SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

SUMMARY OF THE DRAFT FINAL REPORT

DECEMBER 2017

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This Summary of the draft Final Report supports and refers to the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory draft Final Report. There is also a set of appendices. Each document has been published separately, but together they form the totality of the draft Final Report.

The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory
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Cover: Pool, Finke River, James Range by Benjamin Landara.

Credit: Benjamin Landara, Pool, Finke River, James Range, © the artist licensed by Aboriginal Artists Agency, image courtesy of Araluen Arts Centre.

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Introduction

"There was once a town in the heart of America where all life seemed to live in harmony with its surroundings. The town lay in the midst of a checkerboard of prosperous farms, with fields of grain and hillsides of orchards where, in spring, white clouds of bloom drifted above the green field. In autumn, oak and maple and birch set up a blaze of colour that flamed and flickered across a backdrop of pine. Then foxes barked in the hills and deer silently crossed the fields, half hidden in the mists of the fall mornings.

Along the roads, laurel, viburnum and alder, great ferns and wildflowers delighted the traveller's eye through much of the year. Even in the winter the roadsides were places of beauty where countless birds came to feed on the berries and on the seed heads of the dried weeds rising above the snow. The countryside was, in fact, famous for the abundance and variety of its birdlife, and when the flood of migrants was pouring through in spring and fall people travelled from great distances to observe them. Others came to fish the streams, which flowed clear and cold out of the hills and contained shady pools where trout lay. So it had been from the days many years ago when the first settlers readied their houses, sank their wells and built their barns.

Then a strange blight crept over the area and everything began to change. Some evil spell had settled on the community; mysterious maladies swept the flocks of chickens; the cattle and sheep sickened and died. Everywhere was a shadow of death. The farmers spoke of much illness among their families. In the town the doctors had become more and more puzzled by new kinds of sickness appearing among their patients. There had been several sudden and unexplained deaths, not only among adults but even among children, who would be stricken suddenly while at play and die within a few hours.

There was a strange stillness. The birds, for example - where had they gone? Many people spoke of them, puzzled and disturbed. The feeding stations in the backyards were deserted. The few birds seen anywhere were moribund; they trembled violently and could not fly. It was spring without voices. On the mornings that had once throbbed with the dawn chorus of robins, catbirds, doves, jays, wrens and scores of other bird voices there was now no sound; only silence lay over the fields and woods and marsh.

On the farms the hens brooded, but no chicks hatched. The farmers complained that they were unable to raise any pigs - the litters were small and the young survived only a few days. The apple trees were coming into bloom but no bees droned among the blossoms, so there was no pollination and there would be no fruit.

The roadsides, once so attractive, were now lined with browned and withered vegetation as though swept by fire. These, too, were silent, deserted by all living things. Even the streams were now lifeless. Anglers no longer visited them, for all fish had died.

In the gutters under eaves and between the shingles of the roofs, a white granular powder still showed a few patches; some weeks before it had fallen like snow upon the roofs and the lawns, the fields and streams.

No witchcraft, no enemy action had silenced the rebirth of new life in this stricken world. The people had done it themselves." [1]

So wrote Rachel Carson in her celebrated cautionary tale *Silent Spring*. Published in 1962, the book documented her concern about the indiscriminate use of pesticides, especially DDT, and their adverse effect on the environment. More broadly, it powerfully detailed the often unforeseen and potentially catastrophic consequences that unchecked industrialisation can have on humanity. Although met with predictably trenchant opposition by the chemical manufacturing sector, this seminal work introduced the notion of environmental conservation to the wider American public. Importantly, it inspired a movement that was instrumental in the establishment of the US Environmental Protection Agency.

Over a half a century later and the central tenet of the book resonates ever louder, especially as we enter an era of dangerous anthropogenic climate change.

1 Carson 1962, pp 1-3.

In the United States of America (**US**), the 'shale gale' gas revolution turned the US from an energy importer into an energy exporter. It transformed the energy market in North America and significantly affected world trade in gas and oil. But with this change came cost. In some jurisdictions the industry developed in a virtual legislative lacuna, with poor regulatory governance resulting in even poorer environmental outcomes. The term 'fracking', whether for coal seam, tight or shale gas, has therefore become synonymous with water contamination, water depletion, land degradation, air pollution and chronic health problems.

It is no doubt because of these issues, and the understandable public anxiety accompanying them, that fracking has been legislatively prohibited in Victoria and is the subject of a moratorium in Tasmania, New South Wales and Western Australia. Overseas it has been banned in countries such as France, Germany and Scotland, in two provinces in Canada (New Brunswick and Nova Scotia) and in several states in the US (Vermont, New York and Maryland, for example). The development and regulation of any onshore unconventional gas industry is an equally contentious matter in the Northern Territory (**NT**). The last three Territory governments have commissioned reviews and inquiries into the onshore unconventional petroleum industry in an attempt to address and alleviate community concerns in this regard.

In 2012, the former Labor Government commissioned Dr Tina Hunter from the Faculty of Law at Bond University to report on the capacity of the NT's legal framework to regulate the development of shale gas in the Northern Territory (**2012 Hunter Report**). A key recommendation from the 2011 Hunter Report was that Government should prioritise the development and implementation of environmental regulations under the *Petroleum Act 1984* (NT).

In March 2014, the former Country Liberal Party (**CLP**) Government appointed Dr Allan Hawke AC as the Commissioner of an inquiry under the *Inquiries Act 1945* (NT) into hydraulic fracturing. Dr Hawke provided his report to the Government in November 2014 (**2014 Hawke Report**). One of the recommendations of the 2014 Hawke Report was that the Government conduct a review of the environmental assessment and approval processes in the NT. Accordingly, the CLP Government re-engaged Dr Hawke to conduct this work. Dr Hawke's second report (**2015 Hawke Report**) was released in late 2015. The 2015 Hawke Report did not relate directly to hydraulic fracturing, rather it provided the Government with guidance on how activities with environmental impacts, such as hydraulic fracturing, might be effectively regulated.

Following the 2012 Hunter Report and the 2014 and 2015 Hawke Reports, the CLP Government enacted the *Petroleum (Environment) Regulations 2016* (NT) (**Petroleum Environment Regulations**)*.* The Petroleum Environment Regulations implemented many of the recommendations made in the earlier reports.

In early 2016, the CLP Government commissioned Dr Tina Hunter to conduct an independent assessment of the draft Petroleum Environment Regulations (**2016 Hunter Report**). Although Dr Hunter described the Petroleum Environment Regulations as "*a quantum leap from the Northern Territory regulations of old*", she went on to note that further reforms to the regulatory framework were required in order to increase industry certainty, the accountability of the regulator, and the transparency of decision making.

On 14 September 2016, the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional shale reservoirs in the NT. The Chief Minister also announced that he would appoint an independent scientific panel to inquire into the potential impacts and risks associated with hydraulic fracturing. Accordingly, on 3 December 2016, the Government announced that it had established the Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory (**Inquiry**) under the *Inquiries Act 1945* (NT). The Government has stated publicly that the moratorium will stay in place for the duration of the Inquiry.

The Inquiry is chaired by the Hon Justice Rachel Pepper, a judge of the Land and Environment Court of New South Wales. The Inquiry panel is comprised of a number of eminent scientists across a range of relevant disciplines (**Panel**). A list of the names and biographies of the Chair and the Panel members can be found on the Inquiry's website at www.frackinginquiry.nt.gov.au.

The purpose of the Inquiry is found in the Terms of Reference (also located on the Inquiry's website). 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 (for a full description of the Inquiry's purpose and its risk assessment methodology see Chapters 1 and 4 of the draft Final Report, respectively):

- the nature and extent of the risks identified with the hydraulic fracturing of onshore unconventional shale reservoirs and its associated activities on the environmental (aquatic, terrestrial and atmospheric), social, cultural and economic conditions of the 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 Inquiry differs markedly from its predecessors by reason of its wide scope and its strong mandate to consult widely with Territorians. The Inquiry has taken this mandate very seriously, as the discussion of the work of the Inquiry and the description of its community engagement in Chapters 2 and 3 demonstrates. The extensive consultation process established by the Inquiry has been enthusiastically embraced by Territorians, with community groups, environmental groups, Land Councils, local councils, government agencies, industry and individual members of the public participating in the Inquiry at live-streamed public hearings, in community forums, and by writing more than 500 submissions.

In this context, it must be noted that the strong antipathy surrounding fracking demonstrated during the first round of consultations held by the Inquiry was also present during the second round of consultations. For a sizeable majority of the people attending the public hearings and the community forums, the consensus was that hydraulic fracturing for onshore shale gas in the NT is not safe, is not trusted, and is not wanted.

But as stated in the *Interim Report*, and as continued to be observed throughout the Inquiry, this is not a universally held view. Many groups and individuals expressed the opinion that adequately safeguarded by a sufficiently robust and vigorously enforced regulatory regime, the onshore extraction of shale gas could be beneficial to the NT, creating short and long-term employment opportunities and raising much needed revenue for the Government and for Aboriginal and non-Aboriginal communities. While promises of jobs and growth in the petroleum industry have all too often proven to be inflated estimates, the economic modelling commissioned by the Inquiry strongly suggests that tangible economic advantages will flow to the NT if this industry is permitted to proceed by the Government.

The task of this Inquiry is not to recommend to the Government that it retain or lift the moratorium. That decision is inherently political, and as such, is for the Government alone to make. Rather, the work of the Inquiry is to identify and assess, based on the most current and best available relevant scientific evidence, the environmental, social, cultural and economic risks associated with hydraulic fracturing for onshore shale gas in the NT, and to make recommendations to mitigate those risks, where possible, to acceptable levels. In circumstances where insufficient data has existed to undertake this task, the Inquiry has not hesitated in recommending that the necessary additional information be obtained prior to the development of any onshore shale gas industry in the NT.

Having regard to the final list of issues, or risks, identified by the Inquiry (contained in Appendix 2) and the risk assessment methodology applied by Panel in its analysis of those risks (as described immediately below in relation to Chapter 4), the principal findings and the recommendations of the Inquiry are set out as follows.

Evidence and risk assessment methodology (Chapter 4)

Having regard to the most current and relevant scientific literature and submissions received, the Panel has collected and analysed the available evidence concerning the final list of issues, or risks, identified after consultation with the community, industry, Land Councils, local government, environmental groups, and government agencies. The issues were grouped into the following broad categories (or themes):

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

The principles of ecologically sustainable development are at the core of the Panel's analysis. The Panel used these principles to formulate values and objectives as an initial part of the risk assessment process, and to identify the mechanisms that will ensure those objectives are achieved. The process that the Panel has followed to assess each of the above issues has been tailored to the nature of the issue.

It became apparent during the Panel's deliberations, taking into account the published scientific evidence and the submissions received, that the biophysical (water, land, air) and public health risks would be best assessed by applying a standardised qualitative, multi-step risk assessment process. The Panel has assessed these risks in terms of the likelihood of that risk occurring, and the consequence if that risk were to eventuate. This methodology has been applied in Chapters 7 to 10, covering water, land, air and public health, respectively. A similar approached is to be employed by the consultants engaged to undertake the social impact assessment (**SIA**) on behalf of the Panel (Chapter 12). By contrast, the themes of Aboriginal people and their culture (Chapter 11) and economic impacts (Chapter 13) are not suited to this type of assessment. Accordingly, the methods used to assess the nature of these risks are described and implemented separately in each of those Chapters.

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

An assessment of risk was only undertaken where there was sufficient information or evidence to do so. The assessment assumed the application of the current governance 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 was invoked where there was a possibility that the consequence of the risk was an unacceptable impact on the value sought to be protected. In this case, mitigation measures must be implemented until such time as it can be proven by acquisition of additional information that the risk does not require the initially prescribed level of mitigation.

Shale gas extraction and development (Chapter 5)

This Chapter describes what unconventional shale gas is, the gas extraction process including hydraulic fracturing, the steps involved in the development of a shale gas industry, the critical issue of well integrity, water requirements, and the nature of the wastewaters produced that require management. The issues of solid waste management, seismic activity and the potential for subsidence are also reviewed. The content of this Chapter provides much of the evidence needed to support the risk assessments undertaken in Chapters 7 to 10.

The commercial production of shale gas is the culmination of a process spanning several years, which includes exploration, drilling, hydraulic fracturing, testing and economic analysis. It is possible that even after several years of exploration and investigation, the potential resource can be found to be uneconomic. Even if the resource is economic, it will take several more years of development before full-scale production comes online. Based on overseas experience, an individual shale gas well can be expected to produce for several decades before finally being decommissioned.

Well integrity

The possibility that water resources, in particular, groundwater, could be contaminated by activities associated with the extraction of shale gas was the major concern of all communities consulted by the Panel. Accordingly, much attention has been paid to the issue of well integrity. The International Standards Organisation defines well integrity as referring to *"maintaining full control of fluids (or gasses) 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."* [2]

In addition to conducting its own research on well integrity, the Panel commissioned CSIRO to conduct an extensive and in-depth review of all aspects of this topic. The complete report by CSIRO is contained in Appendix 14. The Panel has drawn upon this report to produce the sections relating to well integrity issues in this Chapter. However, it should be noted that all conclusions and recommendations are those of the Panel.

CSIRO reviewed the well barrier and well integrity failure rates that have reported in the open literature. The term 'well barrier failure' is identified in a number of ways, including by sustained casing pressure in the well. By contrast, '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 the failure of individual barriers and well integrity failure, a distinction that is critical because full integrity failure (that is, the failure of multiple barriers) is required to provide a pathway for the contamination of the environment.

CSIRO found that historically, the highest instance of well barrier integrity failure is due to insufficient or poor quality cement coverage to seal aquifers and/or hydrocarbon-bearing formations. Therefore, the quality and extent of vertical coverage along the well during the initial cementing job, and the maintenance of the integrity of the cement over time, are critical.

CSIRO found overall, largely using data sets from the US, that the rate of well integrity failure that has the potential to cause environmental contamination is approximately of 0.1%, with several studies finding no well integrity failure. The rate for a single well barrier failure was much higher, however, in the order of 1-10%. However, there were very few single barrier failures observed for wells constructed to Category 9 (see **Table 5.2** of the draft Final Report for a description of well categories) or above. The Amungee NW-1H well that was constructed by Origin in the Beetaloo Sub-basin was of Category 9 standard, with casing cemented to the surface along the entire length of the well.

Abandonment (where the wells are decommissioned and 'plugged and abandoned') is the final phase in the well life cycle. This long-term issue is also of major concern to communities. The goal of plugging and abandoning the well is to ensure the integrity of the well in perpetuity by effectively re-establishing the natural barriers formed by impermeable rock layers drilled through to reach the resource. The aims of abandonment are to:

- prevent 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.

CSIRO found that for shale gas wells abandoned using existing practice, if any of the potential leakage pathways were to develop, it is highly unlikely that they would allow large fluid flow rates along the well bore. The small cross-sectional areas and long vertical lengths of the pathways will tend to limit flow. The low permeability of shale gas formations is also a factor mitigating the potential for adverse impacts caused by loss of well integrity post well abandonment. 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.

2 ISO 2017.

Even though CSIRO concluded that the potential for serious post abandonment integrity issues is low, the Panel has found that there is very little information available worldwide on the performance of abandoned onshore shale gas wells. The assessment of post abandonment performance is an aspect that requires greater attention by both the regulator and industry. This aspect is the subject of specific recommendations by the Panel (see below).

Overall, the Panel concludes that provided that a well is constructed to the high standard required for the particular local geology and has passed all of the relevant integrity tests prior to, during and after hydraulic fracturing, there is a 'low' likelihood of integrity issues arising out of its initial construction. But there should be a program of regular integrity testing throughout the decades-long operational life of the well to ensure that if any problems do develop that they are detected and remediated early. 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.

Measurements after final decommissioning should be conducted to confirm that the plugs have been properly set in the well, and water quality should be continually monitored in groundwater monitoring bores installed adjacent to all well pads. These assurance steps, from well design through to initial integrity testing, operational monitoring and decommissioning, must be subject to independent audit and certification.

Water

Communities are understandably concerned about the amount of water required for drilling and hydraulic fracturing, and the amount of wastewater produced that will require storage and treatment. Estimates based on overseas experience have been provided for the volumes of water required to develop a well, and for the volumes and nature of the wastewaters that may be produced (further information on water-related issues is contained in Chapter 7). In this context, it should be noted that the gas companies are proposing to use multi-well pads (at least 10 wells per pad) to extract the gas. This configuration provides substantial benefits in terms of both reducing the physical footprint of any onshore shale gas industry (see Chapter 8), and in management of the wastewater, because it will facilitate reuse of water to drill and fracture subsequent wells on the well pad.

Shale gas extraction requires the use of large quantities of water, which may be obtained from local surface or groundwater sources, or externally transported to the site. Typical water volumes used are around 1-2 ML for well drilling, and approximately 1-2 ML for each hydraulic fracturing stage. In the US, the most recent long horizontal wells require 30-40 fracturing stages. The indications are that this is analogous to any shale gas industry developed in the NT. The Panel notes that if 1-2 ML of water is required for each stage of fracking, and at least 20 stages of fracking are likely, based on developing industry practice, 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 also depend on the extent of reuse possible, noting that the wells would be fractured sequentially rather than concurrently.

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

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

'Flowback water' is made up of drilling and injected hydraulic fracturing fluids and formation brines that are trapped in the target formations and extracted together with the gas. Water generated after the flowback period, during the lifetime of oil and gas production, is commonly called 'produced water', the composition of which resembles the original formation water present in the shale layer and is typically very saline.

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. Once above ground, the flowback water is usually either stored in temporary storage tanks or ponds, or conveyed by a pipeline to a wastewater treatment plant.

Reuse of flowback water can reduce, but not eliminate, the amount of fresh water needed for hydraulic fracturing because the volume of flowback water from a single well is generally small compared to the total volume needed to fracture a well. The extent of reuse of flowback or produced water depends on its quality because certain contaminants can interfere with hydraulic fracturing performance. The volumes of flowback water likely to be produced by a production environment in the NT are yet to be determined. However, the initial indication from the Amungee-NW-1H test well is that the quality of flowback water from the Velkerri formation is likely to be suitable for reuse.

Chemicals used in fracturing

The nature of chemicals used in hydraulic fracturing is a cause of considerable anxiety to the public. Hydraulic fracturing technology has evolved rapidly over the past decade, and much greater attention is now given to the potential for contamination of below ground and surface environments, with a much smaller fraction of the 1,100 different chemicals identified by the US EPA as having been historically used in the US for hydraulic fracturing now being routinely employed in modern extraction practices. Between January 2011 and February 2013, only 35 of the total identified number of previously used chemicals were used in most of the fracturing operations over that two-year period in the US.

Additionally, there has been a strong move over the last decade by industry to use less toxic and more readily degradable chemicals. However, there still needs to be stringent controls on the transport, storage and use of these chemicals, with the least toxic chemicals available used (that is, a reduction of the risk profile by substitution). Chapters 7 and 10 contain further discussion of the risks associated with hydraulic fracturing chemical usage.

Based on the evidence from the US, the Panel finds that there is significant potential for accidental releases, leaks and spills of hydraulic fracturing chemicals and fluids, flowback and produced water. However, while there have been more than one million fracture stimulations (fracturing) treatments in North America and more than 1,300 in South Australia's Cooper Basin, there has been no reported evidence of fracturing fluid moving from the fractures to near surface aquifers.

The Panel notes that public disclosure of *"specific information regarding chemicals"* used in hydraulic fracturing is required in the NT. Indeed, the chemicals used for the eight unconventional wells that have been hydraulically fractured in the NT are available on the Department of Primary Industry and Resources (**DPIR**) website. However, in common with other jurisdictions, there is currently no requirement to publicly disclose the composition of flowback water. Given that flowback water can contain chemicals (extracted from the shale seam) in addition to those used for hydraulic fracturing, the Panel considers that there must be mandatory disclosure for flowback water given the potential for accidental release of this water to the surface environment.

Management of solid wastes

The solids produced by drilling represent a substantial waste stream associated with the production of shale gas. In the US, the disposal of the large amounts of drill cuttings resulting from full-scale production is a cause of concern given the nature of this material and its potential to leach organic and inorganic components into the near surface environment. A strategic management issue for any potential onshore shale gas industry in the NT will be the question of whether this solid waste should be contained in a purpose-built and engineered centralised facility, or contained and managed on a per well pad basis, as is currently the case during exploration. Protocols and procedures have been developed by regulators, industry and commercial waste handling facilities elsewhere (including Queensland) to screen drilling wastes for metals, naturally occurring radioactive materials, and hydrocarbons, and to separate out cleaner material that can be used for other purposes, such as road base.

Seismic activity

The possibility of hydraulic fracturing causing earthquakes of sufficient magnitude to cause structural damage (2 or greater on the Richter scale) has been raised. 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 to this assessment is if a fault is activated by the reinjection of fluid. The Panel has recommended that seismic activity is monitored during hydraulic fracturing operations and that if such activity exceeds 0.5 on the Richter scale, that the operations be immediately terminated, or pressure reduced in accordance with United Kingdom (**UK**) operational guidelines.

By contrast, there have been many instances of higher magnitude earthquakes resulting from the reinjection of wastewater into petroleum reservoirs. These larger earthquakes are often associated with the reactivation of existing faults within the reservoir formation. This aspect of induced seismic activity is discussed further in Chapter 7. It is recommended that reinjection should not occur unless comprehensive studies are conducted to prove that the risk will be low.

Subsidence

The development of sinkholes as a result of the hydraulic fracturing process has also been identified as potential issue. The Panel considers that sinkholes are highly unlikely to occur 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 should compensate for any small cavities produced by hydraulic fracturing. However, the Panel does note 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.

Recommendation 5.1

That the Government mandate a code of practice setting out minimum requirements for the abandonment of onshore shale gas wells in the NT. The code must be enforceable and include a requirement that:

- ***wells undergo pressure and cement integrity tests prior to abandonment, with any identified defects to be repaired prior to releasing the well for decommissioning; and***
- ***testing must be conducted to confirm that the plugs have been properly set in the well.***

Recommendation 5.2

That the Government mandate a program for the ongoing monitoring of abandoned shale gas wells in the NT. The program must include the ongoing monitoring of water quality by bores installed adjacent to the well and the results of such monitoring to be published in real-time.

Recommendation 5.3

That in consultation with industry and other stakeholders, the Government develop and mandate 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 (or equivalent) standard, 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 the results be independently certified, with the immediate remediation of identified issues 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 publicly reported.***

Recommendation 5.4

That gas companies be required to develop and implement a well integrity management system for each well in compliance with ISO 16530-1:2017.

That 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 lifecycle;***
- ***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 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.*

Recommendation 5.5

That the composition (inorganics, organics and NORMs) of flowback fluids, in addition to hydraulic fracturing fluids, be made publicly available.

Recommendation 5.6

That in consultation with industry and the community, the Government develop 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 absence of any treatment and disposal facilities in the NT for wastewater and brines produced by the industry be addressed as a matter of priority.

Recommendation 5.7

That in consultation with 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 the shale gas industry.[3]

Recommendation 5.8

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

Onshore shale gas in Australia and the Northern Territory (Chapter 6)

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 shale gas industry in Australia is still largely in the exploration phase.

The geological basins in the NT that are currently considered to contain not only prospective rocks with the necessary prerequisites for shale gas occurrence, but have also had some confirmation through exploration drilling, are the Amadeus Basin and the Beetaloo Sub-basin in the McArthur Basin. According to Geoscience Australia, total shale gas resources in the NT are currently 257,276 PJ, with almost 70% of this (178,200 PJ) estimated to occur in the Beetaloo Sub-basin[4] (refer Map 1). This resource is larger than any one of the North West Shelf conventional gas resources, the Cooper/ Eromanga basins or the Canning Basin shale gas resources. This suggests that the Beetaloo Sub-basin is a world class resource comparable to several of the major US shale gas basins.

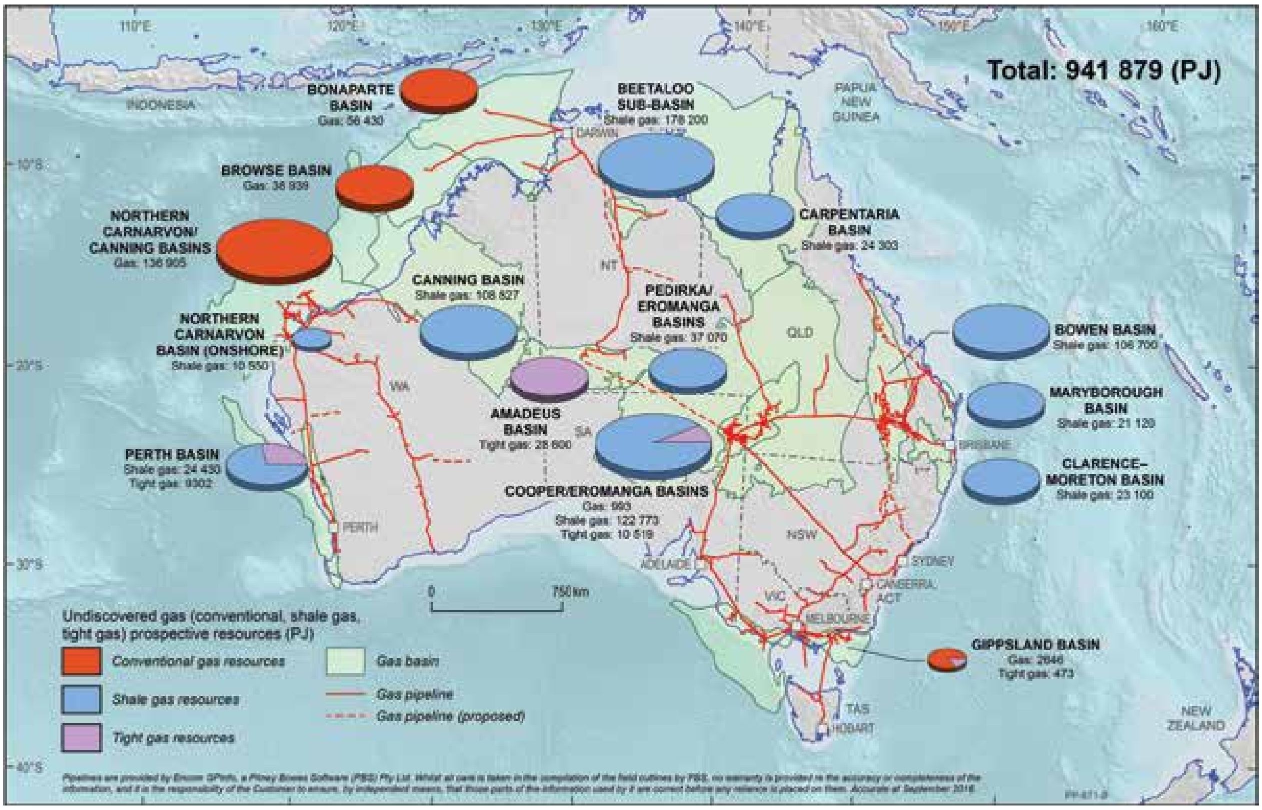
Several other potential basins in the NT have not been extensively or successfully tested to date. These include the broader McArthur Basin, the Wiso Basin, the Georgina Basin, the Perdika Basin and the onshore component of the Bonaparte Basin (refer Map 2). Given the long lead time from exploration to production, the most likely area for any possible shale gas development in the foreseeable future (5-10 years), if the moratorium is lifted by the Government, is the Beetaloo Sub-basin.

3 For example, DEHP 2013; DEHP 2015.
4 Geoscience Australia Submission 296.

The scale of any potential future development in the Beetaloo Sub-basin is difficult to state with any certainty at this early stage of resource assessment and testing. The estimates provided by the three petroleum companies currently involved (Origin, Santos and Pangaea) suggest that combined developments over the next 25 years could result in between 1,000 and 1,200 wells associated with around 150 pads. These estimates, with their associated requirements for infrastructure (well pads, roads and pipelines) and water inputs have been used by the Panel as the basis for the risk assessments conducted in Chapters 7 to 10 of this Report. Whether the proposed developments would proceed in parallel or sequentially will have a significant impact on the demand timeline for transport, drilling and hydraulic fracturing equipment, associated infrastructure, and workforce requirements.

It is noted that the development estimates provided by industry are consistent with the ranges used by ACIL Allen Consulting Pty Ltd (**ACIL Allen**) for its economic analysis (Chapter 13 and Appendix 16). These are considerably smaller than the estimates provided by DPIR in its written submission to the Panel, noting the DPIR estimates are based on maximum potential supply unconstrained by any economic factors (for example, the ability of the market to absorb the anticipated volume of production).

Map 1: Summary of Australia's prospective gas resources. Source: Geoscience Australia.[5]



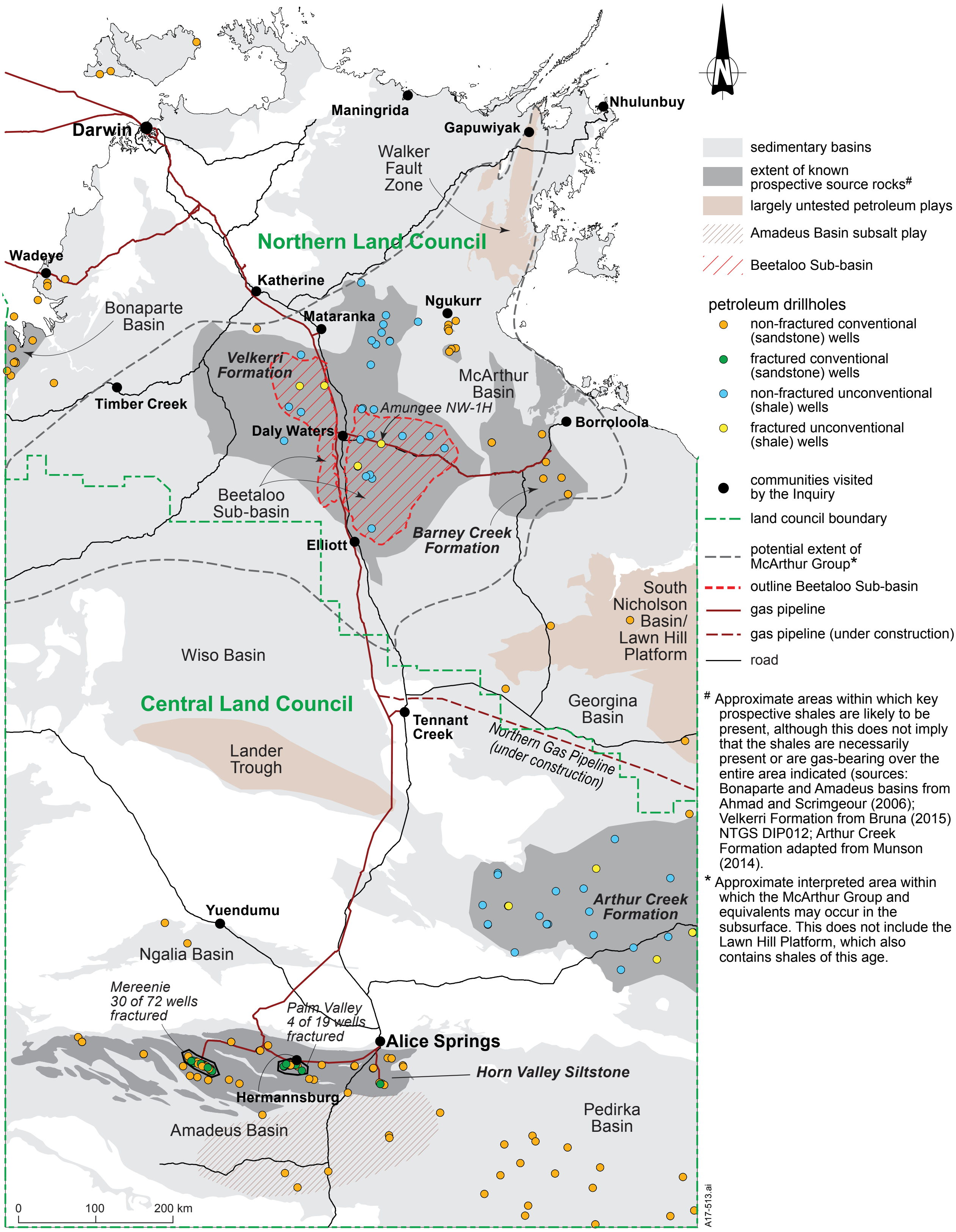
The actual infrastructure requirements (in particular, the numbers and density of well pads through time) will require careful scrutiny in the event that the moratorium is lifted and a commercial supply of gas is developed. Experience in the US has shown that production from individual wells, and ultimately from a whole field, declines over time, requiring additional wells to be commissioned, or the re-fracking of existing ones, to meet demand. These production declines can have significant (initially unexpected) implications for the future lateral extent of a gas field 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 shale gas basins in the NT to inform this long-term planning issue.

It is apparent that there is considerable uncertainty about the likely scale and rate of development of any shale gas industry in the Northern Territory if the moratorium is lifted by the Government.

5 Geoscience Australia submission 296.

Map 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.



NORTHERN TERRITORY GOVERNMENT

Water (Chapter 7)

Sustainable management of surface and groundwater resources will be crucial to the development of any onshore unconventional shale gas industry in the NT. This will involve the protection of three water-related environmental values: water quantity, water quality and aquatic ecosystems. These values will be protected by the achievement of three objectives: first, by ensuring surface and groundwater resources are used sustainably; second, by maintaining acceptable quality of surface and groundwaters; and third, by adequately protecting ecosystems that are dependent on surface or groundwater. The Beetaloo Sub-basin is the most prospective area in the NT for shale gas development and the prospective shale gas region for which the most data on water resources is available. It has therefore been used as a case study for a more detailed assessment of water-related risks associated with any shale gas development.

High flow in Newcastle Creek. Source: Matt Bolam.

The first part of Chapter 7 provides an overview of the surface water and groundwater resources in the NT and some of the regulations that govern use. The likely per-well water requirements for a medium-scale shale industry is then estimated to provide context for assessing how much water might be required. It became apparent to the Panel that there was not enough information for most of the prospective shale gas regions in the NT to be able to estimate the sustainable groundwater yield for any possible onshore shale gas industry. Although 90% of the current regional demand for water in the NT is supplied by groundwater, the bores that extract this water for communities (and, therefore, which are most monitored) are clustered in close proximity to these communities and do not provide the required regional information about aquifer properties.

The Panel has assessed twenty water related risks using the risk assessment framework detailed in Chapter 4. The Panel identified three high-priority issues from the risks assessed, namely: unsustainable groundwater use, the contamination of groundwater with hydraulic fracturing fluids and wastewater from leaky wells or from on-site surface spills, and the effect of any water quantity and quality risks on either surface and/or groundwater dependent ecosystems (**GDEs**).

Water quantity

The Panel has assessed the risks of any onshore shale gas industry in the NT having unacceptable effects on the sustainable use of surface and groundwater resources. The Panel used a feasible development scenario for the Beetaloo Sub-basin, comprising 1,000 to 1,200 hydraulically fractured shale gas wells (possibly 150 well pads) and estimated that this will require an average of 2,500 ML/y (up to 5,000 ML/y at peak demand), or a total of 20,000 to 60,000 ML of water over 25 years.

Impact on surface water supplies

The temporary nature of the surface water resources (rivers, streams and waterholes) in the semi-arid and arid regions of NT make it unlikely that surface waters would be used for hydraulic fracturing. The Panel has therefore assessed the risk to surface water supplies as 'low', and has recommended that the use of surface water resources for hydraulic fracturing should be prohibited for two reasons:

- first, the resource will only be potentially available for part of the year (wet season) with implications for the dry season if excessive amounts are extracted, particularly near the end of the wet season, leaving less water to fill wetlands and waterholes; and
- second, 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 year overly complex (for example, each river system would need its own set of rules) and very challenging to regulate.

To ensure that surface water resources are not used for hydraulic fracturing, it will be important that the new Water Allocation Plan (**WAP**) proposed for any region for which shale gas development is proposed prohibits the use of these water resources for this purpose.

Impact on groundwater supplies

Groundwater is likely to be the most economically viable water source for hydraulic fracturing in semi-arid and arid areas of the NT (for example, the Beetaloo Sub-basin). It is possible that water could be transported to well sites, but this would be expensive. There is a reasonable understanding of the shallower groundwater systems in the Beetaloo Sub-basin. The principal groundwater resource is the Cambrian Limestone Aquifer (**CLA**). In the northern Beetaloo Sub-basin (Mataranka to Daly Waters), it consists of the Gum Ridge and Tindall aquifers. In the southern Beetaloo Sub-basin (Daly Waters to Elliott), it consists of both an upper system, the Anthony Lagoon Formation, and a lower system, the Gum Ridge Formation. The available information suggests aquifers in the northern region are reasonably well recharged each year, while those in the southern basin are poorly recharged. The groundwater flow over the bulk of the Beetaloo Sub-basin is towards the north and very slow (around 1 m/y). The northern CLA is critical for maintaining baseflow in the Roper River system, sustaining Elsey National Park, Mataranka thermal pools, Red Lily Lagoon, and the riparian vegetation along the Roper River beyond the Beetaloo Sub-basin.

Regional impacts

The Panel has assessed the risk that any onshore unconventional 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 domestic use, use by other industries, and for the environment. It has concluded that there is insufficient information to permit a full assessment of the risks to groundwater resources from any shale gas industry established in the Beetaloo Sub-basin. Accordingly, the Panel has recommended that a strategic regional environmental and baseline assessment (**SREBA**) be undertaken to provide more detailed information on the groundwater resources before any approvals are granted for shale gas production. Further, the Panel has recommended 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;
- the Daly-Roper Water Control District be extended south to include all the Beetaloo Sub-basin; and
- a separate WAP be developed for the northern and southern regions of the Beetaloo Sub-basin.

Local impacts

The Panel has also examined the risk that water use by any onshore shale gas industry will cause an unacceptable local drawdown of nearby water supply bores, making it difficult for groundwater to be extracted for use in communities, for agriculture, for pastoralism, for ecosystems, or for cultural purposes. The limited available information suggests that there is a 'low' risk of a local drawdown of groundwater greater than 1 m at distances beyond 1 km from the gas company bore field. Hydrogeological investigations and groundwater modelling studies undertaken as part of the recommended regional assessment will permit confirmation of this distance. Additionally, the Panel has recommended that:

- the proposed new WAPs for the Beetaloo Sub-basin include provisions that adequately control both the rate and volume of water extraction by gas companies;
- gas companies be required to monitor drawdown in local water supply bores; and
- gas companies be required to 'make good' any problems if this drawdown is found to be excessive.

Water quality

The Panel's second objective in assessing the water-related risks was to ensure that the quality of surface and groundwaters (aquifers) is maintained in an acceptable condition for all users. The Panel expects any onshore shale gas operation to produce considerable volumes of wastewater (hydraulic fracturing fluids, flowback and produced water) that could pose a risk to surface and groundwater resources. The composition, management and potential reuse of such wastewaters is detailed in Chapter 5.

In undertaking its assessment of risks to water quality, the Panel has defined 'acceptable' as being that the *"quality of surface and ground (aquifer) waters should not be degraded such that they can no longer support their current highest level beneficial use"*. This means that the quality of the water should not be affected such that it can no longer support human drinking, agriculture, stock watering or aquatic ecosystems, as judged by the relevant Australian water quality criteria.

Leaky wells

Maintenance of well integrity during the initial hydraulic fracturing phase, through the decades-long operating life of a well, and for the period post decommissioning, are key concerns of the community. As discussed above, the Panel commissioned CSIRO to undertake a detailed review of this issue.

The Panel has distinguished between wells that leak methane only and those that leak both methane and flowback and/or produced water (formation water). This distinction is made because measurements of methane gas concentrations are often used as the sole indicator of problems with well integrity and the potential for groundwater contamination. However, the Panel has found that while there is a 'low' to 'medium' likelihood of detecting increases in methane in groundwater near shale gas wells, based largely on experience in the US, the likelihood of wastewater (salts and chemicals) being introduced from depth as a result of hydraulic fracturing is 'unlikely' to 'remote'. It is the salts and chemicals that are most likely to degrade the quality of groundwater, and not methane, as methane is non-toxic in groundwater.

In assessing the risk of aquifer contamination, the Panel considered two pathways: first, the entry of contaminants into an aquifer and second, the behaviour and transport of the contaminants in the aquifer to reach a water supply bore (or aquatic ecosystem). Three plausible pathways by which contaminants can feasibly move from depth to a surface aquifer have been considered:

- the rupture of the well casing during hydraulic fracturing - likelihood 'low', provided world leading practice guidelines for testing of well structural integrity are implemented and enforced;
- growth of hydraulic fractures from the shale deposit to the aquifer - likelihood 'low', given the very large distances (1 to 4 km) between the shale deposit and the surface aquifer; and
- growth of fractures into a pre-existing fault - likelihood 'low', provided that there is proper planning in the well design phase to avoid any faults.

In relation to wastewater, the Panel found that based on the available evidence, the likelihood of the upward migration from the shale formation of hydraulic fracturing fluids and chemicals leached from the shale and causing contamination of a surface aquifer is 'very low'. Further, if these contaminants did enter an aquifer, for example in the Beetaloo Sub-basin, the rate of transport would be so slow (m/y) that it would take decades for this water to move 100 m, during which time concentrations would be reduced by dilution and microbial decomposition processes.

In relation to methane, the Panel used extensive data from the US to assess the likelihood of upward migration of methane to be 'low' to 'medium', and if wells are constructed to Category 9 standard or above, with cementing along the full length of the well bore, the likelihood will be 'remote' to 'very low'. The consequence to water quality (specifically the impact on groundwater used for drinking or stock watering) from the occurrence of methane is assessed as 'low' because methane in water is non-toxic. But the presence of methane above a threshold value of 10-28 mg/L could result in an explosion risk under certain circumstances. The Panel has therefore recommended that:

- a minimum offset distance of 1 km be established between water supply bores and well pads, although this distance may need to be changed subject to improved information on the hydraulic potential for transport of contaminants and the likely drawdown areas from any groundwater extraction; and
- real-time groundwater monitoring of groundwater quality occur around each well pad, particularly during hydraulic fracturing.

Spills

The Panel has considered the risk from spills of contaminated wastewater or fracturing chemicals occurring both on a well pad site and off-site from road or rail transport or pipelines.

The Panel considered two pathways in assessing the likelihood of an on-site 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/rock layer to enter the aquifer. While the evidence is unequivocal that spills of chemicals and contaminated wastewater are very likely to occur, predictive modelling suggests that the likelihood of spills travelling through the 30-100 m of soil and rock to the aquifer in the Beetaloo Sub-basin is 'low'. To further reduce this risk, the Panel has recommended that a wastewater spills containment and management plan should be prepared by the gas companies for each well pad using a rigorous set of world leading practice guidelines, and that these waste management plans be approved and enforced by the regulator. Further recommendations are that:

- enclosed tanks should be used to hold wastewater in preference to open ponds;
- the well pad site should be treated (for example, with a geomembrane) to prevent the infiltration of wastewater spills into underlying soil; and
- a real-time groundwater monitoring program be established around each well pad, particularly during hydraulic fracturing.

If any onshore shale gas industry is developed in the NT it will require that hydraulic fracturing chemicals and fluid additives are transported to the various shale gas sites, with an attendant risk that spills may occur during transportation. Additionally, the transport of wastewater by pipeline for reuse or to a treatment plant also has the potential for spills to occur due to broken pipelines. The Panel notes that the transport of dangerous goods is covered by the *Dangerous Goods by Road and Rail (National Uniform Legislation) Act 2010* (NT), and that the current industry practice for the transportation of chemicals requires that both primary and secondary containment measures be in place. However, the Panel has a number of concerns with the transportation of hydraulic fracturing chemicals that it cannot resolve at this stage and has recommended that the regulator consider:

- the issues raised by the Panel regarding the administration and enforcement of the regulations governing the transport of dangerous goods and the adequacy of clean-up management practices;
- whether restrictions need to be placed on the transport of hydraulic fracturing chemicals during the wet season, particularly on unsealed roads; and
- whether rail transport of some or all of the hydraulic fracturing chemicals and other consumables required by the gas companies should be considered.

Reinjection of wastewaters

The reinjection of wastewater into Class II wells associated with extraction of oil and gas from conventional reservoirs is a common practice by gas companies overseas, particularly in the US.

This practice has, however, been associated with seismic activity. The practice is becoming less prevalent due to greater reuse of flowback water and additional regulatory measures. The Panel has recommended that reinjection of treated or untreated wastewaters (for example, brines) into deeper aquifers and conventional reservoirs should not be permitted until detailed investigation is undertaken to determine whether or not the risks associated with this practice can be managed to acceptable levels.

Changes in groundwater pressure

The extraction of the water required for hydraulic fracturing from local groundwater systems can result in a decrease in the groundwater pressure in that particular aquifer, which may result in underlying or overlying groundwater bodies flowing into that aquifer possibly changing the water quality. The Panel considers that these risks are insufficiently understood, and has therefore recommended that site-specific hydraulic modelling of the local groundwater system should be undertaken as part of any environmental risk assessment before any production approval for shale gas is granted. This modelling must demonstrate that there will be no unacceptable impact on groundwater quality and quantity due to the hydraulic fracturing.

Discharge of wastewaters to surface water

The discharge of treated shale gas wastewaters to permanently flowing waterways is a relatively common practice overseas, although this practice is diminishing as more flowback and produced water is reused in the hydraulic fracturing process. But, the Panel considers that the discharge of shale gas wastewaters to the largely temporary surface waters in the semi-arid and arid regions of the NT is problematic in that it is difficult to predict the behaviour of any contaminants discharged to such systems. In particular, the variable nature of these temporary streams and waterholes would make it likely that discharged contaminants would be trapped in the waterholes left after the temporary streams ceased to flow. For this reason, the Panel has recommended that the discharge of shale gas hydraulic fracturing wastewater (treated or untreated) to either drainage lines, waterways, temporary stream systems or waterholes should not be permitted.

Adverse effects of linear infrastructure (roads, pipelines)

The establishment of any onshore shale gas industry in 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 consequent increase in sediment loads entering streams. The Panel has recommended that in order to minimise the potential for new linear infrastructure to adversely affect the flow and quality of surface waters, the regulator should ensure that the design and planning of all roads and pipelines is developed initially at the landscape or regional scale to avoid unforeseen consequences arising from an incremental and ad hoc rollout of linear infrastructure. The on-ground construction of this infrastructure should be guided by a world leading practice manual designed specifically for the NT to minimise possible unacceptable impacts on surface water flows and erosion.

Aquatic ecosystems

The Panel has found there is a considerable lack of detailed knowledge of the aquatic ecology and biodiversity of surface and groundwater systems, particularly in the semi-arid and arid regions of the NT. Improving this knowledge base should be a focus of the SREBA.

Water quantity

Changes to the natural flow regime of rivers and wetlands through water extraction or discharge of wastewater can have unacceptable impacts on water-dependent ecosystems, including on aquatic wildlife. This is particularly so for the temporary surface water bodies that exist in the semi-arid and arid regions of the NT. To avoid these impacts, the Panel has recommended that the use of surface water resources for shale gas hydraulic fracturing should be prohibited, and that the discharge of treated or untreated shale gas wastewater to drainage lines, waterways or temporary stream systems must also be prohibited.

The northern region of the NT has many GDEs, both aquatic and terrestrial, that could be affected by groundwater extraction. This does not appear to be the case in the semi-arid and arid region of the Beetaloo Sub-basin, where there are very few, if any, surface water ecosystems or GDEs. As stated above, there is considerable evidence that the CLA is very important for the Roper River system, particularly during the dry season. It is unlikely that water extraction from the CLA in the Beetaloo Sub-basin, approximately 150-200 km away, could have an effect on groundwater inflows to the Roper River because 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.

However, the Panel has been provided with evidence showing that the majority of the recharge of the CLA in the Roper River region occurs locally (within 50 km of the river) during the wet season. Accordingly, the boundary of the recommended SREBA should be extended to include this region, noting that there are currently petroleum exploration leases over this area.

Water quality

The Panel has assessed the risks to surface water ecosystems from shale gas hydraulic fracturing wastewater contaminants as 'low', provided that the discharge of wastewaters to surface water bodies is prohibited, and that effective management practices are in place to prevent any accidental spills from well pads, road tankers, or pipelines, from entering these water bodies.

The Panel has not been able to fully assess the risk that aquifer contamination will result in unacceptable impacts on GDEs because very little is known about them, particularly in the Beetaloo Sub-basin. GDEs, including stygofauna (animals that live exclusively in aquifers), must be part of the recommended SREBA.

In summary, while the Panel has been able to use the available evidence to assess the risk of contamination of groundwater from leaky wells and from on-site surface spills as 'low', there is still uncertainty about the fate of some contaminants should these enter the groundwater. Additionally, the Panel has not been able to make a definitive assessment of the risk of unsustainable groundwater use, unacceptable contamination of groundwaters, or unacceptable impacts on aquatic ecosystems, because of a lack of baseline information and knowledge of the surface and groundwater systems and the aquatic ecosystems.

For this reason, the Panel recommends that a comprehensive SREBA of any prospective shale gas basin must be undertaken prior to the grant of any production licence for any onshore shale gas industry. The initial SREBA should be undertaken for the Beetaloo Sub-basin.

Recommendation 7.1

That before any production licence is granted to extract onshore shale gas, the Water Act be amended to require gas companies to obtain water extraction licences under that Act. That the Government introduce a charge on water in the NT for all onshore shale gas activities.

Recommendation 7.2

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

Recommendation 7.3

That the Government develop specific guidelines for human 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.

Recommendation 7.4

That a strategic regional environmental and baseline assessment (SREBA), including a regional groundwater model, be developed and undertaken for any prospective shale gas basin before any production licences are granted for shale gas activities in that basin, commencing with the Beetaloo Sub-basin.

Recommendation 7.5

That the use of all surface water resources for all onshore unconventional shale gas hydraulic fracturing in the NT be prohibited.

Recommendation 7.6

That in relation to the Beetaloo Sub-basin:

- *the Daly-Roper WCD be extended south to include all the Beetaloo Sub-basin;*
- *a separate WAP be developed for the northern and southern regions of the Beetaloo Sub-basin;*
- *the new northern Basin WAP provide 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 Basin WAP prohibits water extraction for shale gas production until the nature and extent of the groundwater resource and recharge rates in that area is 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 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 be prohibited until there is sufficient information to demonstrate that it will have no adverse impacts on existing users and the environment.

Recommendation 7.7

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

- *the drilling of onshore shale gas petroleum wells within 1 km of existing or proposed groundwater bores be prohibited unless hydrogeological investigations and groundwater modelling indicate that a different distance is appropriate, or if the landholder is in agreement with a closer distance;*
- *additional information on the aquifer characteristics is obtained as a result of the regional environmental and baseline assessment recommended in Section 7.4.1;*
- *relevant WAPs include provisions that adequately control both the rate and volume of water extraction by the gas companies;*
- *gas companies be required, at their expense, to monitor drawdown in local water supply bores; and*
- *companies be required to 'make good' any problems if this drawdown is found to be excessive (that is greater than 1 m).*

Recommendation 7.8

That reinjection of wastewater into deep aquifers and conventional reservoirs should be prohibited until comprehensive geotechnical investigations are undertaken to show that no seismic activity will occur.

Recommendation 7.9

That the following information about hydraulic fracturing fluids must be reported and publicly disclosed about hydraulic fracturing fluids prior to any hydraulic fracturing for onshore shale gas:

- *the chemicals to be used;*
- *the purpose of the chemicals;*
- *how the chemicals will be managed 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 be reported and publicly disclosed:

- *the chemicals and NORMs found;*
- *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 their enforcement.*

Recommendation 7.10

That in order to minimise the risk of groundwater contamination from leaky gas wells:

- *all wells to be hydraulically fractured must be constructed to at least Category 9 or equivalent and tested to ensure well integrity before and after hydraulic fracturing, with the results certified by the regulator (see also Recommendations 5.3 and 5.4);*
- *a minimum offset distance of at least 1 km between water supply bores and well pads must be adopted unless specific site-specific information is available to the contrary (see also Recommendation 7.7);*
- *a robust and rapid wastewater spill clean up management plan must be prepared for each well pad to ensure immediate remediation in the event of a spill: and*
- *real-time publicly available groundwater quality monitoring must be implemented around each well pad to detect any groundwater contamination. Multilevel observation bores must be used to ensure full coverage of the aquifer horizon, with a level of vertical resolution sufficient to be able to identify the location of any leak.*

Recommendation 7.11

That 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, which must be approved prior to the commencement of hydraulic fracturing;*
- *enclosed tanks must be used to hold all wastewater;*
- *the well pad site must be treated (for example, with a geomembrane) to prevent the infiltration of wastewater spills into underlying soil and thence into to an aquifer; and*
- *a real-time publicly accessible monitoring program for each well pad must be established.*

Recommendation 7.12

That the Government undertake 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; and*
- *whether rail transport of some or all of the hydraulic fracturing chemicals and other consumables required should be used.*

Recommendation 7.13

That the reinjection of treated or untreated wastewaters (including brines) into aquifers not be permitted until detailed investigations are undertaken to determine whether or not the risks associated with this practice can be managed to acceptable levels.

Recommendation 7.14

That gas companies must submit details of all known fault locations and geomechanical planning to the regulator.

Recommendation 7.15

That appropriate site-specific modelling of the local groundwater system must be undertaken before any water is extracted for the purposes of onshore hydraulic fracturing for shale gas in order to ensure that there are no unacceptable impacts on groundwater quality and quantity.

Recommendation 7.16

That the discharge of shale gas hydraulic fracturing wastewater (treated or untreated) to either drainage lines, waterways, temporary stream systems or waterholes not be permitted.

Recommendation 7.17

That to minimise the adverse impacts of 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.***

Recommendation 7.18

That the Beetaloo Sub-basin SREBA should take into account all groundwater dependent ecosystems in the Roper River region.

Recommendation 7.19

That the Beetaloo Sub-basin SREBA should take into account all subterranean aquatic ecosystems in the Roper River region.

Land (Chapter 8)

The NT is internationally renowned for its vast and often spectacular landscapes, many of which have outstanding wilderness values and represent an iconic part of the Australian outback. These landscapes also have exceptional terrestrial biodiversity values, featuring a wide range of habitats and high levels of species diversity and endemism. The landscapes are especially important to the cultural practices of Aboriginal people, who retain the deep cultural and spiritual connection to country that has endured for millennia. It is also the case more broadly that people are attracted to the Territory's unspoiled landscapes, which is why most non-residents choose to visit, making their preservation fundamental to the tourism industry.

Chapter 8 summarises the existing knowledge regarding terrestrial ecosystems and terrestrial biodiversity in the NT. Additionally, the Panel has identified the likely infrastructure needs of any onshore shale gas industry, using the Beetaloo Sub-basin as a case study. Both on-site (roads, pipelines, drilling rigs and water storage facilities) and off-site (roads, pipelines and gas treatment facilities) infrastructure needs are discussed.

Chapter 8 provides the Panel's assessment of the land-related risks associated with any onshore shale gas development in the NT relative to two land-related values: terrestrial biodiversity and ecosystem health, and landscape amenity. The Panel finds that the development of any onshore shale gas industry will only be acceptable if these values are adequately protected. This can be achieved through the following environmental objectives:

- that there is a low risk of impact on the terrestrial biodiversity values of affected bioregions;
- that overall terrestrial ecosystem health, including the provision of ecosystem services, is maintained;

- that onshore shale gas surface infrastructure does not become a dominant feature of the landscape; and
- that the volumes of heavy-vehicle traffic do not have an unacceptable impact on landscape amenity and place identity.

In total, the Panel has assessed eight land-based risks to terrestrial biodiversity and ecosystem health, and landscape amenity.

Biodiversity and ecosystem health

Inappropriate location of shale gas development within a region

It is the Panel's view that shale gas development should be excluded from areas where regional conservation values are high, which would include all declared national parks and other conservation reserves. However, because most of the NT has never been systematically surveyed for plants and animals because of its vast size and remoteness, the location of areas of regionally high conservation value are not well known.

Given this lack of comprehensive and systematic information on the biodiversity assets of prospective shale gas regions, the Panel has assessed that there is 'high' risk of any onshore shale gas development occurring in (currently undocumented) areas of high conservation value. The Panel has determined that this risk can be mitigated if the findings from a SREBA of biodiversity values conducted prior to any production approvals for onshore shale gas development are granted.

Spread of invasive species

Weed invasion is a major driver of terrestrial biodiversity decline globally and is a serious threat to biodiversity in the NT and throughout Australia's rangelands. At least $15 million is spent annually on weed management in the NT. The spread of weeds occurs largely through transport by contaminated vehicles and equipment. The Panel's assessment is that there is a 'high' risk of substantial spread of invasive weed species because of the large number of additional personnel (company and contractors), vehicles, and vehicle trips that are associated with any onshore shale gas development. Strengthening the current regulatory regime to ensure that shale gas companies are required to do all things necessary to implement statutory regional weed management plans will reduce the risk of the spread of weeds. For example, gas companies can be made liable for compliance with the terms of statutory weed management plans, such as surveying and monitoring development areas, adopting relevant seed hygiene protocols, and notifying the appropriate regulator of areas where weeds have been observed.

The Panel has also identified a risk of the possible spread of existing exotic ants, such as African big-headed ant and the Yellow crazy ant, which are known to have substantial impacts on native biodiversity, and the introduction of other tropical ant species, such as the Red imported fire ant and the Little fire ant (these are already established in Queensland).

Finally, feral animals such as camels, cats, dogs, donkeys, foxes, pigs, and horses, cause major environmental damage in the NT, including adverse impacts on biodiversity, vegetation and water. These animals are already well established in the NT, and it is unlikely that any onshore shale gas industry will significantly affect their population dynamics or ecological impacts.

Impact of changed fire regimes

Any onshore shale gas industry in the NT will require the construction of a comprehensive interconnected network of access roads and other linear infrastructure (pipeline corridors), which could result in changes to regional fire regimes, which in turn could cause unacceptable impacts on terrestrial ecosystems, threaten lives and property, and cause economic loss.

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, where there is generally fuel available for fire in most years, than in arid regions. The Panel considers that there is a 'high' risk of increased fire frequency associated with the development of any shale gas industry in the NT, but that this can be significantly reduced by the introduction of the following mitigation measures:

- limit ignitions, including those due to smoking by industry employees in the field;

- ensure that a regional fire management plan is developed and implemented by all relevant land tenure holders, including gas companies;
- undertake annual fire mapping of permit areas to monitor any increase in fire frequency due to onshore shale gas development, and compare it with a baseline established for at least the previous decade prior to the commencement of any onshore shale gas development; and
- implement management actions, such as prescribed fuel reduction burns, at key locations to reduce fuel loads and protect key values and assets, on the basis of annual fuel load data.

Changes to native vegetation

A shale gas industry will inevitably involve vegetation clearing, given that the NT is almost entirely covered by native vegetation. Clearing of vegetation for infrastructure will result in direct habitat loss, and the fragmentation of faunal habitat. There is also the risk of impacts from vegetation fragmentation and edge effects, although the Panel's view is that these are significantly less in the open savannahs and grasslands of the NT than in dense forests where most fragmentation research has been conducted.

Industry forecasts are for well pad densities of one well pad per 10-20 km^2 (average spacing between well pads of 2 to 4 km), which will require vegetation clearing of approximately 2% of an identified development area. Using this data, the Panel has assessed the overall risk of unacceptable changes to native vegetation as 'medium'. There are a number of ways this risk of vegetation and habitat loss could be mitigated, including:

- limiting the surface footprint and, therefore, the extent of land clearing through the efficient design of access roads and pipeline corridors, and through regional planning, including the co-location of shared infrastructure among different gas companies;
- monitoring any threatened species at risk through habitat fragmentation, and implementing appropriate management plans where necessary; and
- effectively rehabilitating cleared areas at the completion of development such that vegetation is re-established and edge and fragmentation effects are reduced.

Roads and pipelines as ecological barriers and corridors

The construction of roads and pipeline corridors are a necessary part of any onshore shale gas development. However, these can disrupt important ecological processes, including changing the flow of water, sediment and nutrients across landscapes; accelerating runoff and/or erosion processes; reducing the spread of ecologically important fire; clearing vegetation or habitat that provide productivity hotspots, seasonal refugia or regionally significant feeding and breeding resources; and facilitating the spread of weeds. Given the biodiversity value of the large-scale and relatively intact ecosystems of the NT, the Panel has assessed the risk of vegetation clearing and fragmentation impacts of roads and pipeline corridors as 'medium'. The Panel has identified a number of measures that can reduce this risk including:

- improving information on key habitat patches at the regional scale that should be avoided by any infrastructure development, and ensuring environmental management plans (**EMPs**) use this information to plan corridor routes;
- keeping corridor widths to a minimum with pipelines buried, ensuring best practice management of stockpiles, spoil piles and topsoil during trenching and replacement during landform rehabilitation after pipeline trenching, and revegetating the disturbed ground as soon as possible;
- undertaking construction activities only during the dry season; and
- constructing roads and pipeline corridors to minimise the interference with wet season surface water flow paths and to minimise erosion of exposed (road) surfaces and drains, and complying with proper design for fauna passage at all stream crossings.

Other impacts on wildlife

The Panel has also assessed other possible impacts on wildlife from contaminated wastewater and spills, noise, light and increased human activity (see Chapter 8 for further detail).

Landscape amenity

The Panel's second objective in assessing the land-related risks of any onshore shale gas industry in the NT is to ensure that the perception of people living in and visiting with NT that it is a place of largely unspoiled landscapes is not diminished. Two aspects of this objective were assessed: first, the risk of unacceptable landscape transformation; and second, the risk of high volumes of heavy-vehicle traffic during the extraction and construction phase.

Landscape transformations

Landscape transformation, where surface infrastructure becomes a highly visible and dominant feature of the landscape due to the close spacing of well pads, has often been the experience with onshore unconventional gas developments overseas. The Panel has defined acceptable landscape change as a result of onshore 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 infrastructure from public roads in areas where development occurs.

The Panel's assessment is that it is likely that the infrastructure associated with any onshore shale gas industry in the Beetaloo Sub-basin will be visible from some public roads, particularly during the extraction stage. However, the Panel has found it difficult to assess the consequences of this change to the amenity value for tourists and Territorians because of the subjective nature of such changes.

The Panel has identified two ways in which the impacts of any onshore shale gas industry on landscape amenity can be reduced. The first is to minimise the surface footprint of each development, and the second is to reduce the visibility of infrastructure within particular development areas.

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

Increase in heavy-vehicle traffic

The development of an onshore shale gas industry will require high volumes of heavy-vehicle traffic. This can have a significant impact on landscape amenity and place identity both within, and beyond, a specific development area, including for residents of communities located on, and tourists travelling along, major highways. Impacts can be through traffic congestion on what are currently 'outback' roads with light traffic, or through the high visibility of heavy vehicles creating the perception of landscape industrialisation.

The Panel was not able to make an assessment of this risk because of a lack of relevant information on the estimated increase in heavy-vehicle traffic that will result from the development of any onshore shale gas industry in the Beetaloo Sub-basin, or elsewhere in the NT. Information is required on the estimated increase in volume at various times of the year, the types of vehicles (heavy vehicles compared with other vehicles), routes, and the cumulative effects of multiple onshore shale gas development areas. The Panel recognises that the gas companies will be required to address traffic risks as part of their EMPs.

Three measures were identified that could assist in minimising the impacts of heavy-vehicle traffic:

- upgrading major highways by building overtaking lanes and dual carriageways;
- regulating industry traffic during peak times of road use by tourists, for example, requiring heavy vehicles to travel at night; and
- the use of rail rather than road transports to deliver some supplies to the region. Pangaea has suggested that the existing Adelaide to Darwin railway line might be an option to meet some of industry's transport requirements, but there has been no formal analysis of the feasibility of this, or the extent to which it will reduce road transport requirements.

Need for the strategic development of any onshore shale gas industry

The Panel heard many concerns expressed by the community that the development of any onshore shale gas industry in the NT could occur in the same piecemeal and often inadequately (initially, at least) regulated manner as the Queensland CSG industry. The Panel is of the opinion that this should not occur and to ensure it does not, has recommended that the development of prospective shale gas regions in the NT should occur in a controlled, strategic and coordinated manner. There are many instances where a coordinated approach to infrastructure rollout would be advantageous, including for road networks, pipeline networks, water treatment facilities, and gas processing facilities.

Recommendation 8.1

That strategic regional terrestrial biodiversity assessments are conducted as part of a SREBA for all bioregions prior to any onshore shale gas production, with all onshore shale gas development excluded from areas considered to be of high conservation value. The results of the SREBA must inform any decision to release land for exploration as specified in Recommendation 14.2 and be considered by the decision-maker in respect of any activity-based EMP.

Recommendation 8.2

That a baseline assessment of all weeds within a permit area be conducted prior to any onshore shale gas exploration or development and that ongoing weed monitoring be undertaken to inform any weed management measures necessary to ensure no incursions or spread of weeds. Gas companies must have a dedicated weeds officer whose role is to monitor well pads, roads and pipeline corridors for weeds.

Recommendation 8.3

That gas companies be required to have a weed management plan in place prior to entering onto a petroleum permit. The plan must be consistent with all relevant statutory weed management plans and relevant threat abatement plans established under the EPBC Act.

Recommendation 8.4

That gas companies be required to comply with any statutory regional fire management plan. The fire management plan should:

- ***address the impact that any onshore shale gas industry will have on fire regimes in the NT, and how those impacts should 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 baseline data to be established for at least the decade prior to commencement of any onshore shale gas development; and***

- *require the implementation of management actions, such as prescribed fuel reduction burns at strategic locations, to reduce fuel loads and protect key values and assets if required on the basis of the annual fuel monitoring data.*

Recommendation 8.5

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 any such 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 8.6

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 8.7

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 8.8

That to compensate for any local vegetation, habitat and biodiversity loss, the Government develop and implement an environmental offset policy to ensure that, where environmental impacts and risks are unable to be avoided or adequately mitigated, they are offset.

Recommendation 8.9

That the Government consider the establishment and operation of local Aboriginal land ranger programs to undertake land conservation activities.

Recommendation 8.10

That environmental legislation include a requirement for gas companies to identify critical habitats during corridor construction and select an appropriate mechanism to avoid detrimental impact on them.

Recommendation 8.11

That corridor widths be kept to a minimum, with pipelines and other linear infrastructure buried, except for necessary inspection points, and the disturbed ground 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 detrimental impact 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, and comply with design for fauna passage.

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.

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 infrastructure within any development areas is not visible from major public roads.***

Recommendation 8.16

That the Government assess the impact that all 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 - Darwin railway line to reduce heavy-vehicle road use; and***
- ***road upgrades.***

Greenhouse gas emissions (Chapter 9)

The extraction and subsequent use (the 'life cycle') of shale gas results in the emission of greenhouse gases (**GHG**) such as methane and carbon dioxide. Concern has been raised that these emissions will exacerbate climate change. Chapter 9 contains the Panel's review of the relevant literature on emissions from shale gas operations and its application to any new shale gas field in the NT; assesses the risk of methane and GHG released during the extraction, distribution and subsequent use of that gas; discusses the monitoring and reporting of methane emissions; assesses the risks of methane emissions from abandoned wells; and recommends how to mitigate these risks to an acceptable level.

Greenhouse gases

GHG warm the planet by absorbing energy and slowing the rate at which the energy escapes into space. They act like an insulating blanket. GHG emissions are major contributors to climate change. In 2015, Australia signed the agreement negotiated at the United Nations Framework Convention on Climate Change, Paris Climate Conference (**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"*. As part of the Paris Agreement, the Commonwealth Government has committed to reduce GHG emissions to 26-28% below 2005 levels by 2030. Australian emissions are projected to be 592 Mt carbon dioxide equivalent (**CO_2e**) in 2030, which will require a reduction of 990-1055 Mt CO_2e in cumulative emissions between 2021 and 2030. Some key observations are that:

- global atmospheric concentrations of the major long-lived GHG continue to rise. For example, since pre-industrial times, the global mean carbon dioxide level has risen 42% to 399 ppm, and methane concentration has risen 154% to 1.8 ppm;
- the total annual global anthropogenic GHG emissions comprises 76% carbon dioxide and 16% methane emissions (the balance is nitrous oxide and fluorinated gases);
- only a small proportion of annual methane emissions from all sources (natural and anthropogenic) remain in the atmosphere and contribute to the annual warming effect; and
- annual fugitive methane emissions from natural gas production are about 0.2% of the annual anthropogenic greenhouse warming effect of carbon dioxide (based on data over the past decade).

Upstream GHG emissions

GHG, including both carbon dioxide and methane, are emitted during the upstream stage.

Fugitive methane emissions include both unintentional and intentional releases (for operational reasons). The key findings are that:

- typically, upstream GHG emissions for a US shale gas field (pre 2012) are 15.5 g CO_2e/MJ of life-time natural gas production, where the methane emission rate of 11.9 g CO_2e /MJ (or 1.8% of life-time production) represents 77% of the total upstream emissions; and
- the application of available emission reduction technologies can typically result in 23% lower upstream GHG emissions, and an overall 31% reduction in methane emissions compared with historical practices for shale gas wells.

Methane emissions

Methane emissions are the major contributor to upstream GHG emissions from shale gas operations and they are amenable to mitigation to reduce the emission levels. Consideration is given in this Chapter to the measurement of methane emissions; inventory estimates of emission levels; a comparison of emissions from shale gas operations with other sources of methane emissions; and an assessment of the risk of emissions from any new gas field in the NT is undertaken by comparing the upstream methane emissions with global GHG emissions. The key findings are that:

- over recent years, upstream methane emissions have been consistently reduced, so that the current inventory estimates for Australia are 0.48-0.59% and for the US, 1.25%. These values underestimate field based measurements, which range from 1.6-1.9%. Further research is required to better understand the differences between these inventory estimates and field-based estimates;
- emissions that are released during the shale gas exploration stage, such as venting during flowback, can be significant and must be minimised;
- a large proportion of fugitive emissions come from a small number of high-emitting sources, but these super-emitters also present opportunities for mitigation by applying industry world leading practices;
- methane emissions from any new gas field in the NT (assumed to be 365 PJ/y) would be similar to the methane emissions from the enteric fermentation of livestock in the NT but would be greater than the emissions from waste;
- fugitive methane emissions from any new onshore shale gas field in the NT are estimated to be worth $72 million per year, indicating that there are environmental benefits and economic incentives for gas companies to reduced methane emissions;
- fugitive emissions from natural gas production in the NT are expected to be about 3% of Australia's Inventory methane emissions and 0.04% of the global anthropogenic methane emissions, so the consequential effect of fugitive methane emissions from any new shale gas field in the NT will be low; and
- the Panel has assessed the risk of fugitive methane emissions from any new shale gas industry in the NT, without any further mitigation, to be 'medium'.

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 any onshore shale gas operation. Options for monitoring methane emissions have been considered by the Panel, including coverage over different spatial dimensions and the equipment that can be used to measure methane levels. The key findings 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 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 field measurements of methane emissions and field level methane measurements are not routinely undertaken; and
- the Panel has assessed the risk of non-detection of abnormal levels of fugitive methane emissions from any new shale gas industry in the NT, without any further mitigation, to be 'medium'.

Life cycle GHG emissions from a new gas field

The life cycle of shale gas involves both upstream (extraction through to distribution) and downstream use (such as power generation, heating, or a possible feedstock for industrial manufacture). Estimates are given for the quantities of life cycle GHG emissions for any new shale gas fields in the NT. These results are used in a risk assessment by comparing the life cycle emissions with global GHG emissions. The key findings are that:

- GHG emissions from any new shale gas field (assumed to be 365 PJ/y) in the NT would contribute around 5% of Australian GHG emissions and 0.05% of global GHG emissions;
- the risk of life cycle GHG emissions associated with any new shale gas industry in the NT, before any further mitigation, is 'medium'; and
- because there is little opportunity to reduce GHG from the downstream stage, the focus for risk reduction for life cycle GHG emissions must be on reducing upstream methane emissions.

Life cycle GHG emissions: technology comparisons for electricity production

The Panel has made a comparison between 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 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 17% 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 and roughly equivalent to those from conventional gas-generated electricity. Natural gas combined cycle power plants have a lower climate impact than supercritical pulverised coal power, provided methane emission rates are lower than 3.3%;
- the 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 MWh than solar electricity; and
- 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 and complement variable renewable electricity generation.

Methane emissions from abandoned shale gas wells

Abandoned oil and gas wells provide a potential pathway for subsurface migration and emissions of methane to the atmosphere. Estimates are given for the quantity of methane emissions from plugged, unplugged and decommissioned wells. These results have been used in a risk assessment comparing the emissions from 1,000 decommissioned wells in the NT, with global methane emissions. The key findings are that:

- the evidence of methane emissions from decommissioned and abandoned gas wells is mixed. It is clear, however, that properly decommissioned wells (abandoned wells that have been cut-off, sealed (plugged), and then buried under soil) have lower methane emissions than wells that have been abandoned with wellhead 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 1000 decommissioned wells is estimated to represent 0.3% of Australia's Inventory methane emissions and 0.005% of the global anthropogenic methane, so the consequential effect of fugitive methane emissions from any new shale gas field in the NT will be low; and
- the assessed risk of fugitive methane emissions from decommissioned wells from any new onshore shale gas industry in the NT is assessed, without any further mitigation, as 'medium'.

The Panel has formed the view that to reduce fugitive emissions from abandoned wells, all post-production wells must be decommissioned in accordance with world leading practice.

Risk assessment summary

For any new onshore shale gas field in the NT, the Panel has assessed the risks to climate change associated with GHG emissions, including methane, and assessed that each of these risks, without any further mitigation, to be 'medium'. As each of the assessed risks is 'medium', further mitigation is required to achieve an acceptable level of risk. The decision on the extent of mitigation required has been guided by the principles of ESD, while at the same time recognising that there are community concerns and lack of trust with industry and with the Government's ability to adequately manage and control industry. The Panel has therefore formed the view that further mitigation is required.

Conclusion

The Panel has formed the view that the collective application of mitigation measures, including the introduction of methane monitoring and reporting; well decommissioning; and the mitigation measures in **Table 9.10**, (of the draft Final Report) will result in lower levels of emissions of methane and GHG. Collectively, these additional mitigation measures are deemed to achieve an acceptable risk for methane and GHG emissions from any new onshore shale gas field in the NT.

Recommendation 9.1

That to reduce the risk of upstream methane emissions from onshore shale gas wells in the NT the Government implement the US EPA New Source Performance Standards of 2012 and 2016.[6]

Recommendation 9.2

That a code of practice be developed and implemented for the ongoing monitoring, detection and reporting of methane emissions from onshore shale gas fields and wells once production of any onshore shale gas commences.[7]

Recommendation 9.3

That baseline monitoring of methane concentrations be undertaken for at least one year prior to the commencement of shale gas production on a production licence.

Recommendation 9.4

That baseline and ongoing monitoring be the responsibility of the regulator, undertaken by an independent third party, and funded by industry.

Recommendation 9.5

That all monitoring results should be published online on a continuous basis in real time.

Recommendation 9.6

That once emission concentration limits are exceeded, the regulator must be notified, investigations must be undertaken to identify the source(s) of the excess levels, and make-good provisions be undertaken by industry where necessary. These measures are to be the responsibility of industry.

Recommendation 9.7

That the action framework outlined in Table 9.10 of the draft Final Report be implemented to mitigate any supplementary risks that may prevent the achievement of lower levels of fugitive methane emissions.

6 Refer to Section 9.3 for details (in the draft Final Report).
7 Refer to Section 9.5.6 for details (in the draft Final Report).

Public health (Chapter 10)

The potential impacts of any onshore shale gas development in the NT on public health have been considered in two broad categories. The first relates to adverse health effects in people, defined as the induction or exacerbation of specific diseases, or induced dysfunction of critical organs and physiological systems. These adverse health effects can result from exposures to chemicals associated with hydraulic fracturing activities, either associated with the contamination of aquifers and consequent ingestion by humans or livestock through drinking water, or with airborne emissions of volatile compounds from wellheads. The chemicals under consideration include those used in hydraulic fracturing fluid formulations and those of geological origin brought to the surface with flowback water.

The Panel's assessment of the risks was generally 'low' for likelihood and 'low-moderate' for consequence, with these categorisations being highly dependent on site-specific factors, such as the proximity to habitation, potential pathways for contamination of surface and sub-surface water bodies, and the efficacy of regulatory controls over the exploration, production and decommissioning processes. In some cases, there was insufficient information to determine the precise level of the risks, but the Panel has provided advice on measures that would be likely to mitigate the potential risks.

The Panel's analysis was informed by formal human health risk assessments (**HHRA**) commissioned by Origin for existing shale gas development in the Beetaloo Sub-basin; by Santos for its Narrabri CSG project and for its GLNG project in the Surat and Bowen Basins of south west Queensland; by a WA Health HHRA of potential groundwater contamination associated with hydraulic fracturing for gas in shale deposits; and by assessment of the health risks associated with benzene, toluene, ethylbenzene and xylenes (**BTEX**) in CSG flowback water from the Gloucester Basin of the Waukivory CSG project. Further useful information on risk assessment methodologies and potential chemicals of concern is available in the report of National Chemicals Risk Assessment (**NCRA**) for CSG, recently released by the Australian Government.

The Panel considered health risks associated with airborne contaminants (volatile organic compounds, gases, vapours and dusts) that could affect people living downwind of well heads and gas processing facilities. Assessment of these risks was primarily informed by published reports from international gas developments (primarily in the US) and by experiences with CSG projects in Queensland.

The Panel concluded that these chemically related health risks will require site-specific formal HHRA, including an analysis of the pathways by which people and communities can be exposed. The Panel notes that some HHRA reports already produced by Origin and Santos have not addressed potential off-site exposures, on the basis that such exposures are likely to be 'incomplete pathways'. While the Panel accepts that the likelihood of off-site pathways actually resulting in significant health exposures for people living away from the sources of exposure is likely to be 'low', it notes that NCRA guidance relating to the conduct of HHRA for CSG requires that such pathways be considered.

The second category of potential impacts on public health considered by the Panel relates to the possible indirect negative effects on health associated with any onshore shale gas industry. These health effects are associated with impacts on wellbeing and socioeconomic factors. Accident trauma associated with increased road traffic, or 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 (fly-in, fly-out, or **FIFO**, work practices) were considered by the Panel, but the likelihood and consequence of such health risks are difficult to categorise. They are highly dependent on the scope of any proposed onshore shale gas development, as well as the stage of that development (exploration, production and decommissioning). The Panel has concluded that the potential likelihood and consequences of socioeconomic factors affecting public health will need to be considered on a local or regional basis once the scope of any proposed development has been defined, and that this will need to be measured against some baseline data collated ahead of any development.

Recommendation 10.1

That formal site or regional-specific HHRA reports be prepared and approved prior to the grant of any production licence for the purpose of any shale gas development. Such HHRA reports to 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 estimates assessments of exposure pathways that are deemed to be incomplete.

Recommendation 10.2

That to better inform the human health risk assessments, the following knowledge gaps must be addressed and published:

- ***contemporary knowledge of the chemicals proposed to be used in hydraulic fracking fluids for onshore shale gas extraction in the NT;***
- ***details of the chemical composition of flowback and produced water in the NT; and***
- ***the proposed methods of treatment and/or disposal of flowback and produced water.***

Recommendation 10.3

That in consultation with industry, landowners and local communities, the regulator set appropriate setback distances to minimise risks identified in HHRA reports, including potential pathways for waterborne and airborne contaminants, for all shale gas development (exploration and production). Such setback distances to be not less than 1,600 m.

Aboriginal people and their culture (Chapter 11)

Chapter 11 explores the impact that the development of any onshore shale gas industry will have on Aboriginal people, their land and their culture. The Panel acknowledges the strong connection that Aboriginal people have with their country, including water bodies, and that any interference with that connection will have significant cultural and social ramifications for Aboriginal people and their communities.

Chapter 11 summarises the different laws that protect Aboriginal people, their land and their culture in the NT. First, there is the *Aboriginal Land Rights (Northern Territory) Act 1976* (Cth) (**Land Rights Act**). The Land Rights Act is a landmark piece of legislation that emerged out of Woodward J's landmark report into Aboriginal land rights in the NT in the 1970s and gives traditional Aboriginal owners rights to control activities on their land. The Land Rights Act vests around half the area of the NT, and most of its coastline, to Aboriginal land trusts in fee simple. The land trusts can only deal with the land in accordance with the rules set out in the Land Rights Act. Those rules require that traditional Aboriginal owners must be consulted and give their consent to an activity on that land before it can occur.

Second, there is the *Native Title Act 1993* (Cth) (**Native Title Act**), which was the result of the High Court's seminal decision in *Mabo v Queensland (No 2)* [1992] HCA 23; (1992) 175 CLR 1. The High Court has subsequently held that the grant of a pastoral lease by the Government will not extinguish native title. This means that native title and pastoral leases can coexist. The rules set out in the Native Title Act therefore apply to about half the land mass of the NT.

Third, and in addition to the two Commonwealth Acts described above, there are NT laws designed to protect Aboriginal people and their culture. The Land Rights Act allows the Government to make legislation for the purposes of protecting sacred sites. Accordingly, the NT has introduced the *Northern Territory Sacred Sites Act 1989* (NT) (**Sacred Sites Act**) for the protection of sacred sites. The Sacred Sites Act establishes the Aboriginal Areas Protection Authority (**AAPA**), which is an independent authority tasked with keeping a register of sacred sites and issuing gas companies Authority Certificates, which include conditions on how activities can occur so that sacred sites are protected.

Fourth, the NT's environmental assessment legislation, the *Environmental Assessment Act 1982* (NT), requires cultural impacts to be considered as part of the assessment process. The Panel's view is that the cultural impacts of any onshore shale gas development must be better integrated into the NT's broader environmental assessment process. Specifically, AAPA should be provided with a copy of any application to extract water, drill, or conduct hydraulic fracturing early in any assessment process so that it can consult with Aboriginal custodians about the best way to protect any sacred sites that may be affected by those activities. Presently, AAPA is engaged too late in the assessment and approval process and has a limited opportunity to make a meaningful contribution in terms of how impacts on sacred sites can be managed.

In Chapter 11 the Panel identifies some risks that the development of any onshore shale gas industry may have on Aboriginal people and culture. The Panel acknowledges that sacred sites exist underground and is concerned that the extensive underground impacts of any shale gas industry (through drilling, hydraulic fracturing, and water extraction) may damage sacred sites. Damage to sacred sites carries serious consequences for Aboriginal custodians. The Panel recommends that, in relation to drilling and hydraulic fracturing, gas companies be required to get an Authority Certificate from AAPA prior to commencing these activities.

The Panel was also concerned that the broader Aboriginal community has not been adequately informed about the shale gas industry and its potential impact on Aboriginal communities. Having said this, the Panel is satisfied that, subject to some recommendations to strengthen the consultation and agreement-making process, the processes set out in the Land Rights Act and Native Title Act ensure that traditional Aboriginal owners are informed and consulted about development on their country. The Panel observed, however, that the lack of information in the broader Aboriginal community has led to extensive community unrest in communities likely to be affected by any onshore shale gas development. The Panel observed that parties on either side of the 'fracking debate' have filled an existing information void with misinformation. Aboriginal people told the Panel that communities were being divided between those in favour of hydraulic fracturing and those against it. The Panel recommends that Government, Land Councils and AAPA collaborate to ensure that accurate, reliable, and trusted information is communicated to all Aboriginal people living in communities that may be affected by any onshore shale gas industry.

Community members at the Inquiry's Jilkminggan community forum in August 2017.

The main recommendation in Chapter 11 is that the cultural impacts associated with the development of any onshore shale gas industry must be fully explained prior to the development of that industry and that a plan be put in place to manage those impacts on Aboriginal people and their communities. Aboriginal people and their representatives must be involved in the design and implementation of any such plan.

Recommendation 11.1

That gas companies be required to obtain an Authority Certificate before undertaking any onshore shale gas activity.

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.*

Recommendation 11.3

That legislation for the protection of sacred sites be amended so that sub-surface formations can be included as a sacred site or a feature of a sacred site.

Recommendation 11.4

That gas companies be required to provide a statement to native title holders with information of the kind required under s 41(6) of the Land Rights Act for the purposes of negotiating a petroleum exploration agreement under the future act provisions of the Native Title Act.

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.

Recommendation 11.6

That Land Councils, AAPA, and the Government cooperate to ensure that reliable, accessible (including with the use of interpreters), trusted, and accurate information about any onshore shale gas industry is effectively communicated to all Aboriginal people that will be affected by any onshore shale gas industry.

That the gas industry fund the design and delivery of any information programs.

Recommendation 11.7

That Land Councils, traditional Aboriginal owners and gas companies consider making all, or if this is not appropriate, part, of negotiated petroleum exploration agreements publicly available.

Recommendation 11.8

That a comprehensive assessment of the cultural impacts of any onshore shale gas development be completed prior to the grant of any production licence. 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.*

Social impacts (Chapter 12)

There are multiple factors that contribute to making the NT unique, not least of which is the varied social composition of its communities that span urban, regional and remote areas. Such uniqueness suggests the need for caution when making recommendations about the risks associated with the social impacts of any onshore shale gas industry in the Territory. However, social science literature suggests that with most risks and associated uncertainties, people will generally respond in a similar way. Therefore, examining the peer reviewed literature and drawing upon experiences from other mining and gas developments can be useful both in identifying the potential quantum of impacts in addition to noting the best ways to mitigate and/or circumvent the negative social impacts while also capitalising on any benefits. What is critical, however, is to ensure that all of these potential social impacts are 'ground truthed' with people living across the NT. It is highly unlikely that the needs and concerns of those living in remote Aboriginal communities will be the same as pastoralists or those living in more urban areas.

From a review of the literature, local and international case studies, and throughout the consultations, what has emerged is a clear need for a strategic approach to identifying and understanding the social impacts and risks for different communities. The literature on social licence to operate (**SLO**) stresses the importance of procedural fairness and trust to ensure that individuals feel listened to. Critical to this is giving a voice to all those who have a stake in the outcome. While this can be done through conventional methods for a large proportion of the population, it is impossible to do so for more marginalised groups. This requires a much more nuanced approach to engagement and consultation and is something that cannot be done overnight. Therefore, to properly identify the social and cumulative impacts that are likely to emerge from any onshore shale gas industry in the NT an investment of resources, both time and money, is required to ensure that all Territorians are heard.

One overarching concern evident in many submissions made to the Panel, is that the benefits of any onshore shale gas development will be short-term and flow to outside parties, while the costs may be long-term and be borne by the people of the NT. This concern stems, in part, from expectations that any onshore shale gas industry in the NT will follow a 'boom and bust' trajectory similar to the CSG industry in Queensland. Further, there are fears that an influx of FIFO and/or 'drive-in, drive-out' (**DIDO**) workers, and other sudden changes, will harm NT communities by straining public infrastructure and services, inflating (and then deflating) house and rental prices, eroding community cohesion, and disrupting people's sense of place and identity.

Countering these concerns, many submissions expressed the view that any onshore shale gas industry would deliver lasting benefits to the NT by creating jobs and business opportunities while bringing about improvements to infrastructure and services that in many areas are viewed as inadequate. From this perspective, an onshore shale gas industry is seen by some as the NT's best hope for economic development, and a potentially stabilising influence in an environment that is subject to highly seasonal employment opportunities. While the potential for social impacts is acknowledged, a number of submissions expressed a belief that a shale gas industry can coexist successfully with existing industries while contributing positively to NT communities.

But it is evident that many people remain opposed to hydraulic fracturing in the NT notwithstanding its purported benefits and industry's assurances that the social and environmental risks can be managed. Much of this opposition appears to stem from a lack of trust towards industry and a lack of faith in the Government's capacity to regulate it. Insofar as industry has failed to gain the trust and acceptance of community, several submissions argue that it has not yet earned an SLO.

Throughout the consultations and submissions, the Panel heard that activist groups were not bound by a set of formal requirements to engage with communities which led to misinformation being disseminated in some communities. Conversely, requests for accurate, credible and trusted information about hydraulic fracturing were often not available. The need for accurate and trustworthy information to ensure a level playing field for all interested parties is an important consideration for the Government when deciding what, if any, next steps for an onshore shale gas industry should be.

The submissions emphasise that at least two conditions are crucial if industry is to gain the community's trust and acceptance. The first is engagement practices that are more inclusive and empowering, and the second, is the establishment of an independent body to oversee various aspects of industry's governance. In addition, understanding the 'NT way' is imperative for industry to gain any traction in the NT, a view that was echoed across multiple submissions, especially from the pastoral and Aboriginal communities.

NT pastoral enterprise.

Recommendation 12.1

That as part of any strategic SIA early, and adequate consultation be undertaken on road use and related infrastructure requirements that result in realistic road upgrade and work schedules to support the required transport infrastructure for any unconventional shale gas industry and other users.

Recommendation 12.2

That gas companies ensure the provision of adequate and sustainable funding to ensure the identified infrastructure requirements are met and maintained appropriately.

Recommendation 12.3

That consideration be given to the development of road use agreements between gas companies and local councils that include safety considerations and ensure monitoring for compliance, including reporting requirements.

Recommendation 12.4

That gas companies be required to work closely with the Government and local communities early in any onshore shale gas development projects to ensure that any potential impacts on services are mitigated.

Recommendation 12.5

That any strategic social impact assessment anticipate the long-term impacts and requirements for housing (not just through construction phase) to adequately mitigate the risk of inflated real estate prices and shortages within a community.

Recommendation 12.6

That in consultation with local communities, Aboriginal 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 construction/development phase.

Recommendation 12.7

That there be a minimum standard set for gas companies to source goods, services and workers from local communities. This should include ensuring training programs are developed for Aboriginal and other local workers to develop the necessary skill sets and to improve their opportunities for local employment in any onshore shale gas industry.

Recommendation 12.8

That gas companies use a range of mediums to proactively work with local businesses to ensure they are able and adequately skilled to compete for contracts. They should follow the steps outlined above by the Queensland Gasfields Commission to assist them to be ready to participate in any economic opportunities that may emerge.

Recommendation 12.9

That the Government regulate to ensure that existing and future users of land can continue to enjoy their rights and interests in the land, including a mechanism to compensate for, among other things:

- *loss of use of surface area where infrastructure is installed;*
- *diminution of the use made or that may be made of the land or any improvement on it;*
- *severance of any part of the land from other areas of the landholder's property; and*
- *any cost, damage or loss arising from the carrying out of activities on the land.*

Recommendation 12.10

That gas companies be required to 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 Aboriginal land councils and local councils, to ensure that the needs of all parties are accommodated.

Recommendation 12.11

That gas companies must develop and implement a social impact management plan which details how they will optimise the relationship with the community prior to any onshore shale gas development. This plan must be developed in consultation with Aboriginal land councils and local councils to ensure that it meets community needs and be presented to the regulator for approval prior to any production approval being granted.

Recommendation 12.12

That gas companies be required to develop a social impact management plan that outlines how they intend to develop and continue their SLO within each of the communities they will operate in. This should be developed in conjunction with any SIA, and introduced as early as possible, preferably in the exploration phase, to ensure that any potential changes can be flagged in advance to allow communities time to adapt and prepare for the changes.

Recommendation 12.13

That a strategic SIA, separate from an Environmental Impact Statement, be conducted in advance of any onshore shale gas development, during the exploration phase. Such SIAs must be conducted holistically to anticipate any expected impacts on infrastructure and services, and to mitigate potential negative impacts, and be funded by industry.

Recommendation 12.14

That early engagement and communication of the findings of the strategic SIA be systematically undertaken with all potentially affected communities and with all levels of government to ensure that unintended consequences are limited and shared understanding of roles and responsibilities, including financial responsibilities, can be developed.

Recommendation 12.15

That ongoing monitoring and measurement of social and cumulative impacts be undertaken with the results publicly available.

Recommendation 12.16

That in order to operationalise an SIA framework in the NT the Government should make the following structural reforms:

- ***introduce mechanisms for strategic assessment, either through a Strategic Assessment Agreement under the EBPC Act, or through reforms proposed in the 2015 Hawke Report. A strategic SIA is needed to decide if any onshore shale gas industry should go ahead, and if so, under what conditions;***
- ***establish or enhance an independent authoritative body, such as the EPA or a newly established independent regulator (see Chapter 14), with powers to request information from, and to facilitate the collaboration between individual gas companies, and between gas companies, government agencies (including local government), communities and landholders;***
- ***establish a long-term participatory regional monitoring framework, overseen by the EPA or the independent regulator, with secure funding (raised from industry levies) and able to endure multiple election cycles; and***
- ***establish periodic and standardised reporting to communities on the social, economic and environmental performance of the industry through either the independent regulator or a specialised research institution. This includes information from the monitoring of key indicators, and an industry-wide complaints and escalation process.***

Economic impacts (Chapter 13)

Chapter 13 examines future economic development trajectories for the NT over 25 years from 2018 to 2043, based on five different development scenarios:

- **Baseline scenario:** where the moratorium remains in place over the modelled period;
- **Calm scenario:** where the moratorium is lifted in 2017-18, but only exploration and appraisal activity occurs for a period of three years and development is found to not be commercially viable;
- **Breeze scenario:** where the moratorium is lifted, exploration and appraisal activity occurs, and a small scale development occurs (100 terajoules per day (TJ/day), or 36.5 PJ per annum);
- **Wind scenario:** where the moratorium is lifted, and a moderate scale development occurs (400 TJ/day, or 146 PJ per annum); and
- **Gale scenario:** where the moratorium is lifted, and a larger scale development occurs (1,000 TJ/day, or 365 PJ per annum).

The modelling of the scenarios was undertaken by ACIL Allen, an independent economic consultancy firm engaged by the Panel.

ACIL Allen was requested to model the additional economic impacts (benefits and risks) the NT might receive if the Government lifted the hydraulic fracturing moratorium and an onshore shale gas industry was developed in the NT. Under all scenarios, the modelling indicates that key economic indicators for the NT, such as real output, real income, jobs and population, will grow in the period to 2043 with or without the moratorium being lifted.

The Gale scenario delivers the greatest economic benefits for the NT over the 25 year modelled period, with real output estimated to be $17.5 billion greater than under the Baseline scenario (at an average of $674.4 million per annum), an additional 13,611 direct and indirect FTE jobs (524 FTE jobs per annum) being created, and an additional population growth of 32,252 persons. Over the 25 year modelled period, the Government would collect an additional $3.72 billion in taxation revenue ($143.2 million per annum), which includes $1.79 billion in additional royalties, and the Commonwealth would collect an additional $1.75 billion in tax receipts.

In the Wind scenario, NT real output is estimated to increase by $12.1 billion over the 25 year modelled period (at an average of $466.4 million per annum), with an additional 6,559 direct and indirect FTE jobs (252 FTE jobs per annum), and an additional population growth of 15,480 persons. Over the 25 year modelled period the Government would collect an additional $2.09 billion in real taxation revenue ($80.6 million per annum), which includes $894.6 million in additional royalties, and the Commonwealth would collect an additional $4.58 billion in tax receipts.

In the Breeze scenario, NT real output is estimated to increase by $5.1 billion over the 25 year modelled period (at an average of $196.5 million per annum), with an additional 2,145 direct and indirect FTE jobs (82 FTE jobs per annum), and an additional population growth of 5,061 persons. Over the 25 year modelled period the Government would collect an additional $757 million in real taxation revenue ($29.1 million per annum), which includes $309.2 million in additional royalties, and the Commonwealth would collect an additional $1.31 billion in tax receipts.

ACIL Allen was also required to model the impact of any onshore shale gas industry on existing industries in the NT. Many submissions that the Panel received suggested that the development of an onshore shale gas industry would have significant adverse impacts on business operations, particularly in the pastoral, agricultural, horticultural and tourism industries. The main concerns were that these industries would have fewer resources available for productive use (land and water, for example), additional competition for skilled and unskilled labour, increased use of infrastructure (such as roads), and an impact on visual amenity and reputational risk.

It is acknowledged that any onshore shale gas industry could put additional pressure on infrastructure. Potential funding options to mitigate this pressure are discussed in the Chapter. ACIL Allen's assessment indicated that there are likely to be minimal industry coexistence risks because prospective shale gas regions have significant groundwater reserves and the land area used by the industry would be very small under all development scenarios.

The Panel considered ACIL Allen's modelling and policy analysis and the issues raised by the submission in developing its recommendations. The recommendations aim to balance the twin goals of maximising the 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 key recommendations identify the need for early and ongoing engagement between all stakeholders to identify the risks and opportunities that may be associated with any potential onshore shale gas development. There is a clear role for the Government to work with stakeholders to develop and implement pathways to mitigate risks and to resolve conflict between stakeholders, especially where agreement between the parties cannot be reached (recommendations regarding land access agreements to resolve conflict are discussed in Chapters 11 and 14). The Panel is also of the opinion the Government should work with all stakeholders to maximise localised benefits from any onshore shale gas development, including local employment opportunities, and opportunities for existing and new local businesses to supply goods and services to any shale gas projects. While not being prescriptive with respect to how the Government uses any additional revenue from any onshore shale gas development, the Panel recommends that in developing its annual budget the Government consider the source of royalty revenue and ensures source regions benefit through greater infrastructure and services expenditure.

Regarding infrastructure, the Panel recommends that the Government, together with all stakeholders, including the Commonwealth Government, identify potential bottlenecks and any additional economic, social and civic infrastructure requirements. Where gas companies capture the benefits of infrastructure, it is reasonable that they fund it. Where there are broader societal benefits, there is a role for Government to support infrastructure development. There may also be opportunities to leverage Commonwealth Government infrastructure funding to assist in funding any new infrastructure that may be required.

Recommendation 13.1

That in developing its budget the Government consider the source of royalty revenue to ensure that regions that are the source of taxation revenue benefit from any onshore shale gas extraction activity that has occurred in that region.

Recommendation 13.2

That the Government work 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 to maximise local employment.

Recommendation 13.3

That the Government work 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 ensure 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 work with gas companies and local suppliers to ensure there is early knowledge of local supply and service opportunities for all phases of any onshore shale gas development.

Recommendation 13.6

That the Government work with gas companies and local suppliers (regional and Territory wide) to identify immediate supply opportunities and to map future potential supply opportunities. This should be done in consultation with the ICN-NT and the Chamber of Commerce.

Recommendation 13.7

That the Government work 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 13.8

That the Government assist regional businesses to obtain quality assurance certification and to partner with larger suppliers to encourage greater local supply, employment and knowledge transfer.

Recommendation 13.9

That the Government work with gas companies, peak bodies of affected industries, and affected stakeholders to identify and resolve potentially negative economic impacts of any onshore shale gas development on other industries.

Recommendation 13.10

That the Government work with all levels of government, peak organisations, communities and gas companies to identify and manage infrastructure risks, including identifying options to fund any new infrastructure or upgrade existing infrastructure.

Regulatory reform (Chapter 14)

The design and implementation of a robust regulatory framework is the primary way that the Government can ensure that any onshore shale gas industry develops in a way that protects the environment, is safe to humans, and meets community expectations. Most, if not all, of the environmental impacts and risks associated with hydraulic fracturing and any onshore shale gas industry can, in the Panel's view, be effectively managed and mitigated to an acceptable level by strong governance. For example, the law can, among other things:

- expressly prohibit a particular activity or use of a chemical;
- prescribe that leading practice standards be used;
- mandate transparency and accountable decision-making;
- mandate regular and rigorous monitoring and enforcement regimes; and
- impose tough penalties for non-compliance.

During consultations the public expressed an acute lack of confidence in the current regulatory framework in the NT. The Panel's view is that this concern is justified and that the regulatory regime in the NT must be strengthened and reformed to ensure that any onshore shale gas industry develops in accordance with community requirements, properly reflects and operationalises the principles of ESD, and provides industry with a framework within which it can earn and maintain an SLO.

Making land available for any onshore gas exploration

The land release process is the process whereby land is 'released' or made available for exploration. Once the land has been released by the Government, gas companies can lodge an application for a petroleum exploration permit over that land. The Panel reviewed the land release process in the NT and proposed ways that it can be improved.

The Panel noted that the Minister for Resources currently has a great deal of discretion, but limited accountability and transparency, in relation to which land is released for any onshore shale gas exploration. For example, the Petroleum Act does not require the Minister to consider competing land uses, or the views of the public or any stakeholders. Nor is the Minister required to explain to the community why certain land has been released.

The Panel's view is that the Petroleum Act must require the Minister to be more transparent, consultative, accountable, and strategic about the release of land. In particular, the Petroleum Act should require the Minister to publish the Minister's intention to release specified land for any onshore shale gas exploration. The community should also be given an opportunity to comment on the proposed release. The Minister should be required to consider whether any onshore shale gas industry can coexist with existing or future uses of land and whether the land is in fact prospective for onshore shale gas before land is released.

The Panel has also recommended that certain parts of the NT should never be 'released' for any onshore shale gas exploration. This includes areas of high tourism value, towns and residential areas, national parks, conservation reserves and areas of high ecological and cultural significance. The Panel recommended that these areas be declared 'no go zones' or 'reserved blocks' under the Petroleum Act to ensure they are never impacted by any onshore shale gas development.

Accessing pastoral land

Gas companies will require access to pastoral land to explore for any onshore shale gas (access to Indigenous land in the NT is discussed in Chapter 11). The Panel has acknowledged that, although pastoralists do not have a freehold interest in land, they have a very deep and personal connection to the land that they manage and they have property rights under the Pastoral Land Act that require protection.

It is apparent that the present land access regime in the NT has the real capacity to fail to facilitate a cooperative relationship between gas companies and the pastoral industry. The Panel has concluded that the current land access regime in the NT can be strengthened in several ways, including by ensuring that the agreement-making process is fair and balanced. First, the Panel has recommended that there must be a statutory requirement for a land access agreement to be in place before gas companies gain access to pastoral land. The process must be enshrined in statute, not unenforceable guidelines. Second, there must be mandatory provisions included in land access agreements that provide a minimum level of protection of the interests of pastoralists. The mandatory provisions include 'make good' provisions for any damage that has occurred to water or land and a requirement that gas companies pay for all reasonable costs associated with negotiation of the agreement.

Improved decision-making

The Panel has considered the current assessment and approval processes under the Petroleum Act and subordinate legislation. The Panel has examined the process that leads up to decisions about the release of land for any onshore shale gas exploration, the grant of a petroleum permit, the approval of a draft environment management plan (**EMP**), and the approval of other activities, such as hydraulic fracturing. The Panel has made recommendations to increase the transparency of the decision-making process, the accountability of the decision-maker, and the quality of the decision making.

For example, the Panel has proposed that the Minister for Resources be required to consider whether a gas company is a 'fit and proper person' when deciding whether or not to grant an exploration permit or a production licence. The Panel has also proposed that the Minister publish the reasons why he or she determined that the gas company was a fit and proper person.

The Panel has recommended that all EMPs be published online prior to Ministerial approval so that the community and interested stakeholders have an opportunity to comment. Again, the Minister should be required to publish his or her reasons for coming to a particular decision and the factors that were considered in making that decision.

The Panel has recommended that decision-makers can be made more accountable by broadening the current review process to enable those directly and indirectly affected by decisions concerning any onshore shale gas development to challenge that decision.

Improved financial assurances

All governments should have a financial assurance system in place to ensure that there are adequate resources available for remediation and rehabilitation in the event a gas company fails to meet its legal obligations for any reason. The Panel has concluded that the present financial assurance system in the NT is inadequate and opaque. The Panel has proposed that the Government develop a leading practice financial assurance regime, that comprises transparent environmental rehabilitation bonds as well as a non-refundable levy to ensure that funds are available for the long term monitoring of wells and, if required, the management and rehabilitation of abandoned wells.

Objective-based regulation, minimum standards and codes of practice

The Panel is supportive of the Government's adoption of an objective-based regulatory framework. Objective-based regulation provides room for innovation and flexibility and places the responsibility on the gas industry, not the Government, to demonstrate that agreed environmental objectives have been achieved. The Panel was concerned, however, that too much objective-based regulation will not provide certainty to the community, the regulator, or to industry. There is some doubt as to what an *"acceptable"* level of risk is, and what the terms *"as low as reasonably practicable"* and *"good oilfield practice"* in the governing legislation mean. This is particularly so where any onshore shale gas industry will be new and there are no precedents to inform what the Minister will deem to be *"acceptable"*.

The Panel has therefore proposed that the objective-based regulatory framework be supported by clear, prescriptive, and enforceable codes of practice to render unequivocal exactly what is required of industry. Elsewhere in this report the Panel has recommended that codes of practice be developed for, among other things, well integrity and well abandonment.

Options for reform of the regulator

The Panel has noted the widespread perception in the community that the current regulator, DPIR, is not independent. The Panel has concluded that this perception is derived, in part, from the role that DPIR has as the regulator and promoter of any onshore shale gas industry. The Panel has concluded that these two responsibilities must be separated to ensure that decision-making is independent.

The Panel has provided two options to resolve this tension. Option 1 takes into account the Government's current environmental reform agenda, which contemplates the introduction of uniform environment legislation in the NT ('**Environment Protection Act**'). The new environment legislation will be the responsibility of the Minister for Environment. Under the new legislation, activities with an environmental impact, including any onshore shale gas activities, will be assessed by an independent shale gas advisory group (possibly the EPA) and approved by the Minister for Environment. When deciding whether or not an activity can go ahead, the advisory group and the Minister will only consider environmental matters in accordance with the environmental legislation, and not matters in relation to the development or promotion of the industry. If the advisory group, or the Minister, is not satisfied that the environmental impacts of any onshore shale gas development can be reduced to acceptable levels, the development cannot proceed. Having a separate environmental approval for any onshore shale gas activity will give the community confidence that environmental considerations are given primacy when decisions are made about the development of the onshore shale gas industry.

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

For both of the options, the Panel has recommended that decisions about water extraction remain the responsibility of the Water Controller under the Water Act. This will ensure that decisions about water are made by a single decision-maker, which minimises the risk that water resources will be over-allocated.

Recommendation 14.1

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

Recommendation 14.2

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

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

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

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

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

Recommendation 14.3

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

Recommendation 14.4

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

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

Recommendation 14.5

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

That the land access agreement be required by legislation.

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

Recommendation 14.6

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

Recommendation 14.7

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

Recommendation 14.8

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

Recommendation 14.9

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

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

Recommendation 14.10

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

Recommendation 14.11

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

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

Recommendation 14.12

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

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

Recommendation 14.13

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

Recommendation 14.14

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

That all comments made on draft EMPs be published.

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

Recommendation 14.15

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

Recommendation 14.16

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

Recommendation 14.17

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

Recommendation 14.18

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

Recommendation 14.19

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

Recommendation 14.20

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

Recommendation 14.21

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

Recommendation 14.22

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

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

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

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

Recommendation 14.23

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

Recommendation 14.24

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

Recommendation 14.25

That the Government enact whistleblower protections.

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

Recommendation 14.26

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

Recommendation 14.27

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

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

Recommendation 14.28

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

Recommendation 14.29

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

Recommendation 14.30

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

Recommendation 14.31

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

Recommendation 14.32

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

Strategic regional environmental and baseline assessment (Chapter 15)

The need for a robust baseline assessment has, especially in relation to the biophysical (water, land and air) risks presented by any onshore shale gas industry, been raised in most submissions (both written and verbal) received from environmental groups, the community, industry, and government agencies.

The lack of adequate pre-development assessment and environmental baseline data is routinely cited as being one of the biggest negative environmental regulation and management-related issues associated with the rapid development of the shale gas industry in the US and the CSG industry in Queensland.

Based on the scientific evidence it has examined to date, the Panel has concluded that there is a substantive lack of baseline data required to:

- inform understanding of the Territory's unique environmental values;
- adequately assess the risk profile of any onshore shale gas industry in the NT;
- facilitate strategic water and land use planning; and
- fully inform issues associated with social impacts, human health and Aboriginal people and their culture.

Given the magnitude of the problem, the Panel has provided specific guidance on the scope and content of the environmental assessment and baseline studies required to develop any onshore shale gas industry in the NT if the Government decides to lift the moratorium. The Panel strongly recommends that such assessments must be carried out prior to any production approvals being granted.

Bameranji Waterhole, Hayfield Station 2017.

The term ‘strategic regional environmental and baseline assessment’ (or SREBA) is used by the Panel to describe the broad aim of what is required by any assessment. High level scopes of work are provided in Chapter 15, and recommendations are made about how the components of the assessments should be executed. It is not the intention of the Panel to be rigorously prescriptive, with much of the specific details of the content for a SREBA requiring development and approval by the regulator after consultation with relevant stakeholders.

A SREBA will provide the foundation for a planning framework that gives certainty to both the public and industry, and to ensure satisfactory environmental outcomes by addressing the potential for cumulative impacts across broad regions. The Panel recommends that the Beetaloo Sub-basin should be the first priority for any such assessment.

But the acquisition of data should not stop with a SREBA, with work needing to progressively transition to an operational surveillance/performance monitoring program in the event that there is the commercial production of onshore shale gas. In this context, it should be noted that in the semi-arid and arid regions of the NT multiple year baseline biological datasets are particularly important given the very high inter-annual variability of rainfall and its effects on terrestrial and aquatic ecosystem form and function.

Recommendation 15.1

That a strategic regional environmental and baseline assessment (SREBA) be undertaken prior to the grant of any production licence for onshore shale gas.

Conclusion

No industry is completely without risk. And the development of any onshore shale gas industry in the NT is no exception. But having considered the most current available scientific literature and data from a wide range of sources, and noting the recent and continuing technological improvements in the extraction of onshore shale gas, the conclusion of this Inquiry is that the challenges and risks associated with any onshore shale gas industry in the NT are manageable by, among other things:

- releasing land that is environmentally, socially and culturally appropriate for use for shale gas development;
- the completion of a SREBA to gather essential baseline data prior to any onshore shale gas industry being developed;
- implementing an area or regional-based approval system;
- mandating world leading engineering standards for the construction, maintenance and de-commissioning of all onshore shale gas wells and for the extraction of shale gas by hydraulic fracturing;
- implementing new technologies where relevant as soon as they become available;
- requiring the comprehensive monitoring and reporting of all aspects of onshore shale gas operations with real-time public scrutiny of the resulting data;
- ensuring that the regulator is independent insofar as the agency that is responsible for promoting any onshore shale gas resource is not the same agency responsible for its regulation;
- reforming the current regulatory framework governing onshore shale gas development in the NT to strengthen transparency and accountability of all decision-making and to ensure a stringent system of compliance and enforcement; and
- introducing full fee recovery to fund the necessary regulatory reforms and to ensure that strong oversight is maintained.

Of course, nothing is guaranteed. And with any new industry it is not uncommon for problems to emerge. However, it is the Panel’s opinion that, provided that the recommendations made in this Report are adopted and implemented, not only should the risk of any harm be minimised to an acceptable level, in some instances, it can be avoided altogether.

In short, the Panel is of the opinion that with enactment of robust and rigorously enforced safeguards, the waters shall continue to flow *"clear and cold out of the hills"* [8] and the "*dawn chorus of"* Magpie Geese, Brolgas, Budgerigars, Black Kites, Blue-winged Kookaburras "*and scores of other bird voices"* [9] shall continue to reverberate across the NT landscape notwithstanding the development of any onshore shale gas industry.

Brolgas, Northern Territory. Source: Alamy Stock Photo.

8 Carson 1962, p 1.
9 Carson 1962, p 2, with apologies.

SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

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