SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

SUMMARY OF THE FINAL REPORT

APRIL 2018

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

The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory
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Image: Mick Wallangkarri Tjakamarra, Water Dreaming with bushtucker, 1972, acrylic on board, 65 x 45.5 cm (irregular). Araluen Art Collection. Winner of the 1972 Caltex Art Award. Acquired by the Central Australian Art Society. Donated to the Alice Springs Town Council in 1989 for the people of Alice Springs. © the artist licensed by Aboriginal Artists Agency, image courtesy of Araluen Arts Centre.

Contents

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 documents her concern about the indiscriminate use of pesticides, especially DDT, and their adverse effect on the environment. More broadly, it powerfully details 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 potentially catastrophic anthropogenic climate change.

1 Carson 1962, pp 1-3.

In the United States of America (**US**), the 'shale gale' gas revolution transformed the energy market in that country and significantly affected world trade in gas and oil. But with change came cost. In some jurisdictions, the industry developed in an almost legislative lacuna, with poor regulatory governance resulting in poor 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 hydraulic fracturing has been legislatively prohibited in Victoria, and is the subject of a moratorium in Tasmania, New South Wales (**NSW**) and Western Australia (**WA**). 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 shale 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 shale gas 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 2012 Hunter Report was that Government should prioritise the development and implementation of environmental regulations under the *Petroleum Act 1984* (NT) (**Petroleum Act**). 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.

Finally, on 14 September 2016, the Chief Minister of the Northern Territory, the Hon. Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore 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 under the *Inquiries Act 1945* (NT) (**Inquiry**).

The Inquiry is chaired by the Hon. Justice Rachel Pepper, a current 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 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 (located at Appendix 1). While limited to onshore shale gas only (that is, for example, shale liquids and tight gas are excluded), the Terms of Reference were nevertheless broad in their scope. They required 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 Report, respectively):

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

The Inquiry differs markedly from its predecessors by reason of its wide scope and its strong mandate to consult widely with Territorians. The Inquiry took this mandate seriously, as the discussion of the work of the Inquiry and the description of its community engagement in Chapters 1 to 3 demonstrates. The extensive consultation process established by the Inquiry was 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 either at live-streamed public hearings, in community forums, and/or by writing more than 1250 submissions.

In this context, it must be noted that the strong antipathy surrounding hydraulic fracturing for onshore shale gas demonstrated during the consultations did not abate. For a significant majority of the people participating in the Inquiry, the overwhelming 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 *Draft Final Report* (**Draft Final 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 rigorously enforced improved regulatory regime, the onshore extraction of shale gas could be advantageous 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 illusory, the economic modelling commissioned by the Inquiry indicates that tangible economic benefits can flow to the NT if this industry proceeds.

But 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 has been 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 exists 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)

The Panel collected and analysed the latest available evidence concerning the final list of issues, or risks, identified in consultation with the community, industry, land councils, local government, environmental groups, and government agencies (see Appendix 2). 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; and
- regulatory reform (including land access).

The principles of ecologically sustainable development (**ESD**) were 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 mitigation measures to ensure that those objectives are achieved. The process that the Panel has followed to assess each issue has been tailored to the nature of the issue.

It became apparent during the Panel's deliberations that the biophysical (water, land, air) and public health risks were best assessed by applying a standardised qualitative, multi-step risk assessment process. The Panel 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 approach was employed by the consultants engaged by the Panel to develop a social impact assessment (**SIA**) framework (Chapter 12). By contrast, Chapters 11 (concerning Aboriginal people and their culture) and the economic impacts of any onshore shale gas industry in the NT (Chapter 13) were not suited to this type of assessment. Accordingly, the methods used to assess the nature of those risks are described separately in those Chapters.

Regulatory reform (Chapter 14) is considered by the Panel to be a mitigating factor for the risks identified. That is, if the regulatory framework is sufficiently robust in content and enforcement, it will reduce the risks posed by the development of any onshore shale gas industry. In this context, the Panel assumed that the reforms that it has recommended will be implemented in full, noting the concern expressed in many written submissions and during the community forums that the failure by the Government to implement the regulatory reforms was itself a risk.

An assessment of risk was only undertaken where there was sufficient information or evidence to do so. The assessment assumed the existence of the current governance regime and applied measures to mitigate this risk. 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 if there was a possibility that the consequence of the risk would cause an unacceptable impact on the value sought to be protected. In this case, maximum safeguards were applied until it could be demonstrated by the acquisition of additional information that the risk does not require the initially prescribed high level of mitigation (for a detailed description of the content of the precautionary principle and its application, see Chapter 14).

Shale gas extraction and development (Chapter 5)

This Chapter describes what onshore shale gas is, the shale gas extraction process, including hydraulic fracturing, the steps involved in the development of a shale gas industry, the critical issue of well integrity, water use and the nature and management of the produced wastewaters. The issues of solid waste management, seismic activity and the potential for subsidence are also discussed. 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 onshore shale gas is the culmination of a process spanning several years, which includes exploration, appraisal, delineation and production (see Chapter 15). It is possible that even after many years of exploration and investigation, the potential resource may be found to be uneconomic. Even if the resource is found to be commercially viable, it will take additional years of development before commercial production occurs. Based on overseas experience, a shale gas well can be expected to produce gas for several decades before being decommissioned.

Well integrity

The possibility that water resources, particularly groundwater, can be contaminated by activities associated with the extraction of onshore shale gas was a major concern to the public, environmental groups and many key stakeholders. Accordingly, considerable attention has been paid to the issue of well integrity. The International Standards Organisation defines well integrity as, *"maintaining full control of fluids (or gases) within a well at all times by employing and* *maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment."* [2]

In addition to conducting its own research on well integrity, the Panel commissioned Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) to conduct an extensive and in-depth review of all aspects of this complex topic, noting that it has been the subject of considerable scientific debate over the past decade. The complete report by CSIRO is contained in Appendix 14. While the Panel has drawn upon this report, all conclusions and recommendations are those of the Panel.

CSIRO reviewed the well barrier and well integrity failure rates that have been reported in the open literature. 'Well barrier failure' can be identified in a number of ways, including by testing the 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, which is critical because full well 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, together with the maintenance of the integrity of the cement over time, are critical.

Overall, CSIRO found, largely using data sets from the US, that for wells constructed to modern standards, the rate of well integrity failure that has the potential to cause environmental contamination is approximately 0.1% (or 1 in 1000), with several studies finding no well integrity failure. The rate for a single well barrier failure was much higher, namely, 1–10%. However, there were very few single barrier failures observed for wells constructed to Category 9 or equivalent (see **Table 5.2** for a description of well categories). The Amungee NW-1H well that was constructed by Origin in the Beetaloo Sub-basin was a Category 9 well, with casing cemented to the surface along the length of the well.

The final phase in the well lifecycle starts when a well is decommissioned and 'plugged'. The long-term integrity of wells post decommissioning was a matter of major concern to most people that were at the community consultations.

The goal of plugging and decommissioning 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 decommissioning 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 decommissioned using existing best practice, if any of the potential leakage pathways were to develop, it was highly unlikely that they would allow substantial fluid flow rates along the well bore. The small cross-sectional areas and long vertical lengths of the pathways would 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 decommissioning. Pressures within the part of the reservoir accessed by the well will have been depleted by production, and the very low permeability of the shale will prevent gas from other parts of the reservoir migrating to the well.

Sometimes the term 'abandonment', or 'orphan', is used by the gas industry to describe the process of decommissioning. The term suggests a well abandoned in the landscape, with no one to check on either its short-or longer-term environmental performance. In many jurisdictions, including in the NT, there has historically been no requirement for surveillance of decommissioned wells.

2 ISO 2017.

Even though CSIRO concluded that the potential for serious post decommissioning integrity issues is low, the Panel has found that there is very little information available worldwide on the post decommissioning performance of onshore shale gas wells. The assessment of post decommissioning performance and the issue of well stewardship over the long term is an aspect that requires much greater attention by the regulator and the gas industry. Accordingly, this important issue is the subject of several specific recommendations by the Panel (see Chapter 5).

Overall, the Panel concluded that, provided that a well is constructed to a high standard and in a way that takes into account the 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. However, there must be a program of regular integrity testing throughout the decades-long operational life of the well to ensure that if any problems develop, they are detected and remediated early. In particular, the well must pass a rigorous set of integrity tests prior to being decommissioned because once this process has been completed, 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. There should also be ongoing programs of water quality monitoring (in groundwater monitoring bores installed adjacent to all well pads) and measurements of methane fluxes in the atmosphere above the buried well. These assurance steps, from well design through to initial integrity testing, operational monitoring, decommissioning, and post-decommissioning monitoring, must also 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 to the Panel 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). This is summarised below. In this context, it should be noted that the gas companies in the Beetaloo Sub-basin are proposing to use multi-well pads (at least 10 wells per pad) to extract the gas. This configuration provides substantial benefits both in terms of reducing the physical terrestrial 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.

Onshore shale gas extraction requires the use of large quantities of water, which may be obtained from local surface or groundwater sources, or must be 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 have required 30–40 fracturing stages. Recent indications are that this is analogous to any onshore shale gas industry to be developed in the NT. The Panel notes that if 1–2 ML of water is required for each stage of hydraulic fracturing, and at least 20 stages are likely, based on developing industry practice, at least 40 ML of storage will be needed per well. This volume will not be cumulative for a multi-well pad configuration, and will depend on the extent of reuse possible, noting that the wells may 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' comprises 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 the chemicals used in hydraulic fracturing is a cause of considerable anxiety to the community. 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. Only a fraction of the 1,100 different chemicals identified by the US EPA as having been used in the US for hydraulic fracturing are now being routinely employed in modern extraction practices. For example, between January 2011 and February 2013, only 35 of the total identified number of chemicals previously used were employed in a majority of the fracturing operations in the US. In addition, there has been a strong move over the last decade by the gas 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 only the least toxic available chemicals being used (that is, a reduction of the risk profile by substitution). Chapters 7 and 10 contain further discussion of the risks associated with the chemicals used in hydraulic fracturing.

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. Most of the reported incidents of contamination of surface waterways and groundwater have been the result of surface leaks and spills. Effective management of these surface issues is therefore a key requirement for any onshore shale gas industry in the NT.

There is no reported evidence of fracturing fluid or formation water moving from the fractures in the shale formation to near surface aquifers from the more than one million hydraulic fractures in North America and more than 2,000 in the Cooper Basin in South Australia (**SA**). This is providing that the hydraulic fracturing is not conducted in proximity to a major vertically transmissive fault or adjacent to an improperly decommissioned deep gas or petroleum well. The former risk factor has been specifically addressed by one of the Panel's recommendations, while the latter risk factor is unlikely to occur in the NT because there has been so little prior exploration (or production) for shale gas and hydrocarbons.

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 shale gas 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 of the composition of 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 onshore shale gas. In the US, the disposal of the large amounts of drill cuttings resulting from commercial 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 presently the case for 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 (**NORMs**) 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 examined. Based on an extensive review of the evidence, the Panel has concluded that this is unlikely to occur as a result of hydraulic fracturing for onshore shale gas in the NT. The only exception to this assessment is if a fault is activated by the reinjection of fluid. The Panel has recommended that seismic activity be monitored during all hydraulic fracturing operations and that if activity exceeds 0.5 on the Richter scale, that the operation 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' and acceptable.

Subsidence

The Panel considers that development of sinkholes as a result of the hydraulic fracturing process is highly unlikely because of the large vertical distance (several thousand metres) between the hydraulic fracturing zone (the shale formation) 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 prior to the grant of any further exploration approvals, the Government mandates an enforceable code of practice setting out minimum requirements for the decommissioning of any onshore shale gas wells in the NT. The development of this code must draw on world-leading practice. It must be sufficiently flexible to accommodate improved decommissioning technologies. The code must include a requirement that:

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

Recommendation 5.2

That the Government:

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

Recommendation 5.3

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

- ***all onshore shale gas wells (including exploration wells constructed for the purposes of production testing) be constructed to at least a Category 9 standard (unless it can be demonstrated by performance modelling/assessment that an alternative design would***

- *give at least an equivalent level of protection), with cementing extending up to at least the shallowest problematic hydrocarbon-bearing, organic carbon rich or saline aquifer zone;*
- *all wells be fully tested for integrity before and after hydraulic fracturing and that the results be independently certified, with the immediate remediation of identified issues being required;*
- *an ongoing program of integrity testing be established for each well during its operational life. For example, every two years initially for a period of 10 years and then at five-yearly intervals thereafter to ensure that if any issues develop, they are detected early and remediated; and*
- *the results of all well integrity testing programs and any remedial actions undertaken be published as soon as they are available.*

Recommendation 5.4

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

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

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

Recommendation 5.5

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

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

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

Recommendation 5.6

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

Recommendation 5.7

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

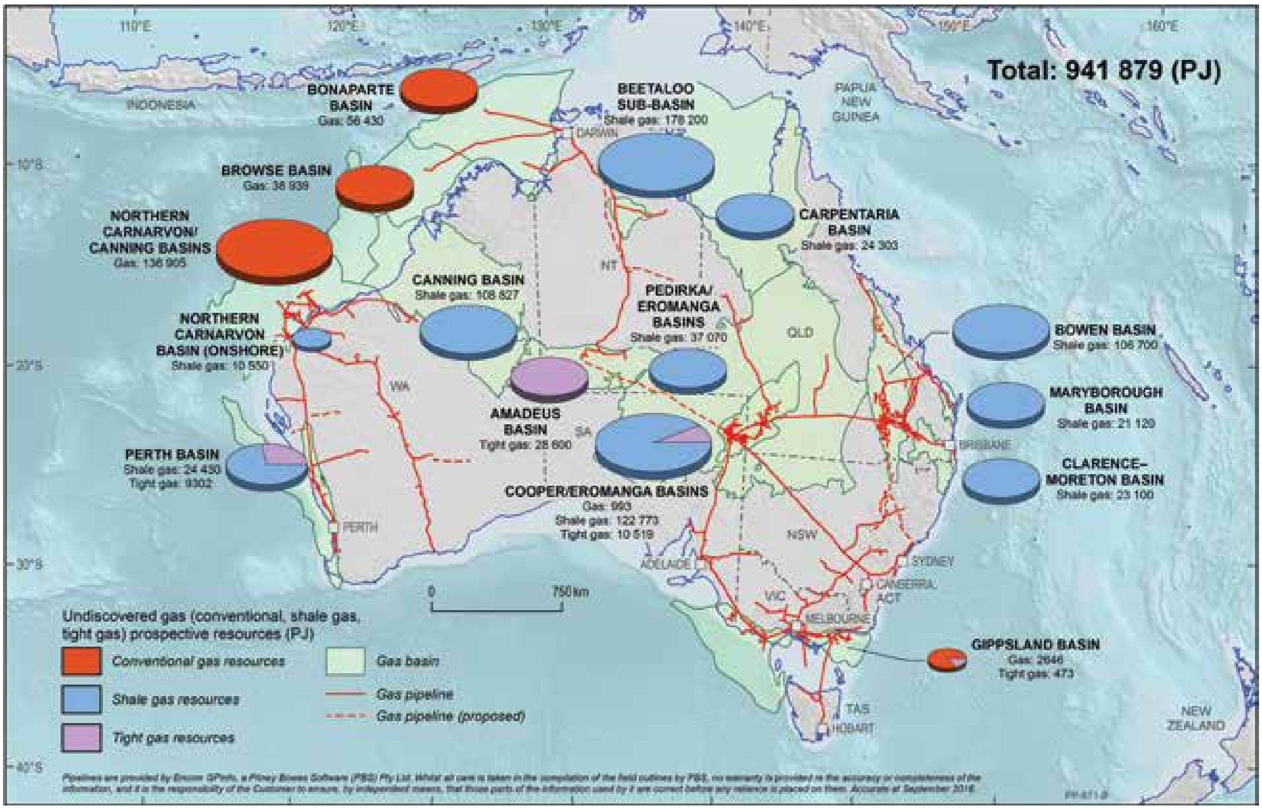
Onshore shale gas in Australia and the Northern Territory (Chapter 6)

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[3] (see **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 (see **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.

Map 1: Summary of Australia's prospective gas resources. Source: Geoscience Australia.[4]



The Panel has not considered the issue of shale liquids being associated with any potential shale gas development because they are outside the Inquiry's Terms of Reference. Although the potential for liquids to be associated with a number of shale formations in the NT is known, to date, the only declared contingent shale petroleum resource has been for dry gas from the Velkerri formation in the Beetaloo Sub-basin. All other potential liquids resources remain

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

insufficiently explored and/or unlikely to be economically feasible as an oil development.[5] Therefore, if there was to be shale liquids production, it would in all likelihood be primarily as a gas play with a much smaller volumetric percentage of liquids production. The Panel's view is that if this occurred, it would not materially affect the risk assessments and recommendations contained in this Report.

The scale of any potential onshore shale gas 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 three petroleum companies (Origin, Santos and Pangaea) suggest that combined development 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 will 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 somewhat larger than the ranges used by ACIL Allen Consulting Pty Ltd (**ACIL Allen**) for its economic analysis (Chapter 13 and Appendix 16). However, the estimates from both the gas industry and ACIL Allen are both considerably smaller than the estimates provided by DPIR, noting that the DPIR estimates were based on maximum potential supply unconstrained by any economic factors (for example, the cost of supply or the ability of the market to absorb the anticipated volume of production).

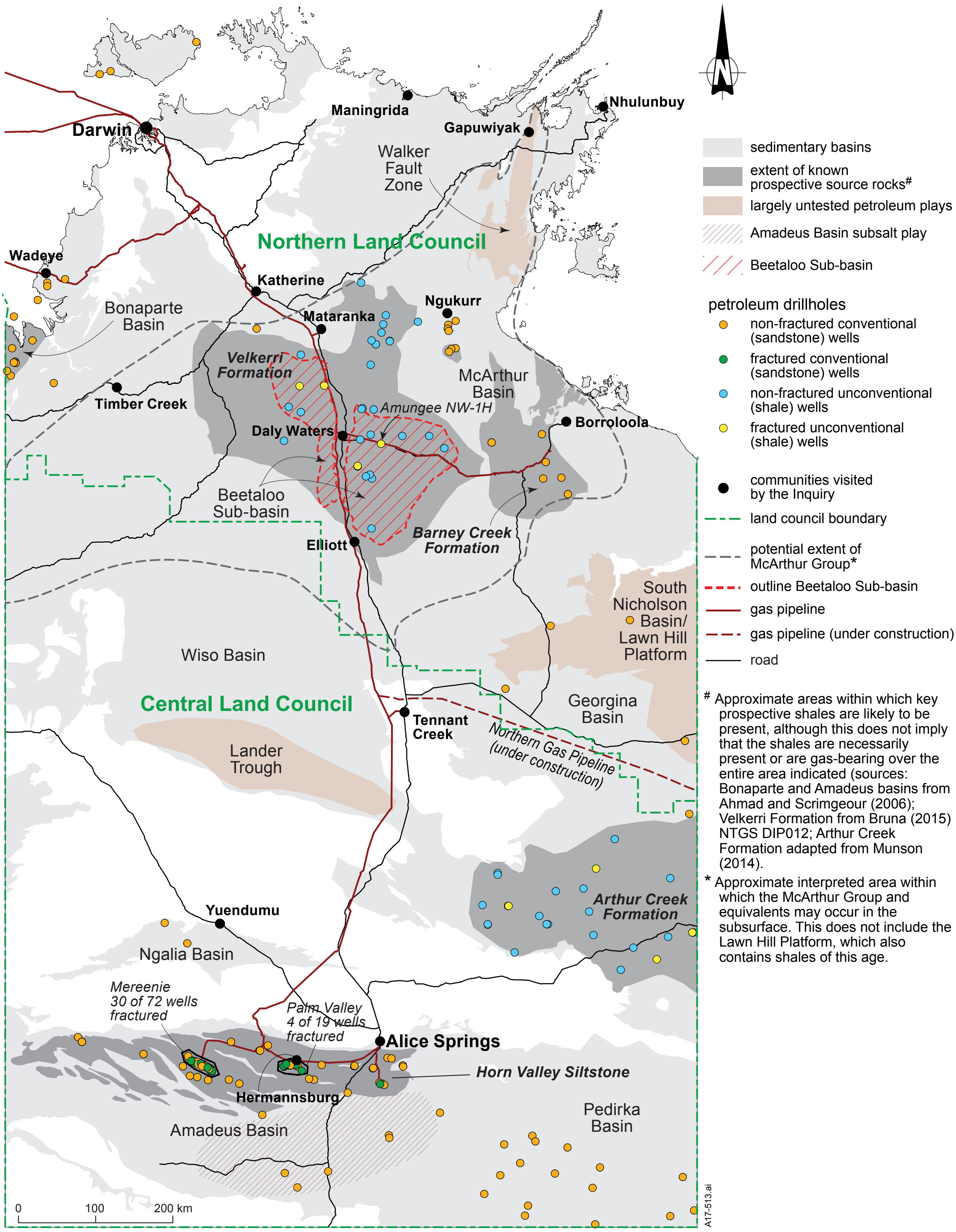
The actual infrastructure requirements (in particular, the numbers and density of well pads through time) will require careful scrutiny in the event that the moratorium is lifted and a commercial supply of gas is developed. Experience in the US has shown that production from individual wells, and ultimately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

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

5 Australian Energy Resources Assessment

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.



Water (Chapter 7)

Sustainable management of surface and groundwater resources will be crucial to the development of any onshore 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 any onshore shale gas development and the prospective onshore 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 onshore 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 the regulations that govern their use. The likely per-well water requirements for a medium-scale onshore shale gas industry is estimated to provide context for assessing how much water might be required. During the course of the Inquiry, it became apparent to the Panel that there was not enough information for most of the onshore shale gas regions in the NT to be able to estimate the sustainable groundwater yield for any 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 the most monitored) are clustered in close proximity to these communities and do not provide the required regional information about aquifer properties. There is also information on groundwater from pastoralist bores, but again, this is insufficient for regulating water use by any new onshore shale gas industry.

The Panel assessed 20 water-related risks using the risk assessment framework detailed in Chapter 4. Three high-priority issues were identified from the risks assessed: 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 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 of 1,000 to 1,200 hydraulically fractured shale gas wells (on approximately 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.

Currently, petroleum activities are exempt from the application of certain conditions of the *Water Act 1992* (**NT Water Act),** including the requirement to have a water extraction licence. The Panel has recommended that the Water Act be amended to require gas companies to obtain a water extraction licence and that the Government introduces a charge on water extraction for all onshore shale gas activities.

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 will need its own set of rules) and very challenging to regulate.

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 assessed the risk that any onshore shale gas industry will use an excessive amount of groundwater, which could result in an unacceptable reduction in the amount of water available regionally for domestic use, use by other industries (such as agriculture and pastoralism), 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 further production approvals are granted for any onshore shale gas activities. 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 a SREBA;

- the Daly-Roper Water Control District be extended south to include all of the Beetaloo Sub-basin; and
- a separate water allocation plan (**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, agriculture, pastoralism, ecosystems, or 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 a gas company bore field. Hydrogeological investigations and groundwater modelling studies undertaken as part of a recommended SREBA will confirm 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 to the extent that it can no longer support human drinking, agriculture, stock watering or aquatic ecosystems, in accordance with the relevant Australian drinking water and water quality guidelines.

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 community concerns. The Panel commissioned CSIRO to undertake a detailed review of this issue.

The Panel has distinguished between faulty 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 onshore 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 not toxic in groundwater.

In assessing the risk of aquifer contamination from leaky wells, the Panel considered two pathways: first, the entry of contaminants into an aquifer; and second, the behaviour and transport of the contaminants within the aquifer to reach a water supply bore (or aquatic ecosystem). Three plausible pathways by which contaminants could 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 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 mixing 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'. If wells are constructed to Category 9 standard or equivalent, with cementing along the full length of the well bore, the likelihood will be 'remote' to 'very low'. The consequence for 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 that will come from any SREBA; and
- monitoring of groundwater quality occurs at each well pad, particularly during hydraulic fracturing, and that this monitoring data is made publicly available.

Spills

The Panel has considered the risk from spills of contaminated wastewater or hydraulic 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 spill 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 must be used to hold wastewater in preference to open ponds;
- the well pad site must be treated (for example, with a geomembrane or clay liner) to prevent the infiltration of wastewater spills into underlying soil; and
- a groundwater monitoring program must be established around each well pad, particularly during hydraulic fracturing, and that this monitoring data is made publicly available.

If any onshore shale gas industry is developed in the NT, it will require the transportation of hydraulic fracturing chemicals and fluid additives to site, 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, although this risk is likely to be 'low' since the pipelines will be buried. 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 are 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 considers whether:

- restrictions need to be placed on the transport of hydraulic fracturing chemicals during the wet season, particularly on unsealed roads; and
- rail transport of some or all of the hydraulic fracturing chemicals and other consumables is required by the gas companies.

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 been associated with seismic activity and is becoming less prevalent due to greater reuse of flowback water in hydraulic fracturing and the introduction of 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, resulting 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 be undertaken as part of any SREBA before any further production approvals are granted. This modelling must demonstrate that there will be no unacceptable impacts 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 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 major 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 any 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 any onshore shale gas hydraulic fracturing be prohibited, and that the discharge of treated or untreated wastewater to drainage lines, waterways or temporary stream systems 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 regions 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 only a few 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 Beetaloo Sub-basin SREBA should be extended to include this region, noting that there are currently petroleum exploration permits granted over this area.

Water quality

The Panel 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 so 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 onshore shale gas basin must be undertaken prior to the grant of any further production approvals for any onshore shale gas industry. The initial SREBA should be undertaken for the Beetaloo Sub-basin.

Recommendation 7.1

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

Recommendation 7.2

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

Recommendation 7.3

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

Recommendation 7.4

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

Recommendation 7.5

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

Recommendation 7.6

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

Recommendation 7.7

That in relation to the Beetaloo Sub-basin:

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

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

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

Recommendation 7.8

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

- *that prior to the grant of any further exploration approvals, the extraction of water from water bores to supply water for hydraulic fracturing be prohibited within at least 1 km of existing or proposed groundwater bores (that are used for domestic or stock use) unless hydrogeological* *investigations and groundwater modelling, including the SREBA, indicate that a different distance is appropriate, or if the landholder agrees to a variation of this distance;*

- *that relevant WAPs include provisions that adequately control both the rate and volume of water extraction by the gas companies;*
- *that gas companies be required, at their expense, to monitor drawdown in local water supply bores; and*
- *that gas companies be required to immediately 'make good' and rectify any problems if the drawdown is found to be excessive.*

Recommendation 7.9

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

Recommendation 7.10

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

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

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

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

Recommendation 7.11

That prior to the grant of any further exploration approvals, in order to minimise the risk of groundwater contamination from leaky gas wells:

- *all wells subject to hydraulic fracturing must be constructed to at least Category 9 (or equivalent) and tested to ensure well integrity before and after hydraulic fracturing, with the integrity test results certified by the regulator and publicly disclosed online;*
- *a minimum offset distance of at least 1 km between water supply bores and well pads must be adopted unless site-specific information of the kind described in Recommendation 7.8 is available to the contrary;*
- *where a well is hydraulically fractured, monitoring of groundwater be undertaken around each well pad to detect any groundwater contamination using multilevel observation bores to ensure full coverage of the horizon, of any aquifer(s) containing water of sufficient quality to be of value for environmental or consumptive use;*
- *all existing well pads are to be equipped with multilevel observation bores (as above);*

- *as a minimum, electrical conductivity data from each level of the monitor bore array should be measured and results electronically transmitted from the well pad site to the regulator as soon as they are available. The utility of continuous monitoring for other parameters should be reviewed every five years or as soon as advances in monitoring technology become commercially available; and*
- *other water quality indicators, as determined by the regulator, should be measured quarterly, with the results publicly disclosed online as soon as reasonably practical from the date of sampling. This monitoring regime should continue for three years and be reviewed for suitability by the regulator.*

Recommendation 7.12

That prior to the grant of any further exploration approvals, to reduce the risk of contamination of surface aquifers from on-site spills of wastewater:

- *the EMP for each well pad must include an enforceable wastewater management plan and spill management plan;*
- *enclosed tanks must be used to hold all wastewater; and*
- *the well pad site must be bunded to prevent any runoff of wastewater, and be treated (for example, with a geomembrane or clay liner) to prevent the infiltration of wastewater spills into underlying soil.*

Recommendation 7.13

Upon a gas company undertaking any exploration activity or production activity, monitoring of the groundwater must be implemented around each well pad to detect any groundwater contamination, adopting the monitoring outlined in Recommendation 7.11. If contamination is detected, remediation must commence immediately.

Recommendation 7.14

That the Government, having regard to the measures detailed in Recommendation 5.5, undertakes a review to determine whether:

- *restrictions need to be placed on the transport of hydraulic fracturing chemicals and wastewater during the wet season, particularly on unsealed roads, to avoid the risk of spills; and*
- *rail transport of some or all of the hydraulic fracturing chemicals and other consumables required, be used to avoid the risk of spills.*

Recommendation 7.15

That gas companies must submit details of the locations of all faults that could compromise well integrity. The occurrence of any faults must be addressed in the well design plan submitted to the regulator for approval. The details of all faults and the well design plans must be publicly disclosed online as soon as they are available.

Recommendation 7.16

That appropriate modelling of the local and regional groundwater system must be undertaken before any production approvals are granted to ensure that there are no unacceptable impacts on groundwater quality and quantity. This modelling should be undertaken as part of a SREBA.

Recommendation 7.17

That prior to the grant of any further exploration approvals, the discharge of any onshore shale gas hydraulic fracturing wastewater (treated or untreated) to either drainage lines, waterways, temporary stream systems or waterholes be prohibited.

Recommendation 7.18

That to minimise the adverse impacts of any onshore shale gas infrastructure (roads and pipelines) on the flow and quality of surface waters, the Government must ensure that:

- ***landscape or regional impacts are considered in the design and planning phase of development to avoid unforeseen consequences arising from the incremental (piecemeal) rollout of linear infrastructure; and***
- ***roads and pipeline corridors must be constructed to:***
  - ***minimise the interference with wet season surface water flow paths;***
  - ***minimise erosion of exposed (road) surfaces and drains;***
  - ***ensure fauna passage at all stream crossings; and***
  - ***comply with relevant guidelines such as the International Erosion Control Association Best Practice for Erosion and Sediment Control and the Australian Pipeline Industry Association Code of Environmental Practice 2009.***

Recommendation 7.19

That the SREBA undertaken for the Beetaloo Sub-basin must take into account groundwater-dependent ecosystems in the Roper River region, including identification and characterisation of aquatic ecosystems, and provide measures to ensure the protection of these ecosystems.

Recommendation 7.20

That the Beetaloo Sub-basin SREBA must identify and characterise all subterranean aquaticecosystems, with particular emphasis on 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 which 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 Aboriginal people, who retain a deep cultural and spiritual connection to country that has endured for millennia. More broadly, it is also the case that people are attracted to the Territory's unspoiled landscapes, which is why most tourists choose to visit, making the preservation of these landscapes fundamental to the tourism industry.

Chapter 8 summarises the existing knowledge of terrestrial ecosystems and biodiversity in the NT. Additionally, it identifies 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 also gives the Panel's assessment of the 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 no impact on the terrestrial biodiversity values of affected bioregions;
- that overall terrestrial ecosystem health, including the provision of ecosystem services, is maintained at the regional scale;
- that any 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 assessed eight land-based risks to terrestrial biodiversity and ecosystem health, and landscape amenity.

Biodiversity and ecosystem health

Inappropriate location of any onshore shale gas development within a region

It is the Panel's view that any onshore 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 assessed that there is 'high' risk that any onshore shale gas development will occur in (currently undocumented) an area of high conservation value. The Panel has determined that this risk can be mitigated if a regional biodiversity assessment (as part of a SREBA) is conducted prior to the further grant of any production approvals for onshore shale gas development.

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 associated with any onshore shale gas development. Strengthening the current regulatory regime to ensure that 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 should 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 the 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. But these animals are already well established in the NT, and therefore, 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 pipeline corridors, which could result in changes to regional fire regimes. This 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 the 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 gas industry employees in the field;
- ensure that a regional fire management plan is developed and implemented by all relevant landholders and 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 an established 10-year baseline prior to the commencement of any onshore shale gas development; and
- implement management actions, such as prescribed fuel reduction burns, if fire frequency has increased due to onshore shale gas activity.

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. The Panel's view is that the impacts of habitat fragmentation (including abiotic edge effects) due to linear clearing 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 (with an 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 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 can be mitigated, including:

- limiting the surface footprint, and therefore, the extent of land clearing through the efficient design of access roads and pipeline corridors, the co-location of shared infrastructure among different gas companies, and the use of existing roads and tracks on pastoral properties;
- 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 so that vegetation is reestablished and edge and fragmentation effects are reduced.

Roads and pipelines as ecological barriers and corridors

The construction of roads and pipeline corridors is 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 assessed the risk of vegetation clearing and the fragmentation impacts of roads and pipeline corridors as 'medium'. The Panel has identified a number of measures that can reduce this risk, including:

- keeping corridor widths to a minimum and burying pipelines;
- ensuring best-practice management of stockpiles, spoil piles and topsoil during trenching and replacement during landform rehabilitation after pipeline trenching;
- revegetating the disturbed ground as soon as possible; 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.

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.

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 the NT that the NT 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 required for drilling and hydraulic fracturing.

Landscape transformations

Landscape transformation, where surface infrastructure becomes a dominant feature of the landscape due to the close spacing of well pads, has sometimes been the experience with onshore unconventional gas developments overseas. In the Panel's view, an acceptable landscape change means 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 this development occurs.

The Panel's assessment is that without mitigation, 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. However, the Panel has found it difficult to assess the consequences of this change in amenity for tourists and Territorians because of its subjective nature.

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 exclude development from areas of especially high landscape value, and the second is to reduce the visibility of infrastructure within 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 may include traffic congestion on what are currently 'outback' roads, or 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. The Panel recognises that the gas companies are required to address traffic risks as part of their environment management plans (**EMP**). However, there needs to be a regional approach to compiling and assessing information 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 developments in different locations. 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; and
- investigating the use of rail transport 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 the suggestion or the extent to which it will reduce road transport requirements.

Recommendation 8.1

That:

- ***strategic regional terrestrial biodiversity assessments be conducted as part of a SREBA prior to the granting of any further production approvals;***
- ***any onshore shale gas development be excluded from areas considered to be of high conservation value; and***
- ***the results of the SREBA must inform any decision to release land for exploration permits as specified in Recommendation 14.2 and, upon completion, must be considered by the decision-maker in the granting of any future exploration approvals.***

Recommendation 8.2

That a baseline weed assessment be conducted over all areas that will be accessed by a gas company on an exploration permit prior to any exploration activities being carried out on that area and that ongoing weed monitoring be undertaken to inform any weed management measures necessary to ensure no incursions or spread of weeds.

Recommendation 8.3

That, at all times, gas companies must have a dedicated weeds officer for each gasfield who is responsible for weed management and whose role includes:

- ***training all field workers in the identification of weeds, especially gamba and grader grass, and to establish an effective reporting system for any suspected weed incursions;***
- ***designing and implementing effective weed surveillance; and***
- ***ensuring prompt and effective management of any weed incursions in consultation with affected landholders.***

That the gas industry funds a dedicated officer responsible for weed management associated with any onshore shale gas development. This officer is to be located in the Government's Weed Management Branch in a regional centre. The officer will be responsible for:

- ***coordinating regional weed baseline assessments and subsequent weed surveillance; and***
- ***overseeing strategic and effective management of any weed incursions by gas companies.***

Recommendation 8.4

That gas companies must be required to have an approved weed management plan for any area the subject of an exploration permit prior to any part of that area being accessed for the carrying out of any exploration activities. The WMP must be consistent with all relevant statutory obligations and relevant threat abatement plans established under the EPBC Act.

Recommendation 8.5

That gas companies be required to comply with any statutory regional fire management plan within their area of exploration and/or production activity. The fire management plan must:

- ***address the impacts that any onshore shale gas industry will have on fire regimes in the NT and identify how those impacts will be managed;***
- ***establish robust monitoring programs for assessing seasonal conditions and fuel loads;***

- *require that annual fire mapping be undertaken to monitor any increase in fire frequency due to any onshore shale gas development;*
- *require that all existing baseline data for at least the decade prior to commencement of any exploration activity be collated and published;*
- *implement management actions, such as prescribed fuel reduction burns at strategic locations, if fire frequency is shown to have increased due to onshore shale gas activity; and*
- *facilitate support for local volunteer fire brigades to increase regional capacity for fire management.*

Recommendation 8.6

That as part of a SREBA, a study be undertaken to determine if any threatened species are likely to be affected by the cumulative effects of vegetation and habitat loss, and if so, that there be ongoing monitoring of the populations of these species. If monitoring reveals a decline in populations (compared with pre-development baselines), management plans aimed at mitigating these declines must be developed and implemented.

Recommendation 8.7

That the area of vegetation cleared for infrastructure development (well pads, roads and pipeline corridors) be minimised through the efficient design of flowlines and access roads, and where possible, the co-location of shared infrastructure by gas companies.

Recommendation 8.8

That well pads and pipeline corridors be progressively rehabilitated, with native vegetation re-established such that the corridors become ecologically integrated into the surrounding landscape.

Recommendation 8.9

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

That the Government considers the funding of local Aboriginal land ranger programs to undertake land conservation activities as an appropriate offset.

Recommendation 8.10

That gas companies be required to identify critical habitats during corridor construction and select an appropriate mechanism to avoid any impact on them.

Recommendation 8.11

That clearing for corridors, well pads and other operational areas be kept to a minimum, that pipelines and other linear infrastructure be buried (except for necessary inspection points), and that all disturbed ground be revegetated.

Recommendation 8.12

That directional drilling under stream crossings be used in preference to trenching unless geomorphic and hydrological investigations confirm that trenching will have no adverse impact on water flow patterns and waterhole water retention timing.

Recommendation 8.13

That roads and pipeline surface water flow paths minimise erosion of all exposed surfaces and drains.

Recommendation 8.14

That all corridors be constructed to minimise the interference with wet season stream crossings and comply with relevant guidelines, such as the International Erosion Control Association Best Practice for Erosion and Sediment Control and the Australian Pipeline Industry Association Code of Environmental Practice 2009.

Recommendation 8.15

That to minimise the impact of any onshore shale gas industry on landscape amenity, gas companies must demonstrate that they have minimised the surface footprint of development to ALARP, including that:

- ***well pads are spaced a minimum of 2 km apart; and***
- ***the long-term infrastructure within any development area (exploration or production) has little to no visibility from any major public roads.***

Recommendation 8.16

That the Government assesses the impact that any heavy-vehicle traffic associated with any onshore shale gas industry will have on the NT's transport system and develops a management plan to mitigate such impacts. Consideration must be given to:

- ***forecast traffic volume and roads used;***
- ***the feasibility of using the existing Adelaide to Darwin railway line (or some other railway network) to reduce heavy-vehicle road use; and***
- ***road upgrades.***

Greenhouse gas emissions (Chapter 9)

The extraction and subsequent use (the 'lifecycle') of shale gas results in the emission of greenhouse gases (**GHG**) such as methane and carbon dioxide. During the hearings, community consultations and submissions, concern was raised that these emissions will exacerbate climate change and contribute to the adverse impacts associated with global warming. Some people suggested that the development of any onshore shale gas industry in the NT should not proceed under any circumstances.

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; an assessment of the risk of methane and GHG released during the extraction, processing, transport and distribution (upstream stage) and the subsequent combustion of that gas for industrial, commercial or domestic uses (downstream stage); consideration of the monitoring and reporting of methane emissions; an assessment of the risks of methane emissions from post-production wells; and recommendations on how to mitigate these risks to achieve acceptable outcomes.

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 Australian 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. 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 45% to 403.3 ppm, while methane concentration has risen 157% to 1.85 ppm;

- the total annual global anthropogenic GHG emissions comprises 76% carbon dioxide and 16% methane emissions (the balance is nitrous oxide and fluorinated gases);
- to limit total human-induced warming to less than 2°C will require cumulative CO_2 emissions from all anthropogenic sources since 1870 to remain below about 2,900 Gt CO_2 by 2100 (the 'global carbon budget'). Total cumulative emissions from 1870 to 2016 were 2,199 Gt CO_2;
- in recent decades, changes in climate have caused impacts on natural and human systems on all continents and across all oceans; and
- limiting the devastating impacts of climate change will require substantial and sustained reductions in GHG emissions, which, together with adaptation, can limit climate change risks.

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 CO2e/MJ of life-time natural gas production, where the methane emission rate of 11.9 g CO2e /MJ (or 1.8% of life-time production) represents 77% of the total upstream emissions; and
- the application of available and proven 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.

Emission-reduction technologies include: capturing gas during well completions and workovers for processing rather than venting to atmosphere; flaring rather than venting; stricter leakage controls on equipment such as pneumatic pumps and compressor stations; and rules for finding and repairing leaks.

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. Having regard 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 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 around 0.7%, and for the US around 1.25%. These values underestimate field-based measurements, which range from 1.3–2.2% based on one comprehensive study. Further research is required to better understand the differences between these inventory 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 comes 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 shale gas field in the NT (assumed to be 365 PJ/y) would be similar to the methane emissions from the enteric fermentation of entire 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 $62 million per year, indicating that there are environmental benefits and economic incentives for gas companies to reduced methane emissions; and
- fugitive emissions from natural gas production in the NT are expected to be about 3% of Australia's inventory methane emissions and 0.03% of the global anthropogenic methane emissions. The Panel assessed the risk of fugitive methane emissions from any new shale gas industry in the NT, without any further mitigation, to be 'medium'.

Because the assessed risk is 'medium', it is therefore necessary to mitigate this risk. One strategy is to introduce new standards and technologies. Further mitigation strategies are considered below.

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 currently relies on using emission factor calculations and measurements;
- current inventory estimates underestimate basin-wide measurements of methane emissions, and basin-wide methane measurements are not routinely undertaken; and
- the Panel assessed the risk of non-detection of abnormal levels of fugitive methane emissions from any new onshore shale gas industry in the NT, without any further mitigation, as 'medium'.

Because the assessed risk is 'medium' it is necessary to mitigate this risk. Mitigation strategies have been identified, based on measurements of methane concentrations, to enable abnormal methane emissions (above background levels) to be detected and repaired quickly before large releases occur. After mitigation, the level of risk remains 'medium'. This is considered further in the Risk assessment summary section below.

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. Estimates are given for the quantities of life cycle GHG emissions for any new onshore shale gasfield in the NT producing 73,365 and 1,240 PJ/y. These emission estimates are used in a risk assessment by comparing the life cycle emissions with Australian and global GHG emissions from gasfields producing 365 and 1,240 PJ/y. The key findings are that:

- GHG emissions from any new onshore shale gas field in the NT producing 365 PJ/y would contribute around 4.5% of Australian GHG emissions and around 0.05% of global GHG emissions;
- for a gasfield producing 1,240 PJ/y (with LNG exports of 80% and domestic consumption of 20%), the Australian component of emissions is around 6.6% of Australian GHG emissions and 0.07% of global GHG emissions. The total emissions (emitted in both Australia and overseas) is approximately 0.17% of global GHG emissions; and
- the assessed risk associated with life cycle GHG emissions is 'medium' for a gasfield producing 365 PJ/y; 'medium' for the Australian emission component associated with a gasfield producing 1,240 PJ/y; and 'high' for the global emissions (both in Australia and overseas) associated with a gasfield producing 1,240 PJ/y.

These assessments represent unmitigated risk levels. At these levels, the assessed GHG risks are, in the Panel's view, unacceptable. These risks must, however, be mitigated. This is considered further in "*Risk assessment summary*" below.

Life cycle GHG emissions: technology comparisons for electricity production

The Panel made a comparison between the life cycle emissions produced from electricity generation by natural gas plants and those produced by 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 22% of the life cycle GHG emissions;

- the life cycle GHG emissions from shale gas generated electricity are 50–60% of that from coal-generated electricity and almost 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 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 (wells that have been cut-off, sealed (plugged) and buried under soil) generally have lower methane emissions than wells that have been abandoned with well head infrastructure left above the surface;
- there is a need to improve the integrity performance of decommissioned wells over the long term, that is, 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; 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 assessed the unmitigated risks to climate change associated with methane emissions and GHG emissions (including methane) to be either 'medium' or 'high'. At these levels of risk, further mitigation is required.

After the implementation of a suite of mitigation measures for methane emissions, these emissions will be reduced to a level that is consistent with the achievement of the acceptability criterion for methane emissions (see **Table 9.9**). Nevertheless, the mitigated methane emission risk will remain 'medium' and further mitigation of the risk of methane emissions is necessary. This is considered in the broader context of mitigating GHG emissions.

After mitigation of methane emissions, the residual life cycle GHG emissions (principally CO_2 and CH_4) are reduced slightly, but they remain significant and they have the same risk levels as previously assessed, namely, either 'medium' or 'high'. These are unacceptable risk levels. Accordingly, the Panel has formed the view that the life cycle GHG emissions must have a 'low' risk and meet the acceptability criteria (see **Table 9.9**). These objectives can be achieved by seeking to offset the life cycle GHG emissions to ensure that there is no net increase in life cycle GHG emissions in Australia from any onshore shale gas produced in the NT. The Panel recognises that while this may present a challenging task to governments, it is based on the principles of ESD and reflects the widespread and strongly held concerns expressed to the Panel regarding the impacts of increased GHG emissions. To achieve this outcome, a variety of possible strategies are outlined in the Report. The implementation of these possible strategies is beyond the scope of the Inquiry's Terms of Reference.

Assuming the mitigation of methane emissions as recommended in this Report and assuming that GHG emissions are fully offset so that there is no net increase in the life cycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT, the Panel has concluded that this represents an acceptable outcome and risk to the community.

Recommendation 9.1

That to reduce the risk of upstream methane emissions from any onshore shale gas wells, the Government implement the US EPA New Source Performance Standards of 2012 and 2016.

Recommendation 9.2

That prior to the grant of any further exploration approvals, a code of practice be developed and implemented for the ongoing monitoring, detection and reporting of methane emissions from any onshore shale gasfields and wells.

Recommendation 9.3

That baseline monitoring of methane concentrations be undertaken for at least six months prior to the grant of any further exploration approvals. In areas where hydraulic fracturing has already occurred, the baseline monitoring should be undertaken at least a year prior to the grant of any production approvals.

Recommendation 9.4

That baseline and ongoing monitoring be the responsibility of the regulator and funded by the gas industry.

Recommendation 9.5

That all monitoring results must be made publically available online on a continuous basis in real time.

Recommendation 9.6

That once emission concentration limits are exceeded, as soon as reasonably practicable the regulator must be notified, an investigation must be undertaken by the gas company to identify the source or sources of the emissions, and make-good provisions be carried out by the gas industry.

Recommendation 9.7

That the action framework outlined in Table 9.10 be implemented to lower fugitive methane emissions.

Recommendation 9.8

That the NT and Australian governments seek to ensure that there is no net increase in the life cycle GHG emissions emitted in Australia from any onshore shale gas produced in the NT.

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 well heads. 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 onshore 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 southwest Queensland; by a WA Health HHRA of potential groundwater contamination associated with hydraulic fracturing for gas in shale deposits; and by an 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 also considered the potential for human exposures to occur through contamination of food sources, including animals and plants. A mitigating factor for this potential exposure pathway is degradation or metabolism of the chemicals over time, reducing the toxic impact of some of the likely chemical exposures.

The Panel concluded that 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 the 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. However, the likelihood and consequence of such health risks are difficult to categorise because they are highly dependent on the scope of any proposed onshore shale gas development, as well as the stage of that development (exploration, production or 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 (see Chapter 12).

Recommendation 10.1

That formal site or regional-specific HHRA reports be prepared and approved by the regulator prior to the grant of any production approvals. Such HHRA reports must address the potential human exposures and health risks associated with the exploration for, and the production of, any shale gas development, off-site transport, and the decommissioning of wells, as recommended in NCRA guidance. The HHRA reports must include risk estimate assessments for exposure pathways that are deemed to be incomplete.

Recommendation 10.2

That in consultation with the gas industry, landholders, Land Councils, local government and local communities, the Government mandates an appropriate setback distance from all gas well heads, pipelines and gas processing facilities to a habitable dwelling (including all buildings or premises where people reside or work, schools and associated playgrounds, permanent sporting facilities and hospitals or other community medical facilities) in order to minimise risks identified in HHRA reports, including potential pathways for waterborne and airborne contaminants. Such setback distances should not be less than 2 km and should apply to all exploration and production activities.

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 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, in 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. This rule applies to the granting of petroleum exploration permits.

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 co-exist. 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 purpose of protecting sacred sites. Accordingly, the NT 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 on country can be carried out in order to protect sacred sites.

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 for onshore shale gas 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 the risks that the development of any onshore shale gas industry may have on Aboriginal people and their culture. The Panel acknowledged that sacred sites exist underground and was 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 recommended 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 has also recommended that the Sacred Sites Act be amended to make it clear that it applies to sacred sites that exist underground.

The Panel was concerned that the broader Aboriginal community has not been adequately informed about any onshore shale gas industry and its potential impact on Aboriginal communities. Having said this, the Panel is satisfied that subject to the implementation of recommendations to strengthen the consultation and agreement-making process, the procedures set out in the Land Rights Act and Native Title Act ensure that traditional Aboriginal owners and native title holders 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. 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 accurate, reliable, and trusted information is communicated by a trusted third party 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 developed 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 prior to the grant of any exploration and production approvals.

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 the Sacred Sites Act be amended to protect all sub-surface features of a sacred site.

Recommendation 11.4

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

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 in collaboration with the Government, Land Councils and AAPA, an independent, third-party designs and implements an information program to ensure that reliable, accessible, trusted and accurate information about any onshore shale gas industry is effectively communicated to all Aboriginal people who will be affected by any onshore shale gas industry.

That the program be funded by the gas industry.

Recommendation 11.7

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

Recommendation 11.8

That a comprehensive assessment of the cultural impacts of any onshore shale gas industry must be completed prior to the grant of any production approvals. The cultural assessment must:

- ***be designed in consultation with Land Councils and AAPA;***
- ***engage traditional Aboriginal owners, native title holders and the affected Aboriginal communities, and be conducted in accordance with world-leading practice; and***
- ***be resourced by the gas industry.***

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. Chapter 12 details the key concerns that arose in the submissions and during the community consultations and examines the likely social impacts that may emerge from any shale gas industry in the NT.

A social impact has been described as, "*any change that arises from new developments and infrastructure projects that positively or negatively influence the preferences, wellbeing, behaviour or perception of individuals, groups, social categories and society in general.*" An essential element of any SIA is to ensure that baseline data is collected on impacts identified and derived from the specific concerns of each local community. Ensuring participation of all affected stakeholder groups is necessary in any SIA. The aim of the SIA framework is to ensure that every potentially affected stakeholder, particularly those most vulnerable to social change, has the ability and freedom to participate in, and be appropriately engaged and consulted on, all relevant social impact matters.

To further explore the issue and gain a better understanding of how the potential social impacts might affect communities in the NT, the Panel commissioned Coffey Services Australia Pty Ltd (**Coffey**) to undertake the following work (the **Coffey Reports**):

- the development of a social impact assessment (**SIA**) framework (or methodology) (**CSRM Report**);
- an identification of the key elements that comprise a social licence to operate (**SLO**) (**CSIRO Report**);
- a case study of the Beetaloo Sub-basin (**Beetaloo Sub-basin Case Study**); and
- an application of the SIA framework contained in the CSRM Report to the Beetaloo Sub-basin (**Beetaloo Sub-basin SIA Report**).

It must be observed from the outset that the Coffey reports are not, and were never intended to be, an SIA. Nor was Coffey asked to determine if any potential onshore shale gas industry held an SLO in the NT. Consequently, it did not undertake this task.

While Coffey developed the SIA framework specifically for use in the NT, it also drew upon SIA experience in other jurisdictions, in addition to world-leading practice. In addition to an analysis of the potential social impacts identified during the course of the Panel's consultations, key elements of what an SLO for any onshore shale gas industry in the NT, and particularly in the Beetaloo Sub-basin, might look like have been examined.

Any attempt to understand social impacts and social change in NT communities as a result of any shale gas development must consider the complex and fraught history of various federal and Territory Government interventions and policies designed to bring about social change and economic development in these communities. This includes an awareness of an ongoing legacy of trauma, grief and loss among Aboriginal people – the cumulative impacts of colonisation, dispossession of and removal from traditional lands, discrimination and paternalistic social policies.

An essential element of any SIA is to ensure that baseline data is collected on impacts identified and derived from the specific concerns of each local community. Ensuring participation of all affected stakeholder groups is necessary in any SIA. The aim of the SIA framework is to ensure that every potentially affected stakeholder, particularly those most vulnerable to social change, has the ability and freedom to participate in, and be appropriately engaged and consulted on, all relevant social impact matters.

The SIA framework has four principal steps, which include:

- first, a strategic assessment to understand the scale and scope of the industry, what the baseline is and what the key issues are;
- second, an ongoing regional participatory monitoring and evaluation framework, which must be an open access resource;
- third, project level assessments; and
- fourth, collaborative strategies to enhance positive, and mitigate negative, social impacts.

From a review of the literature, local and international case studies, and throughout the consultations, what has emerged is a need for a strategic approach to identifying and understanding the social impacts and risks for different communities. The literature on 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 and vulnerable groups. A more nuanced approach to engagement and consultation is required, which 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 of the 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 that experienced by the CSG industry in Queensland. Further, there are fears that an influx of FIFO and/or 'drive-in, drive-out' 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.

Conversely, several submissions expressed the view that any onshore shale gas industry would deliver lasting benefits to the NT by creating jobs and business opportunities and by improving infrastructure and services that in many areas are viewed as inadequate. An onshore shale gas industry is seen by some as the NT's best hope for economic development. A number of submissions expressed a belief that any onshore shale gas industry can co-exist successfully with existing industries, such as pastoralism, while contributing positively to NT communities.

The Beetaloo Sub-basin Case Study identified that significant disparity exists across the Beetaloo Sub-basin between the regional service centres and remote Aboriginal communities, affecting access to services, housing, access to a functioning labour market, health and education status. A key issue is how affected communities might realise – or not – opportunities from any onshore shale gas development. Aboriginal communities in the Beetaloo Sub-basin, in common with other remote Aboriginal populations in the NT, have young populations. A consequence of this is a diminished capacity of the adult population to transmit cultural knowledge and information to emerging generations.

With respect to SLO, it was evident from those who attended the community consultations and public hearings that many people remain opposed to hydraulic fracturing in the NT and that, in their view, there is an absence of an SLO for any shale gas industry in the Territory. Much of this opposition appears to stem from a lack of trust towards the gas industry and a lack of faith in the Government's capacity to regulate any such industry. Throughout the consultations and submissions, the Panel heard that misinformation was being disseminated in some communities. Conversely, accurate, credible and trusted information about hydraulic fracturing was often not available, even upon request.

The CSIRO Report demonstrates that at least two conditions are necessary if the gas industry is to gain the community's trust and acceptance, or an SLO. The first is engagement practices that are more participatory, inclusive and empowering, and the second, is the establishment of a strong, independent regulator to oversee various aspects of the industry's governance. Finally, an understanding of the 'NT way' was considered imperative for any onshore shale gas industry to gain an SLO in the NT. A view that was echoed across multiple submissions, especially from pastoralists and Aboriginal communities.

The Panel's central recommendation is that if the Government lifts the moratorium, the SIA framework described in this Chapter must be implemented prior to the grant of any production approvals (see Chapter 16) and wholly separate from any environmental impact statement.

Katherine community forum, March 2017.

Recommendation 12.1

That a strategic SIA, separate from an EIS, must be conducted for any onshore shale gas development prior to any production approvals being granted.

Recommendation 12.2

That the strategic SIA be funded by the gas industry.

Recommendation 12.3

That the strategic SIA must be conducted comprehensively and in such a manner that it will anticipate any expected impacts on infrastructure and services and to mitigate potential negative impacts.

Recommendation 12.4

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

Recommendation 12.5

That ongoing monitoring and measurement of social and cumulative impacts be undertaken, with the results being made publicly available online as soon as they are available.

Recommendation 12.6

That a strategic SIA be conducted as part of any SREBA to obtain essential baseline data.

Recommendation 12.7

That in order to operationalise an SIA framework in the NT, the Government must:

- *give the regulator power to request information from, and to facilitate the collaboration between, individual gas companies, government agencies (including local government), Land Councils, communities and potentially affected landholders;*
- *establish a long-term participatory regional monitoring framework, overseen by the regulator, with secure funding from the gas industry and able to endure multiple election cycles; and*
- *establish periodic and standardised reporting to communities on the social, cultural, economic and environmental performance of the industry through either the regulator or a specialised research institution. This includes information from the monitoring of key indicators, and an industry-wide complaints and escalation process.*

Recommendation 12.8

That as part of any strategic SIA and prior to any significant increase in traffic as a result of any onshore shale gas industry, consultation must be undertaken on road use and related infrastructure requirements that results in road upgrades and work schedules to the appropriate Austroad standards and commensurate with the anticipated vehicle type required for any onshore shale gas industry.

Recommendation 12.9

That gas companies provide the necessary funds to ensure the ongoing maintenance requirements for road infrastructure are met for the life of any onshore shale gas project. These should be based on the individual gas company's percentage of tonnage hauled along the roads.

Recommendation 12.10

That road use agreements between gas companies and local NT road authorities be mandated to include safety considerations and to ensure monitoring for compliance and reporting requirements.

Recommendation 12.11

That gas companies be required to work closely with all levels of government, Land Councils and local communities early in any onshore shale gas development project to quantify the potential impacts on health and educational services and ensure steps to mitigate adverse impacts are implemented.

Recommendation 12.12

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

Recommendation 12.13

That in consultation with all local community stakeholders, Land Councils, local government and the Government, gas companies be required to provide accommodation, whether temporary or permanent, which must be completed prior to the granting of any production approvals.

Recommendation 12.14

That to the extent practicable, gas companies be required to source goods, services and workers from local communities. This must include the development of training programs for Aboriginal and other local workers to develop the necessary skills and expertise to maximise opportunities for local employment in any onshore shale gas industry.

Recommendation 12.15

That gas companies work proactively with local businesses, local government, Government, Land Councils and communities to ensure that local businesses are able and adequately skilled to compete for contracts, and to assist local businesses to be ready to participate in any economic opportunities that may emerge.

Recommendation 12.16

That gas companies must establish a relationship with communities to determine how to best facilitate community cohesion on an individual and collective level. This should be done in consultation with all landholders, Land Councils and local government, to ensure that the needs of all stakeholders are accommodated.

Recommendation 12.17

That a representative community advisory group be established to act as a conduit for ongoing monitoring of community cohesion.

Recommendation 12.18

That gas companies must develop and implement a social impact management plan for communities, detailing how they will optimise the relationship with a community prior to the grant of any production approvals. This plan should be developed in consultation with all landholders, Land Councils and local government to ensure that it meets community needs. The regulator must consent to the plan prior to the grant of any production approvals.

Recommendation 12.19

That gas companies be required to develop a social impact management plan that outlines how they intend to develop, obtain and maintain their SLO within communities. This must be developed *in conjunction with any SIA, and should be implemented prior to the grant of any further production approvals, to ensure that any potential changes can be identified in advance to allow communities time to adapt and prepare for the changes.*

Recommendation 12.20

That as part of the SREBA for the Beetaloo Sub-basin, a strategic SIA be conducted to obtain essential bawseline data prior to the granting of any further production approvals.

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

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 any onshore shale gas development is found to not be commercially viable;
- **Breeze scenario:** where the moratorium is lifted, exploration and appraisal activity occur, 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 were to lift the hydraulic fracturing moratorium and an onshore shale gas industry was established 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). There is also an additional requirement for labour resources over the modelled period equal to an average of 524 FTEs (13,611 job years). 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). There is also an additional requirement for labour resources over the modelled period equal to an average of 252 FTEs (6,559 job years). 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). There is also with an additional requirement for labour resources over the modelled period equal to an average of 82 FTEs (2,145 job years). 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), there would be additional competition for skilled and unskilled labour, there would be increased use of infrastructure (such as roads), and there would be an impact on visual amenity and reputational risk.

It must be acknowledged that any onshore shale gas industry may 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 submissions 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 Chapter 14). The Panel is also of the opinion the Government must 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 (especially for Aboriginal people). 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 considers 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 Australian Government, identifies 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 the Government to support infrastructure development. There may also be opportunities to leverage Australian Government infrastructure funding to assist in funding any new infrastructure that may be required.

Recommendation 13.1

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

That the Government works with local government, stakeholders, Land Councils, and local communities in the design and implementation of all such programs.

Recommendation 13.2

That the Government works with stakeholders and gas companies to ensure that there is early knowledge of the labour and skills required for all phases of any onshore shale gas development in order to maximise local employment.

Recommendation 13.3

That the Government works with gas companies, training providers, local workers, job seekers, Land Councils and local Aboriginal corporations and communities to maximise opportunities for local people to obtain employment during all phases of any onshore shale gas development.

Recommendation 13.4

That the Government ensures that training providers and gas companies collaborate so that skill requirements are clearly understood by training providers, and that trainees acquire appropriate skills.

Recommendation 13.5

That the Government works with gas companies, training providers, Land Councils, local government, and local communities in the setting of local employment targets, including local employment targets for Aboriginal people.

Recommendation 13.6

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

Recommendation 13.7

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

Recommendation 13.8

That the Government works with gas companies, Land Councils, local Aboriginal corporations, Aboriginal communities, and businesses to identify local supply and service opportunities to keep sustainable economic benefits on country.

Recommendation 13.9

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

Recommendation 13.10

That the Government works with gas companies, Land Councils, local governments, local suppliers and businesses to devise and implement local procurement targets.

Recommendation 13.11

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

Recommendation 13.12

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

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 and should 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 NT regulatory framework. The Panel's view is that this concern is justified and that the regulatory regime must be strengthened 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.

Of course, regulatory reform requires resources, both financial and non-financial. To this extent, the Panel has recommended that the Government must implement a full fee recovery system to ensure that it is the shale gas industry, and not the taxpayer, that pays for all necessary regulatory changes and ongoing governance.

Making land available for any onshore gas exploration

The land release process is the process whereby land is 'released', that is, 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 1984 (NT) (**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 co-exist with existing or future uses of land, and whether the land is in fact prospective for onshore shale gas before it 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, areas of high ecological value, areas of cultural significance and Indigenous Protected Areas. The Panel recommended that these areas be declared 'no go zones' or 'reserved blocks' under the Petroleum Act to ensure that they are never affected 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 1992 (NT) (Pastoral Land Act) that require protection.

It is apparent that the present land access regime in the NT has the real capacity not 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 must 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 for pastoralists. The mandatory provisions include 'make good' provisions for any damage that has occurred to water or land, indemnities, a requirement that gas companies pay for all reasonable costs associated with negotiation of the agreement and minimum levels of compensation.

Improved decision-making and greater access to justice

The Panel considered the current assessment and approval processes under the Petroleum Act and subordinate legislation. The Panel examined the statutory processes that lead to decisions about the release of land for any onshore shale gas exploration, the grant of a petroleum permit, the approval of a draft 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 recommended 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 recommended that the Minister publish reasons why he or she has 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 must 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 also recommended that decision-makers be made more accountable by broadening the current review processes to enable those directly and indirectly affected by decisions concerning any onshore shale gas development to challenge decisions in an appropriate court or tribunal.

Mitigating 'exploration creep'

During the course of consultations, many members of the community and some stakeholders expressed a concern about 'exploration creep', that is, the risk that a large number of exploration wells are constructed, drilled and hydraulically fractured on an exploration permit, rather than on a production licence, prior to the completion of a SREBA and the implementation of many of the Panel's recommendations. The Panel agrees that safeguards are needed to mitigate this risk. The cumulative impacts of any onshore shale gas activities that occur during the exploration phase of development must be assessed, taken into account and appropriately mitigated. The Panel has therefore recommended strengthening the Petroleum Environment Regulations to explicitly require the Minister for Resources, when considering whether to approve an EMP for an exploration activity, to consider the cumulative effects of onshore shale gas activities in the region.

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 concluded that the present financial assurance system in the NT is inadequate and opaque. The Panel has proposed that the Government develops 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 the management and rehabilitation of abandoned wells.

Objective-based regulation, minimum standards and codes of practice

The Panel supports 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 the gas 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.

Tougher sanctions for non-compliance

Having regard to the range and quantum of penalties for breaches of laws designed to protect the environment in other jurisdictions, the Panel is of the view that the sanctions for non-compliance of environmental laws in the NT in respect of any onshore shale gas industry must be strengthened, and it has made recommendations to this effect.

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 considered 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 (for example, 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 activity can be reduced to acceptable levels, the activity cannot proceed. Having a separate environmental approval for any onshore shale gas activity will give the community confidence that environmental considerations are given primary weight when decisions are made about the development of any onshore shale gas industry. Option 1 is considered an appropriate regulatory model in the short term.

Option 2 draws from regulatory models seen in leading-practice jurisdictions, such as the Alberta Energy Regulation and the BC Oil and Gas Commission in Canada. It proposes the establishment of a new and separate 'one-stop-shop' independent regulator, the NT Onshore Shale Gas Regulator (**OSGR**), to regulate all aspects of any onshore shale gas industry, including environmental matters, resource management matters, operational matters and compliance and enforcement. The OSGR will not, however, have responsibility for promotional matters or decisions about which land is released. These matters will remain the responsibility of the Minister for Resources and DPIR. The OSGR will be established under new bespoke onshore shale gas legislation (**Onshore Shale Gas Act**), which will be the responsibility of the Minister for Environment. The Panel recommends that Government consider whether Option 2 should be adopted in the future.

For both 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 to minimise the risk that water resources are over-allocated.

Recommendation 14.1

That prior to the granting of any further production approvals, the Government designs and implements a full cost-recovery system for the regulation of any onshore shale gas industry.

Recommendation 14.2

That the Minister must immediately notify the public of any proposed land release for any onshore shale gas exploration.

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

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

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

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

Recommendation 14.3

That Government not approve any application for an exploration permit in relation to areas that are not prospective for onshore shale gas or where co-existence is not possible. Priority must be given to the areas identified in Recommendation 14.4.

Recommendation 14.4

That prior to the grant of any further exploration approvals, the following areas must be declared reserved blocks under s 9 of the Petroleum Act, each with an appropriate buffer zone:

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

Recommendation 14.5

That the Government immediately considers and implements mechanisms to retrospectively apply Recommendation 14.4 to granted exploration permits.

Recommendation 14.6

That a statutory land access agreement be required by legislation.

That prior to undertaking any onshore shale gas activity on a Pastoral Lease (including but not limited to any exploration or production activity), a land access agreement must be negotiated and signed by the Pastoral Lessee and the gas company.

That breach of the land access agreement be a breach of the relevant exploration or production approval giving rise to the onshore shale gas activity being carried out on the land.

Recommendation 14.7

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

Recommendation 14.8

That prior to the grant of any further exploration permits or production approvals, the Government enacts a minimum mandatory compensation scheme payable to Pastoral Lessees for all onshore shale gas production on their Pastoral Lease. Compensation should be calculated by reference to the impact that the development will have on the Pastoral Lease and the Pastoral Lessee, for example, the number of wells drilled, the value of the land (both before and after), and the area of land cleared and rendered unavailable for pastoral activities.

Recommendation 14.9

That the Government considers whether a royalty payment scheme should be implemented to compensate Pastoral Lessees prior to any further production approvals being granted.

Recommendation 14.10

That any person may lodge an objection to the proposed grant of an exploration permit within a prescribed time limit.

That all objections received by the Minister must be published online.

That the Minister must, in determining whether to grant or refuse the application, take into account any objection received.

Recommendation 14.11

That the Petroleum Act be amended to make the principles of ESD a mandatory relevant consideration for any decision made under that Act in relation to any onshore shale gas industry. That the principles of ESD must be taken into account and applied by a decision-maker in respect of all decisions concerning any onshore shale gas industry.

Recommendation 14.12

That the Minister must not grant any further exploration permits unless satisfied that theapplicant (including any related entity) is a fit and proper person, taking into account, among other things, the applicant's environmental history and history of compliance with the Petroleum Act and any other relevant legislation both domestically and overseas.

That failure to disclose a matter upon request relevant to the determination of whether an applicant is a fit and proper person will result in civil and/or criminal sanctions under the Petroleum Act.

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

Recommendation 14.13

That prior to the grant of any further production approvals, the Government develops and implements a financial assurance framework for the onshore shale gas industry that:

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

Recommendation 14.14

That prior to the grant of any further production approvals, the Government imposes a non-refundable levy for the long-term monitoring, management and remediation of abandoned onshore shale gas wells in the NT.

Recommendation 14.15

That prior to the grant of any further exploration approvals, all draft EMPs for hydraulic fracturing must be published in print and online and available for public comment prior to Ministerial approval.

That all comments made on draft EMPs must be published online.

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

Recommendation 14.16

That prior to the grant of any further exploration approvals, all notices and reports of environmental incidents, including reports about reportable incidents under the Petroleum Environment Regulations, must be published immediately upon notification in print and online.

Recommendation 14.17

That prior to the grant of any further production approvals, the Schedule be repealed and replaced with legislation to regulate land clearing, seismic surveys, well construction, drilling, hydraulic fracturing, and well decommissioning and abandonment.

Recommendation 14.18

That prior to the grant of any further exploration approvals, the Government develops and implements enforceable codes of practice with minimum prescriptive standards and requirements in relation to all exploration and production activities, including but not limited to, land clearing, seismic surveys, well construction, drilling, hydraulic fracturing and decommissioning and abandonment.

Recommendation 14.19

That prior to granting any further exploration approvals, cl 3(2)(b) of Sch 1 of the Petroleum Environment Regulations be amended to read as follows:

"3(2)(b) [delete 'as far as practicable'] any cumulative effects of those impacts and risks when considered both together and in conjunction with other events, activities <u>or industries, including any other petroleum activities and extractive industries, that have occurred</u> or that may occur in or near the location of the activity or in or near the region, area <u>or play where the regulated activity is located"</u>.

Recommendation 14.20

That the Minister must be satisfied that an applicant is a fit and proper person to hold a production licence, taking into account, among other things, the applicant's environmental history and history of compliance with the Petroleum Act and any other relevant legislation both domestically and overseas.

That failure to disclose a matter relevant to the determination of whether an applicant is a fit and proper person upon request will result in civil and/or criminal sanctions under the Petroleum Act.

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

Recommendation 14.21

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

Recommendation 14.22

That prior to the granting of any further production approvals, the Government considers developing and implementing regional or area-based assessment for the regulation of any onshore shale gas industry in the NT.

Recommendation 14.23

That prior to the grant of any further exploration approvals, the Petroleum Act and Petroleum Environment Regulations be amended to allow open standing to challenge administrative decisions made under these enactments.

Recommendation 14.24

That prior to the granting of any further production approvals, merits review be available in relation to decisions under the Petroleum Act and Petroleum Environment Regulations including, but not limited to, decisions made in relation to the granting of all EMPs.

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

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

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

Recommendation 14.25

That prior to any further production approvals being granted, where litigation is brought genuinely in the public interest, costs rules be amended to allow NT courts to not make an order for the payment of costs against an unsuccessful public interest litigant.

Recommendation 14.26

That prior to the grant of any further exploration approvals, the Government develops and implements a robust and transparent compliance and monitoring strategy, having regard to the principles set out in the ANAO Administering Regulation: Achieving the right balance guide, and the policy in SA.

Recommendation 14.27

That prior to the grant of any production approvals, the Government enacts whistleblower protections in respect of any onshore shale gas industry.

That prior to any further exploration approvals being granted, a hotline be established permitting anonymous reporting about any onshore shale gas industry non-compliance. That all such reports be immediately investigated.

Recommendation 14.28

That prior to the grant of any further production approvals, the Government considers developing and implementing a tiered regulatory model such as the one in SA, whereby gas companies with a demonstrated record of good governance and compliance require a lower level of monitoring, with a corresponding reduction in regulatory fees.

Recommendation 14.29

That prior the grant of any further production approvals, the Government enacts a broader range of powers to sanction, including but not limited to:

- *remediation and rehabilitation orders;*
- *revocation, suspension or variation orders;*
- *enforceable undertakings;*
- *injunctions (mandatory and prohibitory); and*
- *civil penalties.*

Recommendation 14.30

That prior to the grant of any further production approvals, the Government enacts provisions establishing a chain of responsibility for gas companies and related parties to ensure compliance with environmental obligations.

Recommendation 14.31

That prior to the grant of any further production approvals, the Government allows civil enforcement proceedings to be instituted to enforce potential or actual non-compliance with any legislation governing any onshore shale gas industry.

Recommendation 14.32

That prior to the grant of any further production approvals, the Government enacts provisions that reverse the onus of proof or create rebuttable presumptions for pollution and environmental harm offences for all onshore shale gas activities.

Recommendation 14.33

That prior to the grant of any further production approvals, criminal penalties for environmental harm under the Petroleum Act and Petroleum Environment Regulations be reviewed and increased in line with world-leading practice.

Recommendation 14.34

That prior to the grant of any further exploration approvals, in order to ensure independence and accountability, there must be a clear separation between the agency with responsibility for regulating the environmental impacts and risks associated with any onshore shale gas industry and the agency responsible for promoting that industry.

Recommendation 14.35

That prior to the granting of any further production approvals, the Government considers establishing a one-stop-shop single, separate and independent shale gas regulator to regulate all aspects of any onshore shale gas industry in the NT (with the exception of the grant of exploration permits and the grant of water approvals).

Strategic regional environmental and baseline assessment (Chapter 15)

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

The lack of adequate pre-development assessment and environmental baseline data is routinely cited as one of the biggest 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 examined to date, the Panel has concluded that there is a lack of baseline data required to:

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

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 lifts the moratorium. The Panel strongly recommends that such assessments must be carried out, and the findings included in the environmental assessment process, 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 what is required by any assessment. High-level scopes of work are provided in the Chapter, and recommendations are made about how the elements of a SREBA should be executed. It is not the intention of the Panel to be rigorously prescriptive, with much of the specific detail of the content of 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 the gas industry, and ensures that satisfactory environmental outcomes are achieved 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 SREBA.

Many submissions to the Panel requested that all elements of a SREBA should be completed before any further exploration (including any further hydraulic fracturing) for onshore shale gas is approved in the NT. The Panel has considered these submissions carefully, however, the final position of the Panel is that while there are some elements of a SREBA that must be implemented immediately, there are others that can proceed in parallel with the relatively small activity footprints associated with exploration activity. This is especially true given the protections that will be afforded by the mandatory implementation of improved well integrity construction and management systems, water and air (methane) quality monitoring and public reporting regimes, before approval can be given for any future hydraulic fracturing, including that associated with exploration.

The time taken to complete a SREBA will depend on the climatic, biophysical, ecosystem, social and cultural constraints on establishing a robust baseline and environmental dataset, which will vary depending on where in the NT the SREBA is being conducted. For example, in the Beetaloo Sub-basin, the timeframe for the hydrological and terrestrial and aquatic biodiversity components is likely to be around three to five years based on the variable but reasonably predictable seasonal rainfall in that region.

A SREBA must nevertheless be completed in a timely manner. The conclusions from a SREBA must therefore be available and taken into account prior to the grant of any further production approvals.

The conduct of a SREBA will require substantial resourcing (funds and personnel). Funding for this work should be provided by governments (Territory and federal) and industry.

The acquisition of regional data will not stop with the completion a SREBA, with work needed to progressively transition the key elements of a SREBA to an operational surveillance/performance monitoring program if an onshore shale gas industry develops in the NT.

Recommendation 15.1

That a strategic regional environmental and baseline assessment (SREBA) be undertaken prior to the granting of any further production approvals.

Recommendation 15.2

That the regulator oversees the auditing and the data-collection processes and provides a central repository for all data informing any SREBA.

Recommendation 15.3

That a SREBA:

- ***should be completed within five years from the first grant of exploration approvals; and***
- ***must be completed prior to the grant of any production approvals.***

Implementation (Chapter 16)

The recommendations in this Report are a complete package. That is, they must be implemented in their entirety in order to mitigate the risks associated with any onshore shale gas industry in the NT to an acceptable level. Further, if the Government lifts the moratorium, the recommendations must be implemented in a clear, timely and transparent manner.

The Panel has considered the timing of the implementation of its recommendations. It has distinguished between the recommendations that are designed to address the risks associated with exploratory drilling and hydraulic fracturing for onshore shale gas (exploration activities) and the recommendations that are designed to address the risks associated with larger-scale development involving the drilling and hydraulic fracturing of shale gas wells on production licences for the purpose of commercial production (**production activities**).

The Panel notes that under the current law, an exploration permit is not sufficient on its own to allow a gas company to conduct an exploration activity. The company must also have all necessary operational approvals under the Schedule and an environmental approval under the Petroleum Environment Regulations (**exploration approvals**). Similarly, in order to conduct a production activity, a gas company needs a production licence, as well as operational approvals under the Schedule and an environmental approval under the Petroleum Environment Regulations (**production approvals**). The Panel has therefore tied the timing of its recommendations to the granting of exploration or production approvals.

It is the Panel's view that certain recommendations must be implemented before any further drilling or hydraulic fracturing takes place in the NT. Therefore, prior to granting any further exploration approvals, the Government must implement the key recommendations listed in **Table 16.1**.

Other recommendations are designed to address the risks associated with larger-scale onshore shale gas development. These recommendations do not need to be implemented immediately, but must be implemented prior to the granting of any further production approvals. Unless otherwise indicated in the Report, the recommendations not listed in **Table 16.1** must be implemented prior to the granting of any further production approvals.

The Panel recognises that implementing the recommendations will require substantial and sustained resources, including legal, engineering, and scientific resources, in addition to monetary resources. It is the Panel's view that the gas industry must be primarily responsible for funding the costs associated with regulating any onshore shale gas development. The Government must also investigate funding from the Australian Government.

Implementing the recommendations contained in this Report represents a significant reform agenda for the Government. If the Government lifts the moratorium, an implementation framework must be developed immediately to identify when, how and by whom the recommendations are to be implemented. Accordingly, there should be a centralised, well-resourced, skilled and experienced implementation unit established in the Department of the Chief Minister to coordinate the implementation of the reforms. It is essential that people and/or organisations with specialist skills are recruited to assist the implementation unit.

Finally, it is the Panel's view that the Government should establish a Community and Onshore Gas Industry and Business Reference Group (Reference Group), comprising representatives from the community, environmental groups, local business, the gas industry, Land Councils and local government. The Reference Group is to provide a medium through which the Government can constructively consult with, provide information to, and obtain feedback from, key stakeholders on the implementation framework. This will ensure the framework aligns with community and industry expectations. The Reference Group will also enable key stakeholders to communicate any concerns about the implementation framework directly to the Government.

Table 16.1: Key recommendations that must be implemented prior to any further exploration approvals being granted.

Recommendation	Description
5.1	Development and implementation of a code of practice for the decommissioning of onshore shale gas wells.
5.3	Development and implementation of a code of practice to ensure the integrity of onshore shale gas wells.
5.4	Well integrity management systems and plans mandated for all onshore shale gas wells to be hydraulically fractured.
5.5 and **7.12**	Development of a wastewater management framework, including an auditable system for tracking movements of wastewater.
7.1	Gas companies must have a water extraction licence under the Water Act to extract water for hydraulic fracturing.
7.6	Prohibition on the use of surface water for hydraulic fracturing.
7.8	Prohibition on the installation of groundwater extraction bores to supply water for hydraulic fracturing within 1 km of an existing or proposed domestic or stock water supply bore.
7.9	Prohibition on the reinjection of wastewater into deep aquifers and conventional reservoirs.
7.10	Mandatory disclosure of all chemicals (including metals, salts and NORMs) in hydraulic fracturing fluids, flowback and produced water.
7.11 and **7.13**	Petroleum wells be constructed to at least Category 9 or equivalent. Prohibition on petroleum wells being drilled within 1 km of an existing or proposed groundwater supply bore. Groundwater must be monitored using multilevel monitoring bores.
7.17	Prohibition on the discharge of treated or untreated wastewater into waterways.
8.2	Completion of a baseline weed assessment in all areas of the exploration permit accessed by a gas company.
8.3	Gas companies must have a dedicated weeds officer.
8.4	Gas companies must have an approved weed management plan in place.
9.2	Development and implementation of a code of practice for the ongoing monitoring of methane from shale gas wells.
9.3	Monitoring of methane concentrations for a six month period.
9.5 and **9.6**	Requirement for ongoing methane monitoring and reporting.
10.2	Prohibition on all exploration and production activity within 2 km of any habitable dwelling.
11.1	Existence of an Authority Certificate.
14.4	'No go zones' declared.
14.15	The community must be given an opportunity to comment upon all draft environmental management plans submitted to the Government for approval.
14.16	Requirement that all reports and notices on environmental incidents are publicly disclosed.
14.18	Enforceable codes of practice be mandated for drilling and hydraulic fracturing activites.
14.19	Cumulative impacts of petroleum and other activities in the region must be considered by a decision-maker.
14.23	Open standing for judicial review of decisions made under the Petroleum Act and Petroleum Environment Regulations.
14.26	A monitoring and compliance strategy must be developed and implemented.
14.27	A whistleblower hotline must be established and any reports to it must be immediately investigated.
14.34	There must be a clear separation between the agencies responsible for environmental and promotional approvals.

Recommendation 16.1

That the Government implements all of the recommendations in this Report.

Recommendation 16.2

That an implementation framework including details of who, when and how each of the recommendations will be implemented, be completed within three months from any lifting of the moratorium.

Recommendation 16.3

That a centralised, well-resourced, experienced and skilled Implementation Unit be established immediately within the Department of Chief Minister to coordinate the development of the implementation framework.

Recommendation 16.4

That a Community and Onshore Shale Gas Industry and Business Reference Group be established to provide feedback to Government on the development of an implementation framework, and its subsequent execution, if the Government lifts the moratorium.

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 latest and best-available scientific 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 can be appropriately managed by, among other things:

- releasing land that is environmentally, socially and culturally appropriate for use for shale gas development;
- 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;
- implementing area (regional) based approval processes;
- the completion of a SREBA before production to gather essential baseline data prior to any onshore shale gas industry being developed;
- insisting on a standalone comprehensive SIA for each onshore shale gas project;
- ensuring that traditional Aboriginal owners and Aboriginal communities are properly and comprehensively consulted about all aspects (positive and negative) of any onshore shale gas project on or affecting their country;
- ensuring that the regulator is truly independent and that laws protecting the environment are properly enforced with sufficiently stringent sanctions for non-compliance;
- ensuring greater access to justice;
- reforming the current regulatory framework governing onshore shale gas development in the NT to strengthen transparency and accountability of all decision-making;
- introducing full fee recovery to fund the necessary regulatory reforms and to ensure that strong oversight is maintained; and
- ensuring that all of the recommendations contained in this Report are implemented in full.

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 all of the recommendations made in this Report are adopted and implemented in their entirety, not only should the risks associated with an onshore shale gas industry be minimised to an acceptable level, in some instances, they can be avoided altogether.

In short, the Panel is of the opinion that with the full enactment and implementation of the robust and rigorously enforced safeguards recommended in this Report, the waters shall continue to flow "*clear and cold out of the hills*"[6] and the "*dawn chorus of*" Magpie Geese, Brolgas, Budgerigars, Black Kites, Blue-winged Kookaburras "*and scores of other bird voices*"[7] shall continue to reverberate across the NT landscape.

Brolgas, Northern Territory. Source: Alamy Stock Photo.

6 Carson 1962, p 1.
7 Carson 1962, p 2, with apologies

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