited pool of excess and skilled labour, major projects (that is, projects of national or international scale) can have significant disruptive impacts on the economy, and society more broadly (see Chapter 12 for more detail). The objective for policy makers is to maximise the benefits while minimising the risks and ensuring that there is a high degree of certainty for all stakeholders.

ACIL Allen identified the main risks for the Government as:

- managing an increase in Government revenue;
- managing increased demand for labour;
- maximising local expenditure and opportunities;
- managing potential industry coexistence issues;
- addressing potential infrastructure constraints; and
- having appropriate industry regulation.

ACIL Allen's assessment of these risks and the potential policy options to address them are discussed below.

13.6.1 Increased Government revenue

Additional taxation revenue will flow to the Government if the moratorium is lifted, both directly through increased royalty and payroll tax payments and indirectly through additional GST revenue distributed back to the NT. The Commonwealth collects GST, all of which is re-distributed to the jurisdictions, with the proportion each jurisdiction receives determined by the Australian Treasurer based on recommendations from the Grants Commission.

Additional revenue accruing to the NT Government over the 25-year modelled period under each of the development scenarios where gas production occurs is $757 million (at an average of $29.1 million per annum) in the Breeze scenario, $2.09 billion (at an average of $80.6 million per annum) in the Wind scenario and $3.72 billion (at an average of $143.2 million per annum) in the Gale scenario. In the Gale scenario, this equates to a sizeable increase to the NT's recurrent revenue base of 2.2%, or more than 8% if Commonwealth Grants are excluded.[71]

ACIL Allen's modelling also outlines potentially strong growth in Commonwealth revenue over the 25-year modelled period. This increase is despite the likely cascading impact of reduced gas prices from the development of an onshore shale gas industry reducing the income earned by that industry outside of the NT. The increase in Commonwealth revenue where gas production occurs is $1.3 billion (at an average of $50.2 million per annum) in the Breeze scenario, $4.6 billion (at an average of $176.2 million per annum) in the Wind scenario and $5.5 billion (at an average of $210.4 million per annum) in the Gale scenario.

After collecting the additional revenue, the Government must decide how it will be used. This is primarily a distribution issue, with both geographic and intergenerational dimensions. While the pressure to spend any increased revenue is likely to be strong, there are also options for the Government to manage the additional revenue for the purposes of intergenerational equity.

71 ACIL Allen 2017, p 135.

ACIL Allen's research suggests there is a case for windfall royalty revenue to be treated differently to general government income.[72] This is because the Government is selling the right to mine a non-renewable resource, which is a one-off transaction. In this respect, mining royalties are different to taxes on income or consumption, which have perennial tax bases. Revenue raised from royalties should therefore be used to compensate society for the realisation of the value.

This can be done by investing in the physical or human capital of the economy, to improve its productivity, or by warehousing the revenue in a special fund. ACIL Allen identifies two ways to do this; namely, a sovereign wealth fund, and/or a stabilisation fund.

Traditionally, wealth funds are used to accumulate revenue associated with windfall gains or with the extraction of non-renewable resources. The WA Government developed a sovereign wealth fund, the *Western Australian Future Fund*, in its 2012–13 Budget as a way of warehousing some of the proceeds of the iron ore royalty boom. The Fund received an initial capital injection of $1 billion between 2012–13 and 2015–16, and receives ongoing injections equal to 1% of the State's royalty revenue per annum.[73]

While well-intentioned, the broader settings of the WA Government's finances are, however, not ideal to host a wealth fund given its significant public debt and high operating and cash deficits. This means the WA Government is effectively borrowing money to store in the fund. It is important to consider the state of public finances when making such significant, long-range decisions.[74]

There are also a number of examples of countries that use a sovereign wealth fund for the purposes of stabilising government finances. These kinds of funds tend to be short-to medium-term in focus, and are used as a 'banking' mechanism for countries with volatile, uncertain revenue bases. These funds tend to have strict rules concerning when money may be deposited and withdrawn. The objective of smoothing out fluctuations in government revenue is to avoid large deficits or increased spending of short-term increases in revenue.

Notwithstanding the potential value of wealth and stabilisation funds, several submissions to the Panel suggested an infrastructure deficit in the NT (this is supported by Government analysis, notably, with respect to transport infrastructure[75] and public housing), and it is likely that worthwhile projects, with long-term, intergenerational benefits streams could readily be found to utilise any additional revenue that the Government receives as a result of development of any onshore shale gas industry.

This raises the issue of the distribution of benefits across the NT from additional tax revenue. There are several options to distribute benefits across regions, with one recent example being WA's 'Royalties for Regions' program. This program has the objective of promoting and facilitating economic, business and social development in regional WA. It has been in place since 2008–09. The program quarantines 25% of royalty revenue (up to an annual amount of $1 billion) for spending on regional development projects, town beautification and social programs. Since December 2008 the program has invested over $6.9 billion into more than 3,700 projects to improve infrastructure and services across regional WA.[76] Since 2008-09, there have also been a series of changes to the program to improve transparency, decision-making, and accountability, and to shift its focus to job-creating projects rather than delivering community amenity projects and, importantly, to introduce an expenditure cap with annual reviews of the cap.

But WA's independent Economic Regulation Authority (**ERA**) has noted that the quarantining of substantial revenue for regional projects reduces budget flexibility and inhibits proper capital prioritisation.[77] The ERA further states that,

> *"hypothecation of royalty income is not an ideal way to demonstrate the Government's commitment to regional development. Hypothecation results in an arbitrary annual allocation of total expenditure, rather than considering economic conditions, affordability, competing government priorities, or the quality of projects under consideration. It would be a coincidence if the amount allocated to regional projects under the program reflected the optimum level of expenditure."*[78]

72 ACIL Allen 2017, p 152.
73 ACIL Allen 2017, p 153.
74 ACIL Allen 2017, p 153.
75 NT Government 2014.
76 WA Department of Primary Industries and Regional Development 2017.
77 Economic Regulation Authority Western Australia 2014, p 66.
78 Economic Regulation Authority Western Australia 2014, p 82.

The ERA also notes that the quarantining of royalties at a time when significant royalty revenue was having a negative impact on WA's GST allocation resulted in the proportion of the budget available for regional expenditure being higher than anticipated, and that the subsequent lack of budget flexibility contributed to Standard & Poor's downgrade of the WA's credit rating.

Others have suggested that the Royalties for Regions program provides substantial infrastructure and service projects to regional communities, but have questioned the program's governance arrangements and the capacity to assess whether it is achieving its objectives.[79]

Based on the development scenarios modelled by ACIL Allen it is unlikely that revenue streams associated with the development of any onshore shale gas industry in the NT will be of a scale to warrant the development of a specialist fund for the purposes of fiscal stabilisation or intergenerational equity. Additionally, the literature suggests that there is no clear evidence of broader societal benefits to the NT from implementing policies to retain a proportion of royalty revenues in the regions where resource extraction occurs. However, ACIL Allen's analysis has noted that, based on its consultations, it is worth considering the benefits and costs of implementing such policy options given the significance to regional populations of ensuring that at least some of the additional taxation revenue is used to benefit residents in affected areas.

Recommendation 13.1

That in developing its budget, the Government must have regard to the source of royalty revenue and must ensure that regions that are the source of taxation revenue benefit from any onshore shale gas extraction activity that has occurred in their region.

That the Government works with local government, stakeholders, Land Councils, and local communities in the design and implementation of all such programs.

13.6.2 Managing an increased demand for labour

The development of any onshore shale gas industry in the NT has the potential for substantial labour benefits in the form of job creation, skills development, and workforce diversification. An increase in the demand for labour due to the development of the industry can be measured by the direct labour that is hired to work on the construction and operation phases of the development, as well as the indirect employment impact from the jobs generated by additional spending in the economy.

ACIL Allen estimates that the direct and indirect employment impact of the industry will be an average 82 FTE (Breeze), 252 FTE (Wind), and 524 FTE (Gale) per annum, with much of this employment likely to occur in regional areas where development activities will occur. It is through the salaries and wages associated with employment that regional communities are likely to see real benefits from the creation of an onshore shale gas industry, with increases in real income and living standards.

Any emergence of an onshore shale gas industry in the NT should create economic development opportunities in regional areas that will be in close proximity to Aboriginal communities, or in regions with large Aboriginal populations. Private sector employment opportunities in these regions tend to be scarce, and relatively low rates of employment is one of the factors contributing to poor economic and social outcomes experienced by Aboriginal people. Research demonstrates that increasing Aboriginal employment rates will result in extensive economic, health and social gains to Aboriginal people and communities. The challenge for policy makers is to devise a strategy for improving employment as efficiently as possible, and that minimises expenditure in the form of labour market assistance for people who would have found a job in any event.[80]

The extent to which employment opportunities are realised will depend on the skill sets of local job seekers and the availability of training to gain the required skills. There has been a strong commitment by local companies to develop local skills for any onshore shale gas industry. For example, MS Contracting is an NT company that has developed skill sets of local people in and around the Beetaloo Sub-basin. MS Contracting, which has previously been awarded contracts by Pangaea, has established the Flying Fox Station - Centre of Excellence. This facility provides

79 Office of the Auditor General Western Australia 2014.
80 Gray et al. 2014.

for persons to experience *"live-in, real life training"* with 32-person accommodation, workshops, equipment and machinery operations and training for Certificate III in Civil Construction.[81]

Consultation with local Aboriginal communities identified a preference to maximise the use of local job seekers to assist in keeping development benefits on country. The NLC also noted that many Aboriginal communities are remote and largely reliant on welfare, and that a mature and well-designed onshore shale gas industry offers the potential to address a number of the economic pressures placed on people living under these conditions, including through direct employment and training opportunities related to the exploration and production of onshore shale gas.[82] Pangaea has previously worked in partnership with the NLC and MS Contracting to develop and deliver a program of industry-specific training targeted to the local traditional Aboriginal owners. It provided participants with the minimum entry level skills for employment within the Pangaea tenements.[83] Pangaea, Origin and Santos have all previously invested in training and development with local communities in the NT, and have cited their intention to increase this activity if the moratorium is lifted.[84] All three companies have cited employment outcomes in other States as evidence of their ability to maximise local benefits and increase participation for local people and businesses.

Nonetheless, given the remote locations of the potential development sites in the NT, it is expected that there will be an unavoidable need in the short to medium-term for a significant proportion of the workforce (with the required technical skills) to be employed on a FIFO or DIDO basis. It is during this short-to medium-term demand that the NT labour market can respond through developing education and training opportunities that will create in people skills that are applicable to the onshore shale gas industry. Over time, it is expected that the local employment content of the industry will increase as the skills and experience of the local workforce grows.

Having said this, recent research in the UK context reports that,

> *"the expansion of the shale gas industry will not automatically deliver significant economic benefits to the local economies in which it operates, unless supply chains are embedded more firmly within the region and a higher proportion of the workforce is drawn from the local community."*[85]

This suggests that there is a strong incentive for the Government to work with gas companies, local residents, Aboriginal people and local businesses to identify, as early as possible in the development process, opportunities to partner and develop the skills and processes necessary to be part of the supply chain for goods, services and labour.

There will be opportunities for the Government to maximise the workforce benefits of any onshore shale gas development and to ensure that these benefits are able to be accessed by all job seekers in the NT. There is a critical role for the Government in coordinating the requirements of any onshore shale gas industry with employment and training providers and local businesses. This includes identifying the timing of any development and the skills required for the exploration, construction and production phases of the industry. It is also important to work with employment agencies and training providers to ensure that they match their services to the needs of any onshore shale gas industry. This will assist in maximising local employment benefits and promoting the distribution of those labour benefits to job seekers throughout the Territory.

There will also be advantages in setting local Aboriginal and non-Aboriginal employment targets.

Programs that aim to facilitate the flow of information between employers, trainers and job seekers will be important tools in ensuring positive local employment outcomes for the NT workforce.

81 MS Contracting submission 1238.
82 NLC submission 214, p 33.
83 Pangaea submission 60, pp 19–24.
84 Santos submission 1249, pp 6–9; Origin submission 1248, pp 5–6; Pangaea submission 1147.
85 Whyman 2017.

Recommendation 13.2

That the Government works with stakeholders and gas companies to ensure that there is early knowledge of the labour and skills required for all phases of any onshore shale gas development in order to maximise local employment.

Recommendation 13.3

That the Government works with gas companies, training providers, local workers, job seekers, Land Councils and local Aboriginal corporations and communities to maximise opportunities for local people to obtain employment during all phases of any onshore shale gas development.

Recommendation 13.4

That the Government ensures that training providers and gas companies collaborate so that skill requirements are clearly understood by training providers, and that trainees acquire appropriate skills.

Recommendation 13.5

That the Government works with gas companies, training providers, Land Councils, local government, and local communities in the setting of local employment targets, including local employment targets for Aboriginal people.

13.6.3 Maximising local expenditure and opportunities

Local content policy is founded on the principle of full, fair and reasonable opportunity for local businesses to secure work on large public and private sector projects. The development of any onshore shale gas industry in the NT offers opportunities for local businesses through an expected higher local spend. A recent example of local content is the Aboriginal-owned and Elliott-based Triple P Contracting, which has been awarded a $200,000 per annum well monitoring contract with Origin requiring it to expand its workforce by two FTE.[86]

There is always the risk of a mismatch between the expectations of gas companies and the capabilities and services of local suppliers, which results in local businesses missing out on business opportunities. There is a vital role for the Government to play in ensuring that there is an information flow from gas companies regarding available local business opportunities. There is also a cognate role for the Government to work with local businesses to ensure that they properly communicate their capabilities and availability to industry. Encouragingly, many resource companies are realising that hiring and sourcing locally is a key element in building positive, long-term relationships with communities and regions, providing business benefits through cost reductions and efficiency improvements and earning and maintaining an SLO.

From a corporate perspective, local economic participation is seen as one means of maintaining an SLO, by giving communities a stake in the project, as well as having the advantage of having a supplier located nearby. From a community perspective, the participation of local businesses in a resource project is a means by which the benefits of resource development can flow into communities. The benefits of supply chain participation have become particularly apparent in Aboriginal communities where there are agreements to enable greater Aboriginal economic participation and to support the development of Aboriginal owned enterprises.[87]

The desire to increase local content is not restricted to gas companies. Increasing local procurement is supported by the Government in order to promote private sector led development and improved living standards by strengthening the small to medium enterprise sector. The Government has a number of initiatives in place to capture the benefits from any onshore shale gas development, including the Building Northern Territory Industry Participation Policy, a procurement program requiring local content, and a partnership with the Industry Capability Network Northern Territory (**ICN-NT**), to ensure that the Government's commitment to local participation is met.[88]

There will also be benefits in setting local content targets for gas companies and contractors to maximise the capture of direct and indirect spending in the NT. There is further benefit in working

86 Macdonald-Smith 2017.
87 Esteves and Barclay 2011.
88 Department of Trade, Business and Innovation 2011.

with gas companies to promote the services of local businesses, particularly those in regional and remote areas insofar as it assists in distributing the benefits of development to businesses located throughout the Territory. The Panel received several submissions from gas companies and local businesses recognising the importance of local business participation, which includes establishing hard local procurement and employment targets integrated with community business.[89] Addressing information asymmetries by identifying the timing of development, and the goods and services required for the construction and operation phases of development, is an important role for the Government in maximising local content opportunities.

Recommendation 13.6

That the Government works with gas companies and local suppliers to ensure that there is early knowledge of local supply and service opportunities for all phases of any onshore shale gas development.

Recommendation 13.7

That the Government works with gas companies and local suppliers (regional and Territory wide) to identify immediate supply opportunities and to facilitate future potential supply opportunities. This should be done in consultation with the ICN-NT and the Chamber of Commerce.

Recommendation 13.8

That the Government works with gas companies, Land Councils, local Aboriginal corporations, Aboriginal communities, and businesses to identify local supply and service opportunities to keep sustainable economic benefits on country.

Recommendation 13.9

That the Government assists regional businesses to obtain quality assurance certification and to partner with larger suppliers to encourage greater local supply, employment and knowledge transfer.

Recommendation 13.10

That the Government works with gas companies, Land Councils, local governments, local suppliers and businesses to devise and implement local procurement targets.

13.6.4 Managing potential industry coexistence issues

The issue of industry coexistence and the ability of an onshore shale gas industry to integrate with the existing industry structures of the NT was raised by most stakeholders consulted by ACIL Allen and with the Panel during community consultations. Of concern is the extent to which any onshore shale gas industry may impede or distort the allocation of the economic factors of production, particularly natural resources such as land and water. The clearing of native vegetation will be required for well pad construction, roads and other linear infrastructure (see Chapter 8). The amount of cleared land depends on the size of development required.

ACIL Allen has accounted for the opportunity cost of this land by assuming that it is made unavailable for pastoralism, as areas like the Beetaloo Sub-basin are predominantly beneath pastoral lease. Under the assumptions regarding water use, the industry may use between 4.2 GL (Breeze), 11.2 GL (Wind), and 28.2 GL (Gale) of water, respectively, over the 25-year modelled period. This represents average consumption of 0.17 GL (Breeze), 0.45 GL (Wind) and 1.13 GL (Gale) per annum under each scenario. This is significantly less than the Australian Bureau of Statistics' estimate of agricultural water use in the NT; namely, 47 GL in 2015–16.[90]

In stakeholder consultations, ACIL Allen received information to suggest there are a range of options available to any onshore shale gas industry to source water, both potable and

89 Origin submission 1248, p 6; Pangaea submission 1147, p 11; Oilfield Connect Pty Ltd, submission 1164 (**Oilfield Connect submission 1164**); Katherine Mining Services Association, submission 1255 (**KMSA submission 1255**).

90 ABS 2017b.

non-potable, in a manner that minimises tensions with existing users.[91] Water is unlikely to be an economic constraint on the development of any onshore shale gas industry, and the prospect of a reduction in water availability for the non-shale gas industry users in the aggregate is limited. In an economic sense, this means there is unlikely to be a material opportunity cost from the use of water by any onshore shale gas development.

It is therefore unlikely that any onshore shale gas industry will impede the existing allocation of natural factors of production in the NT in an economic sense. However, it is important for the Government to remain aware of the activities of gas companies and to carefully monitor the industry's use of the NT's natural resources. This should primarily occur through regulation, in relation to which the Panel has made recommendations in Chapter 7 regarding water licensing, a charge for water extraction, and WAPs.

Recommendation 13.11

That the Government works with gas companies, peak bodies of affected industries, and affected stakeholders to identify and resolve all potentially negative economic impacts of any onshore shale gas development on other industries.

13.6.5 Addressing potential infrastructure constraints

The development of any onshore shale gas industry in the NT will place additional pressure on existing and planned infrastructure, including economic, social and civic infrastructure. There will be an increased demand for road, rail and port infrastructure to transport goods and personnel to and from any onshore shale gas development sites. There may also be additional pressure on social infrastructure such as health, education and civic services, particularly in regional areas where infrastructure often has limited capacity to respond to rapid increases in demand.

Development of infrastructure by, and for, any onshore shale gas industry will have social and economic benefits for the NT, particularly for regional areas where much of the infrastructure development is likely to occur. Some of this infrastructure development will be undertaken by industry, but there is also an essential role for the Government to invest in economic infrastructure to encourage growth. The Government's infrastructure priorities are detailed in the *Northern Territory 10-Year Infrastructure Plan,*[92] and a regular review of the Plan will allow industry-related projects to emerge as priorities as they come closer to commencement. The current Infrastructure Plan includes projects to progressively upgrade the Stuart, Carpentaria, Buntine and Tablelands Highways, which could support the development of any onshore shale gas industry and minimise impacts on existing users.

The Australian Government has also committed in the May 2017 Budget to fund a pre-feasibility study and cost-benefit analysis of a potential gas pipeline linking the NT to Moomba in SA.[93]

The Australian Government's $5 billion Northern Australia Infrastructure Facility (**NAIF**) is another potential source of support for project-specific infrastructure, as well as infrastructure that can support multiple users or produce benefits to the broader economy and community.[94] A key objective of the NAIF is to support infrastructure development, recognising that infrastructure is a fundamental driver of economic change that can stimulate productivity and economic and employment growth, especially in remote areas, by encouraging private sector investment and increasing accessibility to markets.

ACIL Allen's consultation found that there were perceived issues with some infrastructure that would support the development of any onshore shale gas industry, for example, the capacity of the Stuart and Carpentaria Highways to support increased development-related traffic volumes.

Similar to the challenges presented by managing gas industry coexistence, a key issue is finding public policy positions that create certainty for all stakeholders and that encourage development, while also balancing efficient resource use and societal concerns.

91 ACIL Allen 2017, p 158.
92 NT Government 10 year Infrastructure Plan.
93 Australian Government 2017c, p 93.
94 *Northern Australia Infrastructure Facility Investment Mandate Direction* 2016, made under the *Northern Australia Infrastructure Facility Act 2016* (Cth).

Recommendation 13.12

That the Government works with all levels of government, (including the Australian Government), peak organisations, communities and gas companies to identify and manage infrastructure risks, including identifying and implementing options to fund any new infrastructure or upgrade existing infrastructure.

13.6.6 Appropriate industry regulation

Petroleum extraction is subject to significant regulatory requirements that reflect its heightened safety risks and potential adverse environmental impacts. During ACIL Allen's stakeholder consultation, gas companies unsurprisingly did not express dissatisfaction with the current regulatory regime for petroleum extraction in the NT.

The Fraser Institute's *Global Petroleum Survey 2015* found that the NT was rated as the third most development-favourable jurisdiction in Australia from a regulatory perspective and the 34th most favourable of the 126 jurisdictions surveyed by the Institute. This is not necessarily a good thing from an environmental perspective.

The most substantive issue regarding gas industry regulation was a perception the Government is not fully equipped to regulate any onshore shale gas industry. This was an issue that private sector, government and non-government organisation stakeholders raised with ACIL Allen and the Panel. Regulatory enforcement is critical to facilitating an SLO. The significant land mass of the Territory and the remote location of prospective shale gas developments, makes regulation of the industry challenging.

ACIL Allen noted that the level of funding for petroleum regulation in the NT is low compared to other jurisdictions in Australia. The level of funding is not necessarily a measure of the level of service delivery, but the difference between the NT and other jurisdictions suggests that this is an issue to be examined further, especially as the compliance and enforcement capacity of the regulator is a significant concern of the community. Given the current financial challenges, there is a need for the Government to examine innovative approaches to regulation, including the consideration of a levy on onshore shale gas companies to greater fund regulatory activities.

Leading-practice principles suggest industry should 'pay its way' when it comes to regulation. This is because appropriate regulations and enforcement is critical to the industry earning an SLO. Gas companies are also the major beneficiary of a regulatory regime that enables the safe development of the industry. There is scope to increase current fees and charges for any potential onshore shale gas industry (which are low at present) to fund any uplift in expenditure required to more adequately resource government regulators. This is discussed further in Chapter 14.

13.7 Conclusion

ACIL Allen's economic impact assessment modelling reports that lifting the moratorium on hydraulic fracturing in the NT may deliver (depending on the outcomes of reservoir exploration and gas production activities) tangible economic benefits in the form of increased income, output, employment and taxation revenue, and an increase in the NT's population. The extent of economic benefit increases with the volume of onshore shale gas that is extracted and commercially produced.

However, the Panel believes that the potential negative impacts on other industries must be considered, together with the policy options to mitigate those impacts, while identifying and capturing opportunities to maximise benefits that can accrue to local and regional communities (and the NT more broadly) from any onshore shale gas development.

It is acknowledged that any onshore shale gas industry development could put additional pressure on infrastructure, and identifying and funding options to alleviate this pressure must be examined. There are minimal coexistence risks as prospective onshore shale gas regions have significant groundwater reserves, and the land area used by the industry is very small under all development scenarios.

The Panel has considered ACIL Allen's modelling and policy analysis and the issues raised in the submissions in developing its recommendations. The recommendations aim to balance the dual goals of maximising local benefits (locally, regionally and across the NT) of the development of any onshore shale gas industry, while not disrupting the efficient allocation of resources (such as capital and labour) that will be necessary to make the industry competitive.

The Panel's principal recommendations identify the need for early and ongoing engagement between all stakeholders to identify risks and opportunities that may be associated with any onshore shale gas development. There is a clear and critical role for the Government to work with stakeholders to develop and implement pathways that aim to mitigate risks and resolve conflict.

The Panel is also of the opinion that the Government must work with all stakeholders to maximise local benefits from industry development, including local employment opportunities, and opportunities for existing and new local businesses to supply goods and services to the industry. While not being prescriptive with respect to how the Government uses any additional revenue, the Panel recommends that in developing its budget, the Government considers the source of royalty revenue and ensures that source regions benefit through greater infrastructure and services expenditure.

REGULATORY REFORM

14

14.1 Introduction

Each year, the Fraser Institute publishes the *Global Petroleum Survey*, which ranks jurisdictions around the world in terms of their attractiveness for gas companies. The Institute examines the reasons why a gas company would or would not invest in a particular jurisdiction, including tax rates, regulatory obligations, environmental regulations, and political stability. For several years, the NT was favourably ranked in the survey (except in 2016, when there was not enough data available to rank the NT).[1]

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

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

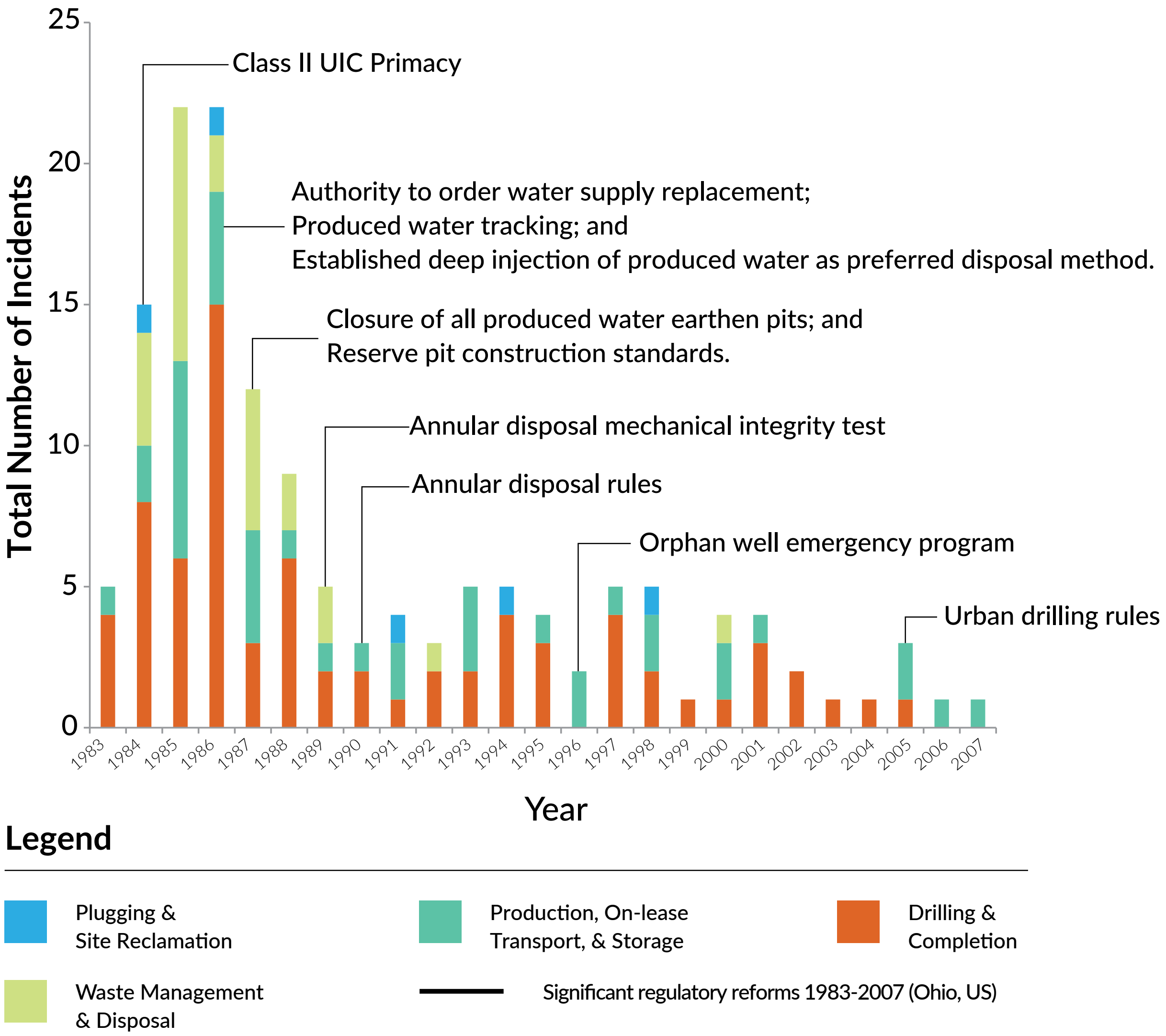
Where environmental risks and impacts are identified, it is generally legal regulation that provides the appropriate mitigation measure, whether by prohibiting an activity, by prescribing that world-leading practice standards and technologies are used, by mandating transparency and accountable decision-making, and/or by imposing rigorous monitoring and enforcement regimes and tough penalties for non-compliance. As shown in **Figure 14.1** an increase in prescription can have a correlative decrease in the number of incidents.

During the public hearings and community forums and in many of the submissions received by the Panel, the community expressed an acute lack of confidence in the current regulatory framework.[2] It is the Panel's view that this concern is justified and that the regulatory regime in the NT must be reformed to ensure that any onshore shale gas industry develops in accordance with community expectations and properly reflects and operationalises the principles of ESD.

Well integrity discussions during Gapuwiyak community forums, February 2018.

1 Fraser Institute 2016.
2 M Haswell submission 183, p 14; EDO submission 213, p 36; NTCA submission 217, p 8; NLC submission 214, p 39; Mr Justin Tutty, submission 152 (**J Tutty submission 152**), p 2; Lock the Gate submission 171, p 68; ECNT submission 188, p 3; AFANT submission 190, p 7; C Roth submission 191, pp 15-16; Coomalie Council submission 15; CDRC submission 76, p 1; NLC submission 647, p 29.

Figure 14.1: Incidents caused by regulated activities by year and key regulatory reforms. Source: FracFocus.[3]



14.2 Community consultations

The Panel heard from a variety of stakeholders, including many members of the public, that they did not trust the regulator, or the present regulatory framework, to adequately protect the environment from the adverse impacts of any onshore shale gas development.[4] This is significant because *"a corresponding social licence will not be achieved unless the community has confidence in the Government to effectively regulate the industry."*[5]

Many people noted legacy mines that have not been properly rehabilitated, such as the Mt Todd gold mine and Rum Jungle, and current mines that continue to cause environmental damage, such as McArthur River, as examples of the Government's failings in this regard.[6]

3 http://fracfocus.org/sites/default/files/publications/state_oil__gas_agency_groundwater_investigations_optimized.pdf
4 For example, see EDO submission 456, p 3.
5 EDO submission 456, p 3.
6 PAN submission 51, p 4; Ms Jean McDonald, submission 182 (J McDonald submission 182), p 5; Climate Action Darwin submission 151, p 14; Doctors for the Environment submission 630, p 5.

Some of the key criticisms of the current regulatory framework were that:

- when regard is had to other extractive industries (such as mining), the regulator has been unable to prevent environmental harm and has been unwilling to ensure compliance with title conditions, or has refused to take enforcement action in relation to non-compliance;[7]
- it does not take into account the cumulative impacts of any industry, but assesses impacts on an activity-by-activity basis;[8]
- the requirement for baseline testing of groundwater, surface water, soil, sediment and air quality is not mandated, and adequate data does not exist;
- there is no 'fit and proper person' test or other requirement that a gas company's environmental history be considered prior to any approval being granted;
- no third party merits review rights or open standing for judicial review is provided; and
- land access arrangements for pastoralists are currently inadequate and that there are no statutory provisions requiring the negotiation of land access agreement.[9]

14.3 Overview of regulation of shale gas in the NT

14.3.1 Ownership of petroleum

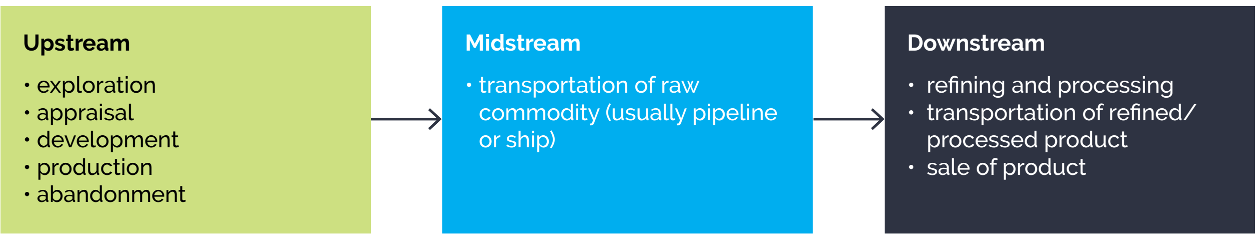
Like all other Australian jurisdictions, all petroleum resources in the NT, including shale gas reserves, are owned by the Government.[10] While the Government owns all of the petroleum, it does not explore for or produce petroleum resources. To do so is risky and expensive and requires extensive technical expertise. Accordingly, like all other jurisdictions in Australia, the Government relies upon gas companies to explore for petroleum on its behalf. This shifts the risks of exploration away from the Government (and the taxpayer). The gas companies that explore for, and develop, natural gas are typically large international petroleum companies that have the size, expertise and finances to navigate the risks and uncertainties associated with exploring for gas.

Nevertheless, it is incumbent on the Government to create a policy and regulatory regime that strikes the right balance between, on the one hand, attracting gas companies to the NT to explore for, and produce, gas, and on the other hand, ensuring that such development is regulated effectively and in accordance with community expectations. Gas companies are more likely to invest in jurisdictions where the legal framework is certain and where they can be confident that they will get a return on their investment.

14.3.2 Phases of development

The development of onshore shale gas resources into products for use by consumers (for domestic and commercial use, such as air conditioning or manufacturing) is characterised by three distinct phases: the upstream phase, the midstream phase and the downstream phase.[11]

Figure 14.2: Phases of the development of petroleum resources. Source: Hunter.[12]



7 CLC submission 47, Appendix A, p 9.
8 CLC submission 47, Appendix A, pp 8-9.
9 EDO submission 213, pp 9, 18; North Star Pastoral, submission 467 (**North Star submission 467**); NTCA submission 217, pp 2-4; CPC submission 218, p 4.
10 See s 69(1) of the *Northern Territory (Self Government) Act 1978* (Cth), whereby the Commonwealth vests all of its interests in petroleum in the Crown of the NT.
11 Hunter 2013, p 6.
12 Hunter and Chandler 2013.

The 'upstream phase' comprises the following:

- **exploration**: which is the search for commercially viable petroleum resources. It comprises aerial surveys, seismic surveys and the drilling and hydraulic fracturing of exploration wells;
- **appraisal:** which is the process of confirming the size, quality and commercial potential of a petroleum resource. The appraisal phase may involve the drilling of appraisal wells near the exploration wells;
- **development:** which involves the declaration of a commercially viable petroleum reservoir, the planning process to exploit the petroleum, and the construction of production facilities;
- **production:** which involves the extraction of petroleum from the well; and
- **decommissioning** and **abandonment:** which involves the cessation of production, the plugging of wells and the decommissioning of field structures, and the transfer of ownership of the well from the gas company to the Government (see the more detailed description in Section 5.3.2.5).[13]

The 'midstream phase' involves transport, storage and marketing. Pipelines are used to transport petroleum to a processing facility or to a tanker terminal for transport to a port that has a processing facility.[14]

The 'downstream phase' involves the processing of petroleum and the marketing and distribution of petroleum products.[15]

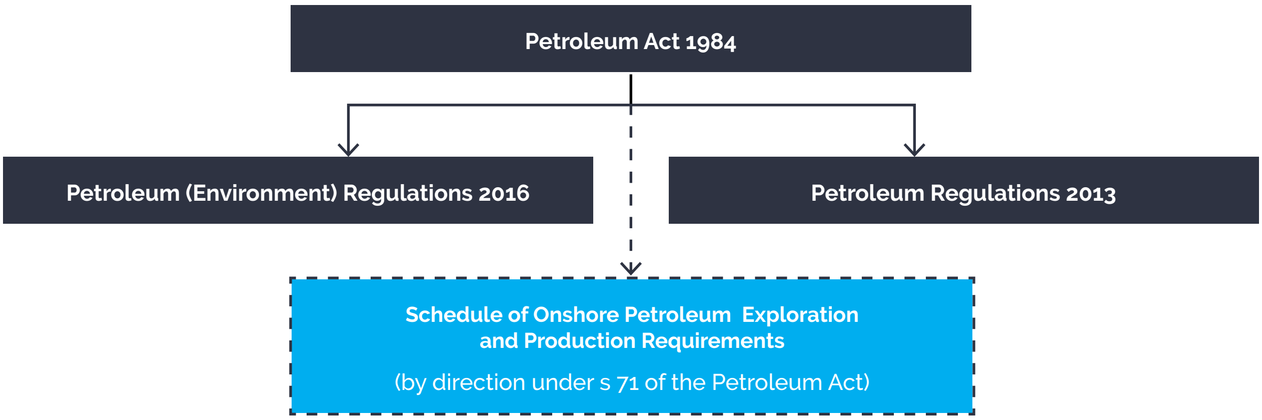
This Chapter will focus on the governance of the upstream phase only. It is this phase that has the greatest capacity for risk in the NT.

14.3.3 Overview of NT petroleum legislation

The Petroleum Act is the primary piece of legislation that regulates any onshore shale gas industry in the NT. It is supported by the *Petroleum Regulations* 1994 (NT) (**Petroleum Regulations**), the Petroleum Environment Regulations and the Schedule, as well as a series of non-enforceable guidelines and policy documents.

The Petroleum Regulations regulate fees in relation to petroleum activities.[16] The Petroleum Environment Regulations require approvals from the Minister for Resources for all activities that may have an environmental impact. The Schedule contains many provisions that are generally found in regulations, including the regulation of drilling and well activities, reporting and data, production, and geological and geophysical surveying.[17]

Figure 14.3: Overview of NT petroleum legislation.



13 Hunter and Chandler 2013, pp 7-8.
14 Hunter and Chandler 2013, p 8.
15 Hunter and Chandler 2013, p 9.
16 DPIR and DENR submission 492, Attachment A, p 26.
17 2012 Hunter Report, p 27.

14.3.3.1 Petroleum Act

The Petroleum Act sets out a statutory regime for the granting of petroleum interests and titles for exploration, production and ancillary activities associated with exploiting any onshore shale gas, as well the assessment of proposed technical works programs within these titles.[18] It also administers the reporting of data, collection of royalties and, to the extent reasonably practicable, the reduction of harm to the environment during petroleum exploration and production activities.[19] In exchange for the exclusive right to produce and sell onshore shale gas, the Petroleum Act requires that gas companies pay 10% of the gross value of the petroleum at the wellhead back to the Government. back to the Government.[20]

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

14.3.3.2 Petroleum Environment Regulations

While the Petroleum Act does not, on its face, manage environmental risks and impacts, the Act allows the making of regulations for the protection of the environment.[21] The Petroleum Environment Regulations were introduced in July 2016 for this purpose.[22] The objective of the Petroleum Environment Regulations is to:

> *"set out a clear risk management framework for environmental aspects of petroleum activities and require the Minister to consider the principles of ecologically sustainable development (ESD), publish approved EMPs in full and ensure that risks and impacts are reduced to as low as reasonably practicable (ALARP) and acceptable levels. This requires that risks and impacts are identified and assessed, that stakeholders are engaged in setting objectives and outcomes as well as the elimination or mitigation of risks and impacts, with specific performance standards around the controls put in place and measurement criteria and reporting commitments of those performance standards."*[23]

The Petroleum Environment Regulations apply to any petroleum activity that has an environmental impact. This includes hydraulic fracturing because *"hydraulic fracturing"*[24] is listed as a *"regulated activity."* It is an offence to conduct hydraulic fracturing without an approved EMP.[25]

A plan will be approved if the Minister for Resources is satisfied that certain approval criteria have been met. In particular, the Minister must be satisfied that the plan will reduce all environmental impacts and risks associated with the activity to levels that are both ALARP and acceptable. The Minister determines what an *"acceptable"* level of risk is by reference to the principles of ESD and any recommendations from the EPA. The Minister must publish reasons for his or her decision.

The Petroleum Environment Regulations implement many of the recommendations from the

- 2012 and 2016 Hunter Reports and 2014 and 2015 Hawke Reports. They:
- are objective-based, with the capacity to add conditions (which may be prescriptive) on an approval;
- attempt to operationalise the principles of ESD by requiring the Minister to consider those principles as part of the decision-making process;
- ensure a level of transparency by requiring the public release of EMPs and the Minister's statement of reasons for approving a plan;
- require stakeholder engagement as a precursor to the submission of an EMP;

18 Petroleum Act, s 3.
19 Petroleum Act, s 3.
20 Petroleum Act, s 84.
21 Petroleum Act, s 118(3).
22 DPIR submission 226, p 38.
23 DPIR submission 226, p 38.
24 Petroleum Environment Regulations, cl 5.
25 Petroleum Environment Regulations, cl 30.

- require the Minister to consider any recommendations made from the EPA when making a decision about a plan; and
- operationalise the ALARP test in the decision-making process.[26]

The ways in which the regulations can be strengthened further to increase transparency and accountability in the decision-making process are discussed in Section 14.7.3.1.

14.3.3.3 The Schedule

The Schedule operates alongside the Petroleum Environment Regulations and the Petroleum Act to regulate certain petroleum activities, such as seismic surveys used in exploration, the design, construction and drilling of wells, and well integrity. The Schedule, by itself, is not enforceable.[27] It is given legal effect by the Minister for Resources, who issues each interest holder (gas company) with a direction under s 71 of the Petroleum Act requiring the interest holder to comply with the terms of the Schedule.[28]

The Schedule has been described as an ineffective regulatory tool.[29] In its current form, it is highly prescriptive, which means that it focusses more on what gas companies must do rather than whether or not they have achieved specified environmental outcomes for a particular activity. While the Panel's view is that there is a role for some prescriptive regulation in the NT context (see Section 14.7.4 below), a purely prescriptive regulatory framework will not promote best practice and will not facilitate the development and adoption of new and effective technologies and methodologies to mitigate environmental risks. In addition, the Schedule is not subject to any type of regulatory impact assessment. While this type of regulation gives the Government significant flexibility (the Schedule can be amended immediately by the Minister), it is problematic, in the Panel's view, for the reasons set out in Section 14.7.3.2.

In both the 2012 and the 2016 Hunter Reports, the phasing out of the Schedule was recommended.[30] DPIR has publicly committed to phasing out the Schedule and replacing it with exploration and production regulations, but this is yet to occur.[31]

26 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.
27 2016 Hunter Report, p 15.
28 Petroleum Act, s 71.
29 2016 Hunter Report, p 15.
30 2016 Hunter Report, p 15; 2012 Hunter Report.
31 DPIR submission 226, p 38.

14.3.4 Process to explore for and produce any onshore shale gas

The process for gaining the rights to explore for, and produce, any onshore unconventional shale gas in the NT is set out in **Figure 14.4**. Before any exploration activity can occur in the NT, the Government must release the land for exploration (**Step 1**). Once land is released gas companies make bids for the land (**Step 2**) and the Minister for Resources selects the most meritorious application for consideration of the grant (**Step 3**).[32] The requirements of the Native Title Act and Land Rights Act must then be complied with (**Step 4**).[33] The requirements of the Native Title Act and Land Rights Act, which require the gas company to enter into negotiations with traditional Aboriginal owners, must be complied with (see Section 11.3.3 where this is discussed in further detail) (**Step 4**). The Minister grants the exploration permit to the gas company (**Step 5**). There is a non-statutory requirement to reach an agreement with pastoralists in respect of a proposed exploration program (**Step 6**) (see Section 14.6.1). For any activity that will have an environmental impact, the gas company must submit a draft EMP for approval by the Minister for Resources, and the Minister makes a decision to either approve or not approve the plan (an environmental approval) (**Step 7**). Certain activities, such as drilling and hydraulic fracturing, also require the gas company to submit an application for approvals under the Schedule (an operational approval) (**Step 7**). The Minister then issues operational approvals, if appropriate, under the Schedule (**Step 7**). It is important to note that a gas company can only proceed with an activity on an exploration permit, such as hydraulic fracturing, if all of Steps 1 to 7 have been completed. In other words, an exploration permit does not, of itself, give the gas company a right to conduct hydraulic fracturing. Rather, 'exploration approvals' are required under the Petroleum Environment Regulations and the Schedule for any exploration activity to proceed on an exploration permit (see also Chapter 16 and the Glossary). In the event that a commercial onshore shale gas reserve has been discovered, a gas company can apply for a production licence (**Step 8**). Only if all of the conditions of the exploration permit have been met and the requirements of the Native Title Act and Land Rights Act have been satisfied (**Step 9**) must the Minister for Resources grant a production licence (**Step 10**). However, once again, this is does not mean that production activity can, without more, proceed. Any production activity that will have an environmental impact must have an approved EMP in place (an environmental approval), and certain activities, such as drilling, hydraulic fracturing and seismic surveys, will also require approvals under the Schedule (an operational approval. Together, 'production approvals' for production activity on a production licence. See also Chapter 16 and the Glossary) (**Step 11**). As with exploration activities (including hydraulic fracturing) on an exploration permit, clearing, drilling and hydraulic fracturing on a production licence can only occur if a gas company has both environmental and operational approvals, or production approvals.

32 DPIR submission 226, p 13.
33 NLC submission 647, p 29.

Figure 14.4: Steps required to undertake shale gas activities in the NT under the current regulatory framework.

Step 1 - Land Release

The Government invites applications for exploration permits (EP) over particular blocks of land.

Step 2 - Gas company bids for an EP

Step 3 - Minister selects the most meritorious application for consideration of grant

Step 4 - Requirements of the Native Title Act and Land Rights Act are satisfied

If the EP application is over native title land or Aboriginal land, the requirements of the Native Title Act and the Land Rights Act must be met.

Step 5 - Minister for Resources grants the EP to the gas company

The EP gives a gas company the exclusive right to conduct exploration over the permit area but more approvals are needed before shale gas activities, such as hydraulic fracturing, can occur.

Step 6 - Access agreements over pastoral land are made

If the EP is over a Pastoral Lease, the proponent must come to an agreement with the pastoralist (this is a non-statutory requirement).

Step 7 - Approvals for exploration activity

The gas company applies to the Minister for Resources for approval to conduct certain activities, such as seismic activities, hydraulic fracturing, drilling and flaring under the Schedule.

The gas company applies to the Minister for Resources for an environmental approval under the Petroleum Environment Regulations for any activity that will have an environmental impact, including hydraulic fracturing.

Shale gas activity can proceed on an EP

Only when the gas company has a granted EP, access agreements with traditional owners and pastoralists have been reached, and approvals under the Schedule and the environment regulations have been given can a regulated activity, like hydraulic fracturing, be done.

Step 8 - Gas company applies for a production licence (PL)

The gas company will get a PL if it has complied with the terms of the EP and has found an economic reserve.

Step 9 - Requirements of the Native Title Act and Land Rights Act are satisfied

Step 10 - Minister for Resources grants the PL to the gas company

The Minister for Resources decides whether or not to grant a PL, which gives the gas company the right to produce and sell gas. The gas company cannot conduct any activity until all the necessary approvals (below) are granted.

Step 11 - Approvals for production activity

The gas company applies to the Minister for Resources for approval to conduct certain activities, such as seismic activities, hydraulic fracturing, drilling and flaring under the Schedule.

The gas company applies to the Minister for Resources for an environmental approval under the Petroleum Environment Regulations for any activity that will have an environmental impact, including hydraulic fracturing.

Shale gas activity can proceed on a PL

Only when the gas company has a granted PL and approvals under the Schedule and the Petroleum Environment Regulations have been given can a regulated activity, like hydraulic fracturing, be done.

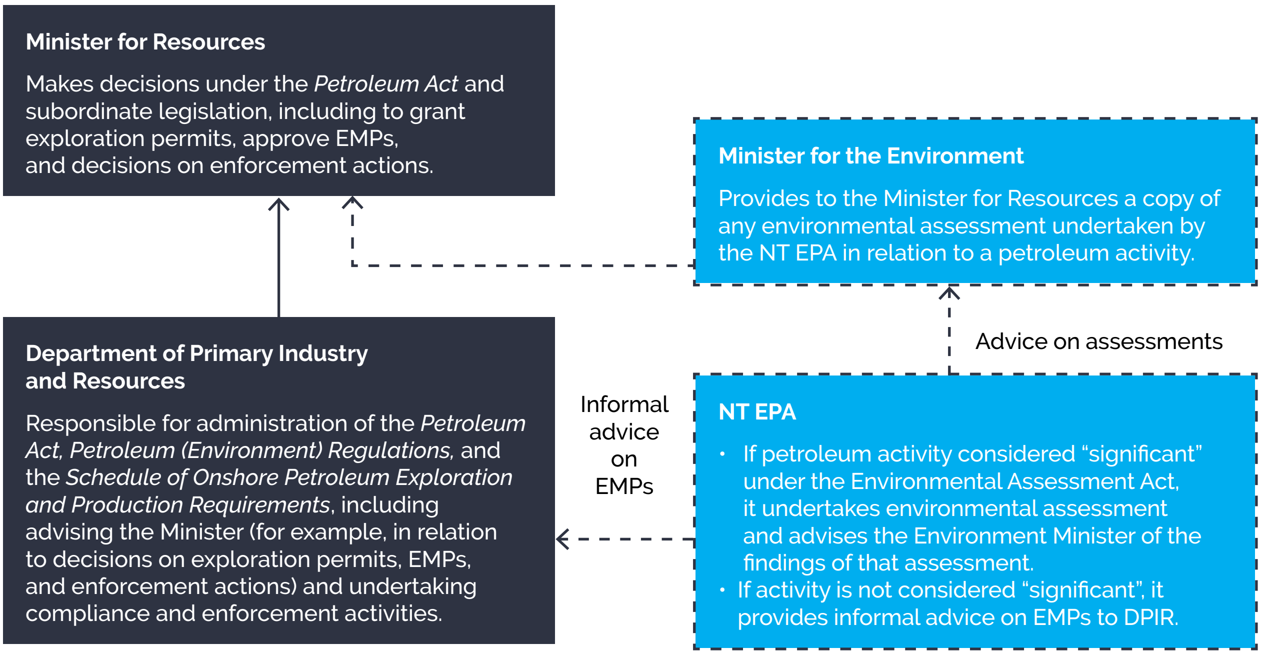
14.4 The regulators

It is important to understand which Government departments and agencies administer the laws regulating any onshore shale gas development in the NT, and which departments and agencies have decision-making roles under those laws (see **Table 14.1** and **Figure 14.5**).

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

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

Figure 14.5: Departments and agencies that are involved in regulating onshore shale gas development in the NT.



14.4.1 DPIR

As indicated above, the Minister for Primary Industry and Resources is currently the responsible Minister under the Petroleum Act, and officers in the Energy Division in DPIR administer that Act and are responsible for compliance and enforcement.[34]

14.4.2 EPA

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

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

The Waste Management Act does not apply inside petroleum permits where all contaminants and wastes associated with an activity remain on the permit area.[35] The Waste Management Act requires gas companies to have a licence for the collection, transport, storage, treatment and disposal of *"listed wastes"*,[36] many of which are chemicals used for hydraulic fracturing or that are found in wastewater. The EPA issues those licences.

14.4.3 Water Controller

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

The Water Act currently exempts gas companies from the need to get a water extraction licence under that Act. The Government has committed to reforming this position[37] and, given the large volumes of water required by any onshore shale gas industry in full production (see Chapter 7), the Panel has recommended that the Act be reformed to require gas companies to obtain and pay for a water extraction licence under the Water Act for the purposes of hydraulic fracturing (see ***Recommendation 7.1*** and ***7.2***).[38] This is to ensure that water use by any onshore shale gas industry is sustainably managed.

14.4.4 NT Worksafe

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

While the regulation of occupational health and safety matters by a separate safety body is an accepted practice,[39] there is the potential for regulatory gaps and overlaps to arise.[40] Regulatory overlap has the capacity to erode the community's confidence in the regulatory framework because it creates uncertainty about who the regulator is. As noted by the Productivity Commission, regulatory overlap also means that information needs to be provided to multiple regulators and go through multiple processes, which can add to compliance costs.[41] Regulatory overlap is a form of regulatory burden and should be removed. The Panel has observed some regulatory overlap between DPIR and NT Worksafe, including requirements for spill contingency plans under work health and safety legislation as well as the Schedule. While not the subject of a

34 See the current Administrative Arrangements Order under s 35 of the Interpretation Act 1978 (NT) at https://legislation.nt.gov.au/en/Legislation/ADMINISTRATIVE-ARRANGEMENTS-ORDER.
35 Waste Management Act, s 6.
36 Waste Management Act, s 30(3).
37 DENR submission 230, p 7; NT Parliament 2016, p 145; DPIR and DENR submission 492, Attachment A, p 22.
38 There is universal support for this: see EDO submission 456, p 4; Origin submission 476, p 3.
39 2012 Hunter Report, p 29.
40 2012 Hunter Report, p 29.
41 Productivity Commission 2009, p 34.

recommendation by the Panel on the basis that occupational health and safety matters fall outside the Terms of Reference, this overlap should nevertheless be addressed by the Government. plans under work health and safety legislation as well as the Schedule.[42] While not the subject of a recommendation by the Panel, this overlap should be addressed by the Government.

14.4.5 Regulatory fees

A key component of a robust regulatory regime is an adequately resourced regulator.[43] As Dr Tina Hunter noted in her 2016 Report, the success of any regulatory framework depends on adequate resourcing of the regulator, and in this regard, *"as onshore petroleum activities increase, staffing levels at the Regulator will also need to increase."*[44] One of the community's main concerns about the regulation of any onshore gas industry in the NT was that the regulator would not be sufficiently resourced to have thorough oversight of the industry, especially having regard to NT specific factors such as its small population, its extensive geography, and the challenge of overseeing an often remotely operated industry.[45] Various stakeholders thought that DPIR was *"under resourced and under staffed"*, which jeopardised the ability of the agency to perform its statutory duties.[46] The EDO noted:

> *"significant concerns about the ability of the Northern Territory government to adequately regulate a production-scale gas industry. The Northern Territory has difficulty attracting and retaining staff with adequate expertise and the small population and revenue base of the Northern Territory sees the [DPIR] and Northern Territory EPA compliance teams far smaller than those that exist in other states and territories."* [47]

The NLC noted that it *"has doubts that existing Government, Regulatory and Land Management bodies in the Northern Territory currently hold sufficient capacity to adequately manage rapid development of the onshore oil and gas industry"* [48] and that *"the Northern Territory Government may be insufficiently resourced to monitor the full extent of future environmental impacts posed by the development of the onshore oil and gas industry."* [49]

Regulatory bodies are generally funded either by the government through its budgetary process, or on a full cost recovery basis, where the regulated industry is required, through fees and levies, to fund all of the regulatory burden (known as full cost recovery). With the latter principle, the cost of governance of a particular industry is not borne by the public. In 2001, following an extensive inquiry, the Productivity Commission released Cost Recovery by Commonwealth Agencies which, among other things, concluded that, *"the prices of regulated products should incorporate all of the costs of bringing those products to market, including the administrative costs of regulation."* [50]

In 2002, the Australian Government adopted a general policy of full cost recovery. The most recent iteration of this policy, the 2014 Australian Government Cost Recovery Guidelines, states that *"where appropriate, non-government recipients of specific government activities should be charged some or all of the costs of those activities,"* [51] and moreover, that fees should generally be set to cover the full cost of the activities.[52] It is consistent with a user-pays, market-driven approach to regulation. It also operationalises the principles of ESD insofar as it is an aspect of the polluter-pays principle.

The regulation of the offshore petroleum industry has been considered by the Commonwealth to be appropriate for full cost recovery, with the National Offshore Petroleum Safety and Environmental Management Authority (**NOPSEMA**) operating on a full cost recovery basis.[53]
Other Commonwealth agencies, such as the Australian Securities and Investment Commission (**ASIC**), have adopted similar funding structures to ensure that the costs of ASIC's regulatory activities fall on those who create the need for regulation.[54]

42 See s 357 of the Work Health and Safety (National Uniform Legislation) Regulations 2012 (NT) which requires a spill contingency system to be in place, and cl 214 of the Schedule, which requires actions to be taken in accordance with an "approved spill contingency plan" in the event of a petroleum or chemical spill.
43 Hawke EPBC Act Review, pp 11, 16; NLC submission 647, p 29.
44 2016 Hunter Report, p 4.
45 See, for example: NLC submission 214, pp 39-40; NLC submission 471, p 25; CLC submission 47, Appendix A p 9; NLC submission 647, p 29; EDO submission 456, p 10.
46 Lock the Gate submission 171, p 69; Climate Action Darwin submission 175, p 14; NARMCO submission 186, p 9.
47 EDO submission 213, p 36.
48 NLC submission 214, p 39.
49 NLC submission 214, p 41.
50 Productivity Commission 2001, p xiii.
51 Cost Recovery Guidelines, p 5.
52 Cost Recovery Guidelines, p 6.
53 NOPSEMA cost recovery and levies; see also Productivity Commission 2009, p 265.
54 *ASIC Supervisory Cost Recovery Act 2017* (Cth). See EDO submission 456, pp 10-12.

In Queensland, there is precedent for such an approach with respect to the regulation of health and safety in oil and gas operations. In 2010, a full cost-recovery model was introduced to recover from industry the cost of employing new inspectors, training existing inspectors and other administrative burdens.[55]

DPIR has informed the Panel that it supports a full cost-recovery model for the regulation of onshore shale gas development in the NT.[56] Any cost recovery mechanism must, however, be designed to:

- avoid fee duplication; and
- minimise gas companies avoiding fees through active non-compliance.[57]

In the NT, gas companies are currently required to pay regulatory fees for a number of approvals, including applications for exploration permits and production licences, applications to renew, vary or extend titles, and other annual fees. These fees are deposited into general Government revenue and then returned to DPIR as part of the budgetary process for use for regulatory activities.[58] These fees, however, would not cover the full costs of regulating any onshore gas industry.[59]

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

Table 14.2: Fees payable in different jurisdictions.[60]

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

55 EDO submission 456, p 11.
56 DPIR submission 424, pp 20-21.
57 Hawke EPBC Act Review, para 109, p 16.
58 DPIR submission 226, pp 26 and 186.
59 NT Agency Budget Statements 2017-18, pp 175, 185.
60 With respect to the latter three jurisdictions, care must be taken in any comparison, however, because the regulation of NOPSEMA offshore petroleum is a different to onshore petroleum, and the fees charged in the two Canadian jurisdictions are calculated on production volume rather than permit fees alone.

Table 14.2 highlights that there is scope for fee increases in the NT to properly fund the regulation of any onshore shale gas industry.[61]

The Panel considers, given that the benefit of the regulatory activities goes primarily to an identifiable group, that is, the gas companies, that the regulation of any onshore shale gas industry in the NT should be conducted on a full cost recovery basis.

Recommendation 14.1

That prior to the granting of any further production approvals, the Government designs and implements a full cost-recovery system for the regulation of any onshore shale gas industry.

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

14.5.1 Land release process

Before any onshore shale gas activities can occur in the NT, land must be made available for exploration. The process of making land available is referred to as the 'land release process' (see **Figure 14.6**). Once land is 'released' by the Government, gas companies can make a bid to the Government to place an application over the area. No activities can take place over the area at this stage. Once an exploration permit is granted, a gas company has the exclusive right to explore for shale gas, subject to the requirement to obtain the other approvals discussed below in Section 14.7.

As shown in **Figure 14.7**, approximately 85% of the NT land mass has been released for exploration and is either subject to an application for, or is the subject of, a granted exploration permit.

Figure 14.6: Current process for land release in the NT.

Minister for Resources decides which land to release

May take into account land release policy (not required to)

→

Minister for Resources publishes a notice inviting applications in relation to that land

Petroleum Act, s 16

→

Companies apply for exploration permits in relation to that land

Petroleum Act, s 16

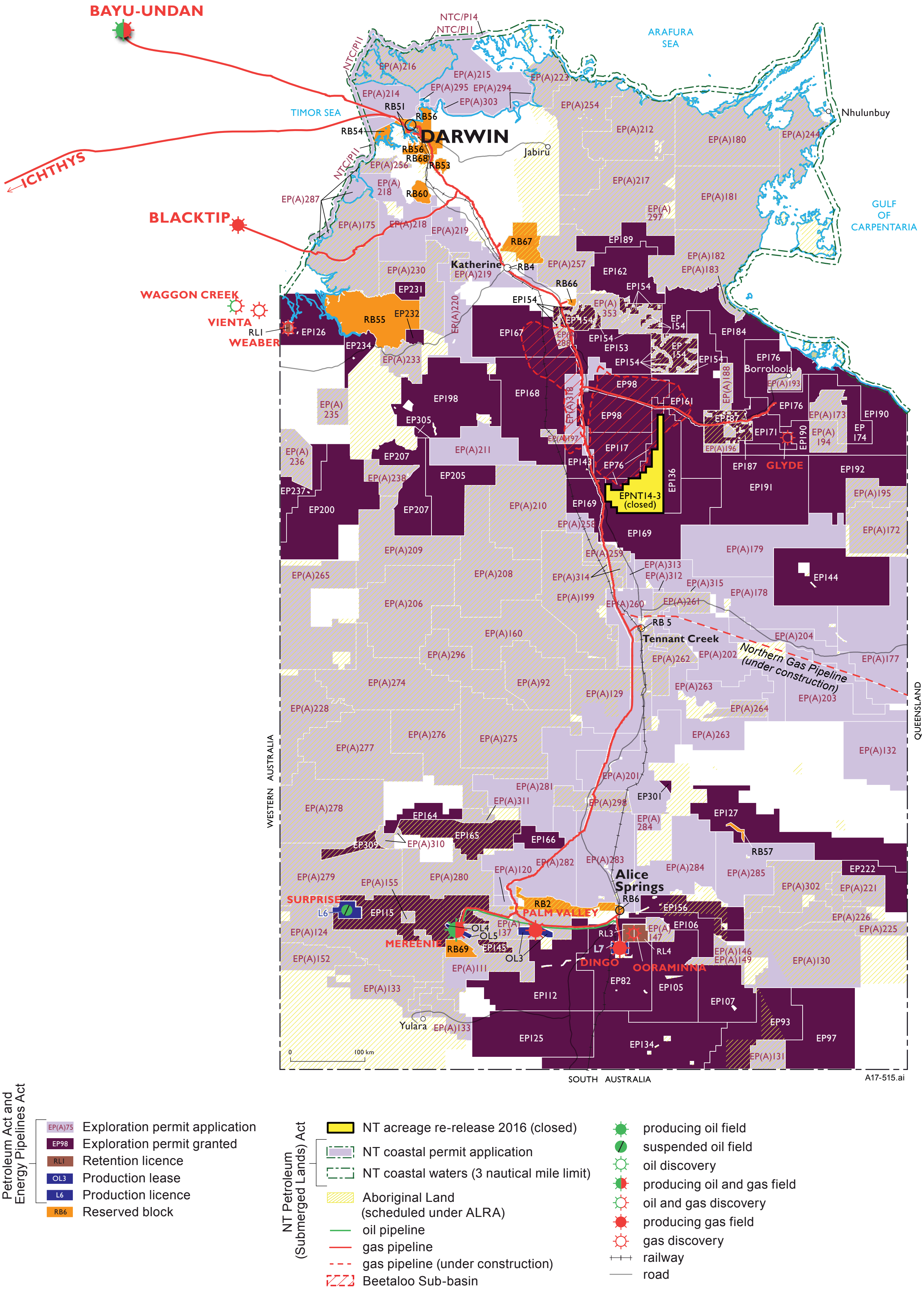
During consultations, **Figure 14.7** has been used by those opposed to any onshore shale gas industry to argue that the Government prioritises economic development in the NT over the environment. Many of the areas covered by an application or granted permit are arguably areas with little or no prospectivity for shale gas (for the prospective onshore shale gas areas in the NT, see **Figure 6.6**). It is important to note that not all of the applications have been granted, which was a misunderstanding evident at the community consultations and in various submissions.[62] Rather, only a portion of these applications have been granted. Approximately 25% of the NT is subject to a granted petroleum exploration permit.

The reasons most of the NT has been 'released' for exploration are two-fold. First, prior to 1 January 2014, applications for a petroleum exploration permit were awarded on a 'first-in first-served' or an 'over-the-counter' basis.[63] All land was considered 'available', or 'released', and gas companies could simply make an application over the counter for an exploration permit. Second, following the shale gas revolution in the US, gas companies were actively looking for areas that may be prospective for shale gas, and the NT was deemed to be a highly prospective area. This resulted in permit applications being made over 85% of the NT.[64]

On 1 January 2014, the Petroleum Act was amended to enable the Government to invite applications from gas companies only over areas that had been 'released'. The amendments were arguably too late because most of the land was already 'released' and under application. There is now very little land left to be 'released'. DPIR has advised the Panel that only two areas of land have been released since the 2014 amendments.[65]

61 EDO submission 635, p 11.
62 EDO submission 635, p 2.
63 DPIR submission 492, Attachment A.
64 DPIR submission 226, p 13; DPIR and DENR submission 492, Attachment A, p 11.
65 DPIR and DENR submission 492, Attachment A, p 13.

Figure 14.7: Onshore petroleum titles and developments. Source: DPIR.



The new land release process under the Petroleum Act operates by the Minister publishing a notice in a newspaper inviting gas companies to apply for an exploration permit on *"any of the blocks specified in the notice"*.[66] The Petroleum Act does not provide any details on how the Minister decides which land should be released. DPIR has, however, established the following informal process. Before land is released, DPIR considers:

- the prospectivity of the relevant land for oil and gas exploration;
- the views of certain stakeholders, including Government agencies, Aboriginal Land Councils and local councils; and
- whether the land is in an area of intensive agriculture, high ecological value, culturally significant or an area of strategic importance.[67]

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

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

Recommendation 14.2

That the Minister must immediately notify the public of any proposed land release for any onshore shale gas exploration.

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

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

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

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

The Panel also recommends that the Government facilitate the withdrawal of all extant applications for exploration permits in respect of areas that are either not prospective for onshore shale gas or that are areas where there is intensive agriculture, are of high ecological value, are of high scenic value, are culturally significant, or are of strategic significance (that is, were co-existence is unlikely). This recommendation should be adopted notwithstanding the fact that some of the applications are presently subject to the negotiation processes set out in the Native Title Act and the Land Rights Act (see Chapter 11). Industry, Land Councils and traditional Aboriginal owners should work with DPIR in this regard. DPIR indicated that it has already commenced this process, with one applicant withdrawing 22 applications in 2016.[68]

66 Petroleum Act, s 16(1); DPIR submission 226, p 18.
67 DPIR submission 226, pp 18, 312.
68 DPIR submission 226, p 14.

Recommendation 14.3

That Government not approve any application for an exploration permit in relation to areas that are not prospective for onshore shale gas or where co-existence is not possible. Priority must be given to the areas identified in Recommendation 14.4.

14.5.2 Reserved blocks

There are some areas of the NT that should never be released for exploration for onshore shale gas. Where an area of land is deemed to be permanently unsuitable for any type of exploration activity, the Minister for Resources can declare it to be a "reserved block" under the Petroleum Act. A reserved block is a 'no go zone', which means it cannot be considered by the Minister as part of the land release process and can never be subject to a petroleum exploration or production permit.[69]

The areas that are currently reserved blocks in the NT are shown in **Figure 14.8**. Some, but not all, national parks are reserved blocks (for example, Nitmiluk National Park and Watarrka National Park).[70] Petroleum exploration has occurred within at least one national park in the NT, namely, Limmen National Park.[71]

During consultations the Panel heard that more areas should be declared or reserved blocks or 'no go zones'. The Panel agrees that areas of high tourism value (for example, Mataranka Hot Springs), towns and residential areas (including areas that include assets of strategic importance to nearby residential areas), national parks, conservation reserves, areas of high ecological value and areas of cultural significance should be made reserved blocks under the Petroleum Act, because any onshore shale gas industry is unlikely to be able to coexist with these uses of land. This will ensure that these areas are never considered by the Minister to be potentially released as part of the land release process described above. The Panel notes that this is consistent with Government policy as set out in the *"Where oil and gas activities can occur"* guideline.[72]

The Panel heard that land used for intensive agriculture should also be made a 'no go zone' or reserved block.[73] But co-existence between the agricultural and any onshore shale gas industry may, in some cases, be possible. For example, in its submission to the Panel, the NT Farmers Association indicated that both the existing and future areas of high agricultural value were readily identifiable and had been spatially mapped.[74] The possibility of co-existence between certain industries should therefore be considered on a case-by-case basis. The land release process recommended above will allow landowners of intensive agricultural land to consult with Government about whether or not co-existence between current land use and any onshore shale gas industry is possible. If it is not, then the Government should not release that land for exploration.

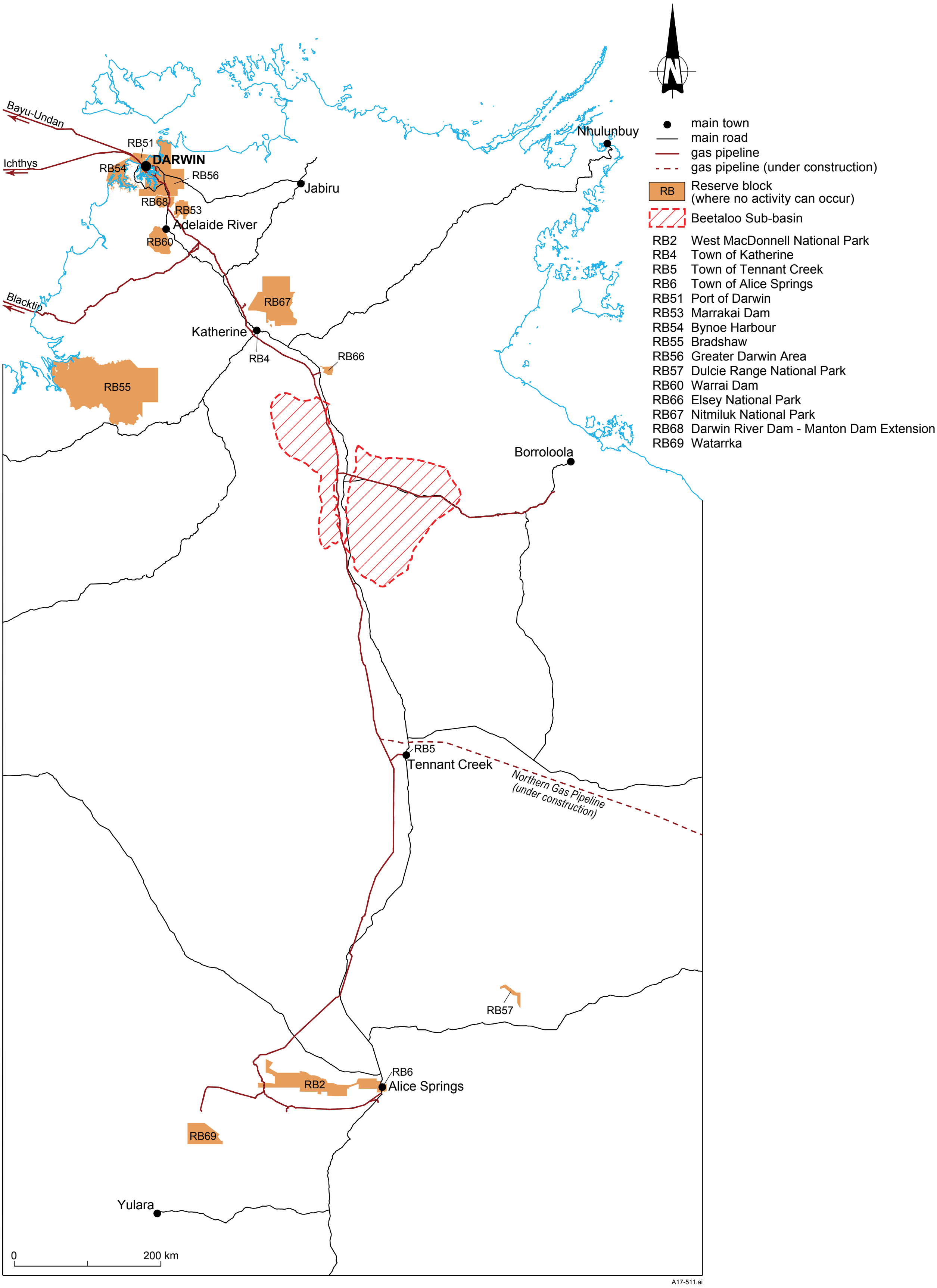
Recommendation 14.4

That prior to the grant of any further exploration approvals, the following areas must be declared reserved blocks under s 9 of the Petroleum Act, each with an appropriate buffer zone:

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

69 Petroleum Act, s 9.
70 DPIR submission 226, p 14.
71 EDO submission 213, p 20
72 NT Government 2015, p 9.
73 Northern Territory Farmers Association, submission 652 (**NT Farmers submission 652**).
74 NT Farmers submission 652, slide 5.

Figure 14.8: Current reserved blocks in the NT. Source: DPIR.



NORTHERN TERRITORY GOVERNMENT

It is noted that the process set out at Section 14.5.1, including the implementation of ***Recommendation 14.2***, should ensure that areas of intensive agriculture, high ecological value, high scenic value, that are culturally significant or are of strategic significance, will not be the subject of an exploration permit (assuming that the Minister is satisfied, following consideration of the community's views, that co-existence with the onshore shale gas industry is not possible at a particular point in time). However, to remove any ambiguity these areas have been included in the above recommendation.

Recommendation 14.4 is prospective in nature and does not apply to land already the subject of a granted exploration permit. Consideration must be given to how the areas identified in ***Recommendation 14.4*** can retrospectively be made no go zones. The Panel recognises that this may give rise to complex legal issues that involve questions of potential sovereign risk and the payment of compensation to existing EP holders by the Government.

Recommendation 14.5

That the Government immediately considers and implements mechanisms to retrospectively apply Recommendation 14.4 to granted exploration permits.

14.6 Land access for onshore shale gas activities

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

- Aboriginal land under the Land Rights Act (see Chapter 11);
- land where native title rights and interests have not been extinguished and where the Native Title Act applies (see Chapter 11); and
- pastoral leases granted under the Pastoral Land Act 1992 (NT) (**Pastoral Leases**).

A map showing the different types of land tenure in the Northern Territory is in Chapter 11 at **Figure 11.2**. The Figure shows that different types of interests in land can overlap. For example, a parcel of land can be subject to a petroleum exploration permit, a pastoral lease, and native title. This gives rise to a complex land access regime in the Territory because it means that, at a minimum, the Petroleum Act, the Pastoral Land Act and the Native Title Act will apply to that particular piece of land.

The Panel does not believe that the laws that govern land access to pastoral land should be the same as the laws that govern access to native title or Aboriginal land because the underlying property interests of pastoral leases, native title and Aboriginal land are very different.[75] The issues surrounding land access management for Aboriginal land held under the Land Rights Act and the Native Title Act, including the legal requirement for gas companies to reach agreement with traditional owners,[76] are dealt with in Chapter 11.

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

75 EDO submission 635, p 5.
76 NLC submission 647, p 29.

Table 14.3: Land tenure in the NT.

	Pastoral Lease	Native Title	Aboriginal Land	Freehold Land	Crown Land
Total area as a percentage of the land mass of the Northern Territory	44%	47%	48%	1%	4%
Percentage of the area that is subject to a petroleum interest (exploration or production)	53%	52%	6%	4%	37%
Type of interest	Leasehold interest granted under the *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

14.6.1 Access to Pastoral Leases

Gas companies require access to Pastoral Leases to exercise their statutory right to explore for and extract petroleum on the permit area.[77] Pastoral Leases are issued by the Crown under the Pastoral Land Act. The holder of the lease (**pastoralist** or **Pastoral Lessee**) must use the lease area for pastoral purposes.[78] The rights and obligations of pastoralists are set out in legislation, supporting regulations, and the lease document. Pastoralists do not own the land, and unlike the holder of a freehold interest, they do not have the right to exclusive possession of the Pastoral Lease area. A pastoralist must pay rent to the landowner (the pastoral lessor) in exchange for the rights given under the Pastoral Lease.[79] Pastoralists, like native title holders, Aboriginal land trusts, and owners of fee simple interests, do not own subsurface petroleum resources, such as shale gas.[80]

77 Petroleum Act, s 29(1).
78 *Pastoral Land Act* 1992 (NT), s 38(1)(d). There is a regime in the Act that allows pastoralists to use their leases for non-pastoral purposes.
79 *Pastoral Land Act* 1992 (NT), s 55.
80 *Pastoral Land Act* 1992 (NT), s 38(1)(b); Petroleum Act, s 6. Regarding Aboriginal trust land see Land Rights Act, s 12(2), which reserves the rights to all minerals, including petroleum, to the Commonwealth, or the Territory, as the case may be. Most submissions acknowledged that minerals and petroleum are reserved to the Crown: see R Sullivan submission 18, p 2; DPIR submission 226, p 15; R Dunbar submission 75, p 1.

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

Unlike many other jurisdictions in Australia, there is no statutory requirement in the NT for a gas company to enter into an access and/or compensation agreement with a pastoralist. Once a petroleum exploration permit is granted, a gas company has the exclusive right to enter and remain on the permit area to explore for gas.[81] The Petroleum Act does, however, require the gas company to, by agreement, compensate a pastoralist for any deprivation of use or enjoyment of the land or damage caused by the company.[82] If agreement as to the amount of compensation cannot be reached then either party can refer the matter to Northern Territory Civil and Administrative Tribunal (**NTCAT**).[83] The Act requires the gas company to give notice to the owner or occupier of the relevant land before commencing exploration.[84]

14.6.1.1 Access under the Land Access Guidelines

DPIR has developed the Land Access Guidelines, which set out a non-statutory process whereby petroleum companies can access Pastoral Leases (**Figure 14.9**). The Land Access Guidelines were the result of negotiations between DPIR, the NTCA and APPEA.[85] However, no statutory amendments were made to formalise the agreed process. In other words, the process set out in the Land Access Guidelines has no legislative force. The Panel considers this a weakness of the present land access regime.[86]

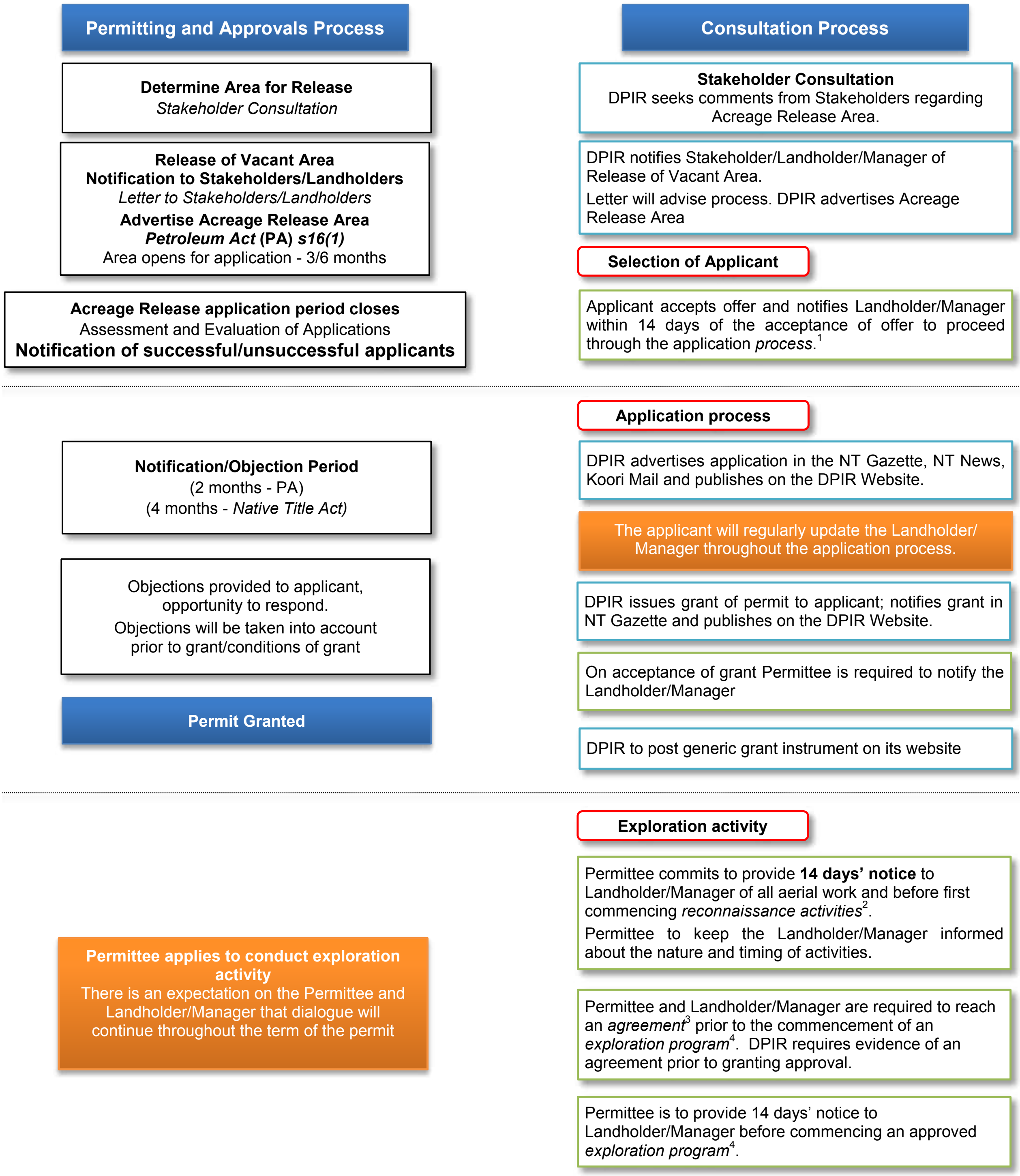
The Land Access Guidelines require the pastoralist and the gas company to reach an agreement prior to the commencement of an exploration program. The Land Access Guidelines do not stipulate what must be included in the agreement. The parties have 60 days to reach an agreement from the date the proponent sends the pastoralist a notice of intention to commence negotiations. If agreement cannot be reached within 60 days, either party may refer negotiations to an Arbitration Panel to make a determination over conditions of access. The Arbitration Panel is comprised of the Chief Executives of DPIR; DENR; the Department of Infrastructure, Planning and Logistics; and industry representatives.[87] The Arbitration Panel has 21 days to make its recommendations. If the parties do not agree with the decision of the Arbitration Panel, *"they retain the right to seek further review through the judicial system"*, which is likely to be protracted and costly.[88]

14.6.1.2 Access under the Petroleum Environment Regulations

The Petroleum Environment Regulations do not require an access and/or compensation agreement to be negotiated between a gas company and a pastoralist. Nor do they give pastoralists the right to veto onshore shale gas activities. Rather, the Regulations set out a process for stakeholder engagement every time a gas company proposes to undertake a *"regulated activity",* which is an activity that has or will have an environmental impact.[89] The Petroleum Environment Regulations require a gas company to consult with stakeholders about their proposed activity and give such stakeholders the opportunity to respond to the information prior to submitting an EMP to the Government.[90] Under the Petroleum Environment Regulations, *"stakeholders"* are people that may be affected by the regulated activity and include pastoralists (see also Section 14.7.3.1).

81 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 program and other exploration": Petroleum Act, s 29(2)(d).
82 Petroleum Act, ss 81-82.
83 Petroleum Act, s 81(3).
84 Petroleum Act, s 81(2).
85 DPIR submission 226, pp 15.
86 See also EDO submission 213, p 9; R Dunbar submission 75, p 3.
87 DPIR submission 226, p 184.
88 DPIR submission 226, p 184.
89 Petroleum Environment Regulations, cl 7. See Petroleum Environment Regulations, cl 5 for the definition of "regulated activity".
90 Petroleum Environment Regulations, cl 7(2)(b).

Figure 14.9: Overview of Pastoral Lease and land access. Source: DPIR.[91]



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

91 DPIR submission 226, p 144.

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

There is an undeniably strong relationship between pastoralists and the land they manage, notwithstanding the absence of freehold title. Some pastoralists have been involved in the pastoral industry for many generations, raising families and building successful businesses in remote parts of the NT.[92] It is plain that many pastoralists feel a deep and personal sense of belonging and control over their Pastoral Lease even though they do not own the land or have any rights in the sub-surface petroleum resources.

It was submitted by gas companies that, in general, the current land access regime facilitates agreement making and a cooperative relationship between pastoralists and gas companies.[93] Various gas companies cited the number of access agreements that they have entered into as evidence that the present land access regime works. APPEA noted that, *"over 50 pastoralists have land access agreements in place and are working collaboratively with our industry."* [94] 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."* [95] Some pastoralists also thought that the current access regime was working effectively.[96]

Origin, however, acknowledged that not all relationships with pastoralists have been harmonious. But it observed that the reasons for relationship breakdowns *"do not share any particular root cause, but rather reflect the complex external environment in which we are negotiating and operating under and the inherent uncertainty and challenges of person to company relationships."* [97]

Various submissions noted that the current land access regime gives more negotiating power to gas companies than to pastoralists.[98] One stakeholder opined that any *"power imbalance"* is the result of pastoralists' *"limited experience in undertaking such negotiations compared to explorers, who may have negotiated hundreds of such agreements; the asymmetry of information regarding the potential impact of the exploration activity; and an imbalance of power, as in most cases, rural land holders are legally required to allow explorers to access their land."* [99]

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 in the context of running a pastoral business.[100] Various submissions supported the establishment of an independent gas commissioner, similar to the Gasfields Commission in Queensland, to facilitate agreement-making between pastoralists and gas companies. Others proposed that there be a statutory requirement that all legal costs associated with agreement-making be paid for by the gas companies.[101] The Panel notes that this is usually agreed to by gas companies.[102]

Central to the success of the negotiation process is adequate time to negotiate an access agreement, access to independent and affordable legal advice, and clarity on the legal (and other specialist advice) requirements of the agreement-making process. The Panel does not advocate the creation of a body such as the Queensland Gasfields Commission for this purpose. That body has been criticised as having been subject to regulatory capture by the unconventional gas industry and failing to adequately protect the interests of landholders.[103] This has led to the creation of another regulatory body to deal with land access issues between the CSG industry and landholders, the Land Access Ombudsman.[104] Instead, the Panel is of the opinion that reform

92 R Dunbar submission 75, p 4.
93 Pangaea submission 220; Terrabos Consulting submission 180; Santos Ltd, submission 58 (**Santos submission 58**); Santos submission 168; Origin submission 153; Australian Pipelines and Gas Association and Energy Networks Australia, submission 101 (**APGA and ENA submission 101**); Roper Resources, submission 181 (**Roper Resources submission 181**); Oilfield Connect submission 174; B Sullivan submission 160; MS Contracting submission 166; APPEA submission 215; R Sullivan submission 243, pp 1-2.
94 APPEA submission 215, p 5; Origin submission 153, p 156; Santos submission 58, p 7; Pangaea submission 220, p 81. See also Terrabos Consulting submission 180, p 7.
95 Origin submission 155, p 157.
96 B Sullivan submission 160, p 7; R Sullivan submission 18, pp 1-2.
97 Origin submission 153, p 157.
98 NTCA submission 32, p 1.
99 North Star submission 155, p 5. The submission refers to the Productivity Commission's Mineral and Energy Resource Exploration, Inquiry Report No 65, Canberra, 2013, pp 18, 133.
100 S Bury submission 189, p 4. Armour submission 23, p 3; Lock the Gate recommended a fully independent ombudsman be created to act as an umpire in disputes between landholders, traditional owners and gas companies, Lock the Gate submission 171, p 74.
101 Armour submission 23, p 3; Lock the Gate recommended a fully independent ombudsman be created to act as an umpire in disputes between landholders, traditional owners and gas companies, Lock the Gate submission 171, p 74.
102 Origin submission 153, p 156; Santos submission 168, p 115.
103 Gasfields Commission Review; Queensland Gasfields Commission 2017a.
104 *Land Access Ombudsman Act* 2017 (Qld).

other than a creation of a separate regulator agency dealing exclusively with issues arising between pastoralists and gas companies must be considered. This is discussed further below in Section 14.12.2.

14.6.1.4 Pastoralists should not have a statutory right of veto

One way to mitigate any power imbalance between pastoralists and gas companies is to enshrine a statutory right of veto to allow pastoralists to refuse access to Pastoral Leases. The NT does not give pastoralists a statutory right of veto to petroleum companies accessing Pastoral Leases to conduct petroleum activities. Various stakeholders told the Panel that pastoralists should have a right of veto.[105] Those in support of a statutory veto right thought that it would fix the power imbalance between gas companies and pastoralists described above.[106] This is the official position of the NTCA.[107] However, this view is not universally held among pastoralists and does not occur in other jurisdictions, as **Table 14.4** below demonstrates.[108]

Table 14.4: Comparison of state protections for access to private land for exploration. Source: Lazarus Report.[109]

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

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

105 See North Star submission 155; Lock the Gate submission 171; S Bury submission 189, p 4; NTCA submission 217, p 2; NTCA submission 32, p 7; R Dunbar submission 75, p 2; C Dennison submission 5, p 2; NTCA submission 639, p 33.
106 NTCA submission 32, p 1; H Bender submission 632.
107 NTCA submission 32.
108 Terrabos Consulting submission 180, pp 8-10; MS Contracting submission 166, section 5.1; R Sullivan submission 18, p 2; North Australian Rural Management Consultants, submission 1264 (**NARMCO submission 1264**), pp 3-4.
109 Lazarus Report, pp 24-25, citing Productivity Commission 2013, p 121.

The Panel was presented with a number of arguments why pastoralists should not have the right to veto access by gas companies seeking to gain access to their land.[110] These arguments may be summarised as follows:

- granting a right to veto access by gas companies would be the same as giving pastoralists de facto ownership over shale gas reservoirs, which they do not own.[111] Furthermore, with approximately 25% of the Pastoral Leases in the Northern Territory under some form of foreign ownership, a de facto ownership right over gas resources would effectively give foreign investors the power to *"stop Territorians benefiting from [their] resources"*;[112]
- a right of veto might mean that pastoralists could negotiate excessive payments in exchange for their consent, which may not be proportional to the level of impact that the development has had on the Pastoral Lease and which may reduce the money available for other purposes, such as environmental protection or the amount of revenue that would go to the Government under any statutory royalty regime;[113]
- a veto right might have an impact on the amount of rent that pastoralists are required to pay under the Pastoral Land Act, which is calculated on the unimproved value of the land;[114]
- a veto right could have an impact on the rate of economic development in the NT because it would be *"a huge red flag to all investors to stay away from the Northern Territory, making this a clear 'no-go' place, as at any time someone can simply pull the rug from beneath your business, without the need to show cause"*;[115]
- a right of veto might place pastoralists under potential "unfair and distressing" pressure from environmental activists.[116] One stakeholder argued that there was *"substantial pressure placed on Aboriginal people from activists as they have the right of veto, with scare tactics and misinformation"*;[117]
- traditional Aboriginal owners' right to veto the grant of a petroleum exploration permit under the Land Rights Act (described in Chapter 11) does not justify giving pastoralists a similar statutory right. The policy reasons behind the exploration veto in the Land Rights Act are historical and complex. Various stakeholders pointed to the key differences between the proprietary nature of Aboriginal land under the Land Rights Act (inalienable freehold) and Pastoral Leases (transferable leasehold) to submit that pastoralists should not be afforded a veto right of the kind set out under the Land Rights Act;[118] and
- in any event, a statutory veto right ought not be necessary to negotiate fair access and compensation arrangements for pastoralists and that any power imbalance could be adequately addressed using other measures, such as, for example, a statutory requirement for all reasonable legal fees to be paid by the gas companies.[119]

The Panel agrees that there should be no statutory right of veto for pastoralists. Various submissions referred to the access agreement for CSG operations entered into between Santos, AGL, NSW Farmers, Cotton Australia and the NSW Irrigators Council in March 2014,[120] and subsequently the Country Women's Association and Dairy Connect in September 2015, as a high water mark of land access arrangements in Australia. The gas companies that are a party to that document have agreed that farmers have the right to say 'yes' or 'no' to the conduct of CSG operations on their land.[121] The signatories agreed that:

- any landholder must be allowed to freely express their views on the type of drilling operations that should or should not take place on their land without criticism, pressure, harassment or intimidation, and any landholder is at liberty to say 'yes' or 'no' to the conduct of unconventional gas activities on their land;

110 Mr Paul Brant, submission 71 (**P Brant submission 71**); Origin submission 153, p 154; Terrabos Consulting submission 180; B Sullivan submission 160; MS Contracting submission 166; R Sullivan submission 18; Oilfield Connect submission 174; Roper Resources submission 181; Santos submission 58; Australian Pipelines and Gas Association (AGPA) and Energy Networks Australia (ENA), submission 101.

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

112 Terrabos Consulting submission 180, p 8.

113 APPEA submission 215, p 94.

114 MS Contracting submission 166, p 5; see also B Sullivan submission 160, p 6; Terrabos Consulting submission 180, p 8.

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

116 Origin submission 153, p 165.

117 Terrabos Consulting submission 180, p 9.

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

119 Terrabos Consulting submission 180, p 8.

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

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

- Santos and AGL confirmed that they will respect a landholder's wishes and not enter a landholder's property to conduct drilling operations where that landholder has clearly expressed the view that this activity would be unwelcome; and
- the parties will uphold the landholder's decision to allow access for drilling activities, and not support attempts by third party groups to interfere with any agreed operations, and that the parties will condemn bullying, harassment and intimidation in relation to agreed drilling operations.

It remains open for gas companies in the NT to make a private agreement of this kind with pastoralists. The principles, while not formalised by legislation or government policy, serve a powerful normative purpose and assist in building trust and acceptance, which are necessary components of any SLO (Chapter 12). While the Panel does not formally recommend that a similar agreement be adopted in the NT, major stakeholders should contemplate endorsing a similar proposal, and aspects of the agreement ought to be reflected in improved land access arrangements (discussed in detail in Section 14.6.1.5).

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

It is the Panel's strong view that, prior to any access to a Pastoral Lease, a signed land access agreement (**statutory land access agreement**) must exist between the Pastoral Lessee and the gas company, and moreover, that the obligation to finalise such an agreement must be statutorily mandated.[122] As stated above, the Land Access Guidelines in existence in the NT are not binding.

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

If the parties do not agree and cannot finalise a land access agreement within a specified period of time, then similar to the procedure under the Native Title Act, a referral mechanism to a court or tribunal, such as NTCAT, for adjudication of the dispute must be provided.

Recommendation 14.6

That a statutory land access agreement be required by legislation.

That prior to undertaking any onshore shale gas activity on a Pastoral Lease (including but not limited to any exploration or production activity), a land access agreement must be negotiated and signed by the Pastoral Lessee and the gas company.

That breach of the land access agreement be a breach of the relevant exploration or production approval giving rise to the onshore shale gas activity being carried out on the land.

At a minimum, the statutory land access agreement should contain the following non-negotiable protections for Pastoral Lessees:[123]

- minimum notice periods, given either orally or in writing, except in the case of emergencies;
- an obligation to conduct the onshore shale gas activities in a manner that minimises disturbance to livestock and property;
- an obligation to return any gates to their original position unless advised otherwise by the Pastoral Lessee;
- an obligation to obtain the Pastoral Lessee's consent prior to the erection of any gate, fence or other barrier on the land;
- an obligation to repair any gate, fence, grid or other barrier on the land damaged or harmed by the gas company or any subcontractor engaged in onshore shale gas activity on the land;

122 NTCA submission 32, p 4.
123 See the *Farming Land Access Agreement Template for Petroleum Exploration Activities under the Petroleum and Geothermal Energy Resources Act 1967*, October 2015 (WA); Department of Natural Resources and Mines, *Land Access Code*, version 2, September 2016 (Qld); Department of Industry, Exploration code of practice: petroleum land access, December 2016 (NSW); NTCA submission 217, pp 2-4; NTCA submission 639, pp 26-27; Emanate Legal, submission 661.

- agreement upon the location and size of any camps on the land necessary to conduct the onshore shale gas activities;
- notification to the pastoral lessee as soon as practically possible of all spills, incidents, harm or damage to the Pastoral Lease and its infrastructure and operation;
- a minimum amount of compensation payable for each well drilled (see the discussion in Section 14.6.1.6 below);
- compensation for any decrease in the value of the land;[124]
- 'make good' provisions for any damage or harm to the water (surface and ground), land, infrastructure, or operation of the Pastoral Lease. The onus of proof is to be reversed so that the obligation is on the gas company to demonstrate that the harm or damage was not caused by the onshore shale gas activities;
- indemnification for any harm or damage caused by any third party engaged by the gas company or any of its sub-contractors to the water (surface and ground), land, infrastructure or operation of the Pastoral Lease;
- the provision of appropriate guarantees where the holder of the approval to carry out the relevant onshore shale gas activity is not the person or company undertaking the activities on the land;
- to the extent reasonable and permitted by law, a release by the gas company of the Pastoral Lessee for any death or personal injury to the gas company's personnel, damage to or loss of the gas company's property or consequential loss, including financial loss;
- restrictions on, and notifications of, the sale, assignment or transfer of any rights or obligation by the gas company;[125]
- no confidentiality clause unless by mutual agreement of the parties;
- payment of all reasonable legal, financial and technical fees incurred in respect of the agreement must be borne by the gas company holding the approval for the activity;
- the payment of all duties and taxes payable in respect of the land access agreement;
- clear dispute resolution mechanisms;
- clear termination mechanisms;
- agreement on access points, roads and tracks prior to entering onto the lease;
- induction training for all employees or contractors of the gas company;
- an obligation to prevent the spread of weeds, feral pests and diseases, and to ensure biosecurity;
- clear obligations with respect to rehabilitation and remediation, including the provision for the independent assessment of all rehabilitation and remediation; and
- the ability to renegotiate the land access agreement after a specified period of time, including post-exploration and pre-production.

Statutorily enacted minimum contractual protections assist in shifting any power imbalance back in favour of the Pastoral Lessee. In light of some of the adverse experiences between Pastoral Lessees and gas companies that the Panel was informed of during its trip to the Surat Basin in Queensland, such provisions are necessary. Their willing acceptance by any gas company seeking to engage in onshore shale gas activities in the NT may be seen as an aspect of the industry's acquisition of an SLO in the Territory. The experience of at least one Pastoral Lessee indicates that in the absence of such provisions, gas companies will seek to agree to minimum, not maximum, leaseholder contractual arrangements.[126] The experience of some landholders in Queensland that the Panel consulted with validates this view. Having said this, any statutory land access agreement should contain terms that ensure a minimum degree of protection to the Pastoral Lessee while nevertheless ensuring sufficient flexibility in any negotiations between the parties.

124 The activity associated with any onshore shale gas development can have a negative impact upon the value of land subject to a Pastoral Lease. This can be due to, for example, a decrease in available land for farming, increased noise levels, access arrangements and loss of income. In Queensland, gas companies are liable to compensate land owners and occupiers for any decrease in the value of land arising from their activities: *Mineral and Energy Resources (Common Provisions)* Act 2014 (Qld), s 81.

125 Origin submission 544, p 14.

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

Recommendation 14.7

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

NT pastoral enterprise.

14.6.1.6 Compensation for onshore shale gas activities occurring on Pastoral Leases

Pastoralists should, however, be financially compensated for any onshore shale gas development on their Pastoral Lease. Many submissions echoed the sentiment expressed by the Commonwealth Minister for Resources and Northern Australia, Senator the Hon Matthew Canavan, in his media announcement of 9 May 2017, regarding the Commonwealth's $28.7 million investment in east coast gas security, *"our natural resources belong to all Australians, but it's only fair that the landholders who allow access to these resources on their land receive a fair return."* [127] Many stakeholders were generally in favour of the concept that pastoralists should be compensated for the impact of exploration on their Pastoral Lease. Some, however, expressed a contrary view, concerned that the payments (or other benefits) received by Pastoral Lessees would not be shared for the public good: *"if the cattle industry was to earn a large chunk of royalty from the Northern Territory public resources, how many schools, hospitals will they build, how many roads, bridges, water storage/drainage infrastructure will they construct?"* [128]

The Panel is of the opinion that absent a right of veto, it is not unreasonable for Pastoral Lessees to seek some form of financial benefit for the inconvenience and disruption imposed upon them by the development of any onshore shale gas industry. As one stakeholder said, *"a revenue stream for a pastoralist from oil and gas could underpin their cattle business; hence they have skin in the game with the end result they are a beef and cattle producer. They would therefore be more inclined to support the industry and be proactive in assisting its development."* [129]

127 Canavan, media release, 9 May 2017.
128 Oilfield Connect submission 174, p 46; see also APPEA submission 215, p 94.
129 Terrabos Consulting submission 180, pp 7-8; R Dunbar submission 75, p 3.

There are several options for financial recompense. First, a mandatory minimum compensation payment scheme (that is, a scheme that provides the parties with the ability to negotiate a greater amount of compensation than a minimum prescribed amount[130]) calculated by reference to the number of wells drilled on the Pastoral Lease and the area of land cleared and rendered unavailable to the Pastoral Lessee. One transparent method of calculating this head of compensation is an annual fee by reference to the improved value of the land. As discussed above, reasonable fees for negotiating any statutory land access agreement should also be payable by the gas company.

Recommendation 14.8

That prior to the grant of any further exploration permits or production approvals, the Government enacts a minimum mandatory compensation scheme payable to Pastoral Lessees for all onshore shale gas production on their Pastoral Lease. Compensation should be calculated by reference to the impact that the development will have on the Pastoral Lease and the Pastoral Lessee, for example, the number of wells drilled, the value of the land (both before and after), and the area of land cleared and rendered unavailable for pastoral activities.

Consideration was given by the Panel to whether a royalties payment scheme similar to the PACE Royalties Return Scheme in SA (which provides that 10% of royalties the SA Government collects goes back to the landowners whose property overlies a new petroleum field that is brought into production[131]), or the Royalty Return Scheme proposed by the Commonwealth's Department of Industry, Innovation and Science ought to be recommended.[132] This financial compensation can confer a tangible benefit upon landowners.[133] This is important because, echoing the quote above, *"community and landowner acceptance and agreement to host onshore gas activity is essential for the timely development of onshore gas"*.[134]

Having said this, there are sound arguments against the establishment of such a scheme, not the least of which is that it is not available to native title holders, and moreover, the tenure of pastoralists, unlike the relevant landholders in SA to whom the scheme applies, is not freehold. While the NTCA supported such a scheme being implemented, some submissions were opposed to the suggestion.[135] It is for this reason that the recommendation remains for 'consideration' only.

Recommendation 14.9

That the Government considers whether a royalty payment scheme should be implemented to compensate Pastoral Lessees prior to any further production approvals being granted.

14.7 Exploration for onshore shale gas

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

14.7.1 Exploration permits

Exploration for onshore shale gas is governed by the Petroleum Act, the Petroleum Environment Regulations and the Schedule (see **Figure 14.10**). In order to explore for gas in the NT, a gas company must have an exploration permit, which is granted under the Petroleum Act. An exploration permit grants the proponent the exclusive right to explore for petroleum and to carry out such operations and execute such works as are necessary for that purpose in the exploration permit area.[136]

130 Cf NTCA submission 1199, p 2.
131 Department of Industry, Innovation and Science, submission 299 (DIIS submission 299), section 2.3, p 4.
132 DIIS submission 299, p 6 and Department of Industry, Innovation and Science, submission 459 (DIIS submission 459).
133 NTCA submission 639, p 27.
134 DIIS submission 299, section 2.3, p 4.
135 Oilfield Connect, submission 643 (**Oilfield Connect submission 643**), p 15; North Star Pastoral, submission 535 (**North Star submission 535**), p 5; NARMCO submission 1264, p 5.
136 Petroleum Act, s 29(1).

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

- a proposed technical works program for exploration of the blocks during each year of the term of the proposed exploration permit;
- evidence of the technical and financial capacity of the gas company to carry out the proposed technical works program and to comply with the Petroleum Act;
- the name of the designated operator and evidence of the technical capacity of the operator to carry out the proposed technical works program; and
- the prescribed application fee.[137]

The Minister must publish notice of the application. The notice must include the name of the gas company, identification of the land over which the application applies, and a statement that a person who has an estate or interest in that land, or in land contiguous with that land, may, within two months, lodge an objection to the granting of the permit.[138] Copies of any objections lodged in response to the notice must be provided to the gas company, and the gas company may lodge responses to those objections within 30 days.[139] If the land under application is Aboriginal land under the Land Rights Act or is subject to native title, the processes set out in Chapter 11 must be complied with before the permit can be granted. In making a decision about whether to grant or refuse the exploration permit, the Minister must considerr:

- the application;
- any objections to the grant of the exploration permit;
- any replies or other comments of the gas company;
- any other information that the Minister requested from the gas company; and
- any other matter that the Minister considers relevant to the application.[140]

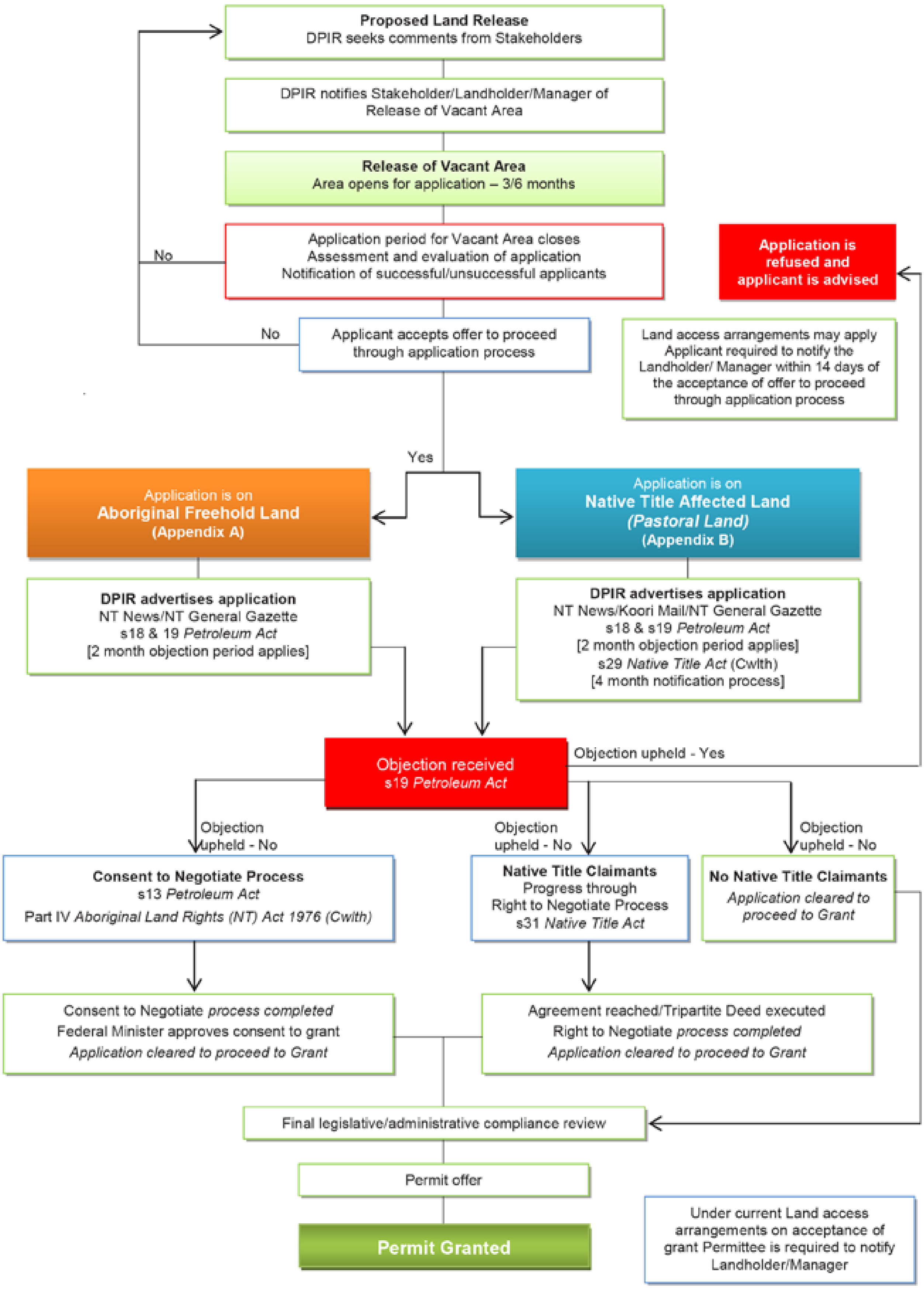
If the Minister decides to grant the exploration permit, the Minister must give the gas company a notice setting out the conditions under which such a permit would be granted and a specified date (at least 28 days after the date of the notice) after which the application will lapse if the Minister has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

If the Minister receives written acceptance of conditions from the gas company, the Minister must grant the exploration permit subject to those conditions.[141]

If the Minister decides to refuse to grant the exploration permit, the Minister must inform the gas company of this decision, provide reasons for the decision and notify the gas company that it may apply for review of the decision. The gas company may, if it is dissatisfied with a decision of the Minister to refuse to grant an exploration permit, seek a review of that decision.[142] The review is conducted by a panel appointed by the Minister, who will review the decision on its merits and make a recommendation to the Minister to confirm or revoke the decision.[143] The Minister may choose to accept or reject the panel's recommendation.

137 Currently set at $5,280; Petroleum Act, s 16.
138 Petroleum Act, s 18.
139 Petroleum Act, s 19.
140 Petroleum Act, s 20(2).
141 Petroleum Act, s 20.
142 Petroleum Act, s 57AB.
143 Petroleum Act, s 57AD.

Figure 14.10: Flowchart of the exploration permit process. Source: DPIR.[144]



144 DPIR submission 226, p 129.

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

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

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

- pay annual fees and royalties;
- conduct all operations in accordance with "good oilfield practice" and the approved technical works program; and
- cause as little disturbance as practicable to the environment and comply with any directions given by the Minister.[145]

14.7.1.1 Objections to applications

As described above, a person who has an estate or interest in the land the subject of an exploration permit application, or in land contiguous with that land, may lodge an objection to the granting of the permit, which the gas company can respond to, and which the Minister must take into account when making a decision to grant or to refuse to grant the title.[146]

However, other landholders in the region, communities, experts, and interest groups (such as environmental groups) do not have the ability to object or provide material for the Minister's consideration in making a decision on the application. This limits the Minister's access to information, which can lead to uninformed and inferior decision-making. Allowing access to, and consideration of, a greater range of views and information facilitates better decision-making, including in relation to any conditions to be placed on the title. It also facilitates transparency and accountability and encourages greater faith in the decision-making process. In short, it assists in establishing an SLO. This occurs in NSW, where public comment in relation to applications for coal and petroleum exploration titles (including CSG) is permitted.[147] For the purposes of transparency and accountability, all objections should be made public.

Recommendation 14.10

That any person may lodge an objection to the proposed grant of an exploration permit within a prescribed time limit.

That all objections received by the Minister must be published online.

That the Minister must, in determining whether to grant or refuse the application, take into account any objection received.

14.7.1.2 Principles of ESD to be applied

Many submissions to the Panel argued that, given the apparent scientific uncertainty associated with the nature, extent and management of the environmental risks associated with hydraulic fracturing, the regulatory framework should apply the principles of ESD, and in particular, the precautionary principle, to prevent any onshore shale gas activity.[148] 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."[149]*

145 Petroleum Act, s 58.
146 Petroleum Act, ss 18-20.
147 NSW Public Comment Policy.
148 EDO submission 213, p 10; S Bury submission 189, p 2; M Haswell submission 183, pp 14, 17; PHAA submission 107, p 4; H Bender submission 144, pp 54-55. For example, the EDO submitted that there was enough uncertainty surrounding the environmental impacts of hydraulic fracturing to justify the application of the precautionary principle: "the overwhelming impression that [the EDO] has gleaned from the material is that there is a great deal of uncertainty with respect to the impacts of [hydraulic fracturing].": EDO submission 213, p 10; EDO submission 635, p 40.
149 1992 Rio Declaration, Principle 15. See also the useful discussion of the principle in the Newfoundland and Labrador Report, pp 92-93.

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

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

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

In *Telstra Corporation Ltd v Hornsby Shire Council,* Preston J of the Land and Environment Court gave a full explanation of the ambit of the principle and conditions precedent to its application.[150] The scope of the principle, and its application can be modified by Parliament. The principles of ESD are defined in the Petroleum Environment Regulations as follows:

> *"a) decision-making processes should effectively integrate both long-term and short-term economic, environmental, social and equitable considerations;*
> *b) if there are threats of serious or irreversible environmental damage, lack of full scientific certainty should not be used as a reason for postponing measures to prevent environmental degradation;*
> *c)the principle of inter-generational equity - that the present generation should ensure that the health, diversity and productivity of the environment is maintained or enhanced for the benefit of future generations;*
> *d) the conservation of biological diversity and ecological integrity should be a fundamental consideration in decision-making; and*
> *e) improved valuation, pricing and incentive mechanisms should be promoted."* [151]

One of the objects of the Petroleum Environment Regulations is *"to ensure that regulated activities are carried out in a manner consistent with the principles of ecologically sustainable development"*.[152] The Minister is required to take into account the principles of ESD in making decisions in relation to approval of EMPs under the Regulations, but not under the Petroleum Act. This is not sufficient in the Panel's opinion. All of the principles of ESD, including the precautionary principle, should be taken into account and applied by decision-makers at all levels of decision-making in respect of any onshore shale gas industry.

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

> *"While somewhat beneficial, for the precautionary principle to actually achieve what it is intended to, it must be 'operationalized' in some way. One of the criticisms levelled at the precautionary principle is that it has simply become part of legislative decision-making process, a tick a box, as opposed to a rule that produces a particular outcome. The [Petroleum Environment] Regulations are an example of legislation that makes the precautionary principle one of a number of boxes that must be ticked during decision making. In the case of the Regulations, the Minister must tick the precautionary principle box (by taking into account principles of ESD) before approving an Environmental Plan under r 9(2) of the Regulations. The Regulations fail to meaningfully operationalize the principle."* [153]

150 *Telstra Corporation Ltd v Hornsby Shire Council* (2006) 67 NSWLR 256; [2006] NSWLEC 133 at [125]-[186].
151 Petroleum Environment Regulations, cl 4.
152 Petroleum Environment Regulations, cl 2(a).
153 EDO submission 213, p 12; S Bury submission 189, p 2; M Haswell submission 183, p 14.

One way in which the principles of ESD, including the precautionary principle, can be 'operationalised' within the regulatory framework is by requiring the decision-maker to take the principles into account and to apply them when making decisions about the onshore shale gas industry. This is particularly important in respect of decisions such as whether or not to grant or refuse an exploration permit, retention licence, or production licence under the Petroleum Act.

Recommendation 14.11

That the Petroleum Act be amended to make the principles of ESD a mandatory relevant consideration for any decision made under that Act in relation to any onshore shale gas industry.

That the principles of ESD must be taken into account and applied by a decision-maker in respect of all decisions concerning any onshore shale gas industry.

14.7.1.3 Consideration of a 'fit and proper person' test

A gas company must submit, as part of its application for an exploration permit, evidence of its technical and financial capacity to carry out the proposed works program and to comply with the Petroleum Act. The Minister is required to consider this information as part of his or her consideration of any application.[154] However, there is currently no requirement to include information about the gas company's history of regulatory compliance or history of environmental management. This history is relevant to the likelihood of the gas company complying with the Petroleum Act and the works program.

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

> *"in its oral submission to the Inquiry, APPEA's Matt Doman, noted, 'there are many companies that don't have any oil or gas expertise or experience that hold petroleum exploration licences'" and that "given the heavy reliance placed on operators to do the right thing in the NT, particularly with an objective based set of regulations, this is a major concern."*[155]

Taking into account whether a gas company is a fit and proper person is not novel in the petroleum industry. In NSW, for example, the relevant Minister may take into account whether a gas operator is a fit and proper person to hold a licence when making a decision in relation to the grant of a petroleum title (including whether or not to grant, transfer, cancel, or restrict operations under a petroleum title).[156] In determining whether the company or person is a fit and proper person, the Minister may take a number of matters into account, including:

- whether the person, or in the case of a body corporate, a director of the body corporate or of a related body corporate, has environmental compliance or criminal conduct issues;
- the person's, or in the case of a body corporate, a director of the body corporate or of a related body corporate, record of compliance with relevant environmental and other legislation;
- whether, in the opinion of the Minister, the person or director is not of good repute or not of good character; or
- whether the person or director has demonstrated to the Minister the financial capacity to comply with any obligations under the petroleum title.[157]

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

> *"(a) the person's history in relation to environmental matters; and*
>
> *(b) if the person is a body corporate—the history of its executive officers in relation to environmental matters; and*
>
> *(c) if the person is a body corporate that is a subsidiary of another body or company (the parent body)—the history in relation to environmental matters of the parent body and its executive officers."*[158]

154 Petroleum Act, s 20(2)(a).
155 EDO submission 213, p 37.
156 *Petroleum (Onshore) Act (NSW)*, s 24A.
157 *Petroleum (Onshore)* Act (NSW), s 24A(2).
158 EPBC Act, s 136(4).

There are also a number of Commonwealth and State schemes that require decision-makers to take into account whether applicants for licences for specialised activities are fit and proper persons to hold the relevant licence.[159] In Victoria, the *Mineral Resources (Sustainable Development)* Act 1990 (Vic) requires that, prior to granting an exploration permit with respect to mineral resources, the Minister must be satisfied that the applicant is a fit and proper person to hold an exploration licence.[160] This includes, but is not limited to, taking into account whether the applicant or an associate of the applicant has breached that Act in the past, or has been convicted of an offence related to fraud or dishonesty.[161]

The Panel therefore considers it to be a reasonable measure to require the Minister to determine whether a gas company is a fit and proper person to conduct any onshore shale gas activities in the NT. This consideration should not be limited to the entity seeking to conduct the onshore shale gas activities, or to the entity's compliance history in the NT. Rather, it should encompass all related entities and extend to both domestic and overseas compliance history.

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

Finally, failure to disclose, upon request, matters relevant to determining whether or not a person or company is a fit and proper person should attract sanction under the Petroleum Act.[162]

Recommendation 14.12

That the Minister must not grant any further exploration permits unless satisfied that the applicant (including any related entity) is a fit and proper person, taking into account, among other things, the applicant's environmental history and history of compliance with the Petroleum Act and any other relevant legislation both domestically and overseas.

That failure to disclose a matter upon request relevant to the determination of whether an applicant is a fit and proper person will result in civil and/or criminal sanctions under the Petroleum Act.

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

14.7.2 Financial assurances

14.7.2.1 Rehabilitation bonds and securities

Financial assurance programs ensure that adequate resources are available to remediate a site in the event that a gas company fails to meet its legal obligations. The purpose of a financial assurance program is that the costs of rehabilitation are not passed on to the Government, and therefore, taxpayers.[163]

A bond or security is an amount of money that a gas company lodges with the Government to guarantee that certain obligations (usually, in this context, in relation to rehabilitation or remediation) are met. In the event that these obligations are not met, the Government uses the money for these purposes. In the NT gas companies are currently required to provide two securities. The first is a security in the amount of $10,000 to secure the gas company's compliance with the Act and conditions on the exploration permit under s 79 of the Petroleum Act.[164] It is not clear which provisions of the Act or conditions of the exploration permit the $10,000 is intended to secure. The second is an *"environmental rehabilitation security"*, that DPIR requires to be lodged "prior to the approval of any regulated petroleum activity" (there is no statutory requirement for this though).[165] As to the method used to calculate the security, DPIR told the Panel that it requires gas companies to fill in a spreadsheet *"with detailed questions and*

159 For example, *Ozone Protection and Synthetic Greenhouse Gas Management Act* (Cth), s 16; Mining Act 1992 (NSW), s 380A; *Protection of the Environment Operations Act 1997* (NSW), s 83.
160 *Mineral Resources (Sustainable Development) Act 1990* (Vic), s 15(6)(a).
161 *Mineral Resources (Sustainable Development) Act 1990* (Vic), s 16(1).
162 See, for example, s 489 of the EPBC Act.
163 STRONGER Guidelines, p 33.
164 DPIR submission 226, p 24; Department of Primary Industry and Resources, submission 295 (**DPIR submission 295**), p 1
165 DPIR submission 295, p 1; DPIR submission 226, p 30.

calculations to determine actual clean-up cost." [166] The gas company's calculation is subsequently verified, or altered, by DPIR officers, the bond is paid, and the activity proceeds.[167] The amount of the environmental rehabilitation security is not currently publicly disclosed, (although it should be noted that the Government has recently changed its policy with respect to mining securities - not petroleum securities - and these are now publicly disclosed).[168]

Rehabilitation securities for extractive industries have been an issue in a number of Australian jurisdictions, many proving to be inadequate to meet the actual cost of rehabilitation many years later. A recent review of Queensland's financial assurance framework for resource exploration and extraction estimated that it cost Queensland $73 million over a five-year period due to that State having underestimated the need for rehabilitation.[169] The review cites an example of an insolvent company where the security held was $3.6 million whereas the estimated rehabilitation cost was $80 million.

In NSW, the Auditor-General undertook a performance audit of mining rehabilitation security deposits required by the Department of Planning and Environment to assess whether that Department had maintained adequate security deposits to cover the liabilities associated with mine closures, including rehabilitation.[170] The 2017 *NSW Auditor-General's Report to Parliament: Mining Rehabilitation Security Deposits* concluded that the securities held were *"unlikely to cover the full cost of rehabilitation on each mine site."* [171] The rehabilitation cost calculation tool the Department had used had a number of deficiencies, including that several activities required to properly effect closure were not included and others had been underestimated, that the costs and allowances in the tool had not been updated since 2013, and that the Department could not provide the basis for the rates and allowances in the tool.

In Queensland, these issues have been recently examined. In April 2017, the Queensland government published Better Mine Rehabilitation for Queensland after it was found that only 9% of land disturbed by mining in that state had been rehabilitated and that the government was owed $7.3 billion in outstanding mine rehabilitation liability. As a result, the Mineral and Energy Resources (Financial Provisioning) Bill 2017 was introduced in the Queensland Parliament in October 2017. Although it lapsed as a consequence of the election in that state, it has since been reintroduced. The Bill provides for, among other things, Progressive Rehabilitation and Closure Plans and seeks to include community consultation in the formulation of such plans.[172]

The importance of an appropriate and transparent rehabilitation security or bond was raised many times in submissions and during community consultations. The Panel recommends that, in consultation with the community and stakeholders, the Government develops a transparent financial assurance framework for the onshore shale gas industry.[173] The framework must clearly identify the types of onshore shale gas activities that require a financial assurance and clearly set out how each security is calculated.[174] The quantum of all securities lodged under the Petroleum Act, including the methodology used to calculate the security and the purpose of the security, must be publicly disclosed.[175]

Recommendation 14.13

That prior to the grant of any further production approvals, the Government develops and implements a financial assurance framework for the onshore shale gas industry that:

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

166 DPIR submission 295, p 2.
167 DPIR submission 295, p 2.
168 DPIR submission 295, p 2.
169 Queensland Financial Assurance Review, p 1.
170 Queensland Financial Assurance Review, p 1.
171 NSW Auditor General 2017, p 3. A similar discussion paper has been released for public comment by the Department of Planning and Environment (NSW Department of Planning and Environment 2017).
172 Covington et al. 2018.
173 STRONGER Guidelines, p 67.
174 STRONGER Guidelines, p 34.
175 Vowles, media release, 12 September 2017; DPIR Mining securities.

14.7.2.2 Abandoned well fund

The Panel heard many concerns around the long-term management and safety of onshore shale gas wells, particularly in circumstances where the gas company has gone into liquidation or where the rehabilitation security is not sufficient to cover the costs of rehabilitation.[176] In these circumstances, it is the Government that bears the financial cost associated with remediating any abandoned wells that may not have been properly decommissioned. The Government must ensure that there is adequate funding available so that it can undertake any assessment, plugging, closure, decommissioning, or other remedy required.[177] The NLC submitted that any framework regulating an onshore shale gas industry must consider:

> *"the potential for future environmental impacts caused by abandoned wells and associated infrastructure, where responsibility for them ultimately rests, and how the costs associated with their maintenance will be managed."*[178]

Ms Charmaine Roth observed that,

> *"the costs of continuous monitoring of air and groundwater around each and every abandoned well, along with the ongoing repairs and any possible future cleanup, should not be financed from the public purse. Companies that are set to make profits from extensive numbers of wells which have an estimated approximate production life of twenty years' maximum, should not expect the taxpayer to be financing their perpetual care."*[179]

The Panel agrees with this position.

The issue is recognised in other jurisdictions where petroleum activities occur, for example, in Texas, USA and Alberta, Canada. Regulators in these jurisdictions impose a levy on operators, which is placed in a fund that pays for the remediation of, and other costs associated with, abandoned sites. For instance, Texas has a program in place to plug wells and clean up abandoned oilfield sites using funds collected from operators as part of their permit applications, statutory fees and bond fees.[180] The regulator publishes quarterly reports on the expenditure and details of the sites that it has remediated and makes these reports available to the public.[181] Similarly, Alberta has an abandoned well fund, the purpose of which is to pay for:

- suspension costs, abandonment costs and related reclamation costs in respect of orphan wells, facilities, facility sites and well sites;
- costs incurred in pursuing reimbursement for the above costs from the person responsible for paying them; and
- any other costs directly related to the operations of the AER in respect of the fund.[182]

The fund is funded by a levy prescribed by the AER, which is payable annually.[183] The levy is $15 million CND for the industry, with each licensee or approval holder paying an amount proportionate to their deemed liabilities as a percentage of the total deemed liability of the industry.[184] Similarly, in New Zealand operators pay a levy into a fund that can be used to remediate leaks from abandoned wells.[185]

Although no fund exists in Australia in relation to the onshore shale gas industry, it does with respect to other extractive industries. In 2013 the NT introduced an annual levy on mining securities to be used to address the rehabilitation of legacy mines. The levy is 1% of the total calculated rehabilitation cost of each operation authorised under the *Mining Management Act 2001 (NT)*. The cost to business is offset by a 10% discount on the security payable under that Act.

176 Ms Charmaine Roth, submission 457 (**C Roth submission 457**), pp 7, 10; North Star Pastoral, submission 447 (**North Star submission 447**), p 7; Lock the Gate submission 437, pp 11, 13; Dr Errol Lawson, submission 369 (**E Lawson submission 369**), p 7; United Voice Northern Territory Branch, submission 314 (**United Voice submission 314**), pp 4, 6.
177 STRONGER Guidelines, p 64; EDO submission 635, p 4.
178 NLC submission 214, p 41.
179 C Roth submission 457, p 10.
180 Texas Railroad Commission 2016.
181 Reports on site remediation are available at: http://www.rrc.state.tx.us/oil-gas/environmental-cleanup-programs/oil-gas-regulation-and-cleanup-fund/.
182 *Oil and Gas Conservation Act (Alberta)*, s 70.
183 *Oil and Gas Conservation Act (Alberta)*, ss 73-74.
184 AER 2016.
185 Government of Saskatchewan 2017.

WA has a *Mining Rehabilitation Fund*, established in 2012,[186] towards which tenement holders under the *Mining Act 1978* (WA) are required to make annual contributions based on the level and type of disturbance and the amount of rehabilitation required for each tenement.

These funds are important where a jurisdiction has a legacy of abandoned sites with no known owner.[187] The 2014 Hawke Report noted as follows:

> *"the possibility that wells may leak and require significant remedial action decades after they are decommissioned presents a significant challenge for government policy and regulation. Even with open-ended liability of operators for abandoned wells, it may be difficult to enforce remediation decades after a well is decommissioned (analogous with the burden that government has often adopted in the remediation of legacy mine sites, in the NT and elsewhere)... This issue may potentially be addressed through some form of common liability or rehabilitation fund, one model for which is the WA Mining Rehabilitation Fund."*[188]

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

> *"In many cases, the exploration leases will change hands and so there is some uncertainty about financial responsibility in the unlikely event that one of these "decommissioned" wells were to lose integrity leading to an environmental incident. DME is currently in the very early stages of investigating the possible introduction of an 'Abandoned Wells Legacy Fund'. This fund would build over time and be held by the NT Government. A possible model is one where operators contribute to the Fund in exchange for some reduction of the Environment Rehabilitation Bond. If adopted, the initiative will need to be legislated"* [189]

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

Recommendation 14.14

That prior to the grant of any further production approvals, the Government imposes a non-refundable levy for the long-term monitoring, management and remediation of abandoned onshore shale gas wells in the NT.

14.7.3 Environmental and operational approvals

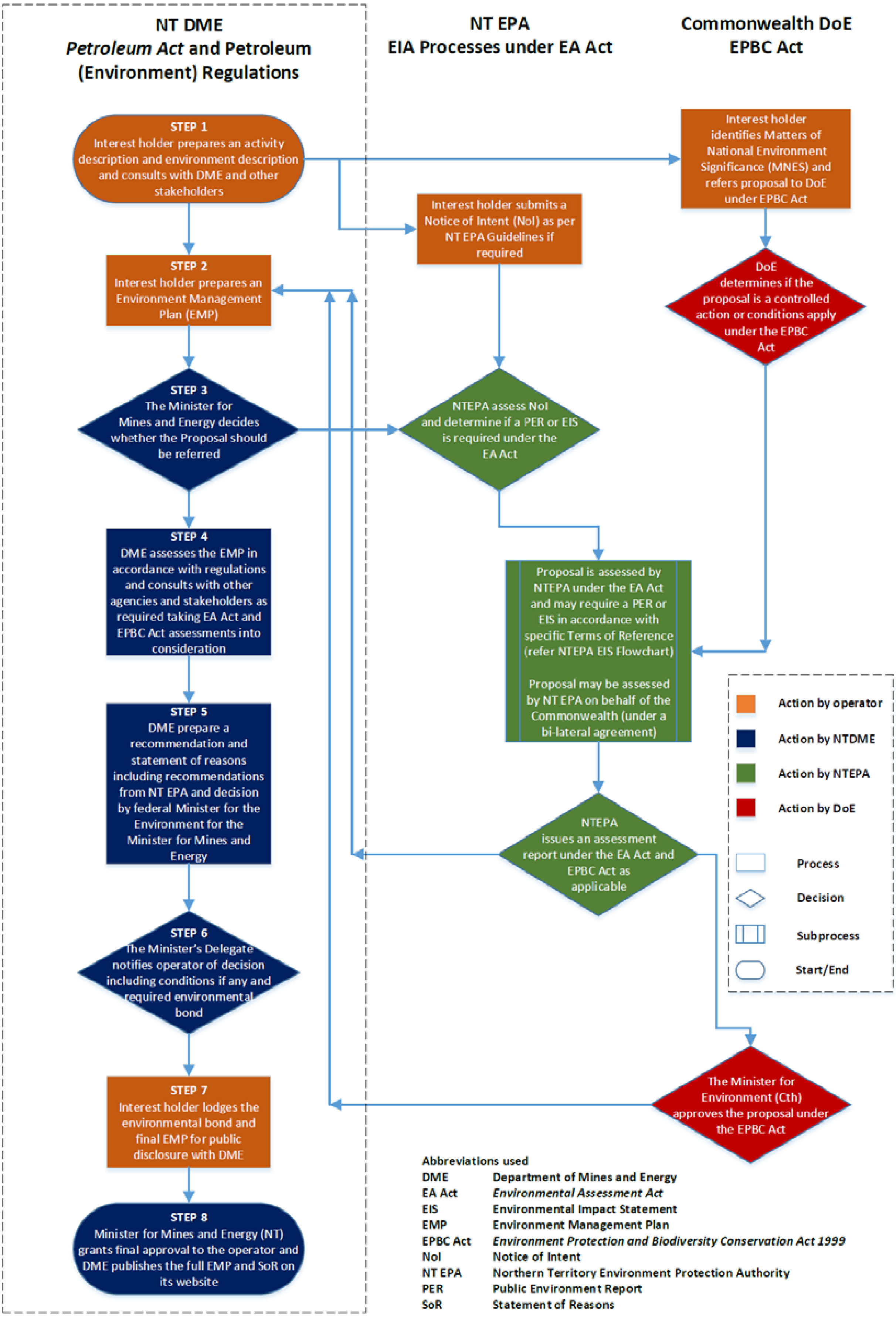
The grant of an exploration permit does not, by itself, grant a gas company the right to undertake activities such as drilling or hydraulically fracturing a petroleum well.[190] Other approvals are required, including approvals under the Petroleum Act, environmental approvals under the Petroleum Environment Regulations, and approvals under the Schedule.

DPIR submitted that an overarching 'Petroleum Project Approval' is required before any activity can commence in respect of a granted exploration,[191] but the Panel could not find any legislative basis for this assertion. The concept of an overarching project approval appears in the *Well Drilling, Work-over or Stimulation Application Assessment Process*[192] and *Well Drilling, Work- over or Stimulation Activities Applications Guidelines*, but the contents of these documents are not enforceable. Rather, depending on the type of activity proposed, various plans and other materials must be submitted, each of which must be separately approved before an activity can proceed. There is no single overarching statutory project approval.

The process for obtaining environmental and operational approvals is shown in **Figure 14.11**.

186 Under the Mining Rehabilitation Fund Act 2012 (WA).
187 DPIR submission 424, p 4.
188 2014 Hawke Report, p 132.
189 NT DME 2016, pp 8-9.
190 DPIR submission 226, p 28.
191 DPIR submission 226, p 28.
192 DPIR submission 226, p 187.

Figure 14.11: The process for obtaining EMP approval and operational approvals for exploration. Source: DPIR



14.7.3.1 Environmental approvals

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

With very few exceptions, any activity that will have an adverse environmental impact must be approved by the Minister for Resources. This is the case regardless of how significant, or not, the potential environmental impact of that activity may be (as noted in Section 14.4.2, only activities that will have a *"significant"* environmental impact are assessed under the EAA). If an activity is undertaken without an approval in place, it will constitute a breach of the Petroleum Environment Regulations and penalties will apply.[193] The only activities that do not require an approval under the Regulations are:

- taking water samples;
- taking rock samples without the use of heavy machinery;
- walking or driving on the permit area to do either of the above activities; and
- airborne surveys.[194]

The Petroleum Environment Regulations expressly provide that drilling, hydraulic fracturing, and the release of any contaminant or waste material must be approved by the Minister before they can take place.[195]

If an activity will have an environmental impact and does not fall into one of the exceptions above then an approved EMP must be in place before the activity can commence. The process for getting the approved EMP in place is as follows. First, a gas company must prepare a draft EMP. The draft EMP must contain certain information, including an identification of all of the environmental risks associated with the activity and the ways by which the gas company will reduce those risks to a level of risk that is both *"acceptable"* and ALARP.[196]

Second, the gas company must consult with all *"stakeholders"* (see also Section 14.6.1.2). A *"stakeholder"* is defined in the Petroleum Environment Regulations as any person whose rights or activities may be directly affected by the environmental impacts of the proposed activity or an agent or representative of such a person.[197] The regulations do not prescribe who is a *"stakeholder"*; however, pastoralists and Land Councils would arguably be included in the definition, providing them with an opportunity to comment on the proposed plan (and have those comments considered by the Minister).[198] Section 11.3.5 and ***Recommendation 11.2*** include a discussion on how the regulatory framework can be further amended to protect Aboriginal culture, including sites, and how traditional knowledge can be integrated into the environmental assessment and approval process.[199] The gas company must give information to stakeholders about the activity and the possible risks associated with the activity.[200] The views of all stakeholders, and the gas company's response to those views, must be included in the draft EMP that is submitted to the Minister for Resources for assessment.[201] Stakeholders are not able to comment on the draft EMP once it has been submitted to the Minister, and stakeholders will not see the final EMP until it has been approved by the Minister and published online.

The Energy Division in DPIR assesses the draft EMP. DPIR uses an online explanatory guide entitled *Petroleum (Environment) Regulations - An Explanatory Guide 6 July 2016,*[202] an internal guideline, and an internal checklist to access the draft EMP.[203] None of the guidelines or checklists are legally enforceable, which means that a gas company's non-compliance with these documents is not lawful grounds for the Minister for Resources to refuse to approve a draft EMP. The Minister can only refuse to approve an EMP if the approval criteria set out in the Petroleum Environment Regulations are not met.

193 Petroleum Environment Regulations, cl 30.
194 Petroleum Environment Regulations, cl 5.
195 Petroleum Environment Regulations, cl 5.
196 Petroleum Environment Regulations, cl 9 and Sch 1.
197 Petroleum Environment Regulations, cl 7(3).
198 NLC submission 647, p 30.
199 NLC submission 647, p 32.
200 Petroleum Environment Regulations, cl 7(2).
201 Petroleum Environment Regulations, Sch 1, Pt 3.
202 Petroleum Environment Regulations Guide.
203 DPIR submission 226, pp 195-220.

If the Minister is satisfied that the approval criteria have been met, then the Minister must approve the EMP.[204] The Minister must be satisfied that the implementation of the EMP will reduce all environmental risks and impacts associated with the activity to a level that is both *"acceptable"* and ALARP. This requirement mirrors petroleum environmental laws in WA[205] and in the Commonwealth in relation to offshore waters.[206] Some stakeholders argued that the terms *"acceptable"* and ALARP should be defined in legislation,[207] but the Panel is not convinced that this is necessary to ensure that development occurs in a manner consistent with the principles of ESD. The Minister must decide what an *"acceptable"* level of risk is from time to time for a certain activity after taking into account the principles of ESD as well as any recommendations made by other regulatory bodies, such as the EPA. The meaning of an *"acceptable"* level of risk is a fluid concept and will change over time as community attitudes change, new technologies evolve, and international and domestic health standards for drinking water, noise and emissions change (see Chapter 4 for a discussion about *'acceptability'*).

In making a determination as to *'acceptability'*, the Minister must consider two matters. First, the principles of ESD,[208] including the precautionary principle. Second, any recommendations from the EPA but only if the EPA has assessed the EMP under the EAA. If no assessment is required under the EAA, then the Minister for Resources is not required to consider the EPA's recommendations concerning the draft EMP. To reiterate, activity will only be formally assessed under the EAA if it will have a *"significant"* environmental impact, and to date, no exploration petroleum activities have been deemed *"significant"*, and therefore, formally assessed by the EPA under the EAA.

The Minister for Resources can place enforceable conditions on environmental approvals, and those conditions must be complied with notwithstanding anything to the contrary in the EMP.[209] The ability to place enforceable environmental conditions on an environmental approval was considered by Dr Hawke to be an effective way to operationalise the principles ESD.[210] It is also an effective way to ensure that certain minimum standards or requirements are met.[211] For example, it is possible for the Minister to require that a gas company complies with specific codes of practice as a condition of an approval.

The Panel's view is that greater transparency must be afforded to the process outlined above. The broader community does not have an opportunity to provide input into draft EMPs. The first time that the public sees an EMP (except those persons that must be consulted because they are *stakeholders"* directly affected by the proposed activity)[212] is after the EMP has been approved by the Minister for Resources.[213] There is also no opportunity for "*stakeholders"* to see the version of the draft EMP that a gas company submits to the Minister. Stakeholders also do not know if or how their comments and feedback have been incorporated into the plan. The public and stakeholders only see the approved EMP after the Minister has assessed and approved it.

To increase transparency and accountability, the community must be given an opportunity to comment on draft EMPs for any onshore shale gas activity.[214] The timeframe for public comment should be set out clearly in legislation.[215] The consultation must be taken into account by the Minister in assessing and approving the EMP.

Recommendation 14.15

That prior to the grant of any further exploration approvals, all draft EMPs for hydraulic fracturing must be published in print and online and available for public comment prior to Ministerial approval.

That all comments made on draft EMPs must be published online.

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

204 Petroleum Environment Regulations, cl 9.
205 Petroleum and Geothermal Energy Resources (Environment) Regulations 2012 (WA), cl 11(1)(b)-(c).
206 Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 (Cth), cl 11(1)(b) -(c).
207 NLC submission 647, p 33.
208 Petroleum Environment Regulations, cl 9(2).
209 Petroleum Environment Regulations, cl 11(2)(a)(i).
210 2015 Hawke Report, pp xi and 8.
211 EDO submission 635, p 4.
212 Petroleum Environment Regulations, cl 7(3).
213 Petroleum Environment Regulations, cl 24.
214 EDO submission 635, p 4.
215 Origin submission 544, p 15.

Once an EMP is approved, it is published together with the Minister's statement of reasons for approving the EMP.[216] The Petroleum Environment Regulations do not specify where or how the approved EMP and the statement of reasons are published. To date DPIR has published the approved plans on the Department's website. The Minister's statement of reasons must explain how the principles of ESD have been taken into account and how the Minister took into account the EPA's recommendations (if any).[217] The Minister must also publish all reports provided to the Minister on environmental matters relevant to the EMP.[218] This includes all baseline and monitoring data.[219]

While this provides a considerable level of transparency, it can be improved. For example, the Petroleum Environment Regulations require gas companies to give notice to DPIR if a *"reportable incident"* occurs.[220] A *"reportable incident"* is an incident arising from an approved activity that causes material or serious environmental harm (*"material"* and *"serious environmental harm"* is means harm that is not trivial or negligible). It is not clear whether reports about reportable incidents are required to be publicly disclosed. The Panel's view is that all incident reports must be made publicly available to ensure that the community and other stakeholders *"can be assured that there [are] no long term or widespread environmental impacts and so that similar incidents do not occur in the future."* [221]

Recommendation 14.16

That prior to the grant of any further exploration approvals, all notices and reports of environmental incidents, including reports about reportable incidents under the Petroleum Environment Regulations, must be published immediately upon notification in print and online.

14.7.3.2 Operational approvals

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

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

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

As stated above, the Schedule is not legislation and does not have force. It is effectively a series of standing directions.[222] When the Minister for Resources issues a permit to a gas company (see Section 14.7.1), the Minister also gives the gas company a direction under the Petroleum Act that the company must comply with the terms of the Schedule. If a gas company does not comply with a provision of the Schedule, the Minister can impose a standard penalty,[223] cancel the permit,[224] and if necessary, the Minister can *"do all or any of the things required by the [Schedule] to be done."* [225]

The Schedule purports to prescribe matters that are usually described as 'operational' and that are usually found in primary and secondary legislation.[226] For example, the Schedule regulates seismic surveys and well activities, including drilling programs and hydraulic fracturing. DPIR describes the Schedule as a document that, *"includes detailed requirements for the management*

216 Petroleum Environment Regulations, cl 24.
217 Petroleum Environment Regulations, cl 12(3).
218 Petroleum Environment Regulations, cl 25.
219 Petroleum Environment Regulations, cl 25.
220 Petroleum Environment Regulations, cl 33(1); DPIR submission 226, pp 245-249
221 NLC submission 214, p 11.
222 Petroleum Act, s 71.
223 Petroleum Act, s 71(3).
224 Petroleum Act, s 74(1)(c).
225 Petroleum Act, s 72(1).
226 2012 Hunter Report, p 30.

of seismic survey, drilling, completing and testing of wells including hydraulic fracturing. It also sets out requirements for the reporting of incidents, daily reporting requirements and data collection and transfer". [227]

In other Australian jurisdictions, these activities are regulated by legislation.[228] See, for example, WA's P*etroleum and Geothermal Energy Resources (Resource and Management Administration) Regulations 2015 and the Commonwealth's Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011* (which regulate seismic surveys and well activities in onshore WA and offshore respectively).

The Schedule requires specific petroleum activities to be approved prior to commencement. Activities that require approval include hydraulic fracturing,[229] drilling[230] and seismic surveys.[231] The requirements of the Schedule for drilling and hydraulic fracturing are set out in Chapter 5. There are other petroleum activities that do not require a Ministerial approval but which must conform to the requirements of the Schedule. For example, the abandonment of a well does not require an approval from the Minister, but the Schedule requires that a cement plug be placed in the well in zones 100 metres above and 50 metres below any petroleum or water.[232] It is not clear to the Panel why these requirements are in place and whether or not they reflect leading practice standards.

The use of the Schedule to regulate drilling activities and hydraulic fracturing is problematic. The Schedule has not been drafted in accordance with legislative drafting principles. It uses industry jargon, which is not always defined and which creates issues of enforceability. The Schedule is not always clear about the information that must be submitted to the Minister for the purposes of obtaining an approval, the timeframe within which the Minister must make a decision, or the matters the Minister must consider when making a decision (for example, approved spill contingency plans must be complied with, but there is no process set out for what must be included in a plan or how the plan is approved). The Schedule also duplicates provisions in work health and safety legislation and other legislation.[233] The Schedule purports to provide powers to inspectors, however, this cannot be effected by Ministerial direction, which is how the Schedule is enforced. The Schedule offers the community no certainty that industry will comply with leading practice standards when it undertakes petroleum activities. And DPIR relies on guidelines, which are unenforceable, to fill in the gaps where the Schedule is deficient.

DPIR noted the limitations of the Schedule in its submission to the Panel, namely, that *"the Schedule, which is rule-based, is intensive on regulators and proponents and lacks the flexibility to regulate the technologically complex and evolving petroleum industry."* [234]

DPIR intends to replace the Schedule with resource management and administration regulations of the kind in WA and for Commonwealth offshore waters,[235] however, this has not yet occurred. The Schedule must be repealed and replaced with enforceable and objective-based resource management and administration regulations as soon as possible. The regulations must be supported by enforceable codes that clarify exactly what is expected of the industry.[236]

Recommendation 14.17

That prior to the grant of any further production approvals, the Schedule be repealed and replaced with legislation to regulate land clearing, seismic surveys, well construction, drilling, hydraulic fracturing, and well decommissioning and abandonment.

14.7.4 Minimum standards and codes of practice

The NT is moving away from prescriptive regulation towards *"risk-based"* and *"outcome-focussed governance".*[237] The latter is generally regarded as a more effective and efficient method of

227 DPIR submission 226, p 11.
228 See, for example, Pt 2 of the Petroleum and Geothermal Energy Resources (Resource and Management Administration) Regulations 2015 (WA), which regulates seismic surveys and Pt 3 manages well activities; Pt 6 of the Petroleum and Geothermal Energy Regulations 2013 (SA) regulates "operational issues", including geophysical surveys (Div 1) and drilling (Div 2).
229 Schedule, cl 342(1).
230 Schedule, cl 301(1).
231 Schedule, cl 503(1).
232 Schedule, cl 329(1).
233 See, for example, cls 201(4) and 501.
234 DPIR submission, p 38.
235 DPIR submission 226, p 12; DPIR submission 492, p 6.
236 2012 Hunter Report, pp 6, 31.
237 DPIR submission 226, p 38.

regulation that encourages innovation, flexibility and leading practice.[238] However, the corollary to the flexibility afforded by risk-based, outcome-focussed regulation is a lack of clarity and certainty about how a particular activity should be regulated. For example, as discussed in Section 14.7.3.1, the Petroleum Environment Regulations require a gas company to demonstrate that it will reduce environmental risks and impacts to levels that are *"acceptable"* and ALARP, but the meaning of these terms is equivocal. Similar concerns exist in relation to with the term *"good oilfield practice"*, which appears in the Petroleum Act. Gas companies must, *"conduct all operations in relation to the exploration permit…with reasonable diligence, in particular in accordance with good oilfield practice; and the approved technical works programme."* [239] The term *"good oilfield practice"* has been criticised in the NT for being *"broad, vague and, given the vast variation in oilfield practices around the world lacks any type of certainty and would be difficult to enforce."* [240] The nebulousness of the term was found to have contributed to the regulatory failure under investigation in the Montara Commission of Inquiry:

> *"the current regulatory regime has effectively eliminated all levels of prescription in relation to well integrity, defaulting to an undefined standard of 'good oilfield practice'. This has left regulators with an ambiguous standard to rely on when assessing applications submitted by operators. The Inquiry considers that this ambiguity is likely to have contributed to very basic requirements of well integrity being overlooked by both PTTEPAA and the NT DoR. This suggests that the pendulum may have swung too far away from prescriptive standards."* [241]

In that Inquiry, it was recommended that the requirement of *"good oilfield practice"* be supplemented by the inclusion of minimum compliance standards.[242] Various stakeholders support the proposition that a level of prescription should form part of the regulatory framework to ensure that all stakeholders understand exactly what is required.[243] The EDO submitted that in the NT, a combination of both objective and prescriptive regulation is appropriate. It stated that prescriptive standards:

- create certainty and a clear standard of behaviour that must be met;
- are easier to apply consistently; and
- are easier to enforce.[244]

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

> *"having prescriptive requirements alongside objective requirements actually helps to provide clarity of expectations for operators. But, more importantly, it provides for greater ease of use by regulators in the Northern Territory. For example, compulsory design specifications for well integrity will allow all operators, regardless of their sophistication, to know exactly what is required of them. By contrast, objective based requirements provide a far less certain level of direction and are far more complicated to assess and enforce."* [245]

The success of an objective-based regulatory framework relies on a level of sophistication and diligence in an operator that is not always present. The Australian Panel of Experts on Environmental Law (**APEEL**) in a recent review of environmental laws in Australia opined that a risk-based, outcomes-focussed approach could provide a sufficiently rigorous regulatory regime provided that it is *"rigorous, efficient, transparent and well managed."* The APEEL was nevertheless *"skeptical about the likelihood of these conditions being met in practice"* [246] concluding that:

> *"there is a serious danger that risk-based regulation can become a process of negotiated regulatory outcomes in which the outcomes specified may be compromised or arbitrary and their accomplishment is neither monitored nor guaranteed."* [247]

238 2016 Hunter Report, p 4.
239 Petroleum Act, s 58(b).
240 EDO submission 213, p 8.
241 Report of the Montara Commission of Inquiry, p 32.
242 Report of the Montara Commission of Inquiry, p 15.
243 NLC submission 647, p 3; EDO submission 635, p 4.
244 EDO submission 213, p 16.
245 EDO submission 213, p 16.
246 APEEL Technical Paper 1, p 41.
247 APEEL Technical Paper 1, p 41.

Codes of practice are used in many jurisdictions to provide regulatory clarity. For example, in NSW the relevant Minister may impose conditions on petroleum titles that require the title holder to comply with any Codes of Practice or standards.[248] There are a number of codes and standards that apply to the unconventional gas industry in that State. In relation to well casings, the *Code of Practice for Coal Seam Gas Well Integrity*[249] provides the following requirement, directed towards the objective of a well casing withstanding stress:

> *"Casing, casing connections, wellheads, and valves used in a CSG well must be designed to withstand the loads and pressures that may act on them throughout the entire well life cycle. This includes casing running and cementing, any treatment pressures, production pressures, any potential corrosive conditions, and other factors pertinent to local experience and operational conditions".*[250]

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

- baseline testing and monitoring by an independent third party required prior to the proposed activity; [251]
- the design and construction of wells in a very specific way to ensure long-term well integrity; [252]
- methane emissions not exceeding a certain limits; [253]
- the prohibition of the use of BTEX chemicals; [254] and
- the disclosure of all chemicals used in hydraulic fracturing.[255]

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

> *"would be supportive of legislative or regulatory amendment to enable best practice well construction and decommissioning. This may include the Code of Practice for Constructing and Abandoning Petroleum and Associated Bores in Queensland or Guidance and Specifications provided by American Petroleum Institute."*[256]

Recommendation 14.18

That prior to the grant of any further exploration approvals, the Government develops and implements enforceable codes of practice with minimum prescriptive standards and requirements in relation to all exploration and production activities, including but not limited to, land clearing, seismic surveys, well construction, drilling, hydraulic fracturing and decommissioning and abandonment.

14.7.5 Mitigating 'exploration creep'

The community and various stakeholders have referred to the risk that a large number of exploration wells can potentially be constructed, drilled and hydraulically fractured (exploration activity) under exploration approvals granted on an exploration permit prior to the completion of

248 Petroleum Act, Sch 1B, cl 6(2)(c).
249 Available at: http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0006/516174/Code-of-Practice-for-Coal-Seam-Gas-Well-Integrity.PDF
250 NSW Well Integrity Code, 4.2.2(a).
251 EDO submission 213, p 18; H Bender submission 144, p 3; Lock the Gate submission 171, pp 68, 72; ECNT submission 188, p 2; S Bury submission 189, p 3; C Roth submission 191, p 25; AFANT submission 190, p 8. Ms Helen Bender (H Bender submission 144, p 3) proposed 5-10 years minimum; Dr Scott Wilson suggested baseline studies should be conducted "over several seasons to account for natural weather, climactic and lifecycle fluctuations/perturbations" (EDO submission 213, p 19); and Ms Charmaine Roth (C Roth submission 191, p 25) proposed that seven years of baseline monitoring should be undertaken.
252 For example, the NLC proposed that petroleum wells should be constructed with multiple (that is, a minimum of five) layers of casing cemented in place: NLC submission 214, p 42.
253 Lock the Gate submission, p 73.
254 H Bender submission 144, p 59. The Panel notes that cl 342(3) of the Schedule prohibits the addition of BTEX compounds to hydraulic fracturing fluids.
255 EDO submission 213, p 28; M Haswell submission 183, p 14; Frack Free Darwin, submission 141 (**FFD submission 141**), p 11; Ms Juliet Saltmarsh, submission 165 (**J Saltmarsh submission 165**), p 2; Lock the Gate submission 171, p 71; H Bender submission 144, p 59.
256 Santos submission 168, p 104.

a SREBA and prior to many of the recommendations in this Report being implemented (see **Table 16.1** and the discussion in Chapter 16).[257] This is known as 'exploration creep'. Put another way, there is a real concern that the risks attendant with production could be realised if exploration is sufficiently intensive.

The Panel agrees that safeguards must exist to ensure that this is not permitted and that the cumulative impacts of any onshore shale gas activities that occur during the exploration phase of development are assessed, taken into account and appropriately mitigated. This is an aspect of the application of the principles of ESD.

The Petroleum Environment Regulations currently provide that all EMPs (needed for all drilling and hydraulic fracturing, whether for exploration or production purposes) must include *"as far as practicable – any cumulative effects of those impacts and risks when considering both together and in conjunction with other events that may occur in or near the location of the activity"*.

Only if the Minister for Resources is *"reasonably satisfied"* that the EMP meets *"the approval criteria"* can the Minister approve it.[258] The 'approval criteria' are contained in the Petroleum Environment Regulations and include details of all direct and indirect *"environmental impacts and environmental risks"* of the proposed activity. The assessment of these criteria must include the cumulative impacts referred to above and the principles of ESD.[259] In other words, the Minister must be reasonably satisfied that whenever drilling or hydraulic fracturing for onshore shale gas is sought to be carried out, the cumulative impacts of the activity, whether for the purposes of exploration or production, must be consistent with the principles of ESD, which include the precautionary principle.

In the Panel's view, these provisions, together with the recommendation requiring that the principles of ESD be enshrined in the Petroleum Act (***Recommendation 14.11***) and the need for area-based regulation (***Recommendation 14.22***), are arguably sufficient to mitigate against exploration creep. However, ambiguity nevertheless remains surrounding the effect of the caveat *"as far as practicable"* and the geographical reach of the composite phrase *"in or near the location of the activity"*. Statutory amendment is therefore recommended to remove any doubt.

Recommendation 14.19

That prior to granting any further exploration approvals, cl 3(2)(b) of Sch 1 of the Petroleum Environment Regulations be amended to read as follows:

> ***"3(2)(b) [delete 'as far as practicable'] any cumulative effects of those impacts and risks when considered both together and in conjunction with other events, activities <u>or industries, including any other petroleum activities and extractive industries, that have occurred or</u> that may occur in or near the location of the activity or in or near the region, area <u>or play where the regulated activity is located</u>".***

14.8 Production

14.8.1 Application for and granting of a production licence

The holder of an exploration permit or a retention licence may apply for a production licence in relation to the whole or part of his or her exploration permit or licence area.[260] Applications for production licences must include (among other things):

- a technical works program specifying the proposals for exploration, appraisal and production of petroleum within the proposed licence area;
- evidence of the technical and financial capacity of the gas company to carry out the technical works program and its ability to comply with the Petroleum Act;
- measures to protect the environment, including measures to be undertaken by the gas company for the rehabilitation of the licence area or other affected areas;
- the prescribed application fee; and
- any other information in support of the application as the gas company thinks fit.[261]

257 Environment Centre NT, submission 1177 (ECNT submission 1177), p 2; EDO submission 456.
258 Petroleum Environment Regulations, cl 11(2)(a).
259 Petroleum Environment Regulations, cl 9(1) and (2) together with Sch 1, cl 3(2)(b).
260 Petroleum Act, s 44.
261 Petroleum Act, s 45.

Unlike applications for exploration permits, where the Minister has the discretion to grant or to refuse to grant the permit, when a production licence is applied for and the gas company has complied with the exploration permit conditions, any directions given to the holder by the Minister, its obligations under the Petroleum Act, and has discovered a commercially exploitable amount of shale gas within the exploration permit area the Minister must grant the production licence, subject to any conditions the Minister sees fit.[262]

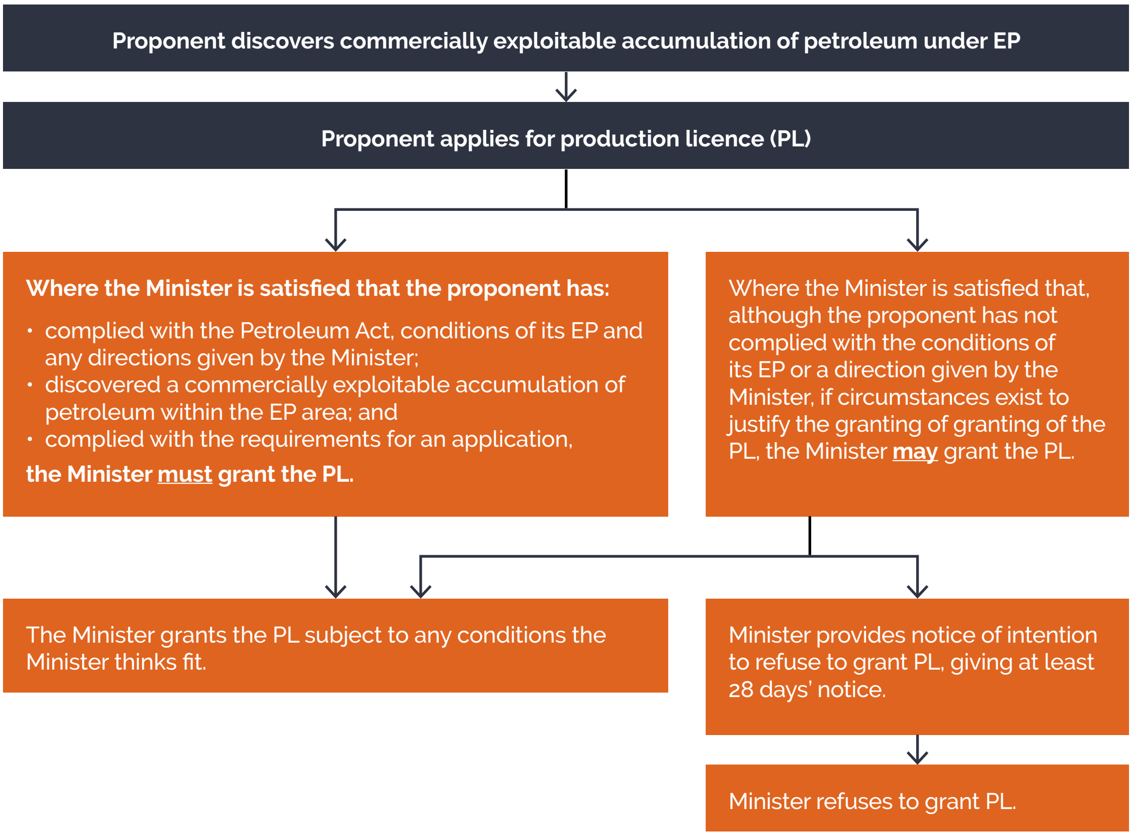
However, the Minister does have discretion in circumstances where:

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

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

- the production licensee must use the licence area continuously and exclusively for the purposes for which it is granted;
- the production licensee must not produce gas obtained from the licence area until the Minister authorises the commencement of production operations;
- the production licensee must pay royalties under the Petroleum Act on petroleum produced;
- the production licensee must maintain an approved insurance policy for well redrilling and well recompletion expenses and for damages arising out of damage to property or the environment, including by pollution, seepage or contamination; and
- any such conditions as the Minister thinks fit and specifies in the licence document.[263]

Figure 14.12: Process of obtaining a production licence under the Petroleum Act.



262 Petroleum Act, ss 47, 54.
263 Petroleum Act, s 54.

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

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

Recommendation 14.20

That the Minister must be satisfied that an applicant is a fit and proper person to hold a production licence, taking into account, among other things, the applicant's environmental history and history of compliance with the Petroleum Act and any other relevant legislation both domestically and overseas.

That failure to disclose a matter relevant to the determination of whether an applicant is a fit and proper person upon request will result in civil and/or criminal sanctions under the Petroleum Act.

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

14.8.2 Cumulative impacts and area or regional-based assessment

The current regulatory model in the NT typically occurs on a well-by-well, well-pad-by-well-pad, or project-by-project basis, and looks at individual actions at individual sites. This approach impedes consideration of the cumulative and regional effects of multiple drilling, production and transport activities on the environment, especially with respect to water and land use. As the discussion earlier in this Report notes (see Chapters 5 and 8), development of any onshore shale gas industry will involve considerable activity to build the necessary infrastructure, drill wells, extract the resources, process it and transport it to market. The cumulative and regional impact of these activities, especially with respect to their impact on water, land and air, demands an appropriate regulatory response. This is one of the international principles formulated by the International Energy Agency in its report *Golden Rules for a Golden Age of Gas*.[264]

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

In the context of any development of shale gas reserves in the NT, the desirability of regional or area-based assessment is particularly strong because, relative to conventional gas, there is a greater scale of development, use of water, and infrastructure required to extract and produce shale gas. Accordingly, the only way to adequately manage the cumulative effects of any onshore shale gas development is at the regional, and not the local, scale.[265] Various jurisdictions employ regional, area or play-based assessment. In Canada, both Alberta and British Columbia (considered to have leading unconventional gas governance), have either developed, or have trialled, 'play-based' or 'area-based' assessment for unconventional oil and gas resource development.

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

264 IEA 2012, p 47, cited in Lazarus Report, p 41.
265 Council of Canadian Academies 2014, section 9.5.

safety, the environment, and the resource. The aim is to reduce cumulative effects, encourage oil and gas company collaboration, develop play-specific requirements, enhance public participation and disclosure, and develop single application and decision-making process.

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

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

> *"It is a different and more effective way of characterizing landscape of unconventional gas basins to inform decisions on oil and gas applications. The Commission uses ABA to address the long term effects of oil and gas activity in its decision-making. Various decisions involving roads, water, seismic activity, well and facility locations and pipeline corridors cause cumulative effects to both environmental and social values. Considering effects on only a project – or sector- specific basis can allow unintended impacts to accumulate over time. … This approach allows the Commission to manage industry activity comprehensively to protect ecological, social and cultural heritage values. The actions that will be assessed are the combined footprint impact of industrial development on the selected values…broad impacts can be considered when looking at specific application of activities, rather than just the localized effects of one permit."*[266]

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

Regional planning as a measure to regulate risk management and address cumulative impacts was also recognised by Nova Scotia in the *Report of the Nova Scotia Independent Panel on Hydraulic Fracturing*,[267] although the report observed that *"it is important to note that regional planning is not a substitute for specific decisions about specific proposals, and that community participation in regional planning does not oust public involvement at other decision-making stages."*[268] The Panel endorses this view.

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

266 BC Oil and Gas Commission 2017b.
267 Wheeler et al. 2014, pp 272-273.
268 Wheeler et al. 2014, p 273.

the geology of the area, the potential for interconnectivity between aquifers in the area and the cumulative impacts of water extraction by petroleum tenure holders.

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

ACOLA has stated that, *"the concept of risk-based and play-based regulation proposed by Alberta could be applicable to the Australian regulatory framework for shale gas and warrants further consideration."*[269]

The benefits of strategic, area or regional-based assessment and regulation include:[270]

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

Disadvantages include:

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

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

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

Recommendation 14.21

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

Recommendation 14.22

That prior to the granting of any further production approvals, the Government considers developing and implementing regional or area-based assessment for the regulation of any onshore shale gas industry in the NT.

269 ACOLA Report, pp 27, 172; EDO submission 213.
270 Council of Canadian Academies 2014, p 206; ACOLA Report, p 172.

14.9 Challenging decisions

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

14.9.1 Standing

In order to challenge a decision, a person or entity must have the 'standing' to do so. A person or entity with standing is usually taken to mean a person or entity whose 'interests' have been adversely affected by a decision. Generally, under the common law, interests are taken to mean financial or proprietorial.[271] Mere intellectual or emotional concern is not sufficient,[272] but a cultural interest may suffice.[273]

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

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

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

if, at any time in the two years immediately before the decision the individual or organisation has engaged in a series of activities in Australia or an external Territory for protection or conservation of, or research into, the environment.[274] The Federal Court of Australia is not inundated with challenges under the EPBC Act, notwithstanding the provision of extended standing.[275]

'Open standing' is a type of standing provided by legislation that permits anyone to bring an action in relation to a decision irrespective of whether or not he or she is directly or indirectly affected by the decision. Open standing (or at the very least, broad categories of standing) is central to the proper administration of justice. The greater the access to justice by the public, the more accountable, transparent and improved decision-making is. Access to justice is an aspect of the rule of law and is, on any view, a necessary component of an SLO insofar as it promotes transparency and accountability and has a tendency to engender trust in the Government and the gas industry.[276]

The Land and Environment Court of NSW has open standing in respect of many of the statutes governing its jurisdiction.[277] The floodgates have not opened, the Court lists are not full of spurious claims and developments are not delayed as a consequence.[278]

Costs sanctions against the unsuccessful party usually prevent vexatious claims being brought in jurisdictions that have open or extended standing, and there is no cogent evidence to suggest that more cases are brought in legal systems that entertain broader standing provisions than in those that have more restrictive standing provisions.[279]

Recommendation 14.23

That prior to the grant of any further exploration approvals, the Petroleum Act and Petroleum Environment Regulations be amended to allow open standing to challenge administrative decisions made under these enactments.

271 See *Australian Conservation Foundation v Commonwealth* (1980) 146 CLR 493.
272 See *Australian Conservation Foundation v Commonwealth* (1980) 146 CLR 493.
273 See *Onus v Alcoa of Australia Ltd* (1981) 149 CLR 27.
274 EPBC Act, s 487.
275 Pepper 2017.
276 Pepper 2017.
277 See, for example, s 9.45 (*"any person"*) of the *Environment Planning and Assessment Act 1979* (NSW).
278 Pepper 2017.
279 Pepper 2017.

14.9.2 Types of review

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

14.9.2.1 Judicial review

Broadly speaking, judicial review proceedings are those where the court determines whether the decision made by the original decision-maker was lawfully made. Judicial review is not concerned with examining whether the decision made was the preferable decision. It is concerned with the lawfulness of the process by which a decision was made.[280]

The Petroleum Act makes no provision for judicial review for decisions made under it,[281] and unlike other Australian jurisdictions, the NT does not have a statutory judicial review framework. This means that any rights of judicial review in relation to decisions made under the Petroleum Act or Petroleum Environment Regulations are based in common law.

However, judicial review serves a purpose that is broader than the individual decision or matter. It (and other forms of independent review) *"safeguards the practice of decisions being made in accordance with the rule of law, contributes to quality in decision-making, ensures decision-makers are accountable in an open forum, develops environmental jurisprudence, and highlights problems and issues to be the subject of reform."*[282]

The Panel therefore repeats ***Recommendation 14.23*** with respect to standing.

14.9.2.2 Merits review

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

A form of merits review is provided for under the Petroleum Act to gas companies that are dissatisfied with a decision not to grant an exploration permit, production licence or retention licence, or to grant any of those approvals subject to conditions.[283] However, the review is conducted internally by a panel appointed by the Minister, which then provides a recommendation to the Minister, which the Minister may elect to accept or not.[284]

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

- the approval of an EMP subject to conditions;
- the refusal to refuse to approve an EMP;
- the revision of an EMP; and
- the revocation of an approval of an EMP.[285]

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

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

Merits review fosters better decision-making. The Commonwealth Administrative Review Council (**ARC**) considers that *"the central purpose of the system of merits review is improving agencies' decision-making generally by correcting errors and modelling good administrative practice"* [286] and that *"merits review ensures that the openness and accountability of decisions made by government are enhanced"*.[287] Merits review facilitates transparency by providing a forum where all the facts and issues relevant to a particular decision can be tested. This transparency results in better

280 See, for example, in relation to the Carmichael Coal Mine and Rail Project, *Australian Conservation Foundation Incorporated v Minister for the Environment* [2016] FCA 104 at [4].
281 The Panel notes s 57M in Pt IIA of the Petroleum Act, which contains a provision that provides for judicial review of some petroleum activities affecting native title rights and interests however it is not yet operational.
282 APEEL Technical Paper 8, p 20.
283 Petroleum Act, s 57AB.
284 Petroleum Act, ss 57AC-57AE.
285 Petroleum Environment Regulations, cl 29, Sch 2.
286 Administrative Review Council 2007, p 11.
287 Administrative Review Council 1999, para 1.5.

decision-making because a decision-maker who knows that his or her decision may be subject to a public review on the merits will take particular care to ensure that it is defensible. Improved decision-making and transparency means that the public and other stakeholders will have more faith in the decision-maker and the decisions made. This is crucial for any regulator of any onshore shale gas in the NT and will encourage the establishment of an SLO.

Many submissions argued in favour of the inclusion of merits review, particularly 'third party' merits review, in legislation governing any onshore unconventional shale gas industry.[288] The EDO submitted that such rights should be included in all legislation that has as one of its objectives the protection of the environment.[289]

DENR has acknowledged the importance of access to justice, and has committed to including avenues for review of decisions in respect of environmental assessment and approvals, including to *"limited third parties"*, such as members of environmental or industry groups, Land Councils and local government bodies, or people who have made a genuine submission during the assessment and approval process.[290]

The ARC considers that, as a matter of principle, an administrative decision that will, or is likely to, affect the interests of a person should, in the absence of good reason to the contrary, be subject to merits review, and that a broad approach should be taken in identifying decisions as being suitable for merits review.[291]

Recommendation 14.24

That prior to the granting of any further production approvals, merits review be available in relation to decisions under the Petroleum Act and Petroleum Environment Regulations including, but not limited to, decisions made in relation to the granting of all EMPs.

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

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

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

14.9.3 Costs

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

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

In some jurisdictions, environmental litigation that has been genuinely brought 'in the public interest' and where there is no disentitling conduct, does not attract a costs sanction in the event of a loss. That is to say, even if the party bringing the action loses, each party will bear their own

288 For example, North Star submission 447, pp 4-5; Lock the Gate submission 437, p 11; EDO submission 213, p 15.
289 EDO submission 213, p 15.
290 DENR Discussion Paper, pp 6, 20.
291 Administrative Review Council 1999, paras 2.1, 2.4.

costs. For example, the Land and Environment Court of NSW can decide, if it is satisfied the proceedings have been brought in the public interest:

- not to make an order for the payment of costs against an unsuccessful applicant;
- not to make an order requiring the applicant to provide security for the respondent's costs; or
- not to make an order requiring the applicant to give any undertakings as to damages.[292]

However, this discretion is not exercised lightly. Clear jurisprudence and rules exist to ensure that frivolous and vexatious proceedings, or disentitling conduct (such as delay) by an applicant, will result in an award of costs.[293] In order for the Court to exercise its discretion, three things must be addressed. First, that the litigation is properly characterised as having been brought in the public interest. Second, there must be 'something more' than the mere characterisation of 'public interest'. And third, there must be consideration of whether there are any countervailing circumstances that would prevent the proceedings being characterised as having been brought in the public interest.[294]

Another measure to mitigate against the inhibiting effect of an adverse costs order is protective costs orders, where a party may seek to have the amount of costs that it may be liable for capped at a fixed amount. An applicant to the Federal Court of Australia can apply for a protective costs order, which caps the amount the losing party must pay to the successful party for the costs of the matter.[295] This has recently been utilised in public interest environmental litigation in the NT in relation to the construction of the controversial Port Melville on the Tiwi Islands.[296]

The Panel notes in this context that NTCAT is a 'no costs' jurisdiction, meaning that the default rule is that parties pay their own costs.[297]

Recommendation 14.25

That prior to any further production approvals being granted, where litigation is brought genuinely in the public interest, costs rules be amended to allow NT courts to not make an order for the payment of costs against an unsuccessful public interest litigant.

14.10 Compliance and enforcement

There is little utility in adopting even the best regulatory framework if it is not complied with.[298] The Panel heard from both the community and other stakeholders that they have little confidence in the regulator's capacity or willingness to enforce compliance with the present regulatory framework. This lack of faith stems, in large part, from previous experience with extractive industries in the NT where it is perceived that inadequate action on the part of the regulator has occurred. A frequently cited example of poor regulation of extractive industries by the Government is the ongoing and unaddressed pollution from the McArthur River Mine.[299]

Many submissions raised the findings of the Montara Inquiry. That Inquiry found that the relationship between the regulator and the proponent in that matter *"had become far too comfortable"* and that a factor leading to the poor standards was the *"minimalist approach to regulatory oversight"* by the regulator.[300]

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

292 *Land and Environment Court Rules 2007* (NSW), r 4.2.
293 Darwin Major Business Group, submission 536, p 4.
294 See *Caroona Coal Action Group Inc v Coal Mines Australia Pty Ltd* (2010) 173 LGERA 280. Merely claiming that proceedings have been brought in the 'public interest' will not be sufficient; there must be *"something more"*.
295 *Federal Court Rules 2011* (Cth), r 40.51.
296 *The Environment Centre Northern Territory Incorporated v Minister for the Environment (Commonwealth)* NTD3/2016, Order dated 13 April 2016; ABC News 2016.
297 *Northern Territory Civil and Administrative Tribunal Act 2014* (NT), s 131.
298 Productivity Commission 2013, p 103.
299 Raised, for example, at community consultations in Borroloola.
300 Mr Roger Heapy, submission 448 (**R Heapy submission 448**), Attachment 2; Lock the Gate submission 171, p 62; Report of the Montara Commission of Inquiry, p 16.

14.10.1 Compliance and monitoring

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

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

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

14.10.1.1 The need for a detailed and transparent compliance policy

Under the Petroleum Act, Petroleum Environment Regulations and Schedule, gas companies must self-report in relation to a range of incidents. For example, as is noted above at Section 14.7.3.1, the Petroleum Environment Regulations require gas companies to notify the Minister of the occurrence of a 'reportable incident' and provide a comprehensive report of the incident.[301]

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

- death or serious injury;[302]
- serious damage other than environmental harm;[303]
- a potentially hazardous event;[304]
- damage resulting in loss of structural integrity;[305]
- emergencies;[306] and
- failure to achieve casing cementing requirements.[307]

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

DPIR noted that *"during the life of the project, compliance measures in place include mandatory self-reporting, inspections and audits"* [308] and provided the Panel with a number of checklists to be used by inspectors in conducting site inspections. However, it is not clear how often these inspections occur, what auditing activities take place, or whether there is an overarching strategy informing compliance monitoring activities. This is imperative for appropriate risk management, particularly in relation to an objective-based regulatory framework.

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

It notes that *"a systematic, risk-based program of compliance review activities provides a regulator with a cost-effective approach to monitoring compliance, enables available resources to be targeted to higher priority regulatory risks and to respond proactively to changing and emerging risks."* [309]

What is essential is the development and implementation of a compliance monitoring and enforcement strategy.[310]

301 Petroleum Environment Regulations, cls 33-35.
302 Schedule, cl 284.
303 Schedule, cl 286.
304 Schedule, cl 287.
305 Schedule, cl 288.
306 Schedule, cl 290.
307 Schedule, cl 307.
308 DPIR submission 226, p 33.
309 ANAO 2014, p 41.
310 ANAO 2014, pp 41-52.

The Panel notes that the *"Compliance and Enforcement Policy"* referred to by DPIR, while a good overview of general compliance and enforcement principles, does not set out how these principles will be followed, nor does it articulate specific activities to be undertaken with regard to the regulator's powers under the Petroleum Act. By way of contrast, the SA regulator has a lengthy and detailed compliance and enforcement policy, setting out expectations on gas companies, enforcement tools available to the regulator, and enforcement policies for classes of non-compliance. The policy provides transparency and certainty for both industry and the broader communityof non-compliance. The policy provides transparency and certainty for both industry and the broader community.

Recommendation 14.26

That prior to the grant of any further exploration approvals, the Government develops and implements a robust and transparent compliance and monitoring strategy, having regard to the principles set out in the ANAO Administering Regulation: Achieving the right balance guide, and the policy in SA.

14.10.1.2 Whistleblowers

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

Some submissions alleged a culture of deliberate non-reporting of compliance incidents by Origin in relation to its Queensland CSG facilities.[311]

Whistleblowing is not without risk for those who expose wrongdoing,[312] and protections must exist or the capacity to allow the whistleblower to remain anonymous must be provided for.

Recommendation 14.27

That prior to the grant of any production approvals, the Government enacts whistleblower protections in respect of any onshore shale gas industry.

That prior to any further exploration approvals being granted, a hotline be established permitting anonymous reporting about any onshore shale gas industry non-compliance. That all such reports be immediately investigated.

14.10.1.3 Tiered approach

SA has adopted a targeted approach to inspections and other monitoring activities. This is achieved by a two-tier approach classifying various regulated unconventional gas activities as either 'high level official surveillance' or 'low level official surveillance'. In SA it is a mandatory condition of petroleum titles to divide regulated activities to be carried out under the licence into activities requiring high level official surveillance and those requiring low level official surveillance. All activities are initially classified as requiring high level official surveillance, unless the licensee satisfies the Minister that, in view of the licensee's demonstrated competence to comply with statutory requirements and the conditions of its licence, the activities should be classified as requiring low level official surveillance.[313] The SA Department of Premier and Cabinet (the agency with the responsibility for regulating the onshore unconventional gas industry in that State) has characterised the main difference between high and low surveillance activities as *"the extent of regulatory scrutiny given by the regulator in the activity assessment and approval process and the surveillance level required whilst monitoring the activities as they are undertaken by the licensees"*[314] and that:

> *"operators who achieve low-level official surveillance classification have extensive experience operating in the relevant region and have demonstrated their capability to continually perform in a manner which achieves the requirements of the relevant approved SEO and other regulatory requirements."* [315]

311 For example, Lock the Gate submission 171, p 70; Mr Joseph Costelloe, submission 85.
312 Ferguson 2017.
313 *Petroleum and Geothermal Energy Act 2000 (SA)*, s 74(2); *Petroleum and Geothermal Energy Regulations 2013* (SA), cl 16-17.
314 SA 2016 Compliance Report, p 18.
315 SA 2016 Compliance Report, p 19.

The Minister's prior written approval is required for activities requiring high level official surveillance.[316] The Minister may, by written notice to a licensee, change the classification of activities under the relevant licence conditions.[317]

Significantly, if regulated activities are classified as requiring a low level of surveillance, the annual licence fee is reduced and the administrative burden is reduced.[318] This acts as a powerful incentive on gas companies to comply with the regulatory framework. It also has the advantage of efficiently allocating regulatory resources towards the more problematic and less compliant gas companies. In a jurisdiction as large and remote as the NT, such a model is attractive.[319]

Recommendation 14.28

That prior to the grant of any further production approvals, the Government considers developing and implementing a tiered regulatory model such as the one in SA, whereby gas companies with a demonstrated record of good governance and compliance require a lower level of monitoring, with a corresponding reduction in regulatory fees.

14.10.2 Enforcement

14.10.2.1 Increasing the range of enforcement options

Without enforcement, conditions placed on titles and approvals are ineffective.[320] Many submissions expressed concern about the ability or willingness of the regulator to take enforcement action in relation to non-compliance by petroleum and other extractive industry companies. The EDO noted that the NT has an: *"appalling environmental assessment regime, poor track record of cowboy operators and ad hoc and lax enforcement of environmental laws."* [321] Obligations imposed on gas companies must be clear and enforceable to encourage compliance.[322] As discussed above, especially in respect of the Schedule, this is not necessarily the case in the NT. Furthermore, a robust regulatory framework should provide a range of enforcement powers and mechanisms to enable the regulator to take action that is proportionate to the risk posed by any non-compliance.[323]

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

A modern regulatory system should provide a range of tools (sanctions) to the regulator to encourage flexibility in responding to instances of non-compliance. In NSW, for example, remediation directions are provided for. The Minister may require a person who is, or has been, the holder of a petroleum title to take steps necessary to give effect to any condition on the title relating to protection or rehabilitation of the environment.[324] Failure to comply with such a direction is punishable by a maximum penalty of $220,000 for an individual or $1,100,000 for a body corporate.[325] If the person does not comply, the Minister may cause the rehabilitation (or protection) of the environment to be carried out. Any expenses incurred in doing so are a debt payable by the gas company to the State.[326]

Under the EPBC Act, the relevant Minister has the power to vary, suspend or revoke a granted approval to carry out an activity if there has been non-compliance with a condition attached to the approval.[327]

In 2014 the Commonwealth enacted the *Regulatory Powers (Standard Provisions)* Act 2014 (Cth) (**RP Act**), which contains a framework of standard regulatory powers to be adopted by Commonwealth regulators. NOPSEMA has implemented the framework. The RP Act provides

316 *Petroleum and Geothermal Energy Act 2000* (SA), s 74(3); the *Petroleum and Geothermal Energy Regulations 2013* (SA), cl 18-20.
317 *Petroleum and Geothermal Energy Act 2000* (SA), s 74(4); the *Petroleum and Geothermal Energy Regulations 2013* (SA), cl 21.
318 *Petroleum and Geothermal Energy Act 2000* (SA), s 74(5).
319 EDO submission 456, p 10; Lock the Gate submission 1250, p 22; Australian Petroleum Production and Exploration Association, submission 623 (**APPEA submission 623**), p 27.
320 Productivity Commission 2013, p 103.
321 EDO submission 213, p 5.
322 EDO submission 456, p 3.
323 ANAO 2014, p 51.
324 *Petroleum (Onshore) Act 1991* (NSW), s 75.
325 *Petroleum (Onshore) Act 1991* (NSW), s 78A.
326 *Petroleum (Onshore) Act 1991* (NSW), s 78D.
327 EPBC Act, Div 3, ss 143-145.

for civil penalties,[328] infringement notices,[329] enforceable undertakings,[330] and injunctions.[331] The availability of these responses means that a regulator, such as NOPSEMA, is able to take punitive action where, for example, the transgression does not support the expense and burden of evidence of criminal proceedings. In order to provide the regulator with sufficient flexibility required to efficiently regulate any onshore shale gas industry, the Panel is of the view that the compliance and enforcement powers in the Petroleum Act and Petroleum Environment Regulations should be enhanced to afford a greater range of sanctions at its disposal.

Recommendation 14.29

That prior the grant of any further production approvals, the Government enacts a broader range of powers to sanction, including but not limited to:

- ***remediation and rehabilitation orders;***
- ***revocation, suspension or variation orders;***
- ***enforceable undertakings;***
- ***injunctions (mandatory and prohibitory); and***
- ***civil penalties.***

14.10.2.2 Chain of responsibility

In 2016, the Queensland Government introduced 'chain of responsibility' legislation to respond to the issue of companies, particularly those in financial difficulty, avoiding their environmental obligations.[332] A related person of a company in financial difficulty can now be issued with an environmental protection order (**EPO**) requiring them to undertake specific actions within specific timeframes. This can include actions to prevent or minimise environmental harm or to rehabilitate or restore land.[333]

Related persons include parent companies and those who have a relevant connection to the company due to their capacity to significantly benefit financially from the company's activities or their ability to influence the company's compliance with its environmental obligations.[334] Although this definition potentially encompasses a large number of people, the decision to issue an EPO to a related person must be made in accordance with guidelines issued by the Queensland Department of Environment and Heritage Protection.[335] The guideline states that the related person is culpable because of their participation in the company's avoidance, or attempted avoidance, of its environmental obligations.[336] The decision to issue an EPO to a related person is a reviewable decision.[337]

The Panel is of the view that similar legislative provisions should be introduced in the NT to ensure that gas companies cannot avoid their environmental responsibilities and that those who are in a position to influence a company's compliance are held accountable. As discussed above (Section 14.4.5), the Government should not bear the costs of environmental management and rehabilitation.

Recommendation 14.30

That prior to the grant of any further production approvals, the Government enacts provisions establishing a chain of responsibility for gas companies and related parties to ensure compliance with environmental obligations.

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328 *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 4.
329 *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 5.
330 *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 6.
331 *Regulatory Powers (Standard Provisions) Act 2014* (Cth), Pt 7.
332 *Environmental Protection (Chain of Responsibility) Amendment Act 2016* (Qld).
333 *Environmental Protection Act 1994* (Qld), s 363AD.
334 *Environmental Protection Act 1994* (Qld), s 363AB.
335 *Environmental Protection Act 1994* (Qld), s 363ABA(a).
336 Queensland DEHP Guideline, p 15.
337 *Environmental Protection Act 1994* (Qld), ss 519-539.

14.10.2.3 Civil enforcement

The Australian Law Reform Commission has observed that:

> *"Political, bureaucratic and financial constraints mean the Attorney-General and other government plaintiffs cannot adequately represent the public interest in all matters. There is an important role to be played by private plaintiffs in the maintenance of the rule of law through the review of government decisions and the enforcement of statutory rights and obligations."* [338]

In some jurisdictions, such as NSW, members of the public can apply to a court to remedy or restrain breaches of environmental legislation in order to enforce environmental protections.[339] These actions are called 'civil enforcement' proceedings.

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

- remedy or restrain a breach of that Act or its regulations;[340] or
- restrain a breach of any other Act if the breach is causing or is likely to cause harm to the environment.[341]

The EPBC Act provides that the relevant Minister or an *"interested person"*[342] may apply to the Federal Court of Australia for an injunction in relation to conduct amounting to a breach of that Act or its regulations.[343] The Court may, if it considers it appropriate to do so, make an order requiring the person engaging in the conduct amounting to a breach to carry out an act to remedy or stop the breach (including repairing or mitigating damage to the environment).[344]

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

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

Recommendation 14.31

That prior to the grant of any further production approvals, the Government allows civil enforcement proceedings to be instituted to enforce potential or actual non-compliance with any legislation governing any onshore shale gas industry.

14.10.2.4 Reversal of the onus of proof

A common concern of participants at consultations was the unreasonable burden of proving environmental harm believed to be caused by a gas company's activities in civil proceedings.[345] This is because the onus of proof generally falls on the complainant. Discharging this onus is expensive, usually requiring expert evidence. Pennsylvania has dealt with this issue by implementing a rebuttable presumption that a well operator is responsible for the pollution of a water supply that is within 1000 feet of the oil or gas well, where the pollution occurred within six months after the completion or drilling or alteration of the well.[346] Reversing this presumption can be done by proving:

- the pollution existed prior to the drilling or alteration activity as determined by a pre-drilling or pre-alteration survey;
- the landowner or water purveyor refused to allow the operator access to conduct a pre-drilling or pre-alteration survey;
- the water supply is not within 1,000 feet of the well;

338 ALRC 1996, para 4.15.
339 Preston 2011, p 72.
340 *Protection of the Environment Operations Act 1997* (NSW), s 252.
341 *Protection of the Environment Operations Act 1997* (NSW), s 253.
342 An "interested person" is defined in s 475 of the EPBC Act.
343 EPBC Act, s 475.
344 EPBC Act, s 475.
345 See, for example, North Star Pastoral, submission 453 (North Star submission 453), p 5; Lock the Gate submission 437, p 10.
346 *Oil and Gas Act 2012, s 208* (58 Pa Cons Stat Sec. 601.208); *Unconventional Gas Regulations 2016*, cl 51 (25 Pa. Code §78a.51.).

- the pollution occurred more than six months after completion of drilling or alteration activities; or
- the pollution occurred as the result of some cause other than the drilling or alteration activity.[347]

In order to use these defences, the gas company must retain the services of an independent certified laboratory to conduct the pre-drilling or pre-alteration survey of water supplies. A copy of the results of must relevantly be submitted to the regulator and the landowner.[348]

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

> *"affirmatively prove by clear and convincing evidence any of the following: the water source is not within 1,500 ft of the well site; the pollution or diminution occurred prior to high volume horizontal hydraulic fracturing operations or more than 30 months after the completion of the high volume horizontal hydraulic fracturing operations; or the pollution or diminution occurred as the result of an identifiable cause other than the high volume horizontal hydraulic fracturing operations."* [349]

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

Reversing the onus of proof was supported by many submissions to the Panel.[350] For example, the EDO noted that, *"oil and gas industry representatives have expressed a high level of confidence in their processes and ability to manage the potential impacts of their industry on water resources. Given that, the EDO expects that Industry would support our recommendation for legislation to include a rebuttable presumption that gas operators are liable for water pollution."* [351]

Recommendation 14.32

That prior to the grant of any further production approvals, the Government enacts provisions that reverse the onus of proof or create rebuttable presumptions for pollution and environmental harm offences for all onshore shale gas activities.

It should be noted that the recommendation above is directed only towards civil proceedings and not criminal proceedings, where an accused must always be presumed innocent unless proven otherwise by the prosecutor beyond reasonable doubt.[352]

14.10.2.5 Criminal penalties should be increased

Where sanctions consist of other pecuniary penalties, the penalty must be sufficiently high to deter non-compliance, rather than the cost of doing business.[353] This is an aspect of the principles of ESD and the polluter-pays principle. The *Guide to Framing Commonwealth Offences* notes that:

> *"A maximum penalty should aim to provide an effective deterrent to the commission of the offence, and should reflect the seriousness of the offence within the relevant legislative scheme. A higher maximum penalty will be justified where there are strong incentives to commit the offence, or where the consequences of the commission of the offence are particularly dangerous or damaging."* [354]

347 *Oil and Gas Act 2012,* s 208 (58 Pa Cons Stat Sec. 601.208).
348 *Oil and Gas Act 2012, s 208* (58 Pa Cons Stat Sec. 601.208); *Unconventional Gas Regulations 2016*, cl 51 (25 Pa. Code §78a.52.).
349 *Illinois Hydraulic Fracturing Regulatory Act*, s 1-85.
350 North Star submission 447, p 5; Lock the Gate submission 437, p 10; EDO submissions 213 and 635; NLC submission 647, p 34; North Star submission 535, p 6.
351 EDO submission 213, p 24.
352 APPEA submission 623, p 27.
353 See, for example, Judicial Commission of NSW 2014; Guide to Framing Commonwealth Offences, p 37.
354 Guide to Framing Commonwealth Offences, p 38.

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

The most serious environmental offence in the Petroleum Act carries a maximum penalty of $592,900 or five years imprisonment for an individual, or $2,962,960 for a body corporate.[355] These are inadequate because, first, the offence requires knowledge by the offender that serious or material environmental harm might result.[356] Second, in the context of any shale gas development, the maximum penalty arguably is not likely to be a real deterrent. For example, Santos notes that in the two years from 2013 to 2014, its expenditure on exploration and development in SA was $779 million.[357]

By way of comparison, the maximum penalty for an equivalent offence under the *Protection of the Environment Operations Act 1997* (NSW) is $5,000,000 for a body corporate, or $1,000,000 and/or seven years imprisonment for an individual.[358]

Most penalties for offences under the Petroleum Act and Petroleum Environment Regulations are significantly smaller than the maximum penalty above. For example, the maximum penalty for non-compliance with the Petroleum Act is $15,400 for an individual and $77,000 for a body corporate.[359] In NSW, the maximum penalty for non-compliance with a condition of a petroleum title is $220,000 for an individual and $1,100,000 for a body corporate.[360] In SA, the penalty for breach of a licence condition is $120,000.[361]

Under the Petroleum Environment Regulations non-compliance with an EMP carries a maximum penalty of $30,800. By way of contrast, in Queensland non-compliance with an environmental authority in relation to activities under a petroleum title carries a maximum penalty of $567,675.[362]

Recommendation 14.33

That prior to the grant of any further production approvals, criminal penalties for environmental harm under the Petroleum Act and Petroleum Environment Regulations be reviewed and increased in line with world-leading practice.

14.11 Water approvals

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

The Panel notes that the Government has committed to applying the Water Act to petroleum activities, and the Panel agrees that this should be done (see ***Recommendation 7.1***).[363] It is important to note that the Water Act deals with activities other than water extraction. For example, the Water Act requires a person to have an approval to interfere with waterways, construction dams, recharge an aquifer, pollute and to drill a bore. While the Panel supports the need for water extraction to be regulated by a single regulator, care must be taken to ensure that the application of the Water Act to petroleum activities will not duplicate assessments and approvals that are required under other legislation, including petroleum and environment legislation.

355 Petroleum Act, s 117AAC.
356 Intentionally releasing contaminant or waste material.
357 Santos submission 168, p 119.
358 *Protection of the Environment Operations Act 1997* (NSW), s 119.
359 Petroleum Act, s 106.
360 *Petroleum (Onshore) Act 1991* (NSW), s 125E.
361 *Petroleum and Geothermal Energy Act 2000* (SA), s 77.
362 *Environmental Protection Act 1994* (Qld), ss 430 and 437.
363 DENR submission 230, p 7; see also NT Parliament 2016, p 145.

14.12 Towards a new regulatory model

14.12.1 The need for a new regulatory model

Petroleum projects have a tendency to be large and complex. From the community's perspective it is essential that, at the very least, if such projects are permitted, they must satisfy reasonable requirements aimed at protecting the environment, protecting human health and safety, and ensuring fairness with respect to land access. But it is also important to achieve these objectives without imposing unnecessary regulatory burden and costs and allowing any industry to operate efficiently.

Principles of good governance include clarity of purpose and function, well designed rules that are efficient and effective, accountability and transparency, trust and independence, consistent and fair processes and practices, appropriate institutional frameworks, appropriate resourcing of regulatory bodies and appropriately skilled regulatory bodies.[364] The Chief Scientist and Engineer of NSW described the key characteristics for an effective regulator as including:[365]

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

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

14.12.1.1 Independence

The effectiveness of any regulatory framework is premised on an independent, competent and well-resourced regulator to enforce compliance with the regime.[366] The need for an independent regulator was raised in many submissions.[367] The Panel noted the widely and strongly held view in the community that DPIR is not independent from industry. Some submissions noted that there was a strong risk of regulatory capture.[368] The CLC recommended that there be *"external independent scrutiny over DME regulation...to allay concern over a perceived lack of independence"*. [369]

The Panel's main concern with the current regulatory framework is that the Minister for Resources and DPIR have responsibility for both the promotion and the regulation of industry. On one hand, the Petroleum Act sets up a framework for the promotion of exploration and production activities and the collection of royalties,[370] and on the other hand, the Act seeks to ensure that petroleum development occurs in a way that reduces the risk *"so far as is reasonable and practicable, of harm to the environment during activities associated with exploration of or production of petroleum".*[371] It is not difficult to comprehend how perceptions of regulatory capture arise in a jurisdiction where the promotional and regulatory functions are consolidated into a single decision-maker.

Therefore, to ensure that environmental decisions are being made independently from the promotion of any onshore shale gas industry, the Panel proposes that the regulation of the industry be the responsibility of an entity that does not also have responsibility for promoting the industry.[372]

364 Finkel et al. 2017, pp 342-343; Productivity Commission 2013, Ch 4; Productivity Commission 2009, Chs 3-4 and 9-10, in particular.
365 NSW Report, section 6.2.4, p 45.
366 J McDonald submission 182, p 6; M Haswell submission 183, p 18; H Bender submission 144.
367 For example, NTCA submission 32, p 9; Regional Development Australia, submission 110 (**RDA submission 110**), p 1; CLC submission 47, Appendix B of Attachment, p 1; J Saltmarsh submission, p 2.
368 S Bury submission 189, p 4; NARMCO submission 186, p 10.
369 CLC submission 47, Appendix B of Attachment, p 1.
370 Petroleum Act, ss 3(2)(d), 84(1); DPIR and DENR submission 492, Attachment A, p 25.
371 Petroleum Act, s 3(2)(f).
372 EDO submission 213, p 6.

Recommendation 14.34

That prior to the grant of any further exploration approvals, in order to ensure independence and accountability, there must be a clear separation between the agency with responsibility for regulating the environmental impacts and risks associated with any onshore shale gas industry and the agency responsible for promoting that industry.

14.12.1.2 Transparency and accountability

Transparent decision-making by an accountable regulator is the cornerstone of a trusted and efficient regulatory regime.[373] If the community has visibility of and, where appropriate, is able to participate in the decision-making process that leads to the development of any onshore shale gas industry, it is more likely that the community will support the decisions that are made and that the industry will earn an SLO.

The Petroleum Environment Regulations were an important first step in improving the transparency and accountability of the decision-maker. As discussed in Section 14.7.3.1, the regulations require the Minister for Resources to consider the views of stakeholders when deciding whether or not to approve or refuse an EMP. They also make the Minister accountable to the community by requiring the Minister to publish reasons why the EMP was approved and how the principles of ESD, or any recommendations from the EPA, were taken into account.

The regulations require all approved EMPs to be made publicly available. The Panel has made recommendations about how those regulations can be further strengthened to increase transparency, including that draft EMPs for hydraulic fracturing be made available for public input prior to approval. This is consistent with the approach being adopted by the Commonwealth in respect of offshore waters.

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

14.12.1.3 Resourcing

If the Government lifts the moratorium and determines to strengthen the regulatory regime in the manner recommended in this Report, more resources will be needed to design, implement and enforce the new regulatory framework (see the discussion above in Section 14.4.5). Inadequate resourcing and concomitant lack of expertise due to an inability to attract and retain qualified personnel in regulatory agencies can lead to inefficiencies and inadequate regulatory decisions.[374]

As some of the submissions noted, there are difficulties associated with regulating an industry whose activities occur in remote locations. Dr Liz Moore observed that, *"the extreme remoteness of many sites and the dispersed nature of unconventional fracking"* will create a real risk that that regulatory framework *"would not be adhered to at all times"*.[375] 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"*.[376]

14.12.2 Options for reform of the regulator

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

- retain the current system with incremental changes;
- create a single environmental approval with the Minister for the Environment as the decision-maker; and
- a sectoral 'one-stop-shop' model of various project approvals under separate legislation brought together under a primary sectoral approval through a lead agency or department.[377]

373 See generally, Productivity Commission 2009.
374 Productivity Commission 2009, p 279; EDO submission 456, pp 10-12.
375 Dr Liz Moore, submission 179 (**L Moore submission 197**), p 2; see also J McDonald submission 182, p 6.
376 EDO submission 213, p 36.
377 2015 Hawke Report, Ch 3.

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

In both Option 1 and 2, is it proposed that the executive (that is, a Minister) remains the accountable decision-maker. This approach is consistent with Australia's Westminster system. It is an important accountability mechanism. In short, if the public does not approve of Ministerial decisions with respect to any onshore shale gas industry, its disapproval may be exercised at an electoral level. It must also be acknowledged that research indicates that regulatory frameworks that separate the regulator from the executive arm of government do not necessarily guarantee better decisions.[378] It is also important to note that the independence of Ministerial decisions can be strengthened by requiring Ministers to consider and respond in a transparent way to the advice of statutorily independent entities whenever they exercise their statutory powers. Both Option 1 and 2 adopt this principle.

In developing Options 1 and 2, the Panel has examined, and rejected, the 'lead agency approach' adopted in SA and WA. Under a lead agency approach, approval of most, if not all, aspects of an application to carry out onshore unconventional petroleum activities rest with one designated agency. The agency coordinates all necessary approvals and information regarding those approvals. It maintains control of the application and assessment process of those approvals and consults with other relevant agencies, rather than formally referring an application to a separate agency for assessment. The lead agency approach is advantageous insofar as it is able to efficiently mobilise resources, streamline approval processes, and minimise delay. However, this approach can be deficient in that it is readily amenable to regulatory capture by industry and may be perceived as lacking in independence and being infected with a pro-development bias at the expense of decision-making in the public interest,[379] particularly where the lead agency is the same agency that releases land for petroleum activities. Although these issues may be mitigated by clearly defining legislative responsibilities and having transparent regulatory processes that promote accountability, and while SA appears to have avoided these criticisms, given the sustained community anxiety expressed to the Panel about the deficiencies of the current governance framework in the NT, especially with respect to DPIR, it is unlikely that the adoption of a model where the regulator performs both a promotional role and a governance and enforcement role is appropriate in the NT context.

14.12.2.1 Option 1

The first option takes into account and aligns closely with the Government's *"existing environmental reform process"*[380] (described below) and proposes that all petroleum activities must have a separate environmental approval under uniform environmental legislation that is administered by an entity other than the entity responsible for promoting the industry (presently DPIR). Once fully implemented, it will ensure a clear demarcation between decisions relating to the promotion and development of any onshore shale gas industry, on the one hand, and decisions about the protection of the environment, on the other. The model is consistent with Dr Hunter's view that environmental management should be the responsibility of an entity other than the person responsible for resource management:

> *"resource management and environmental management/regulation functions should be separate to reduce conflict of interest. Worldwide experience, recently with the Montara and Macondo blowouts, has demonstrated that resource management and environmental management functions should be separated."*[381]

Under this model, two approvals are required before a petroleum activity can proceed: one from the Minister for Resources under the Petroleum Act; and the other from the Minister for the Environment under newly enacted uniform environmental protection legislation. While the requirement for two approvals for one activity may appear inefficient, it ensures that decisions about the environment are made completely independently from other issues that the current regulator has to balance, such as the promotion of exploration for petroleum resources and issues relating to resource management.

378 Coglianese 2015, pp 42, 100-101.
379 NZ Report 2014, p 67.
380 Item 5 of the Inquiry's Terms of Reference. It has the support of the EDO. See EDO submission 635, p 3.
381 2012 Hunter Report, p 35.

14.12.2.2 The Government's environmental reform agenda

The Government is proposing to introduce new environmental protection legislation, called the Environmental Protection Act (**EP Act**), in the near future. The new EP Act will replace the current Environmental Assessment Act, the Waste Management and Pollution Control Act, the Mining Management Act and the Petroleum Environment Regulations. The new EP Act will require that all activities that have an environmental impact, including any onshore unconventional shale gas activities, will require a separate environmental approval under that Act in addition to any other non-environmental approvals that may be required under other legislation, including, for example, the Petroleum Act.[382] The Minister with statutory responsibility for the new EP Act will be the Minister for the Environment, supported by a stronger, better-resourced and fully independent EPA.[383]

It is currently proposed that development of the legislation will occur in two stages. Stage 1 involves the reform of the current Environmental Assessment Act and introduction of the requirement of an environmental approval issued by the Minister for Environment. Stage 2 involves merging the provisions of the Waste Management and Pollution Control Act and the environmental assessment and approval provisions in petroleum and mining legislation (including the Petroleum Environment Regulations) into the new EP Act. Completion of the reforms will mean that only one set of environmental laws will apply to an onshore shale gas project, which contrasts with the current system, whereby various acts and regulators have jurisdiction over environmental matters.[384] When Stage 2 of the proposed legislative reforms is complete, only one environmental assessment is undertaken, which will increase efficiency (currently, an environmental assessment is technically required under the Petroleum Environment Regulations and, if the activity will have a *"significant"* environmental impact, the Environmental Assessment Act).

14.12.2.3 A separate environmental approval for onshore shale gas activities

It is recommended that Stage 2 of the new EP Act be completed as soon as possible to ensure that the Minister for the Environment provides a separate and independent environmental approval for all petroleum activities that have an environmental impact, including hydraulic fracturing (in this regard, see ***Recommendation 14.34***). When deciding whether or not to approve an activity, the EP Act will require the Minister not merely to consider but to apply the principles of ESD and take into account the advice from a wholly independent shale gas advisory body. The advisory body must include persons with scientific expertise in the management of environmental risks and impacts associated with the onshore shale gas industry. The body must consult widely with other experts within the Government, including, for example, AAPA and the Weeds, Land Resources and Water divisions in DENR, when providing advice to the Minister for Environment. The independent advisory body can be the independent EPA, provided that the EPA is strengthened to include expertise in managing the environmental impacts associated with the development of any onshore shale gas industry.[385] The Minister for Environment must be satisfied that there is EMP in place to ensure that the environmental risks and impacts associated with the shale gas activity have been reduced to levels that are acceptable and as low as reasonably practicable. Consistent with the current regulatory framework for petroleum activities, all environment plans, approvals and reasons for all approvals must be published. The EP Act must, where relevant, accommodate the recommendations made in this Report.

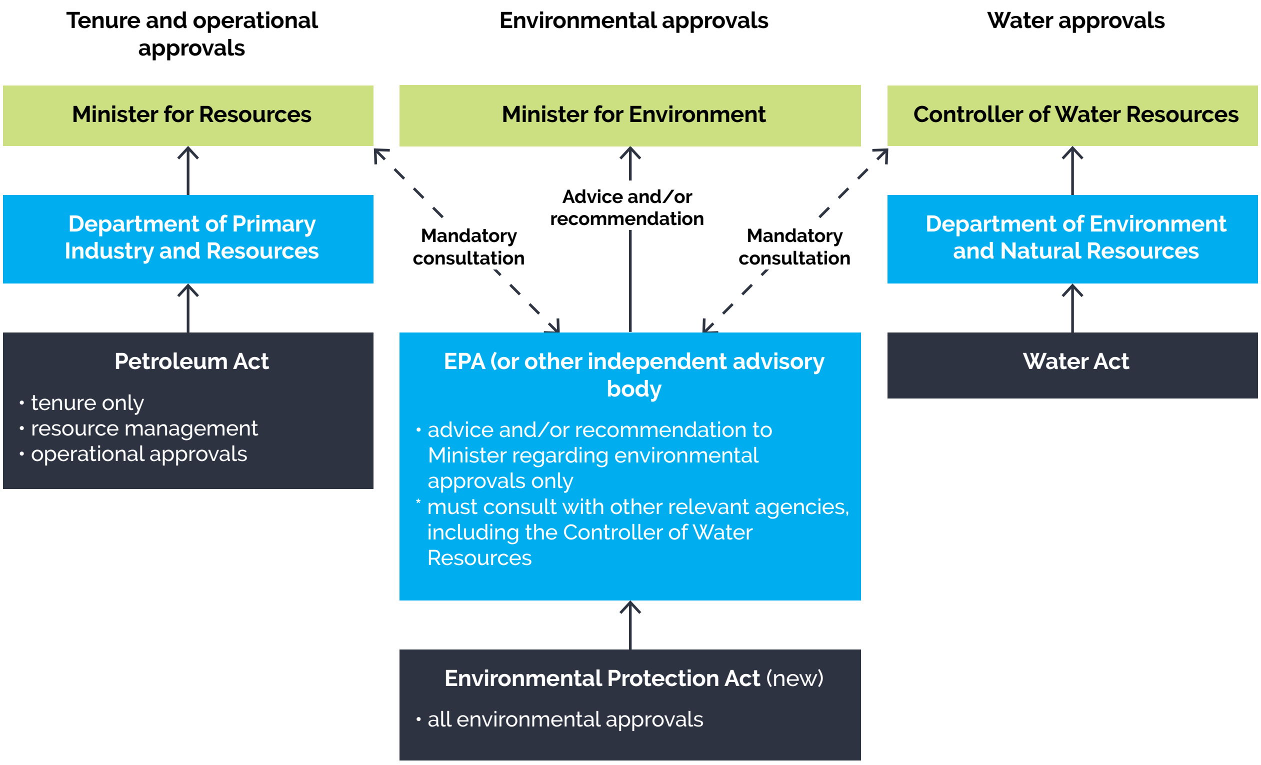
Under Option 1, the Minister for Resources, supported by DPIR, will retain responsibility for the Petroleum Act and all subordinate legislation under that Act. The Petroleum Act will eventually be amended to remove all environmental matters, which will be transferred to the EP Act. The Petroleum Environment Regulations will eventually be repealed. The Petroleum Act will continue to regulate the calculation and collection of royalties (which can remain the responsibility of the Treasurer), the land release process, titles administration, data collection and resource management under new resource management and administration regulations consistent with ***Recommendation 14.17***. Decisions about water allocation and use will remain the responsibility of the Controller of Water Resources under the Water Act (see Section 14.11).

382 Territory Labor 2016, p 12; DENR Discussion Paper, p 5.
383 Territory Labor 2016, p 12; DENR Discussion Paper, p 5.
384 2012 Hunter Report, p 34.
385 CSRM Report, p 27, considers that *"an independent agency, in this case the EPA, would be best suited to administer and regulate strategic assessment of shale gas development in the NT."*

The requirement for a separate environmental assessment and approval for petroleum activities exists in other jurisdictions. For example, in Queensland, a gas company can only undertake activities if it has an environmental authority under separate environmental legislation (*the Environmental Protection Act 1994* (Qld)). This requirement is in addition to a permit given under the *Petroleum and Gas (Production and Safety) Act 2004* (Qld). To increase efficiency, activities are assessed depending on the perceived level of risk, with lower impact activities being approved subject to standard conditions providing certain specified criteria are met.[386] If the criteria are not met then an assessment is required.[387]

In the short term, the 'single and separate environmental approval' model in Option 1 is considered by the Panel as the most efficient and appropriate way for the Government to regulate any onshore shale gas industry. This reform should be immediately implemented prior to any further approvals for exploration or production activity being granted.

Figure 14.13: Option 1 – a separate environmental approval for onshore shale gas activities.



14.12.2.4 Option 2: a one-stop-shop single independent regulator

While not envisaged by the Government's current reform agenda, Option 2 involves the creation of a wholly separate and independent 'one-stop-shop' single regulator (the **'Onshore Shale Gas Regulator'**, or **'OSGR'**), which would be responsible for all assessments and approvals for any onshore shale gas industry, except those with respect to land release (that is to say, promotion of the resource) and water.[388]

Option 2 draws from regulatory models seen in leading-practice jurisdictions and proposes the establishment of a new single onshore shale gas regulator, the OSGR, to regulate all aspects of an onshore shale gas industry, including environmental matters, resource management matters, and operational matters. The OSGR would assess and recommend the granting of, or refusal to grant, all approvals, except water approvals (for the reasons given above in Section 14.11), for all onshore shale gas activities in the NT. The power to grant all approvals in respect of all onshore shale gas activities (except those with respect to water and the release of land for petroleum

386 *Environment Protection Act 1994 (Qld), s 122.*
387 *Environment Protection Act 1994 (Qld), s 124.*
388 It is supported by the NLC (see NLC submission 647, p 2) and APPEA (see APPEA submission 623, p 28).

activities) would be reposed in the Minister for the Environment. The power must be exercised having regard to the recommendation of the OSGR, which would be published. All decisions made by the Minister contrary to the recommendation of OSGR must be accompanied by published written reasons.

New legislation would be required to establish the OSGR, namely, the 'Onshore Shale Gas Act' ('**OSG Act**'), which would ultimately, in conformity with fundamental democratic principles under a Westminster system of government, report to and be the responsibility of the Minister for Environment.

As stated above, the OSGR is intended to be apolitical, sit outside the Government and be independent in terms of its decision-making. Its membership, including the head of the OSGR, would comprise independent experts and scientists, not departmental officers. In order to promote independence, the members would be appointed for at least five-year terms. Appointments would be made by a separate advisory body comprised of major stakeholders including the Government, Land Councils, APAA, industry, the EDO and the NTCA. It would be funded on a full fee recovery basis from the Government by receipts from the gas industry (as discussed above in Section 14.4.5). Further, the creation of a single one-stop-shop regulator would facilitate area-based regulation in respect of the assessment of all operational and environmental onshore shale gas approvals (see Section 14.8.2).

It is important that the OSGR have a regional presence, with offices and officers located in areas geographically proximate to any onshore shale gas activities and not merely in Darwin or Katherine (which is how the BCOGC operates, with offices in both Fort St John and Victoria). The principal elements of Option 2 and the OSGR are as follows:

- the repeal and replacement of all existing legislation that would otherwise regulate an onshore shale gas industry in the NT, with the exception of the promotion of the industry, with the OSG Act;
- the OSGR would have the power to assess and recommend the granting of, or refusal to grant, all operational and environmental approvals (both in respect of exploration and production), except water approvals and the promotion of the resource;
- the OSGR would be responsible for all compliance and enforcement, including complaints, dispute resolution (at first instance) concerning land access to non-Indigenous land (in relation to Indigenous land see the discussion in Chapter 11), and the imposition of sanctions, both civil and criminal. Appeals from decisions of the OSGR in this regard would lie to an appropriate tribunal or court such as the NTCAT or the Supreme Court;
- the OSGR would have complete responsibility for engagement between the gas industry, the community and other industries in the NT;
- the OSGR would have responsibility for public education, especially setting out clearly the rights of those affected by any onshore shale gas industry;
- regional representation;
- the creation of an OSGR website to serve as a 'one-stop-shop' information portal for all onshore shale gas activities in the NT. All data collected from independent monitoring and information required to be provided by the gas industry as reflected in the recommendations made in this Report would be published on the website. All approvals, decisions, comments and consultations reflected in the recommendations made in this Report would similarly be required to be published on this website; and
- membership of OSGR would be for a minimum fixed-term period of five to seven years to facilitate independence in decision-making.

Option 2 is not novel. As was quoted by DPIR in its submission to the Panel:

> *"Safety and pollution prevention programs are more effective if a single agency is responsible and accountable for the regulation of operations. Unfortunately, legislative bodies do not always comprehend the safety and environmental risks associated with fragmented or compartmentalized regulatory regimes. These risks include regulatory gaps, overlap, confusion, inconsistencies, and conflicting standards. Also, a sufficient number of competent regulatory personnel may not be available to staff multiple agencies. Ideally, one agency would be responsible for all regulatory aspects of drilling and production operations. Safety and pollution prevention are inextricably linked and both should be regulated by this agency."*[389]

The model has support overseas in Canada in Alberta (the AER) and BC (the BCOGC). It has been mooted in the UK by the Royal Society and Royal Academy of Engineers,[390] and the Task Force on Shale Gas.[391] It was the preferred model of the NSW Chief Scientist and Engineer in her *Independent Review of Coal Seam Gas Activities in NSW*.[392] As Prof Mary O'Kane observed:

> *"the Review believes that there are significant advantages to having a single regulator in a whole-of-resource context. These include efficiencies, knowledge sharing… Well-constructed, a single regulator would have the capacity to draw on expertise both from within and outside Government… Having a single regulator means that all issues associated with environmental risks, health risks, water risks and pollution risks would be managed by one regulatory agency."*[393]

Option 2 overcomes a recognised source of regulatory burden, namely, a duplication of regulators.[394] This can lead to unnecessary compliance costs, inconsistent regulation, inconsistent reporting requirements and community confusion.[395] As the EPA correctly noted in its submission to the Panel, *"multiple environmental regulators cause community confusion"*.[396] This was what the Panel observed after speaking to various stakeholders and landholders in Queensland.

While the Panel agrees with submissions to the effect that it would be preferable if all onshore petroleum activities fell under the purview of an expanded single regulator,[397] such a recommendation falls outside the Inquiry's Terms of Reference.

The Panel recognises, however, the fundamental nature of the regulatory changes necessitated by Option 2 and the fact that they cannot be made immediately. For this reason, the Panel recommends that the promulgation of the OSG Act and the creation of the OSGR occur prior to any commercial production of any onshore shale gas in the NT. In due course, however, OSGR (albeit renamed) would be expected to have responsibility for all aspects of the industry, including exploration and production.

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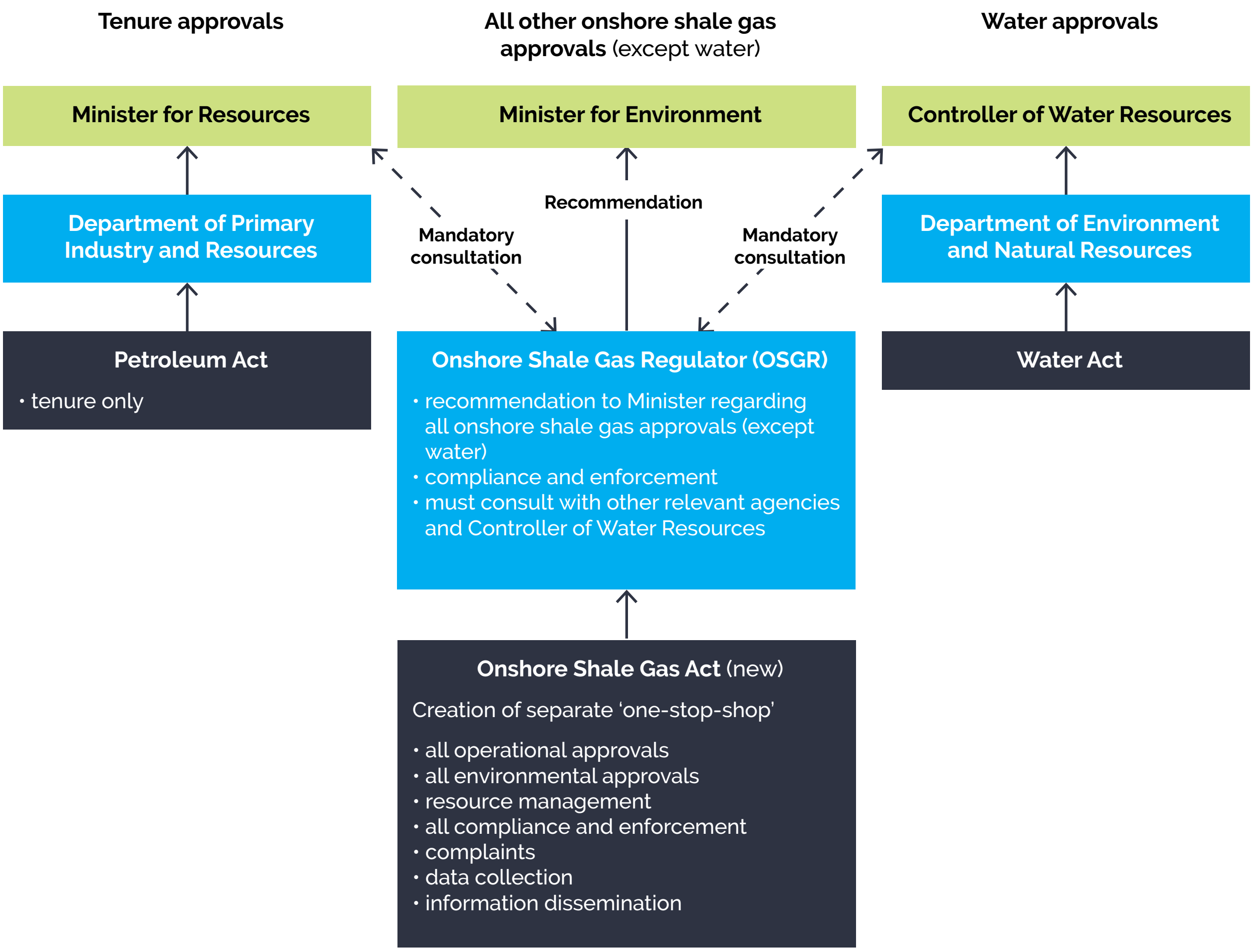
389 Elmer P Danenberger, *submission to Montara Inquiry*, quoted in DPIR submission 226, p 37.
390 Royal Society Report, p 55.
391 UK Task Force on Shale Gas 2015, pp 15-16.
392 NSW Report, section 6.2.4.
393 NSW Report, section 6.2.4, p 45.
394 Productivity Commission 2013, pp 84-85; NT EPA 2017, section 4.3, p 11.
395 Productivity Commission 2013, p 85; NT EPA 2017, section 4.3, p 11.
396 EPA submission 417, p 11.
397 NLC submission 647, p 2.

Figure 14.14: Option 2 – Establishment of a new Onshore Shale Gas Regulator (the OSGR).



Recommendation 14.35

That prior to the granting of any further production approvals, the Government considers establishing a one-stop-shop single, separate and independent shale gas regulator to regulate all aspects of any onshore shale gas industry in the NT (with the exception of the grant of exploration permits and the grant of water approvals).

14.13 Conclusion

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

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

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

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

STRATEGIC REGIONAL ENVIRONMENTAL AND BASELINE ASSESSMENT

15

15.1 Introduction

The lack of adequate pre-development assessment and environmental baseline data is routinely cited as being one of the biggest environmental regulation and management-related issues associated with the shale gas industry in the US and with the CSG industry in Queensland.[1]

The need for robust baseline data has been emphasised and echoed in many of the submissions received by the Panel, during the community forums, and in various publications on hydraulic fracturing and extraction of shale gas.[2] Recommendation 4 from the 2012 Hunter Report specifically referred to the need for baseline water data,[3] and recommendation 15 from the 2015 Hawke Report referred to the need to "*strengthen long-term strategic land use planning so that environmental considerations and constraints - including threatened species impacts - are considered when strategic land use decisions are being made.*"[4]

Without adequate pre-development baseline information, the magnitude of any post-development change cannot be effectively predicted, or its impact assessed. Comprehensive regional baseline datasets are essential to underpin modelling of the possible impacts of any new industry and to inform the site-specific quantitative risk assessments that are being conducted by industry and being submitted to regulators for assessment.[5] The absence of robust baseline information not only negatively affects the ability of the industry, the Government, the community, and affected landholders to be able to strategically plan for the rollout of any onshore shale gas industry, it also impedes identification of key sensitivities in the regional context and to openly and constructively investigate and resolve issues that may arise as a result.[6]

The lack of an integrated strategic and coordinated approach to data collection over large geographic regions in which multiple industry players are involved can further result in inconsistencies between datasets, and therefore, prejudice the subsequent usefulness of such data for developing region-wide assessment and management models. An Australian example of where this has been effectively addressed for water-related data is provided by OGIA in Queensland, which was established to develop and house an integrated groundwater model for the Surat Basin and to provide an independent assessment of likely impacts. [7]

It has also been noted by the Panel (see Chapters 7 and 8) that there is generally poor spatial coverage of data on surface and groundwater characteristics and of both aquatic and terrestrial biodiversity in the regions of the NT most likely to be affected by any onshore shale gas industry. Based on evidence provided to the Panel, there is very limited understanding of the attributes and behaviour of surface waters and groundwater, or their relationship with aquatic or groundwater-dependent, or groundwater-influenced, ecosystems. Distributions of most species are known only in general terms, and there is very limited knowledge of geographic patterns of diversity and endemism and the dependence of that biodiversity on specific surface and groundwater resources. Such limited information on biodiversity assets and their location in prospective onshore shale gas development regions represents a significant knowledge gap, impeding the ability to properly assess the risks of any shale gas development (especially cumulative risks over large areas). It also reduces the ability to plan the location of infrastructure to avoid, or minimise, the risk of unacceptable impacts to local flora and fauna (both aquatic and terrestrial).

The Panel considers that it is essential that the key knowledge gaps identified in this Report be addressed prior to the granting of any further production approvals (see Chapter 16 and the Glossary). This knowledge is required before many of the required key risk assessments can be completed. The overarching framework for these assessments has been described by the Panel

1 US EPA 2016a; Jackson et al. 2013b; ACOLA Report; Queensland Gasfields Commission 2017a.
2 See, for example, Newfoundland and Labrador Report.
3 2012 Hunter Report.
4 2015 Hawke Report
5 Australian Department of the Environment and Energy 2017c.
6 Queensland Gasfields Commission 2017a.
7 Queensland Gasfields Commission 2017a, p 52.

as a 'strategic regional environmental and baseline assessment', or 'SREBA'. The purpose of a SREBA is to provide the information necessary for appropriate decisions to be made about the development of any onshore shale gas industry in the NT, including assessment of water and biodiversity resources, to inform land-use planning, and the collection of baseline data to provide a reference point for ongoing monitoring. In this Chapter, the scope of a SREBA is outlined, along with recommendations for its commencement and completion.

Recommendation 15.1

That a strategic regional environmental and baseline assessment (SREBA) be undertaken prior to the granting of any further production approvals.

15.2 Scope of strategic regional environmental and baseline assessment

The inclusion of the term 'regional' to describe the assessment is deliberate. This is because onshore shale gas plays typically extend over large areas that often include whole aquifer systems and large sections of river catchments, together with multiple social and cultural contexts. Only a regional assessment will provide the foundation for a planning framework for any development that gives certainty to both the gas industry and local and play-based communities, and which will achieve better environmental outcomes by addressing the potential for cumulative impacts across broad areas (for a discussion of area-based regulation, see Section 14.8.2 and ***Recommendations 14.21*** and ***14.22***).

Bioregional planning based on strategic assessment is widely recognised, including by the EPA,[8] as the most appropriate basis for limiting the impacts of regional development on biodiversity. It is formally recognised under the EPBC Act, especially for *"large-scale industrial development and associated infrastructure"* (see likewise the discussion in Section 8.4.1).[9]

But a SREBA framework as recommended by the Panel is much broader than the scope of the bioregional assessment process that has been developed and applied by the Australian Government for the assessment of regions affected, or potentially affected, by large coal mines or by the extraction of CSG.[10] Those bioregional assessments are limited to the assessment of water assets and water-dependent ecosystems by virtue of constraints imposed by the 'water trigger' provision of the EPBC Act. Water related aspects of the extraction of onshore shale gas are not included within the ambit of the EPBC Act (see Section 7.2.4.4), and only MNES that might be at risk of a significant impact (for example, rare and endangered species, or Ramsar wetlands) by a development are required to be assessed under that Act. Areas of high conservation significance by virtue of special local assemblages of plants and animals are not specifically addressed by the provisions of the EPBC Act unless they constitute habitat for rare and endangered species. In addition, the bioregional assessments completed to date have largely relied on existing datasets. This approach is especially problematic in the NT where, as noted in Chapters 7 and 8, there is generally poor survey coverage of aquatic and terrestrial biological assets.

As proposed by the Panel, a SREBA would consist of the physical, biological, public health, social and cultural elements outlined below to address the key knowledge gaps identified in this Report.

8 EPA submission 417, p 3.
9 Australian Government 2011.
10 Barrett et al. 2013.

15.2.1 Water quality and quantity

A SREBA should address the following objectives with respect to water quality and water quantity, namely, to:

- establish a baseline for groundwater and surface water hydrology over a period that is representative of the climatic cycles of the area and of the geological and geomorphological variation across the region;
- characterise the hydrostratigraphy of the region sufficient to identify and characterise the aquifer systems and any interconnectivity that could be affected by the extraction of water for any onshore shale gas development;
- quantify recharge rates (and where possible, recharge zones) and to establish the sustainable yield for potentially affected aquifer systems;
- develop a suitably calibrated groundwater-surface water flow model(s) to quantify the connectivity between groundwater and surface water systems to predict the likely impacts of hydrological perturbation as the result of any potential onshore shale gas development and production;
- establish a baseline for water quality, including measuring vertical profiles of water quality parameters through potentially affected aquifers and surface waters, noting that this will need to be done at a number of locations across a region to inform the lateral variations in quality. In semi-arid and arid regions, particular attention should be paid to the water quality of perennial to near-perennial water bodies that are likely to provide dry season refugia for aquatic biota and drinking water sources for wildlife; and
- define, using baseline water quality data, a staged operational regime (that is, response trigger levels) for remedial action in the event of upward trending key water quality indicators, such as dissolved methane and/or electrical conductivity.

15.2.2 Surface aquatic and groundwater dependent ecosystems

A SREBA should address the following objectives with respect to surface aquatic ecosystems and GDEs, namely, to:

- determine locations of ecologically important perennial and temporary waterbodies and dry season aquatic refugia;
- characterise the wet season surface water flow regime (including overland flow);
- characterise the dependency or degree of influence on ecosystems by groundwater, and their likely sensitivity to shale gas-related water extraction; and
- characterise inter-annual and seasonal water quality variability, with particular focus on dry season aquatic refugia (see above).

15.2.3 Terrestrial ecosystems

A SREBA should address the following objectives with respect to terrestrial ecosystems, namely, to:

- identify locations of high conservation value within affected IBRA bioregions[11] through systematic survey of vascular plants, vertebrates and selected invertebrate taxa;
- establish current distribution and densities of occurrence of weed species throughout the region; and
- determine if any threatened species are likely to be seriously affected by the cumulative effects of habitat loss and fragmentation that could accompany any onshore shale gas development.

15.2.4 Greenhouse gas emissions

A SREBA should address the following objectives with respect to GHG, namely, to:

- establish a regional baseline for methane concentrations and fluxes; and
- identify any locations that have substantively higher emissions than the regional average and to determine, where possible, the reasons for these anomalies.

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11 Thackway and Cresswell 1995.

15.2.5 Public health

A SREBA should collect baseline data on the frequency and duration of the occurrence of symptoms commonly associated with irritant substances (for example, sore eyes, respiratory irritation and asthma).

15.2.6 Social impacts

A SREBA should address the social impacts of any onshore shale gas industry in accordance with the SIA framework discussed in detail in Chapter 12.

15.2.7 Aboriginal people and their culture

A SREBA should consider cultural impacts and should:

- be designed in consultation with Land Councils and AAPA; and
- engage traditional Aboriginal owners, native title holders and affected Aboriginal communities, and be conducted in accordance with world leading practice, as discussed in Chapter 11 (see ***Recommendation 11.8***).

15.3 Guidance for undertaking a SREBA

While it is not the intention of the Panel to be overly prescriptive in relation to the content of any SREBA, there are a number of overarching issues that must be addressed when designing and developing scopes of work for any SREBA to ensure a proper outcome.

In particular, it must be recognised that much of the work that has been undertaken to date has been opportunistic (that is, the use of existing data collected for other purposes), or spatially restricted, rather than being regionally strategic for the purposes of providing the pre-development data required to underpin effective land use planning and to properly inform the environmental performance of any onshore shale gas industry. This situation is aptly described, using groundwater as an example, by the quotation below from a recent paper describing the status of monitoring (baseline and otherwise) for methane and other contaminants in relation to the industry in the US:[12]

"Present-day monitoring efforts do not consider the groundwater resource in its entirety and involve only periodic sampling from existing sparsely located domestic wells, which serve as receptors at risk, rather than adequate monitors for groundwater impact evaluation."

While this example relates to the US, the situation is similar in Australia.

15.3.1 Water

The data collected for the regional assessment must be sufficient to inform the water supply, surface and groundwater interactions, and water quality components of the baseline assessment. Further, the data must add to the knowledge base of these systems in the NT. Useful guidance for this process has been developed by the Victorian EPA[13] and the IESC[14].

15.3.1.1 Water supply

The key groundwater parameters are recharge rate, recharge mechanism, sustainable yield and flow velocity. As noted in Chapter 7, these four components are not well defined over much of the NT. Even for the most well characterised groundwater system in the Beetaloo Sub-basin, there is still missing data, especially in the southern part of the Sub-basin.

Recharge can be inferred from water balance models, but this is a relatively unsophisticated approach that is subject to considerable uncertainty,[15] especially in the case of stratified aquifer systems. Leading practice for measuring these parameters uses a combination of geochemical fingerprinting and stable isotope measurements.[16] Work of this type needs to be done regionally to determine the extent of heterogeneity in aquifer systems because sustainable yield in one part of a shale basin may be very different to other (lower rainfall) parts. Santos and Origin have

12 Cahill et al. 2017, p 293.
13 Victorian EPA 2006.
14 IESC 2015.
15 Crosbie et al. 2010; Suckow et al. 2016.
16 Suckow et al. 2016; Suckow et al. 2017.

recently commissioned CSIRO to undertake these measurements across their lease areas in the Beetaloo Sub-basin, including the southern Beetaloo area.[17]

15.3.1.2 Surface and groundwater interactions

The regional assessment should identify locations where groundwater aquifers intersect with surface waters, and the extent and importance of any ecosystems dependent on, or influenced by, groundwater. In particular, the locations of groundwater-fed springs and dry season aquatic refugia must be identified and characterised, and the sensitivity of these assets to the extraction of groundwater should be assessed.

For all relevant water resources and water dependent assets, a description of baseline conditions, and conceptual and numerical computer models of potential impacts of any onshore shale gas industry need to be developed. Numerical modelling should be undertaken to inform an understanding of potential impacts to a particular water resource. Such models should be constructed in accordance with the conceptual model, be calibrated and verified with appropriate baseline data, and should explore the probability of a range of possible outcomes based on uncertainty analysis.[18]

For a Beetaloo Sub-basin SREBA, one particular focus should be a better understanding of the importance of the CLA in sustaining the Mataranka Springs and the Roper and Daly rivers, and the potential for any onshore shale gas industry to adversely affect this aquifer system.

15.3.1.3 Water quality

The standard set of water quality parameters that have been measured throughout the NT by the Power and Water Corporation have focussed on the inorganic (salts and metals) and microbiological indicators most relevant to assessing near-surface systems for human drinking, stock watering, or agricultural uses.[19] There are no extended time series baseline datasets for these parameters that can assist in diagnosing potentially contaminated groundwater with natural inorganic (including NORM) and organic chemicals (methane and hydrocarbons) that originate from depth as a result of hydraulic fracturing activity for onshore shale gas in the NT.[20]

It is only recently that a more comprehensive range of water quality measurements have been obtained for the Beetaloo Sub-basin from samples collected by consultants engaged by the gas industry.[21] These measurements will need to be extended regionally and seasonally over several years to provide a robust baseline dataset.[22] The analytical detection limits (**DLs**) that are specified will also need to be fit-for-purpose. The lowest DLs appropriate for water quality assessments must be used, noting that the DLs needed for environmental baseline assessments are generally lower than those required for human drinking water.

As stated in Chapter 7, methane will be a key water quality parameter because 'fugitive' methane is the most likely substance to be found in groundwater close to shale gas extraction wells. The baseline needs to determine both the concentrations and geologic origin ('thermogenic' - deep shale gas, and 'biogenic' - near-surface microbiological origin) of measured methane.[23] Determining the origin of methane can be established using a combination of isotopic ratio measurements and gas compositions. Establishing a reliable baseline for methane in water requires specialist expertise.[24]

A fundamental limitation on the rigour and usefulness of the water data acquired to date (and this is likely to include the current CSIRO work) is that it has mainly come from bores constructed for the purpose of domestic supply or stock watering, with variable bore depths and screened intervals. While the groundwater quality data from these bores is adequate for a preliminary assessment, the data obtained to date are not sufficient to properly inform the development of a regionally extensive industry that has the potential to contaminate groundwater by salts or gas for three principal reasons:

- first, aquifer systems can be vertically stratified, with overlying younger water flowing

17 Santos submission 420, pp 10-11; Origin submission 469, Attachment 1, p 12.
18 Barnett et al. 2012.
19 Power and Water Corporation 2016.
20 For example, Appendix A in Australian Department of the Environment and Energy 2017c.
21 Origin submission 153, Appendix 4.
22 See Jackson et al. 2013b for a comprehensive discussion of the issues and the extent of the monitoring required.
23 Currell et al. 2017.
24 Currell et al. 2017; Walker and Mallants 2014.

across the top of the aquifer profile and much older water residing below it. Therefore, measurements of groundwater age that do not specifically address this issue can yield estimates of recharge (and therefore sustainable yield) that are incorrect and;[25]

- second, the concentrations of dissolved oxygen through the aquifer need to be determined to inform the potential for degradation of fugitive methane in groundwater by aerobic or anaerobic microbial pathways (see Section 7.6.1), and the potential for the occurrence of stygofauna; and
- third, the baseline concentrations of major ions must be established through the aquifer profile to provide a reference condition against which leakage of flowback water from a well, or from a surface spill contaminating the groundwater, can be assessed.

Obtaining this information will require the targeted installation of multilevel piezometer arrays screened across a number of discrete vertical intervals to permit sampling through time and conducted reliably and reproducibly at each horizon. In this context, the Panel has recommended that multilevel bores be used for performance monitoring of installed shale gas extraction wells (see ***Recommendation 7.11***).

15.3.1.4 Collation of data and quality control of data-collection process

A central issue regarding the integrity of regional baseline assessments is the quality of the data being collected. Typically, multiple entities collect water samples and submit them for analysis to different commercial laboratories. This is currently the case in the Beetaloo Sub-basin where different consultants are engaged by different gas companies to do their baseline work.

All data being collected for a SREBA must be collated into a single repository database. Ideally, this collation should be performed regularly to ensure that any identified issues are addressed as expeditiously as possible, including inconsistencies in analysis quality and achieved quantification limits. Adequate resourcing must be provided to ensure that the data is uploaded regularly and any problems immediately identified and rectified.

Ongoing attention to quality control is critical because variances in sampling methods, sample processing, and laboratory analysis procedures, can lead to significant systematic variation between datasets consisting of the same set of measured parameters.

To minimise the potential for problems, there should be an annual field and laboratory evaluation component built into the work program for any consultants involved in the assessment program. Specifically, this should comprise samples collected (annually, at minimum) from several bores nominated by the regulator, with the resultant field and laboratory data being compared and assessed by the regulator, or by an independent consultant engaged by the regulator. In this way, any bias or systemic issue can be identified at the earliest opportunity and corrective action taken. If this does not occur, unexplained discrepancies between datasets being obtained across the same region may result.

The Panel recommends that the regulator play a central role in auditing the data and the data-collection process, not only to avoid discrepancies, but to give the community confidence in the scientific independence and rigour of the process.

This control of data quality and review by the regulator must apply to all components of any SREBA.

Recommendation 15.2

That the regulator oversees the auditing and the data-collection processes and provides a central repository for all data informing any SREBA.

25 Suckow et al. 2017.

15.3.2 Aquatic and stygofauna biodiversity

For surface water ecosystems, there are few generic protocols for assessment of biodiversity that will be equally applicable to all NT waters. The Australian River Assessment System (**AusRivAS**) models have been developed for parts of the NT, and can be used to obtain generic river health biodiversity data for some systems in the Top End.[26] However, it only provides information on higher taxonomic level biodiversity of macroinvertebrates, which is one component of biodiversity in the waters of the NT. More recently, Townsend et al. provided more general commentary on approaches to river health assessment in the wet-dry tropics,[27] but again, this was focussed on stream health assessment, and not on the development of a biodiversity baseline. For a SREBA a broader range of taxonomic groups should be considered, including fish and other vertebrates, macroinvertebrates, macrophytes and algae, and microcrustaceans that can play dominant roles in the aquatic biodiversity of some NT waters.

The NT straddles a number of major Australian drainage divisions, including the Lake Eyre Basin, Tanami-Timor Sea, North Western Plateau and Carpentaria Coast,[28] aand some spring systems associated with the Great Artesian Basin. The Carpentaria Coast drainage division is the current remnant of a previously much more extensive Lake Carpentaria catchment at lower sea level[29] tthat connected what are current drainage divisions of the NT, Queensland and southern Papua New Guinea. Inundation of that catchment by sea level rise has resulted in patchy remnant populations of aquatic organisms that were formerly more widespread, with an example being the Finniss River Grunter,[30] which is only known to occur in one NT river, its nearest relative found in Papua New Guinea.

The fact that most surface waters of the NT have been poorly studied highlights the need for detailed surveys before the production phase of a regionally extensive industry, such as onshore shale gas, commences. Specifically, the aquatic biodiversity of the NT is not well known, the distributions of its species is uncertain, even for fish, and the locations of key refugia, sensitive assemblages, and isolated populations are poorly documented. The Panel finds that, without detailed baseline data, it is not possible to understand the key sensitivities in any region proposed for any onshore shale gas industry. Planning to manage possible impacts on aquatic ecosystems must therefore be guided by the application of the precautionary principle. Accordingly, assessing the risk to surface water aquatic ecosystems from the accidental release of shale gas wastewaters will need to be based on expert opinion. This is correct for not only Top End ecosystems, but also for the much less studied semi-arid and arid ecosystems.

In the less reliably inundated semi-arid and arid systems, baseline data collection is made especially difficult because planning for sampling is exacerbated by unpredictability. It is further complicated by the fact that in any one period of inundation, only part of the biodiversity may be apparent because of high variability in the development of assemblages of organisms between wetting-drying cycles and geographically within temporary water networks due to:

- stochastic recruitment effects on assemblage development;[31]
- in-built genetic variability in timing and triggers for ending aestivation within populations ('spreading the risk') and among different species;[32]
- physical and chemical constraints on assemblage successions and variability among years, which require different benchmarking between inundation events. For example, the initial assemblage composition (and therefore process of ecosystem successional development) in salt lakes is contingent upon the amount of inflow in the initial re-wetting of the ecosystem, with different taxa favoured by different salinities;[33]
- changes in the relative input of surface and groundwater flows (particularly to pools/refugia) at different phases of the wetting-drying cycle, with implications for water persistence and water quality; and

26 See https://ausrivas.ewater.org.au/.
27 Townsend et al. 2012.
28 BOM River Regions.
29 Reeves et al. 2008.
30 DENR 2006.
31 Vanschoenwinkel et al. 2010.
32 Simovich and Hathaway 1997.
33 Suter et al. 1995; Halse et al. 1998; Cale et al. 2004.

- the extent of connectivity between refugia and newly inundated habitats, geographically and temporally, strongly affecting recruitment opportunities and sequences, and therefore, the resultant biological interactions.[34]

Accordingly, it is essential that any SREBA is designed to include multiple-year sampling of aquatic ecosystems. As a general rule in the Top End two to five years of baseline data will be required to achieve adequate coverage of inter-annual variability,[35] while in drier zones a longer timeframe is required.

The timing of sampling will be dependent on the hydrological cycle of the water bodies of interest. For example, King et al. identified three phases of the seasonal flow regime for perennial and intermittent rivers in tropical savannah climates: the wet-dry transition; the dry season; and the dry-wet season transition.[36] They identified each hydrological phase as ecologically important, albeit in different ways. However, Humphrey and Pigeon[37] identified the recessional flow phase in the wet-dry transition as the best period for sampling the macroinvertebrate assemblage in these seasonal tropics, because it represents the period of maximum biodiversity in an established assemblage. In systems with different inundation patterns and durations, the timing of sampling in each inundation cycle will need to be adapted, and optimal timing may differ for different taxonomic groups.

There is no specific guidance on measuring the biodiversity of stygofauna in the NT, but policies have been developed for WA, NSW and Queensland that are generally applicable to the NT.[38] The comments above concerning the limitations of using existing bores for characterising the groundwater quality baseline are equally applicable to establishing a baseline for stygofauna biodiversity, but bores developed for a regional assessment of groundwater quality can also be designed to be appropriate for stygofauna assessment.

Timing may be less critical for the assessment of surface GDEs than for non-groundwater dependent surface water ecosystems. However, access may be more difficult in the wet season in the wet-dry tropics, or immediately after the less predictable rainfall further south. Again, for these systems, a broad range of taxonomic groups should be considered, including fish and other vertebrates, macrophytes and algae. Microcrustaceans and terrestrial vegetation and associated fauna should also be considered.

Bameranji Waterhole, Hayfield Station 2017.

34 Sheldon et al. 2003; Sheldon et al. 2010.
35 Humphrey et al. 1995.
36 King et al. 2015, pp 747-753.
37 Humphrey and Pidgeon 2001.
38 WA EPA 2007; WA EPA 2016; Serov et al. 2012; Queensland DSITI 2015.

15.3.3 Terrestrial biodiversity

The Panel's assessment is that the risk of inappropriate location of any onshore shale gas development would be both 'low' and acceptable, provided that a SREBA of terrestrial biodiversity values is undertaken to ensure that the development is excluded from any identified areas of high conservation value. These regional assessments should be comprehensive,[39] both in terms of space (covering all major vegetation types across the region) and biota (including all groups of vascular plants and terrestrial vertebrates, and representative terrestrial invertebrates).[40] The data should be assessed for patterns of species richness and endemism, and for the occurrence of threatened species.

The EPA has developed guidelines for assessing impacts on terrestrial biodiversity. [41] The recommended assessment methodology utilises a combination of desktop assessments and field verification to identify and map vegetation communities, the presence of threatened flora and fauna under the TPWC Act, critical habitat, MNES, and the presence of weed and pest species.

While the EPA guidelines provides a good starting point for what is required, it should be noted that across much of the NT, there is insufficient coverage of survey data to be able to place a strong degree of reliance on existing mapping datasets. This applies especially to the coverage of ground data that will be required for a regional assessment of an industry with a potentially large footprint and a potentially significant cumulative impact, as distinct from an individual project assessment with a smaller total footprint (for example, a medium sized mine). Significant on-ground work will therefore be needed to comprehensively map the occurrence and distribution of terrestrial biodiversity assets of regions likely to be affected by the extraction of any onshore shale gas.

As discussed above for water, it will be critical to ensure that verifiably consistent methods are being used by the different consultants engaged to undertake the baseline assessment for the gas companies that hold permits in prospective shale gas basins. If not, the integrity and usefulness of any SREBA may be compromised.

15.3.4 Greenhouse gas emissions

Establishing an appropriate methane baseline is important to provide an understanding of pre-existing pollutant sources, which is necessary to predict cumulative impacts from any proposed onshore shale gas development. In the Beetaloo Sub-basin, for example, there are a range of natural GHG emission sources likely to contribute to the regional GHG (including methane) budget. These include biomass burning, temporary wetlands, termites, and agricultural and pastoral activities. These emission sources will vary significantly both temporally and spatially, and therefore, a robust GHG baseline program is required.

Many of the technical issues involved with estimating fluxes of methane to the atmosphere have been addressed in Chapter 9 (Section 9.5), noting that such measurements are complex and require well developed expertise and specialist equipment. GISERA has undertaken detailed measurements of methane concentrations in the Surat Basin in Queensland over the last three years, which provide a good reference for future monitoring programs.[42] It is noted that both Origin and Santos are in the planning phase of a baseline methane assessment in the Beetaloo Sub-basin.[43]

15.3.5 Public health

Section 10.2 references the community demand for adequate baseline data on public and environmental health to be collected ahead of any onshore shale gas development, so that future impacts of the industry can be reliably assessed. The Panel has recommended the need for a completed SREBA that includes baseline human health data prior to the granting of any production approvals (see the Glossary and Chapter 16) in any of the prospective onshore shale gas regions in the NT.

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39 EDO submission 456, p 27.
40 ALEC submission 88, p 16; ALEC submission 238, p 12.
41 NT EPA 2013.
42 Day et al. 2013; Day et al. 2015; Etheridge et al. 2017.
43 Santos submission 168, p 110; Origin submission 433, p 58.

The Panel does not underestimate the difficulties of compiling this public health data. It is not known by the Panel what type of health data is held by regional hospitals or community health centres. Nor is it clear how accessible this data is, given the privacy issues surrounding its collation. Collection of public health data through community surveys of self-reported symptoms and health status may be one way of collecting the information, but the utility and reliability of this survey data is problematic. Section 10.3.3.1 discusses some of the limitations of self-reported public health data in assessing the impacts of airborne pollutants sourced from any onshore shale gas industry.

The sample size is likely to be small for people living in close proximity to any onshore shale gasfield development in the NT, and this is likely to compromise baseline health comparisons with larger regional and Territory wide surveys. However, the Panel suggests that existing models for the assessment of this data, such as that used by the Menzies School of Health Research, may be useful. Such methods have been successfully applied to the prospective assessment of birth outcomes in a relatively small Aboriginal birth cohort.[44]

While supporting the need for collation of baseline regional health data, one industry submission suggests that some of these data already exist in State and Territory health departments and that their collation should not be the responsibility of the gas industry but a responsibility of the Government or an independent agency.[45] It was noted that baseline health statistics were used in an analysis of the impact of CSG activities in Queensland.[46]

Another issue is drawing the boundaries for the public health component of a SREBA. The proximity of humans and livestock ('receptors' in HHRA methodology) to the sources of emissions is an important factor in determining health risks. In the HHRA reports commissioned by the gas industry (see Section 10.1.1.4), a finding that credible exposure pathways leading to nearby residents or people other than onsite workers were 'incomplete' led to the discounting of any potential health impacts on local communities.

In analysing all of the data on airborne and water-borne exposure pathways, the Panel has had difficulty in recommending suitable 'setback' distances between wells, processing facilities, pipelines, and local communities. If any onshore shale gas industry in the NT occurs in areas remote from established towns or local communities, the gathering of public health data from distant sites of habitation may be less useful. If there are isolated pockets of people living in closer proximity to any onshore shale gas development (for example, pastoral homesteads or Aboriginal communities), the small numbers of people may compromise the meaningfulness of any data.

15.3.6 Social impacts

As discussed in Chapter 12, developing a baseline assessment of social and economic data for individual communities and regions has been deemed essential for monitoring and evaluating the effect of any onshore shale gas industry on the NT. Leading SIA practice suggests that such baseline data become a critical reference, along with other benchmark values, against which potential social impacts can be anticipated and change measured. Leading practice for SIA requires that the assessment is not undertaken as a component of an EIS, but rather as a standalone measurement that also anticipates the monitoring of any cumulative impacts that may occur as a result of intersecting and co-occurring industries.

To be successful, any SIA must include participation from a range of stakeholders and communities that are likely to be affected by the industry. On-ground consultation means that each community or region should develop its own framework based on the natural, cultural, social, human, political, financial, built and institutional capitals of that community or region. From this, key indicators can be developed that will take into account both historic trends and any regional aspirations for growth.

In the CSRM Report it is recommended that SIA baseline studies independent of any specific project be carried out based on an adaptive participatory management approach (see the report at Appendix 16). The strategic assessment will provide the framework for project-level assessments, with project-level monitoring providing information to facilitate review and update

44 Menzies 2013.
45 Origin submission 433, p 63.
46 Werner et al. 2017.

of the strategic assessment. It identifies the phases and activities of an SIA, and states how they relate to an adaptive participatory management approach. These will typically take several years and involve extensive community and stakeholder engagement to understand social values, identify and explain potential impacts, and develop, explain, refine and reach agreement on appropriate responses, management measures and initiatives.

Significant disparity exists between the regional service centres and remote Aboriginal communities, affecting access to services, the state of housing, access to a labour market, and differences in health and education status. Any SIA will accordingly need to be mindful of these local considerations.

Based on other Australian and international experiences, it will be critical to monitor the cumulative social impacts that may develop if multiple onshore shale gas projects exist and operate across a common region. Any data gathered by individual gas companies must be shared openly and be made available to the community to ensure that the greatest degree of transparency is afforded to any development. There must be a participatory regional monitoring and an evaluation framework that includes an online open access database of all information arising from any monitoring.

15.3.7 Aboriginal people and their culture

The SREBA should include an assessment of the cultural impacts of any onshore shale gas development and, as discussed in Chapter 11, must:

- be undertaken by a suitably qualified and independent party;
- be designed to engage traditional Aboriginal owners and affected Aboriginal communities to enable Aboriginal people to understand the risks and opportunities associated with the development of any onshore shale gas industry, including the risks to the maintenance of culture and to community cohesion;
- utilise the expertise and knowledge held within the Land Councils and AAPA for both the design and implementation of the assessment;
- be conducted in accordance with world leading practice; and
- be completed and their findings made public before any production approvals are granted.

15.4 Timeframe for a SREBA

During the final round of community consultations, and in many of the recent submissions received by the Panel, many people and stakeholders argued cogently that all elements of a SREBA must be completed before any further exploration activity takes place in the NT for onshore shale gas. It was argued that if exploration activity was allowed to occur prior to the completion of a SREBA (as proposed by the Panel in the Draft Final Report), then:

- the baseline studies obtained as part of a SREBA will not properly form part of any pre-development data (see Section 15.1);
- exploration activity may occur in areas that a SREBA may subsequently identify as inappropriate for any shale gas activity, for example, a no go zone (see ***Recommendation 8.2*** and ***Recommendation 14.4***); and
- exploration activity may occur to such an extent (by reason of exploration creep) that the utility of a SREBA in designing appropriate mitigation measures will have been seriously undermined.

The Panel has considered the timing of any SREBA carefully in light of the community's concerns about exploration activities occurring in the absence of its completion, but ultimately it has not resiled from its original position for the following reasons:

- first, the Panel has proposed that many of the recommendations contained in this Report must be implemented prior to the grant of any further exploration approvals (see **Table 16.1** in Chapter 16). This means that the key risks associated with any drilling and hydraulic fracturing for onshore shale gas will be mitigated from the outset;
- second, the Panel considers that the footprint associated with exploration (up to and including the 'appraisal' phase described in **Table 15.1**) in the Beetaloo Sub-basin is

unlikely to have a significant regional impact for three to five years. While the time taken to complete a SREBA will depend on the specific climatic, biophysical, ecosystem, social and cultural conditions of the region where it is being conducted, the Panel estimates that it will take the same period of time (three to five years) to complete the data acquisition, interpretation and reporting stages of a SREBA for that Sub-basin;

- third, further approvals are required before any exploration activity can occur in the Beetaloo Sub-basin (or any other region). The holding of an exploration permit does not grant a gas company the right to immediately commence drilling or hydraulic fracturing for onshore shale gas. The company must submit a draft EMP for Ministerial approval (which the Panel has recommended be subject to prior public scrutiny: see ***Recommendation 14.15***)) and the Minister must be satisfied that the EMP has identified and reduced all of the risks to a level that is acceptable and ALARP, prior to granting the approval;
- fourth, the implementation of the mitigation measures relating to well integrity, monitoring and public reporting regimes recommended by the Panel in this Report must occur prior to any further exploration approvals being granted (see Chapter 16 and **Table 16.1**). Assuming their implementation, the risk to the environment has been assessed by the Panel as 'low' and acceptable, notwithstanding that a SREBA will not have been completed at this stage;
- fifth, the Panel has made a specific recommendation that the Minister must be satisfied that the cumulative impacts of a proposed activity are thoroughly dealt with in an EMP to mitigate the risk of exploration creep (see ***Recommendation 14.19***); and
- sixth, there is considerable technical merit in any SREBA proceeding in parallel with exploration activity because the activity will provide essential data, such as critical hydrogeological information on groundwater from deep shale drilling, that will form part of the SREBA.

As **Table 15.1** indicates, there are some elements of a SREBA that must commence immediately, while others can proceed in parallel with the relatively small (and controlled) activity footprint of exploration. **Table 15.1** sets out a suggested timeline for any onshore shale gas industry and indicates when various components of a SREBA should commence and be completed. The terms, 'exploration', 'appraisal', and 'delineation', while not necessarily statutorily defined, are terms used by the gas industry to describe the sequential process that is required to prove up a gas resource to a commercially viable stage.[47] This project management is recognised in reporting requirements for the ASX.[48]

The Panel's opinion is that the timeframes shown in **Table 15.1** are reasonable given the availability of the required specialist equipment in Australia and the time needed to interpret the data produced from any early to mid-stage exploration activities.

47 Origin submission 153, p 38; Pangaea submission 1147, pp 5-6.
48 RISC 2013.

Table 15.1: Development timeline and SREBA Implementation.

Stage[1]	Description[2]	Number of wells/size of development	Timeframe for SREBA component to be completed
Exploration	2-5 years	Small number of widely spaced wells to investigate and confirm lateral extent of any onshore shale gas resource.	Prior to the grant of any further <u>exploration approvals</u>. • baseline acquisition of methane concentrations to be undertaken for a six month period (***Recommendation 9.3***); • local groundwater quality data to be acquired using multi-level wells installed adjacent to, and six months prior to the drilling of, any new shale gas exploration wells, (***Recommendation 7.11***); and • other elements of SREBA commence, including: regional surface and groundwater studies (***Recommendation 7.5***); terrestrial bioassessments (***Recommendations 8.2***, ***8.4***, ***8.5***, and ***8.6***); aquatic biodiversity assessments (Section 15.3.2); and social (***Recommendation 12.13***), cultural (***Recommendation 11.8***) and human health (Section 15.3.5) baseline studies.
Appraisal	1 year	Increased number (small) of wells to prove the technical viability of the extraction technology in the target shale formation.	Prior to the grant of any <u>production approvals</u>: • the bulk of the data acquisition required by a SREBA must be completed by the end of appraisal; • key SREBA elements (for example, sustainable yield of groundwater: ***Recommendation 7.16***) must be completed by the end of the delineation phase because the results could have major implications for the location and scale of any onshore shale gas industry and could impact upon the commercial decision to proceed to production; and • full social, cultural, environmental and human health risk assessments must be completed prior to commercial production commencing. These assessments can only be finalised at this late stage because the scale and location(s) of any development will not have been known earlier.
Delineation	2 years	Several multi-well pads constructed to assess economic viability of any commercial scale production. Could potentially produce a marketable quantity of gas.	
Commercial production	6-10 years	Staged construction of successive multi-well pads, increasing to required scale for commercial production.	

1 These descriptions are consistent with accepted gas industry terminology.

2 Theses are indicative only but are based on information provided to the Panel by the gas industry.

A SREBA must be completed by the time any production approvals for production activity are granted (the 'delineation' phase). It is intended that the results from a SREBA form the basis of any decision to grant production approvals on a production licence.

Having said this, the Panel recognises the need for any SREBA to be completed in a timely and efficient manner. The assessment process cannot be open-ended. Communities (local, regional and Territory wide), the Government and gas companies require certainty and finality to the SREBA process.

Recommendation 15.3

That a SREBA:

- ***should be completed within five years from the first grant of exploration approvals; and***
- ***must be completed prior to the grant of any production approvals.***

The acquisition of regional data will not, however, cease with the completion a SREBA. Ongoing work will be required by both the regulator and the gas industry to progressively transition the information obtained from a SREBA into the operational performance and monitoring regimes recommended by the Panel throughout this Report.

IMPLEMENTATION

16

16.1 The Government must accept and implement all of the recommendations

The recommendations in this Report are a complete package. It is only the implementation of the entire package that will create the framework that will mitigate the risks associated with any onshore shale gas industry in the NT to an acceptable level. If the Government does not implement all the Panel's recommendations, then the Panel, in the Panel's assessment, is not able to state with certainty that the identified risks will be mitigated to acceptable levels.

Recommendation 16.1

That the Government implements all of the recommendations in this Report.

16.2 Implementation of recommendations must be clear, timely and transparent

The community's very real and understandable concerns with onshore shale gas extraction (including hydraulic fracturing) and the public's lack of trust in the Government's capacity and/or willingness to regulate any onshore shale gas industry have been discussed in detail in this Report. If the Government lifts the moratorium, the implementation of the recommendations must be effected in a timely and transparent manner to address these concerns. From the outset, there must be clarity about who is implementing the reforms, how they are being implemented, and when they will be implemented.

The clear, timely and transparent implementation of the recommendations is also necessary to provide certainty to any onshore shale gas industry about the regulatory regime that will govern the industry. Industry will be reluctant to invest in a jurisdiction where there is uncertainty about the regulatory framework.

16.3 Timing of the implementation of the recommendations

In the Draft Final Report, the Panel stated that some of the recommendations had to be implemented *"prior to the grant of any production licence"*. For example, the Panel had recommended that the Water Act be amended to apply to any onshore shale gas industry and that a SREBA in the Beetaloo Sub-basin had to be completed before any production licence was granted.

However, during the final round of consultations, stakeholders and members of the public made the following criticisms of the timing of some of the recommendations expressed in the Draft Final Report:

- the gas industry stated that the term *"production licence"* was ambiguous because it could be interpreted as either a reference to the granting of a form of petroleum tenure under Pt 2 Div 4 of the Petroleum Act, or a reference to an authorisation to proceed with commercial development;[1]
- the community and some environmental groups expressed the view that use of the term *"production licence"* as a trigger for the implementation of some recommendations was inappropriate because it enabled drilling and hydraulic fracturing for onshore shale gas to occur on exploration permits in the absence of any substantive regulatory reforms or key baseline studies having been completed, and consequently, the risks associated with any onshore shale gas development would not be properly mitigated;[2] and
- various stakeholders commented on a general lack of detail in respect of when many of the recommendations were to be implemented.

1 Origin submission 544, p 5; Origin submission 1248, p 23.
2 NLC submission 647, p 28; EDO submission 635, p 2; ECNT submission 1177, p 2.

In light of these comments, the Panel has endeavoured in this Report to clarify when the recommendations must be implemented. The Panel has distinguished between the recommendations that are designed to address the risks associated with exploratory drilling and hydraulic fracturing for onshore shale gas (**exploration activities**) and the recommendations that are designed to address the risks associated with larger-scale development involving the drilling and hydraulic fracturing of shale gas wells on production licences for the purpose of commercial production (**production activities**).

16.3.1 Key recommendations to be implemented before any further exploration approvals are granted

The Panel's view is that some risks associated with drilling and hydraulic fracturing must be mitigated immediately, that is to say, before any further drilling or hydraulic fracturing takes place in the NT. This is to address some of the community's concerns that if the Government lifts the moratorium, clearing, drilling and hydraulic fracturing for onshore shale gas could happen in the absence of any regulatory reform.

Under the current law, exploration activities cannot happen on an exploration permit unless a gas company has a granted exploration permit. Of itself, however, an exploration permit does not give a gas company the right to undertake an exploration activity. In addition to the exploration permit, the gas company must also have all necessary operational approvals under the Schedule and an environmental approval (that is, an EMP granted) under the Petroleum Environment Regulations (together, **exploration approvals**) (see Section 14.7). Only when all of the exploration approvals have been granted can a gas company proceed with exploration activities.

The key recommendations that must, in the Panel's opinion, be implemented before any further exploration approvals are granted to carry out exploration activities on an exploration permit are listed in **Table 16.1** below.

Table 16.1: Key recommendations that must be implemented prior to any further exploration approvals being granted.

Recommendation	Description
5.1	Development and implementation of a code of practice for the decommissioning of onshore shale gas wells.
5.3	Development and implementation of a code of practice to ensure the integrity of onshore shale gas wells.
5.4	Well integrity management systems and plans mandated for all onshore shale gas wells to be hydraulically fractured.
5.5 and **7.12**	Development of a wastewater management framework, including an auditable system for tracking movements of wastewater.
7.1	Gas companies must have a water extraction licence under the Water Act to extract water for hydraulic fracturing.
7.6	Prohibition on the use of surface water for hydraulic fracturing.
7.8	Prohibition on the installation of groundwater extraction bores to supply water for hydraulic fracturing within 1 km of an existing or proposed domestic or stock water supply bore.
7.9	Prohibition on the reinjection of wastewater into deep aquifers and conventional reservoirs.
7.10	Mandatory disclosure of all chemicals (including metals, salts and NORMs) in hydraulic fracturing fluids, flowback and produced water.
7.11. and **713**	Petroleum wells be constructed to at least Category 9 or equivalent. Prohibition on petroleum wells being drilled within 1 km of an existing or proposed groundwater supply bore. Groundwater must be monitored using multilevel monitoring bores.
7.17	Prohibition on the discharge of treated or untreated wastewater into waterways.
8.2	Completion of a baseline weed assessment in all areas of the exploration permit accessed by a gas company.
8.3	Gas companies must have a dedicated weeds officer.
8.4	Gas companies must have an approved weed management plan in place.
9.2	Development and implementation of a code of practice for the ongoing monitoring of methane from shale gas wells.
9.3	Monitoring of methane concentrations for a six month period.
9.5 and **9.6**	Requirement for ongoing methane monitoring and reporting.
10.2	Prohibition on all exploration and production activity within 2 km of any habitable dwelling.
11.1	Existence of an Authority Certificate.
14.4	'No go zones' declared.
14.15	The community must be given an opportunity to comment upon all draft environmental management plans submitted to the Government for approval.
14.16	Requirement that all reports and notices on environmental incidents are publicly disclosed.
14.18	Enforceable codes of practice be mandated for drilling and hydraulic fracturing activites.
14.19	Cumulative impacts of petroleum and other activities in the region must be considered by a decision-maker.
14.23	Open standing for judicial review of decisions made under the Petroleum Act and Petroleum Environment Regulations.
14.26	A monitoring and compliance strategy must be developed and implemented.
14.27	A whistleblower hotline must be established and any reports to it must be immediately investigated.
14.34	There must be a clear separation between the agencies responsible for environmental and promotional approvals.

16.3.2 The remaining recommendations are to be implemented before any production approvals are granted

The Panel has identified a series of risks associated with the commercial production of any onshore shale gas industry.

The Draft Final Report proposed that some of the measures directed towards mitigating production activity. For example, a SREBA had to be implemented prior to the grant of a *"production licence"*, but the Panel agrees that the use of this term in this context is inappropriate. A production licence is no more than a form of tenure that must be granted to a gas company if a commercial onshore shale gas resource has been found and if the company has complied with the conditions of its exploration permit.[3] Of itself, the grant of a production licence does not give a gas company the right to carry out a production activity in respect of onshore shale gas. What is additionally required for a gas company to undertake a production activity is the necessary operational approvals granted under the Schedule and an environmental approval (an EMP) granted under the Petroleum Environment Regulations (see Chapter 14.7) (**production approvals**). No production activity (including clearing, drilling and hydraulic fracturing) can happen without the necessary production approvals.

Unless otherwise indicated in the Report, the remaining recommendations not listed in **Table 16.1**, including a SREBA, are to be implemented prior to the granting of any further production approvals. This is to ensure that the commercial production of any onshore shale gas cannot occur absent these recommendations having been implemented and absent a robust regulatory regime having been enacted.

16.4 Resourcing

Implementation of the recommendations will require substantial and sustained resources, including legal, engineering, and scientific resources. As stated in Chapter 14, the Panel's firm view is that any onshore shale gas industry should be responsible for funding the costs associated with regulating it (***Recommendation 14.4***), including the work required to complete a SREBA.

The expertise and independence provided by GISERA and CSIRO has been used in Queensland and NSW in respect of the CSG industry in those States. This may be an appropriate model for the NT.

The Panel is also aware of available funding from the Australian Government in the area of bioregional assessments warranting further investigation by the Government.

16.5 Development of an implementation framework

The Panel recognises that the timely and transparent implementation of its recommendations represents a significant reform agenda for the Government. Some of the recommendations, most notably a SREBA, will take several years to complete. If the Government lifts the moratorium, an implementation framework must be developed immediately to identify when, how and by whom the recommendations will be implemented, noting that the recommendations in **Table 16.1** must be completed prior to the grant of any further exploration approvals.

The framework must propose appropriate governance arrangements, including the establishment of a centralised, well-resourced, skilled and experienced implementation unit in the Department of the Chief Minister to coordinate the implementation of the reforms.

The recommendations cover a wide range of technical and regulatory issues, and therefore, the implementation unit must have access to specialist resources to ensure that the implementation of each recommendation is carried out effectively and in a timely manner. The need for the Government to recruit people and/or organisations with the appropriate capacity was identified as an issue at community consultations. Expertise in project management, petroleum, hydrological, geological, petroleum, chemical and environmental engineering, resources law and law reform, social impact assessment, cultural anthropology and community engagement will be required.

Strong consideration should be given to seconding resources to and/or from domestic and overseas gas regulators such as, for example, OGIA, NOPSEMA, AER and BCOGC.[4]

Efficient and timely access to all necessary expertise will be critical to successful implementation and reform.

3 Petroleum Act, s 29(3) in Pt 2 Div 4.
4 This suggestion came from the BCOGC during the Chair's consultation with that agency.

Recommendation 16.2

That an implementation framework including details of who, when and how each of the recommendations will be implemented, be completed within three months from any lifting of the moratorium.

Recommendation 16.3

That a centralised, well-resourced, experienced and skilled Implementation Unit be established immediately within the Department of Chief Minister to coordinate the development of the implementation framework.

16.6 Establishment of a community, gas industry and business reference group

There must be a mechanism to ensure that the community, gas industry, businesses, and other key stakeholders with an interest in the ecologically sustainable development of any onshore shale gas industry are able to provide input into the development of the Government's implementation framework and to hold the Government to account in relation to implementation of the Panel's recommendations.

It is proposed that a Community and Onshore Shale Gas Industry and Business Reference Group (**Reference Group**) be established comprising representatives from the community, environmental groups, local business, the gas industry, Land Councils and local government. The creation of the Reference Group will assist in establishing trust and confidence in the Government and in the gas industry and facilitate obtaining an SLO. The purpose of the Reference Group will be to:

- provide a medium through which the Government can constructively consult with, provide information to, and obtain feedback from key stakeholders on the implementation framework to ensure that the framework aligns with community and industry expectations; and
- provide a medium through which key stakeholders can communicate their concerns about the implementation framework directly to the Government.

Recommendation 16.4

That a Community and Onshore Shale Gas Industry and Business Reference Group be established to provide feedback to Government on the development of an implementation framework, and its subsequent execution, if the Government lifts the moratorium.

SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

Glossary

Term	Definition
2012 Hunter Report	*Regulation of Unconventional Gas Resource Development in the Northern Territory,* Dr Tina Hunter, 2012
2014 Hawke Report	*Report of the Independent Inquiry into Hydraulic Fracturing in the Northern Territory,* Dr Allan Hawke AC, 2014
2015 Hawke Report	*Review of the Northern Territory Environmental Assessment and Approval Processes,* Dr Allan Hawke AC, 2015
2016 Hunter Report	*Review of the Draft Petroleum (Environment) Regulations and independent assessment of the Regulations against best practice regulation of environmental aspects arising from petroleum activities involving ground disturbance,* Dr Tina Hunter, 2016
AAPA	Aboriginal Areas Protection Authority
ABA	Area-based analysis
Abandonment	A process which involves shutting down the well and rehabilitating the site. It includes decommissioning the well.
ACIL Allen	ACIL Allen Consulting Pty Ltd
ARC	Administrative Review Council
ACOLA	Australian Council of Learned Academies
ACOLA Report	*Engineering Energy: Unconventional Gas Production,* Australian Council of Learned Academies, May 2013
AECOM	AECOM Australia Pty Ltd
AER	Alberta Energy Regulator
AFANT	Amateur Fishermen's Association of the Northern Territory
AHD	Australian Height Datum
ALARP	As low as reasonably practicable
ALEC	Arid Lands Environment Centre
ANAO	Australian National Audit Office
Annulus	The space between surrounding pipe and wellbore.
APEEL	Australian Panel of Experts on Environmental Law
APPEA	Australian Petroleum Production and Exploration Association
API	American Petroleum Institute
ARC	Administrative Review Council
ASIC	Australian Securities and Investment Commission
AusRivAS	Australian River Assessment System
BC	British Columbia, Canada
BCOGC	BC Oil and Gas Commission
Beetaloo Sub-basin Case Study	*Beetaloo Sub-basin Social Impact Assessment Case Study,* Coffey Services Australia Pty Ltd, 17 January 2018
Beetaloo Sub-basin SIA Report	*Beetaloo Sub-basin Social Impact Assessment Summary Report,* Coffey Services Australia Pty Ltd, 17 January 2018
BOM	Bureau of Meteorology
BOP	Blowout preventer equipment installed on the wellhead assemblies to contain wellbore fluids either in the annular space between casing and the tubulars, or in an open hole during well drilling, completion, and testing operations.
BTEX	Benzene, toluene, ethylbenzene, xylenes
Casing	A pipe placed in a well to prevent the wall of the hole from caving in and to prevent movement of fluids from one formation to another.
Casing string	Steel pipe used to line a well and support the rock. The casing extends to the surface and is sealed by a cement sheath between the casing and the rock. Often, multiple casings are used to provide additional barriers between the formation and well.

Term	Definition
Cementing	The application of a liquid slurry of cement and water to various points inside and outside the casing.
CBL	Cement Bond Log. A key method for testing the integrity of cement used in the construction of the well, especially whether the cement is adhering effectively to both sides of the annulus between casings or between the outer casing and the rock sides.
CBI	Confidential business information
CCF	Community Capital Framework
CCGT	Combined-cycle gas turbine (power plant)
CCSG	University of Queensland Centre for Coal Seam Gas
CEM	Conceptual Exposure Model
Central Petroleum	Central Petroleum Limited
CET	Clean energy target
CGE	Computable general equilibrium
CH_4	Methane
Christmas tree	Control valves, pressure gauges and chokes assembled at the top of a well to control the flow of gas after the well has been drilled and completed.
CI	Confidence interval
CLA	Cambrian Limestone Aquifer
CLC	Central Land Council
CLP	Country Liberal Party
CMA	Cumulative management area
CNS	Central nervous system
CO_2	Carbon dioxide
COAG Energy Council	Council of Australian Governments Energy Council
CoC	Chemicals of concern
Coffey	Coffey Services Australia Pty Ltd
Coffey reports	Reports prepared by Coffey: • CSRM Report; • Beetaloo Sub-basin SIA Report; • Beetaloo Sub-basin Case Study; and • CSIRO Report
COP21	Conference of the Parties, United Nations Framework Convention on Climate Change, 21st session. See 'Paris Agreement'.
CRS	Chronic rhinosinusitis
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIRO Report	*Social licence to operate in the Beetaloo Basin and Northern Territory,* Moffat K, Lacey J, McCrea R and Poruschi L, 2017
CSM	Conceptual site model
CSRM	Centre for Social Responsibility in Mining (University of Queensland)
CSRM Report	*A framework for Social Impact Assessment of shale gas development in the Northern Territory,* Witt K, Vivoda V, Everingham J and Bainton N, November 2017
DDPHU	Darling Downs Public Health Unit
Deloitte	Deloitte Access Economics
DENR	Department of Environment and Natural Resources (NT)
DIDO	Drive-in drive-out worker

Term	Definition
DIPL	Department of Infrastructure, Planning and Logistics (NT)
DLs	Detection limits
Drilling fluid/mud	Circulating fluid that lifts rock cuttings from the wellbore to the surface during the drilling operation. Also functions to cool down the drill bit, and is a component of well control.
DPIR	Department of Primary Industry and Resources (NT)
Draft Final Report	Draft Final Report, published December 2017
EAA	Environmental Assessment Act 1982 (NT)
EDO	Environmental Defenders Office NT
EDOA	Environmental Defenders Offices of Australia
EIS	Environmental impact statement
EMP	Environment management plan
EnRiskS	Environment Risk Sciences
EO	Environmental objective
EP	Petroleum exploration permit under the *Petroleum Act 1984* (NT)
EP Act	*Environment Protection Act* - proposed new environmental legislation
EPA	Northern Territory Environment Protection Authority
EPBC Act	*Environment Protection and Biodiversity Conservation Act 1999* (Cth)
EPO	Environmental protection order
ERA	Economic Regulation Authority
ESD	Ecologically sustainable development
EUR	Estimated ultimate recoveries
EV	Environmental values
Exploration activity	Any physical activity associated with drilling and hydraulic fracturing (which may include clearing and/or well construction) pursuant to the granting of exploration approvals for onshore shale gas on an exploration permit.
Exploration approvals	All operational approvals under the Schedule and all environmental approvals under the Petroleum Environment Regulations granted on an exploration permit for an exploration activity.
Exploration creep	Large numbers of exploration wells being drilled and hydraulically fractured pursuant to exploration approvals granted on an exploration permit .
FIFO	Fly-in fly-out worker
Flowback	Allowing fluids to flow from the well following a hydraulic fracturing treatment. Flowback fluid is composed of a mixture of hydraulic fracturing fluid and formation fluid.
Formation fluid	Any fluid within the pores of the rock. It may be water, oil, gas or a mixture. Formation water in shallow aquifers can be fresh. Formation water in deeper layers of rock is typically saline.
FPIC	Free, prior, and informed consent
Fracking	See 'hydraulic fracturing'
Framework	NT Water Allocation Planning Framework
FTE	Full time equivalent
Fugitive emissions	Intentional and unintentional release of greenhouse gases during the production, processing, transport, storage, transmission and distribution of fossil fuels.
GAB	Great Artesian Basin
GDE	Groundwater dependent ecosystems
GDP	Gross domestic product
GHG	Greenhouse gases
GISERA	Gas Industry Social and Environmental Research Alliance
GLNG	Gladstone Liquefied Natural Gas
Government	Northern Territory Government

Term	Definition
GSP	Gross State product
GST	Goods and services tax
GWP	Global warming potential
H2S	Hydrogen sulfide
Hancock Prospecting	Hancock Prospecting Pty Ltd
HDPE	High-density polyethylene
HELE	High efficiency, low emissions power generation
Heritage Act	*Heritage Act 2011* (NT)
HFF	Hydraulic fracturing fluid
HHRA	Human health risk assessment
HI	Hazard index
HIA	Health impact assessment
Horizontal drilling	Drilling of a well in a horizontal or nearhorizontal plane, usually within the target hydrocarbon-bearing formation. Requires the use of directional drilling techniques that allow the deviation of the well on to a desired trajectory.
Hydraulic fracturing	Also known as 'fracking', 'fraccing' or 'fracture simulation'. This is a process by which geological formations bearing hydrocarbons (oil and gas) are 'stimulated' to increase the flow of hydrocarbons and other fluids towards the well. In most cases, hydraulic fracturing is undertaken where the permeability of the formation is initially insufficient to support sustained flow of gas. The process involves the injection of fluids, proppant and additives under high pressure into a geological formation to create a conductive fracture. The fracture extends from the well into the production interval, creating a pathway through which oil or gas is transported to the well.
Hydraulic fracturing fluid / frac fluid	The fluid injected into a well for hydraulic fracturing. Consists of a primary carrier fluid (usually water or a gel), a proppant such as sand and chemicals to modify the fluid properties.
IBRA	International Biogeographic Regionalisation for Australia
IEA	International Energy Agency
IMAP	Inventory Multi-tiered Assessment and Prioritisation
Impact	The difference between what happens as a result of activities and processes, and what happens without them. Impacts can be changes that occur to the natural environment, community or economy. They can be a direct or indirect result of activities, or a cumulative result of multiple activities or processes.
Interim Report	Interim Report, published July 2017
Indigenous land	Land under the Land Rights Act and the Native Title Act
Inquiry	Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory
IPA	Indigenous Protected Areas
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Organisation
Issues Paper	*Background and Issues Paper,* published February 2017
KTP	Key threatening process
Land Access Guidelines	Stakeholder Engagement Guidelines Land Access
Land Rights Act	*Aboriginal Land Rights (Northern Territory) Act 1976* (Cth)
Lazarus Report	*Senate Select Committee on Unconventional Gas Mining Interim Report,* Chaired by Senator Glenn Lazarus in 2016
LCOE	Levelised cost of electricity
LEC	Land and Environment Court of NSW
LNG	Liquefied natural gas
Lock the Gate	Lock the Gate Alliance
LULUCF	Land use, land-use change and forestry

Term	Definition
MAR	Managed aquifer recharge
MEI	Melbourne Energy Institute
Minister for Environment	Northern Territory Minister for Environment and Natural Resources
Minister for Resources	Northern Territory Minister for Primary Industry and Resources
MNES	Matters of national environmental significance
Montara Inquiry	Montara Commission of Inquiry
MSDS	Material Safety Data Sheets
NAIF	Northern Australia Infrastructure Facility
NARMCO	North Australian Rural Management Consultants Pty Ltd
Native Title Act	*Native Title Act 1993* (Cth)
Native title land	Land subject to a native title application or determination under the *Native Title Act 1993* (Cth)
NCRA	National Chemicals Risk Assessment
NEPM	National Environment Protection Measure
NETL	US National Energy Technology Laboratory
NGER	National Greenhouse and Energy Reporting
NGGI	National Greenhouse Gas Inventory
NGP	Northern gas pipeline
NHMRC	National Health and Medical Research Council
NICNAS	National Industrial Chemicals Notification and Assessment Scheme
NIR	National Inventory Report
NLC	Northern Land Council
NNTT	National Native Title Tribunal
N_2O	Nitrous oxide
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NORM	Naturally occurring radioactive materials. Radioactive elements and their decay products found in the environment that have been generated from natural processes.
NO_x	Oxides of nitrogen
NSPS	US EPA New Source Performance Standards
NSW	New South Wales
NTA	*Native Title Act 1993* (Cth)
NT	Northern Territory
NTCA	Northern Territory Cattlemen's Association
NTCAT	Northern Territory Civil and Administrative Tribunal
OCGT	Open cycle gas turbine
OGI	Optical gas imaging
OGIA	Office of Groundwater Impact Assessment
OR	Odds ratio (a measure of association between exposure and outcome)
Overpressure	Occurs when the pore pressure is higher than the hydrostatic pressure, caused by an increase in the amount of fluid or gas in the rock, or changes to the rock that reduce the amount of pore space. If the fluid cannot escape, the result is an increase in pore pressure. Overpressure can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure.
Origin	Origin Energy Limited
OSGR	Onshore Shale Gas Regulator
Panel	The scientific panel appointed by the Chief Minister to conduct the Inquiry
Pangaea	Pangaea Resources Pty Ltd

Term	Definition
Paris Agreement	Decision of the Conference of the Parties, United Nations Framework Convention on Climate Change, Adoption of the Paris Agreement, 21st session, UN Doc FCCC/CP/2015/L.9/Rev.1. See COP21
Pastoral Land Act	*Pastoral Land Act 1992* (NT)
Pastoral Lease	Pastoral leases granted under the *Pastoral Land Act 1992* (NT)
Pastoral lessee/ pastoralist	Holder of a pastoral lease under the *Pastoral Land Act 1992* (NT)
Perforation	A channel created through the casing and cement in a well to allow fluid to flow between the well and the reservoir (hydraulic fracturing fluids into the reservoir, or gas and oil into the well). The most common method uses perforating guns equipped with shaped explosive charges that produce a jet.
Permeability	The measure of the ability of a rock, soil or sediment to yield or transmit a fluid. The magnitude of permeability depends largely on the porosity and the interconnectivity of pores and spaces in the ground.
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 Regulations	*Petroleum Regulations 1994* (NT)
Plug	A mechanical device or material (such as cement) placed within a well to prevent vertical movement of fluids.
PM	Particulate matter
Pressure test	A method of testing well integrity by raising the internal pressure of the well up to maximum expected design parameters.
Production activity	Any physical activity associated with drilling and hydraulic fracturing (which may include clearing and/or well construction) pursuant to the granting of production approvals for onshore shale gas on a production licence.
Production approvals	All operational approvals granted under the Schedule and all environmental approvals granted under the Petroleum Environment Regulations on a production licence for a production activity.
Production casing	A casing string that is set across the reservoir interval and within which the primary completion components are installed.
Production zone	Hydrocarbon producing zone of the shale formation.
Proppant	A component of the hydraulic fracturing fluid system comprised of sand, ceramics or other granular material that 'prop' open fractures to prevent them from closing when the injection is stopped.
RECs	Reduced emission completions
Risk	The probability of an adverse effect in an organism, system or population (or subpopulation) caused under specified circumstances by exposure to an agent.
RMPs	Regional Management Plans
RP Act	Regulatory Powers (*Standard Provisions) Act 2014* (Cth)
SA	South Australia
Sacred Sites Act	*Northern Territory Aboriginal Sacred Sites Act 1989* (NT)
Santos	Santos Ltd
Schedule	*Schedule of Onshore Petroleum Exploration and Production Requirements 2016* (NT)
Seismic survey	A method for imaging the subsurface using controlled seismic energy sources and receivers at the surface. Measures the reflection and refraction of seismic energy as it travels through rock.
SIA	Social impact assessment
SLO	Social licence to operate
SREBA	Strategic regional environmental and baseline assessment
SCVF	Surface casing vent flow. Flow of gas from a vent in the annulus between surface casing and other casing strings in a well.

Term	Definition
SCP	Sustained casing pressure. Sustained pressure in the annulus between casing strings.
TAMEST	The Academy of Medicine, Engineering and Science of Texas
TAP	Threat abatement plan
TDS	Total dissolved salts
TMP	Traffic management plans
TPWC Act	*Territory Parks and Wildlife Conservation Act 1976* (NT)
TWP	Total warming potential
UGE	Unconventional gas extraction
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
UQ	University of Queensland
US	United States of America or United States
US EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOCs	Volatile organic compounds
WA	Western Australia
WAP	Water Allocation Plan
Water Act	*Water Act 1992* (NT)
Waste Management Act	*Waste Management and Pollution Control Act 1998* (NT)
WCD	Water Control District
Weeds Act	*Weeds Management Act 2001* (NT)
Well barrier	Envelope of one or several dependent barrier elements (including casing, cement, and any other downhole or surface sealing components) that prevent fluids from flowing unintentionally between a bore or a well and geological formations, between geological formations or to the surface.
Well integrity	The International Standards organisation defines well integrity as, *"well integrity refers to maintaining full control of fluids (or gases) within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid (gas or liquid) movement between formations with different pressure regimes, or loss of containment to the environment."*
Well integrity failure	Can result from a well breach (or a number of well breaches) and can take the form of a hydrological breach (fluid moves between different geological units) or an environmental breach (fluid leaks from the well and contaminates water resources.
Well pad	The area of land on which the surface infrastructure for drilling and hydraulic fracturing operations are placed. The size of a well pad depends on the type of operation (for example, well pads are larger during the initial drilling and HF than at production).
WIMS	Well integrity management system
Zonal isolation	Exclusion of fluids such as water or gas in one zone from mixing with fluids in another zone.

Units of measurement

Unit	Definition
Bcm	Billion cubic metres
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
mm/y	Millimetres per year
mS/cm	Millisiemens per centimetre (= 1000 uS/cm)
Mt CO_2e	Million tonnes of carbon dioxide equivalent
M_W	Moment magnitude. The moment magnitude scale is based on the total moment release of the earthquake. Moment magnitude estimates are about the same as Richter magnitudes for small to large (ie <8) earthquakes.
MWh	Megawatt-hour
PJ	Petajoules
t	Tonne (1,000 kg)
Tcf	Trillion cubic feet
TDS	Total dissolved salts
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 per centimetre

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